Federal Government of Somalia
Ministry of Energy and Water Resources

Optimized Cost Electricity Generation and Transmission Development Plan for Somalia

June 2025

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GLOSSARY

a, yr.	Annum, year
AC	Alternating Current
AfDB	African Development Bank
ARM	Adequacy Reference Margin
BAU	Business as Usual
B/C	Benefit Cost ratio
BESS	Battery Energy Storage Systems
BtB	Back-to-Back
CAGR	Compound Annual Growth Rate
CAPEX	Capital Expenditure
CB	Circuit Breaker
CBA	Cost Benefit Analysis
CCGT	Combined Cycle Gas Turbines
CF	Capacity Factor
CO2	Carbon dioxide
DC	Direct Current
DS	Diesel
EAPP	Eastern African Power Pool
EE	Energy Efficiency
ENS	Energy Not Supplied
EENS	Expected Energy Not Supplied
EHV	Extra High Voltage
ENS	Energy Not Supplied
ENTSO-E	European Network of Transmission System Operators for Electricity
EPC	Engineering Procurement and Construction
ESIA	Environmental and Social Impact Assessment
ESP	Electricity Supply Providers
EU	European Union
EV	Electric Vehicles
FOR	Forced Outage Rate
FSRU	Floating regasification units
GDP	Gross Domestic Product
GEP	Generation Expansion Plan
GHG	Green House Gas
GT	Gas turbine
HFO	Heavy Fuel Oil
HSDG	High-Speed Diesel Generators
HV	High Voltage
HVDC	High Voltage Direct Current
IEA	International Energy Agency
IEC	International Electrothecnical Comitee
IEP	independent electricity providers
IMF	International Monetary Found
IRR	Internal Rate of Return
LCOE	Levelized Cost of Electricity
LF	Load Factor
LILO	Line-In-Line-Out
LNG	Liquified Natural Gas
LTLF	Long-term load forecasting
MSDG	Medium-Speed Diesel Generators

MTLF	Medium-term load forecasting
NCC	National Control Center
NPC	Net Present Cost
NPV	Net Present Value
NTC	Net Transfer Capacity
O&M	Operational and Maintenance
OCGT	Open Cycle Gas Turbine
OECD	Organisation for Economic Co-operation and Development
OHL	Overhead Line
OHTL	Overhead Transmission Line
OPEX	Operational Expenditure
PSS	Power System Stabilizer
PSS/E	Power System Simulator for Engineering
PST	Phase Shifting Transformer
pu	per unit
PV	Photovoltaic
PV (analysis)	Power-Voltage analysis
PV (econ)	Present Value
RAC	Reliable Available Capacity
RAP	Resettlement Action Plan
RC	Remaining Capacity
RES	Renewable Energy Sources
S/S	Substation
SC	Short Circuit
SEW	Socio-Economic Welfare
SMP	System Marginal Price
SPS	Special Protection Scheme
SRMC	Short Run Marginal Cost
STATCOM	Static Compensator
STLF	Short-term load forecasts
SVC	Static Var Compensator
TEP	Transmission Expansion Plan
TPP	Thermal Power Plant
TSO	Transmission System Operator
TYNDP	Ten Year National Development Plan
UFLS	Under Frequency Load Shedding
UVLS	Under Voltage Load Shedding
VAT	Value Added Tax
VoLL	Value of Lost Load
VSC	Voltage Source Converter
WACC	Weighted Average Cost of Capital
WB	World Bank
WF	Wind Farm
WTE	Waste to Energy

Measurement units

BTU	British Thermal Units
Btu/kWh	British thermal units per kilowatt-hour
GWh	Gigawatt hour
kV	kilovolt
kWh	kilowatt hour
MVA	Mega volt ampere
Mvar	Megavar (million volt-amperes reactive)

MW	Megawatt (million watts)
MWh	Megawatt hour

GENERALITIES AND SCOPE OF WORK

This documents the **Somalia's 20-year Optimized Cost Generation and Transmission Development Plan**.

The plan covers the following main topics and activities.

Load Demand Forecast review, inclusive of:

- evaluation and investigation of the historical data of the electricity generation and demand in Somalia, as well as the analysis of previous existing and available forecasts,
- description of the methodologies for the revision of the load demand forecast according to the literature and best practices and the methodology adopted for Somalia,
- description of the results of the load demand forecast assessment.
- list of the ArcGIS maps of the Load Demand Forecast results

Generation Expansion Plan, that involves the development of a Least-Cost Generation Expansion Plan using a large-scale mixed-integer programming model. The model optimizes the investment and operational costs of the power system over the planning horizon, taking into account technical, economic, and environmental constraints. Key Features of the Generation Expansion Plan approach are listed below:

- Planning Horizon: 20 years (2030–2050)
- Multi-Areas Simulation: The model simulates inter-regional energy exchanges based on available transfer capacities, in coordination with the transmission expansion plan and demand forecasts.
- Optimization Tool: The analysis is performed using OptGen, which minimizes the present value of total system costs—including capital investment, fuel, operation and maintenance—over the study period.
- Reliability Criteria: The model incorporates generation adequacy standards

Transmission Expansion and Optimization of the future power system (generation and transmission), inclusive of:

- description and development of the Transmission Master Plan, illustrating the expected evolution of the transmission grid at the target years objective of the investigations, with reference to the short/mid-term period (2030-2040) and long-term period (2040-2050)
- network analysis of the generation/transmission power system, namely load flow in normal (N) conditions, in case of contingency (N-1) and short circuit analysis
- quantification of the investment and operational expenditures for the new generation and transmission developments
- cost-benefit analysis of the expected generation and transmission master plans.

1 EXECUTIVE SUMMARY

1.1 Power Sector in Somalia

The main characteristics of the electric system in Somalia can be summed up in the following points:

- Presence of isolated networks anchored to specific urban centres with dedicated Electricity Supply Providers (ESPs).
- The ESPs are private enterprises, each of which is vertically integrated as an autonomous parallel electricity provider. Each ESP owns and operates their complete generation-distribution-customer and revenue chain using a radial distribution island network. Generation is primarily high-speed diesel fuel-powered generators (>1,000 rpm).
- Multiple ESPs operates in cities and large urban centres.
- In small cities, there is only one ESP or a group of small independent electricity providers (IEP)[1].
- A consequence of these multiple vertically integrated ESPs is that there are significant electrical losses, reportedly up to 50%, within the urban island radial distribution networks.
- There are no regulations or standards for electrical wiring done within the customer's premises.
- No ESPs share distribution networks. This fact, and the presence of parallel island networks, means that large customers options are utilising two different EPSs or creating their own mini grids.
- The electricity costs are high (because of what is described above).

1.2 Load Demand and Energy Forecast

To quantify the expected electricity consumption of the future Somali power system, both bottom-up and top-down approaches have been developed. The Bottom-Up approach has been mainly performed to develop a load forecast in terms of energy in three different scenarios, for the target years objective of the analysis, in the different areas of the Country, as summarized in Table 1-1.

Table 1-1 – Somalia load demand forecast results – Bottom – Up approach

Sub-grid	Scenario	Item	2030	2035	2040	2045	2050
Banadir Sub-grid	Low	Supplied Demand (GWh)	1,597	3,026	5,438	8,545	11,347
		Peak (MW)	280	531	955	1,501	1,993
	Base	Supplied Demand (GWh)	1,630	3,182	5,884	9,483	12,826
		Peak (MW)	286	559	1,033	1,665	2,252
	High	Supplied Demand (GWh)	1,664	3,347	6,366	10,520	15,125
		Peak (MW)	292	588	1,118	1,848	2,656
Central Sub-grid	Low	Supplied Demand (GWh)	85	303	577	1,288	2,070
		Peak (MW)	15	53	101	226	364
	Base	Supplied Demand (GWh)	85	319	625	1,441	2,365
		Peak (MW)	15	56	110	253	415
	High	Supplied Demand (GWh)	85	336	677	1,612	2,699
		Peak (MW)	15	59	119	283	474
Northeastern Sub-grid	Low	Supplied Demand (GWh)	259	682	1,523	2,873	3,961
		Peak (MW)	45	120	268	505	696
	Base	Supplied Demand (GWh)	264	722	1,663	3,224	4,524
		Peak (MW)	46	127	292	566	795

[1] These small IEPs have been created by expanding from their own generation, and they are the model by which most, if not all current ESPs, began

Sub-grid	Scenario	Item	2030	2035	2040	2045	2050
	High	Supplied Demand (GWh)	270	764	1,815	3,617	5,164
		Peak (MW)	47	134	319	635	907
Northwestern Sub-grid	Low	Supplied Demand (GWh)	1,153	1,923	3,299	5,139	6,749
		Peak (MW)	202	338	579	903	1,185
	Base	Supplied Demand (GWh)	1,177	2,015	3,578	5,763	7,775
		Peak (MW)	207	354	628	1,012	1,365
	High	Supplied Demand (GWh)	1,198	2,109	3,877	6,453	8,942
		Peak (MW)	210	370	681	1,133	1,570
Southern Sub-grid	Low	Supplied Demand (GWh)	155	335	685	1439	2,074
		Peak (MW)	27	59	120	253	364
	Base	Supplied Demand (GWh)	159	353	744	1,615	2,402
		Peak (MW)	28	62	131	284	422
	High	Supplied Demand (GWh)	162	372	808	1,811	2,779
		Peak (MW)	28	65	142	318	488
Southwestern Sub-grid	Low	Supplied Demand (GWh)	78	208	476	921	1,306
		Peak (MW)	14	37	84	162	229
	Base	Supplied Demand (GWh)	80	221	520	1,033	1,492
		Peak (MW)	14	39	91	182	262
	High	Supplied Demand (GWh)	82	234	567	1,159	1,703
		Peak (MW)	14	41	100	204	299

Table 1-2 reports the total electricity consumptions expected for the whole Somali power system.

Table 1-2 – Somalia load demand forecast results – Bottom – Up approach – Total results

Country	Scenario	Item	2030	2035	2040	2045	2050
Somalia	Low	Supplied Demand (GWh)	3,327	6,478	11,999	20,205	27,507
		Peak (MW)	584	1,138	2,107	3,548	4,831
	Base	Supplied Demand (GWh)	3,395	6,813	13,014	22,559	31,383
		Peak (MW)	596	1,196	2,286	3,962	5,512
	High	Supplied Demand (GWh)	3,460	7,163	14,110	25,173	36,412
		Peak (MW)	608	1,258	2,478	4,421	6,395

A Top-Down approach has been performed too. As shown by Figure 1-1, the two approaches are aligned between them, therefore the electricity consumptions reported in the previous tables, in terms of peak and energy, represent the values that will be used in the subsequent analyses, i.e., the generation expansion and transmission expansion plans.

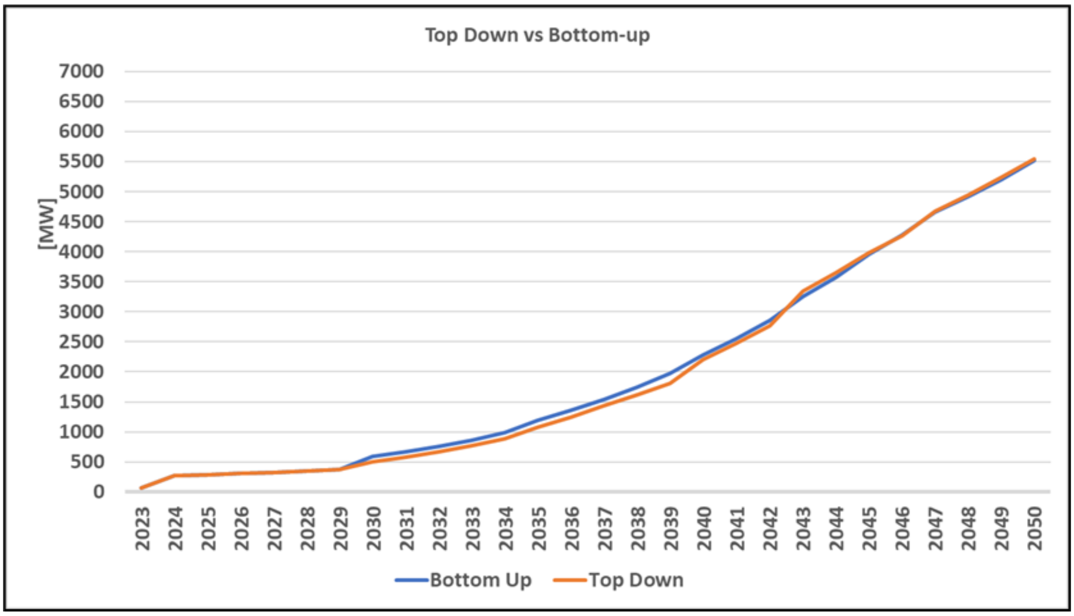


Figure 1-1: Somalia load demand forecast results – Bottom – Up vs Top-Down Approach

It's worth mentioning that load demand forecast values obtained are higher respect to the results obtained in the previous "*Consultancy Services for Feasibility Study for the Ethiopia - Somalia Electricity Transmission Line Interconnections*" for the different assumptions of the demand in 2025 related to the available input data directly collected from ESPs.

1.3 Optimized generation and transmission development plans

Based on the results of the load forecast calculation, the objective of this analysis is to clearly identify physical generation and transmission line equipment and the sequence of their investments required for the generation development plan and the transmission master plan and the associated investment plan aiming at showing the yearly expenditure for each project/cluster of projects. The yearly expenditure is evaluated starting from the commissioning dates of the various projects and estimating the time for their implementation and the distribution of expenses over the time of implementation.

1.3.1 Generation Expansion Plan

The Generation Expansion Plan (GEP) for Somalia covers the period 2030 to 2050, as part of a broader initiative to develop an optimized, cost-effective, and sustainable electricity generation and transmission system. The GEP is designed to ensure that Somalia's growing electricity demand is met reliably, affordably, and in alignment with long-term decarbonization goals.

The GEP is developed using OPTGEN, a state-of-the-art mixed-integer optimization model that minimizes the Net Present Cost (NPC) of the power system. The model incorporates technical, economic, and environmental constraints and simulates inter-regional energy exchanges, reserve requirements, and investment decisions across a 20-year horizon.

The planning process requires the following data:

- Load forecasts (base, low, and high demand scenarios)
- Fuel availability and price projections
- Candidate generation technologies (thermal, renewable, nuclear)
- Transmission network development
- Policy and environmental constraints (e.g., CO_2 pricing)

Somalia is in a favorable starting position. Unlike many countries that must retrofit or decarbonize legacy infrastructure, Somalia has the rare advantage of starting from a blank slate. This presents a strategic opportunity to design and implement a modern, efficient, and low-emission power system from scratch—guided by global best practices and aligned with long-term sustainability goals.

Somalia has significant solar and wind resources, which—if properly explored—can support a high share of renewable energy in the generation mix. The reference scenario projects a renewable penetration of nearly 60% by 2050, including hydro.

Natural gas, whether imported as LNG or sourced domestically, plays a strategic role in providing dispatchable, lower-emission thermal capacity. In scenarios where domestic gas becomes available, system costs decrease and reliance on regasification infrastructure is avoided. One particularly promising strategy is the deployment of dual-fuel Combined Cycle Gas Turbines (CCGTs). These plants can initially operate on natural gas or diesel but be designed to transition to hydrogen as it becomes available. This approach ensures both short-term reliability and long-term compatibility with a decarbonized energy future. Moreover, by integrating hydrogen-readiness and carbon capture compatibility into new thermal infrastructure, Somalia can avoid the costly retrofits that many developed countries are now facing. This proactive planning reduces long-term costs and aligns with global decarbonization trends.

The interconnection with Ethiopia is critical. Its absence would lead to significantly higher system costs and lower renewable integration. Cross-border trade enhances flexibility, reduces system costs and supports regional energy security.

Battery Energy Storage Systems (BESS) are essential for integrating variable renewables and reducing curtailment. Without storage, system costs increase, and renewable penetration drops. Additional flexibility measures—such as demand response and grid-forming inverters—will be needed as RES penetration grows.

The table below reports the outcomes of the optimal generation expansion plan in terms of new installed capacity.

Table 1-3 – Outcomes of the optimal generation expansion plan in terms of new installed capacity

MW	HSDG	MSDG	Diesel OCGT	LNG OCGT	LNG CCGT	Hydro	WTE	BESS	PV	WND
2030	5	20	0	0	0	4.6	0	5	160	0
2031	18	0	0	100	0	0	0	15	38	40
2032	0	10	0	100	0	0	0	10	73	14
2033	2	0	0	0	300	0	0	20	33	18
2034	2	0	0	100	0	0	0	5	28	7
2035	0	0	0	200	0	150	10	10	38	8
2036	0	10	0	0	600	0	0	15	21	67
2037	-6	20	30	0	300	0	0	5	61	38
2038	-7	0	0	0	0	0	0	45	11	69
2039	-8	20	30	0	300	0	0	20	45	33
2040	0	0	60	0	300	0	10	0	12	56
2041	0	20	0	100	0	0	0	20	45	195
2042	0	0	0	0	300	0	0	40	103	342
2043	-2	0	15	0	300	0	0	5	12	239
2044	0	0	0	0	0	0	0	60	30	469
2045	-4	0	0	0	300	0	0	35	520	430
2046	0	0	30	0	0	0	0	125	610	405
2047	0	0	30	0	0	0	0	280	870	380
2048	0	0	0	0	0	0	0	0	650	360
2049	0	0	0	0	0	0	0	450	450	173
2050	0	0	0	0	0	0	0	105	300	287

The expected evolution of the total installed capacity, as well as the subdivision for each technology, is schematically shown in Figure 1-2.
As it is possible to see, the diesel generation is expected to disappear with the development of utility scale power plants, except for the isolated grids that still remain in some areas of the country; on the other hands, the renewable generation play an important role and is expected to be developed in a significant way starting from the mid-terms period, i.e., in coordination with the development of the transmission grid in the areas which are favourable for its development.

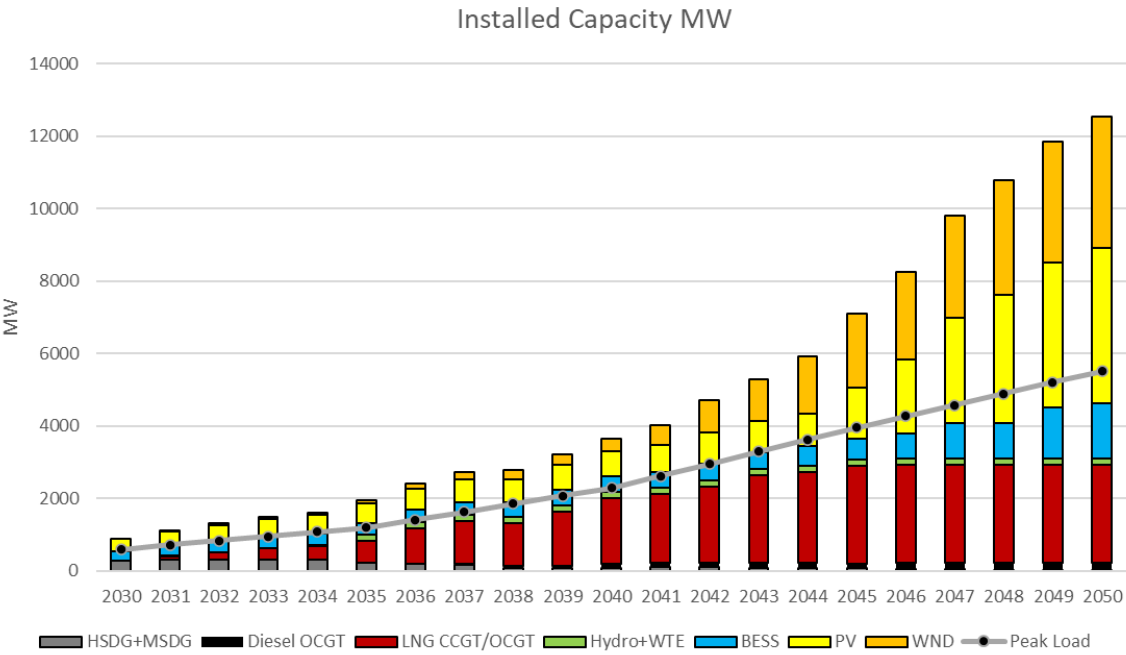


Figure 1-2: Yearly installed capacity

Figure 1-3 shows the most attractive locations for the implementation of thermal power plants. As it is possible to see, the coastal areas, in particular close to the main ports of the country, the main thermal power plants are expected to be developed, mainly for two reasons:

- The fuel availability, with the objective to avoid the contraction of dedicated pipelines to transport this fuel internally and produce electricity far away from the coasts,
- The water availability for cooling.

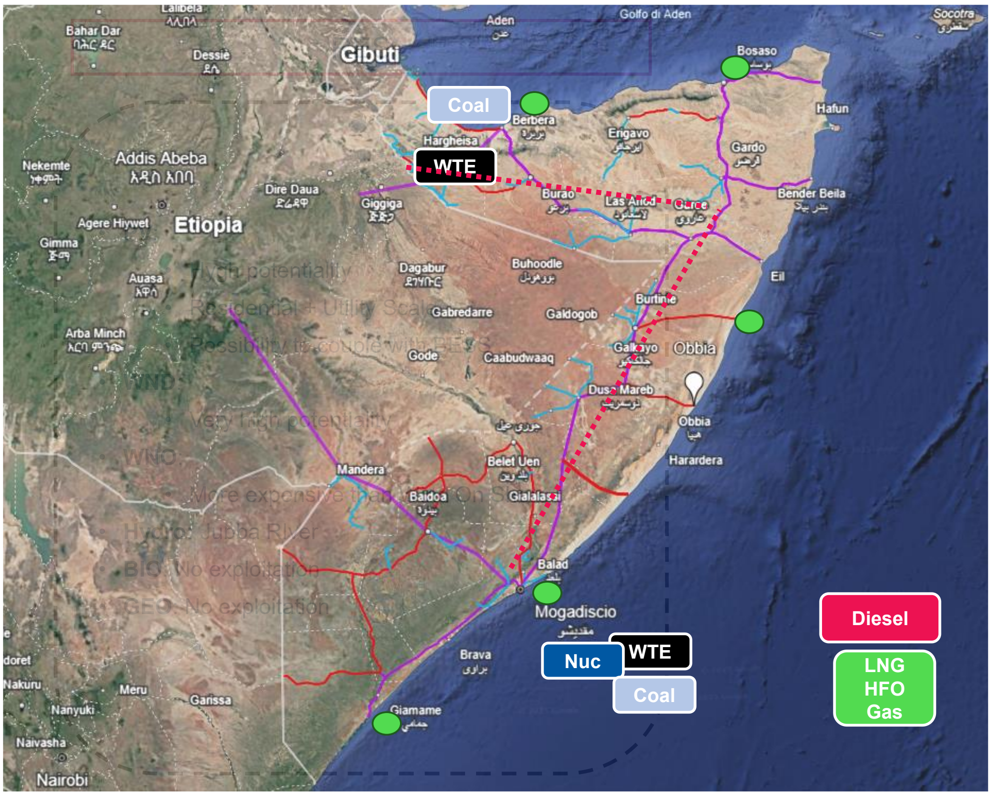


Figure 1-3: Most attractive locations for thermal power plants

Similarly, Figure 1-4 shows the most attractive locations for the implementation of renewable power plants. As it is possible to see, the renewables are mainly concentrated in the north-centre of the country, which represent the areas with the highest potential for PV and wind generation.

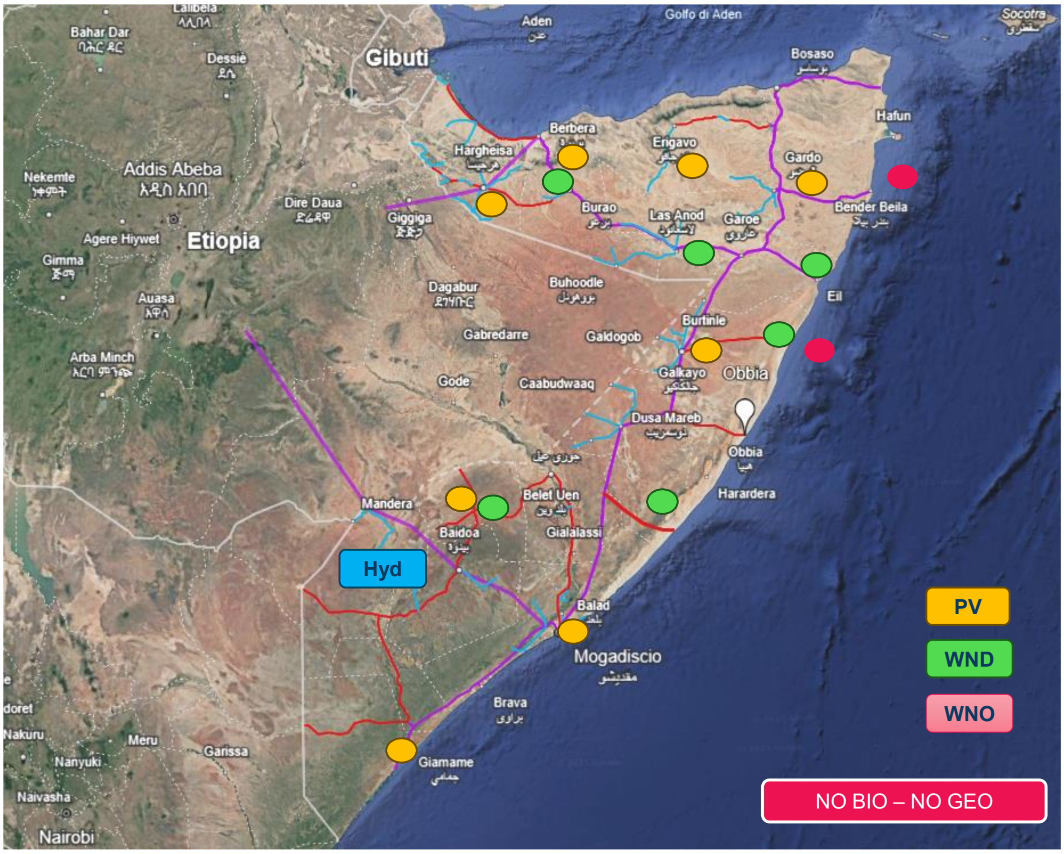


Figure 1-4: Most attractive locations for renewable power plants

Finally, some recommendations are reported in the following points:

1. Accelerate Renewable Energy Deployment: Somalia should prioritize the large-scale deployment of renewable energy technologies—particularly solar PV and wind—which consistently emerge as the most cost-effective and environmentally sustainable options across all scenarios.
2. Invest in Grid Flexibility and Energy Storage: as renewable penetration increases, system flexibility becomes essential. Battery Energy Storage Systems (BESS), demand response, and flexible generation are critical to ensure grid stability and minimize curtailment.
3. Explore Gas Supply Options: Natural gas—whether imported as LNG or sourced domestically—offers a cleaner and more flexible alternative to diesel and coal for dispatchable generation. As a further recommendation, prioritizing floating regasification units (FSRUs) over fixed terminals to reduce stranded asset risk.
4. Prioritize the Ethiopia-Somalia interconnection and explore additional cross-border links to enhance system reliability and economic efficiency.
5. Continuous Monitoring and Plan Updates: Treat the GEP as a living document. Regularly update assumptions and strategies based on evolving demand, technology trends, and geopolitical developments.

1.3.2 Transmission Expansion Plan

The purposes of the transmission expansion plan are:

- Allow the electrification of Somalia and increase the access to electricity,
- Allow the development of new load centers and new types of loads, such as the industrial loads,
- Allow the development of the new generation facilities, both conventional and renewables.

The criteria adopted for the Somalia Transmission Expansion Plan are the following:

- The internal network development starts from the main cities of the country, i.e., Mogadishu and Hargeisa. These two cities are also the locations where the interconnections with Ethiopia are expected to be developed: considering that the appropriate operation of the interconnections with Ethiopia must be coordinated with the development of the internal grid in Somalia, it is of outmost importance to begin the development of the internal transmission grid in Somalia in these areas, to be coordinated with the Ethiopia-Somalia interconnection projects.
- In about 15 years, the objective is to develop an internal network able to substantially reach the majority of load centres in Somalia.
- The capitals of all regions in Somalia will be reached with the 500kV voltage level.
- The internal transmission grid foresees the development of a backbone at 500 kV, then other transmission lines are derived at lower voltage levels, such as:
    - 230 kV level for the connections between cities,
    - 132 kV level for developing the sub-transmission grid close to cities and for connecting minor load centers for short distances.

As a result, the transmission master plan includes the development of:

- 2800 km of transmission lines at 500kV level (excluding the interconnections with Ethiopia), aimed to:
    - connect all capitals of the country,
    - create the north-south EHV backbone aimed to collect conventional and renewable generation and transmit it to the main load centres of the country
    - allow the power exchange with neighbouring countries, especially with Ethiopia, but also with Djibouti and Kenya in the future.
- 3200 km of transmission lines at 230kV level, aimed to:
    - Connect cities between them,
    - Supply the load centres located at a certain distance from the main EHV backbone,
    - Collect part of the renewable generation.
- 2760 km of transmission lines at 132kV level, aimed to electrify the country, reaching towns and villages also in remote areas.

In addition to that, the development of 112 substations at different voltage levels is foreseen.

The investments in transmission lines above mentioned do not include:

- The interconnections with Ethiopia, making part of a dedicated project,
- The subtransmission and distribution infrastructures that are not part of a Transmission Development Plan.

Figure 1-5 shows the indicative structure of the Somalia transmission grid that will be considered in the long-term period (2050).

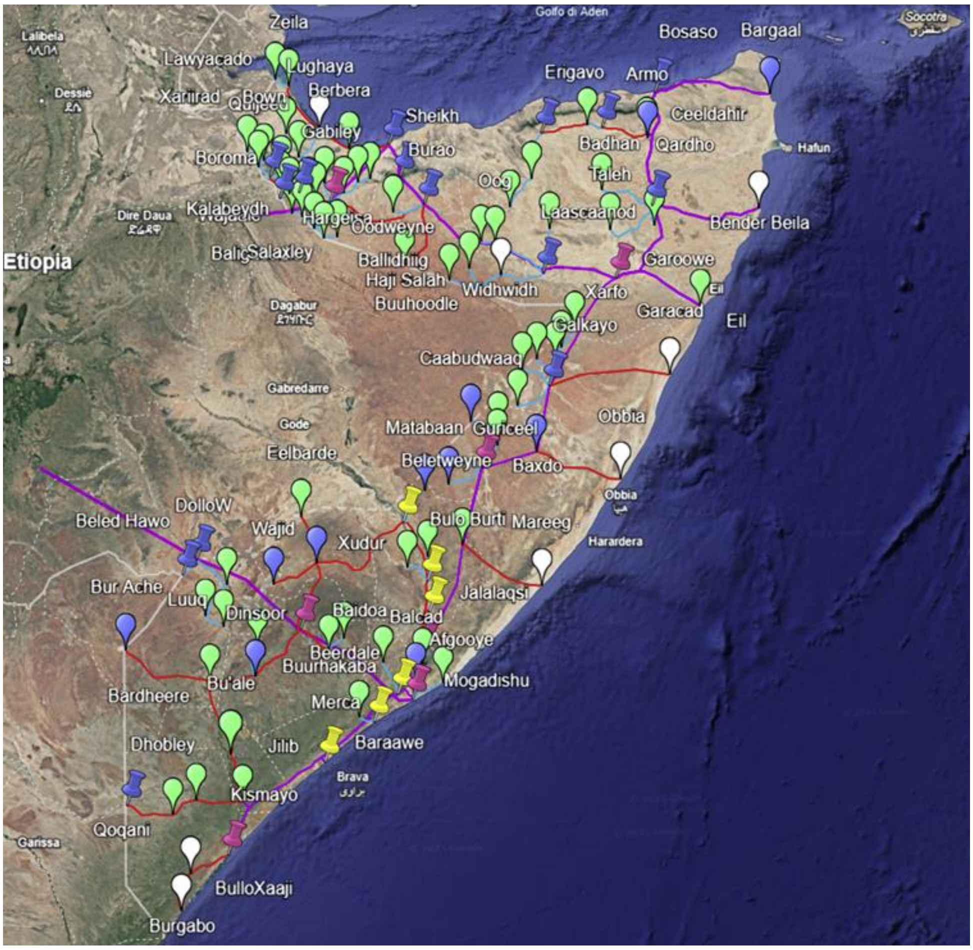


Figure 1-5 – Proposed target structure of Somalia main transmission grid

Of course, the development of the transmission grid is expected to be performed in steps:

- In the short/mid-term period, the transmission grid will be developed mainly in the north and in the south, in order to manage the power exchanges with Ethiopia (thanks to the new interconnections with Ethiopia) and electrify the towns in those areas
- In the long-term period (2040 – 2050), the grid is expected to be developed also in the centre of the country, up to complete the north-south 500kV backbone in the long-term period (2050).

The structure of the transmission grid here proposed has the objective to electrify the country and promote the development of the renewable generation, as well as to allow the development of other interconnections towards Djibouti and Kenya in the long-term period.

1.3.3 Expected investment plan

Based on the generation and transmission developments above mentioned, the expected operational and capital expenditures for generation facilities and transmission infrastructures are reported in the following paragraphs.

1.3.3.1 Generation Expansion Plan

The associated investment and operational costs are reported in Table 1-4. In total, for the generation facilities, the (not actualized) costs are expected to reach USD 22.9 billion in the period 2030-2050, of which USD 11.6 billion as investment costs and USD 11.3 billion as operational costs.

Table 1-4: CAPEX and OPEX disbursement – reference scenario (values not actualized)

Year	CAPEX [M$]	OPEX [M$]	TOTAL [M$]
2030	578	575	1153
2031	218	585	803
2032	189	627	816
2033	148	454	602
2034	131	350	481
2035	455	219	675
2036	679	242	921
2037	327	275	602
2038	102	304	406
2039	411	342	753
2040	486	394	880
2041	433	443	876
2042	710	439	1149
2043	615	479	1095
2044	671	695	1367
2045	1052	773	1825
2046	936	854	1790
2047	1071	915	1987
2048	790	998	1788
2049	591	1131	1722
2050	561	1349	1910
TOTAL	**11157**	**12443**	**23600**

1.3.3.2 Transmission Expansion Plan

Table 1-5 summarizes the expected expenditures related to the investment costs for the transmission infrastructures.
Note: the cost estimation here reported does not include the investment costs of the interconnections with Ethiopia, as well as the costs of other interconnections with neighbouring countries. In total, for the transmission grid, the investment costs are expected to reach USD 4.4 billion up to the year 2050.

Table 1-5 – Cost estimation for transmission facilities – CAPEX subdivision

	Capital Expenditure [M$]					
	2030	2035	2040	2045	2050	**TOTAL**
Transmission Line	808.50	309.56	531.05	780.57	623.30	**3052.98**
Substations	238.81	329.04	265.01	373.54	177.06	**1383.46**
TOTAL	**1047.31**	**638.60**	**796.06**	**1154.11**	**800.36**	

Figure 1-6 reports the expected behaviour of the cumulative investment expenditures over the planning period, from 2030 to 2050, including both transmission lines and S/S. as it is possible to see, the expected investment disbursements for the transmission facilities are expected to be quite distributed over the planning period.

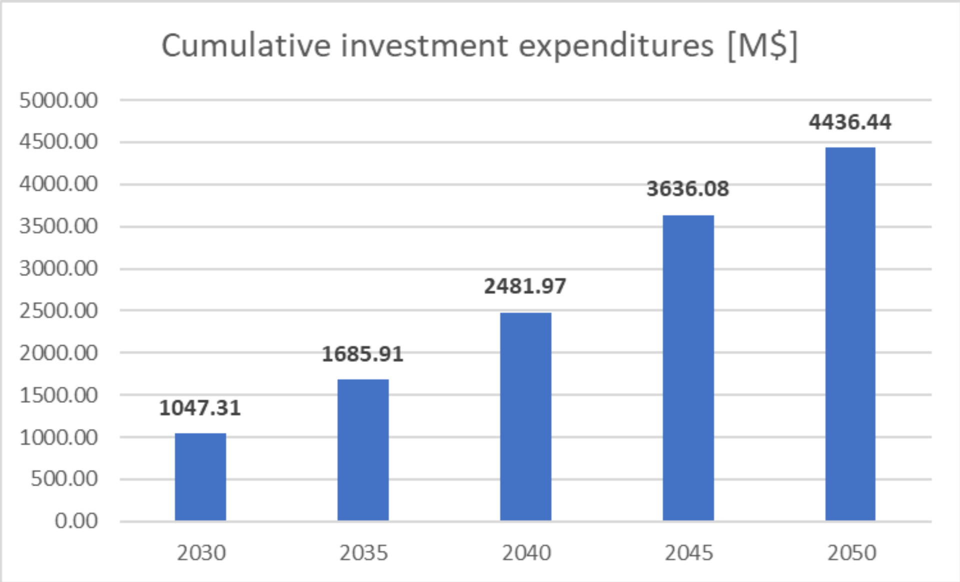


Figure 1-6 – Cumulative investment expenditures [M$]

With reference to the operational expenditures, two types of operational costs shall be considered:

- The fixed operational and maintenance (O&M) costs, calculated as a percentage of the investment costs,
- The cost of losses, whose economic value shall reflect the generation production cost of the power system.

Focusing the attention on the fixed operational and maintenance (O&M) costs (the costs of losses are already included in the operational costs of the generation expansion plan), Table 1-6 reports the cumulative quantification of these costs assuming a total value of 1%/year of the total CAPEX.

Table 1-6 – O&M Cost estimation for transmission facilities – cumulative quantification

	Cumulative O&M Expenditure [M$/year]				
	2030	2035	2040	2045	2050
Transmission Line	8.09	11.18	16.49	24.30	30.53
Substations	2.39	5.68	8.33	12.06	13.83
TOTAL	**10.47**	**16.86**	**24.82**	**36.36**	**44.36**

1.3.4 Cost-benefit analysis

The cost-benefit is based on a comparative approach between two scenarios:

1. Reference Scenario: This scenario includes all planned investments in generation and transmission infrastructures, as defined by the optimal expansion strategy. It accounts for the full spectrum of capital expenditures (CAPEX) and operational expenditures (OPEX) associated with new generation technologies (including renewables and flexible thermal units), as well as the costs of developing and reinforcing the transmission network.
2. Business-as-Usual (BAU) Scenario: In this counterfactual scenario, no coordinated expansion plan is implemented. Instead, the expected load growth is assumed to be met exclusively through the deployment of Medium-Speed Diesel Generators (MSDGs). These units are

characterized by relatively high fuel costs and emission factors. The BAU scenario includes only the CAPEX and OPEX of MSDGs, with no additional investment in transmission infrastructure.

The cost-benefit analysis has been performed adopting two approaches:

First approach: by comparing the total system costs and emissions between these two scenarios, the analysis aims to quantify the economic and environmental benefits of pursuing a structured and forward-looking expansion strategy. These benefits include:

- Reduced fuel consumption and operating costs
- Lower greenhouse gas emissions
- Improved system reliability and resilience
- Enhanced integration of renewable energy sources

Second approach: it quantifies the economic benefits considering the following assumptions:

- Without the investments in generation and transmission facilities, the electricity consumption remains the ones quantified in the BAU scenario of the load forecast analysis, supplied by diesel and a limited PV capacity,
- With the investments in generation and transmission facilities, the electricity consumption is the one considered in the previous Reference Scenario, supplied by the generation mix identified in the generation expansion plan,
- Without considering the monetization of the CO2 emissions.

Modelling assumption used in this cost-benefit analysis are the following (valid for both approaches):

- Constant price approach, economic figures are expressed in US dollars real terms.
- Base Year 2025.
- Commissioning Year of the first projects 2030.
- Project Economic Life 25 years, with a residual value of the project of an additional 25 years.
- CAPEX instalment schedule planned across years uniformly spread in the four years before the implementation of the projects operated in a certain target year.
- Forecasted costs and benefits for each investment are represented annually. The benefits are accounted for from the first year after commissioning.
- No Taxation assumption. The impact of taxation is not considered in the project economic assessments, so the values are to be represented as pre-tax values.
- The Shadow Cost of Carbon has been taken as per ENTSO-E guidelines.
- Discount Rate: the economic discount rate of 7.8% in real terms has been used for the base case of the economic analysis, considering the accelerated economic growth of Somalia.

Both approaches provide very attractive results for the investments in generation and transmission facilities in Somalia, since all economic indices are extremely positive.

Table 1-7 illustrates the economic indicators of the first approach:

Table 1-7: Results of the cost-benefit analysis - first approach

NPV [M$]	36,760
Benefit/Cost	3.52
IRR	64%

As it is possible to see, the economic figures obtained by this first approach determine significant benefits, for Somalia, due to the investments in generation and transmission infrastructures.

The results of the second approach for the quantifications of the economic viability of the Somalia investments in generation and transmission facilities are the following:

Table 1-8: Results of the cost-benefit analysis - second approach

NPV [M$]	17,319
Benefit/Cost	2.779
IRR	37.1%

As it is possible to see, also the economic figures obtained by this second approach determine significant benefits, for Somalia, due to the investments in generation and transmission infrastructures.

1.4 Conclusion and recommendations

1.4.1 Conclusions

Based on the results of the study, the following conclusions are drawn.

- The distances to be covered in Somalia are important, therefore the main transmission grid shall be developed with an adequate voltage level (500 kV)
- Somalia has a great potential for the development of renewable generation (PV, wind onshore and wind offshore), but the transmission grid shall be adequately developed to transport the generation from the generation areas to load centers
- The conventional power plants are expected to be developed mainly along the sea, especially in the main ports of the country. This is due to the need to: i) assure enough water for cooling, ii) minimize the investment costs avoid the need to build pipelines to transport fuel from the coast to internal areas
- The development of the interconnections with other countries, such as Ethiopia (in the mid-term period) and Djibouti and Kenya (in the long-term) opens the possibility to import energy at low cost (hydro energy from Ethiopia) in the short/mid-term period end export renewable energy in the long-term period

1.4.2 Recommendations

Recommendations are made for the following categories:

- The identification and implementation of the priority projects
- The planning of the power system as a whole, considering the national strategies to be implemented
- The development and the operation of the power system

Identification and implementation of the priority projects

- Identify the projects for the transmission grid and generation with the highest priority for their implementation (e.g., based on criteria such as the electrification rate, economic growth, etc.). in this study, the priority projects have been identified as the ones in the short-term period, i.e., the transmission lines and S/S developed in the northern and southern areas. These projects are listed here below for sake of clarity

Table 1-9 – transmission lines expected in the short-term period – priority projects

Operating year	Vnom [kV]	Name	Length [km]	Type
2030	500	Berbera-Burao	125	Single circuit
2030	500	Burao-Laascaanod	250	Single circuit
2030	500	Laascaanod-Garoowe	130	Single circuit
2030	500	Garoowe-Qardho	185	Single circuit
2030	500	Qardho-Bosaso	220	Single circuit
2030	500	Mogadishu-Afgooye	40	Single circuit
2030	500	Afgooye-Baraawe	180	Single circuit
2030	500	Baraawe-Kismayo	250	Single circuit
2030	500	Mogadishu-Jowhar	95	Single circuit
2030	230	Hargeisa-Burao	175	Single circuit

Substations expected in the short-term period – priority projects:

- Afgooye 500/230/132 kV
- Baraawe 500/230 kV
- Kismayo 500/230 kV
- Burao 500/230/132 kV
- Laascaanod 500/230/132 kV
- Garoowe 500/230 kV
- Qardho 500/230/132 kV
- Bosaso 500/230 kV
- Jowhar 500/230/132 kV

- Perform dedicated technical and economic feasibility studies for these projects, with the objective to obtain funds for their realization and implementation (for example, from the WB, AfDB, etc.)
- Perform dedicated environmental and social impact assessment (ESIA study) and the Resettlement Action Plan (RAP) study for the priority projects in accordance with the guidelines of the candidate financiers
- Submit conceptual design, technical specifications and tender documents with the aim to launch tenders for the realization of the priority projects

Planning of the power system as a whole, considering the national strategies to be implemented.

- Periodically update the load forecast analysis, the generation and the transmission expansion plans based on new hypotheses of energy strategies, energy efficiency, renewable integration, fossil fuel exploration, electricity import/export, development of international interconnections, economic growth, electrification rate, etc.
- Complete the transmission and generation development plans with dedicated dynamic analysis to identify the power system stability margin and the possible countermeasures to be adopted, in terms of Special Protection Scheme (SPS), Power System Stabilizer (PSS), implementation of batteries (BESS) for fast primary reserve and frequency control, identification of the presence of inter-area oscillations, etc.
- Assure coordination with regional bodies such as EAPP for the development of the power systems, in terms of standards to be adopted, development of interconnections with other countries, security margins to be assured, etc.

- Create and adequately Capacity Building Program dedicated to the planning of the electrical system in Somalia, based on approach adopted on international levels and in agreement with the EAPP guidelines and procedures to be considered and implemented during the planning of the power system.

Studies dedicated to the development and the operation of the power system

- Develop a National Grid Code in Somalia for the operation of the power system and the future interconnections with other countries, starting from the regional guidelines already defined by EAPP
- Perform dedicated studies for the identification of the most appropriate Under Frequency Load Shedding (UFLS) schemes, Under Voltage Load Shedding (UVLS) thresholds, etc.
- Create and adequately Capacity Building Program dedicated to the operation of the electrical system in Somalia, based on approach adopted on international levels and in agreement with regional bodies such as the EAPP guidelines and procedures to be considered and implemented during the operation phase.
- Develop a National Control Center (NCC) for the control, monitoring and operation of the national power system and the interconnections with neighboring countries
- Before operating the interconnections with other countries, definition of an Interconnection Operation Agreements between Somalia and the other countries for the operation of the interconnections is necessary

2 STATUS OF THE POWER SECTOR IN SOMALIA

The energy currently consumed in the Country is mainly of two categories: the first is the energy used for the electricity production, the second is the energy used for heat generation.

The **main source of electricity production** is diesel-fuelled High Speed Generator Sets (HSGSs).

In addition, there are a limited number of solar photovoltaic generation (PV) added to existing HSGSs based system of some of the various electricity Service Providers' (ESPs) generation and distribution networks: this has resulted in limited synchronized hybrid diesel-solar PV electricity generation systems. Furthermore, the renewable energy sector lacks specific policies and regulations.

Other forms of PV (small home solar, etc) are used for home lighting both in cities and in rural settings, while the use of wind turbine is limited.

The main source of energy for heating is biomass and kerosene, while the use of compressed gas for cooking and some lighting (lamps) is growing rapidly.

Limited access to energy is a second aspect of the Somali energy system. According to the National Transformation Plan (NTP2025), the estimates (2025) indicate that **access to energy in the Country** is around 31% in rural areas and 77% in urban areas, 49 % for the Country as a whole. Studies show that urban areas like Mogadishu have about 77% access to some sort of energy, mostly used for lightning (car batteries and kerosene lamps).

Tariffs are between the highest in the world (0.61 US$ kW/hour on average across the Country); considering an average income of less than 600 USD, the price of energy is then a significant obstacle for the economic development of the Country.

Beyond the described generation infrastructure, as said**, there is no conventional national transmission network**. Instead of a national integrated grid, there are some limited, inefficient distribution lines within major cities that bring power directly from generation sites to customers: the electrical energy is delivered to customers through a set of isolated distribution grids where a great number of generators are connected.

Each **ESP has his own city grid for transmission and distribution**, meaning that there are multiple grids in each city (and the related presence of many electric poles installed in main roads, resulting in safety hazards and inefficiencies).

Another problem is that **regulation of the energy sector**, particularly of the electricity subsectors (generation, transmission and distribution) is limited or not in place at all in Somalia (of course legal frameworks, institutions and varied roles and responsibilities are stipulated in the Electricity Act which allocates relevant mandates in accordance with the Constitution and applicable laws).

The responsibility to oversee operations in the electricity sector at a federal level is in charge of the Ministry of Energy and Water Resources, who has introduced a system where players in the electricity market must register with the Ministry to obtain proper certification.

Each Federal Member State has a ministry or agency responsible for regulating and managing all energy related matters, but the legislative and regulatory powers of the federal member states are confined within the borders of each state, while the Federal Government of Somalia is responsible intra-state issues and international matters.

The identification of the Mini grids locations is strictly dependent (in terms of cost) on existing and planned electricity infrastructure. Figure 2-1 shows the population settlement within 5 and 10 km from the existing mini grids while Table 2-1 shows the percentage of population living in proximity of existing mini grids and medium voltage lines.

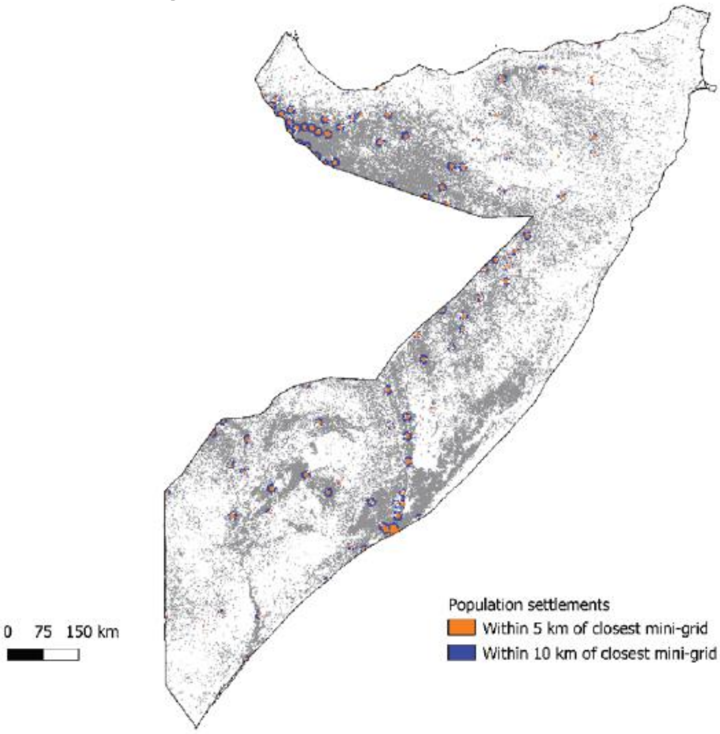


Figure 2-1 -Settlements within 5 and 10 km of existing mini grids

Table 2-1 – Population living in proximity of existing mini-grids and medium-voltage lines

Parameter	Population within 5 km	Population within 10 km
Existing mini grids	44%	50%
Existing MV locations	35%	38%

A list of the ESPs in major centres are reported in Table 2-2, for the medium size centres in Table 2-3 and for the small cities in Table 2-4. The table also shows the level of losses.
About losses, all ESPs for which the information is available, declare that the losses are significant, for both technical and commercial causes, as reported in the tables.

Table 2-2 Current ESPs in major urban centres in Somalia

Urban Center	Population	ESP	Generation	Synchro	Distribution	Losses
Mogadishu	3,000,000	BECO	HSDG, SPV	NO	Radial 11 kV	16.0%
		Blue Sky	HSDG	NO	Radial 11 kV	25.0%
		Mogadishu Power Supply	HSDG	NO	Radial LV	32.0%
Boosaaso	627,999	ENEE	HSDG	NO	Radial 16 kV, 15 kV	35.0%
		Golis	HSDG	NO	Radial LV	30.0%
		Sometel	HSDG	NO	Radial LV	30.0%
Baidoa	264,000	BECO	HSDG	NO	Radial LV	70.0%
Marka	200,000	Marka Electric	HSDG	NO	Radial LV	0.0%

Urban Center	Population	ESP	Generation	Synchro	Distribution	Losses
Garoowe	131,577	NESCOM	HSDG, Wind, SPV, Batt	YES	Radial 11 kV	25.0%
Qardho	89,176	ENEE	HSDG	NO	Radial 15 kV	35.0%
Afgooye	80,635	Hira Electric	HSDG	NO	Radial LV	0.0%
Baletweyne	80,000	DAYAH Electric Company & Altowba electric Company	HSDG, SPV	NO	Radial 11 kV	2.3%
Balad	180,253	BECO	HSDG	NO	Radial LV	19.9%
Hargeisa	1,500,000	Sompower	HSDG, SPV	NO		x
		Telesom	HSDG, SPV	NO	Radial 11 kV	25.0%
		NEC		NO	Radial 11 kV	25.0%
		Maansoor Hotel		NO		x
		Hargeisa Electric Company		NO	Radial 11 kV	30.0%
		Gafane		NO		x
Burao	700,000	BECO	HSDG, SPV	YES		45.0%
	400,000	BEDER			Radial 33 kV, 11 kV	x
Erigavo	250,000		HSDG, SPV	NO		
Borama	150,000	Telesom	HSDG	NO	Radial 11 kV	40.0%
	400,000	ALOOG	HSDG, SPV	NO	Radial 11 kV	40.0%
Badan	180,000	Badhan EC	HSDG, SPV	YES	Radial 11 kV	x
Laascanood	130,000	LESCO	HSDG, SPV, Batt	YES	Radial 11 kV	28.0%
		GURMAD	HSDG, SPV, Batt	YES	Radial 11 kV	25.0%
Berbera	100,000	TAYO	HSDG	NO		x

There are 2 sets of population data provided for Burao
There are 2 sets of population data provided for Borama

Table 2-3 Current ESPs in medium size centres in Somalia

Urban Center	Population	ESP	Generation	Synchro	Distribution	Losses
Abuduwak	40,000	Elays Electric Company	HSDG	NO	Radial LV	19.5%
		DAYAH	HSDG	NO	Radial LV	7.3%
Adado	25,000	Adado Electric Supply	HSDG	NO	Radial LV	14.5%
Balanbal	25,000	Balanbal EC	HSDG	NO	Radial LV	20.0%
Dhuusmareb	30,000	Hilaac EC	HSDG	NO	Radial LV	20.0%
Gurieel	38,500	KAAH	HSDG	NO	Radial LV	20.2%
		Being Googe Power Supply	HSDG	NO	Radial LV	15.0%
Buule Butre	45,000	Fanoole Company	HSDG	NO	Radial LV	25.0%
Hawadley	41,000	Llyas Electric	HSDG	NO	Radial LV	7.3%

Urban Center	Population	ESP	Generation	Synchro	Distribution	Losses
Balad Xawo	45,000	Somali Power and Lightning Company	HSDG	NO	Radial 11 kV	40.9%
Doolow	25,000	Somali Power and Lightning Company	HSDG	NO	Radial LV	42.9%
Baraawe	33,000	BECO	HSDG	NO	Radial LV	20.0%
Hudur	27,000	Afar Indhud EC	HSDG	NO	Radial LV	18.7%
Gabiley	30,000	SOMPOWER	HSDG, SPV	NO	Radial 11 kV	19.0%
Wajaale	20,000	TELESOM	HSDG	NO	Radial 11 kV	40.0%
		SOMPOWER	HSDG	NO	Radial 11 kV	40.0%
Shiekh	20,000	BEDER	HSDG, SPV, Batt	NO	Radial 11 kV	30.0%
Buhodle		TELESOM	HSDG, SPV, Batt	NO	Radial LV	x

Table 2-4 Current ESPs or stand-alone generators in small town in Somalia–

Urban Center	Population	ESP	Generation	Synchro	Distribution	Losses
Jowhar	8,000	Daatax Muxidn	HSDG	NO	Radial LV	x
		Power Supply GPS	HSDG	NO	Radial LV	x
Qalimow	3,800	Galimoow	HSDG	NO	Radial LV	x
Luuq	17,000	Juba EC	HSDG	NO	Radial LV	x
Carmo	7,500	Liolis Power	HSDG	NO	Radial LV	40.0%
Ceeldahir	5,000		HSDG	NO	Radial LV	x
Berdaale	12,000	Faraj EC	HSDG	NO	Radial LV	15.5%
Dilla	2,880	Mohammed Ali EC	HSDG	NO	Radial LV	40.0%
Daca-Budhug	3,000	Liban Group	HSDG, SPV, Batt	NO	Radial LV	x

The table below shows the installed capacity and the distribution information coming from the ESP.

Table 2-5 - Installed capacity and distribution information

Sub grid name		Eastern	Central	Southern	Banaadir	Northeastern	Southwestern	TOTAL
Generation	PV (kW)	-	1,000	-	8,004	2,804	-	11,808
	Wind (kW)	-	-	-	-	750	-	750
	Diesel (kW)		8,100	15,553	26,230	17,463	16,240	95,186
Distribution	HV (km)	-	-	-	-	-	-	-
	MV (km)	-	35	48	232	65	50	430
	LV (km)	-	233	440	770	503	273	2,225

Data about the locations of educational facilities were collected from the federal Ministry of Education, Culture and Higher Education and other entities. In total, 2084 primary and 898 secondary schools were identified. Out of these, only 15% of the primary and 85 of the secondary schools have their geographical locations in the form of coordinates reported while for the other they were retrieved using nomination and information regarding the states, regions and district of these schools.

Figure 1-3 shows the education facilities used for the electrification analysis. In the figure unclassified schools refers to the schools collected by the Wolds Bank and UNICEF.

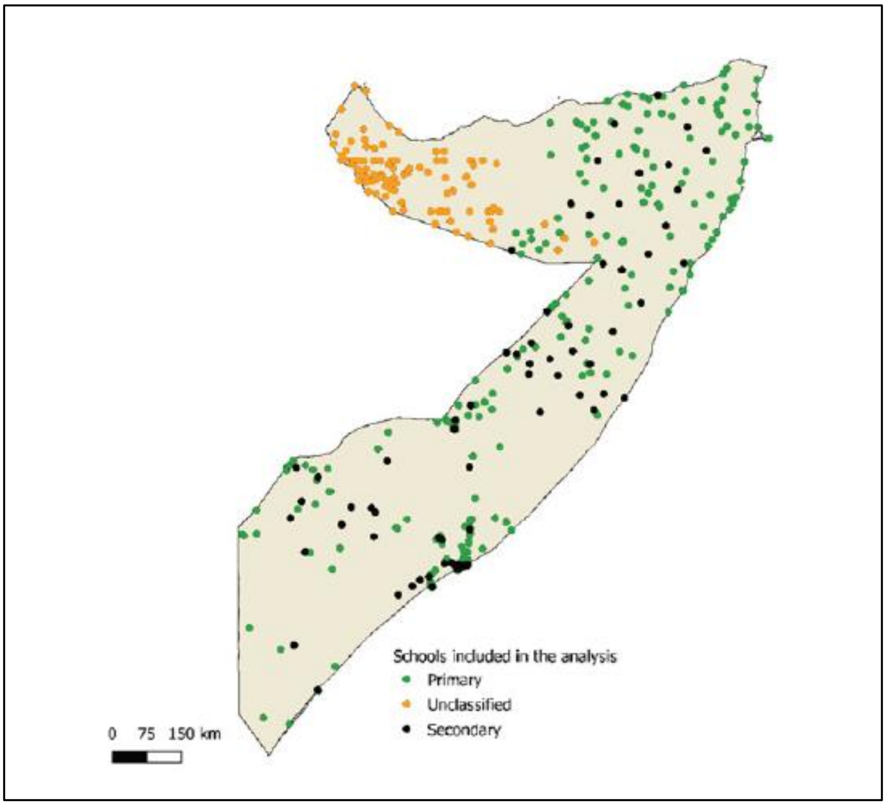


Figure 2-2 Positions of schools included in the analysis

Data about the electricity demand for health facilities were obtained from the Ministry Health and from related database. The health facilities are classified as health centres, hospitals, hearth centres a facilities and health facilities with possible tuberculosis treatment (TB) facilities.

The health facility categories and associate electricity demand are resumed in Table 2-6.

Table 2-6 - The health facility categories and associate electricity demand

Type	Categorization	Electricity demand (kWh/day)
Health posts	Health post (Category I)	4
Health centre	Health centre (Category II)	40
Referral health centre		
TB facilities		
Hospital (small)	Hospital (Category III) in settlements with less than 80,000 people	1200
Hospital (Large)	Hospital (Category III) in major urban settlements with more than 80,000 people	1920

Data about the electricity consumed by the agricultural irrigation were obtained through a very complex and detailed analysis by the Ministry of Agriculture.

Table 2-7 sums up the Yearly electricity demand (MWh/year) for the different categories of consumers considered.

Table 2-7 Yearly electricity demand (MWh/year) for schools, health, and agriculture –

Region	Schools	Health	Agriculture irrigation
Awdal	45	1,132	365
Bakool	14	1,002	1,450
Banaadir	1,318	3,767	150
Bari	145	1,738	0
Bay	87	2,248	11,890
Galguduud	76	3,326	1,370
Gedo	88	2,446	1,710
Hiiraan	150	1,022	4,310
Jubbada Dhexe	0	0	530
Jubbada Hoose	85	1,607	1,410
Mudug	104	3,023	1,210
Nugaal	55	1,441	0
Saaxil	9	1,758	0
Sanaag	46	2,559	0
Shabeellaha Dhexe	51	1,564	15,410
Shabeellaha Hoose	186	2,311	5,380
Sool	82	804	740
Toghdeer	49	1,318	1,400
Woqooyl Galbeed	50	3,739	0
TOTAL	**2,640**	**37,005**	**47,325**

3 LOAD DEMAND FORECAST REVIEW

3.1 Generalities and scope of work

This section includes the results of the Load Demand Forecast review and is organized as described as follows.

- Section 3.2: evaluates and investigates the historical data of the electricity generation and demand in Somalia, as well as the analysis of previous existing and available forecasts,
- Section 3.3: describes the methodologies for the revision of the load demand forecast according to the literature and best practices and the methodology adopted for Somalia,
- Section 3.4: describes the results of the load demand forecast assessment.
- Section 3.5: reports the ArcGIS maps of the Load Demand Forecast results

3.2 Historical data analysis

3.2.1 General overview

As known, in Somalia there is not a national electric transmission grid, and the electrical energy is delivered to customers through a set of isolated distribution grids where a great number of generators is connected.

Historical data about the demand of the Country have been described and reported in the assessment of current situation of the power sector in Somalia and assessment of Somalia energy resources; hereafter a brief summary of these data is reported, with a particular focus to the data useful for the Load Demand Forecast.

The main sources of data described hereafter are:

- The Power Master Plan, Somalia, October 2018 [2]
- The Somali Electricity Access Project [5]
- Data collected with ESPs through on-field activity performed
- Least cost geospatial mapping

3.2.2 The Power Master Plan

The previous Power Master report contains a lot of information. For the Load Demand forecast the main useful data are resumed hereafter.

An estimate of the population in the cities and states was made based on different databases. The results are reported in Table 3-1.

Table 3-1 - Estimated population in 2016– Somalia

Region	Urban	Rural	Nomads	IDPs	TOTAL
Northwestern Sub-Grid	2,156,372	447,315	1,376,731	97,729	4,078,147
Banadir Sub-grid	1,489,051	-	-	429,285	1,918,336
(Galmudug) Central Sub-grid	656,848	153,261	464,708	221,625	1,496,442
(Hirshabelle) Central Sub-grid	227,526	447,391	410,364	119,874	1,205,155
Southern Sub-grid	393,199	566,927	465,414	156,152	1,581,692
Southwestern Sub-grid	430,957	1,535,692	584,778	193,888	2,745,316
Northeastern Sub- grid	709,935	112,312	402,750	68,010	1,292,909
Eastern Sub-grid (Indian Ocean Sub-grid)	NIL	NIL	NIL	NIL	NIL
TOTAL	**6,063,889**	**3,262,800**	**3,704,745**	**1,286,563**	**14,317,996**

An estimate of household sizes: based on some assumptions about the household sizes (Urban households: 6.7 people, Rural households: 6.1 people, Nomads and Internally Displaced Persons: 7.1 people), the estimated number of households was obtained. The numbers are reported in Table 3-2.

Table 3-2 - Estimated number of households 2016 – Somalia –

State	Urban	Rural	Nomads	IDPs	TOTAL
Northwestern Sub-Grid	321,847	73,330	193,906	13,765	**602,847**
Banadir Sub-grid	222,246	-	-	60,463	**282,709**
(Galmudug) Central Sub-grid	98,037	25,125	65,452	31,215	**219,828**
(Hirshabelle) Central Sub-grid	33,959	73,343	57,798	16,884	**181,983**
Southern Sub-grid	58,686	92,939	65,551	21,993	**239,170**
Southwestern Sub-grid	64,322	251,753	82,363	27,308	**425,746**
Northeastern Sub- grid	105,961	18,396	56,725	9,579	**190,660**
Eastern Sub-grid (Indian Ocean Sub-grid)	NIL	NIL	NIL	NIL	NIL
TOTAL	**905,058**	**534,885**	**521,795**	**181,206**	**2,142,944**

An estimate of the customer and the electrification rate growth. Based on the data reported in the previous tables, it is then possible to obtain an estimation of the number of household customers from each state divided between urban, rural and Internally Displaces Persons.

The above population and household estimates were then projected to increase over the forecast period at 2.9% per year until 2027, then at 2.7% thereafter.

Assumptions have been made about the customer addition.

At the end, using all the factors indicated, the obtained customer growth and the electrification rate assumptions are reported in Table 3-3 (For the base scenario, the other two scenarios have been developed but the data are not reported hereafter).

Table 3-3 - Customer and electrification rate growth - Base Scenario – Somalia

State	Growth in Customers 2017 – 2037 (%)			Electrification Rate in 2037 (%)		
	Urban	Rural	IDPs	Urban	Rural	IDPs
Banadir Sub-grid	8.38	-	7.02	86	-	71
(Galmudug) Central Sub-grid	7.02	9.73	9.73	74	64	74
(Hirshabelle) Central Sub-grid	6.32	9.72	9.73	85	7	8
Southern Sub-grid	4.95	9.73	9.1	85	87	88
Northwestern Sub-Grid	3.52	5.64	9.72	86	84	74
Southwestern Sub-grid	6.32	9.73	9.72	80	28	33
Eastern Sub-grid (Indian Ocean Sub-grid)	NIL	NIL	NIL	NIL	NIL	NIL

The assessment of the projected total energy demand and peak load over the forecast period. The energy demand was calculated with a typical bottom-up approach in terms of number of customers, estimated household size, rate of increase of number of customers, customer category (Residential, Commercial, Industrial and Other), etc.

The calculation of the peak demand is performed using the forecast of energy sales by state and applying a load factor.

An estimate of the technical losses. The assumed trend in average energy system losses is illustrated in Figure 3-1.

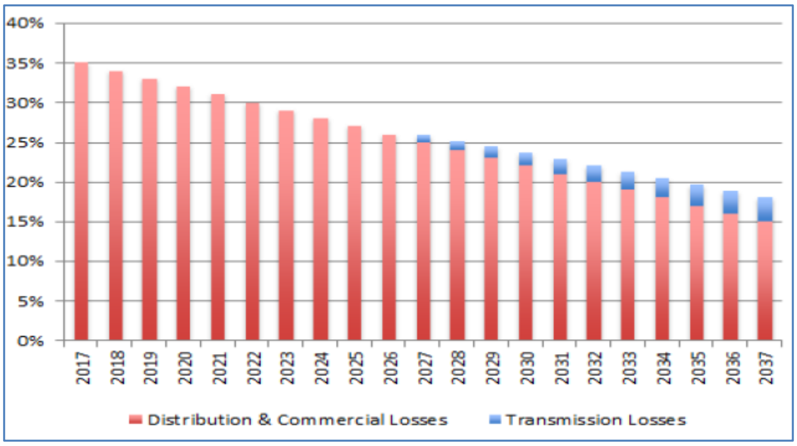


Figure 3-1 – Estimated and projected average energy system losses -

An assessment of the required generation. The main results of the expected required generation reported in the Master Plan are summarized in Table 3-4.

Table 3-4 - Estimated Energy for selected years (GWh)– Somalia

State	2017	2022	Growth 2017-22	2027	Growth 2022-27	2037	Growth 2027-37
Northwestern Sub-Grid	333	496	8.3%	790	9.8%	1,270	4.9%
(Galmudug) Central Sub-grid	216	401	13.2%	740	13.0%	1,490	7.2%
(Hirshabelle) Central Sub-grid	52	88	11.0%	170	14.1%	280	5.1%
Central Sub-grid	18	27	8.4%	50	13.1%	90	6.1%
Southern Sub-grid	83	138	10.6%	260	13.5%	460	5.9%
Southwestern Sub-grid	44	68	8.9%	120	12.0%	220	6.2%
Northeastern Sub- grid	134	224	10.8%	330	8.1%	530	4.9%
Eastern Sub-grid (Indian Ocean Sub-grid)	NIL	NIL	NIL	NIL	NIL	NIL	NIL
TOTAL	**881**	**1,442**	**10.4%**	**2,460**	**11.3%**	**4,340**	**5.8%**

3.2.3 The Somali Electricity Access Project

The objective of this study was to provide an indicative least-cost geospatial electrification plan. These indications are given in three different scenarios (with the horizon year 2030) and contain several updated information. In particular:

An estimated 4.0 out of 15.9 million people in Somalia in 2020 had access to electricity from mini grids. The number is only indicative, since there are areas not surveyed by the Report (especially in Somaliland, where the data were not collected, and in Mogadishu).

A total of 3,193,000 buildings were identified using high-resolution satellite imagery (with a resolution of 0.5m). These results are resumed in Table 3-5.

Table 3-5 Number of identified buildings

Region	Number of identified buildings
Awdal	59,000
Bakool	109,000
Banaadir	396,000
Bari	118,000
Bay	363,000
Galguduud	168,000
Gedo	175,000
Hiiraan	179,000
Jubbada Dhexe	72,000
Jubbada Hoose	131,000
Mudug	142,000
Nugaal	64,000
Saaxil	29,000
Sanaag	74,000
Shabeellaha Dhexe	208,000
Shabeellaha Hoose	333,000
Sool	68,000
Toghdeer	199,000
Woqooyl Galbeed	306,000
TOTAL	**3,193,000**

The population settlement was obtained and classified as urban or rural based on population size and density. According to this analysis 51% of the population lives in urban areas, 23% in rural areas and 26% are nomads. The results are summarized in Figure 3-2.

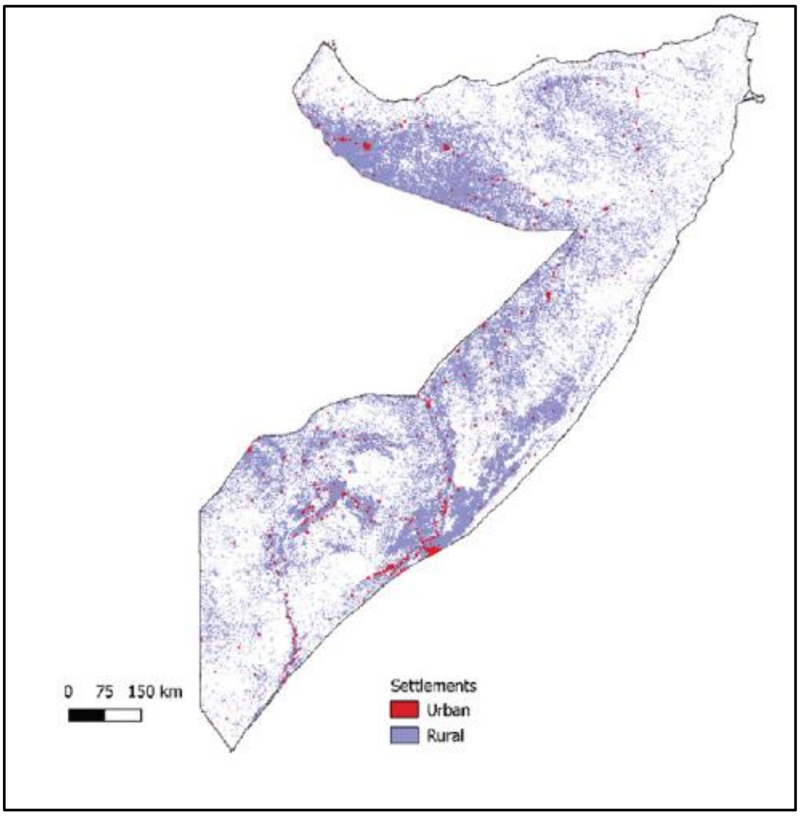


Figure 3-2 Population distribution - Source: Somali Electricity Access Project

The yearly electricity demand for schools, health and agriculture was determined and the results reported in Table 3-6.

Table 3-6 Yearly electricity demand (MWh/year) for schools, health, and agriculture –

Region	Schools	Health	Agriculture irrigation
Awdal	45	1,132	365
Bakool	14	1,002	1,450
Banaadir	1,318	3,767	150
Bari	145	1,738	0
Bay	87	2,248	11,890
Galguduud	76	3,326	1,370
Gedo	88	2,446	1,710
Hiiraan	150	1,022	4,310
Jubbada Dhexe	0	0	530
Jubbada Hoose	85	1,607	1,410
Mudug	104	3,023	1,210
Nugaal	55	1,441	0
Saaxil	9	1,758	0
Sanaag	46	2,559	0
Shabeellaha Dhexe	51	1,564	15,410
Shabeellaha Hoose	186	2,311	5,380
Sool	82	804	740
Toghdeer	49	1,318	1,400
Woqooyl Galbeed	50	3,739	0
TOTAL	**2,640**	**37,005**	**47,325**

3.2.4 Data collected with ESPs through on-field activity

During the year 2025, data was collected with ESP through on field activities performed. The data collected refers to the following ESPs:

- Banadir Electric Company – BECO
- Mogadishu Power Supply - MPS
- BSE Blue Sky Energy
- Cabudwaak Electric Company - CECO
- Al-Towba Electric Company
- DAYAH Power Supply
- Galkayo Electric Company - GECO
- Hilaac Energy & Water Supply
- Shabelle Energy Service
- ENEE Qardho
- NECSOM – National Electricity Corporation of Somalia – Garowe
- NEPCO – National Electric Power Co-Operations – Galkayo
- NEPCO – National Electric Power Co-Operations – Goldogob
- PEPCO – Puntland Electric Power Company– Bosaso
- WESCO – Wamo Energy Service Company – Kismayo
- Gedo Energy Power Company – GEPCOM
- BECO – Baidoa Electric Company
- Barawe Electric Company
- Sool Power

The data collected are described with many details in the assessment of current situation of the power sector and energy resources in Somalia. Hereafter the data useful for load demand forecasts are reported (and in particular the historical and planned consumptions)

Table 3-7 to Table 3-10 show the historical data of electrical consumption for the different ESPs for which data were collected.

Table 3-7 Electrical Consumption – (MWh)

Year	Al-Towba Beledweyne	Dayah Beledweyne	BECO Baidoa	BSE Mogadishu	MPS Mogadishu	BECO Mogadishu
2015	-	-	1,163	18,500	31,904	-
2016	-	-	1,453	24,555	35,094	-
2017	-	-	1,772	32,000	38,603	-
2018	1,102	2,325	1,772	32,305	42,463	-
2019	1,114	3,540	2,735	43,040	46,710	-
2020	1,238	3,950	3,335	57,000	51,381	-
2021	1,360	4,565	4,118	80,070	56,519	-
2022	1,540	4,655	5,147	105,180	62,171	331,755
2023	1,811	5,465	6,113	112,560	83,923	385,176
2024	2,691	5,584	6,833	120,018	127,616	446,804

Table 3-8 – Electrical Consumption –MPS areas (MWh)

Year	Mogadishu Power Supply - MPS								
	Area 2 Balcad	Area 3 Jowhar	Area 4 Marko	Area 5 Baraawe	Area 6 Buuhoolde	Area 7 Qoryooley	Area 8 Buulomareer	Area 9 Shalembood	Area 10 Ceelsha
2024	693	2,048	1,616	931	710	542	722	399	2,778

Table 3-9 –Electricity Consumption – (MWh)

Year	GECO Galkayo	NEPCO Galkayo	NEPCO Goldogob	NECSOM Garowe	PEPCO Bosaso	WESCO Kismayo
2015	4,868	1,978	-	-	-	592
2016	5,112	2,347	-	-	-	657
2017	5,367	2,787	-	-	-	740
2018	5,636	3,310	-	9,128	-	847
2019	5,918	3,931	-	10,892	--	1,078
2020	6,213	4,290	656	11,823	-	1,286
2021	6,524	5,467	709	13,109	12,090	1,678
2022	6,850	6,585	766	15,694	16,420	2,104
2023	7,193	8,036	739	19,209	22,150	2,341
2024	7,552	9,281	893	23,269	23,710	2,640

Table 3-10 – Electricity Consumption – (MWh)

Year	SOOL	BECO Barawe	Shebelle	ENEE Qardho	Hilaac Dhusmareeb
2015		585	351		4,300
2016		667	400		4,730
2017		760	456		5,203
2018	1,354	867	520		5,790
2019	3,025	988	593		6,369
2020	3,384	1,126	676		7,395
2021	4,290	1,284	770	2,108	8,135
2022	4,980	1,464	878	2,910	9,570
2023	6,464	1,669	1,001	3,900	10,527
2024	7,948	1,902	1,141	4,180	11,580

Table 3-11 to Table 3-14 report, for the same ESPs, the Planned Electricity Consumption.

Table 3-11 – Planned Electricity Consumption – (MWh)

Year	Al-Towba Beledweyne	Dayah Beledweyne	BECO Baidoa	BSE Mogadishu	MPS Mogadishu	BECO Mogadishu
2025	3,023	5,968	7,602	139,400	140,378	500,421
2026	3,235	6,386	8,658	198,177	154,416	560,471
2027	3,461	6,833	10,390	220,093	169,857	627,727
2028	3,704	7,311	12,468	242,101	186,843	703,055
2029	3,963	7,823	14,961	265,923	205,527	787,421

2030	4,240	8,371	17,954	293,000	226,080	881,912
2031	4,537	8,873	21,544	322,000	248,688	987,741
2032	4,855	9,228	25,853	355,498	273,557	1,106,270
2033	5,195	9,597	31,024	389,870	300,913	1,239,023
2034	5,558	9,981	37,229	432,006	331,004	1,387,705
2035	5,947	10,380	44,674	471,000	364,105	1,554,230
2040	7,650	12,859	89,349	521,612	586,395	n/a
2045	9,671	16,408	178,698	569,413	780,492	n/a

Table 3-12 – Planned Electricity Consumption –MPS areas (MWh)

Year	Mogadishu Power Supply - MPS								
	Area 2 Balcad	Area 3 Jowhar	Area 4 Marko	Area 5 Baraawe	Area 6 Buuhoolde	Area 7 Qoryooley	Area 8 Buulomareer	Area 9 Shalembood	Area 10 Ceelsha
2025	729	2,297	1,800	1,043	795	607	809	447	2,551
2026	768	2,573	2,000	1,168	891	680	906	501	2,857
2027	809	2,882	2,220	1,308	998	761	1,015	561	3,200
2028	851	3,228	2,460	1,465	1,117	853	1,137	628	3,584
2029	896	3,615	2,720	1,641	1,251	955	1,273	703	4,014
2030	942	4,049	3,000	1,838	1,402	1,070	1,426	788	4,496
2031	991	4,535	3,310	2,058	1,570	1,198	1,597	882	5,035
2032	1,042	5,079	3,650	2,305	1,758	1,342	1,788	988	5,639
2033	1,095	5,688	4,020	2,582	1,969	1,503	2,003	1,106	6,316
2034	1,151	6,371	4,430	2,892	2,205	1,683	2,243	1,239	7,074
2035	1,209	7,135	4,880	3,239	2,470	1,885	2,513	1,388	7,923
2040	1,543	12,574	7,800	5,707	4,353	3,323	4,428	2,446	13,963
2045	1,964	14,000	10,500	10,058	7,671	5,856	7,843	4,311	24,608

Table 3-13 – Planned Electricity Consumption – (MWh)

Year	GECO Galkayo	NEPCO Galkayo	NEPCO Goldogob	NECSOM Garowe	PEPCO Bosaso	WESCO Kismayo
2025	7,930	10,487	965	25,595	27,378	n/a
2026	8,327	11,851	1,042	28,155	32,737	n/a
2027	8,743	13,391	1,125	30,970	39,646	n/a
2028	9,180	15,132	1,216	34,067	47,982	n/a
2029	9,639	17,099	1,313	37,474	56,619	n/a
2030	10,121	19,322	1,418	41,222	67,645	n/a
2031	10,627	21,834	1,532	45,344	80,807	n/a
2032	11,158	24,673	1,655	49,878	95,352	n/a
2033	11,716	27,880	1,788	54,866	113,887	n/a
2034	12,302	31,504	1,931	60,353	136,006	n/a
2035	12,917	35,600	2,086	66,388	166,219	n/a
2040	20,039	65,591	3,067	73,027	202,901	n/a
2045	21,041	120,847	4,510	80,329	239,424	n/a
CAGR (%)	**5.0%**	**13.0%**	**8.0%**	**8.0%**	**11.5%**	n/a

Table 3-14 – Planned Electrical Consumption – (MWh)

Year	SOOL	BECO Barawe	Shebelle	ENEE Qardho	Hilaac Dhusmareeb
2025	9,332	2,308	1,385	6,474	12,470
2026	10,616	2,631	1,578	7,640	13,592
2027	11,696	2,999	1,799	9,017	14,815
2028	12,604	3,419	2,051	10,642	16,148
2029	13,497	3,898	2,339	12,558	17,602
2030	16,919	4,443	2,666	14,819	19,186
2031	20,341	5,065	3,039	17,489	20,913
2032	23,764	5,775	3,465	20,637	22,795
2033	27,186	6,583	3,950	24,354	24,846
2034	30,609	7,505	4,503	28,740	27,083
2035	34,031	8,555	5,133	33,923	29,520
2040	51,143	9,753	5,852	40,042	32,177
2045	68,255	11,118	6,671	47,249	35,073
CAGR (%)	**10.5%**	**8.2%**	**8.2%**	**10.4%**	**5.3%**

For the year 2045 the total expected demand of the Reported ESPs summed up to 1,409 GWh.

3.2.5 Feasibility Study on 15 Urban and Preurban Location

As described in assessment of current situation of the power sector in Somalia, the objective of this study was to conduct a detailed techno-economic feasibility study and prepare a detailed project report (DPR) for installing mini-grid photovoltaic systems at 15 selected sites to reduce diesel consumption and supply reliable power.
Table 3-15 shows the positions of the different villages considered.

Table 3-15 - Geographical positions of the selected sites

Sl. No.	Village Name	Zone	Region	Coordinates
1.	Xudur	Huddur	Bakool	4.118342°N, 43.904221°E
2.	Wajid	Waajid	Bakool	3.807129°N, 43.258546°E
3.	Dinsoor	Dinsoor	Bay	2.397333°N, 42.965721°E
4.	Guriceel	Guriceel	Galgaduud	5.306405°N, 45.872402°E
5.	Abud Wak	Caabudwaaq	Galgaduud	6.244061°N, 46.207349°E
6.	Bahdo	Cadaado	Galgaduud	5.789908°N, 47.227436°E
7.	Jalalaqsi	Jalalaqsi	Hiraan	3.379778°N, 45.599960°E
8.	Balcad	Balcad	Shabella da Dhexe	2.358256°N, 45.385877°E
9.	Matabaan	Matabaan	Hiraan	5.198892°N, 45.524461°E
10.	Badhan	Badhan	Sanaag	10.712901°N, 48.335569°E
11.	Armo	Bari- Cadhmo	Bari	10.568296°N, 49.060148°E
12.	Bargaal	Bari	Bargaal	11.285609°N, 51.077701°E
13.	Elwak	Bardere	Gedo	2.793579°N, 41.014038°E
14.	Beled Hawo	Beled Hawo	Gedo	3.9289°N, 41.8742°E
15.	Dhoobley	Dhoobley	Afmadow	0.4223°N, 41.0219°E

System sizing and optimisation have been performed in parallel using different software outputs; the results are compared and verified for accuracy and adequacy to compete with the site conditions and parameters at might influence the calculations. PV-BESS-DG hybrid system is proposed for the identified site.
The main results are resumed in Table 3-16 where the total energy produced is reported.

Table 3-16 –Energy Supplied from mini grid project (MWh/year)

Site	Name	PV plant production	BESS Energy	Diesel Generators Energy	Total Energy
1	Xudur	3,008	1,632	1,420	6,060
2	Wajid	1,572	1,086	845	3,503
3	Dinsoor	2,496	1,098	816	4,410
4	Guriceel	822	498	319	1.639
5	Abud Wak	795	487	178	1.460
6	Bahdo	444	294	93	831
7	Jalalaqsi	341	244	148	733
8	Balcad	486	183	95	764
9	Matabaan	220	137	107	464
10	Badhan	1,324	575	225	2,124
11	Armo	175	149	26	350
12	Bargaal	82	62	17	161
13	Elwak	141	94	14	249
14	Beled Hawo	33	23	4	60
15	Dhoobley	430	236	92	758

3.2.6 Study on development of the city of Mogadishu

A load demand forecast is reported for the city of Mogadishu in a study focused to the development of the electricity system of the City of Mogadishu.

More in detail, about the demand in the next years, Table 3-17 presents the number of consumers as provided by the ESPs for 2022. As shown by the table:

- BECO clients amount to 190,000 with approximately 8,000 to 10,000 of them being large industrial clients,
- MPS clients amount to 140,000, and approximately 20% of them are supplied with a three-phase connection (large consumers between 200kVA and 2 MVA)
- BSE has 51,453 clients, of which 25% classified as large consumers.

Table 3-17 - Number of consumers according to ESPs

ESP	Number of Consumers	
	Residential	Large
BECO	180,000	10,000
MPS	112,000	28,000
BSE	38,590	12,863

Table 3-18 presents the generation associated with residential and large consumers for each ESP for 2022.

Some considerations about the table:

- According to MPS, the monthly generation was approximately 16,000 MWh, resulting in an annual value of 192,000 MWh. Additionally, for MPS it was assumed that 20% of clients connected via three-phase connections would consume 45% of the generation.

- BSE provided monthly generation data, which added up to 29,245 MWh for 2022.

Table 3-18 - Estimated annual generation for each ESP

ESP	Number of Consumers	
	Residential	Large
BECO	150,000	150,000
MPS	205,600	86,400
BSE	16,085	13,169

About losses:

- According to BECO the overall losses amount to 16%, for MPS the technical losses come up to 32% and 25% the commercial losses, while no information comes from BSE.

In terms of other information, data about the total population of Mogadishu, the average number of people per household, and the electrification rate comes from different sources:

- The size of a household was taken `equal to 6.9 persons, the electrification rate is assumed to be 79%. These values were obtained from the "Somali Health and Demographic Survey Banadir Report, 2020 BDHS[2].
- As of 2022, the population of Mogadishu was reported as 2,497,463 according to World Population Review[3], data, which implies a total of 361,951 households, with 285,941 households connected to the electric grid.

Three scenarios (low, base or medium, high) were developed to assess existing demand and forecasts for both capacity and energy. The proposed growth rates for each scenario were divided into two periods: one from 2025 to 2033 and another from 2034 to 2040 (see Table 3-19).

Table 3-19 - Estimated demand growth rates

Scenario	Growth (%)	
	2025 - 2033	2034 - 2040
Low	8	6
Base	10	10
High	12	10

Table 3-20 shows the data of the demand forecast for the next years.

Table 3-20 - Demand forecast under different scenarios.

Year	Base Forecast		Low Forecast		High Forecast	
	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)	Peak (MW)
2023	542.5	103.2	542.5	103.2	542.5	103.2
2024	651.0	123.9	651.0	123.9	651.0	123.9
2025	716.1	136.2	703.1	133.8	729.1	138.7
2026	787.7	149.9	759.3	144.5	816.6	155.4
2027	866.5	164.9	820.1	156.0	914.6	174.0

[2] https://somalia.unfpa.org/sites/default/files/pub-pdf/bhds_report_2020_final.pdf
[3] https://worldpopulationreview.com/world-cities/mogadishu-population

2028	953.2	181.3	885.7	168.5	1,024.6	194.9
2029	1,048.5	199.5	956.6	182.0	1,147.3	218.3
2030	1,153.3	219.4	1,033.1	196.6	1,285.0	244.5
2031	1,268.6	241.4	1,115.7	212.3	1,439.2	273.8
2032	1,395.5	265.5	1,205.0	229.3	1,611.9	306.7
2033	1,535.1	292.1	1,301.4	247.6	1,805.3	343.5
2034	1,688.6	321.3	1,379.5	262.5	1,985.9	377.8
2035	1,857.4	353.4	1,462.4	278.2	2,184.4	415.6
2036	2,043.2	388.7	1,550.0	294.9	2,404.9	457.2
2037	2,247.5	427.6	1,643.0	312.6	2,643.2	502.9
2038	2,472.2	470.4	1,741.5	331.3	2,907.5	553.2
2039	2,719.5	517.7	1,846.0	351.2	3,198.2	608.5
2040	2,991.4	569.1	1,956.8	372.3	3,518.1	669.3

3.2.7 Data from International Database

To integrate the data collection described in the previous paragraphs, data coming from public international sources has been collected and analyzed.

All these kinds of information can give a contribute for a more accurate assessment of the electricity demand in the next years.

3.2.7.1 GDP

GDP historical data in terms of Constant LCU (Local Currency Unit) from the World Bank (WB) database [6] are reported in Figure 3-3. As is possible to note, there are important variations of the growth rate in the period considered.

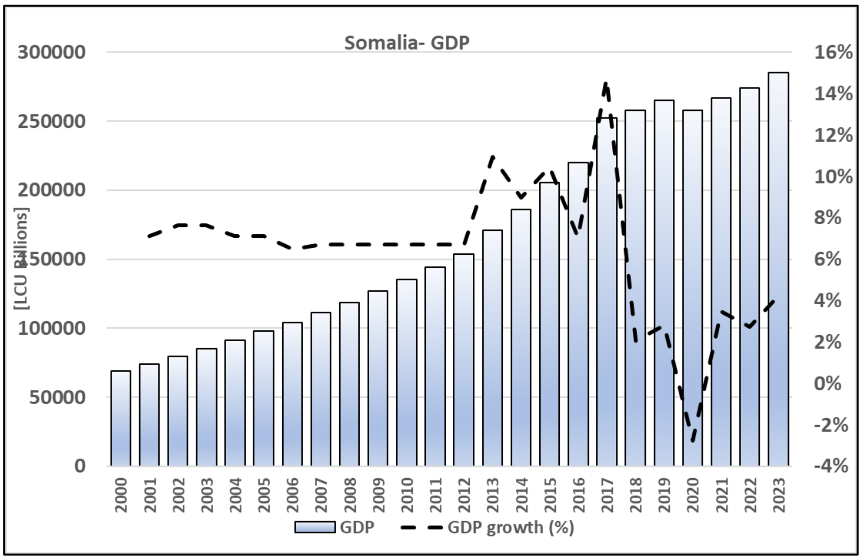


Figure 3-3 – Historical data of GDP – Constant LCU – Somalia – Source [7]

3.2.7.2 Population

Population historical data from the WB database are reported in Figure 3-4

The population which represents an important driver for the estimation of the electricity consumption (as described with more details in the next Chapter), is increasing over the whole past period considered in the figure.

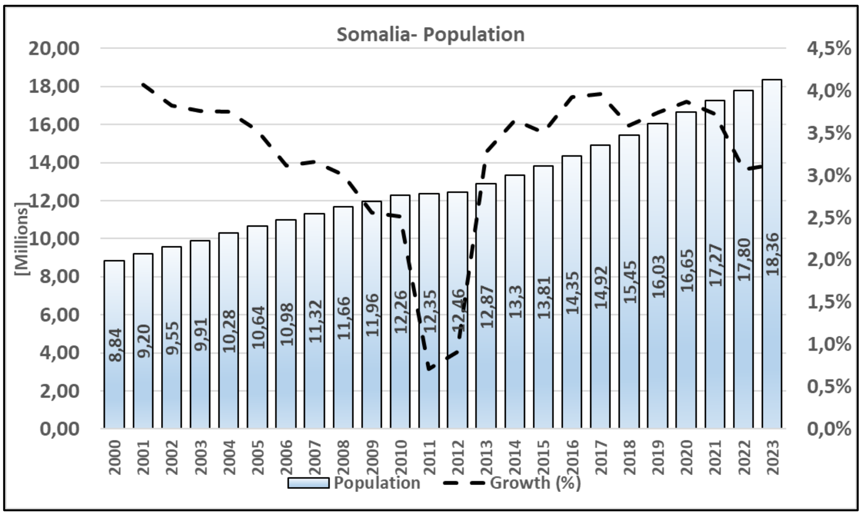


Figure 3-4 – Historical data of Population – Somalia – Source [7]

3.3 METHODOLOGY OF LOAD DEMAND FORECAST

3.3.1 General overview

In general, load forecasts can be divided into three categories (the different time horizons of the load forecasts determine the natures of the same forecasts):

- **Short-term load forecasts (STLF)**: for the day-to-day operation and scheduling of the power system operation (usually from one hour to one week),
- **Medium-term load forecasting (MTLF)**: mainly for the scheduling of fuel supplies and maintenance programmes. It usually covers a period from a week to 5 years,
- **Long-term load forecasting (LTLF)**: mainly for system planning. Typically, the long-term forecast covers a period of 10 to 20 years. Key factors in LTLF include stock of electricity-using equipment, level and type of economic activity, price of electricity, price of substitute sources of energy, non-economic factors such as marketing and conservation campaigns, and weather conditions.

As part of the long-term forecast, the Future Outlook (the Vision 2045) is developed in alignment with the Electricity Supply Industry Vision 2040.

Two main methodologies are usually used in the Long-Term Load Demand forecast:

- **Trend analysis**
  Trend analysis extends past growth rates of electricity demand into the future, using techniques that range from hand-drawn straight lines to complex computer-produced curves.
- **Econometric analysis**
  The econometric analysis combines economic theory and statistical techniques for forecasting electricity demand. The approach estimates the relationship between energy consumption (dependent variables) and factors influencing consumption

3.3.1.1 Trend analysis

Most used mathematical functions for the extrapolation of energy demand (E = energy demand) are reported hereinafter.

Linear extrapolation $E_t = a + bt$

where the variable to be forecast is linearly plotted against time and the resulting plot is extrapolated into reasonable future time spans.

Polynomial (second degree) $Et = a + bt + ct^2$

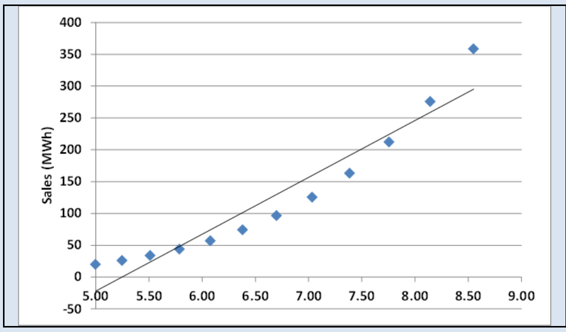
In this relation, the rate of change increases linearly with time (the slope is given by b+2ct)

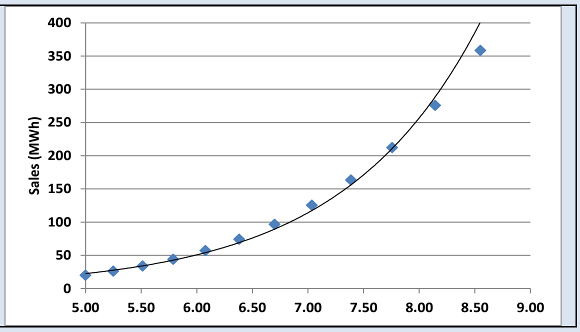
Exponential $E_t = ae^{bt}$

In this case the logarithm of E_t is plotted against time. These semi log plots, which are frequently linear, are then extrapolated to make forecasts. The parameter b gives the exponential growth rate of E_t.

Box 3.1 – Double-log form of the equations

Double logarithmic equations are used when the relationship is non-linear. In the left graph below, the relationship is clearly non-linear. If a linear relationship is fitted to the line and then a forecast prepared using this relationship (i.e., extrapolating the straight line into the future), the result would be an under-estimate of future data. In the right graph below, an exponential curve is fitted to the data, and this fits the data much better. A forecast prepared using this equation would predict the future more accurately. The double-log form of the equation allows a linearized curve to be fitted to non-linear data.





In general, the time trend analysis explains only the most important basic components of the development. To explain with more detail this development, and to describe consumption forecasts for more distant periods of time, multi-correlation methods are better applied, in which it is possible to consider (or to try to consider) the influence of internal and external factors affecting energy consumption.

3.3.1.2 Econometric methods

3.3.1.2.1 Factors affecting electricity demand

Econometric analysis combines economic theory and statistical techniques for forecasting electricity demand trying to estimate the relationships between energy consumption (dependent variables) and socio-economic factors influencing consumption.

The main factor influencing electricity demand is economic growth and the main indicator of economic growth is the GDP. Although there is not a one-to-one relationship between GDP growth rates and electricity demand growth rates, many studies have generally shown a strong positive correlation between incomes (expressed by GDP) and net electricity demand.

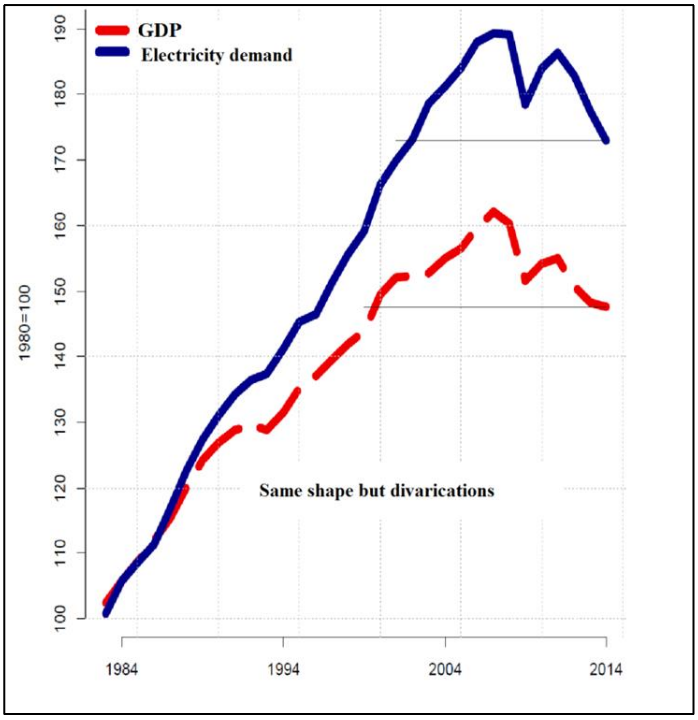


Figure 3-5 –GDP and Electricity demand – Italy 1980 – 2014 (1980 = 100). - Source: TERNA

Generally, increased industrial output contributes to GDP growth and is the key income driver in the industrial sector while household energy consumption is a function of the level of consumer expenditure (related to the number of households and the level of heating and cooling comfort), which is correlated with GDP growth.

Another factor to be considered is the decline, in the long term, of the energy intensity of the economies, which historically experienced in the last years. As far as developing countries are concerned, the S-shaped curve often characterizes the increase in electricity demand, as shown in Figure 3-6, (Source: Eskom and Central Bank of South Africa); an industrial economy is generally more electricity-intensive than a service economy.

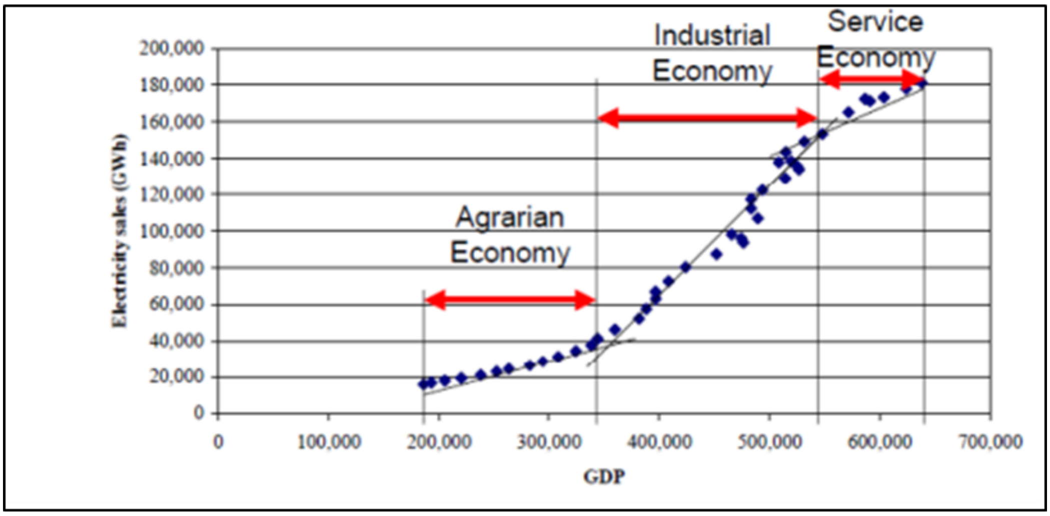


Figure 3-6 – GDP per capita and electricity demand in South Africa

Other factors that influence electricity demand are:

- **Population:** an increase in population means an increase in the number of consumers.

- **Electrification rate:** an increase in the electrification rate means an increase in the number of consumers connected to the electric network (this effect is strictly connected to the previous one).
- **Level of electricity prices and the price of alternative goods:** the first effect of the rising price of electricity is a more efficient use of electricity, with a reduced consumption of energy for the same economic output. This reduction in consumption can be a result of energy savings, profitable energy efficiency measures, or substitution of electricity by other energy sources.
  Furthermore, **subsidies** for certain types of energy consumption can influence the demand considerably, as they change the relative prices for different energy sources, including electricity. Other subsidies, like incentives for better insulation of buildings, may reduce the overall level of energy consumption within households or office buildings.
  Regarding the electricity prices, not only domestic prices, but also international prices have to be considered.
  Note that end-user prices are not only a function of the wholesale electricity price, but also of the distribution tariffs, the transmission tariffs, supply service margins and government consumption taxes, including VAT.
  In any case, the effect of electricity prices on the electricity demand is hard to be separated from the effect of other economic reforms simultaneously applied.
- **Technology changes**: technology change generally reduces electricity consumption and intensity per unit of capita income (new technologies that help to save energy and "optimize" energy consumption can also have a significant impact on electricity demand and its profile).
- **Policy measures**: policy measures can raise awareness and alter preferences.
  For example, the EU policy on global warming issues does not only impact the supply side via CO_2 quota trading, but also the demand side, as it raises awareness for energy preservation and energy efficiency. In general, awareness and information campaigns could also impact the demand.
- **Energy Efficiency (EE) and Demand Side Management/Load Reduction (DSM/LR)** measures must be considered: the impact can be in terms of energy reduction or peak reduction. Typically, these programs are established by Governments or Authorities.
- **Rooftop Solar policy evolution**: the installation of rooftop solar systems has the effect of reducing the expected load at transmission level, especially around midday, when solar generation is high (see also "net metering"). For assessing this impact, appropriate assumptions on the evolution in the years of the rooftop solar program must be made.
- **impact of Electric Vehicles (EV) evolution:** the impact of EV in the grid strongly varies depending on the charging strategy adopted. Depending on the usage patterns, and thus the timing and the amount of charging power they draw from the grid, EVs could have a significant impact on the peak demand of electricity at certain times and locations.

3.3.1.2.2 Econometric models

There are many examples of econometric models. Some of them are reported in the following equations, where:

- $\mathbf{E_t}$ stays for the demand at time t
- $\mathbf{E_{t-1}}$ stays for the demand at time t-1
- **Δ lnEt** stays for the difference between the logarithm of the Demand at time t and the logarithm of the Demand at time t-1
- $\mathbf{GDP_t}$ stays for the Gross Domestic Product at time t
- $\mathbf{GDP_{t-1}}$ stays for the Gross Domestic Product at time t
- **Δ lnGDPt** stays for the difference between the logarithm of the GDP at time t and the logarithm of the GDP at time t-1

The equations of the typical econometric models are:

- **Traditional (mostly used),** in which the electricity consumption is a function of GDP.

  Example of such model: $\mathbf{lnE_t = \alpha + \beta\ lnGDP_t}$

- **Autoregressive 1st order model**, in which the electricity consumption is a function of the GDP and of the electricity consumption of the year before.

  Example of such model: $\mathbf{lnEt = \alpha + \beta 1\ lnE_{t-1} + \beta 2\ lnGDP_t}$

- **VEC model** based on the concept of cointegration and the Engle Granger test.

  Example of such model: $\mathbf{\Delta\ lnEt = \alpha + \beta\ \Delta\ lnGDPt + \lambda\ (lnEt\text{-}1 - a\text{-}\ b\ lnGDPt\text{-}1)}$

  In this model, the variation of the electricity consumption between time t and time t-1 is a function of the variation of GDP for the same time interval plus an error correction term (a short run relationship) (λ is the speed of adjustment).
  The error correction model is a very popular model because it allows for the existence of an underlying or fundamental link between variables (the long-run relationship) as well as for short-run adjustments (i.e., changes) between variables.

3.3.1.3 Top Down and Bottom-Up approaches

The two approaches usually adopted in the long-term forecast are the Top-Down and the Bottom-Up approach (see Figure 3-7).

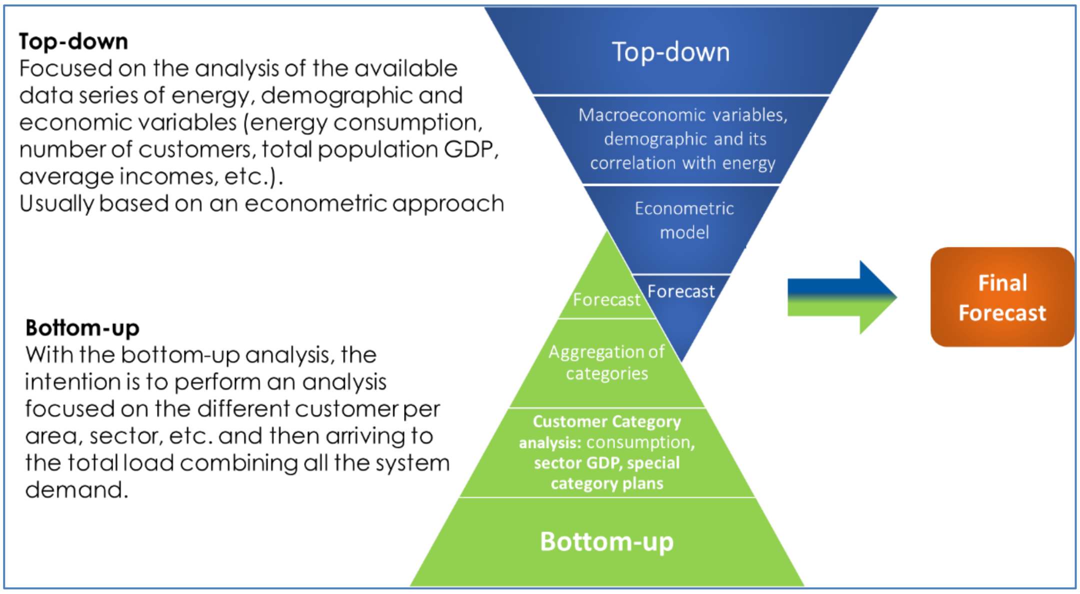


Figure 3-7 – Bottom-up and Top-Down approach

Top-down approach is focused on the analysis of the available data series of energy, demographic, and economic variables (energy consumption, number of customers, total population GDP, average incomes, etc.) and usually is based on an econometric approach.

With **the bottom-up approach**, the objective is to perform an analysis focused on the different customers per area, sector, etc. and then arrive to the total load combining different expected demand by sectors.

3.3.1.4 Some further observations

As a conclusion, there are some further observations about the load demand forecast:

Forecasting is a stochastic problem: forecasting, by nature, is a stochastic problem rather than deterministic and there are no "certainties" in forecasting. The output of a forecasting process is always in a probabilistic form.

All forecasts contain uncertainties: due to the stochastic nature of forecasting, the response variable to forecast is never 100% predictable. The question like "why is your forecast different from the actual?" should have never been asked, because we do expect some differences between the forecasts and actual values (also if data are good, methodologies appropriate and software ok).

All forecasts can be improved: since all forecasts contain uncertainties, there is always room for improvement, at least from the accuracy aspect. In general, the objective of forecast improvement is to enhance the usefulness. Other than uncertainties such as various error metrics, interpretability, traceability and reproducibility, there are some more specific directions for potential improvement:

- *Spread of errors*. Nobody likes to have surprisingly big errors. Reducing the variance or range of the errors means reducing the uncertainty, which consequently increases the usefulness of the forecasts.
- *Interpretability of errors*. For instance, in long-term forecasting, due to the uncertainty in long term weather and economic forecasts, the load forecasts may present some significant errors from time to time. Then it is necessary to understand how much of the error is contributed by modelling error, weather forecast error and economy forecast error. Breaking down the error to its sources increases interpretability as well as the usefulness of forecasts.
- *Requirement of resources*. Resources to build a forecast are in general limited. The limitations may be from data, hardware and effort. Enhancing the simplicity of the forecasting process (by reducing the requirements on these resources), can improve the usefulness of the forecast.

Accuracy is never guaranteed: due to the stochastic nature of forecasting, the future will never repeat the history in exactly the way described by our models. Sometimes, the deviations are large; sometimes, they are small. Even if a forecast could maintain a stable accuracy during the past few years, there is still no guarantee that the same or similar accuracy can be achieved going forward.

Having the second opinion is preferred: there is not a perfect model. Empirically, combining forecasting techniques usually does a better job than each individual by offering more robust and accurate forecasts. Therefore, one of the best practices is to run multiple models and combine the forecasts.

According to Consultant experience in the field, in any case the load demand forecast methodology ***must always be tailored to each specific case and adjusted to data availability.***

3.3.2 Methodology adopted

As said at the end of the previous paragraph, the load demand forecast methodology must always be tailored to each specific case and adjusted to data availability.

For example, the correlation between the GDP and electricity demand is higher in Country having advanced markets (with higher per capita and per GDP consumption) and lower in in Country where the market is not so advanced; in these last cases it must be integrated with other factors (mainly the electrification rate growth, etc.).

The effect of the population growth/electrification growth is different in advanced Countries respect to the not advanced countries. This is shown in Figure 3-8 that reports the per capita electricity consumption in selected Countries in the period 2000 – 2017.

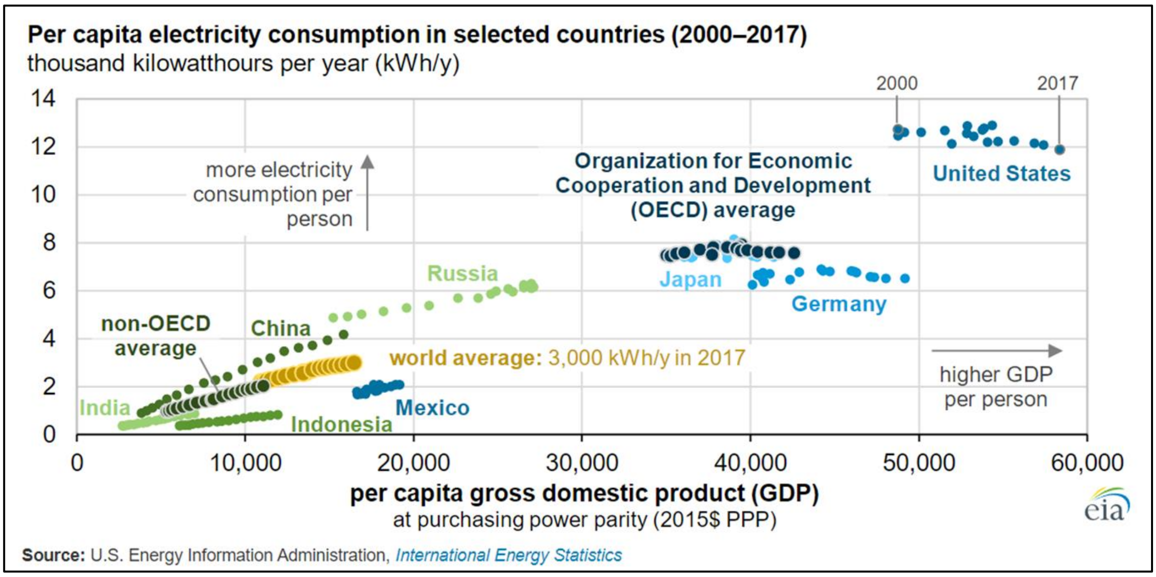


Figure 3-8 – Per capita electricity consumption in selected countries

As shown by the figure above, the increased in the population in not Organisation for Economic Co-operation and Development (OECD) Countries has a double impact: an increase in the consumption (due an higher number of consumers and the development of the electric grid) and an increase in the specific consumption (because, as written in the National Transformation Plan of the Federal Republic of Somalia the energy is key enabler for all the economic growth where different sectors such as industries, agriculture and fisheries demand more energy).

Based on of the described characteristics of the Somalia electric grid, some preliminary definitions are necessary: they are reported hereafter.

- **BAU (Business as Usual) demand.** This is the demand which is supplied by the existing installed capacity and through the existing local distribution networks (since there is no existing transmission network). Due to the lack of generation, the absence of a national transmission grid, the status of distribution grids, etc., in absence of policies improving the electrical system, the electricity consumption is expected to follow a low growth rate in the next years, as a first assumption in line with that of the last years.
- **Potential demand.** This is the demand which could currently be absorbed by the Country, but which is not supplied due to lack of generation, absence of the transmission and distribution networks, etc. This demand is a function of the socioeconomic parameters such as GDP, population growth, etc. The difference between the Potential demand and the BAU Demand can be defined as **Not Served Demand.**
- **Supplied Demand**. This is the demand covered by the generation. This demand is the sum, year by year, of the BAU demand and a part share of the difference between the Potential demand and the BAU Demand Potential Demand (the Not Served Demand); this part share is a function of the coordinated actions taken for the development of the electrical system, including the development of interconnections, the transmission and sub-transmission grid, the local generation capacity and the distribution grids.

According to the characteristics of described Somali electric sector, the methodology adopted requires some clarifications.

Either Top-Down or Bottom-Up approach is based on the analysis of the historical data of the different ESPs where they are available (these can be defined as primary sources of data) and to the data coming by the different documents described in the previous paragraph (secondary sources of data).

Because, as said, the traditional methodologies (trending analysis, econometric modelling) are not applicable, the approach followed is based on a heuristic methodology, i.e., on assumptions and correlations between the demand and the other variables based on the experience and the best practice and described in the next chapters.

For both Top-Down and Bottom-Up approaches three different steps are considered.

- Step 1: determination of the BAU Demand,
- Step 2: determination of Potential Demand,
- Step 3: determination of the Supplied Demand.

Three milestones are being developed, executed, and evaluated over the short, medium, and long terms:

- Short-term 2025-2030
- Medium-term 2030-2040
- Long-term 2040-2045

To assure coherence to the forecast, the Vision 2040 approach (described in assessment of current situation of the power sector and energy resources in Somalia) has been also considered.

3.4 load demand forecast results

3.4.1 Bottom-Up approach

Step 1 - Determination of the BAU Demand

The BAU Demand for Somalia for 2024 has been quantified according to the data coming from the different sources described in the previous paragraphs integrated by the results of the data collected with ESPs through on field activities.

Here

Electricity demand- consumption

- **Banadir sub-grid** – according to the data collected through the on-field activity, the total historical demand supplied by the three ESPs through the on-field activity summed up in 2024 to about 700 GWh. Due to the fact that these three ESPs represent substantially the total generation power plants in the area of Mogadishu, this value must be considered as the current consumption of the grid.
- **Northwestern grid**: this is the second, in terms of demand, area of the Country. For this area the historical data obtained by the on-field activity are not available; in any case from the so called "secondary data"[4], the demand of this grid has been estimated around 400 GWh.
- **For the other sub-grids**: data coming from the different ESPs represent only partially the total demand. For this reason, they have been integrated again with the data coming from secondary data.

Table 3-21 resumes the assumptions made. They represent the BAU demand, as said the demand that will growth in the future according to the planned programs of each ESPs without considering the effects of the development (integration) of the grid.

Table 3-21 BAU Demand – Somalia 2024

Grid	BAU Demand [GWh]
Benadir Sub-grid	700
Central Sub-grid	49
Northeastern Sub-grid	93
Northwestern Sub-grid	400
Southern Sub-grid	58
Southwestern Sub-grid	29
Total	**1,328**

For the future, the BAU Demand will grow accordingly to the planned growths. These growths are different for the different ESPs. A reasonable value is equal to 6 - 7% year.

As said, this growth value must be intended as the value planned by different ESPs without the presence of a national grid interconnecting the different regions/area of the Country (and this is the sense of the term BAU for this kind of demand).

[4] Secondary data are data extracted by documents, reports and through changes of information with different subjects, mainly MoEWR members.

Step 2 - Determination of the Potential Demand

The potential demand is, as said, the demand that could be supplied without the existing limitations. These values are different for the different sub-grids according to the current degree of development of each grid.

Again, on the base of the results of the analysis of different sources of data, the potential demand has been assumed, in 2024, equal (in the base case) to the values reported in Table 3-22.

Table 3-22 Potential Demand – Somalia 2024

Grid	Potential Demand [GWh]
Benadir Sub-grid	950
Central Sub-grid	145
Northeastern Sub-grid	300
Northwestern Sub-grid	821
Southern Sub-grid	173
Southwestern Sub-grid	85
Total	**2,473**

As said, the potential demand will grow according to the growth of the independent variables, namely GDP, population, electrification rate growth, etc..

GDP

GDP historical data evolution has been reported in section 3.2 . Assumptions about GDP evolution in the next years can be divided in different periods .

For the period until the years 2030, the main sources of data are public database (in particular case the IMF database, https://www.imf.org/external/datamapper/profile/SOM; these values are reported in Table 3-23 .

Table 3-23 – GDP growth rate – Source IMF

Period	2025	2026	2027	2028	2029	2030
Real GDP growth	4.0%	4.1	4.1%	4.3%	4.5%	4.5%

After 2030, thanks to a higher availability of electricity generation at a reduced cost in parallel with the expansion of the internal transmission grid (from 2032 also the interconnection with Ethiopia) an increase of GDP.
In particular, for the years after 2030, the same values assumed in the previous study *"Consultancy Services for Feasibility Study for the Ethiopia - Somalia Electricity Transmission Line Interconnections "* are adopted.

Based on the considerations made, the following scenarios have been developed

Base Scenario

A GDP growth rate equal to:

- the IMF assumptions in the period 2025-2030
- 6.5%/year in the period 2031-2035
- 6.0% year in the period 2036 - 2040
- 5.0%/year in the period 2041 - 2043
- 4.0%/year in the year 2044 - 2050

Low Scenario: the same growth of the **Base Scenario** reduced each year by 0.5%
High Scenario the same growth of the **Base Scenario** increased each year by 0.5%

Table 3-24 resumes the assumptions made

Table 3-24 – GDP growth rate assumptions

Period	Low	Base	High
2025	3.5%	4.0%	4.5%
2026	3.6%	4.1%	4.6%
2027	3.6%	4.1%	4.6%
2028	3.8%	4.3%	4.8%
2029	4.0%	4.5%	5.0%
2030	4.0%	4.5%	5.0%
2031 - 2035	6.0%	6.5%	7.0%
2036 - 2040	5.5%	6.0%	6.5%
2041 - 2045	4.5%	5.0%	4.5%
2046 - 2050	3.5%	4.0%	3.5%

Population growth rate

Historical data about population are reported in section 3.2.

According to previous study "Consultancy Services for Feasibility Study for the Ethiopia - Somalia Electricity Transmission Line Interconnections "the assumptions about the growth are reported in Table 3-25.

Table 3-25 - Population growth rate

Period	2023 - 2028	2029- 2040	2041 - 2050
Growth rate	3.1%	3.0%	2.9%

Elasticity of Demand
The elasticity of electricity demand is the ratio between the electricity demand and the GDP (it tries to answer to the question: "*what is the percentage variation of electricity demand respect to a unitary percentage variation of GDP?*").

This value is variable from Country to Country (and from year to year in the same Country) and its determination is very complex (there is a very huge literature on the subject).

A practical indication of this value can be obtained by the analysis of
Figure 3-9 that shows the electricity demand and real GDP growths in emerging and developing economies in the period 1990-2021 (the source of data is the IEA).

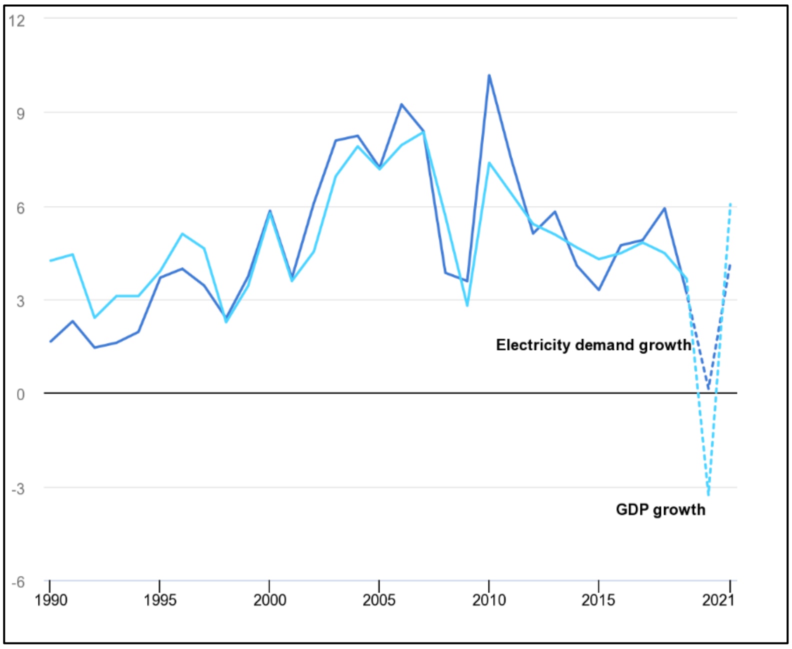


Figure 3-9 - Electricity demand and real GDP growths in emerging and developing economies in the period 1990-2021. Source: https://www.iea.org/data-and-statistics/charts/electricity-demand-and-real-gdp-growth-in-emerging-and-developing-economies-1990-2021

The analysis of the data from the period 2010 – 2019 (not taking into consideration the effect of COVID 19 pandemic) shows an average value of the ratio between electricity demand and GDP growths a little higher than 1 (1.1).

Based on these considerations, the elasticity of Demand is assumed to be equal to 1.1 in the first years and then it is decreasing due to the positive effects produced by the development of the national grid.

As a result, Table 3-26 shows the **potential demand** in the base scenario obtained based on these assumptions. Complete results are reported in Annex 1.

Table 3-26 Estimated potential demand for Somalia – Base scenario – Energy (GWh)

Year	Banadir Sub-grid	Central Sub-grid	Northeastern Sub-grid	Northwestern Sub-grid	Southern Sub-grid	Southwestern Sub-grid
2024	1,000	145	300	821	173	85
2025	1,049	162	332	893	190	93
2026	1,159	181	368	971	212	103
2027	1,279	203	407	1,055	236	115
2028	1,441	230	460	1,168	262	130
2029	1,621	260	519	1,291	292	147
2030	1,823	294	586	1,428	324	166
2031	2,051	333	661	1,578	361	187
2032	2,305	376	745	1,743	401	211
2033	2,590	425	840	1,924	445	238
2034	2,906	480	946	2,122	495	269
2035	3,261	542	1,066	2,340	549	303
2036	3,637	608	1,193	2,561	606	340
2037	4,051	683	1,335	2,803	669	381
2038	4,506	765	1,493	3,064	737	426
2039	5,012	857	1,669	3,349	813	476
2040	5,569	958	1,864	3,657	894	531
2041	6,123	1,060	2,060	3,951	972	587
2042	6,732	1,173	2,276	4,270	1,058	649
2043	7,402	1,297	2,515	4,613	1,152	717
2044	8,061	1,422	2,752	4,937	1,241	785
2045	8,769	1,555	3,004	5,283	1,337	857
2046	9,289	1,667	3,215	5,589	1,414	919
2047	9,829	1,784	3,433	5,912	1,495	983
2048	10,346	1,893	3,636	6,253	1,571	1,044
2049	10,878	2,005	3,843	6,615	1,673	1,107
2050	11,492	2,119	4,054	6,997	1,858	1,170

The figures reported below show the behaviour of the potential demand for each region of Somalia and for all scenarios considered in the load forecast analysis (base, low and high scenarios). For more details and all numbers at the base of the following figure, see Annex 1.

Banadir Sub-grid

Figure 3-10 shows the potential demand of Banadir Sub-grid in the three different scenarios.

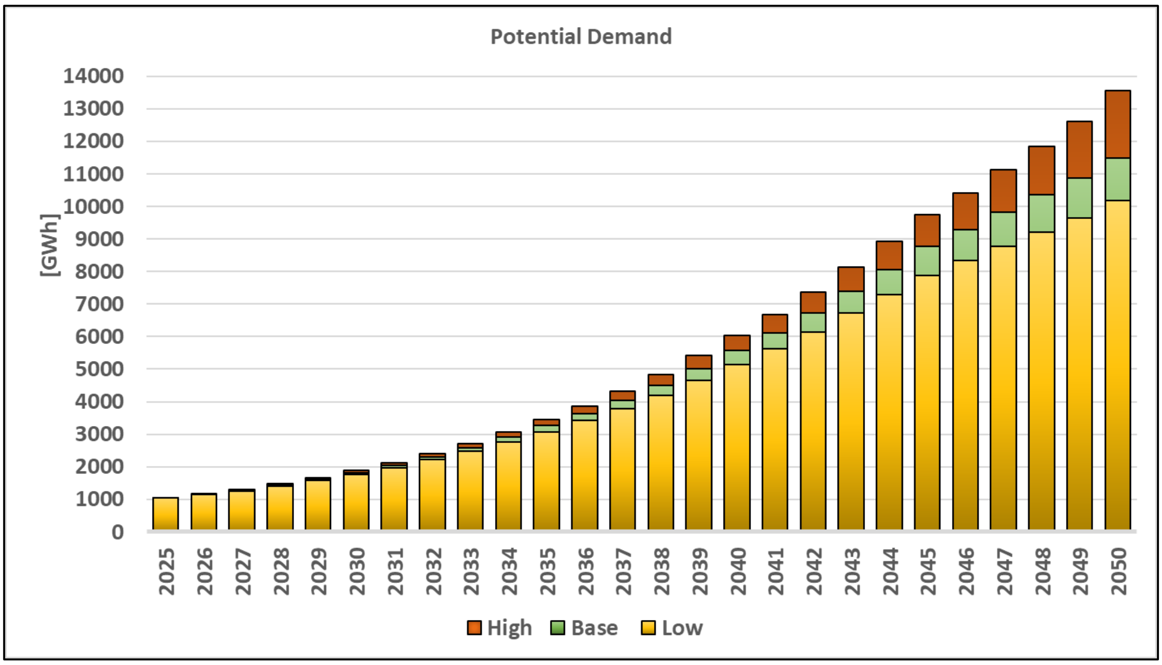


Figure 3-10 – Potential Demand Banadir Sub-grid

Central Sub-grid

Figure 3-11 shows the potential demand of Central Sub-grid in the three different scenarios.

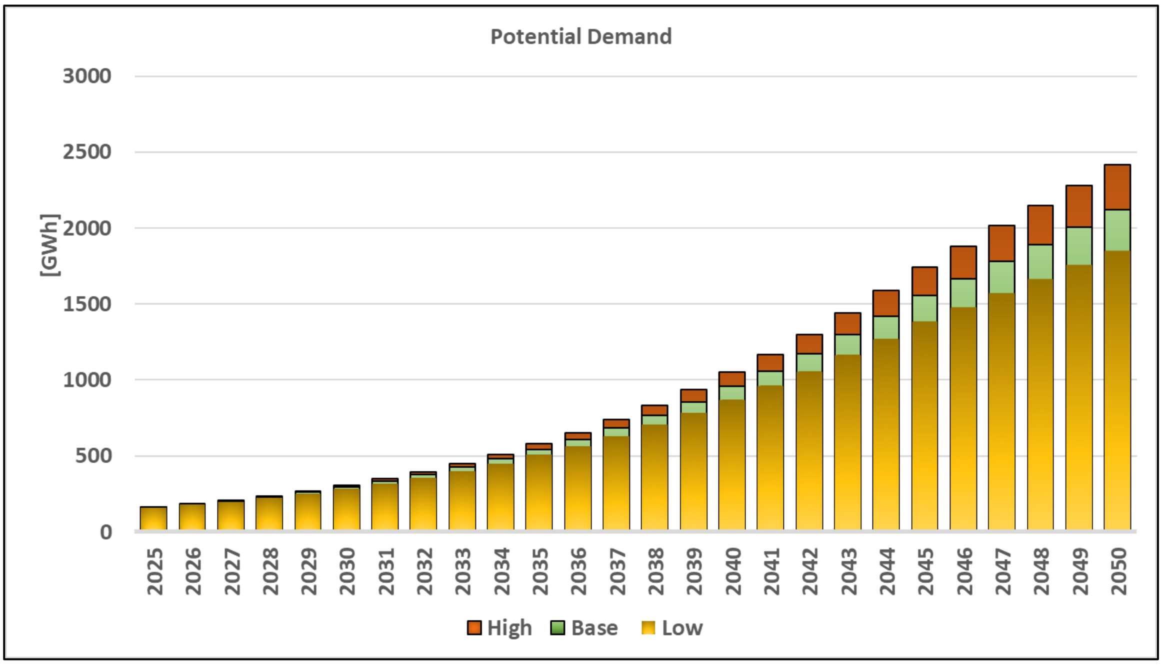


Figure 3-11 – Potential Demand Central Sub-grid

Northeastern Sub-grid

Figure 3-12 shows the potential demand of Northeastern Sub-grid in the three different scenarios.

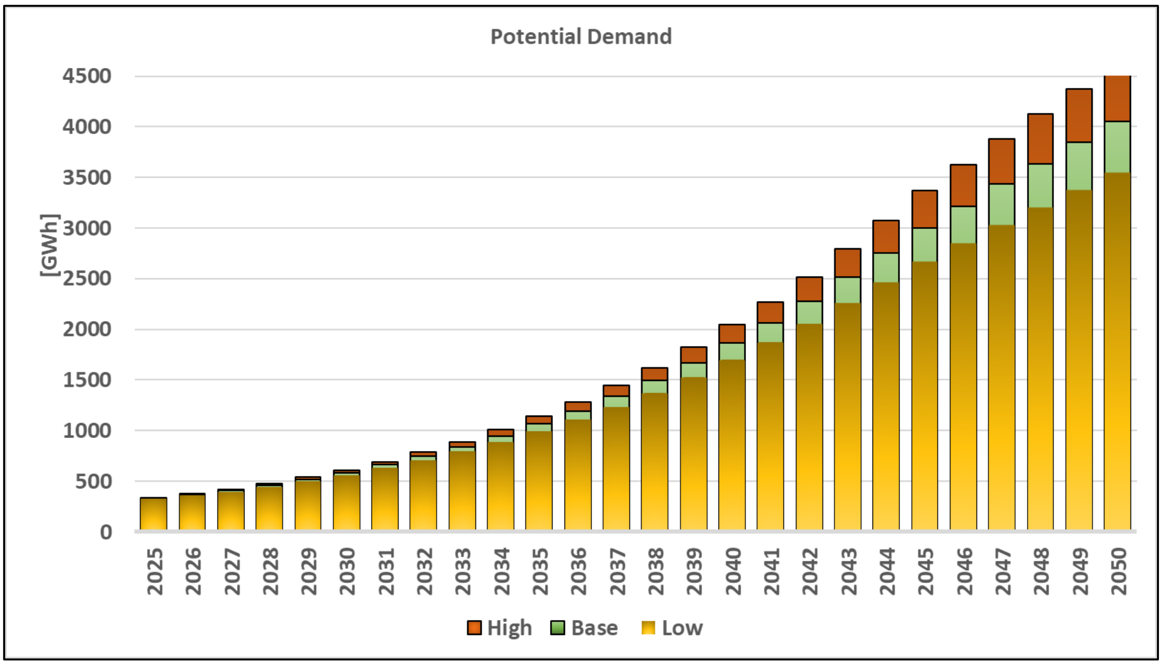


Figure 3-12 – Potential Demand Northeastern Sub-grid

Northwestern Sub-grid

Figure 3-13 shows the potential demand of Northwestern Sub-grid in the three different scenarios.

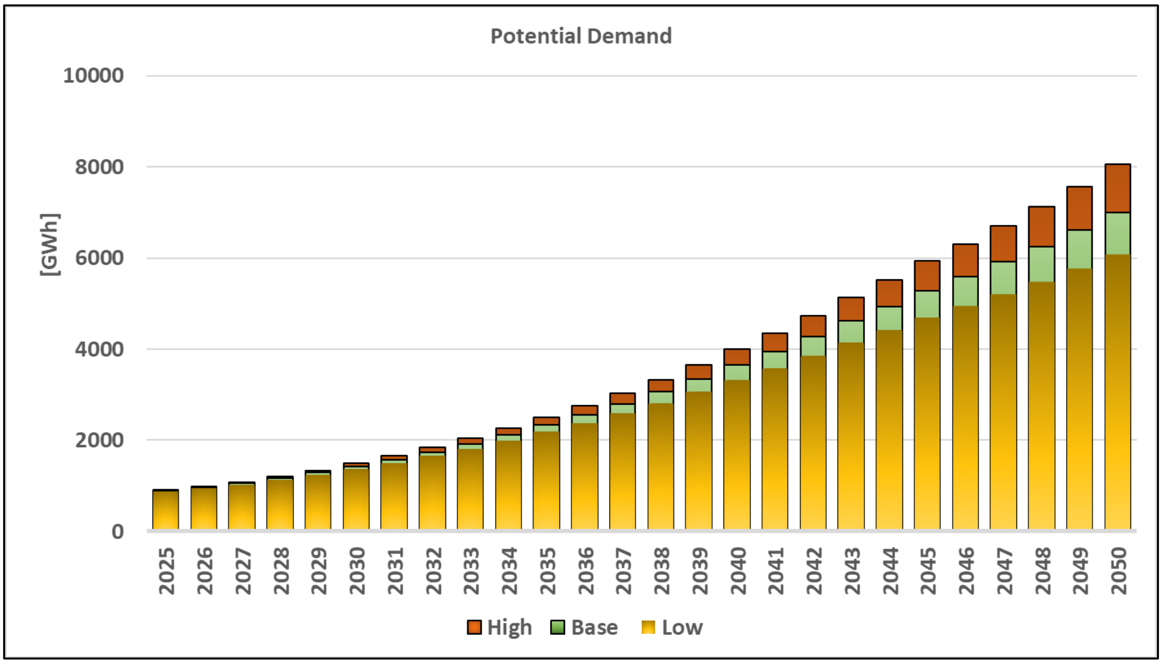


Figure 3-13 – Potential Demand Northwestern Sub-grid

Southern Sub-grid

Figure 3-14 shows the potential demand of Southern Sub-grid in the three different scenarios.

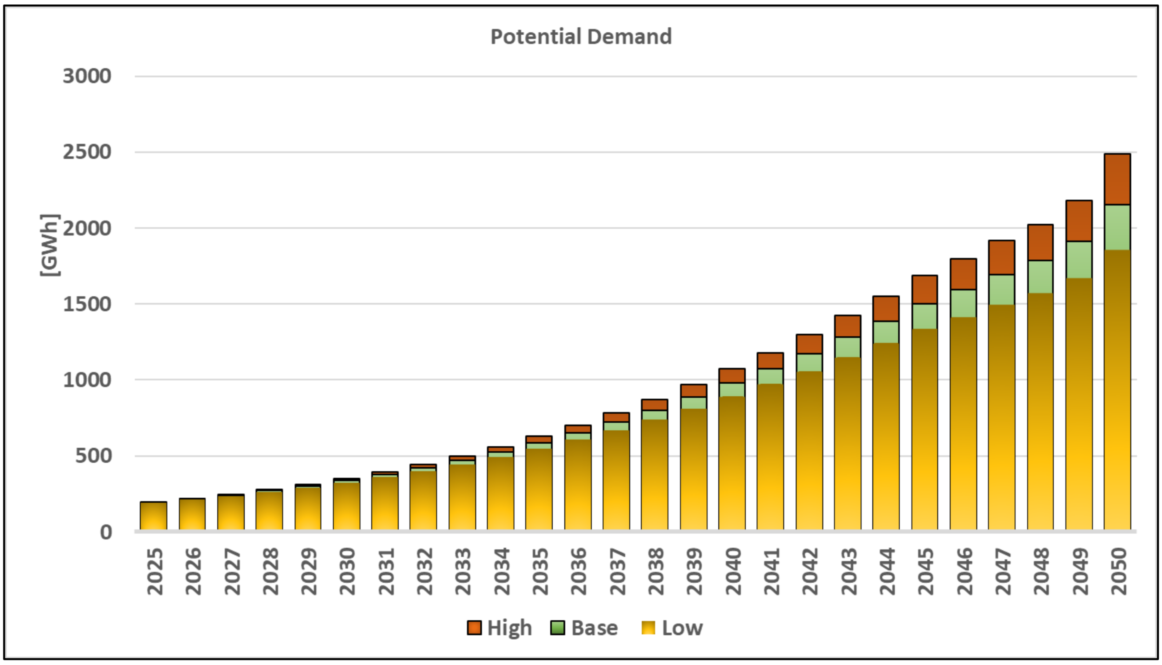


Figure 3-14 – Potential Demand Southern Sub-grid

Southwestern Sub grid

Figure 3-15 shows the potential demand of Southwestern Sub-grid in the three different scenarios.

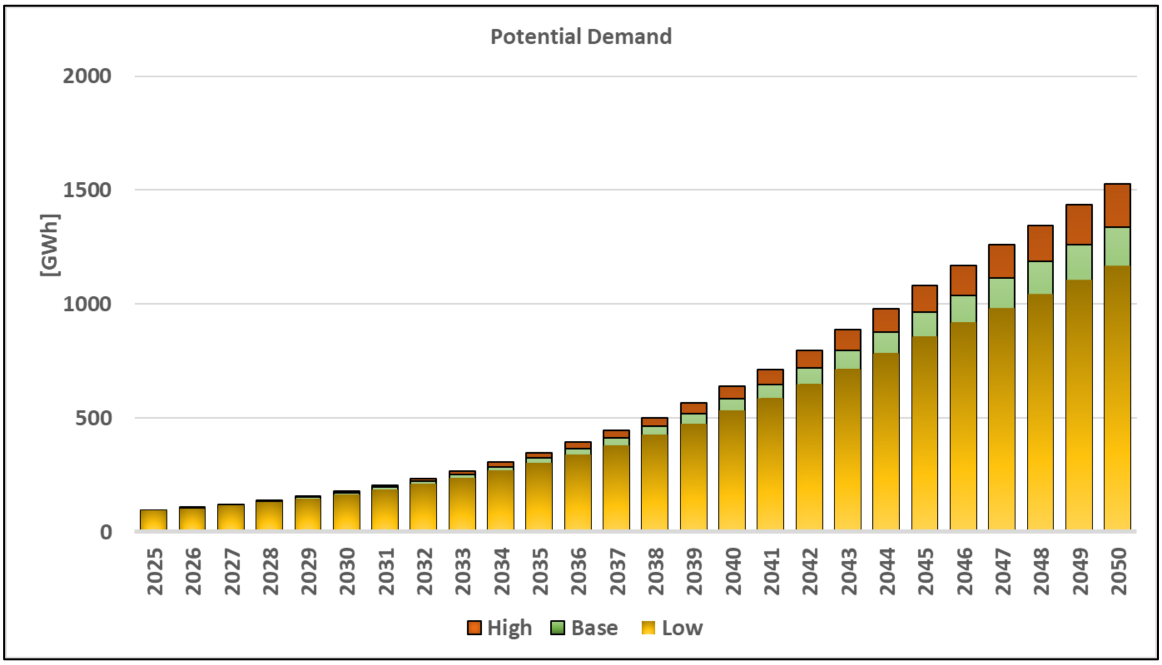


Figure 3-15 – Potential Demand Southwestern Sub-grid

Eastern Sub grid

As said, the National Transformation Plan of the Federal Government However, the document underlines as Somalia is beginning to explore its untapped hydrocarbon resources: the Government has signed 16 Production Sharing Agreements (PSAs) covering onshore and offshore blocks (see Figure 3-16), which have the potential to generate significant revenue through royalties, profit-sharing, and signing bonuses.

Institutions such as the Somalia Petroleum Authority (SPA) and the SONOC are being strengthened to oversee and manage these developments effectively.

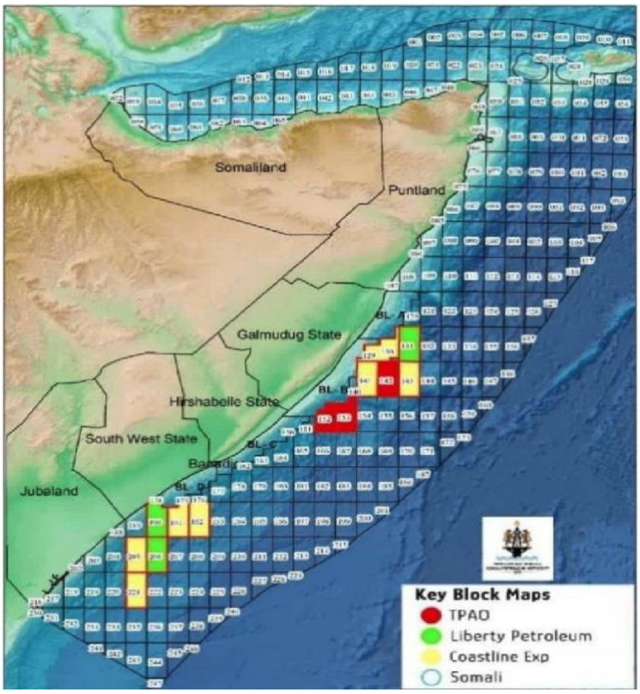


Figure 3-16 – Key Block Maps

The Eastern Sub-grid is a new grid that could supply the electrical demand related to these new activities.

Based on industry studies and engineering reports, the electric power consumption for oil and gas platforms typically ranges from around 5 MW up to 100 MW.
For instance, some reports have cited that larger production platforms may be designed to handle continuous consumption in this range, and in some cases even higher depending on specific operational demands or auxiliary loads like water injection systems and gas lift pumps.

The demand of the Eastern Sub-grid is determined by the number of platforms. In any case, for a 50 MW platform with a continuous consumption it means 438, 000 MWh.

It is to underline that in the world offshore oil and gas platforms consume substantial amounts of electricity, with estimates around 16 terawatt-hours (TWh) annually. This consumption is largely for powering operations like drilling, extraction, processing, and other platform activities.

Traditionally, this electricity is generated on-site using gas turbines or diesel generators, which can result in significant CO_2 emissions and there's a growing push towards utilizing renewable energy sources, such as wind and wave power, to reduce the environmental impact of offshore platforms.

Step 3 - Determination of the Supplied Demand

The supplied demand represents part of the potential demand that is supplied thanks to the presence of local generation and/or the presence of the transmission grid able to transmit the electricity from generators to load canters.

The estimation of the supplied demand in Somalia is related to the different starting years for the development of the internal connections of the different grid, in the different target years 2030, 2035, 2040, 2045 and 2050.

- Target year 2030
    - National grid and generation facilities start their developments giving priority to the electrification of the 7 region capitals
    - Main drivers are the connection of main cities, the electrification of the rural areas and the development of RES generation
- Target year 2035
    - Interconnections between Somalia and Ethiopia are operated. Other interconnections with different foreign countries are not considered
    - National grids keep growing thanks to the connection of other main cities and the evolution of local grids in the central area of the country, generation is continuously developed
- Target year 2040
    - All 7 regional capitals and main cities are connected to the National Grid that, up to now, is still divided in two parts
    - Main drivers are the electrification of rural areas, the creation of a backbone and the significant development of RES potential (both solar PV and wind)
- Target year 2045
    - Spread of electricity starting from the main cities to the rural areas in the whole regions of Somalia
    - Corridors along the coast are created to maximize RES penetration and allow the connection of RES power plants
- Target year 2050
    - Creation of the backbone is complete, Somalia National Grid is complete
    - Backbone is developed along the coast to collect RES production and deliver it to the load centers (and abroad) through several corridors at different voltage levels
    - It is assumed that the transmission network is mainly developed in a single-circuit configuration, except for the two interconnections with Ethiopia and eventually other critical corridors. This will be verified during the network analysis

The supplied demand also includes losses.

At this regard, assumptions have been done about the distribution losses, which are assumed starting from 15% of the total expected consumption in 2025 decreasing up to 10% in the future.

Based on the following assumptions, the following paragraphs reports the detailed supplied demand for each region of Somalia. For a complete description of the numeric values, see Annex 2.1.

Regarding the transmission losses, it is worth mentioning that their quantification is extremely difficult because, currently, the transmission grid does not exist in Somalia, therefore there are not historical series of this type of losses. In any case, it is reasonable to suppose that the transmission losses will be limited to few percentages of total consumption.
More in detail, the following considerations can be made:

- 0% are the transmission losses up to the year at which the transmission grid is supposed to be developed (different years in the different regions), since the transmission grid is not present,
- 1-2% can be the transmission losses since the development of the transmission grid, considering that the expected electricity demand will not charge in a significant way the transmission components.

Considering the hypotheses adopted for the estimation of the electricity demand and the uncertainties related to their quantification, the transmission losses are considered included in the supplied demand.

Banadir Sub-grid

Table 3-27 and Figure 3-17 show the Gross Supplied Demand of Banadir Sub-grid in the three different scenarios.

Table 3-27 Gross Supplied Demand – Banadir Sub-grid –

Year	Low Case		Base case		High Case	
	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]
2025	868	152	868	152	868	152
2026	918	161	918	161	918	161
2027	971	170	971	170	971	170
2028	1,026	180	1,026	180	1,026	180
2029	1,087	191	1,087	191	1,087	191
2030	1,597	280	1,630	286	1,664	292
2031	1,792	315	1,838	323	1,886	331
2032	2,017	354	2,080	365	2,146	377
2033	2,277	400	2,362	415	2,451	430
2034	2,562	450	2,673	469	2,789	490
2035	3,026	531	3,182	559	3,347	588
2036	3,400	597	3,596	632	3,804	668
2037	3,795	667	4,036	709	4,292	754
2038	4,235	744	4,528	795	4,841	850
2039	4,768	837	5,127	900	5,513	968
2040	5,438	955	5,884	1,033	6,366	1,118
2041	5,973	1,049	6,495	1,141	7,062	1,240
2042	6,561	1,152	7,171	1,259	7,836	1,376
2043	7,217	1,268	7,928	1,392	8,707	1,529
2044	7,857	1,380	8,675	1,524	9,575	1,682
2045	8,545	1,501	9,483	1,665	10,520	1,848
2046	9,062	1,591	10,099	1,774	11,305	1,985
2047	9,802	1,722	10,982	1,929	12,417	2,181
2048	10,277	1,805	11,547	2,028	13,224	2,322
2049	10,773	1,892	12,141	2,132	14,082	2,473
2050	11,347	1,993	12,826	2,252	15,125	2,656

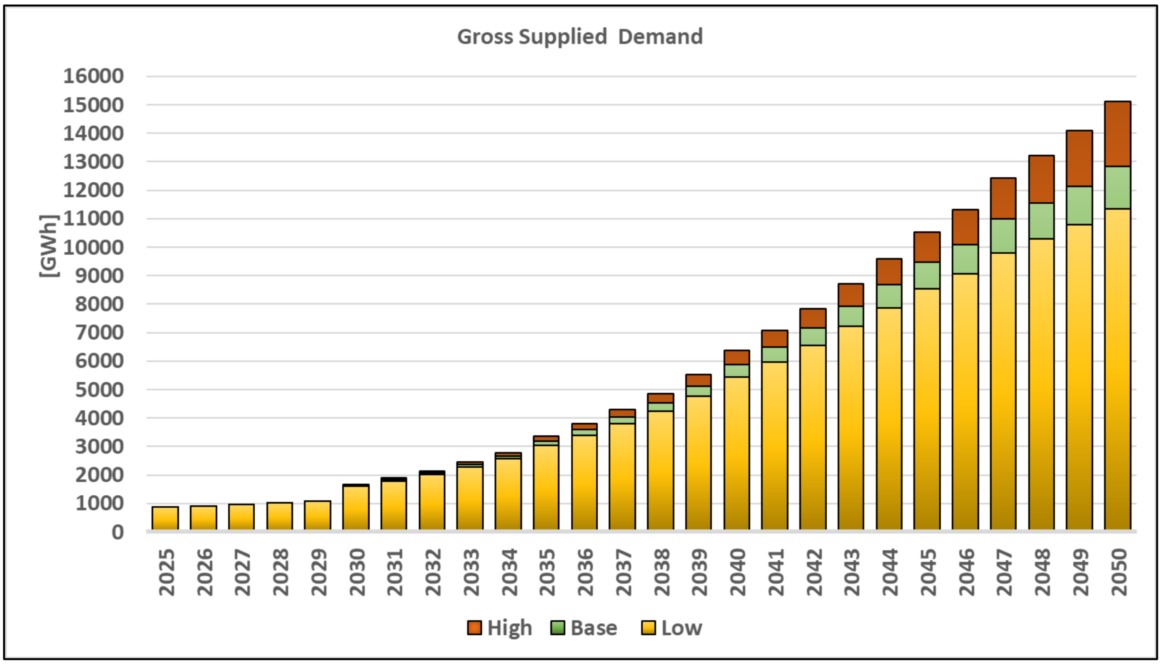


Figure 3-17 – Gross Supplied Demand Banadir Sub-grid

Central Sub-grid

Table 3-28 and Figure 3-18 show the Gross Demand Supply of Central Sub-grid in the three different scenarios.

Table 3-28 Gross Supplied Demand –Central Sub-grid –

Year	Low Case		Base case		High Case	
	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]
2025	61	11	61	11	61	11
2026	65	11	65	11	65	11
2027	70	12	70	12	70	12
2028	74	13	74	13	74	13
2029	80	14	80	14	80	14
2030	85	15	85	15	85	15
2031	91	16	91	16	91	16
2032	97	17	97	17	97	17
2033	103	18	103	18	103	18
2034	110	19	110	19	110	19
2035	303	53	319	56	336	59
2036	345	61	365	64	387	68
2037	386	68	411	72	438	77
2038	433	76	463	81	496	87
2039	493	87	531	93	572	100
2040	577	101	625	110	677	119
2041	631	111	687	121	748	131
2042	792	139	869	153	953	167
2043	924	162	1,021	179	1,127	198
2044	1,065	187	1,183	208	1,315	231
2045	1,288	226	1,441	253	1,612	283
2046	1,599	281	1,802	316	2,029	356
2047	1,760	309	1,993	350	2,255	396
2048	1,861	327	2,113	371	2,397	421
2049	1,965	345	2,238	393	2,546	447
2050	2,070	364	2,365	415	2,699	474

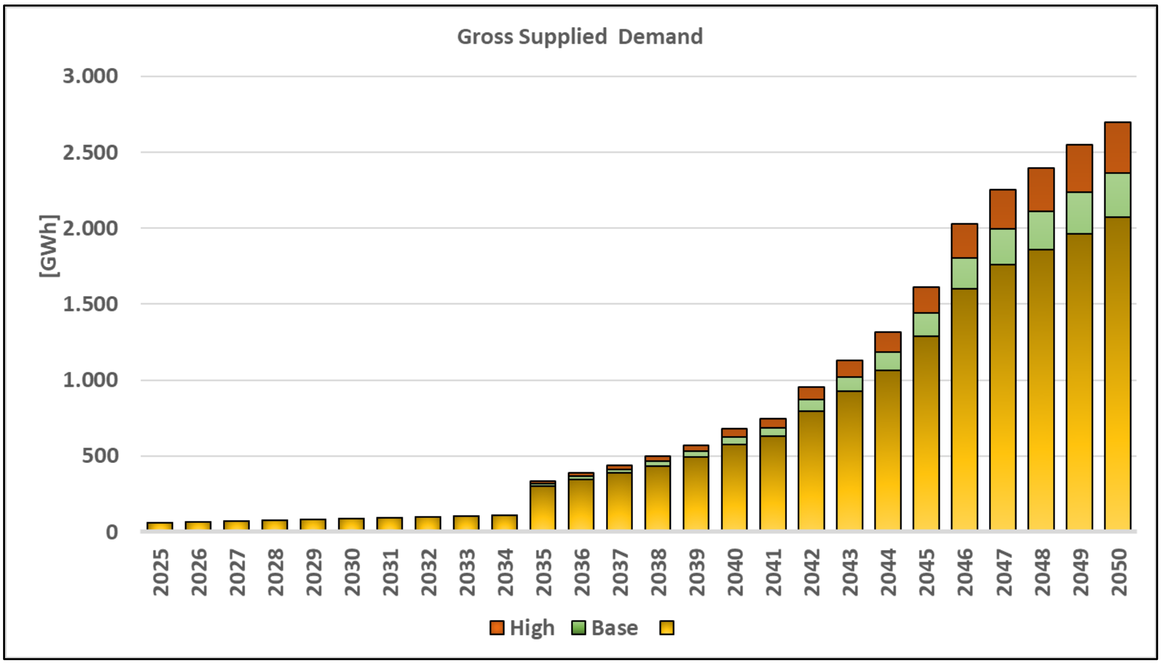


Figure 3-18 – Gross Supplied Demand Central Sub-grid

Northeastern Sub-grid

Table 3-29 and Figure 3-19 shows the Gross Supplied Demand of Northeastern Sub-grid in the three different scenarios.

Table 3-29 Gross Supplied Demand – Northeastern Sub-grid –

Year	Low Case		Base case		High Case	
	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]
2025	116	20	116	20	116	20
2026	124	22	124	22	124	22
2027	132	23	132	23	132	23
2028	141	25	141	25	141	25
2029	151	26	151	26	151	26
2030	259	45	264	46	270	47
2031	311	55	319	56	329	58
2032	373	65	386	68	399	70
2033	446	78	465	82	485	85
2034	534	94	560	98	588	103
2035	682	120	722	127	764	134
2036	805	141	857	151	913	160
2037	947	166	1,015	178	1,089	191
2038	1,073	188	1,156	203	1,246	219
2039	1,217	214	1,318	232	1,429	251
2040	1,523	268	1,663	292	1,815	319
2041	1,723	303	1,890	332	2,074	364
2042	1,947	342	2,148	377	2,370	416
2043	2,397	421	2,664	468	2,958	520
2044	2,628	461	2,935	515	3,276	575
2045	2,873	505	3,224	566	3,617	635
2046	3,083	541	3,474	610	3,913	687
2047	3,388	595	3,835	674	4,339	762
2048	3,574	628	4,058	713	4,605	809
2049	3,767	662	4,290	753	4,882	857
2050	3,961	696	4,524	795	5,164	907

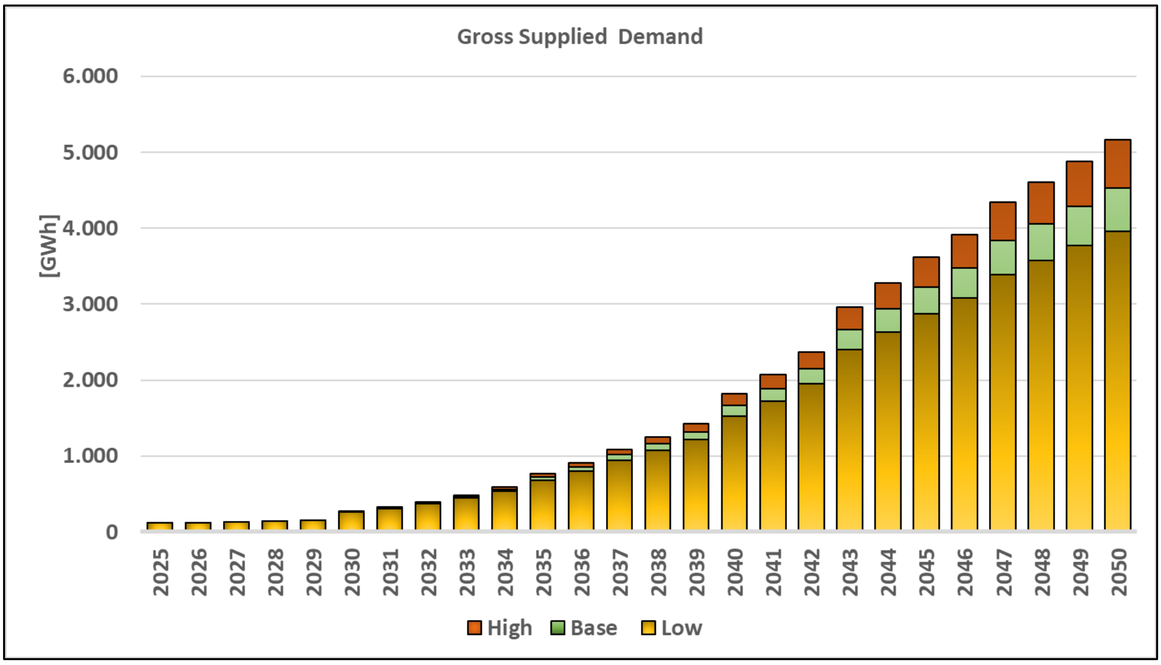


Figure 3-19 – Gross Supplied Demand Northeastern Sub-grid

Northwestern Sub-grid

Table 3-30 and Figure 3-20 shows the Gross Supplied Demand of Northwestern Sub-grid in the three different scenarios.

Table 3-30 Gross Supplied Demand – Northwestern Sub-grid –

Year	Low Case		Base case		High Case	
	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]
2025	501	88	501	88	501	88
2026	535	94	535	94	535	94
2027	571	100	571	100	571	100
2028	606	106	610	107	610	107
2029	647	114	651	114	651	114
2030	1,153	202	1,177	207	1,198	210
2031	1,273	224	1,306	229	1,335	235
2032	1,408	247	1,451	255	1,492	262
2033	1,560	274	1,617	284	1,672	294
2034	1,731	304	1,803	317	1,876	329
2035	1,923	338	2,015	354	2,109	370
2036	2,142	376	2,259	397	2,380	418
2037	2,386	419	2,534	445	2,689	472
2038	2,658	467	2,842	499	3,037	533
2039	2,962	520	3,190	560	3,432	603
2040	3,299	579	3,578	628	3,877	681
2041	3,639	639	3,974	698	4,336	762
2042	4,012	705	4,413	775	4,849	852
2043	4,432	778	4,911	862	5,435	955
2044	4,761	836	5,306	932	5,905	1,037
2045	5,139	903	5,763	1,012	6,453	1,133
2046	5,429	953	6,120	1,075	6,890	1,210
2047	5,820	1,022	6,608	1,161	7,490	1,315
2048	6,114	1,074	6,976	1,225	7,946	1,395
2049	6,424	1,128	7,365	1,293	8,429	1,480
2050	6,749	1,185	7,775	1,365	8,942	1,570

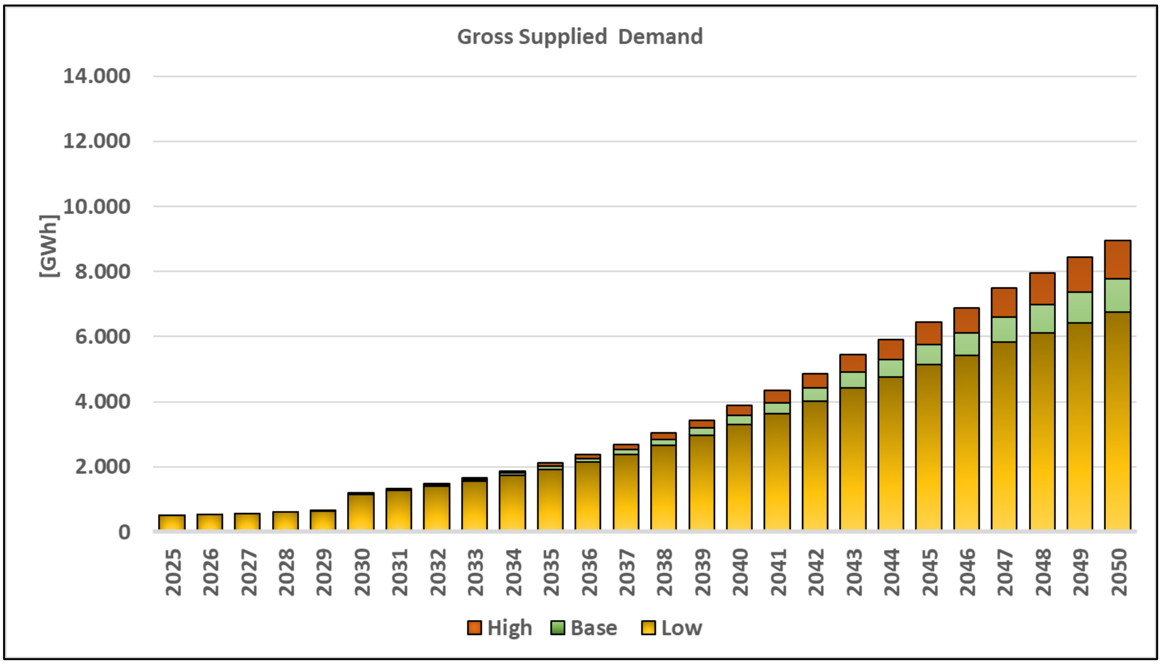


Figure 3-20 – Gross Supplied Demand Northwestern Sub-grid

Southern Sub-grid

Table 3-31 and Figure 3-21 shows the Gross Supplied Demand potential demand of Southern Sub-grid in the three different scenarios.

Table 3-31 Gross Supplied Demand – Southern Sub-grid –

Year	Low Case		Base case		High Case	
	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]
2025	72	13	72	13	72	13
2026	77	14	77	14	77	14
2027	82	14	82	14	82	14
2028	88	15	88	15	88	15
2029	94	17	94	17	94	17
2030	155	27	159	28	162	28
2031	181	32	186	33	191	34
2032	205	36	211	37	218	38
2033	231	41	240	42	249	44
2034	270	47	282	50	295	52
2035	335	59	353	62	372	65
2036	388	68	411	72	436	77
2037	449	79	478	84	510	90
2038	517	91	555	97	596	105
2039	597	105	644	113	696	122
2040	685	120	744	131	808	142
2041	787	138	860	151	940	165
2042	902	158	992	174	1,091	192
2043	1,033	181	1,142	201	1,264	222
2044	1,167	205	1,299	228	1,446	254
2045	1,439	253	1,615	284	1,811	318
2046	1,532	269	1,726	303	1,944	341
2047	1,670	293	1,891	332	2,140	376
2048	1,753	308	1,991	350	2,260	397
2049	1,867	328	2,133	375	2,435	428
2050	2,074	364	2,402	422	2,779	488

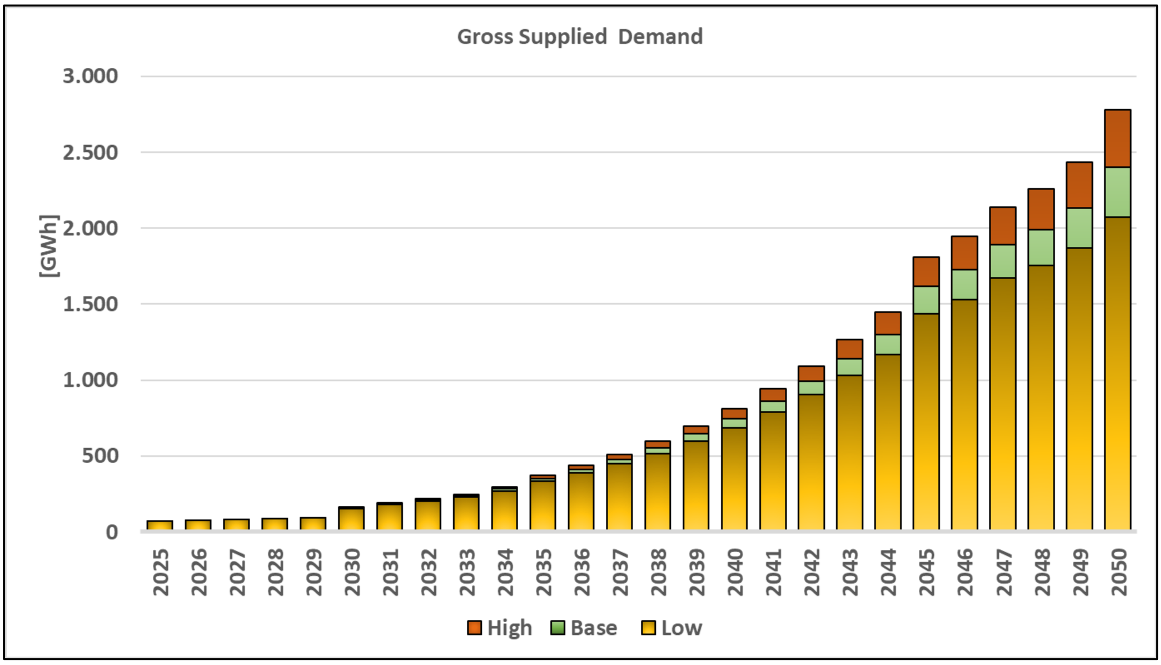


Figure 3-21 – Gross Supplied Demand Southern Sub-grid

Southwestern Sub grid

Table 3-32 and Figure 3-22 show the Gross Supplied Demand of Southwestern Sub-grid in the three different scenarios.

Table 3-32 Gross Supplied Demand – Southwestern Sub-grid –

Year	Low Case		Base case		High Case	
	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]
2025	36	6	36	6	36	6
2026	39	7	39	7	39	7
2027	41	7	41	7	41	7
2028	44	8	44	8	44	8
2029	47	8	47	8	47	8
2030	78	14	80	14	82	14
2031	94	17	97	17	100	17
2032	117	21	121	21	125	22
2033	144	25	150	26	157	28
2034	199	35	210	37	222	39
2035	208	37	221	39	234	41
2036	247	43	263	46	280	49
2037	292	51	313	55	336	59
2038	340	60	367	64	396	70
2039	397	70	430	76	467	82
2040	476	84	520	91	567	100
2041	541	95	594	104	652	114
2042	620	109	685	120	756	133
2043	760	134	845	148	938	165
2044	838	147	935	164	1,044	183
2045	921	162	1,033	182	1,159	204
2046	994	175	1,120	197	1,261	222
2047	1,098	193	1,243	218	1,407	247
2048	1,165	205	1,323	232	1,501	264
2049	1,235	217	1,406	247	1,601	281
2050	1,306	229	1,492	262	1,703	299

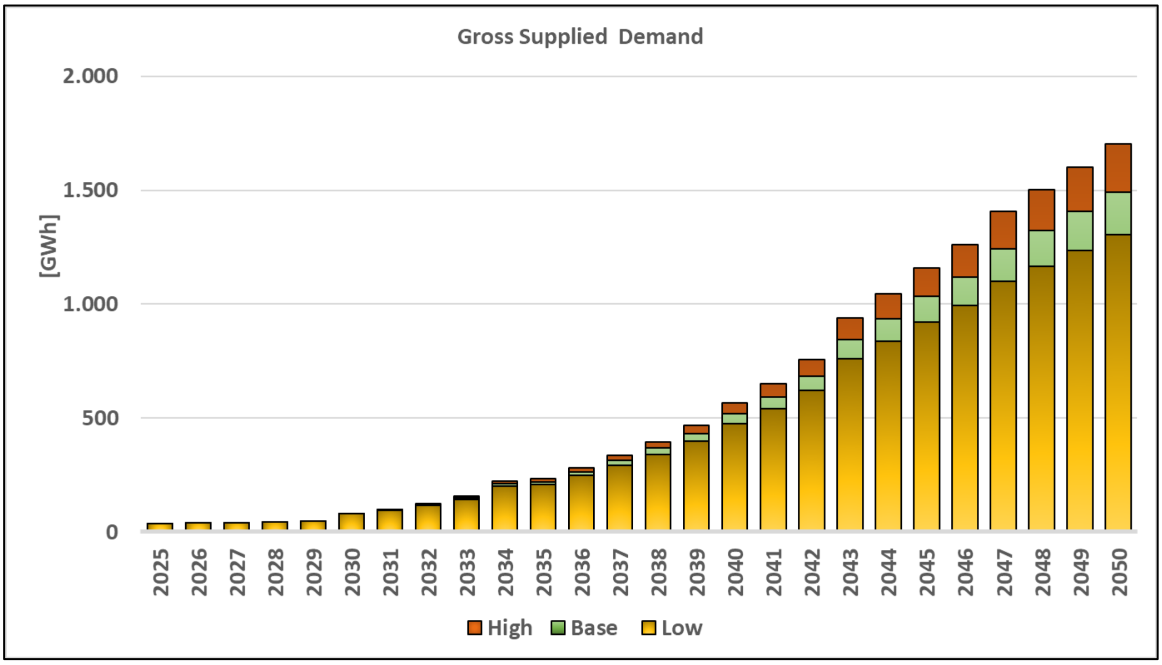


Figure 3-22 – Gross Supplied Demand Southwestern Sub-grid

3.4.2 Top-Down approach

As said, the Top-Down approach considers the total demand of Somalia (the Country as a whole).

The assumptions about the independent variables are substantially the same described for the Bottom-Up approach but applied to the whole Somalia.

The main results are resumed in Table 3-33 for the base case, while complete results are resumed in Annex 2.2.

Table 3-33 Gross Supplied Demand – Top-Down Approach

Year	Low Case		Base case		High Case	
	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]	Demand [GWh]	Peak [MW]
2025	751	132	751	132	751	132
2026	802	141	802	141	802	141
2027	856	150	856	150	856	150
2028	914	161	914	161	914	161
2029	977	172	977	172	977	172
2030	1,872	329	1,916	337	1,962	345
2031	2,275	400	2,345	412	2,417	424
2032	2,748	483	2,851	501	2,959	520
2033	3,305	581	3,452	606	3,607	633
2034	3,959	695	4,162	731	4,377	769
2035	5,081	892	5,386	946	5,709	1,003
2036	5,975	1,049	6,372	1,119	6,796	1,194
2037	7,004	1,230	7,515	1,320	8,064	1,416
2038	7,882	1,384	8,501	1,493	9,170	1,610
2039	8,879	1,559	9,627	1,691	10,438	1,833
2040	11,066	1,943	12,084	2,122	13,195	2,317
2041	12,419	2,181	13,635	2,395	14,966	2,628
2042	13,928	2,446	15,372	2,700	16,963	2,979
2043	17,038	2,992	18,934	3,325	21,032	3,694
2044	18,517	3,252	20,681	3,632	23,087	4,055
2045	20,113	3,532	22,575	3,965	25,326	4,448
2046	21,489	3,774	24,218	4,253	27,278	4,791
2047	23,569	4,139	26,683	4,686	30,189	5,302
2048	24,860	4,366	28,227	4,957	32,031	5,625
2049	26,251	4,610	29,895	5,250	34,023	5,975
2050	27,720	4,868	31,661	5,560	36,139	6,347

3.4.3 Approaches comparison

Figure 3-23 shows the comparison between the two approaches (Top Down and Bottom-Up) described in the previous paragraphs, in the Base case scenario. As shown by the figure, there is a good agreement between the results obtained.

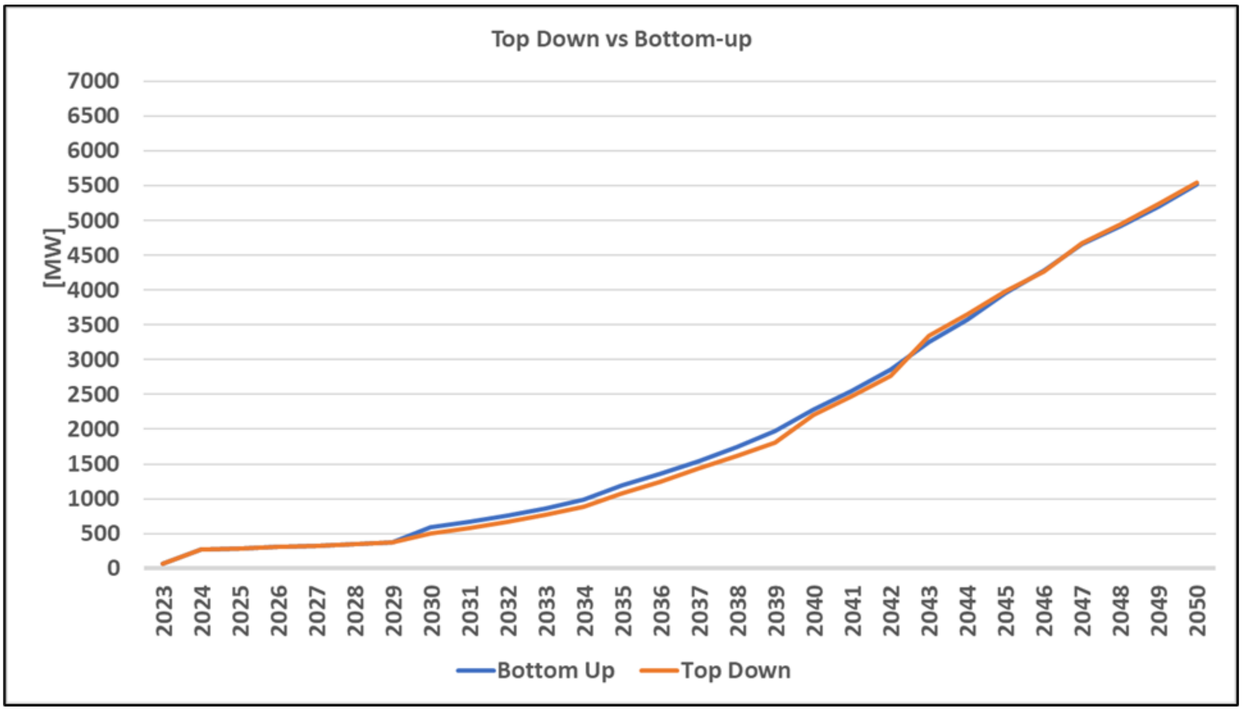


Figure 3-23 – Top-Down vs Bottom-up – Base case

3.4.4 Conclusions

To quantify the expected electricity consumption of the future Somali power system, a load demand forecast has been performed, starting from the analysis and elaboration of data and information contained in many documents, as the previous forecasts, public document describing the strategies of the Government, feasibility studies for the development of the electric system; these data have been also integrated with those collected with the Electricity Supply Providers through on-field activity.

Two different load demand forecast approaches have been developed: namely Bottom-Up and Top-Down.

The Bottom-Up approach has been mainly performed to develop a load forecast in terms of energy and peak, for the target years objective of the analysis, in the different areas of the Country.

Three different scenarios have been developed according to the different assumptions about the evolution in the future of the variables (GDP, population, electrification rate …) that have an effect on the evolution of the electricity demand; in this analysis, the effects of the transmission grid expansion plan have been considered too.

Then the Top-Down approach (based on the analysis of the Country as a whole) has been performed as a benchmark of the results obtained with the Bottom-Up one; the results of the two approaches are aligned between them, therefore the electricity consumption, in terms of peak and energy, represent the values that will be used in the subsequent analyses, i.e., the generation expansion and transmission expansion plans.

Geospatial maps of the evolution of the load Demand Forecast in the target years are obtained too and are reported in the next section.

3.5 ARCGIS MAPS OF LOAD DEMAND FORECAST results

This section reports the maps obtained with ArcGIS of the evolution of the Load Demand Forecast in the different target years.

The methodology adopted has been based on the following points

- The peak load value of each sub-grid (using the latest load estimation) has been allocated to the substations for each year.
- The territory assigned to each of the substations planned for the year 2050 has then be defined through the application of Voronoi polygons, which identify the area of influence based on distance.
- The Somalia territory has been then further subdivided in ArcGIS in a grid of cells of 10kmx10km.
- To each cell has been associated the population density (data retrieved from World Pop https://hub.worldpop.org/geodata/summary?id=49713).
- To each cell is then associated the substation to which it belongs, according to the Voronoi subdivision described above.
- The peak load of each substation is then distributed on the cells of its territory, proportionally to the population density.

Figure 3-24 to Figure 3-28 show the maps obtained

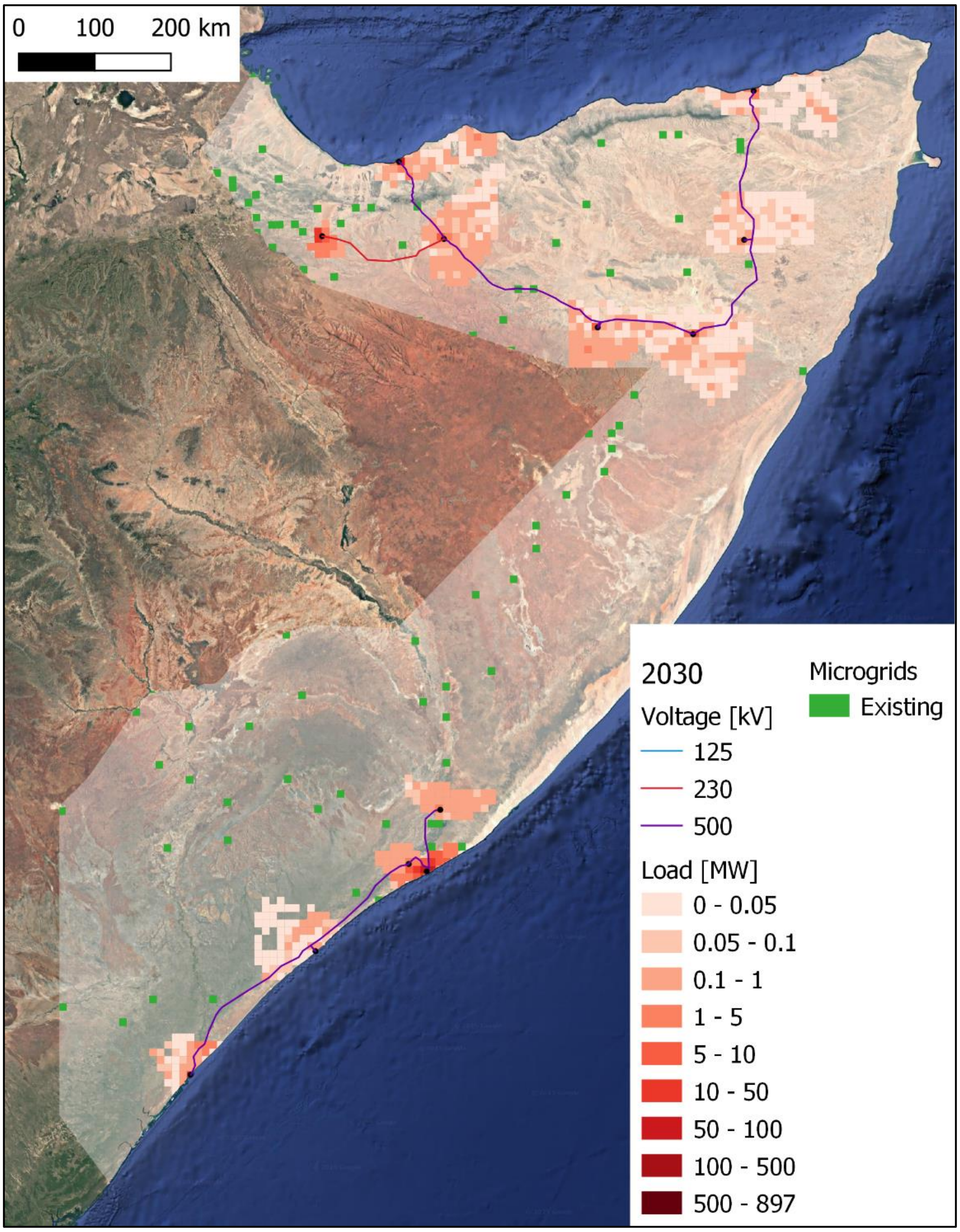


Figure 3-24 – ArcGIS map of Load Demand Forecast – year 2030

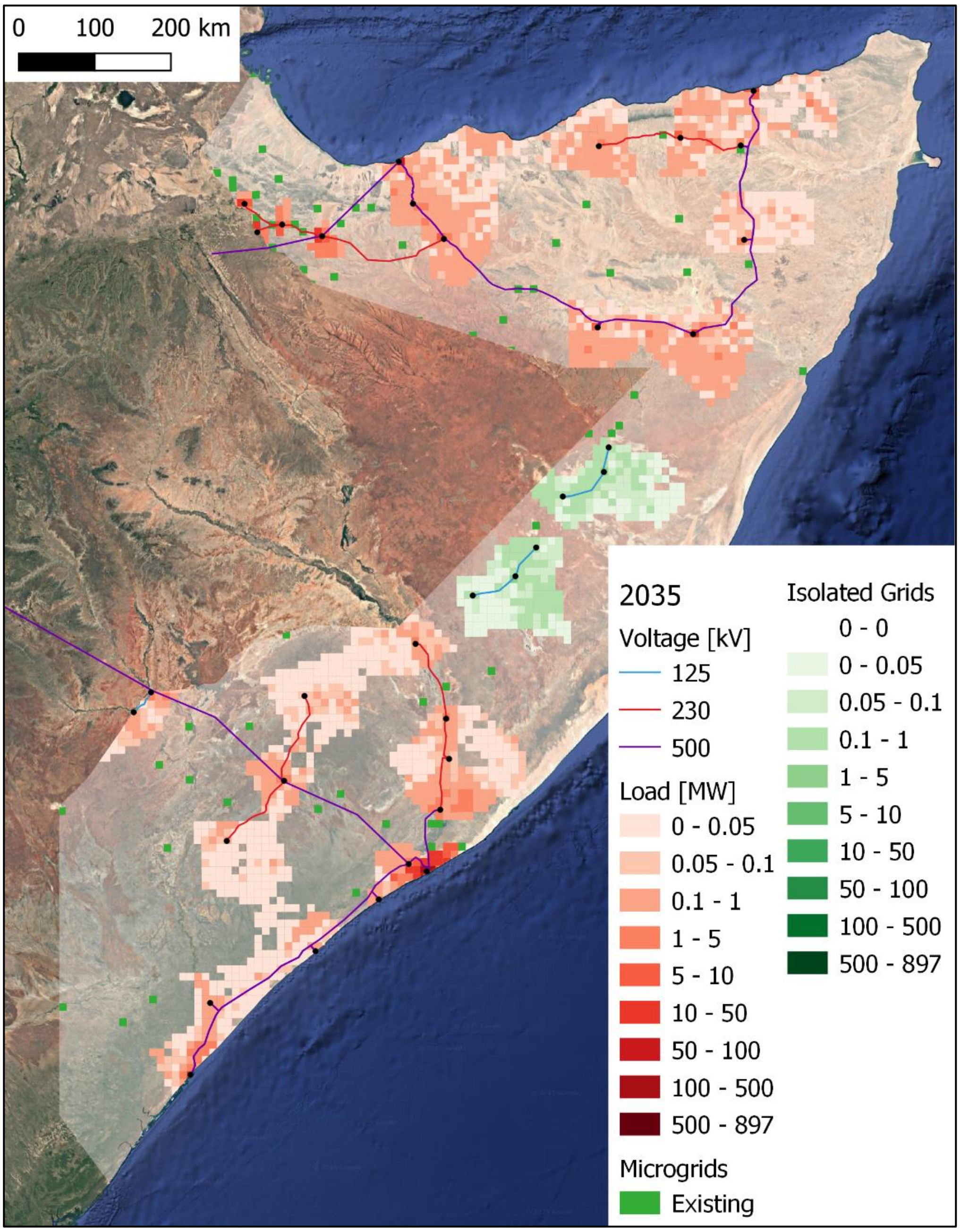


Figure 3-25 – ArcGIS map of Load Demand Forecast – year 2035

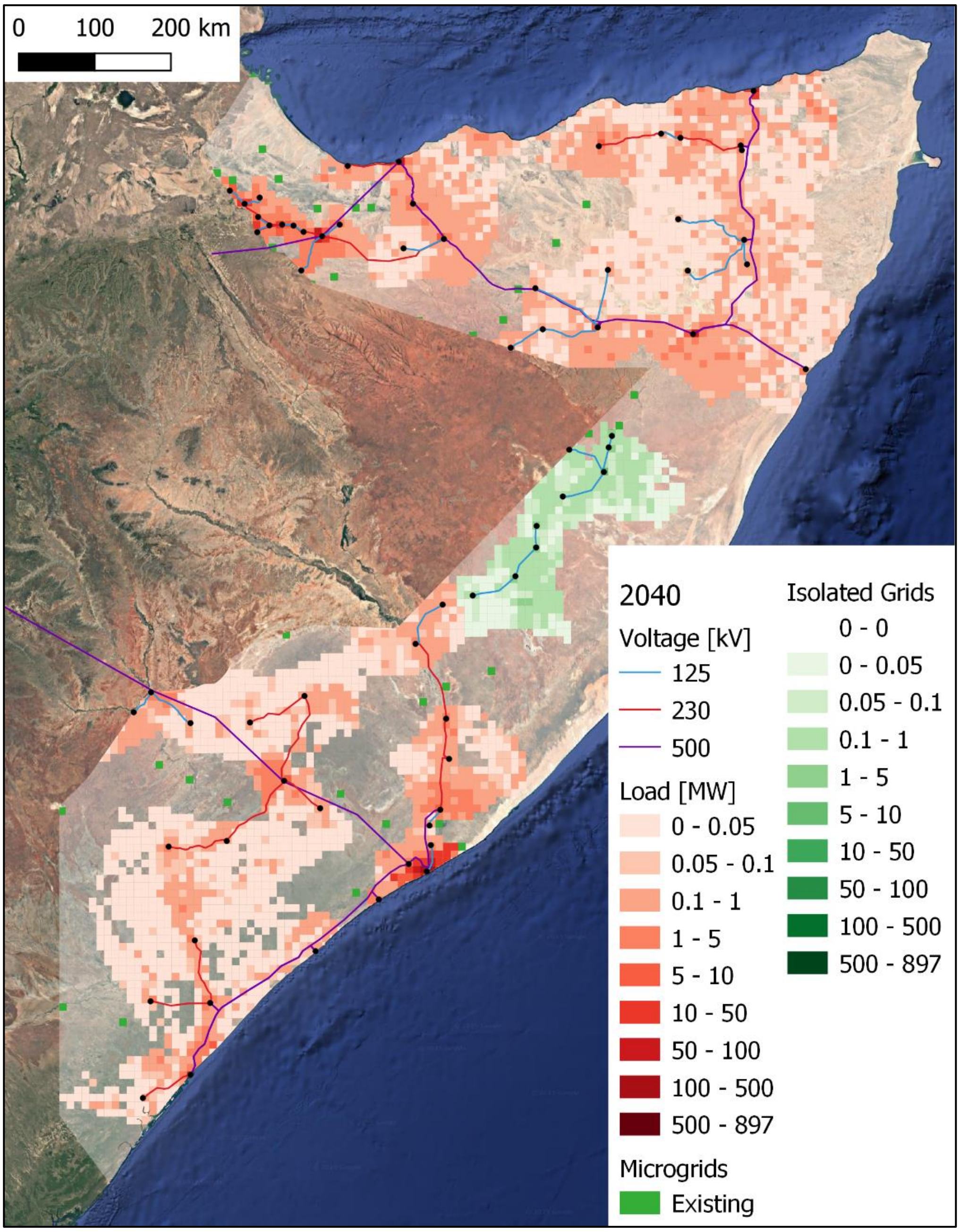


Figure 3-26 – ArcGIS map of Load Demand Forecast – year 2040

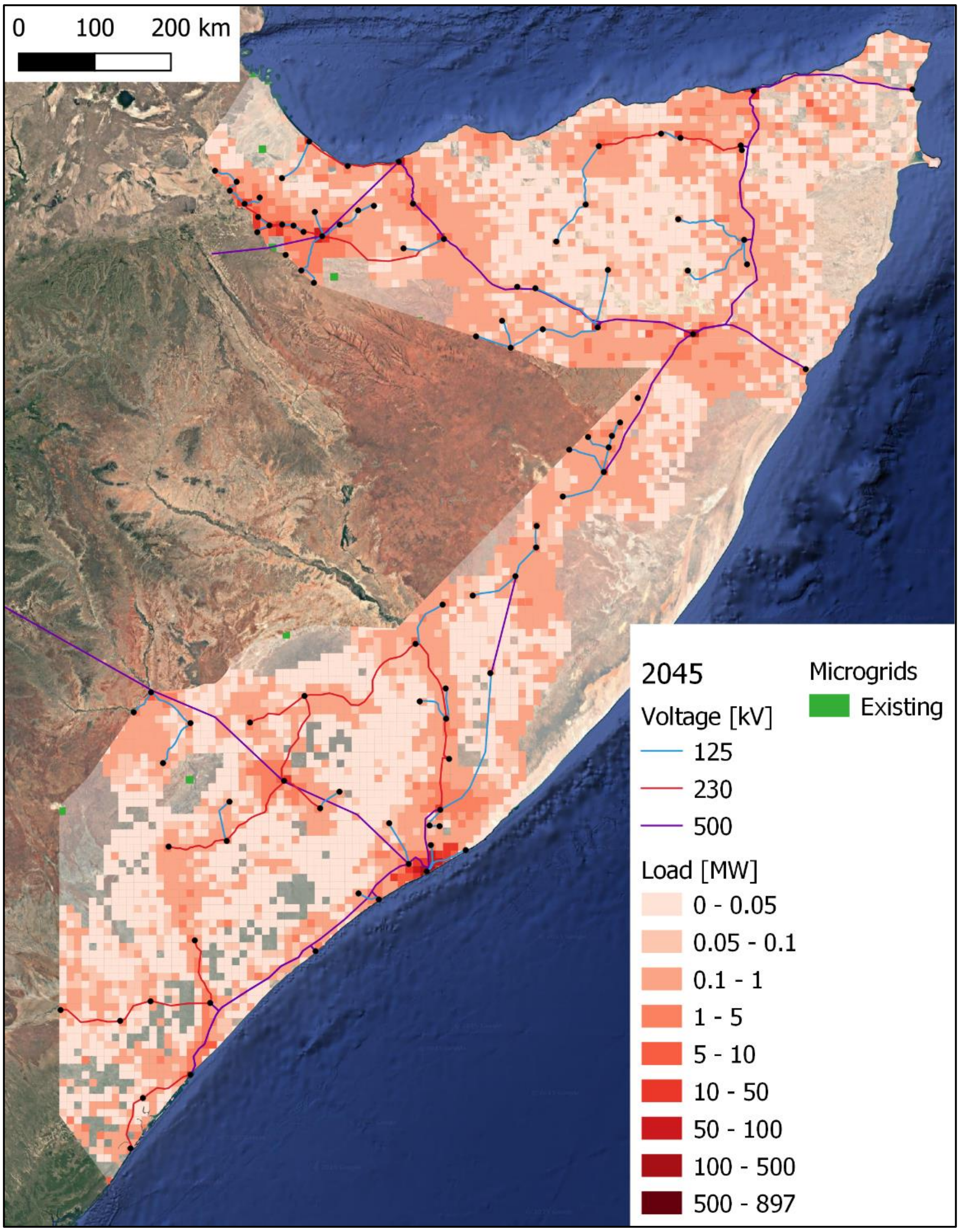


Figure 3-27 – ArcGIS map of Load Demand Forecast – year 2045

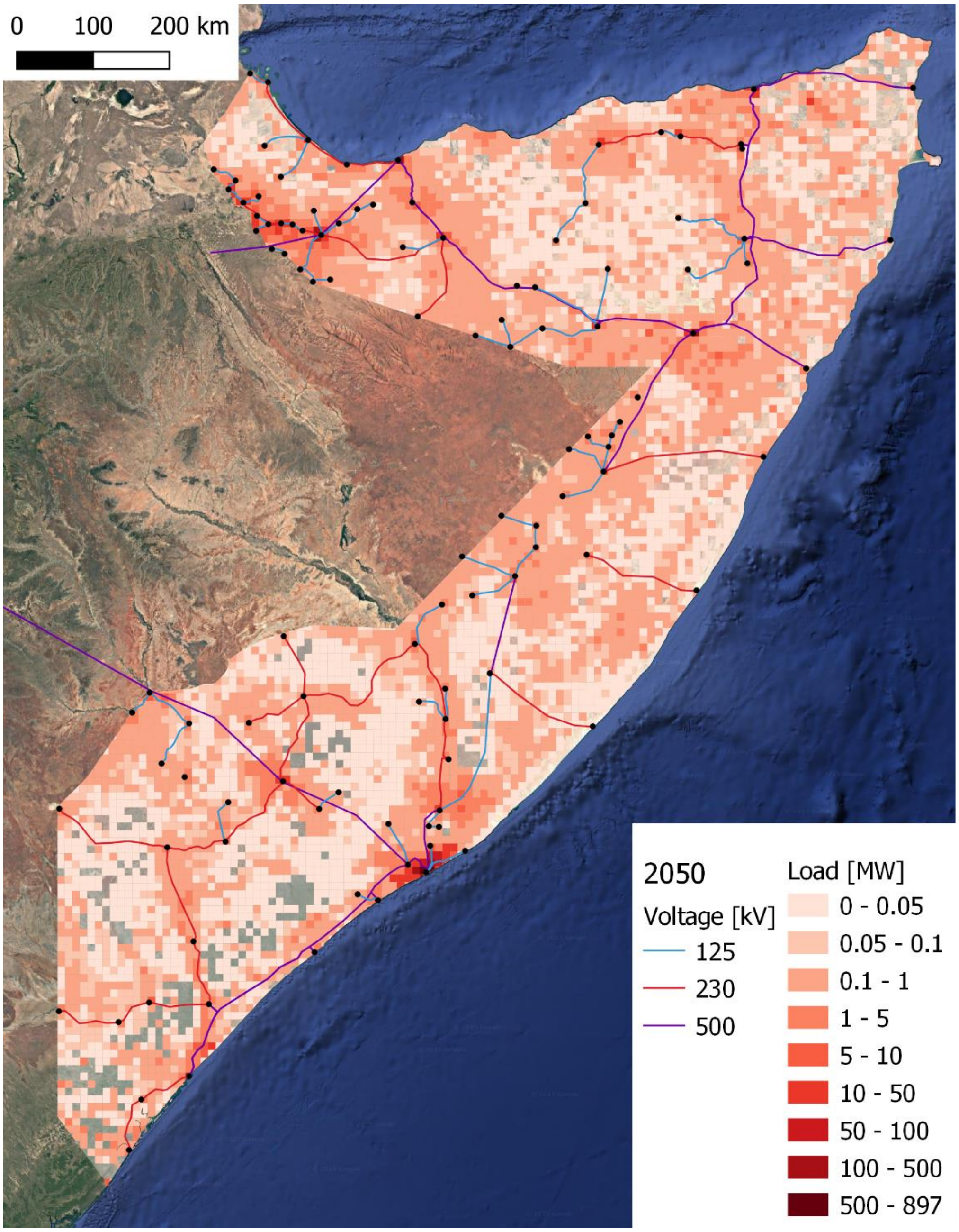


Figure 3-28 – ArcGIS map of Load Demand Forecast – year 2050

3.6 ANNEX 2.1 – FORECAST RESULTS – BOTTOM-UP APPROACH

Banadir Sub – grid

Table A3. 1 - Banadir Sub-grid – Low Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	742	1,044	742	126	868	152
2026	787	1,146	787	131	918	161
2027	834	1,259	834	137	971	170
2028	884	1,411	884	143	1,026	180
2029	937	1,579	937	150	1,087	191
2030	993	1,767	1,380	217	1,597	280
2031	1,053	1,977	1,552	240	1,792	315
2032	1,116	2,210	1,750	266	2,017	354
2033	1,183	2,470	1,981	296	2,277	400
2034	1,254	2,758	2,231	330	2,562	450
2035	1,329	3,079	2,642	384	3,026	531
2036	1,409	3,417	2,975	425	3,400	597
2037	1,493	3,787	3,328	467	3,795	667
2038	1,583	4,192	3,723	512	4,235	744
2039	1,678	4,641	4,196	572	4,768	837
2040	1,778	5,132	4,796	642	5,438	955
2041	1,885	5,616	5,280	693	5,973	1,049
2042	1,998	6,145	5,813	748	6,561	1,152
2043	2,118	6,724	6,402	816	7,217	1,268
2044	2,245	7,288	6,985	872	7,857	1,380
2045	2,380	7,889	7,614	931	8,545	1,501
2046	2,522	8,324	8,092	970	9,062	1,591
2047	2,674	8,773	8,773	1,029	9,802	1,722
2048	2,834	9,208	9,208	1,069	10,277	1,805
2049	3,004	9,653	9,653	1,120	10,773	1,892
2050	3,185	10,167	10,167	1,180	11,347	1,993

Table A3. 2 - Banadir Sub-grid – Base Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	742	1,049	742	126	868	152
2026	787	1,159	787	131	918	161
2027	834	1,279	834	137	971	170
2028	884	1,441	884	143	1,026	180
2029	937	1,621	937	150	1,087	191
2030	993	1,823	1,408	222	1,630	286
2031	1,053	2,051	1,592	246	1,838	323
2032	1,116	2,305	1,805	275	2,080	365
2033	1,183	2,590	2,055	307	2,362	415
2034	1,254	2,906	2,328	345	2,673	469
2035	1,329	3,261	2,778	404	3,182	559
2036	1,409	3,637	3,147	450	3,596	632
2037	1,493	4,051	3,540	496	4,036	709
2038	1,583	4,506	3,980	548	4,528	795
2039	1,678	5,012	4,512	615	5,127	900
2040	1,778	5,569	5,190	694	5,884	1,033
2041	1,885	6,123	5,742	753	6,495	1,141
2042	1,998	6,732	6,354	818	7,171	1,259
2043	2,118	7,402	7,032	896	7,928	1,392
2044	2,245	8,061	7,712	963	8,675	1,524
2045	2,380	8,769	8,449	1,034	9,483	1,665
2046	2,522	9,289	9,018	1,081	10,099	1,774
2047	2,674	9,829	9,829	1,153	10,982	1,929
2048	2,834	10,346	10,346	1,201	11,547	2,028
2049	3,004	10,878	10,878	1,263	12,141	2,132
2050	3,185	11,492	11,492	1,334	12,826	2,252

Table A3. 3 - Banadir Sub-grid – High Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	742	1,055	742	126	868	152
2026	787	1,171	787	131	918	161
2027	834	1,300	834	137	971	170
2028	884	1,471	884	143	1,026	180
2029	937	1,664	937	150	1,087	191
2030	993	1,882	1,437	226	1,664	292
2031	1,053	2,128	1,633	253	1,886	331
2032	1,116	2,403	1,863	283	2,146	377
2033	1,183	2,714	2,132	319	2,451	430
2034	1,254	3,062	2,429	360	2,789	490
2035	1,329	3,453	2,922	425	3,347	588
2036	1,409	3,870	3,329	476	3,804	668
2037	1,493	4,332	3,764	528	4,292	754
2038	1,583	4,842	4,255	586	4,841	850
2039	1,678	5,411	4,851	662	5,513	968
2040	1,778	6,041	5,615	751	6,366	1,118
2041	1,885	6,674	6,243	819	7,062	1,240
2042	1,998	7,373	6,943	893	7,836	1,376
2043	2,118	8,145	7,723	984	8,707	1,529
2044	2,245	8,913	8,513	1,063	9,575	1,682
2045	2,380	9,741	9,373	1,147	10,520	1,848
2046	2,522	10,411	10,095	1,210	11,305	1,985
2047	2,674	11,113	11,113	1,304	12,417	2,181
2048	2,834	11,849	11,849	1,375	13,224	2,322
2049	3,004	12,618	12,618	1,465	14,082	2,473
2050	3,185	13,552	13,552	1,573	15,125	2,656

Central Sub– grid

Table A3. 4 Central Sub-grid – Low Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	52	159	52	9	61	11
2026	56	178	56	9	65	11
2027	60	198	60	10	70	12
2028	64	223	64	10	74	13
2029	69	251	69	11	80	14
2030	73	282	73	12	85	15
2031	79	318	79	12	91	16
2032	84	357	84	13	97	17
2033	90	401	90	13	103	18
2034	96	451	96	14	110	19
2035	103	507	264	38	303	53
2036	110	566	301	43	345	61
2037	118	632	339	48	386	68
2038	126	704	380	52	433	76
2039	135	785	434	59	493	87
2040	144	874	509	68	577	101
2041	154	962	558	73	631	111
2042	165	1,059	702	90	792	139
2043	177	1,166	820	104	924	162
2044	189	1,272	947	118	1,065	187
2045	202	1,384	1,148	140	1,288	226
2046	217	1,478	1,428	171	1,599	281
2047	232	1,575	1,575	185	1,760	309
2048	248	1,667	1,667	194	1,861	327
2049	265	1,760	1,760	204	1,965	345
2050	284	1,855	1,855	215	2,070	364

Table A3. 5 Central Sub-grid– Base Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	52	162	52	9	61	11
2026	56	181	56	9	65	11
2027	60	203	60	10	70	12
2028	64	230	64	10	74	13
2029	69	260	69	11	80	14
2030	73	294	73	12	85	15
2031	79	333	79	12	91	16
2032	84	376	84	13	97	17
2033	90	425	90	13	103	18
2034	96	480	96	14	110	19
2035	103	542	279	41	319	56
2036	110	608	319	46	365	64
2037	118	683	361	51	411	72
2038	126	765	407	56	463	81
2039	135	857	467	64	531	93
2040	144	958	551	74	625	110
2041	154	1,060	607	80	687	121
2042	165	1,173	770	99	869	153
2043	177	1,297	905	115	1,021	179
2044	189	1,422	1,052	131	1,183	208
2045	202	1,555	1,284	157	1,441	253
2046	217	1,667	1,609	193	1,802	316
2047	232	1,784	1,784	209	1,993	350
2048	248	1,893	1,893	220	2,113	371
2049	265	2,005	2,005	233	2,238	393
2050	284	2,119	2,119	246	2,365	415

Table A3. 6 Central Sub-grid– High Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	52	164	52	9	61	11
2026	56	185	56	9	65	11
2027	60	209	60	10	70	12
2028	64	237	64	10	74	13
2029	69	270	69	11	80	14
2030	73	307	73	12	85	15
2031	79	349	79	12	91	16
2032	84	396	84	13	97	17
2033	90	450	90	13	103	18
2034	96	511	96	14	110	19
2035	103	580	294	43	336	59
2036	110	654	339	48	387	68
2037	118	737	384	54	438	77
2038	126	830	436	60	496	87
2039	135	935	503	69	572	100
2040	144	1,050	597	80	677	119
2041	154	1,167	661	87	748	131
2042	165	1,298	845	109	953	167
2043	177	1,443	1,000	127	1,127	198
2044	189	1,588	1,169	146	1,315	231
2045	202	1,745	1,437	176	1,612	283
2046	217	1,879	1,812	217	2,029	356
2047	232	2,018	2,018	237	2,255	396
2048	248	2,148	2,148	249	2,397	421
2049	265	2,282	2,282	265	2,546	447
2050	284	2,418	2,418	281	2,699	474

Northeastern Sub– grid

Table A3. 7 Northeastern Sub-grid – Low Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	99	327	99	17	116	20
2026	106	360	106	18	124	22
2027	113	396	113	19	132	23
2028	121	445	121	20	141	25
2029	130	500	130	21	151	26
2030	139	562	223	35	259	45
2031	149	631	269	42	311	55
2032	159	707	323	49	373	65
2033	170	793	388	58	446	78
2034	182	889	465	69	534	94
2035	195	996	596	87	682	120
2036	208	1,110	704	101	805	141
2037	223	1,236	831	117	947	166
2038	239	1,375	943	130	1,073	188
2039	255	1,530	1,071	146	1,217	214
2040	273	1,700	1,344	180	1,523	268
2041	292	1,870	1,523	200	1,723	303
2042	313	2,056	1,725	222	1,947	342
2043	335	2,261	2,126	271	2,397	421
2044	358	2,462	2,336	292	2,628	461
2045	383	2,674	2,560	313	2,873	505
2046	410	2,851	2,753	330	3,083	541
2047	438	3,032	3,032	356	3,388	595
2048	469	3,202	3,202	372	3,574	628
2049	502	3,375	3,375	392	3,767	662
2050	537	3,549	3,549	412	3,961	696

Table A3. 8 Northeastern Sub-grid– Base Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	99	332	99	17	116	20
2026	106	368	106	18	124	22
2027	113	407	113	19	132	23
2028	121	460	121	20	141	25
2029	130	519	130	21	151	26
2030	139	586	228	36	264	46
2031	149	661	277	43	319	56
2032	159	745	335	51	386	68
2033	170	840	405	60	465	82
2034	182	946	488	72	560	98
2035	195	1,066	630	92	722	127
2036	208	1,193	750	107	857	151
2037	223	1,335	890	125	1,015	178
2038	239	1,493	1,016	140	1,156	203
2039	255	1,669	1,160	158	1,318	232
2040	273	1,864	1,466	196	1,663	292
2041	292	2,060	1,671	219	1,890	332
2042	313	2,276	1,903	245	2,148	377
2043	335	2,515	2,363	301	2,664	468
2044	358	2,752	2,609	326	2,935	515
2045	383	3,004	2,873	351	3,224	566
2046	410	3,215	3,102	372	3,474	610
2047	438	3,433	3,433	403	3,835	674
2048	469	3,636	3,636	422	4,058	713
2049	502	3,843	3,843	446	4,290	753
2050	537	4,054	4,054	471	4,524	795

Table A3. 9 Northeastern Sub-grid– High Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	99	337	99	17	116	20
2026	106	375	106	18	124	22
2027	113	418	113	19	132	23
2028	121	474	121	20	141	25
2029	130	538	130	21	151	26
2030	139	611	233	37	270	47
2031	149	693	285	44	329	58
2032	159	785	347	53	399	70
2033	170	890	422	63	485	85
2034	182	1,007	512	76	588	103
2035	195	1,140	667	97	764	134
2036	208	1,282	799	114	913	160
2037	223	1,442	955	134	1,089	191
2038	239	1,621	1,095	151	1,246	219
2039	255	1,821	1,257	171	1,429	251
2040	273	2,043	1,601	214	1,815	319
2041	292	2,268	1,834	241	2,074	364
2042	313	2,519	2,099	270	2,370	416
2043	335	2,796	2,624	334	2,958	520
2044	358	3,075	2,912	364	3,276	575
2045	383	3,372	3,223	394	3,617	635
2046	410	3,623	3,494	419	3,913	687
2047	438	3,884	3,884	456	4,339	762
2048	469	4,126	4,126	479	4,605	809
2049	502	4,374	4,374	508	4,882	857
2050	537	4,627	4,627	537	5,164	907

Northwestern Sub– grid

Table A3. 10 Northwestern Sub-grid – Low Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	428	879	428	72	501	88
2026	458	951	458	76	535	94
2027	490	1,028	491	81	571	100
2028	524	1,132	522	84	606	106
2029	561	1,244	558	89	647	114
2030	600	1,368	996	156	1,153	202
2031	642	1,505	1,102	170	1,273	224
2032	687	1,653	1,222	186	1,408	247
2033	735	1,815	1,357	203	1,560	274
2034	787	1,992	1,508	223	1,731	304
2035	842	2,185	1,679	244	1,923	338
2036	901	2,380	1,874	268	2,142	376
2037	964	2,591	2,092	294	2,386	419
2038	1,031	2,819	2,335	323	2,658	467
2039	1,104	3,066	2,608	354	2,962	520
2040	1,181	3,332	2,910	389	3,299	579
2041	1,264	3,583	3,217	422	3,639	639
2042	1,352	3,853	3,553	458	4,012	705
2043	1,447	4,143	3,933	499	4,432	778
2044	1,548	4,412	4,234	527	4,761	836
2045	1,656	4,699	4,579	560	5,139	903
2046	1,772	4,946	4,847	582	5,429	953
2047	1,896	5,207	5,207	613	5,820	1,022
2048	2,029	5,481	5,481	633	6,114	1,074
2049	2,171	5,770	5,770	654	6,424	1,128
2050	2,323	6,074	6,074	675	6,749	1,185

Table A3. 11 Northwestern Sub-grid– Base Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	428	893	428	72	501	88
2026	458	971	458	76	535	94
2027	490	1,055	491	81	571	100
2028	524	1,168	525	85	610	107
2029	561	1,291	562	90	651	114
2030	600	1,428	1,017	160	1,177	207
2031	642	1,578	1,131	175	1,306	229
2032	687	1,743	1,259	192	1,451	255
2033	735	1,924	1,406	211	1,617	284
2034	787	2,122	1,572	232	1,803	317
2035	842	2,340	1,760	256	2,015	354
2036	901	2,561	1,977	282	2,259	397
2037	964	2,803	2,222	312	2,534	445
2038	1,031	3,064	2,497	345	2,842	499
2039	1,104	3,349	2,808	382	3,190	560
2040	1,181	3,657	3,156	422	3,578	628
2041	1,264	3,951	3,513	461	3,974	698
2042	1,352	4,270	3,909	504	4,413	775
2043	1,447	4,613	4,359	552	4,911	862
2044	1,548	4,937	4,718	587	5,306	932
2045	1,656	5,283	5,135	628	5,763	1,012
2046	1,772	5,589	5,464	656	6,120	1,075
2047	1,896	5,912	5,912	696	6,608	1,161
2048	2,029	6,253	6,253	723	6,976	1,225
2049	2,171	6,615	6,615	750	7,365	1,293
2050	2,323	6,997	6,997	777	7,775	1,365

Table A3. 12 Northwestern Sub-grid– High Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	428	907	428	72	501	88
2026	458	992	458	76	535	94
2027	490	1,084	491	81	571	100
2028	524	1,205	525	85	610	107
2029	561	1,340	562	90	651	114
2030	600	1,489	1,036	163	1,198	210
2031	642	1,655	1,157	179	1,335	235
2032	687	1,836	1,295	197	1,492	262
2033	735	2,038	1,454	218	1,672	294
2034	787	2,259	1,635	241	1,876	329
2035	842	2,504	1,842	267	2,109	370
2036	901	2,754	2,083	298	2,380	418
2037	964	3,028	2,357	331	2,689	472
2038	1,031	3,326	2,668	369	3,037	533
2039	1,104	3,654	3,022	411	3,432	603
2040	1,181	4,008	3,420	457	3,877	681
2041	1,264	4,352	3,833	503	4,336	762
2042	1,352	4,725	4,295	554	4,849	852
2043	1,447	5,129	4,824	611	5,435	955
2044	1,548	5,516	5,251	654	5,905	1,037
2045	1,656	5,931	5,750	703	6,453	1,133
2046	1,772	6,304	6,151	738	6,890	1,210
2047	1,896	6,701	6,701	789	7,490	1,315
2048	2,029	7,123	7,123	823	7,946	1,395
2049	2,171	7,571	7,571	858	8,429	1,480
2050	2,323	8,048	8,048	894	8,942	1,570

Southern Sub– grid

Table A3. 13 Southern Sub-grid – Low Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	62	190	62	10	72	13
2026	66	212	66	11	77	14
2027	71	236	71	12	82	14
2028	76	262	76	12	88	15
2029	81	292	81	13	94	17
2030	87	324	134	21	155	27
2031	93	361	157	24	181	32
2032	99	401	178	27	205	36
2033	106	445	201	30	231	41
2034	114	495	236	35	270	47
2035	122	549	293	43	335	59
2036	130	606	340	49	388	68
2037	139	669	393	55	449	79
2038	149	737	455	63	517	91
2039	159	813	525	72	597	105
2040	171	894	604	81	685	120
2041	183	972	696	91	787	138
2042	195	1,058	799	103	902	158
2043	209	1,152	916	117	1,033	181
2044	224	1,241	1,038	130	1,167	205
2045	239	1,337	1,282	157	1,439	253
2046	256	1,414	1,368	164	1,532	269
2047	274	1,495	1,495	175	1,670	293
2048	293	1,571	1,571	182	1,753	308
2049	314	1,673	1,673	194	1,867	328
2050	336	1,858	1,858	216	2,074	364

Table A3. 14 Southern Sub-grid – Base Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	62	193	62	10	72	13
2026	66	216	66	11	77	14
2027	71	242	71	12	82	14
2028	76	271	76	12	88	15
2029	81	303	81	13	94	17
2030	87	338	137	22	159	28
2031	93	378	161	25	186	33
2032	99	422	183	28	211	37
2033	106	472	209	31	240	42
2034	114	527	246	36	282	50
2035	122	588	308	45	353	62
2036	130	652	360	51	411	72
2037	139	723	419	59	478	84
2038	149	801	488	67	555	97
2039	159	887	567	77	644	113
2040	171	980	656	88	744	131
2041	183	1,072	761	100	860	151
2042	195	1,172	879	113	992	174
2043	209	1,281	1,013	129	1,142	201
2044	224	1,388	1,155	144	1,299	228
2045	239	1,502	1,439	176	1,615	284
2046	256	1,595	1,542	185	1,726	303
2047	274	1,693	1,693	199	1,891	332
2048	293	1,784	1,784	207	1,991	350
2049	314	1,911	1,911	222	2,133	375
2050	336	2,152	2,152	250	2,402	422

Table A3. 15 Southern Sub-grid – High Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	62	196	62	10	72	13
2026	66	221	66	11	77	14
2027	71	249	71	12	82	14
2028	76	280	76	12	88	15
2029	81	314	81	13	94	17
2030	87	353	140	22	162	28
2031	93	397	166	26	191	34
2032	99	445	189	29	218	38
2033	106	500	216	32	249	44
2034	114	560	257	38	295	52
2035	122	629	324	47	372	65
2036	130	701	381	54	436	77
2037	139	781	447	63	510	90
2038	149	870	524	72	596	105
2039	159	968	612	83	696	122
2040	171	1,075	713	95	808	142
2041	183	1,181	831	109	940	165
2042	195	1,297	967	124	1,091	192
2043	209	1,425	1,121	143	1,264	222
2044	224	1,551	1,285	161	1,446	254
2045	239	1,686	1,614	197	1,811	318
2046	256	1,798	1,736	208	1,944	341
2047	274	1,915	1,915	225	2,140	376
2048	293	2,025	2,025	235	2,260	397
2049	314	2,182	2,182	253	2,435	428
2050	336	2,490	2,490	289	2,779	488

Southwestern Sub– grid

Table A3. 16 Southwestern Sub-grid – Low Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	31	93	31	5	36	6
2026	33	103	33	6	39	7
2027	35	115	35	6	41	7
2028	38	130	38	6	44	8
2029	41	147	41	6	47	8
2030	43	166	68	11	78	14
2031	46	187	82	13	94	17
2032	50	211	101	15	117	21
2033	53	238	125	19	144	25
2034	57	269	173	26	199	35
2035	61	303	182	26	208	37
2036	65	340	216	31	247	43
2037	70	381	256	36	292	51
2038	75	426	299	41	340	60
2039	80	476	349	48	397	70
2040	85	531	420	56	476	84
2041	91	587	478	63	541	95
2042	98	649	550	71	620	109
2043	105	717	674	86	760	134
2044	112	785	745	93	838	147
2045	120	857	820	100	921	162
2046	128	919	887	106	994	175
2047	137	983	983	115	1,098	193
2048	147	1,044	1,044	121	1,165	205
2049	157	1,107	1,107	128	1,235	217
2050	168	1,170	1,170	136	1,306	229

Table A3. 17 Southwestern Sub-grid – Base Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	31	95	31	5	36	6
2026	33	106	33	6	39	7
2027	35	118	35	6	41	7
2028	38	134	38	6	44	8
2029	41	152	41	6	47	8
2030	43	173	69	11	80	14
2031	46	196	84	13	97	17
2032	50	223	105	16	121	21
2033	53	253	131	20	150	26
2034	57	286	183	27	210	37
2035	61	324	193	28	221	39
2036	65	365	230	33	263	46
2037	70	412	275	39	313	55
2038	75	462	323	44	367	64
2039	80	519	379	52	430	76
2040	85	583	458	61	520	91
2041	91	647	525	69	594	104
2042	98	719	607	78	685	120
2043	105	798	749	95	845	148
2044	112	877	832	104	935	164
2045	120	963	921	113	1,033	182
2046	128	1,036	1,000	120	1,120	197
2047	137	1,113	1,113	131	1,243	218
2048	147	1,186	1,186	138	1,323	232
2049	157	1,260	1,260	146	1,406	247
2050	168	1,337	1,337	155	1,492	262

Table A3. 18 Southwestern Sub-grid – High Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	31	96	31	5	36	6
2026	33	108	33	6	39	7
2027	35	121	35	6	41	7
2028	38	138	38	6	44	8
2029	41	158	41	6	47	8
2030	43	180	71	11	82	14
2031	46	206	86	13	100	17
2032	50	235	109	17	125	22
2033	53	268	137	20	157	28
2034	57	305	193	29	222	39
2035	61	347	204	30	234	41
2036	65	393	245	35	280	49
2037	70	445	295	41	336	59
2038	75	502	348	48	396	70
2039	80	567	411	56	467	82
2040	85	639	500	67	567	100
2041	91	713	576	76	652	114
2042	98	795	670	86	756	133
2043	105	887	832	106	938	165
2044	112	980	928	116	1,044	183
2045	120	1,081	1,033	126	1,159	204
2046	128	1,168	1,126	135	1,261	222
2047	137	1,259	1,259	148	1,407	247
2048	147	1,345	1,345	156	1,501	264
2049	157	1,434	1,434	166	1,601	281
2050	168	1,526	1,526	177	1,703	299

3.7 ANNEX 1.2 – FORECAST RESULTS – TOP-DOWN APPROACH

Table A2.19- Low Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	642	2,707	642	109	751	132
2026	687	2,965	687	115	802	141
2027	735	3,248	735	121	856	150
2028	787	3,619	787	127	914	161
2029	842	4,027	842	135	977	172
2030	901	4,482	1,617	255	1,872	329
2031	964	4,988	1,970	305	2,275	400
2032	1,031	5,546	2,386	363	2,748	483
2033	1,104	6,167	2,876	430	3,305	581
2034	1,181	6,850	3,448	511	3,959	695
2035	1,264	7,608	4,436	645	5,081	892
2036	1,352	8,399	5,228	747	5,975	1,049
2037	1,447	9,273	6,142	861	7,004	1,230
2038	1,548	10,226	6,928	954	7,882	1,384
2039	1,656	11,277	7,814	1,065	8,879	1,559
2040	1,772	12,423	9,760	1,306	11,066	1,943
2041	1,896	13,541	10,979	1,441	12,419	2,181
2042	2,029	14,759	12,340	1,588	13,928	2,446
2043	2,171	16,086	15,112	1,925	17,038	2,992
2044	2,323	17,364	16,461	2,055	18,517	3,252
2045	2,486	18,733	17,921	2,192	20,113	3,532
2046	2,660	19,879	19,190	2,299	21,489	3,774
2047	2,846	21,094	21,094	2,475	23,569	4,139
2048	3,045	22,275	22,275	2,585	24,860	4,366
2049	3,258	23,521	23,521	2,730	26,251	4,610
2050	3,486	24,837	24,837	2,883	27,720	4,868

Table A2.20 - Base Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	642	2,750	642	109	751	132
2026	687	3,029	687	115	802	141
2027	735	3,335	735	121	856	150
2028	787	3,735	787	127	914	161
2029	842	4,178	842	135	977	172
2030	901	4,674	1,656	261	1,916	337
2031	964	5,230	2,030	314	2,345	412
2032	1,031	5,843	2,475	376	2,851	501
2033	1,104	6,531	3,003	449	3,452	606
2034	1,181	7,291	3,625	537	4,162	731
2035	1,264	8,140	4,702	684	5,386	946
2036	1,352	9,031	5,575	796	6,372	1,119
2037	1,447	10,019	6,590	924	7,515	1,320
2038	1,548	11,103	7,472	1,029	8,501	1,493
2039	1,656	12,305	8,471	1,155	9,627	1,691
2040	1,772	13,621	10,659	1,426	12,084	2,122
2041	1,896	14,918	12,053	1,582	13,635	2,395
2042	2,029	16,339	13,620	1,752	15,372	2,700
2043	2,171	17,895	16,794	2,140	18,934	3,325
2044	2,323	19,410	18,385	2,296	20,681	3,632
2045	2,486	21,042	20,114	2,461	22,575	3,965
2046	2,660	22,417	21,626	2,591	24,218	4,253
2047	2,846	23,881	23,881	2,802	26,683	4,686
2048	3,045	25,292	25,292	2,936	28,227	4,957
2049	3,258	26,786	26,786	3,109	29,895	5,250
2050	3,486	28,368	28,368	3,293	31,661	5,560

Table A2.21 - High Case

Year	BAU [GWh]	Potential Demand [GWh]	Supplied Demand [GWh]	Losses [GWh]	Gross Supplied Demand [GWh]	Peak (MW)
2025	642	2,794	642	109	751	132
2026	687	3,093	687	115	802	141
2027	735	3,424	735	121	856	150
2028	787	3,854	787	127	914	161
2029	842	4,334	842	135	977	172
2030	901	4,874	1,695	267	1,962	345
2031	964	5,481	2,093	324	2,417	424
2032	1,031	6,155	2,569	391	2,959	520
2033	1,104	6,915	3,138	469	3,607	633
2034	1,181	7,759	3,812	565	4,377	769
2035	1,264	8,705	4,984	725	5,709	1,003
2036	1,352	9,706	5,947	850	6,796	1,194
2037	1,447	10,822	7,072	992	8,064	1,416
2038	1,548	12,051	8,060	1,110	9,170	1,610
2039	1,656	13,420	9,185	1,253	10,438	1,833
2040	1,772	14,927	11,638	1,557	13,195	2,317
2041	1,896	16,427	13,230	1,736	14,966	2,628
2042	2,029	18,078	15,029	1,934	16,963	2,979
2043	2,171	19,896	18,655	2,377	21,032	3,694
2044	2,323	21,686	20,524	2,563	23,087	4,055
2045	2,486	23,622	22,565	2,761	25,326	4,448
2046	2,660	25,264	24,359	2,919	27,278	4,791
2047	2,846	27,019	27,019	3,170	30,189	5,302
2048	3,045	28,699	28,699	3,331	32,031	5,625
2049	3,258	30,485	30,485	3,538	34,023	5,975
2050	3,486	32,381	32,381	3,758	36,139	6,347

4 POWER GENERATION PROJECTS FOR SUPPLY TO THE NATIONAL GRID AND GENERATION EXPANSION PLAN

4.1 GENERALITIES AND SCOPE OF WORK

This section involves the development of a Least-Cost Generation Expansion Plan using a large-scale mixed-integer programming model. The model optimizes the investment and operational costs of the power system over the planning horizon, taking into account technical, economic, and environmental constraints. Key Features of the Generation Expansion Plan approach are listed below:

- Planning Horizon: 20 years (2030–2050)
- Multi-Areas Simulation: The model simulates inter-regional energy exchanges based on available transfer capacities, in coordination with the transmission expansion plan and demand forecasts.
- Optimization Tool: The analysis is performed using OptGen, which minimizes the present value of total system costs—including capital investment, fuel, operation and maintenance—over the study period.
- Reliability Criteria: The model incorporates generation adequacy standards

To ensure that the Generation Expansion Plan remains resilient under varying future conditions, a comprehensive sensitivity analysis is conducted. This analysis evaluates how changes in key assumptions could influence the outcomes of the expansion plan. By exploring a range of plausible scenarios, the planning process becomes more robust, adaptable, and better equipped to handle uncertainty. The list of sensitivities analysis is listed below.

1. Demand Forecast Scenarios
Electricity demand is one of the most critical drivers of generation planning. To account for uncertainty in future consumption patterns, three distinct demand growth trajectories are considered as detailed in Load (demand) forecast.

2. Key Variables Assessed
In addition to demand, several technical and economic parameters are varied to understand their impact on system performance and investment decisions:

- Fuel Price Volatility
- Carbon Pricing (CO_2 Costs)
- Discount Rate Sensitivity
- Capital Investment Costs
- Fuel and Technology Availability
- Interconnection availability with Ethiopia

Each sensitivity scenario is benchmarked against the baseline case to evaluate its implications on key planning outcomes:

- Changes in the Generation Expansion Plan: Identification of shifts in the timing, scale, or type of generation projects required to meet demand under each scenario.
- Total System Cost Variations: Assessment of how different assumptions affect the overall cost of electricity supply, including capital, operational, and fuel costs.
- Penetration of Variable Renewable Energy Sources (V-RES): Analysis of how renewable energy integration levels vary across scenarios

The sensitivity analysis conducted in this study provides essential insights for decision-makers, facilitating the development of a generation strategy that is both cost-efficient under baseline assumptions and resilient to a wide range of future uncertainties.

4.2 Generation Expansion Plan

This section aims to present the methodology and key outcomes of the Generation Expansion Plan (GEP), which, in conjunction with the results from transmission expansion, will serve as the foundation for defining a clear and actionable roadmap for the development of Somalia's electrical system in alignment with projected demand growth.

It is essential to emphasize that the Generation Expansion Plan should be regarded as a starting point for future investigations. As Somalia's socio-economic and infrastructural landscape evolves, the plan must be regularly reviewed and updated to reflect real-world developments and emerging priorities.

To support the decision-making process, a set of sensitivity analyses has been conducted. These scenarios are designed to assess the impact of key variables—such as fuel prices, demand growth rates, and technology costs—on the overall expansion strategy. However, it is crucial that decision-makers maintain the flexibility and foresight to adapt the plan's recommendations in response to future conditions and new insights.

The section is structured as follow:

- A general introduction outlining the scope and objectives of the activity.
- Planning Criteria and Methodology: A detailed explanation of the planning principles and methodological approach adopted for the analysis.
- OptGen Tool and Model Inputs: An overview of the OptGen tool, the optimal generation expansion model used in the study, followed by a description of the input data required for the simulations.
- Summary of Model Outputs: A high-level summary of the key outputs generated by the model.
- Reference Scenario Results: A detailed presentation of the results obtained under the reference scenario.
- Sensitivity Scenarios: A description of the assumptions, methodology, and main outcomes of the sensitivity scenarios, along with a comparison to the reference case.
- Conclusions and Recommendations: Final considerations and strategic recommendations based on the analysis.

4.2.1 General Overview

The primary objective of the analyses presented in this section is to develop a Generation Expansion Plan (GEP) for Somalia covering the period from 2030 to 2050. This plan is designed to ensure that the country's growing electricity demand is met in a reliable, secure, and sustainable manner, in accordance with internationally planning criteria and tailored to the unique characteristics of the Somali power system.

The Generation Expansion Plan is built upon the results of preceding activities:

- <u>Assessment of Existing Power Plants:</u> Provides a critical baseline of the current generation infrastructure and is an indispensable starting point for any forward-looking planning.
- <u>Fuel Availability and Renewable Energy Potential:</u> Evaluates the availability of conventional fuels, together with a detailed mapping of renewable energy resources (solar, wind, hydro, etc.), which are essential for diversifying and decarbonizing the generation mix.
- <u>Load Forecasting:</u> propose three different electricity demand growth scenarios.
- <u>Identification of Candidate Technologies:</u> Defines the technical and economic characteristics of potential new generation assets, including conventional and renewable technologies.

- Transmission Expansion Plan: Outlines the necessary development of the national transmission grid to support the integration of new generation capacity and ensure system reliability.

The Generation Expansion Plan is therefore deeply interconnected with the above activities. Moreover, it serves—together with transmission expansion —as a strategic input for Optimization of the future power system (generation and transmission), which will define the sequencing and prioritization of investments required to implement both the generation and transmission development plans.

A key component of the Generation Expansion Plan is the investment analysis, which quantifies the capital requirements associated with the proposed expansion pathways. This includes estimating the total investment costs for each scenario and defining the expected implementation timeline for new generation assets.

The Generation Expansion Plan is not a static document but should be periodically updated to reflect changes in demand, technology, policy, and market conditions. The inclusion of sensitivity analyses allows stakeholders to explore how key uncertainties—such as fuel prices, renewable integration costs, or demand variability—could influence the optimal expansion path.

The sensitivity scenarios, initially introduced during Power generation projects for supply to the National Grid, are a critical component of the planning process. The following sensitivity scenarios have been developed and analyzed to test the resilience of the Generation Expansion Plan under different future conditions:

- Load Forecast: The generation expansion planning is based on a reference demand growth scenario, but alternative demand trajectories are also considered to test the system's resilience. Higher demand could improve cost-efficiency but require more investment, while lower demand may lead to overcapacity and reduced investment needs:
  - *Base Case Scenario*:
    Represents the most likely growth path, based on current demographic trends, economic projections, and electrification targets.
  - *Low Growth Scenario*:
    Reflects a more conservative path, assuming slower economic development, delayed infrastructure deployment, or lower-than-expected electrification rates.
  - *High Growth Scenario*:
    Assumes accelerated economic activity, rapid urbanization, and aggressive electrification efforts, leading to significantly higher electricity demand.
- Fuel Availability: The availability of domestic natural gas plays a key role in shaping the generation mix. Scenarios also explore the impact of not having access to LNG and the hypothetical introduction of nuclear power from 2040, focusing on economic implications.
- Fuel Price: Variations in fuel prices significantly affect the operational costs of thermal plants. A ±10% price fluctuation is analyzed, along with a scenario introducing a CO_2 price of 80 €/ton, which increases costs for carbon-intensive technologies and influences their competitiveness.
- CAPEX: Capital cost assumptions are particularly important for technologies like renewable. Lower CAPEX for these technologies could shift the generation mix.
- WACC: The cost of capital directly affects the economic attractiveness of different technologies. A low WACC favors capital-intensive options, while a high WACC makes them less competitive, potentially altering investment priorities.
- Interconnection: A sensitivity scenario assumes Somalia remains electrically isolated from neighboring countries throughout the planning horizon. The analysis serves to quantify the strategic value of regional integration. Comparing this isolated scenario with the interconnected reference case highlights how cross-border links can reduce system costs, optimize the generation mix, and enhance renewable energy integration by providing balancing capacity and reducing curtailment. This scenario underscores the opportunity cost of isolation and reinforces the importance of investing in regional transmission infrastructure.

The generation expansion analysis presented in this study is based on a least-cost adequacy assessment approach, implemented using the OPTGEN tool. OPTGEN performs mixed-integer optimization to identify the most cost-effective combination of candidate generation projects, considering both capital expenditures (CAPEX) and operational costs (OPEX) over the entire planning horizon. As previously emphasized, the results of this study should be viewed as a strategic starting point, not a definitive roadmap. They are intended to inform future decisions, which must be continuously updated and refined in response to real-world developments.

It is important to point out that power systems worldwide are moving toward net-zero emissions targets by 2050. This global trend implies a progressive phase-out of fossil fuels, or their continued use only in conjunction with carbon capture and storage (CCS) technologies.

Table 4-1: RES penetration Target 2040 and 2050 in different countries

Country	Target 2040	Target 2050	Source
European Union	50%	90-100%	Green Deal (REPowerEU Plan)
USA	80%	100%	Clean Energy Goals (Biden Administration)
Japan	38%	50-60%	Strategic Energy Plan (6th edition, 2021)
China	50% (on installed capacity)	85%	14th Five-Year Plan, Carbon Neutrality Goal
India	65%	80-85%	National Solar Mission, INDC commitments
Brazil	48%	53%	Plano Nacional de Energia 2050

Somalia is in a favorable starting position. Unlike many countries that must retrofit or decarbonize legacy infrastructure, Somalia has the rare advantage of starting from a blank slate. This presents a strategic opportunity to design and implement a modern, efficient, and low-emission power system from scratch—guided by global best practices and aligned with long-term sustainability goals.

This includes:

- Prioritizing renewable energy from the outset—such as solar and wind—given Somalia's abundant natural resources.
- Designing a flexible and modular grid that can accommodate variable renewable energy sources and future demand growth.
- Incorporating advanced technologies like Battery Energy Storage Systems (BESS), smart grid solutions, and digital monitoring tools to enhance reliability and efficiency.

One particularly promising strategy is the deployment of dual-fuel Combined Cycle Gas Turbines (CCGTs). These plants can initially operate on natural gas or diesel but be designed to transition to hydrogen as it becomes available. This approach ensures both short-term reliability and long-term compatibility with a decarbonized energy future.

Moreover, by integrating hydrogen-readiness and carbon capture compatibility into new thermal infrastructure, Somalia can avoid the costly retrofits that many developed countries are now facing. This proactive planning reduces long-term costs and aligns with global decarbonization trends.

As Somalia moves toward a modern, low-emission power system with high penetration of renewable energy sources (RES), energy storage becomes not just beneficial—but essential. The intermittent nature of solar and wind power means that without adequate storage, the system cannot maintain reliability, stability, or economic efficiency. Without storage, in fact, excess energy during peak generation hours is wasted (curtailed), and fossil-based backup is needed during low-generation periods.

These capabilities make BESS indispensable in systems with high shares of variable renewable energy (VRE). However, as renewable penetration increases beyond 60–70% and is not feasible any more to size thermal generation capacity to match peak demand (as done in traditional systems), additional system services and structural changes become necessary:

- Demand Response and Load Shedding: Flexible loads that can be curtailed or shifted in time to balance the system during stress events.
- Synthetic Inertia and Grid-Forming Inverters: As conventional generators are phased out, synthetic inertia from inverter-based resources becomes critical to maintain frequency stability.
- Long-Duration Storage: Technologies such as hydrogen or compressed air may be needed to cover multi-day or seasonal gaps.
- Flexible Generation: Clean, dispatchable technologies (e.g., hydrogen-ready gas turbines) will still play a role in providing firm capacity.
- Advanced Grid Management: Digital tools, AI-based forecasting, and real-time control systems will be required to manage the complexity of a decentralized, dynamic grid.

4.2.2 Planning Criteria

The Generation Expansion Plan (GEP) is a fundamental component of long-term power system planning. It provides a structured framework for identifying the optimal mix, timing, and location of new generation capacity to meet future electricity demand in a cost-effective, reliable, and sustainable manner. This section outlines the core planning criteria and strategic considerations for the development of the GEP for Somalia, covering the period from 2030 to 2050.

At the heart of the GEP is a least-cost planning approach, which seeks to minimize the total system cost over the entire planning period. This includes:

- Capital investment costs for new generation assets;
- Operational and maintenance costs;
- Fuel and variable production costs;
- Environmental costs.

The optimization process balances these cost components while ensuring that supply meets demand under a range of future scenarios.

The GEP incorporates a strategic vision for renewable energy development. The study evaluates the technical and economic potential of various renewable energy sources—solar, wind, hydro—and assesses their feasible contribution to the generation mix.
A core principle of the GEP is the diversification of electricity supply, both in terms of energy sources and geographic location. This reduces dependency on any single fuel or import, enhances energy security.

4.2.3 OPTGEN Model

OPTGEN is a state-of-art, long-term capacity expansion planning tool specifically designed to support the strategic planning of generation infrastructure in power systems, enabling utilities, regulators, and policymakers to undertake investment decisions. It is particularly well-suited for countries like Somalia, where the power system is being built from scratch and must align with long-term goals such as universal access to electricity, cost efficiency, and decarbonization.

OPTGEN performs mixed-integer linear programming (MILP) to determine the least-cost expansion path for a power system over a multi-decade horizon. The model minimizes the net present value (NPV) of total system costs, which include:

- Least-Cost Investment Pathway: OPTGEN identifies the most cost-effective combination of generation technologies and investment timelines by minimizing the total system cost over the planning horizon. This includes capital expenditures, operational costs, fuel expenses, and emissions-related costs.
- Integration of Renewable Energy: Given Somalia's high solar and wind potential, OPTGEN allows planners to evaluate the optimal share of renewable energy in the generation mix. It considers the variability of these resources and the need for complementary technologies such as battery storage or flexible generation, helping Somalia move toward a low-carbon, resilient energy system.
- Demand-Supply Balancing: OPTGEN simulates long-term electricity demand growth and matches it with appropriate generation capacity.
- Multi-stage investment planning: The tool supports users to define when and where new assets should be built, reinforced, or retired. It also incorporates financial constraints, such as annual investment limits, and can simulate phased development of large infrastructure projects.
- Scenario and Sensitivity Analysis: the tool enables the creation of multiple scenarios to test how the system would perform under different assumptions—such as changes in fuel prices, demand growth, technology costs, or policy shifts. This helps Somali planners understand risks and make robust decisions under uncertainty.
- Policy and Sustainability Alignment: The tool can incorporate national energy policies, renewable targets, and emissions constraints. This ensures that the expansion plan is aligned with Somalia's long-term development goals and international climate commitments.

For further detail, please visit https://www.psr-inc.com/software/optgen.html.

Figure 4-1: Optgen capability

Figure 4-2: PSR in numbers

4.2.4 Input of the model

A Generation Expansion Plan is a strategic tool used to determine the optimal mix, timing, and location of new generation capacity to meet future electricity demand in a reliable, cost-effective, and sustainable manner. The accuracy and usefulness of a GEP depend heavily on the quality, completeness, and consistency of its input data.
These inputs include technical, economic, environmental, and policy details, and must reflect both current system conditions and future projections. Below is a detailed list of the essential inputs required to carry out a robust and credible generation expansion planning process.

Demand Forecasting Inputs

- Historical electricity demand data (hourly, daily, seasonal)
- Projected demand growth (by region and time horizon)
- Peak demand estimates and load duration curves

Existing Generation Fleet

- Installed capacity by plant and technology
- Operational status (available, decommissioned, under maintenance)
- Technical characteristics (efficiency, ramp rates, minimum load)
- Fuel type and consumption rates
- Expected retirement dates
- Emissions details

Candidate Generation Technologies

- List of potential new generation projects (thermal, hydro, solar, wind, geothermal, nuclear, etc.)
- Capital costs (CAPEX) and operational costs (OPEX)
- Construction lead times
- Lifespan and decommissioning costs
- Technology-specific constraints (e.g., site availability, resource potential)
- Flexibility characteristics (e.g., ramping, start-up time)

Fuel Supply and Pricing

- Fuel availability (domestic or imported)
- Fuel price forecasts (diesel, gas, coal, hydrogen, etc.)
- Fuel transport and logistics constraints
- Emissions factors and carbon pricing assumptions

Renewable Energy Resource Data

- Solar irradiance profiles (hourly, seasonal)
- Wind speed data (by location and height)

- Hydrological data for hydroelectric potential

Transmission Network Data
- Existing transmission infrastructure
- Transmission capacity
- Planned transmission projects and reinforcements
- Interconnection capacity with neighboring countries

System Reliability and Reserve Requirements
- Operating reserve requirements

Policy, Regulatory, and Environmental Constraints (if any)
- National energy and climate policies (e.g., net-zero targets)
- Renewable energy targets
- Emissions limits and carbon pricing mechanisms
- Land use and environmental impact restrictions

Economic and Financial Parameters
- Discount rate or Weighted Average Cost of Capital (WACC)
- Inflation
- Investment budget constraints (if any)

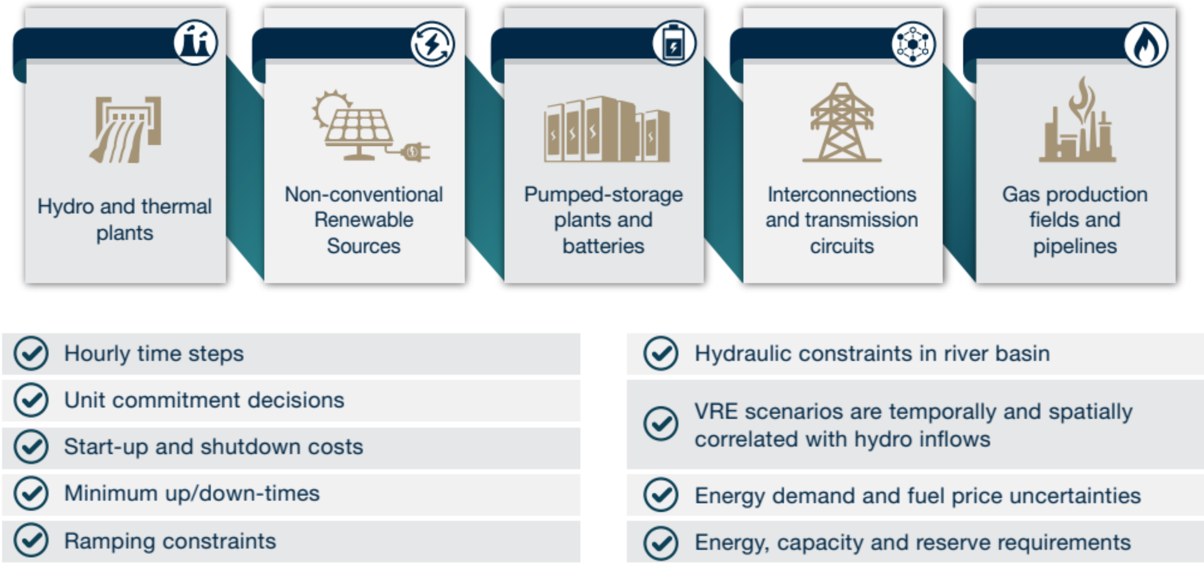


Figure 4-3: Optgen input

4.2.4.1 Economic parameters

In the economic evaluation of generation expansion plans, it is essential to account for the temporal distribution of costs in order to ensure a consistent and meaningful comparison across alternative scenarios. This involves the application of two key financial concepts: inflation rate and discounting rate:

- Inflation is the rate at which the general level of prices for goods and services increases over time, leading to a decrease in the purchasing power of money. It is typically measured as an annual percentage change in a price index, such as the Consumer Price Index (CPI). In the context of a generation expansion plan, inflation plays a critical role in evaluating and comparing future costs of investments, operations, and maintenance. Inflation affects the future prices of equipment and fuel. Ignoring inflation can lead to underestimating the total cost of new generation assets.

- The Weighted Average Cost of Capital (WACC) represents the average rate of return that a company is expected to pay to its investors (both equity and debt holders) for using their capital. It reflects the cost of financing a project and is calculated as a weighted average of the cost of equity and the cost of debt, adjusted for the corporate tax rate.

The total cost of each generation expansion plan is therefore calculated as the sum of the discounted CAPEX and OPEX over the planning horizon. This approach ensures that both upfront investments and long-term operational costs are evaluated on an equal footing, taking into account their respective timing and financial impact.

Table 4-2: Financial assumptions, reference scenario

Financial assumptions	
Inflaction Rate	2.0%
WACC (nominal)	10.0%
WACC real (includes inflaction)	7.8%

The formula shown below illustrates how the real WACC—the discount rate adjusted to exclude inflation—is derived from the nominal WACC. This adjustment ensures that inflation is consistently accounted for across both the discount rate and the projected cash flows.

In energy system models, where long-term projections often span 20–40 years, using real WACC is common practice. This approach simplifies the analysis by removing the need to forecast inflation over extended periods and provides a clearer view of the project's underlying economic performance.

$$WACC_{Real} = \frac{1 + WACC}{1 + inflation} - 1$$

4.2.4.2 Load

Load forecasting represents one of the foundational pillars of any Generation Expansion Plan. It provides the quantitative basis upon which all future capacity planning decisions are made. Accurate projections of peak demand, total annual energy consumption, and the hourly load profile are essential to determine the scale, type, and timing of investments in generation infrastructure.

The installed capacity requirements of a power system can vary significantly depending on these load parameters. For instance, a system with high peak demand but low average consumption may require a different generation mix—often with more flexible or peaking units—compared to a system with a flatter load curve and higher baseload requirements.

For this study, the peak demand and total energy consumption forecasts developed under Load (demand) forecast of the project have been adopted as the primary reference. These projections reflect expected growth in electricity demand across Somalia, driven by factors such as population growth, urbanization, economic development, and electrification of key sectors.

In terms of load profile modeling, the Consultant has developed a standardized hourly load curve for a representative year. This profile is based on prior experience from similar studies conducted in countries with comparable climatic and socio-economic conditions.

The Somali power system exhibits seasonal and intra-day variations in electricity demand as shown in figures below:

- Seasonal Variation: There is a noticeable difference in load patterns between summer and winter months, primarily due to changes in temperature, daylight hours, and cooling needs.

- Daily Load Shape: Within a typical day, the load profile shows significant variation between minimum, average, and peak demand periods.

Figures below present the estimated daily load curve for Somalia's power system in the year 2050 in the reference scenario. It highlights the characteristic shape of demand throughout a 24-hour period, including:

- Morning ramp-up as residential and commercial activities begin;
- Afternoon peak, typically the highest demand period, associated with residential lighting, cooling, and appliance use;
- Overnight off-peak, when demand reaches its lowest levels.

This profile serves as a baseline input for the generation expansion modeling, ensuring that the system is designed not only to meet annual energy needs but also to handle hourly operational challenges.

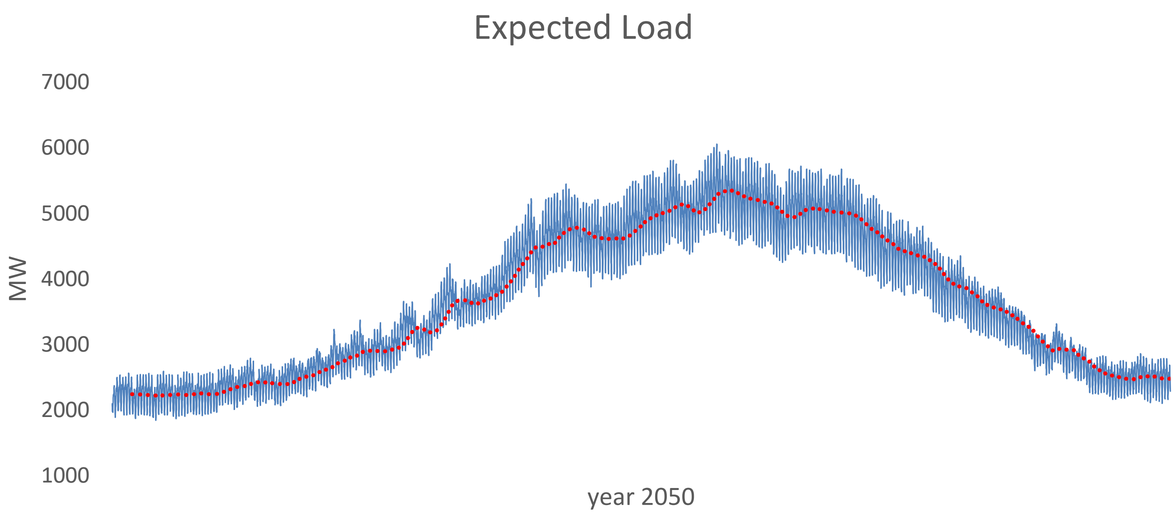


Figure 4-4: Expected Load profile, 2050

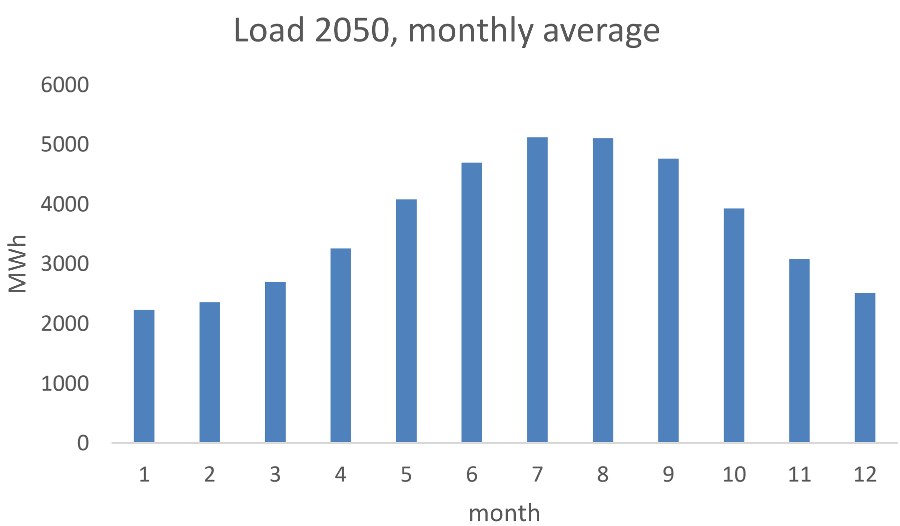


Figure 4-5: Load 2050, monthly average

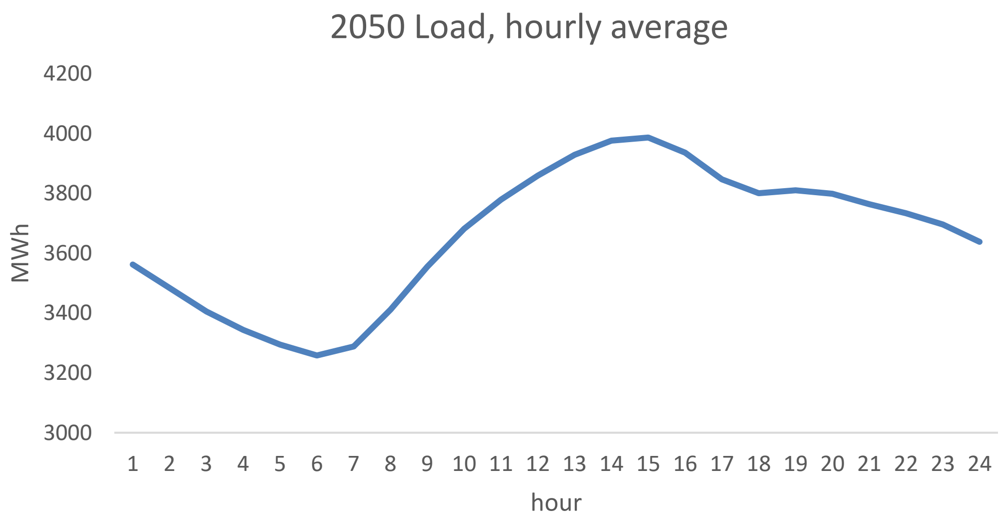


Figure 4-6: Load 2050, Daily average

4.2.4.3 Existing capacity

The starting point for the development of the Generation Expansion Plan is a thorough understanding of the existing power generation system in Somalia. This baseline is essential for identifying capacity gap and planning future investments in a coordinated and cost-effective manner.

A detailed analysis of the current state of the Somali energy sector has been conducted as part of assessment of current situation of the power sector and energy resources in Somalia. The study provides a comprehensive overview of the existing infrastructure, energy mix, and operational characteristics of the national power system.

The full details of this data collection exercise are presented in Chapter 3 of the assessment of current situation of the power sector and energy resources in Somalia.

4.2.4.4 Candidates

The identification and characterization of candidate generation technologies is a critical step in the development of a robust and realistic Generation Expansion Plan (GEP). The selection of candidate technologies for Somalia has been carried out through a structured and context-specific approach, taking into account the country's unique characteristics, including:

- Resource availability (e.g., solar, wind, natural gas, potential for imports)
- Fuel supply constraints and logistics
- Projected electricity demand growth
- Geographic and climatic conditions
- Infrastructure readiness and investment feasibility

This process ensures that the technologies considered in the expansion plan are technically, economically and operationally appropriate for Somalia's evolving power system.

The proposed candidate technologies have been grouped into the following major categories:

- High-Speed Diesel Generators (HSDG)
- Medium-Speed Diesel Generators (MSDG)
- Open Cycle Gas Turbines (OCGT)
- Combined Cycle Gas Turbines (CCGT)
- Coal-Fired Power Plants
- Nuclear Power Plants

- PV
- Wind

Each category represents a different balance of capital cost, operational flexibility, fuel efficiency, and environmental impact.

Within each technology category, further differentiation is made based on:
- Fuel Type: Options include diesel, Light Fuel Oil (LFO), Liquefied Natural Gas (LNG), natural gas (NG), coal, and uranium.
- Installed Capacity: Ranges from small-scale modular units to large centralized plants, depending on the technology and application.
- Configuration: Includes variations such as single-shaft or multi-shaft arrangements and modular setups.

For example, in the case of Combined Cycle Gas Turbines (CCGT), the following configurations may be considered:
- Fuel Options: LNG, LFO, or pipeline NG
- Capacity Range: Typically between 120 MW and 300 MW
- Plant Configuration:
    - 1+1: One gas turbine and one steam turbine
    - 2+1: Two gas turbines and one steam turbine

These variations allow for flexibility in system design and enable planners to tailor solutions to specific regional needs, grid conditions, and investment constraints.

For each candidate technology, a comprehensive set of technical and economic parameters has been defined. These parameters are essential for the modeling and optimization processes carried out in the methodology for optimized cost generation planning, and include:
- Installed Capacity (MW): Minimum and maximum generation capacity
- Heat Rate (kJ/kWh): A measure of thermal efficiency
- Fuel Type: Primary and secondary fuels, if applicable
- Capital Expenditure (CAPEX): Including base plant costs and additional infrastructure (e.g., LNG regasification units)
- Fixed and Variable Operational Expenditures (OPEX): Covering maintenance, staffing, and fuel handling
- Expected Operational Lifetime: Typically 20–40 years, depending on technology
- Forced Outage Rate: Probability of unplanned outages
- Scheduled Maintenance Duration: Expressed in weeks per year

These parameters are used to simulate the performance, cost-effectiveness, and reliability of each technology under different demand and policy scenarios.

A detailed summary of all candidate technologies, including their technical specifications, economic assumptions, and configuration options is provided under the power generation projects for supply to the National Grid section.

4.2.4.5 Fuel prices

For the preparation of the generation expansion plans, the most recent data available from international energy organization databases and relevant studies on fuel price forecasts have been utilized.

The projections are based on the long-term global energy outlook provided by the U.S. Energy Information Administration (EIA), specifically the International Energy Outlook (DOE/EIA). The analysis considers the Reference Case scenario of the energy projections. A summary of the fuel price forecasts for all fuels used in electricity generation is presented in the table below.

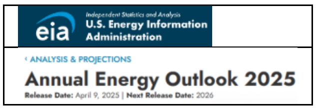


Table 4-3: Fuel prices projections

2024 $/MMBTU	2024	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Electric Power 9/																						
Distillate Fuel Oil	26.14	22.16	22.09	22.66	22.98	23.12	23.27	23.30	23.42	23.58	23.71	23.85	24.09	24.18	24.51	24.64	24.72	25.03	25.61	25.61	25.65	25.74
Residual Fuel Oil	17.39	16.44	16.57	16.48	16.73	16.87	17.06	17.12	17.21	17.33	17.36	17.46	17.52	17.50	17.48	17.20	16.74	16.95	17.40	17.49	17.57	17.85
Natural Gas	2.72	3.43	3.55	4.04	4.32	4.47	4.52	4.50	4.41	4.34	4.28	4.31	4.40	4.49	4.57	4.59	4.59	4.62	4.63	4.59	4.52	4.46
Steam Coal	2.49	2.24	2.20	1.98	1.96	1.97	1.96	1.97	1.94	1.95	2.07	2.06	2.06	2.07	2.07	2.05	2.06	1.88	2.35	2.35	2.35	2.36
Uranium	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75

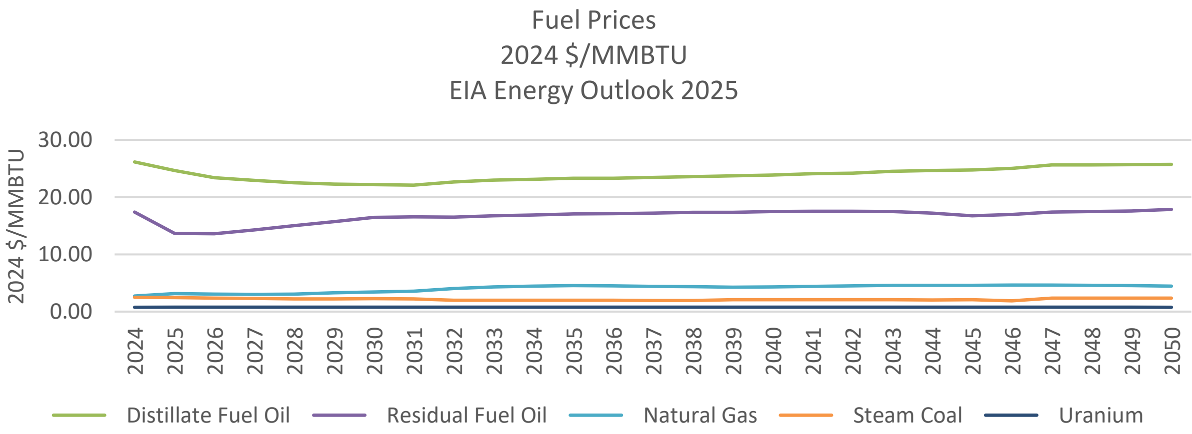


Figure 4-7: Fuel proces projection

Source EIA: https://www.eia.gov/outlooks/aeo/fossil_fuel/

As for LNG, a coefficient of 2 with respect to Natural Gas has been considered based on historical values[5], while for LFO a coefficient of 0.95 with respect to Diesel has been considered[2].

As for Waste to Energy power plant, one of its unique is that the fuel (waste) may have a negative cost. The negative cost of waste can be estimated as the avoided cost of landfill disposal, which typically includes:

- Collection and transportation
- Landfill operation and maintenance
- Environmental mitigation (e.g., leachate treatment, methane capture)
- Land use and long-term monitoring

In many developing countries, these costs range from $10 to $50 per ton. For Somalia we assumed a conservative value of 20 $/ton.

4.2.4.6 Network

In the context of long-term power system planning, the choice of modeling framework plays a crucial role in determining the accuracy, feasibility, and computational efficiency of the analysis. For Somalia's Generation Expansion Plan (GEP), a zonal modeling approach has been adopted. This methodology is

[5] https://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm

widely used in strategic planning studies around the world and is particularly well-suited for countries with developing infrastructure, limited data availability, and emerging electricity markets.

A zonal model divides the national power system into a set of geographically or administratively defined regions, referred to as market zones. Each zone represents an aggregation of:

- Electricity demand (residential, commercial, industrial, etc.)
- Generation resources (existing and candidate plants)
- Transmission infrastructure (modeled as inter-zonal transfer capacities)

In Somalia's case, each district or major region is treated as a distinct market zone. Within each zone, all generation and load are aggregated into a single equivalent node, which simplifies the representation of the system while preserving the essential dynamics of supply, demand, and power flow.

While nodal models provide high spatial resolution by representing each substation or generator individually, they require detailed network data and significantly more computational resources. In contrast, zonal models offer several advantages, especially in the Somali context:

- Simplified data requirements: Ideal for systems where detailed grid topology and operational data are limited or evolving.
- Faster computation: Enables the simulation of long-term scenarios (e.g., 2030–2050) with multiple sensitivities and investment options.
- Strategic focus: Emphasizes high-level investment decisions rather than operational dispatch details.
- Scalability: Easily adaptable as more data becomes available or as the system grows in complexity.

This simplification is widely accepted in international planning practices, particularly for generation expansion studies, where the goal is to identify optimal investment pathways rather than simulate real-time operations.

In the zonal model, inter-zonal transmission links are represented by Net Transfer Capacities (NTCs). These values define the maximum amount of power that can be transferred between zones in each direction, reflecting the physical and operational limits of the transmission network.

Key characteristics of the NTC approach include:

- Dynamic evolution: NTC values are updated annually based on the Transmission Expansion Plan developed in transmission expansion, which outlines planned reinforcements and new interconnections.
- Constraint enforcement: The model ensures that power flows between zones do not exceed the available transfer capacity, preserving system realism.
- Investment signaling: If a zone becomes congested due to limited NTC, the model may prioritize local generation or recommend transmission upgrades.

This approach ensures that generation and transmission planning are co-optimized, avoiding unrealistic scenarios where generation is added without the means to deliver electricity to load centers.

4.2.4.7 Reserve provision

In power system planning, particularly in the development of a Generation Expansion Plan (GEP), the concepts of reserves and security margins are fundamental to ensuring the reliability, stability, and adequacy of electricity supply. These mechanisms are designed to protect the system against uncertainties, unexpected events, and operational variability —especially as systems integrate more variable renewable energy sources.

Reserves refer to the additional generation capacity that is available to the system operator beyond what is needed to meet the expected demand at any given time. These reserves are not used under normal operating conditions but are held in readiness to respond to:

- Sudden increases in demand (e.g., due to weather or economic activity)
- Unexpected outages of generation units (forced outages)
- Transmission failures or bottlenecks
- Variability and forecast errors in renewable generation (e.g., wind and solar)

There are several types of reserves in power systems, each designed to serve a specific operational or strategic purpose. In the context of a Generation Expansion Plan, the primary focus is on Planning Reserves. These reserves represent a capacity margin—an intentional surplus of available generation capacity over the forecasted peak demand.
The purpose of planning reserves is to ensure that the system can reliably meet electricity demand even under extreme or unexpected conditions, such as sudden equipment failures, fuel supply disruptions, or higher-than-anticipated demand peaks.
Planning reserves are typically expressed as a percentage above the projected peak load. A common planning criterion is to maintain a 15–20% reserve margin above the forecasted peak demand. This ensures that the system can withstand the loss of its largest generator or a sudden demand spike.
For Somalia, where the power system is still in its formative stages, incorporating adequate reserves and security margins is essential. Given the country's limited existing infrastructure and high growth potential, the GEP must strike a careful balance between cost-efficiency and system reliability, ensuring that the system is not only affordable but also secure and reliable.

The figure below offers a visual breakdown of how a power system's net generating capacity is allocated and how planners determine whether the system has sufficient spare capacity to ensure reliability. Here an explanation of the key components.

The total Net Generating Capacity of a power system refers to the sum of all available generation units, adjusted for their actual deliverable output. However, not all of this capacity is available at all times. Several deductions must be made to reflect real-world limitations:

- System Services Reserve: A portion of capacity is set aside to provide essential grid services such as frequency regulation, spinning reserve, and voltage support. These services are critical for maintaining the stability of the grid but are not directly used to meet demand.
- Outages: Some generation units may be unexpectedly unavailable due to technical failures or breakdowns. These are referred to as forced outages.
- Overhauls: Scheduled maintenance activities also take units offline temporarily. These are planned but still reduce the available capacity during certain periods.
- Non-Usable Capacity: This includes capacity that, while technically installed, cannot be dispatched due to constraints such as lack of fuel, transmission bottlenecks, or regulatory restrictions.

After accounting for all these deductions, what remains is the reliably available capacity—the portion of the system that can be counted on to meet demand under normal operating conditions.

The next step is to compare this reliably available capacity to the expected electricity demand, particularly during the seasonal peak — the time of year when demand is highest.

The difference between the reliably available capacity and the peak load is what we call the reserve margin. This is the system's safety buffer—its ability to absorb unexpected events without causing blackouts or service interruptions.

The reserve margin serves several critical functions:

- Cushioning against uncertainty: Demand forecasts are never perfect, and generation units can fail. The reserve margin ensures the system can handle these uncertainties.
- Supporting renewable integration: As more variable renewable energy sources (like solar and wind) are added to the grid, the need for reserves increases. These sources are weather-dependent and can fluctuate rapidly, requiring backup capacity to maintain balance.

- Maintaining reliability standards: Most power systems aim for a specific reliability target, such as a Loss of Load Expectation (LOLE) of one day in ten years. The reserve margin is a key tool for achieving this.

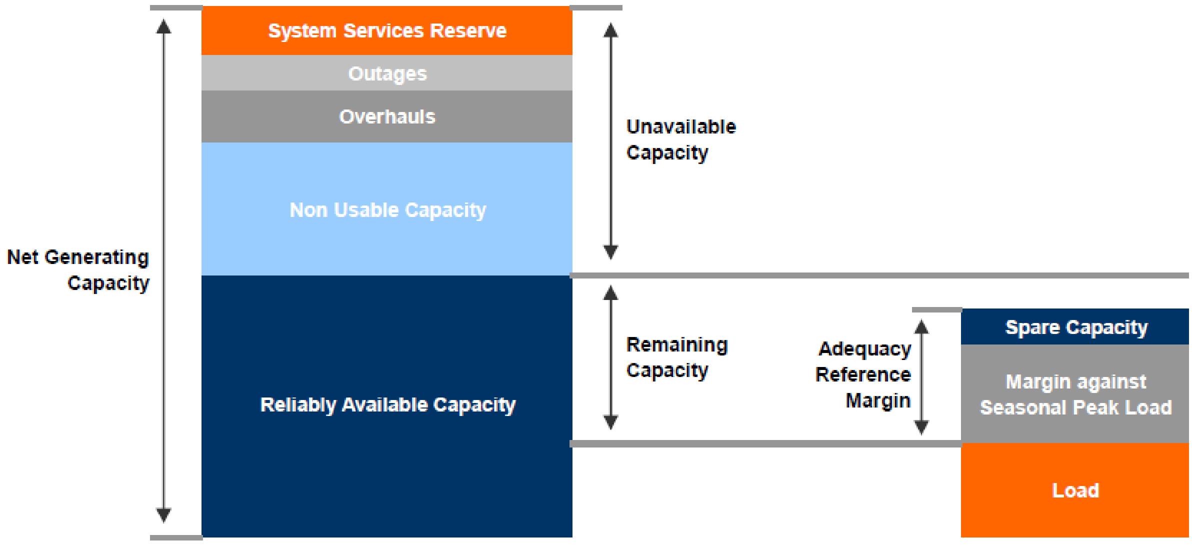


Figure 4-8 – Methodology for Assessment of Generation adequacy of a power system

In traditional power systems, peak demand is met primarily by dispatchable thermal generation, such as gas turbines or diesel generators. However, as power systems evolve toward higher shares of renewable energy, it becomes increasingly important to understand how variable renewable energy (VRE) sources like solar photovoltaic (PV) and wind power contribute to peak demand coverage.
While PV and wind are non-dispatchable and weather-dependent, they do contribute to meeting peak demand, although not at their full installed capacity. This contribution is quantified through a concept known as the capacity credit.

The capacity credit of a generation technology refers to the portion of its installed capacity that can be reliably counted on to meet peak demand:

- For solar PV, the capacity credit is often relatively high in systems where the peak demand occurs during the daytime when solar output is still significant and ranges from 20% to 50%.
- For wind power, the capacity credit depends on the correlation between wind availability and peak demand periods and ranges from 10% to 30%.

Incorporating the peak contribution of PV and wind is essential to avoid overinvestment in firm capacity and to support decarbonization.

4.2.4.8 Exchanges

In the current generation expansion planning exercise, the only cross-border interconnection considered up to the year 2050 is the one with Ethiopia. This choice is based on the availability of reliable technical and planning data.
It is important to emphasize that the presence of this interconnection would only marginally affect the total installed thermal capacity in Somalia. This suggests that the domestic generation system is still required to maintain a significant level of self-sufficiency, even in the presence of cross-border electricity exchanges.
According to the *Ethiopia–Somalia Interconnection Report*, the existing and planned hydropower capacity in Ethiopia is expected to be sufficient to meet 100% of Ethiopia's internal electricity demand,

while also supporting full electricity exports to Somalia (via both interconnection points) up to the year 2044.
However, starting from 2044, the growing electricity demand in Ethiopia will require the commissioning of new gas-fired power plants (likely GGCT technology) to meet domestic needs. From that point onward, the possibility for Somalia to export surplus renewable energy to Ethiopia may emerge, marking a shift in the direction of energy flows.

At this stage, no other interconnections have been included in the analysis. This does not imply that additional interconnections are unlikely or unimportant, but rather that their inclusion would require further data and coordination. Future updates to the model may incorporate additional regional interconnection scenarios to better reflect the evolving geopolitical and infrastructural context.

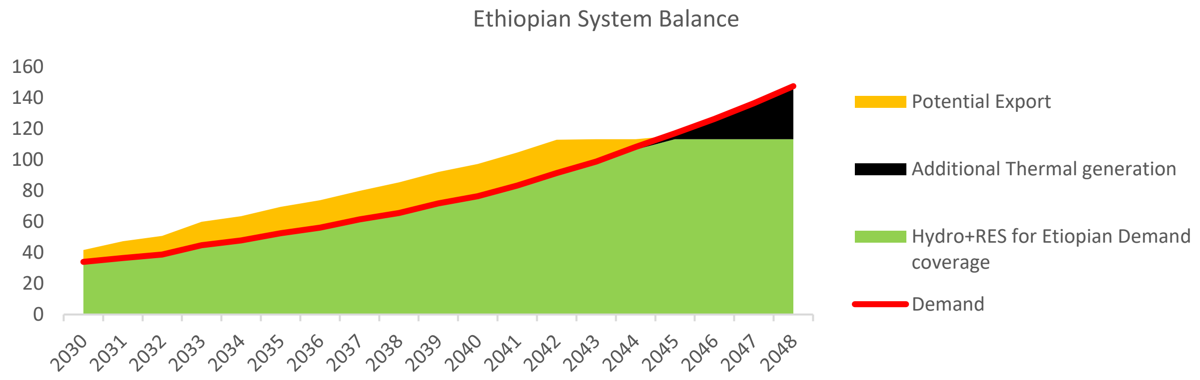


Figure 4-9: Ethiopian system balance

4.2.5 Output of the Model

The generation expansion plan developed using the OptGen model is formulated as a mixed-integer optimization problem. Given a defined set of input parameters—including demand forecasts, technology options, fuel prices, and system constraints—the model determines, for each year of the planning horizon, the optimal set of candidate generation projects to be commissioned.

New generation capacity, renewable energy curtailment, and load shedding are jointly optimized within the generation expansion planning process. These elements are balanced simultaneously during the optimization to ensure that the system meets demand in the most cost-effective and technically feasible manner. As a result, the generation expansion plan provides, on a year-by-year basis, a detailed schedule of new thermal generation candidates to be commissioned.

The model allows demand curtailment as a last-resort option when generation capacity is insufficient to meet load. This is penalized using a high economic cost, commonly referred to as the Value of Lost Load (VoLL), which typically exceeds $1,000/MWh. This high penalty ensures that curtailment is only selected when no other feasible or economic generation option is available.

The model may also result in renewable energy curtailment in scenarios where total generation exceeds demand and system flexibility is limited. While renewable curtailment does not carry an explicit cost in the model, it is implicitly accounted for through the opportunity cost of displacing thermal generation that could otherwise have been avoided.

Additionally, OptGen calculates the total Net Present Cost (NPC) of the system, which serves as a key metric for comparing different planning scenarios under varying assumptions and constraints.

$$Net\ Present\ Cost = \sum_{year} \frac{CAPEX + OPEX}{(1 + WACC_{real})^{year}}$$

Where:

$$WACC_{real} = \frac{1 + WACC}{1 + inflaction} - 1$$

Beyond the economic and technical optimization of generation capacity, the generation expansion plan also provides valuable insights into the energy mix and its environmental implications.
By analyzing the share of electricity generated from renewable sources—such as hydro, solar, and wind—the model quantifies the renewable energy penetration, a metric that serves as a key indicator of progress toward national or regional decarbonization targets.

4.2.6 Results reference scenario

This section summarizes the main outcomes of the generation expansion modeling conducted for Somalia over the period 2030 to 2050, based on the input data provided for the baseline scenario.
The key assumptions underlying the reference scenario are as follows:

- All fuel types are available except natural gas.
- No infrastructure is assumed for gas or oil pipelines within the inland region.
- Transmission network development follows the specifications defined in transmission expansion.
- Electricity demand growth is based on the projections outlined in load (demand) forecast.
- Interconnection with Ethiopia is assumed to become operational starting in 2032.

The results of the generation expansion analysis are presented in the following figures. A comprehensive set of detailed results is also provided in the annex section in tabular format for further reference and analysis.

The figure below illustrates the installed capacity by technology, year by year, over the planning horizon. A key observation is that, particularly in the long term, peak demand exceeds the total installed thermal capacity. In a high RES penetration context, relying solely on thermal capacity to cover peak load would lead to an overestimation of the required thermal fleet, as renewables contribute significantly to meeting demand—even during peak periods.

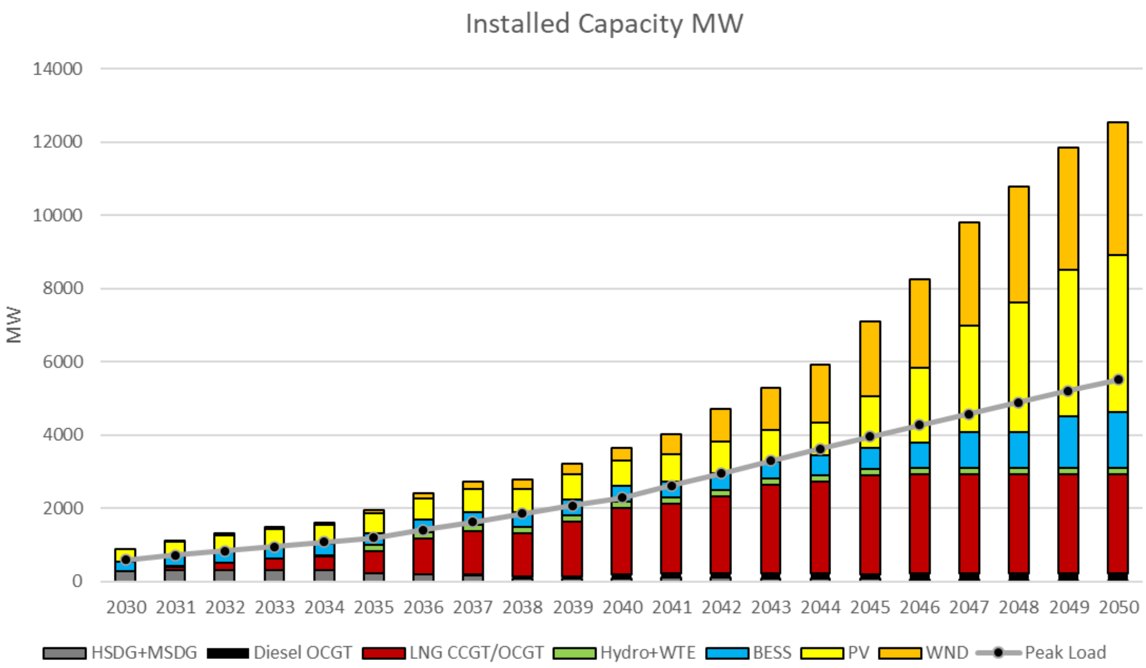


Figure 4-10: Installed capacity over the horizon, reference scenario

The energy balance analysis reveals that, in the long term, Somalia is expected to become a net exporter of electricity to Ethiopia, primarily due to the surplus of renewable generation. This marks a strategic shift in the regional energy landscape, positioning Somalia not only as self-sufficient but also as a contributor to regional energy security.

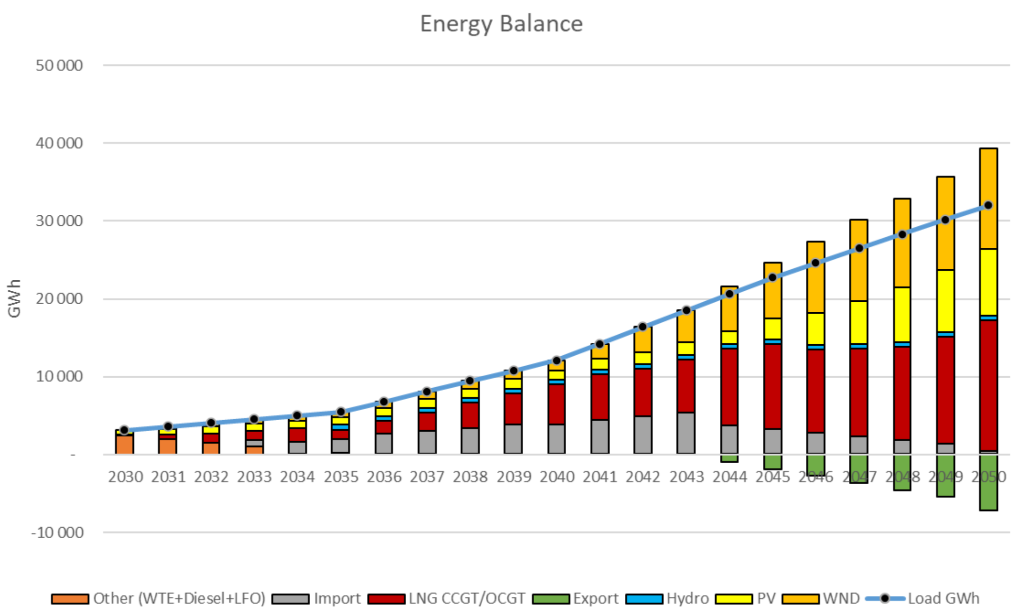


Figure 4-11: Energy Balance, reference scenario

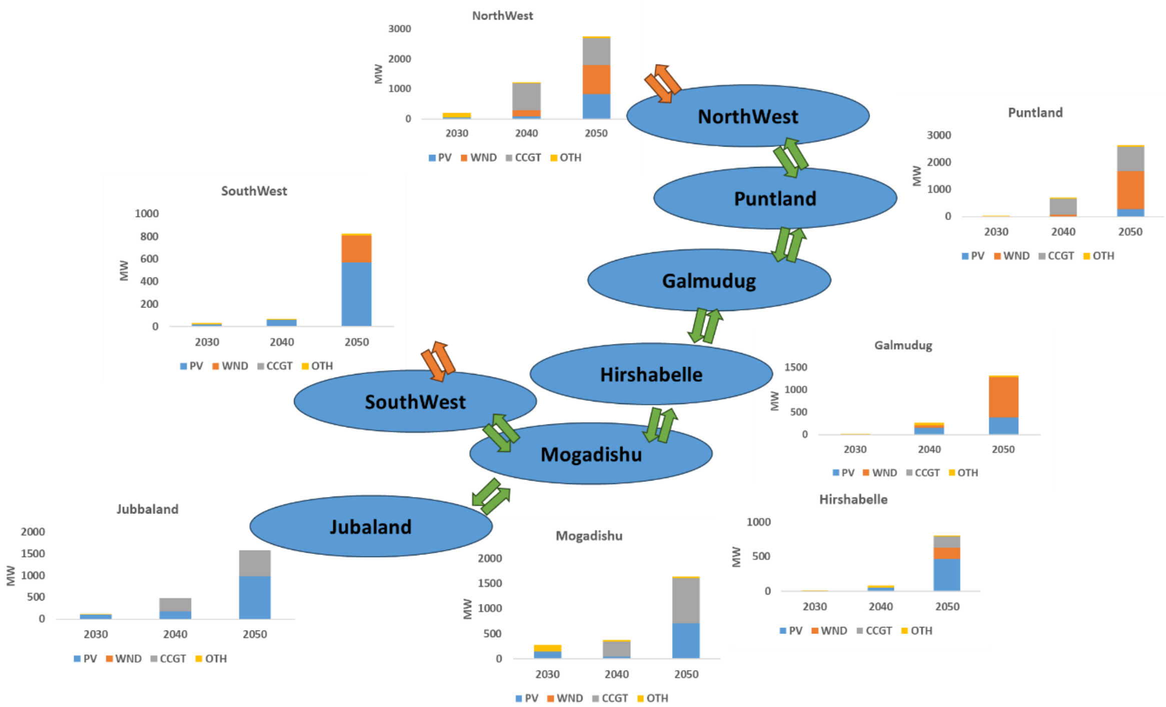


Figure 4-12: Installed generation capacity over the year and the region

A particularly insightful comparison can be made by observing the capacity mix in the years 2030, 2040, and 2050. The system transitions from a heavy reliance on diesel generation in the early years to a more diversified and sustainable mix, incorporating solar, wind, hydro, and gas-fired technologies. This evolution reflects both technological progress and strategic planning aimed at reducing costs and emissions.

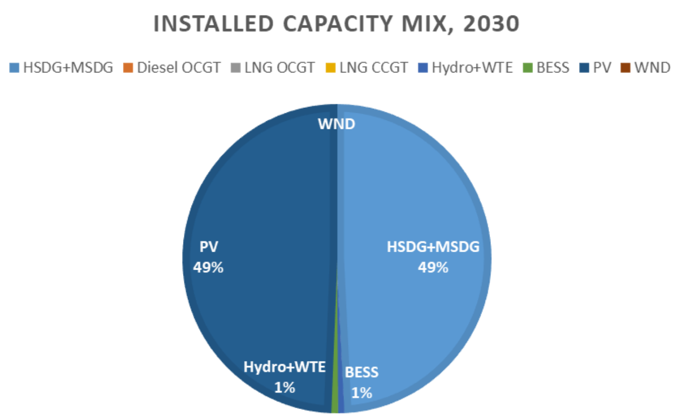


Figure 4-13: Installed capacity mix 2030

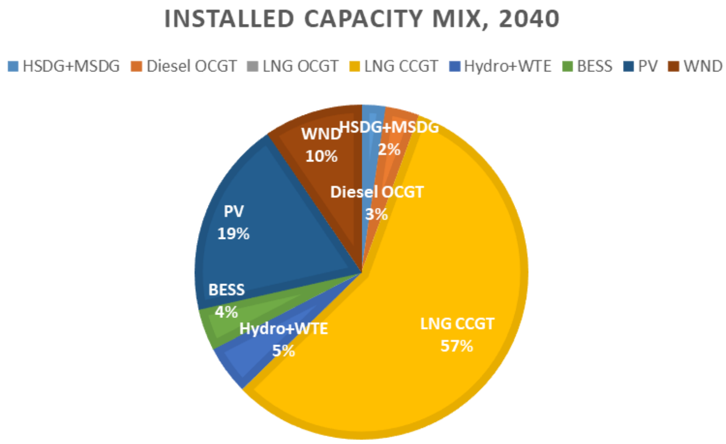


Figure 4-14: Installed capacity mix 20340

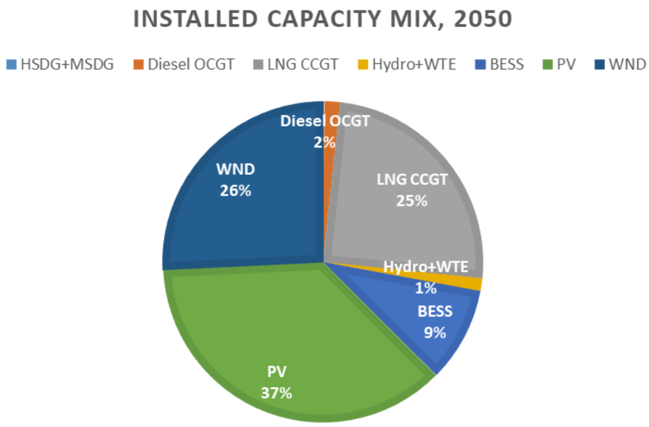


Figure 4-15: Installed capacity mix 2050

Total system costs, broken down into capital expenditures (CAPEX) and operational expenditures (OPEX), are reported both cumulatively for the period 2030–2050 and annually.

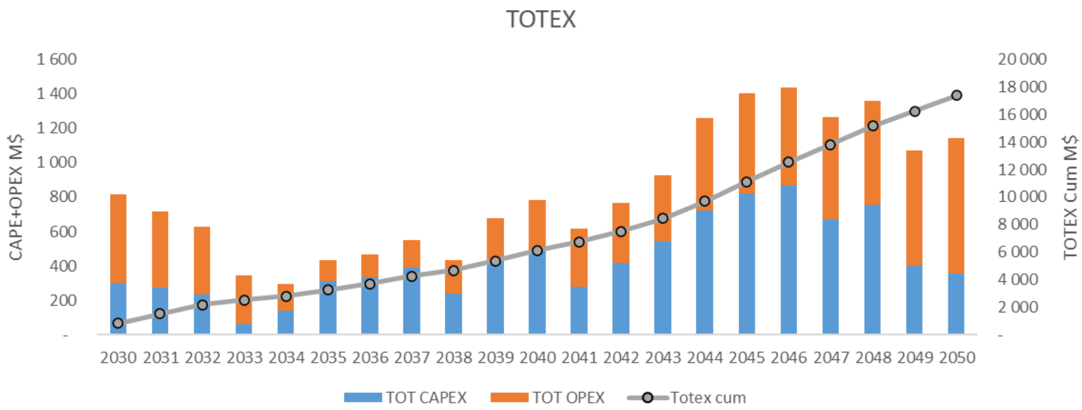


Figure 4-16: Total system costs, reference scenario

Table 4-4: Reference scenario system costs

Reference scenario		
CAPEX 2030-2050	M$	4 846
OPEX 2030-2050	M$	4 847

TOTEX 2030-2050	M$	9 693
Res Penetration 2050	%	59%

A notable trend is the sharp decline in variable operating costs (Short-term Marginal costs, as shown in figure below) starting around 2034, driven by the increasing share of renewables in the generation mix. This shift not only reduces fuel dependency but also enhances long-term cost stability.

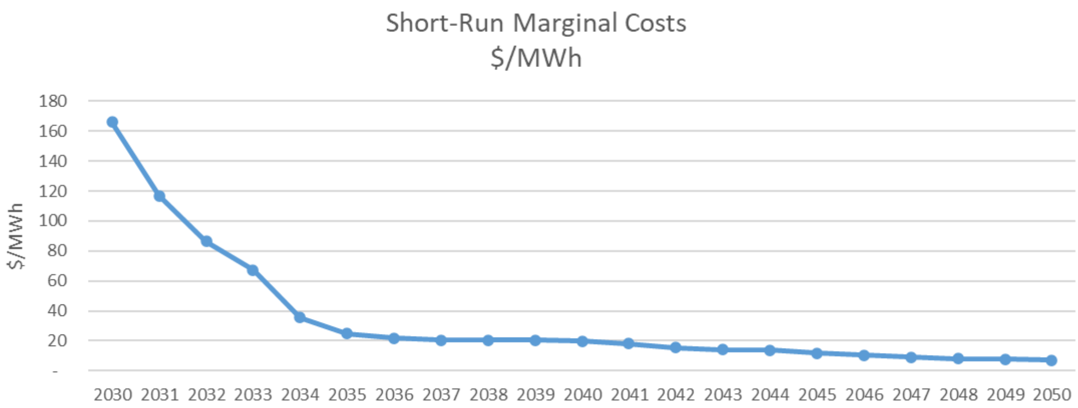


Figure 4-17: Short-run Marginal costs (SRMC) [$/MWh]

The same decline, even if with some discontinuity, can be observed in the Long-Run Marginal Costs LRMC (as shown in figure below) that includes both Opex and Capex.

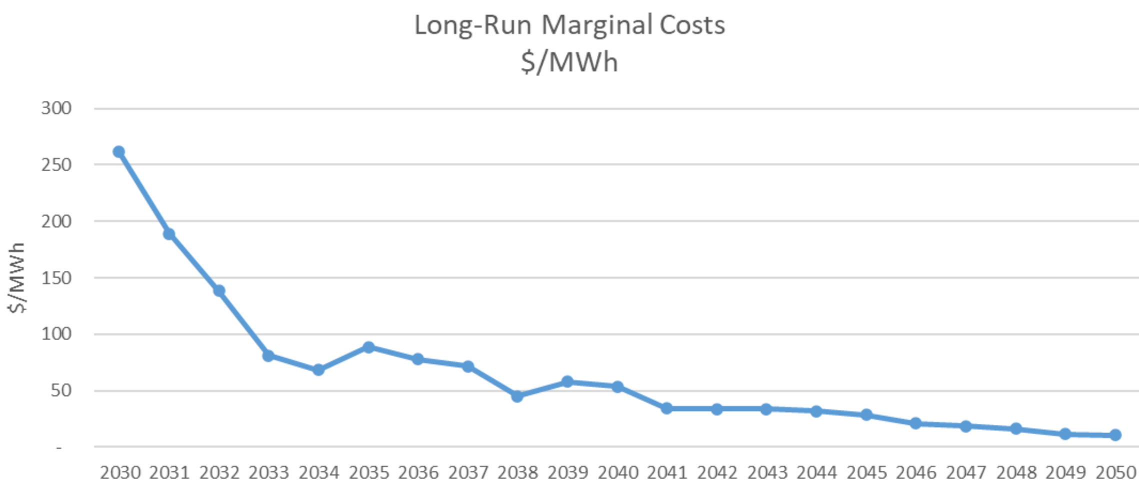


Figure 4-18: Long-run Marginal costs (LRMC) [$/MWh]

$$SRMC\ [\frac{\$}{MWh}] = \frac{OPEX\ [\$]}{Total\ produced\ Energy\ [MWh]}$$

$$LRMC\ [\frac{\$}{MWh}] = \frac{CAPEX + OPEX\ [\$]}{Total\ produced\ Energy\ [MWh]}$$

Renewable energy penetration is projected to steadily increase over the planning horizon, reaching approximately 59% by 2050. This figure includes contributions from hydropower, which plays a key role in providing both clean energy and system flexibility. The growing share of renewables underscores Somalia's potential to transition toward a low-carbon, resilient power system.

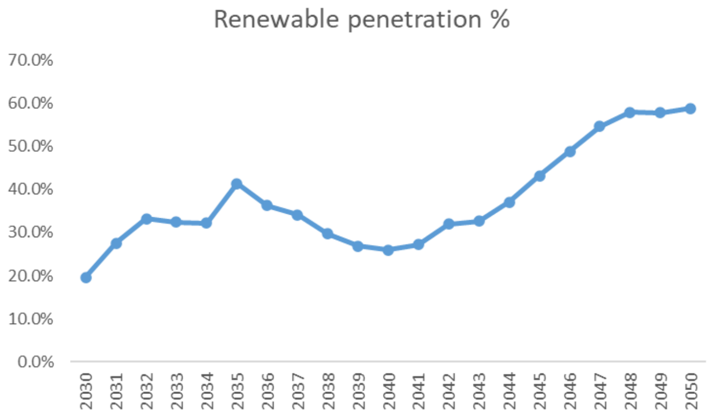


Figure 4-19: Renewable penetration

4.2.7 Sensitivities scenarios

A set of sensitivities scenarios has been performed as described in Power generation projects for supply to the National Grid in order to provide an insight on the impact of sensible variable to the outcomes of the generation expansion plan. As we will see, some variable would have a very little impact, other a huge impact. To follow, a dedicated paragraph for each sensitivity and at the end a comparison with the reference scenario with some final remarks.

Here the list of sensitivity scenarios:

- Load Forecast
- Fuel availability
- Fuel Prices
- CO_2 Price
- CAPEX
- WACC
- Interconnection availability

4.2.7.1 Different Demand scenarios

4.2.7.1.1 Low Demand Growth/High Demand Growth

Given the high level of uncertainty surrounding the future development of Somalia's energy system, particularly in relation to electricity demand growth, a dedicated sensitivity analysis has been conducted to explore the implications of a lower-than-expected and higher-than-expected demand trajectory.

This analysis is essential for testing the robustness and flexibility of the proposed generation expansion strategies under alternative future scenarios. By simulating a scenario with different demand growth, the study aims to assess how key planning indicators—such as installed capacity, system costs, and renewable integration—would be affected if actual demand evolves slowly or fast than projected.

The assumptions for this sensitivity case are based on a downward revision of the demand forecast originally developed in load (demand) forecast. For a detailed explanation of the methodology and assumptions used to construct the demand scenarios as provided in the load (demand) forecast section.

The table below provides a summary of the expected peak demand and annual energy consumption under the low and high - demand scenario, serving as a reference point for comparison with the baseline projections.

Table 4-5: Demand growth assumptions (Peak and Energy)

Country	Scenario	Item	2030	2035	2040	2045	2050
	Low	Supplied Demand (GWh)	2,597	5,752	11,575	20,447	28,012
		Peak (MW)	456	1,010	2,033	3,591	4,920
	High	Supplied Demand (GWh)	2,738	6,453	13,780	25,734	36,611
		Peak (MW)	481	1,133	2,420	4,520	6,430

Table 4-6: Totex and RES penetration comparison

		Low	Base	High
CAPEX 2030-2050	M$	4 328	4 846	5 434
OPEX 2030-2050	M$	4 871	4 847	5 137
TOTEX 2030-2050	M$	9 200	9 693	10 570
Res Penetration 2050	%	54%	59%	61%

When comparing the low-demand growth scenario to the reference scenario, it becomes evident—as expected—that a slower increase in electricity demand results in significantly lower total system costs. This outcome is primarily due to the reduced need for new generation infrastructure, as well as lower fuel and operational expenditures over the planning

cost reduction comes with a trade-off: the penetration of renewable energy sources is also lower in the low-demand scenario. This is due to the fact that the system requires fewer new capacity additions overall, which limits the opportunity to integrate large volumes of variable renewable energy such as solar PV and wind.
Conversely, in the high-demand growth scenario leads to higher total system costs, driven by the need for accelerated investment in generation.

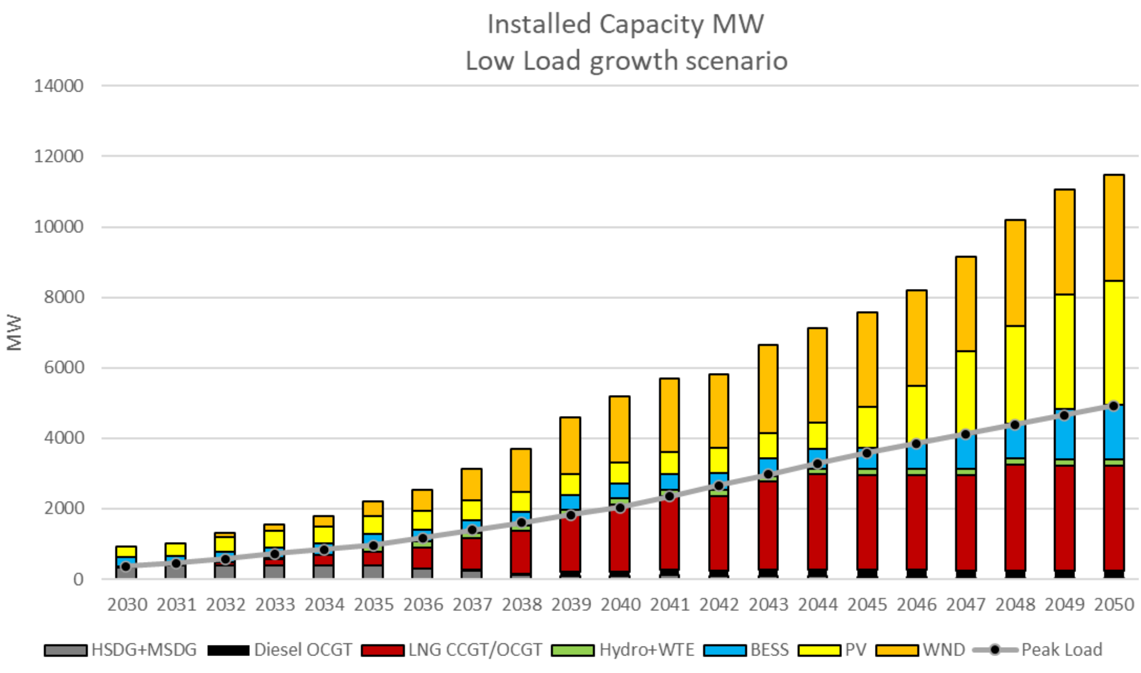


Figure 4-20: Installed capacity for the Low Load growth scenario

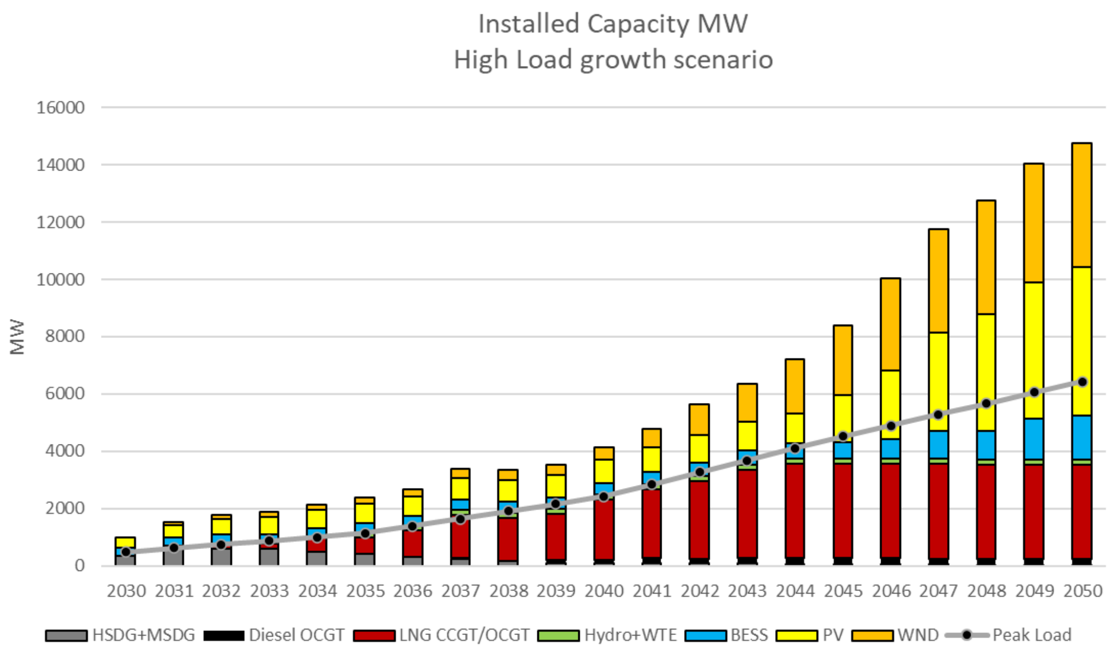


Figure 4-21: Installed capacity for the High Growth scenario

4.2.7.1.2 Different electricity demand distribution across the Somali market zones

The projected load for the Mogadishu area as per table 4-5 has been increased due to the data obtained through on-field activity with ESPs based Mogadishu. Despite the revisions, the overall electricity demand forecast for Somalia remains broadly consistent with the original estimates. Both the national peak load and total energy consumption are only marginally affected, indicating that the revisions primarily impact the internal distribution of demand rather than its total volume.

Table 4-7:New demand forecast for the whole country

Scenario	Item	2030	2035	2040	2045	2050
Base	Supplied Demand (GWh)	3,395	6,813	13,014	22,559	31,383
	Peak (MW)	596	1,196	2,286	3,962	5,512

For a detailed breakdown of the installed capacity by area and technology, please refer to the table provided in the annex. The tables below are intended to facilitate a comparative analysis of the total installed capacity across the different market zones, under the various load projection scenarios. This comparison highlights how regional capacity allocations align with the evolving demand forecasts.

As a general comment to support the interpretation of the results related to the Generation Expansion Plan updated in line with the latest version of the load forecast, it is important to highlight that the most significant changes are primarily associated with the geographical allocation of combined cycle gas turbine (CCGT) power plants.
Specifically, the revised plan foresees the relocation of two CCGT units, each with a capacity of 300 MW, from the macro-region of NorthWest and Puntland to the southern regions of Jubbaland and Mogadishu. This adjustment reflects a strategic response to the updated demand distribution, aiming to better align generation capacity with regional load centers.
In addition to this major shift, some minor modifications are also foreseen in the short term, particularly involving diesel-based open cycle gas turbines (OCGT) and medium-speed diesel generators (MSDG).

These adjustments are relatively limited in scale and are intended to optimize short-term system flexibility and reliability. Overall, the updated Generation Expansion Plan continues to prioritize the siting of generation assets close to demand centers, in order to minimize transmission losses and enhance system efficiency. However, due to the limited number of feasible locations for large thermal power plants and the potential for inter-regional energy exchange, the revised plan remains broadly consistent with the original version in terms of total installed capacity.

Finally, there are no significant changes in the planned installed capacity for solar, wind, or battery energy storage systems (BESS). As a result, the renewable energy penetration target remains stable at approximately 60%, reaffirming the country's possibility to a sustainable and diversified energy mix.

Table 4-8: Installed capacity by market zones

New Load demand forecast (June 2025)

	2030	2035	2040	2045	2050
Galmudug	18	164	350	710	1460
Hirshabelle	11	60	116	110	515
Jubbaland	112	168	495	865	2165
Mogadishu	120	444	370	1185	1860
NorthWest	120	223	890	1465	2475
Puntland	15	133	700	1710	2510
SouthWest	40	55	105	310	840

First Load Demand Forecast version (May 2025)

	2030	2035	2040	2045	2050
Galmudug	18	165	350	710	1460
Hirshabelle	11	81	116	110	515
Jubbaland	114	196	495	565	1850
Mogadishu	130	402	370	1185	1795
NorthWest	170	592	1190	1795	2950
Puntland	20	152	700	2040	2840
SouthWest	41	58	105	310	840

The figure below illustrates the installed capacity by technology, year by year, over the planning horizon. A key observation is that, particularly in the long term, peak demand exceeds the total installed thermal capacity. In a high res penetration context, relying solely on thermal capacity to cover peak load would lead to an overestimation of the required thermal fleet, as renewables contribute significantly to meeting demand—even during peak periods.

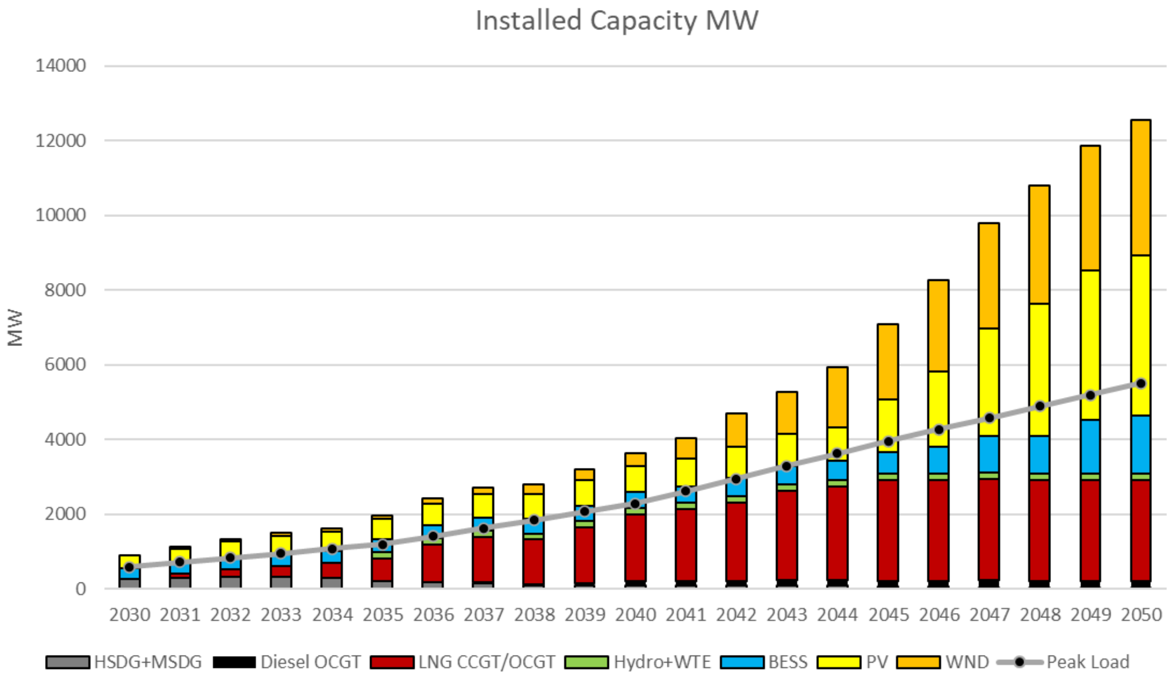


Figure 4-22: Installed capacity over the horizon, reference scenario

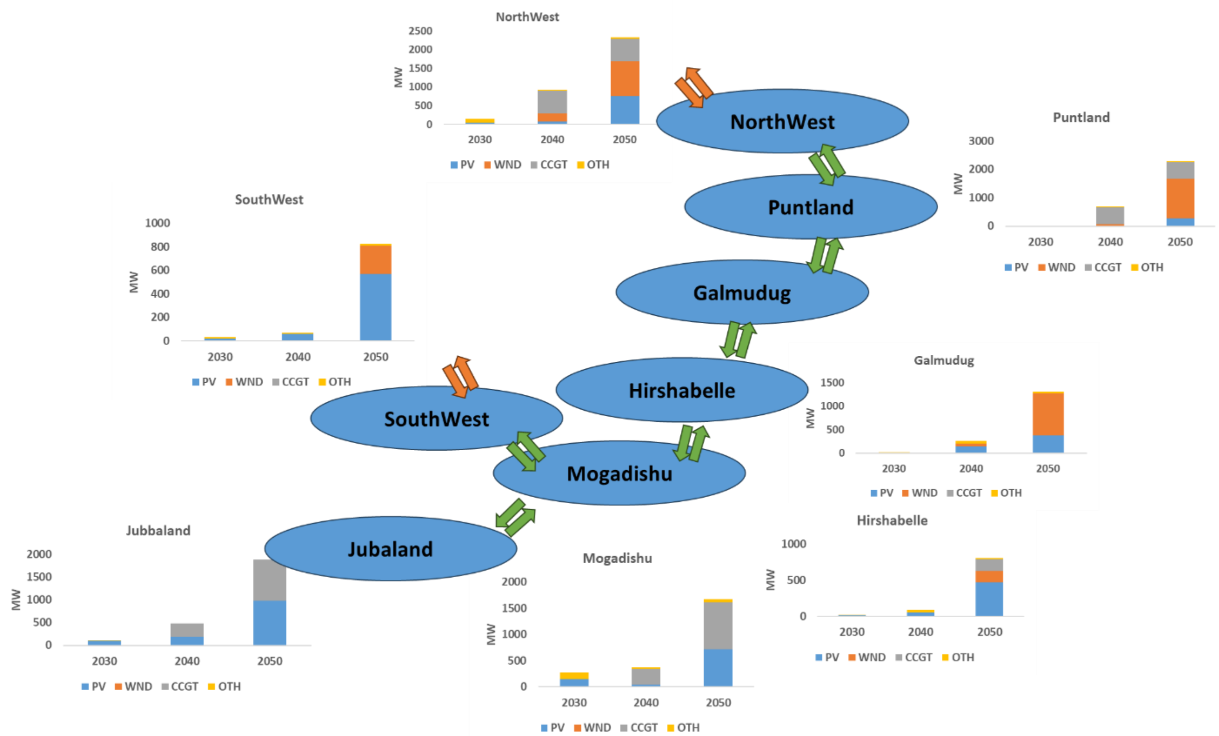


Figure 4-23: Installed generation capacity over the year and the region

Total system costs, broken down into capital expenditures (CAPEX) and operational expenditures (OPEX), are reported both cumulatively for the period 2030–2050 and annually.

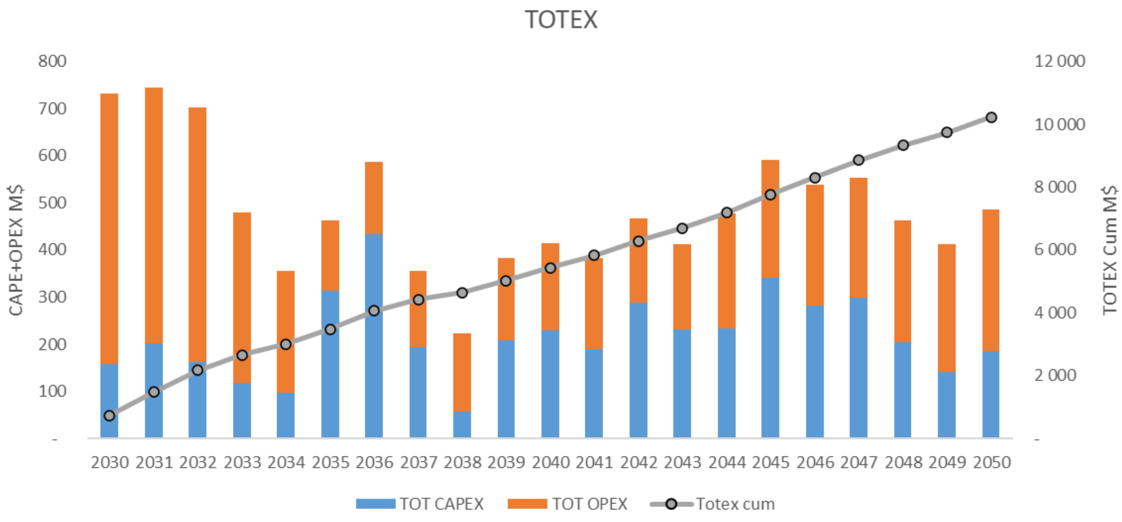


Figure 4-24: Total system costs, reference scenario

Table 4-9: Reference scenario system costs

Reference scenario		
CAPEX 2030-2050	M$	4 568
OPEX 2030-2050	M$	5 660
TOTEX 2030-2050	M$	10 228
Res Penetration 2050	%	59%

A notable trend is the sharp decline in variable operating costs (Short-term Marginal costs, as shown in figure below) starting around 2034, driven by the increasing share of renewables in the generation mix. This shift not only reduces fuel dependency but also enhances long-term cost stability.

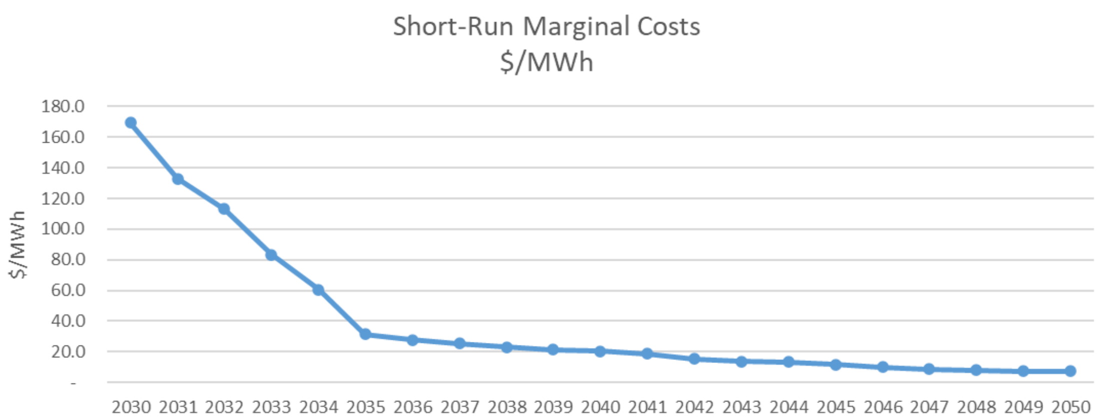


Figure 4-25: Short-run Marginal costs (SRMC) [$/MWh]

The same decline, even if with some discontinuity, can be observed in the Long-Run Marginal Costs LRMC (as shown in figure below) that includes both Opex and Capex.

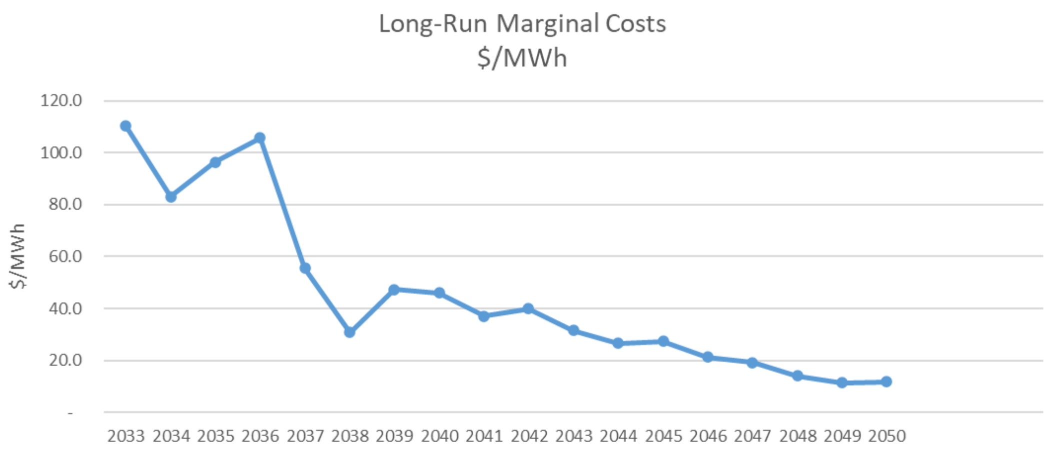


Figure 4-26: Long-run Marginal costs (LRMC) [$/MWh]

$$SRMC\ [\frac{\$}{MWh}] = \frac{OPEX\ [\$]}{Total\ produced\ Energy\ [MWh]}$$

$$LRMC\ [\frac{\$}{MWh}] = \frac{CAPEX + OPEX\ [\$]}{Total\ produced\ Energy\ [MWh]}$$

Renewable energy penetration is projected to steadily increase over the planning horizon, reaching approximately 59% by 2050. This figure includes contributions from hydropower, which plays a key role in providing both clean energy and system flexibility. The growing share of renewables underscores Somalia's potential to transition toward a low-carbon, resilient power system.

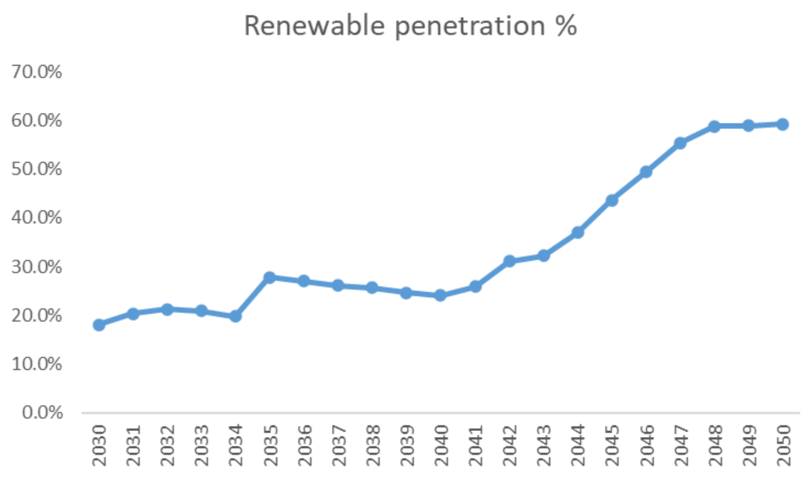


Figure 4-27: Renewable penetration

4.2.7.2 Fuel prices

Fuel prices play a significant role in determining the Levelized Cost of Electricity (LCOE) for thermal generation technologies. As fuel costs represent a substantial portion of the operating expenses for fossil-fuel-based plants, fluctuations in fuel prices can directly influence their LCOE. Consequently, this can affect the merit order—the ranking of generation technologies based on their cost-effectiveness.

This sensitivity is particularly relevant in scenarios where the LCOEs of different technologies are closely aligned. In such cases, even modest changes in fuel prices can shift the relative competitiveness of technologies, potentially altering investment decisions and dispatch priorities.

However, this is not the case in the current analysis. As previously discussed in the Power generation projects for supply to the National Grid, the technologies under consideration exhibit clear cost differentials, with renewable technologies such as photovoltaic (PV) systems maintaining a significant cost advantage over thermal alternatives like LNG Combined Cycle Gas Turbines (CCGTs). Even under a ±10% variation in fuel prices—a range that reflects realistic market volatility—the merit order remains unchanged.

For example, LNG CCGTs continue to exhibit higher LCOEs than PV power plants, even when fuel prices are reduced by 10%. This indicates that such a level of fuel price fluctuation is not sufficient to make thermal technologies more competitive than renewables in the current cost landscape.

This conclusion is further supported by the results of the OptGen optimization model, which shows no variation in the generation expansion decisions across the different fuel price scenarios. While the investment choices remain stable, what does change is the total system operational expenditure (OPEX), which is directly influenced by fuel cost assumptions. It is important to note that OPEX includes not only fuel costs but also other operational components, such as fixed and variable costs. Therefore, while fuel prices change by 10%, the overall impact on total OPEX is slightly lower—approximately 9.5%—due to the presence of these additional cost elements. These impacts on OPEX are summarized in the table below.

Table 4-10: Totex and RES penetration comparison

M$ (2030-2050)	-10% fuel price	Reference	+10% Fuel Price
CAPEX	4 846	4 846	4 846
OPEX	4 389	4 847	5 305
TOTAL SYSTEM COSTS	9 235	9 693	10 151

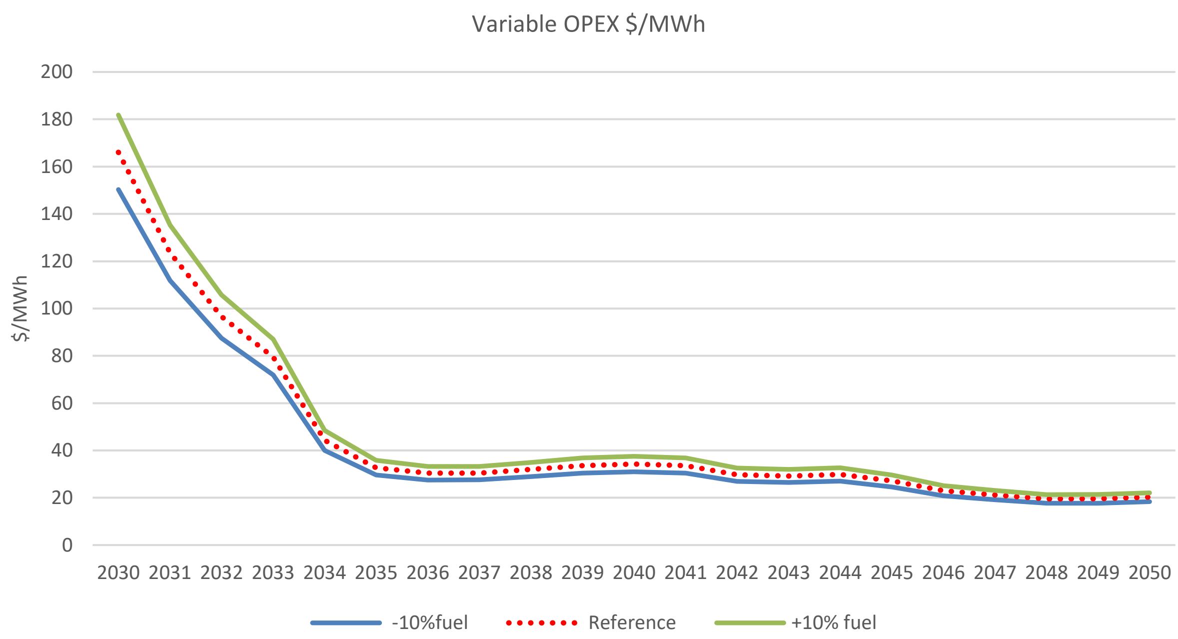


Figure 4-28: Variable OPEX

4.2.7.3 CO2 Emissions

In line with the findings from the fuel price sensitivity analysis, the introduction of a carbon pricing mechanism—modeled through a CO_2 cost sensitivity—provides valuable insights into how environmental externalities influence the generation expansion strategy in Somalia.

As expected, the higher the assumed CO_2 price, the greater the impact on the cost structure of carbon-intensive technologies. Technologies such as coal-fired power plants and diesel generators, which have high specific CO_2 emissions per unit of electricity generated, are the most affected. In contrast, nuclear power and renewable energy sources (e.g., solar PV and wind), which have either zero or negligible direct emissions, remain unaffected by carbon pricing.

As previously discussed in the Power generation projects for supply to the National Grid, the inclusion of a CO_2 cost—set at a representative value of 80 USD/ton—does not alter the merit order of technologies. For instance, LNG Combined Cycle Gas Turbines (CCGTs), which are the most cost-effective among thermal options, still remain more expensive than renewable technologies, even when fuel and CO_2 costs are reduced. Similarly, coal and diesel technologies become significantly more expensive under this assumption, but since they were already less competitive, their relative position in the merit order remains unchanged.

This outcome is confirmed by the OptGen optimization results, which show no change in the generation expansion plan across the CO_2 price scenarios. The model continues to prioritize investment in low-carbon and renewable technologies, reaffirming their economic advantage even in the presence of moderate to high carbon pricing.

Strategic Considerations

Although the generation mix remains stable, it is important to emphasize that CO_2 pricing has a direct impact on operational costs, particularly for fossil-fuel-based plants. This reinforces the importance of minimizing the use of high-emission technologies. In particular, oil-fired power plants, due to their high emissions and cost, should be reserved strictly for emergency or backup purposes, rather than for regular dispatch.

Incorporating environmental costs into planning models not only aligns with global decarbonization goals but also ensures that long-term investment decisions reflect the true societal cost of carbon emissions.

$$CO_2cost\left[\frac{\$}{MWh}\right] = CO_2price\left[\frac{\$}{ton}\right] * CO_2coeff\left[\frac{t}{Gcal}\right] * efficiency\left[\frac{Gcal}{MWh}\right]$$

The table presents the variable CO_2 costs (in $/MWh) for different technologies, calculated solely based on fuel-related emissions. These values are derived using the formula shown, which multiplies the CO_2 price by the emission factor of the specific fuel and adjusts for the efficiency of the power plant.

It is important to note that this calculation only accounts for direct emissions from fuel combustion during electricity generation. It does not include the full lifecycle carbon footprint, such as emissions associated with the construction, manufacturing, or decommissioning of the power plants.

As a result, technologies like nuclear and hydro, which do not emit CO_2 during operation, are shown with zero CO_2 costs in this context—even though they may have some emissions associated with their infrastructure over their lifecycle.

Table 4-11: Variable CO2 costs [$/MWh]

Variable CO2 costs	
	$/MWh

Diesel HSDG 2MW	58.4
Diesel MSDG 10MW	53.5
Diesel MSDG 20MW	51.7
HFO MSDG 10 MW	54.8
HFO MSDG 20 MW	52.3
Diesel OCGT 30 MW	62.4
LNG OCGT 40 MW	32.6
LNG OCGT 100 MW	31.4
LFO OCGT 100 MW	58.4
Gas CCGT 300MW (2+1)	23.6
LNG CCGT 300MW (2+1)	23.6
LFO CCGT 300MW (2+1)	43.2
Coal 200 MW	75.2
Nuclear 300 MW	0.0
Mini Hydro	0.0

Table 4-12: System costs for the "CO2 scenario"

M$ (2030-2050)	Reference	80$/ton CO2
CAPEX	4 846	4 846
OPEX	4 847	6 540
TOTAL SYSTEM COSTS	9 693	11 386

4.2.7.4 Gas availability

The availability of natural gas in Somalia is closely tied to the potential for domestic gas exploitation. However, due to the high level of uncertainty, a scenario assuming domestic gas availability is analyzed as a sensitivity case.
In this scenario, all assumptions remain consistent with those of the reference scenario, with one key exception: LNG-based CCGT (Combined Cycle Gas Turbine) plants are assumed to be fueled directly by domestically produced natural gas. This eliminates the need for regasification infrastructure, resulting in lower capital expenditures (CAPEX) for these plants. Gas-fired CCGT plants are assumed to be installed preferentially along the coast, where access to water for cooling is readily available.

No additional costs for gas pipeline infrastructure are considered, based on the assumption that Somalia would, in any case, need to construct dedicated pipelines for gas export. These same pipelines could be leveraged for domestic thermal power generation, thereby avoiding redundant infrastructure investments.

The results of the optimal generation expansion plan under the gas availability scenario confirm that:

- Since Combined cycle gas turbines (CCGTs) fueled by natural gas exhibit a Levelized Cost of Energy (LCOE) that is comparable to that of photovoltaic (PV) and wind technologies they become more competitive relative to variable renewable energy sources. Consequently, a slightly lower RES penetration is observed in the natural gas scenario. However, it is important to emphasize that this does not undermine the strong role of renewables in the overall energy strategy. The scenario still supports a high level of renewable integration, while highlighting how the availability of competitively priced natural gas can influence the generation mix.
- However, this is offset by a significant reduction in overall system costs, primarily due to the lower OPEX of gas-based generation and the elimination of regasification facilities.

Given the potential economic benefits, it is strongly recommended that Somalia carefully assess the feasibility of domestic gas availability in the near future. If viable, this option could represent the most cost-effective and strategic pathway for the country's power sector development.
While no transition costs are assumed for switching from LNG to domestic gas in CCGT plants, the capital investments required for LNG regasification infrastructure would become "unused" assets in such a scenario. It is worth noting, however, that floating storage and regasification units (FSRUs) offer a high degree of flexibility, as they can be relocated or repurposed for use in other regions. This reinforces the preference for floating regasification systems over fixed onshore facilities when LNG is used, especially in contexts with uncertain long-term gas supply strategies.

Table 4-13: Totex and RES penetration comparison

		Reference scenario	Gas scenario	Variation %
CAPEX 2030-2050	M$	4 869	4 827	-0.4%
OPEX 2030-2050	M$	4 798	3 145	-35.1%
TOTEX 2030-2050	M$	9 666	7 972	-17.8%
Res Penetration 2050	%	59%	57%	- 2%

4.2.7.5 NO BESS

Battery Energy Storage Systems are already becoming a concrete part of the national energy strategy. As of current planning, approximately 50 MW of BESS capacity is expected to be installed by 2030.

In contrast, the scenario presented in this section assumes no additional BESS capacity beyond what is already planned. The purpose of this assumption is to clearly illustrate the consequences of a storage-deficient system, particularly in terms of renewable energy penetration and total system costs.

Here the main outcomes:

- Renewable penetration drops significantly—from 59% in the reference scenario to 40% in the no-storage scenario—due to the system's reduced ability to absorb and manage variable generation.
- Total system costs increase by approximately 2%, reflecting the need for additional flexible thermal capacity and higher operational expenditures to maintain system reliability.

The impact on total system costs would likely be even more significant if environmental externalities were considered into the analysis. Including these costs would provide a more comprehensive assessment of the economic implications of a system without adequate storage capacity.

This comparison reinforces the critical role of BESS in achieving both cost- effective and environmentally sustainable energy development in Somalia.

Table 4-14: Totex and RES penetration comparison

		Reference scenario	NO BESS	Variation %
CAPEX 2030-2050	M$	4 846	4 051	-16.4%
OPEX 2030-2050	M$	4 847	5 775	19.2%
TOTEX 2030-2050	M$	9 693	9 826	1.4%
Res Penetration 2050	%	59%	40%	- 19%

4.2.7.6 *Low Wind CAPEX Benefits*

Capital expenditures (CAPEX) play a crucial role in determining the Levelized Cost of Electricity (LCOE) across different generation technologies. However, modifying CAPEX assumptions for all technologies would be overly complex and may not yield meaningful insights. Therefore, the analysis focuses on technologies whose CAPEX variations are most likely to influence the merit order and, consequently, the generation mix—specifically, onshore wind and Battery Energy Storage Systems (BESS).

A reduction in wind CAPEX could make wind power more economically attractive, potentially surpassing other technologies in cost-competitiveness. This shift would significantly alter the generation mix, increasing the share of wind energy in the system.

The tables present the Levelized Cost of Energy (LCOE) for photovoltaic (PV) and wind technologies under different capital expenditure (CAPEX) assumptions. The reference CAPEX and operational expenditure (OPEX) values are drawn from the *Lazard Levelized Cost of Energy Analysis* published in June 2024, as well as from International Energy Agency (IEA) publications.
Naturally, these figures represent average values within a broader range and are subject to uncertainty. This is particularly true given that costs can vary significantly depending on the specific country or project context. Nevertheless, they provide a solid and internationally recognized baseline for comparative analysis.
In the sensitivity scenario, a reduction in CAPEX relative to the reference value is considered. This lower CAPEX assumption remains within the realistic range of expected cost reductions for wind technology in the medium to long term, based on current market trends and technological advancements.
LCOE is then calculated by incorporating expected inflation rates and the Weighted Average Cost of Capital (WACC), ensuring a consistent and forward-looking economic assessment.

Table 4-15: PV and Wind LCOE under different CAPEX assumptions

Reference scenario	LCOE 2030	LCOE 2040	LCOE 2050
	\$/MWh	\$/MWh	\$/MWh
PV	48.0	44.9	35.4
Wind On Shore	53.3	50.2	47.1

Reference scenario	capex 2030	capex 2040	capex 2050
	\$/kW	\$/kW	\$/kW
PV	700	650	500
Wind On Shore	1500	1400	1300

LOW Wind CAPEX	LCOE 2030	LCOE 2040	LCOE 2050
	\$/MWh	\$/MWh	\$/MWh
PV	48.0	44.9	35.4
Wind On Shore	44.0	40.9	37.8

LOW Wind CAPEX	capex 2030	capex 2040	capex 2050
	\$/kW	\$/kW	\$/kW
PV	700	650	500
Wind On Shore	1200	1100	1000

This expectation is fully validated by the results of the optimal generation expansion analysis, which clearly indicate an increase in both the share of wind energy within the renewable generation mix and the overall renewable energy penetration in the system. As shown in the table and figure below, the optimization model prioritizes wind deployment due to its favorable cost-performance.

Table 4-16: Totex and RES penetration comparison, Low Wind CAPEX

		Reference scenario	Low Wind CAPEX	Variation %
CAPEX 2030-2050	M$	4 846	3 180	-34.38%
OPEX 2030-2050	M$	4 847	4 247	-12.37%
TOTEX 2030-2050	M$	9 693	7 426	-23.38%
Res Penetration 2050	%	59%	60%	+ 1%

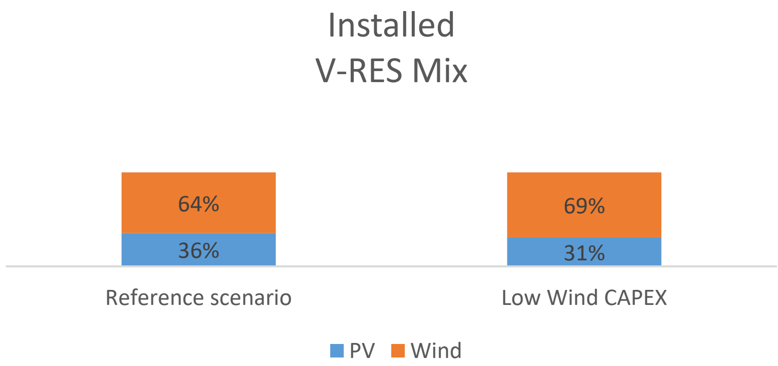


Figure 4-29: Installed V-REX with low wind capex

4.2.7.7 No LNG

The results of the optimal generation expansion plan strongly support the use of natural gas—even in its more expensive form as imported LNG—as a key fuel for future thermal power generation in Somalia. Gas-fired technologies, particularly Combined Cycle Gas Turbines (CCGTs), offer a cost-effective, flexible, and relatively low-emission solution compared to other fossil fuel alternatives.

However, in a scenario where LNG imports are not feasible—due to political instability, security concerns, or logistical constraints—Somalia would be forced to rely exclusively on Diesel, Light Fuel Oil (LFO), and Coal for thermal generation.

Under this constrained scenario, the optimal expansion strategy would shift significantly:

- Coal-fired power plants would become a central component of the generation mix, as they offer lower capital and operational costs compared to LFO-based CCGTs.
- Nevertheless, LFO CCGTs would still be installed to provide the flexibility required for balancing variable renewable energy sources and ensuring grid stability.
- The absence of LNG would lead to:
  - Lower penetration of renewable energy, due to the reduced flexibility and higher costs of the thermal fleet.
  - Higher total system costs, driven by the increased reliance on expensive and less efficient fuels.
  - A significant increase in CO_2 emissions, undermining environmental sustainability goals and potentially affecting international climate commitments.

Given these outcomes, it is crucial for Somali energy planners and policymakers to prioritize the development of LNG import infrastructure and secure long-term gas supply agreements.

Table 4-17: Totex and RES penetration comparison, NO LNG scenario

		Reference scenario	NO LNG	Variation %
CAPEX 2030-2050	M$	4 846	5 399	11.4%
OPEX 2030-2050	M$	4 847	7 607	57.0%
TOTEX 2030-2050	M$	9 693	13 006	34.2%
Res Penetration 2050	%	59%	48%	+-11%

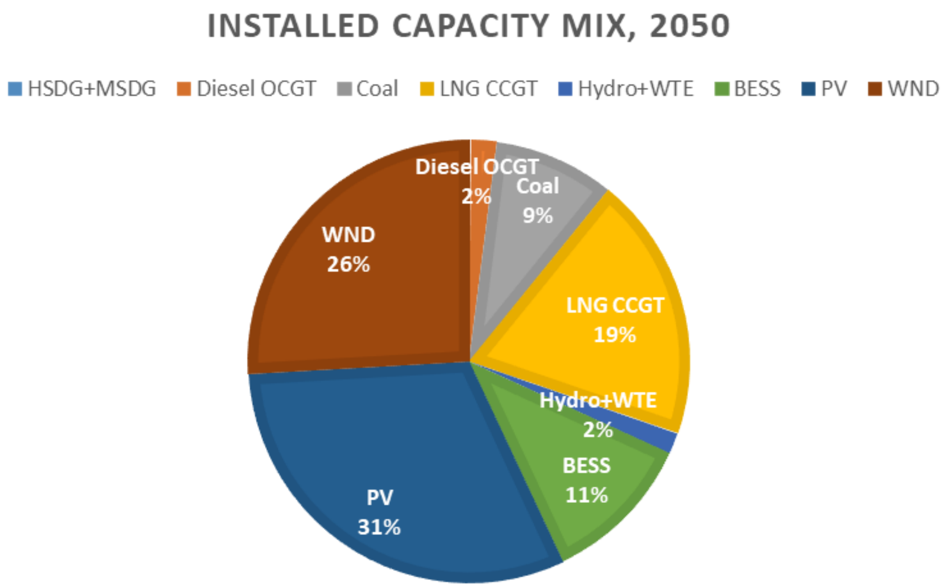


Figure 4-30: Installed capacity mix 2050, NO LNG scenario

4.2.7.8 Without Interconnection

Another sensitivity scenario explored in this analysis assumes the absence of any interconnection between Somalia and neighboring countries, not only in the short term but also throughout the entire planning horizon.
It is important to clarify that this assumption does not reflect a judgment on the likelihood of future interconnection projects. On the contrary, regional interconnection is considered a highly desirable and plausible development. However, this scenario is introduced with the specific objective of quantifying the benefits that cross-border interconnections can bring to the Somali power system.

By comparing this “without Interconnection" scenario with the reference case (which includes interconnection), the analysis aims to highlight the strategic value of regional integration.

The results of the OptGen optimal expansion model clearly demonstrate that the absence of regional interconnection with Ethiopia, would have a significant negative impact on the Somali power system—primarily in terms of operational expenditures (OPEX).

Substantial Increase in OPEX: Without access to low-cost electricity imports from Ethiopia, Somalia would be forced to rely more heavily on domestic thermal generation, which is considerably more expensive with respect to hydro Ethiopian generation. This shift leads to a marked increase in fuel consumption and operating costs.
Capital expenditure (CAPEX) remain relatively stable in the no-interconnection scenario. This is because the overall installed capacity does not increase significantly. The lack of interconnection also results in a lower share of renewable energy in the generation mix. This is due to reduced system flexibility, which

limits the ability to integrate variable renewable sources like solar and wind and a shift in investment priorities toward dispatchable thermal capacity to ensure reliability.

The combined effect of increased OPEX and reduced renewable integration leads to higher total system costs, undermining the affordability and sustainability of the power sector. Greater reliance on fossil fuels would also result in higher greenhouse gas emissions, moving Somalia further away from its climate and sustainability goals.

This scenario serves as a benchmark to demonstrate the opportunity cost of remaining isolated and to reinforce the case for investing in regional transmission infrastructure as a key enabler of a resilient, cost-effective, and sustainable power system.

Table 4-18: Totex and RES penetration comparison , No Ethiopia scenario

		Reference scenario	NO LNG	Variation %
CAPEX 2030-2050	M$	4 846	4 431	-8.6%
OPEX 2030-2050	M$	4 847	6 432	32.7%
TOTEX 2030-2050	M$	9 693	10 863	12.1%
Res Penetration 2050	%	59%	43%	- 16%

4.2.7.9 Nuclear

In the nuclear scenario, it is assumed that a 300 MW nuclear power plant will be commissioned in Mogadishu starting from the year 2040. This facility is considered a "must-run" unit, meaning it is expected to operate continuously at or near full capacity, except during scheduled maintenance or unforeseen outages.
This operational assumption reflects the inherent characteristics of nuclear power plants, which are generally not designed for flexible or load-following operation. Unlike gas turbines or hydroelectric units, nuclear reactors are optimized for base-load generation, providing a stable and uninterrupted supply of electricity.
The rationale behind this must-run status is twofold:

1. Technical Constraints: Nuclear reactors have limited ramping capabilities and are not well-suited to frequent start-stop cycles or rapid output adjustments. Operating them in a flexible mode can lead to increased wear, safety concerns, and reduced efficiency.
2. Economic Justification: Nuclear power plants involve very high capital investment costs, which can only be justified if the plant operates with a high capacity factor—typically above 80%. Maximizing the number of operational hours is essential to reduce the levelized cost of electricity (LCOE) and ensure a viable return on investment.

In the context of a generation expansion plan, the inclusion of a nuclear unit introduces a stable and carbon-free energy source, but also requires careful coordination with more flexible technologies (such as gas turbines, battery storage, or interconnections) to maintain system balance, especially during periods of variable demand or high renewable penetration.

It is important to emphasize that the results of Power generation projects for supply to the National Grid clearly demonstrate that the Levelized Cost of Energy for nuclear power is higher than that of other generation technologies, particularly renewables and LNG-based Combined Cycle Gas Turbines.
This finding is consistent with the outcomes of the OptGen optimization model under the baseline scenario, which does not include nuclear among the recommended thermal generation candidates.
In addition to its economic disadvantages, nuclear technology inherently involves significant risks, including safety concerns, long-term waste management, and the need for strict regulatory oversight. It also tends to attract international attention.

Nevertheless, the inclusion of a nuclear scenario in this analysis reflects the possibility that specific national energy strategies or geopolitical considerations may lead to the adoption of nuclear power as a long-term solution for energy security and decarbonization. The purpose of this sensitivity analysis is therefore to provide a concise but meaningful overview of the economic implications of such a strategic choice.

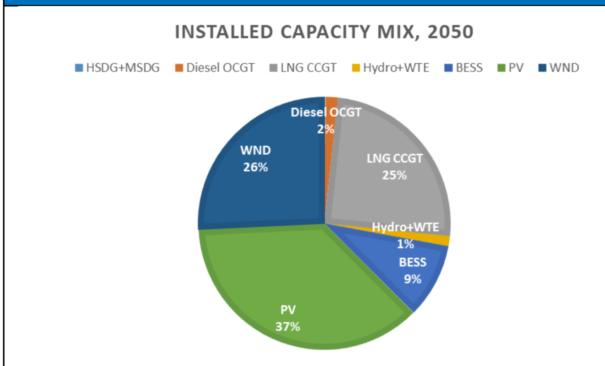
For this scope, the figure below presents a comparison between the total system cost and renewable energy penetration in the nuclear scenario versus the reference scenario. It also illustrates the expected installed capacity mix by 2050.

What emerges from this comparison is that the share of renewable energy in the generation mix is expected to decline in the nuclear scenario. This is primarily due to the limited operational flexibility of nuclear power plants, which reduces the system's ability to integrate variable renewable sources such as solar and wind. The installed capacity of CCGTs is reduced, while more flexible but costly technologies, such as Open Cycle Gas Turbines (OCGTs), show a slight increase to compensate for the system's reduced flexibility.
Overall, the total system cost in the nuclear scenario is higher than in the reference case, highlighting the economic trade-offs associated with the inclusion of nuclear power in the generation expansion strategy.

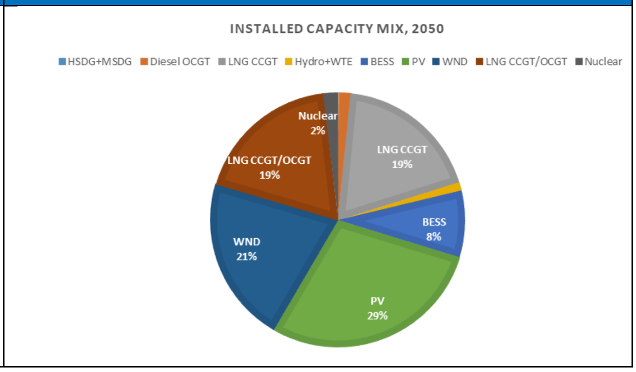
Table 4-19: Totex and RES penetration comparison , Nuclear scenarioTable 4-20: Installed capaci mix 2050, nuclear scenario

		Reference scenario	Nuclear scenario	Variation %
CAPEX 2030-2050	M$	4 846	6 138	27%
OPEX 2030-2050	M$	4 847	4 552	-6%
TOTEX 2030-2050	M$	9 693	10 689	10%
Res Penetration 2050	%	59%	57%	- 2%

Reference Scenario



Nuclear scenario



4.2.7.10 WACC sensitivities

From a valuation perspective, WACC is used to discount future cash flows to their present value.
As previously discussed in the Power generation projects for supply to the National Grid, variations in the Weighted Average Cost of Capital (WACC) can influence the relative competitiveness of energy technologies—particularly between solar photovoltaic (PV) and onshore wind. This is due to the differing capital intensity and cost structures of these technologies.
As shown in the Power generation projects for supply to the National Grid section, changes in WACC do not alter the overall merit order of generation technologies since renewables remain more cost-effective than thermal options, but they can affect the margins between technologies within the renewable

category. Specifically, the gap between the Levelized Cost of Electricity (LCOE) of PV and wind narrows or widens depending on the assumed WACC.

For instance, under a low WACC scenario (5%), the LCOE difference between wind and PV in 2040 is minimal—approximately 0.8 USD/MWh in favor of wind. However, under a high WACC scenario (15%), this difference expands to over 7 USD/MWh, again favoring wind. This shift occurs because:

- Lower WACC benefits technologies with lower capital expenditure (CAPEX), such as PV, by reducing the financial burden of upfront investment.
- Higher WACC, conversely, favors technologies with higher capacity factors and longer asset lifetimes, such as wind, which can better amortize capital costs over time.

Thus, while PV and wind remain broadly competitive under all scenarios, the relative advantage shifts depending on the cost of capital. This dynamic is particularly relevant in investment planning, as it may influence the preferred mix of renewable technologies in the generation portfolio.

It is important to emphasize that the LCOE values presented in the analysis are indicative and highly sensitive to the assumed capacity factor. For variable renewable energy sources (V-RES), the capacity factor is itself influenced by system-level factors such as curtailment, which can vary significantly depending on grid flexibility, storage availability, and demand patterns.

In contrast, thermal technologies—particularly LNG Combined Cycle Gas Turbines (CCGTs), which are the most cost-competitive among fossil-fuel options—are not affected in their relative position by changes in WACC. Even under favorable financial conditions, LNG CCGTs remain more expensive than renewables, and thus do not alter the merit order.

These observations are clearly reflected in the outcomes of the Generation Expansion Plan. Under a 5% WACC scenario, the model selects a higher share of PV capacity. This results in a slightly lower overall renewable penetration by 2050, as PV's lower capacity factor requires more installed capacity to meet the same energy output. Conversely, under a 15% WACC scenario, the model favors onshore wind.

Table 4-21: Totex and RES penetration comparison , WACC sensitivities

		WACC 5%	WACC 10%	WACC 15%
CAPEX 2030-2050	M$	7 873	4 846	3 180
OPEX 2030-2050	M$	7 521	4 847	3 174
TOTEX 2030-2050	M$	15 394	9 693	6 354
Res Penetration 2050	%	58%	59%	61%

Table 4-22: PC and Wind LCOE under different WACC assumptions

LCOE, 2030 $/MWh	WACC 5%	WACC 10%	WACC 15%
PV	32.3	48.0	65.8
Wind On Shore	31.6	44.0	58.1
Delta cost	-0.7	-4	-7.7

LCOE, 2040 $/MWh	WACC 5%	WACC 10%	WACC 15%
PV	30.3	44.9	61.4
Wind On Shore	29.5	40.9	53.8
Delta cost	-0.8	-4	-7.6

LCOE, 2050 $/MWh	WACC 5%	WACC 10%	WACC 15%
PV	24.2	35.4	48.1
Wind On Shore	27.4	37.8	49.5
Delta cost	3.2	2.4	1.4

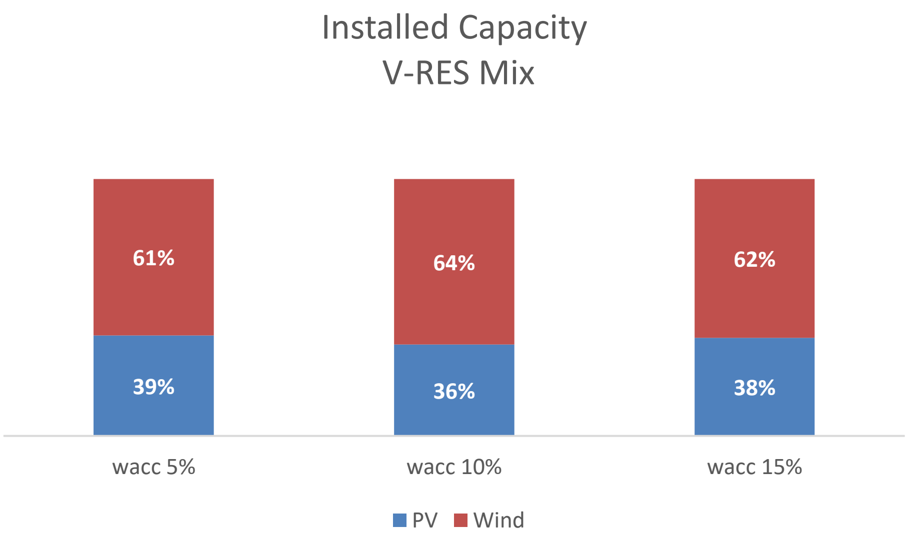


Figure 4-31: V-RES min under different wacc assumptions

4.3 Conclusions and Recommendations

The Generation Expansion Plan (GEP) developed for Somalia offers a strategic, forward-looking roadmap for the development of a reliable, cost-effective, and sustainable power system over the period 2030–2050. Given Somalia's unique position of building its power infrastructure from the ground up, this plan represents a rare opportunity to design a modern, flexible, and low-emission energy system from the outset.

Somalia has significant solar and wind resources, which—if properly explored—can support a high share of renewable energy in the generation mix. The reference scenario projects a renewable penetration of nearly 60% by 2050, including hydro.

Even under conservative assumptions, renewable technologies consistently outperform fossil-based alternatives in terms of cost. Sensitivity analyses confirm that renewables remain the least-cost option even with fuel price or carbon cost fluctuations.

Natural gas, whether imported as LNG or sourced domestically, plays a strategic role in providing dispatchable, lower-emission thermal capacity. In scenarios where domestic gas becomes available, system costs decrease and reliance on regasification infrastructure is avoided.

The interconnection with Ethiopia is critical. Its absence would lead to significantly higher system costs and lower renewable integration. Cross-border trade enhances flexibility, reduces system costs and supports regional energy security.

Battery Energy Storage Systems (BESS) are essential for integrating variable renewables and reducing curtailment. Without storage, system costs increase and renewable penetration drops. Additional flexibility measures—such as demand response and grid-forming inverters—will be needed as RES penetration grows.

Here some recommendations:

1. Accelerate Renewable Energy Deployment: Somalia should prioritize the large-scale deployment of renewable energy technologies—particularly solar PV and wind—which consistently emerge as the most cost-effective and environmentally sustainable options across all scenarios. Develop Flexible and Resilient Infrastructure
2. Invest in Grid Flexibility and Energy Storage: as renewable penetration increases, system flexibility becomes essential. Battery Energy Storage Systems (BESS), demand response, and flexible generation are critical to ensure grid stability and minimize curtailment.
3. Explore Gas Supply Options: Natural gas—whether imported as LNG or sourced domestically—offers a cleaner and more flexible alternative to diesel and coal for dispatchable generation. As a further recommendation, prioritizing floating regasification units (FSRUs) over fixed terminals to reduce stranded asset risk.
4. Prioritize the Ethiopia-Somalia interconnection and explore additional cross-border links to enhance system reliability and economic efficiency.
5. Continuous Monitoring and Plan Updates: Treat the GEP as a living document. Regularly update assumptions and strategies based on evolving demand, technology trends, and geopolitical developments.

4.4 Annex 3.1 – Generation Expansion

Reference scenario

Installed capacity [MW]

Table A3-1: Installed capacity

MW	HSDG	MSDG	Diesel OCGT	LNG OCGT	LNG CCGT	Hydro	WTE	BESS	PV	WND
2030	5	30	0	0	0	4.6	0	5	340	0
2031	18	0	0	100	0	0	0	15	62	70
2032	0	0	0	100	0	0	0	10	77	60
2033	0	0	0	0	0	0	0	20	47	10
2034	0	0	0	100	0	0	0	5	37	20
2035	2	0	0	0	100	150	10	10	37	0
2036	0	10	0	0	300	0	0	15	10	50
2037	-4	20	30	0	300	0	0	5	50	60
2038	-7	-20	0	0	300	0	0	45	0	10
2039	-8	20	90	100	300	0	0	20	30	10
2040	0	0	0	-100	600	0	10	0	10	60
2041	0	20	30	0	0	0	0	20	45	195
2042	0	-10	0	0	0	0	0	40	103	342
2043	-2	0	15	100	300	0	0	5	12	239
2044	0	0	30	0	300	0	0	60	30	469
2045	-4	0	0	0	300	0	0	35	520	430
2046	0	-10	0	0	0	0	0	125	610	695
2047	0	-20	15	0	0	0	0	280	870	330
2048	0	-10	0	0	300	0	0	0	560	310
2049	0	-10	0	0	0	0	0	450	540	128
2050	0	0	0	0	0	0	0	105	370	182

Table A3-2: Installed capacity by Power Plant

Installed capacity MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
PV_Galmudug	10	20	40	50	60	80	90	140	140	140	150	190	190	210	220	220	220	220	220	340	380
PV_Hirshabelle	10	20	30	40	50	50	50	50	50	50	50	50	50	50	50	50	90	300	300	360	470
PV_Jubbaland	100	110	140	160	170	180	180	180	180	180	180	180	180	180	180	250	470	620	980	980	980
PV_Mogadishu	0	10	25	30	35	40	40	40	40	40	40	40	40	40	40	220	350	470	520	670	710
PV_NorthWest	20	40	40	40	40	40	40	40	40	40	40	50	130	130	130	130	260	440	590	670	790
PV_Puntland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	170	170	210	230	280
PV_Southwest	20	22	24	26	28	30	30	30	30	60	60	55	78	70	90	260	280	490	540	560	570
WND_Galmudug	0	10	10	20	20	20	40	40	40	40	60	60	90	120	290	290	430	630	780	860	900
WND_NorthWest	0	40	100	100	110	110	130	170	180	190	220	260	320	320	490	640	690	740	790	840	980
WND_Puntland	0	20	20	20	30	30	40	60	60	60	70	200	460	650	760	980	1020	1150	1260	1310	1390
WNd_Hirshabelle	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	30	90	120	108	160
WND_SouthWest	0	0	0	0	0	0	0	0	0	0	0	25	2	21	40	100	260	200	220	225	240
LNG_CCGT_300Jub	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	600	600	600
LNG_CCGT_300Mog	0	0	0	0	0	0	0	0	0	0	300	300	300	600	900	900	900	900	900	900	900
LNG_CCGT_300NorthW	0	0	0	0	0	300	300	300	600	600	900	900	900	900	900	900	900	900	900	900	900
LNG_CCGT_300Punt	0	0	0	0	0	0	0	300	300	600	600	600	600	600	600	900	900	900	900	900	900
D_OCGT_30Gal	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15
D_OCGT_30Hirsh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15
D_OCGT_30Jub	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15
D_OCGT_30Mog	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30
D_OCGT_30NorthW	0	0	0	0	0	0	0	0	0	30	30	60	60	60	60	60	60	60	60	60	60
D_OCGT_30Punt	0	0	0	0	0	0	0	0	0	30	30	30	30	30	60	60	60	60	60	60	60
D_OCGT_30SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15
LNG_OCGT_100Mog	0	100	100	100	200	200	0	0	0	100	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_100NorthW	0	0	100	100	100	0	0	0	0	0	0	0	0	100	0	0	0	0	0	0	0

Installed capacity MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
LNG_OCGT_100Punt	0	0	0	0	0	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Gal	5	11	11	11	11	11	11	11	4	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Hirsh	0	2	2	2	2	4	4	8	8	6	6	6	6	4	4	0	0	0	0	0	0
D_HSDG_2_Jub	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Mog	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_NorthW	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Punt	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_SouthW	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10Gal	0	20	20	20	20	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0
D_MSDG_10Hirsh	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
D_MSDG_10Mog	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10NorthW	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20Gal	0	0	0	0	0	0	0	0	0	20	20	40	40	40	40	40	40	40	30	20	20
D_MSDG_20Hirsh	0	0	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	0	0	0	0
HFO_MSDG_10SouthW	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0
WTE_Mog	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10
WTE_NorthW	0	0	0	0	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	10
BSS_Gal	0	5	5	15	0	5	10	0	35	10	0	20	40	0	0	0	0	0	0	0	0
BSS_Hir	0	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	250	0
BSS_Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	0	120	0	0	0
BSS_Nor	0	0	0	0	0	0	0	0	0	0	0	0	0	5	60	0	0	155	0	0	0
BSS_Pun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	10
BSS_Sou	5	5	0	0	0	0	0	5	10	10	0	0	0	0	0	0	125	0	0	0	95

Table A3-3: Production GWh

Production GWh	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
HSDG	2505	2004	1514	1003	122	176	141	110	64	0	0	0	0	0	0	0	0	0	0	0	0
MSDG	-	-	-	-	-	-	-	-	-	38	38	46	42	41	32	31	16	4	-	-	-
DieselOCGT	-	-	-	-	-	-	-	13	13	53	53	66	66	72	85	85	85	92	92	92	92
LNGOCGT	-	596	1191	1139	1708	526	-	-	-	175	-	-	-	175	-	-	-	-	-	-	-
LNGCCGT	-	-	-	-	-	738	1677	2304	3234	3879	5064	5949	6230	6888	10243	11532	12578	13373	14655	16813	19985
Hydro	18.4	18.4	18.4	18.4	18.4	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600	600
WTE	0	0	0	0	0	8	8	8	8	8	16	16	16	16	16	16	16	16	16	16	16
PV	596	704	839	922	986	1051	1069	1156	1156	1209	1226	1305	1486	1507	1559	2470	3539	5063	6202	6990	7639
WND	0	264	490	527	603	603	791	1017	1055	1092	1318	2053	3341	4241	6008	7628	9153	10585	11941	12592	13824
Import	0	0	0	911	1549	1752	2500	2910	3319	3729	3800	4293	4787	5280	3600	3133	2667	2200	1734	1267	334
Export	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-980	-1873	-2766	-3659	-4551	-5444	-7230

Table A3-4: Short-Run and Long-Run Marginal Costs [$/MWh]

New capacity M	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
SRMC	166	117	86.4	67.3	35.4	24.8	21.7	20.6	20.5	20.4	19.6	18.1	15.3	14.3	13.8	11.9	10.4	9.0	8.0	7.6	7.2
LRMC	262	189	139	81.1	68.5	88.8	77.6	71.5	45.3	58.0	53.9	34.1	33.7	33.9	32.0	28.4	20.8	18.8	16.2	11.4	10.6

High Demand growth scenario

New capacity M	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
PV_Galmudug	12	24	48	60	72	96	108	168	168	168	180	228	228	252	264	264	264	264	264	408	456
PV_Hirshabelle	12	24	36	48	60	60	60	60	60	60	60	60	60	60	60	60	108	360	360	432	564
PV_Jubbaland	120	132	168	192	204	216	216	216	216	216	216	216	216	216	216	300	564	744	1068	1176	1176
PV_Mogadishu	0	12	30	36	42	48	48	48	48	48	48	48	48	48	48	264	420	564	624	804	852
PV_NorthWest	24	48	48	48	48	48	48	48	48	48	48	60	156	156	156	156	312	528	708	804	948
PV_Puntland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	120	204	204	252	276	336

New capacity M	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
PV_Southwest	24	26.4	28.8	31.2	33.6	36	36	36	36	72	72	66	93.6	84	108	312	336	588	648	672	684
WND_Galmudug	0	12	12	24	24	24	48	48	48	48	72	72	108	144	348	348	516	756	936	1032	1080
WND_NorthWest	0	48	120	120	132	132	156	204	216	228	264	312	384	384	588	768	1176	1176	1176	1176	1176
WND_Puntland	0	24	24	24	36	36	48	72	72	72	84	240	552	780	912	1176	1224	1380	1512	1572	1668
WNd_Hirshabelle	0	0	0	0	0	0	0	0	0	0	0	0	18	18	18	18	30	108	120	129.6	160
WND_SouthWest	0	0	0	0	0	0	0	0	0	0	0	25	2	25.2	40	100	260	200	220	230	240
Nuclear_300Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_120Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_120Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_120NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_120Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_150Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_150Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_150NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_150Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_300Jub	0	0	0	0	0	0	300	300	300	300	300	300	600	600	600	600	600	600	600	600	600
LNG_CCGT_300Mog	0	0	0	0	0	0	0	0	0	0	300	300	300	600	900	900	900	900	900	900	900
LNG_CCGT_300NorthW	0	0	0	0	300	300	300	600	600	600	900	900	900	900	900	900	900	900	900	900	900
LNG_CCGT_300Punt	0	0	0	0	0	0	300	600	600	600	600	900	900	900	900	900	900	900	900	900	900
LNG_CCGT_60Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_60Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_60NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_60Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_OCGT_30Gal	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15
D_OCGT_30Hirsh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15
D_OCGT_30Jub	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15

New capacity M	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
D_OCGT_30Mog	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30
D_OCGT_30NorthW	0	0	0	0	0	0	0	0	0	30	30	60	60	60	60	60	60	60	60	60	60
D_OCGT_30Punt	0	0	0	0	0	0	0	0	0	30	30	30	30	30	60	60	60	60	60	60	60
D_OCGT_30SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15
LFO_OCGT_100Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_100Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_100NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_100Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_100SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_40Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_40Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_40NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_40Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_OCGT_40SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_100Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_100Mog	0	100	100	100	200	200	0	0	0	100	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_100NorthW	0	0	100	100	0	0	0	0	0	0	0	0	0	100	0	0	0	0	0	0	0
LNG_OCGT_100Punt	0	0	0	0	0	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_100SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_40Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_40Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_40NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_40Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_40SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Gal	5	11	11	11	11	11	11	11	4	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Hirsh	0	2	2	2	2	4	4	8	8	6	6	6	6	4	4	0	0	0	0	0	0

New capacity M	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
D_HSDG_2_Jub	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Mog	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_NorthW	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Punt	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_SouthW	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10Gal	0	20	20	20	20	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0
D_MSDG_10Hirsh	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
D_MSDG_10Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10Mog	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10NorthW	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20Gal	0	0	0	0	0	0	0	0	0	20	20	40	40	40	40	40	40	40	30	20	20
D_MSDG_20Hirsh	0	0	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	0	0	0	0
D_MSDG_20Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_10Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_10Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_10NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_10Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_10SouthW	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0
HFO_MSDG_20Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_20Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

New capacity M	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
HFO_MSDG_20NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_20Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_20SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_120Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_120Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_120NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_120Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_120SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_150Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_150Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_150NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_150Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_150SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_300Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_300Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_300NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_300Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_300SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_60Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_60Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_60NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_60Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LFO_CCGT_60SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNO_Galmudug	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WNO_Puntland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Th_EtN	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

New capacity M	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Th_EtS	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WTE_Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WTE_NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Gal	0	5	5	15	0	5	10	0	35	10	0	20	40	0	0	0	0	0	0	0	0
BSS_Hir	0	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	250	0
BSS_Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	0	120	0	0	0
BSS_Nor	0	0	0	0	0	0	0	0	0	0	0	0	0	5	60	0	0	155	0	0	0
BSS_Pun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	10
BSS_Sou	5	5	0	0	0	0	0	5	10	10	0	0	0	0	0	0	125	0	0	0	95

Low Demand growth scenario

MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
PV_Galmudug	8	16	32	40	48	64	72	112	112	112	120	152	152	168	176	176	176	176	176	272	304
PV_Hirshabelle	8	16	24	32	40	40	40	40	40	40	40	40	40	40	40	40	72	240	240	288	376
PV_Jubbaland	80	88	112	128	136	144	144	144	144	144	144	144	144	144	144	200	376	496	712	784	784
PV_Mogadishu	0	8	20	24	28	32	32	32	32	32	32	32	32	32	32	176	280	376	416	536	568
PV_NorthWest	16	32	32	32	32	32	32	32	32	32	32	40	104	104	104	104	208	352	472	536	632
PV_Puntland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	80	136	136	168	184	224
PV_Southwest	16	17.6	19.2	20.8	22.4	24	24	24	24	48	48	44	62.4	56	72	208	224	392	432	448	456
WND_Galmudug	0	8	8	16	16	16	32	32	32	32	48	48	72	96	232	232	344	504	624	688	720
WND_NorthWest	0	32	80	80	88	88	104	136	144	152	176	208	256	256	392	512	784	784	784	784	784
WND_Puntland	0	16	16	16	24	24	32	48	48	48	56	160	368	520	608	784	816	920	1008	1048	1112
WNd_Hirshabelle	0	0	0	0	0	0	0	0	0	0	0	0	9.6	9.6	9.6	9.6	24	57.6	96	69.12	128
WND_SouthWest	0	0	0	0	0	0	0	0	0	0	0	20	1.6	13.44	32	80	208	160	176	184	192

MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
LNG_CCGT_300Jub	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	300	300	300	600	600	600
LNG_CCGT_300Mog	0	0	0	0	0	0	0	0	0	0	0	300	300	600	900	900	900	900	900	900	900
LNG_CCGT_300NorthW	0	0	0	0	0	0	300	300	600	600	900	900	900	900	900	900	900	900	900	900	900
LNG_CCGT_300Punt	0	0	0	0	0	0	0	300	300	600	600	600	600	600	600	600	600	600	600	600	600
D_OCGT_30Gal	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15
D_OCGT_30Hirsh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15
D_OCGT_30Jub	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15	15
D_OCGT_30Mog	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30	30	30
D_OCGT_30NorthW	0	0	0	0	0	0	0	0	0	30	30	60	60	60	60	60	60	60	60	60	60
D_OCGT_30Punt	0	0	0	0	0	0	0	0	0	30	30	30	30	30	60	60	60	60	60	60	60
D_OCGT_30SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15
LNG_OCGT_100Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_100Mog	0	0	100	100	200	200	0	0	0	100	100	0	0	0	0	0	0	0	0	0	0
LNG_OCGT_100NorthW	0	0	0	100	100	100	0	0	0	0	0	0	0	100	0	0	0	0	0	0	0
LNG_OCGT_100Punt	0	0	0	0	0	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Gal	5	11	11	11	11	11	11	11	4	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Hirsh	0	2	2	2	2	4	4	8	8	6	6	6	6	4	4	0	0	0	0	0	0
D_HSDG_2_Jub	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Mog	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_NorthW	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Punt	0	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_SouthW	0	2	2	2	2	2	2	2	2	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10Gal	0	20	20	20	20	20	20	20	20	20	20	20	20	20	0	0	0	0	0	0	0
D_MSDG_10Hirsh	0	0	0	0	0	0	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0
D_MSDG_10Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10Mog	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0

MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
D_MSDG_10NorthW	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_10SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20Gal	0	0	0	0	0	0	0	0	0	20	20	40	40	40	40	40	40	40	30	20	20
D_MSDG_20Hirsh	0	0	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	0	0	0	0
D_MSDG_20Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_10SouthW	10	10	10	10	10	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0
HFO_MSDG_20Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_20Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Gal	0	5	5	15	0	5	10	0	35	10	0	20	40	0	0	0	0	0	0	0	0
BSS_Hir	0	5	5	5	5	5	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	0	250	0
BSS_Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	35	0	120	0	0	0
BSS_Nor	0	0	0	0	0	0	0	0	0	0	0	0	0	5	60	0	0	155	0	0	0
BSS_Pun	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	200	10
BSS_Sou	5	5	0	0	0	0	0	5	10	10	0	0	0	0	0	0	125	0	0	0	95

Revised Demand growth scenario

Installed capacity MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
PV_Galmudug	10	20	40	50	60	80	90	140	140	140	150	190	190	210	220	220	220	220	220	340	380
PV_Hirshabelle	10	14	18	22	26	30	34	38	42	50	50	50	50	50	50	50	90	300	300	360	470
PV_Jubbaland	100	110	140	150	155	160	165	170	175	180	180	180	180	180	180	250	470	620	980	980	980
PV_Mogadishu	0	10	25	30	35	40	40	40	40	40	40	40	40	40	40	220	350	470	520	670	710
PV_NorthWest	20	22	24	26	28	30	32	34	36	38	40	50	130	130	130	130	260	440	590	670	720
PV_Puntland	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	100	170	170	210	230	280
PV_Southwest	20	22	24	26	28	30	30	30	30	60	60	55	78	70	90	260	280	490	540	560	570

Installed capacity MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
WND_Galmudug	0	10	10	20	20	20	40	40	40	40	60	60	90	120	290	290	430	630	780	860	900
WND_NorthWest	0	10	22	30	35	41	86	116	170	195	220	260	320	320	490	640	690	740	790	840	940
WND_Puntland	0	20	22	22	24	26	28	36	51	59	70	200	460	650	760	980	1020	1150	1260	1310	1390
WNd_Hirshabelle	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	30	90	120	108	160
WND_SouthWest	0	0	0	0	0	0	0	0	0	0	0	25	2	21	40	100	260	200	220	225	240
LNG_CCGT_300Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_300Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_300NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG_CCGT_300Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_OCGT_30Gal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_OCGT_30Hirsh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_OCGT_30Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_OCGT_30Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_OCGT_30NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_OCGT_30Punt	0	0	0	0	0	0	300	300	300	300	300	300	300	300	300	600	600	600	600	600	600
D_OCGT_30SouthW	0	0	0	300	300	300	300	300	300	300	300	300	600	900	900	900	900	900	900	900	900
LNG_OCGT_100Mog	0	0	0	0	0	0	300	300	300	300	600	600	600	600	600	600	600	600	600	600	600
LNG_OCGT_100NorthW	0	0	0	0	0	0	0	300	300	600	600	600	600	600	600	600	600	600	600	600	600
LNG_OCGT_100Punt	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Gal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Hirsh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Jub	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_HSDG_2_Mog	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15	15	15	15
D_HSDG_2_NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15
D_HSDG_2_Punt	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	30	30	30	30
D_HSDG_2_SouthW	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	60	60	60	60	60

Installed capacity MW	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
D_MSDG_10Gal	0	0	0	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30
D_MSDG_10Hirsh	0	0	0	0	0	0	0	0	0	30	30	30	30	30	30	30	30	30	30	30	30
D_MSDG_10Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	15	15	15	15	15	15	15	15
D_MSDG_10NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20Gal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
D_MSDG_20Hirsh	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HFO_MSDG_10SouthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WTE_Mog	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WTE_NorthW	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Gal	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Hir	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Jub	0	0	0	0	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Mog	0	100	200	0	0	0	0	0	0	0	0	100	0	0	0	0	0	0	0	0	0
BSS_Nor	0	0	0	0	0	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Pun	0	0	0	0	0	100	100	0	0	0	0	0	0	0	0	0	0	0	0	0	0
BSS_Sou	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

5 TRANSMISSION EXPANSION PLAN AND OPTIMIZATION OF THE FUTURE POWER SYSTEM

5.1 Generalities and scope of work

This section covers Transmission Expansion and Optimization of the future power system (generation and transmission) of the plan.

The section is organized in the following chapters:

- Section 5.2 is devoted to the description and the development of the Transmission Master Plan, illustrating the expected evolution of the transmission grid at the target years objective of the investigations, with reference to the short/mid-term period (2030-2040) and long-term period (2040-2050)
- Section 5.3 include the network analysis of the generation/transmission power system, namely load flow in normal (N) conditions, in case of contingency (N-1) and short circuit analysis
- Section 5.4 includes the quantification of the investment and operational expenditures for the new generation and transmission developments
- Section 5.5 is focused on the cost-benefit analysis of the expected generation and transmission master plans.

In addition, an annex completes the presentation of the results.

5.2 Transmission Expansion Plan

This chapter reports the details of the network analyses performed for the Somali power system.
It is worth to mention that the power system analyses have been performed considering the presence of both interconnections between Ethiopia and Somalia since they are able affect significantly the behaviour of the Somalia network firstly by enabling the possibility to exchange power in both directions, secondly by enhancing system stability and security and lastly increasing the cooperation at a regional level.

5.2.1 General overview

Currently the electricity generation in Somalia is connected to local and isolated off-grids located in the main cities and urban centres, without the presence of a national transmission grid. The objective of this transmission expansion plan study is to develop a high-voltage backbone transiting from the current isolated mini grids to a National Transmission Grid able to allow the development of the generation facilities (conventional and renewables), sustain the economic development of the Country and promote the power exchanges with neighbouring countries through the development of the international interconnections.

The starting point is represented by the transmission expansion plans already studied in the framework of the "*Feasibility Study, Basic Design and Tender documents of the interconnections between Ethiopia and Somalia*" [1] introducing the necessary modifications in terms of system structure, investment priorities, voltage levels, etc. Considering the EAPP Master Plan and guidelines and the National strategies of the Federal Government of Somalia, a roadmap for the development of the transmission grid is based on the following objectives:

- Assure the coordination with the results of the Generation Expansion and the load forecast analysis, allowing the development of the most attractive and economic generation scenarios to meet the load demand forecast,

- Allow the development of the interconnections with the neighbouring countries, particularly with Ethiopia, but also with Djibouti and Kenya, in order to promote the energy trades on a regional level as per the EAPP directives,
- Promote the realization of a National Grid able to connect the existing local off-grids and increasing the electrification rate of the Country.

In order to reach these objectives, the Transmission Expansion Plan is performed:

- For a planning period of 20 years, considering a 5-year step interval (5 target years in total) starting from 2030 up to 2050, and distinguishing the results between the short-medium term (first 10 years) and long-term period,
- Considering different suitable project alternatives and the associated budgetary costs,
- Executing dedicated network analysis (steady-state load flow and short-circuit calculation),
- Calculating all types of fault levels, and their protection system scenarios in terms of maximum fault currents to be interrupted,
- Evaluating the preliminary routing and mapping along each Sub-grid with estimated distances of all backbone transmission lines, middle level transmission lines and sub-transmission line connections,
- Assuring the integration and coordination among Generation expansion and transmission line system expansion,
- Providing a roadmap of the required investments and associated costs.

5.2.2 Adopted approach and assumptions

The elaboration of the Transmission Expansion Plan of Somalia must consider several factors as illustrated hereinafter.

Distribution of cities and towns

Figure 5-1 shows the location of the load centres in Somalia, indicating the centres already equipped with the distribution grid at medium and low voltage levels, and the main cities in the different regions. The development of the internal transmission grid in Southern/Northern Line shall take into account the locations of the main towns and cities inside the Country in order to increase the electrification rate and the access to electricity in all territories. Priority is given for the electrification of the capitals of each region.

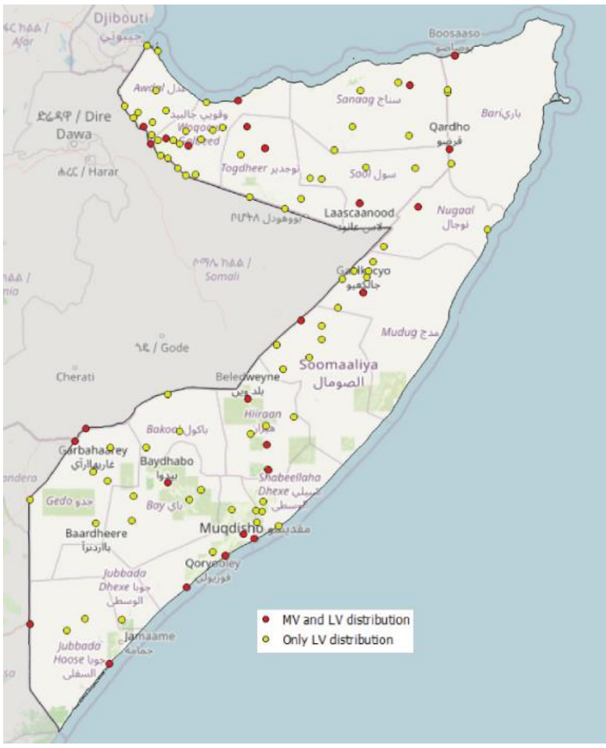


Figure 5-1 – Location of cities and existing areas with distribution grids

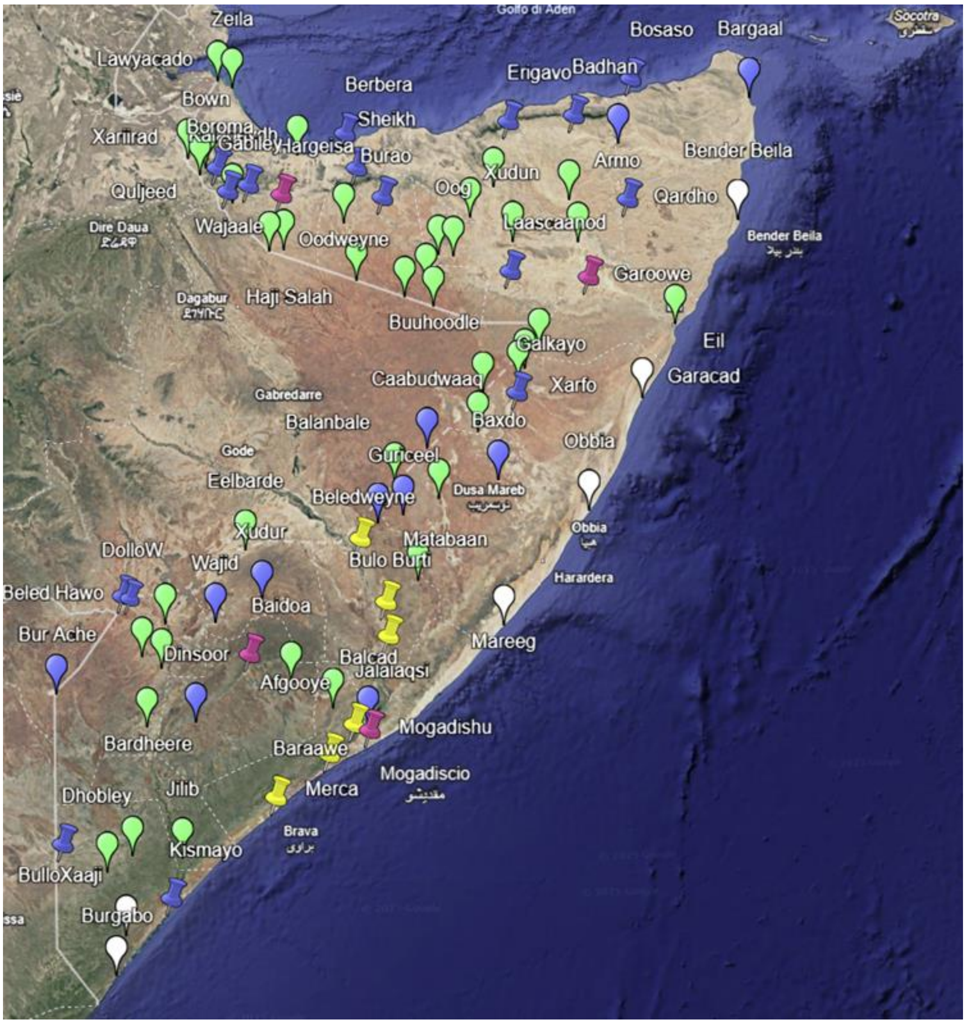


Figure 5-2 – Location of cities and existing areas electrified in the transmission expansion plan

Geographical distances

The geographical distances in Somalia are indicatively reported in Figure 5-3. As it is possible to see, the distances to be considered for the development of the transmission grid are indicatively:

- 700 km from East to West in the northern part of the Country,
- 1000 km from Mogadishu to the north of the Country,
- 500 km from Mogadishu to the south of the Country,

In addition, the distance from main load centres in Somalia with the main generation and load centres in other countries (particularly with Ethiopia and Kenya) are hundreds of kilometres far away between them.

Therefore, the development of the transmission grid shall consider appropriate solutions to deal with such geographical distances that impacts on the static and dynamic stability limits, voltage profiles and reactive power compensation, etc.

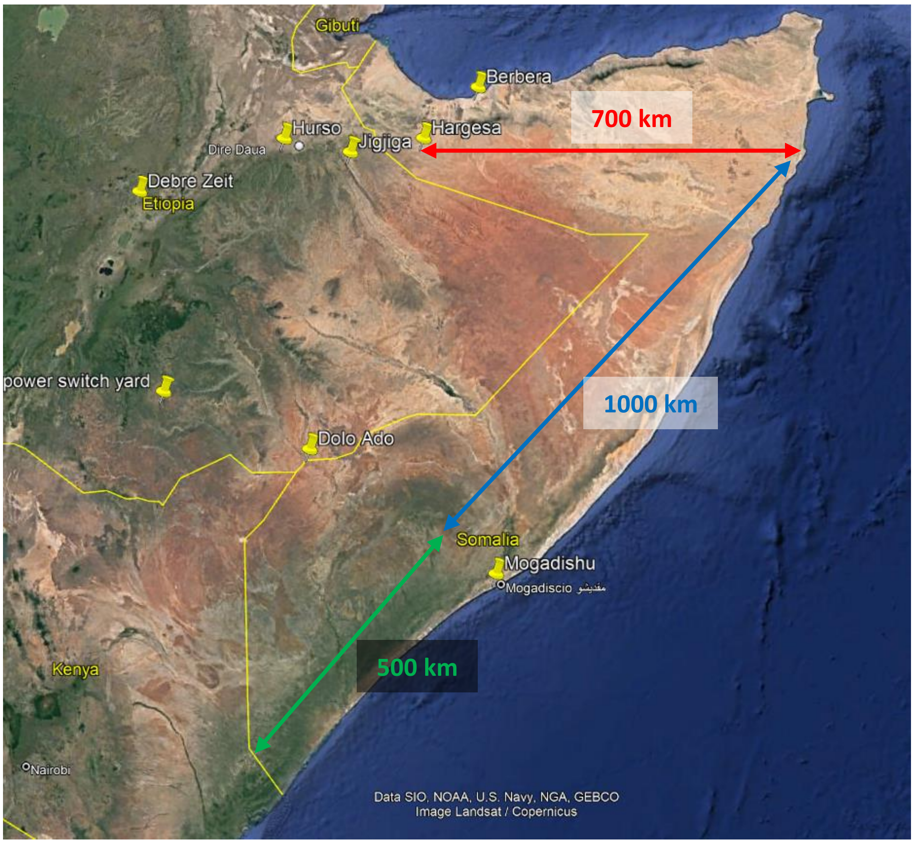


Figure 5-3 – Southern/Northern Line indicative geographical distances

Favourable areas for renewable generation development

Both solar and wind resources have significant potential for electricity generation in the northern and coastal regions of Somalia.

Based on the analyses executed for the identification of the most attractive candidate PV and wind locations reported in Figure 5-4, the transmission shall be developed consequently in order to make feasible the exploitation of this so great potential, especially along the coast of the north-east part of the country, with the possibility to transmit this generation in the other areas of the Country, over long distances.

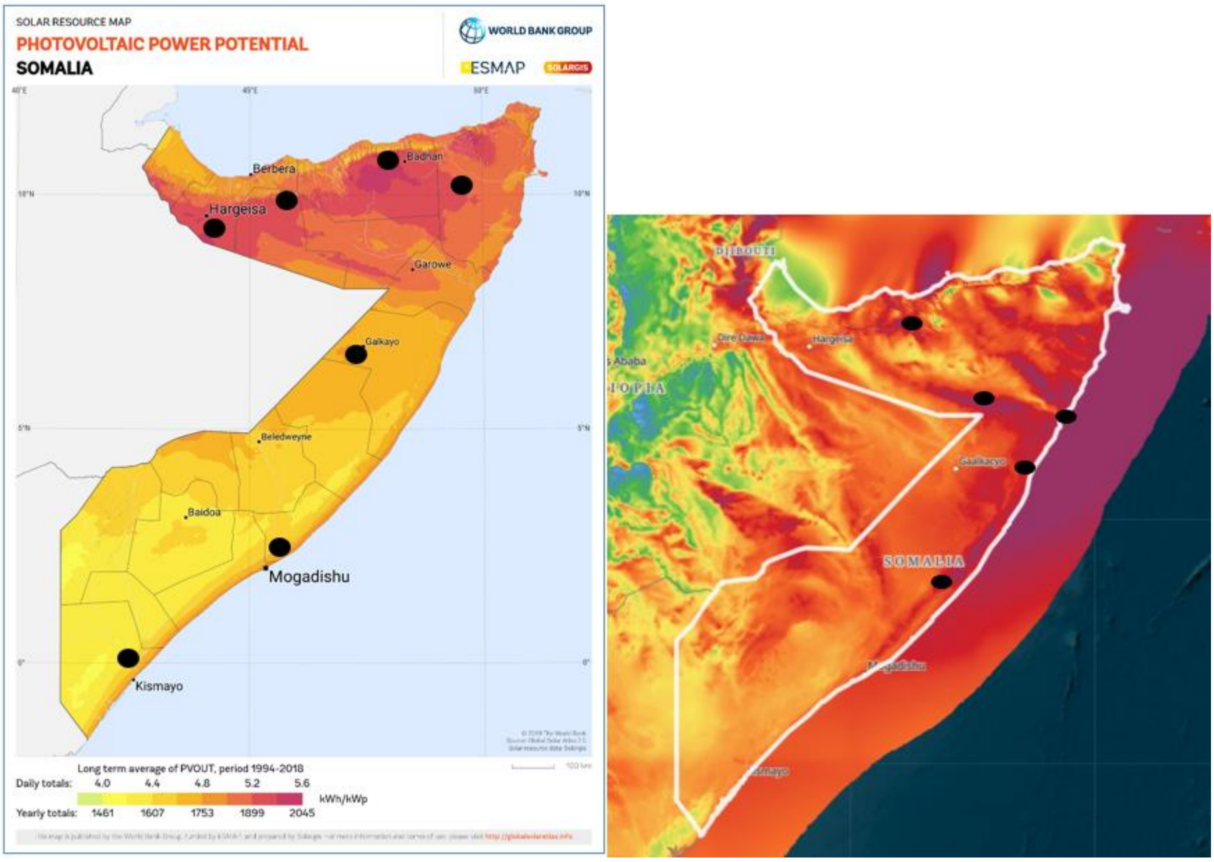


Figure 5-4 –PV potential locations (left) and wind potential locations (right)

5.2.3 Alternatives for the Transmission Expansion Plan

In order to obtain a Least-Cost transmission expansion plan in Somalia, several alternatives are taken into consideration at this stage.

5.2.3.1 Proposed target structure of Somalia Transmission Network

Figure 1-5 shows the indicative structure of the Somalia transmission grid that will be considered in the long-term period (2050).

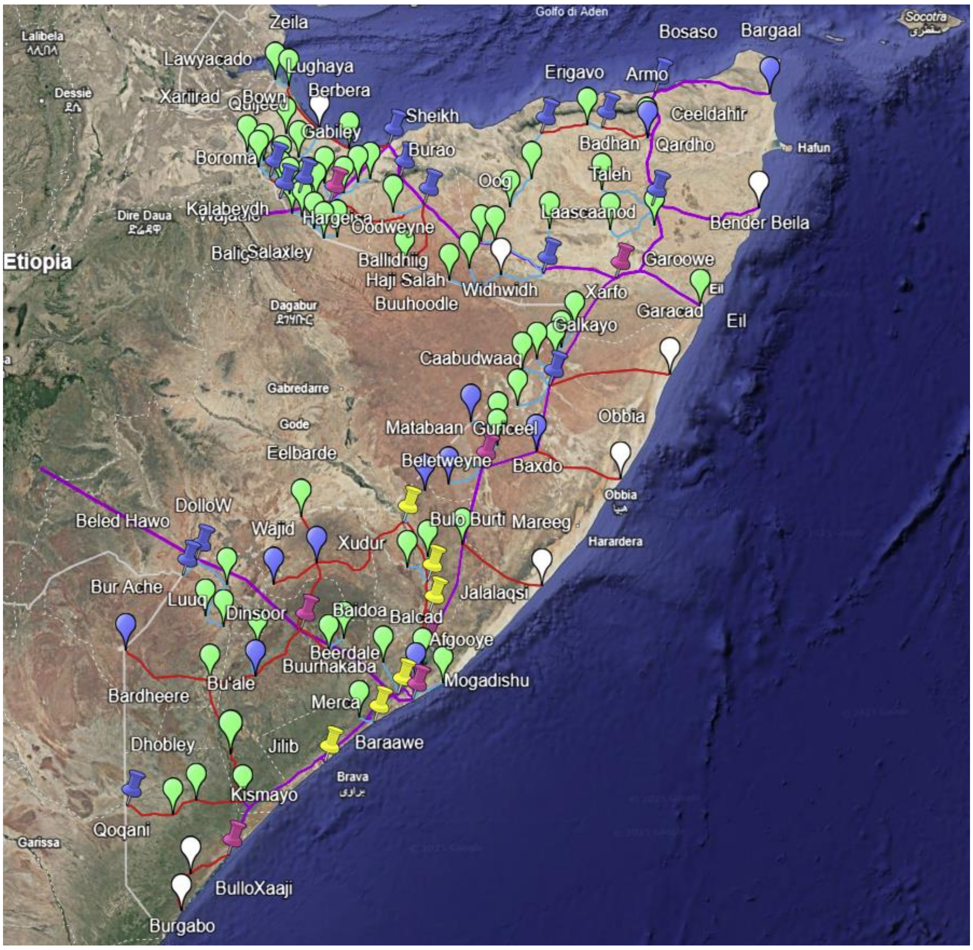


Figure 5-5 – Proposed target structure of Somalia main transmission grid

The purpose of the transmission expansion is to have:

- A backbone at Extra High Voltage (EHV) level from north to south, connected to the interconnections with Ethiopia, able to:
  - transmit power from the generating areas to the load centres,
  - collect and promote the development of the renewable generation (mainly PV and wind onshore and offshore),
  - suitable to develop further interconnections with other countries (Djibouti and Kenya),
- A transmission grid at 230 kV voltage level, connected to the main backbone, with the objective to connect the main cities of the Country,
- A transmission grid at 132 kV voltage level, aimed to supply the load centres that are not the most relevant ones, but that can be towns, villages or load centres in remote areas, where the demand is not expected to be very high.

In general, the city of Mogadishu, which will represent the main load centre in Somalia, will be the point of connection of the EHV backbone and of the southern interconnection with Ethiopia.
Injection points will be generally assured in all S/S in order to supply the local load, with the number of injection points and S/S higher in the areas where the main load centres are located, i.e., close to the main cities.
Regarding the location of the main north-south backbone, Figure 5-6 shows the topographical map of Somalia. Two main alternatives for the development of the north-south EHV corridor are possible:

- Alternative 1 – EHV corridor inside the country, connecting the capital of all states,
- Alternative 2 – EHV corridor mainly developed along the coast, to facilitate the collection of the renewable generation (mainly wind) produced in the north-eastern part of the country.

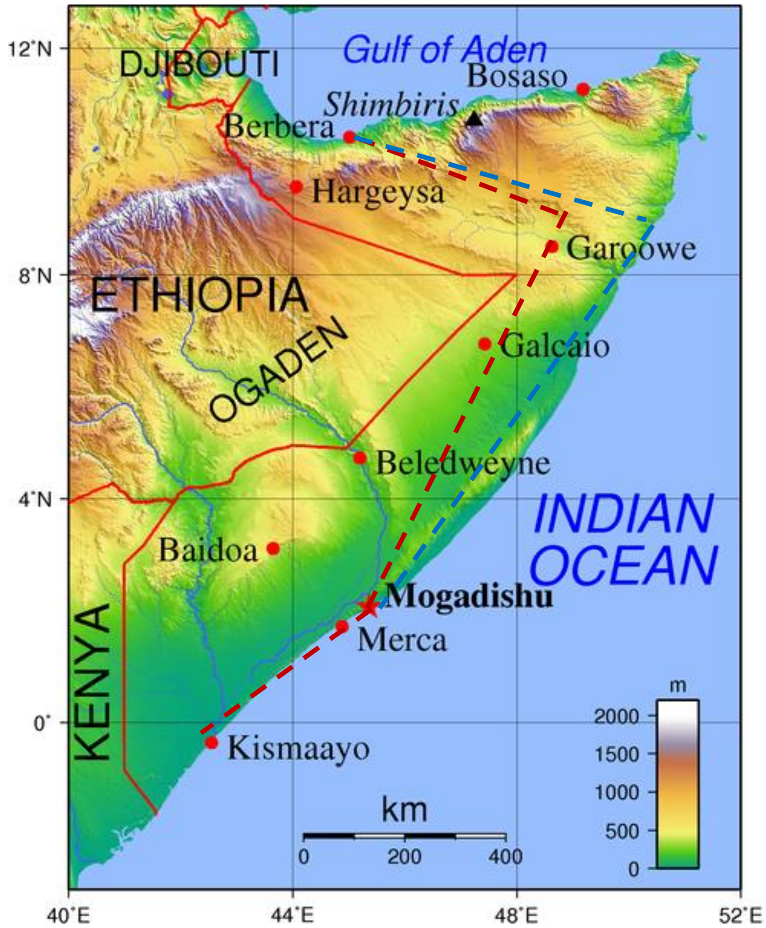


Figure 5-6 – Topographical map of Southern/Northern Line. Alternative 1: red, alternative 2: blue

As it is possible to see from the map:

- Alternative 1 allows to directly reach all capitals of the country with the 500kV voltage level, facilitating the expected development of the electricity consumption in the future,
- Alternative 2 is a little bit longer (so, more expansive) than alternative 1 and need the realization of dedicated 500 kV connection to supply the capitals of the different states.

For these reasons, even though alternative 1 require the realization of dedicated connection to collect the power generated by renewable energy cluster mainly expected along the coast, it is less expensive than the alternative 2.

For the development of the alternative 1, there are not main constraints, such as mountains, for the location of the main EHV backbone.

Regarding the northern part of the country, the EHV backbone tries to avoid the highest mountains moving from East to West. This solution represents the most attractive case for two reasons:

- It represents the easiest solution for the realization of the infrastructure,
- It reduces the total distance (and thus the total costs) of the EHV backbone in comparison with other solutions that can be developed close to the northern coast of Northern Line (in the Bosaso area). Bosaso can be easily electrified with the dedicated line.

Finally, it is worth mentioning that the Transmission Expansion Plan is developed to reach the target to electrify all state capitals within 10 years maximum from the development of the interconnections with Ethiopia, which are expected in operation in 2032.

5.2.3.2 Interconnections with Ethiopia

The interconnections with Ethiopia have been considered exactly equal to the ones studied in the Feasibility study [1] with the only difference that they are expected in operation in 2032 (instead of 2028 as considered in the Ethiopia-Somalia interconnection project).
It is worth mentioning that this difference of the operating year does not impact on the feasibility of the interconnection project, but just represent a shift of the project in comparison with the date originally considered.
Here below, the description of both interconnection between Ethiopia and Somalia is reported.

Northern Interconnection
The structure of the Northern Interconnection between Ethiopia and Somalia is the same as the one studied in the Feasibility study [1] with the same characteristics both in terms of configuration and infrastructure facilities.

More in detail, the characteristics of the Northern Interconnection are the following:

- Components that are part of the projects:
  - Transmission lines for segments Debre Zeit – Hurso, Jigjiga – Hargeisa and Hargeisa – Berbera
  - Substations of Debre Zeit, Hurso, Harar and Jigjiga in Ethiopia, Hargeisa (new S/S) and Berbera (new S/S) in Somalia
- Technology: Alternating Current
- Nominal voltage: 400 kV in Ethiopia, up to the substation of Hargeisa, 500 kV in Somalia for the segment Hargeisa - Berbera
- Configuration: double circuit
- Rated capacity: up to 1000 MW (in both directions) in N and N-1 conditions
- 500/400kV transformation located in Hargeisa S/S

Southern Interconnection
The structure of the Southern Interconnection between Ethiopia and Somalia is derived from the studies performed and certified during the Feasibility study [1] with the same characteristics both in terms of configuration and infrastructure facilities.

More in detail, the characteristics of the Southern Interconnection are the following:

- Components that are part of the projects:
  - Transmission lines for segments Genale Dawa III HPP – Dolo Ado, Dolo Ado – Dollow, Dollow – Baidoa and Baidoa - Mogadishu
  - Substations of Genale Dawa III HPP and Dolo Ado in Ethiopia, Dollow (new S/S), Baidoa (new S/S) and Mogadishu (new S/S) in Somalia
- Technology: Alternating Current
- Nominal voltage: 400 kV in Ethiopia, up to the substation of Dollow, 500 kV in Somalia for the segments Dollow – Baidoa and Baidoa – Mogadishu
- Configuration: double circuit
- Rated capacity: up to 1000 MW (in both directions) in N and N-1 conditions
- 500/400kV transformation located in Dollow S/S
- STATCOM required in the substations of Dolo Ado, Baidoa and Mogadishu

5.2.3.3 Interconnections with other countries

In addition to the interconnections with Ethiopia, the other most attractive interconnections for Somalia will be:

- The interconnection with Djibouti
- The interconnection with Kenya

Interconnection with Djibouti

The interconnection with Djibouti, from Berbera S/S, is indicatively represented in the following figure.

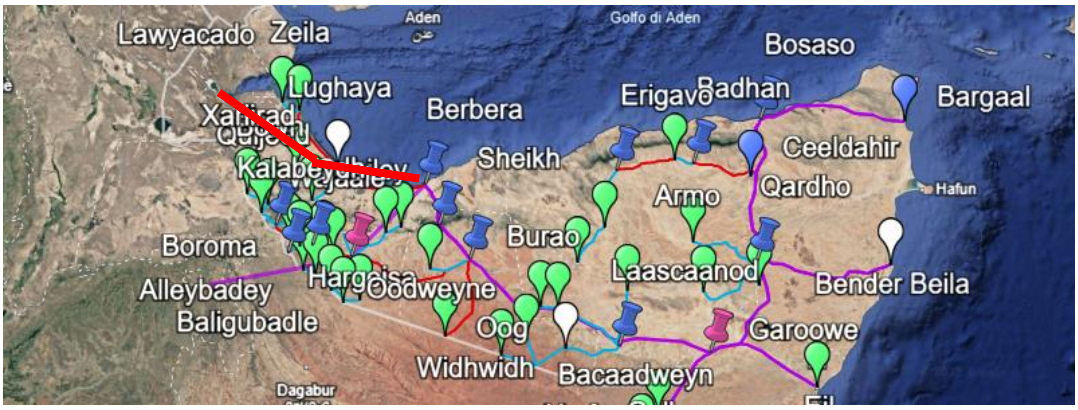


Figure 5-7 – Interconnection Somalia – Djibouti: indicative representation

Considering the limited consumption expected for Djibouti, the future interconnection Somalia – Djibouti can be considered realized, for example, at 230 kV level.

Nevertheless, the realization of the interconnection between Somalia and Djibouti shall be coordinated at regional level, since it cannot forget the expected realization of the interconnection Ethiopia – Djibouti.

In fact, the realization of both interconnections:

- Ethiopia – Somalia
- Ethiopia – Djibouti – Somalia

will create a ring that will most probably create a power loop between the three countries, with the risk that Djibouti will be impacted by a significant power flow in transit from Ethiopia to Somalia and/or vice-versa, in function of the development of generation and electricity demand in the area.

Therefore, this electrical ring between Ethiopia – Djibouti – Somalia – Ethiopia will probably require the installation of some devices able to control the power flows in order to avoid both technical and economic impact caused by unwanted power flows on the transmission grid of a third Country.

One solution to control the power flows on the AC grid is the installation of a Phase Shifting Transformer (PST). A PST is a specialized type of transformer designed to regulate the voltage phase angle difference between two nodes in the power system. It achieves this by injecting a phase-shifted voltage source into the transmission line using a series-connected transformer, which is fed by a shunt transformer.

The configuration of the shunt and series transformer induces the desired phase shift, as schematically illustrated in the following figure.

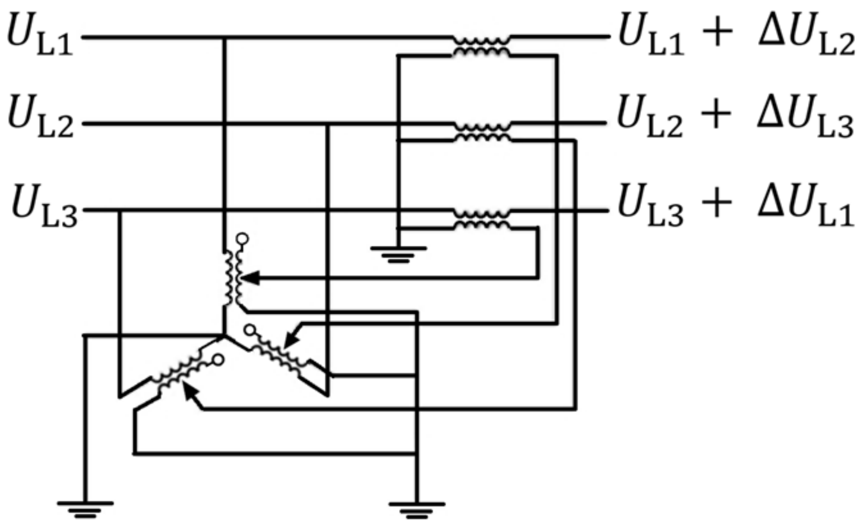


Figure 5-8 – conceptual scheme of a PST

Two control strategies are possible for a PST:

- Preventive Mode: in this mode, the PST maintains a permanent phase shift, allowing for power flow redistribution during line outages. It helps relieve network stresses by redirecting power flows,
- Curative Mode: during normal operation, the phase shift is small (sometimes even zero). However, it is automatically controlled to reduce power flow on overloaded lines, preventing tripping out or to respect the commercial power flow in a certain section of the transmission grid.

The realization of the transmission ring Ethiopia – Djibouti – Somalia – Ethiopia could cause the so-called phenomenon of "power loop" between the three countries, with a high probability to have to install a PST device. This situation can happen frequently when more countries are interconnected between them or when there are many interconnections between two countries: this phenomenon shall be studied with dedicated analyses, but the adoption of a PST device can represent a valid solution to mitigate this effect.

Interconnection with Kenya

The interconnection with Keny S/S, is indicatively represented in the following figure.

The candidate S/S in Somalia for the development of the interconnection with Kenya can be represented by the S/S of Kismayo, where the 500kV voltage level is expected to be developed.

Figure 5-9 – Interconnection Somalia – Kenya: indicative representation

Nevertheless, the realization of the interconnection between Somalia and Kenya shall be once again coordinated at regional level, since it cannot forget the already existing interconnection between Ethiopia and Kenya in HVDC technology.

The Ethiopia – Kenya interconnection is a 2,000 MW HVDC power transmission link between the national electricity systems of Ethiopia and Kenya, through a 1,000 km of high voltage direct current (HVDC) overhead line. The HVDC operates as a bipolar configuration (± 500 kV), although a monopolar operation is allowed. The selection of the HVDC technology was made to create an electrical separation between the two power systems allowing the transmission of significant power without creating dynamic problems.
Therefore, the realization of any interconnection between Somalia and Kenya should be realized in HVDC configuration or in AC technology, but with a Back-to-Back (BtB) converter station in order not to synchronize the power system of Ethiopia and Kenya through Somalia, which could create regional oscillations and instability phenomena.
For the interconnection Somalia – Kenya the VSC technology (for the HVDC or the BtB configuration) is recommended in order to have more flexibility in terms of:

- Power flow control
- Reactive power management and voltage control
- Black-start capacity and restoration procedures
- Network robustness for the operation of the interconnection
- Frequency regulation, reserve and synthetic inertia

Of course, dedicated analyses for this interconnection shall be performed in order to identify the best configurations, rate, connecting S/S, etc., but basically this interconnection can represent an additional opportunity, for Somalia, to export the renewable energy to other countries in the long-term period.

5.2.3.4 Candidate voltage levels

Concerning the EHV level to be considered for the main north-south backbone of the country, the voltage levels 400 kV and 500 kV are considered, since these are the voltage levels for the development of the EHV transmission grid in many countries in the world. Since the transmission grid in Somalia does not exist today, the selection of the highest voltage level shall be evaluated and carefully selected since it will have a strong impact on all developments in the next future. In addition, the selection of the voltage level in Somalia can also have an impact on the interconnections with Ethiopia, Djibouti and Kenya, both in terms of technologies to be adopted for such interconnections and the expected Net Transfer Capacity (NTC).
Higher voltage levels than 500 kV, e.g., 750 kV or even higher, are not taken into consideration because will make more complex the construction and the operation of the transmission grid, since a very high transmission capacity is not needed due to the amount of electricity demand expected in Somalia; furthermore, the investment costs would increase in a significant way. Furthermore, transmission lines and power transformers having a voltage higher than 500 kV would need an adequate network strength to be energized (high short circuit power), which could be difficult for the Somali power system considering the absence of relevant generation facilities and the expected development of renewables (that do not provide a significant contribution to the system strength).
Voltage level lower than 400 kV are considered as intermediate levels, such as the 230 kV for connecting cities between them and 132 kV for supplying the main load centres around cities and for connecting not big towns and other load centres, but there will not be considered for the realization of the main transmission grid since the distances to be covered in Somalia are relevant, and thus the 400 kV and 500 kV remain the most favourable candidates at this purpose.
Other voltage levels candidate for the development of transmission grid directly connected to the load centres, such as 150 kV and 161 kV adopted in some countries in the world are not considered in this transmission expansion plan because they are closer to the 230 kV voltage level respect to the 132 kV level: the introduction of different voltage levels make sense if there is a significant difference between them, since two voltage levels closed each other are not justified and does not cause relevant benefits.

For the same reason, the 330 kV voltage level adopted in some countries in the world is not considered, because it is not justified to develop the 500 kV or 400 kV together with the 330 kV (they are too close each other); the same is valid for the 330 kV together with the 230 kV (they are too close each other); in addition, the 330 kV voltage level is not adopted by other countries in the region.
Regarding the lower voltage levels below 132 kV that will be considered for the sub-transmission grid, these are not the objective for the development of a Transmission Expansion Plan, but in general it is possible to say that the 33kV, for example, will be considered in all proposed S/S in order to supply the local demand in the area (city, town, villages, industrial loads, etc.). In addition, also the 66kV voltage level can be adopted where the distances to the main HV S/S is quite relevant.
Having the need to develop the transmission grid from scratch, also according to the criterion of "proximity" between the different voltage levels, the recommendation is to select voltage level as more distant as possible between them, in order to have a real advantage coming from the development of different levels on the territory. At this regard, it is possible to say as follow:

- 400 kV or 500 kV (one of the two, not both of them) can be developed together with the 230 kV (330 kV to be excluded),
- 230 kV can be developed together with the 132 kV (150 kV and 161 kV to be excluded).

5.2.3.5 Development of the EHV grid for Mogadishu

Mogadishu represents the most important load centre in Somalia, with an expected significant development of electricity consumption, including both residential and industrial consumptions. Considering the current population of about 3 million and the significant increase expected in the future, Mogadishu is expected to remain the most important load center for Somalia also in the next decades.
For these reasons, the development of the transmission grid around Mogadishu shall be carefully evaluated and studied based on the effective load forecast foreseen for that area.
Furthermore, also the area covered by the city is quite relevant, estimated in more than 100 square kilometres, as indicated in the following figures.

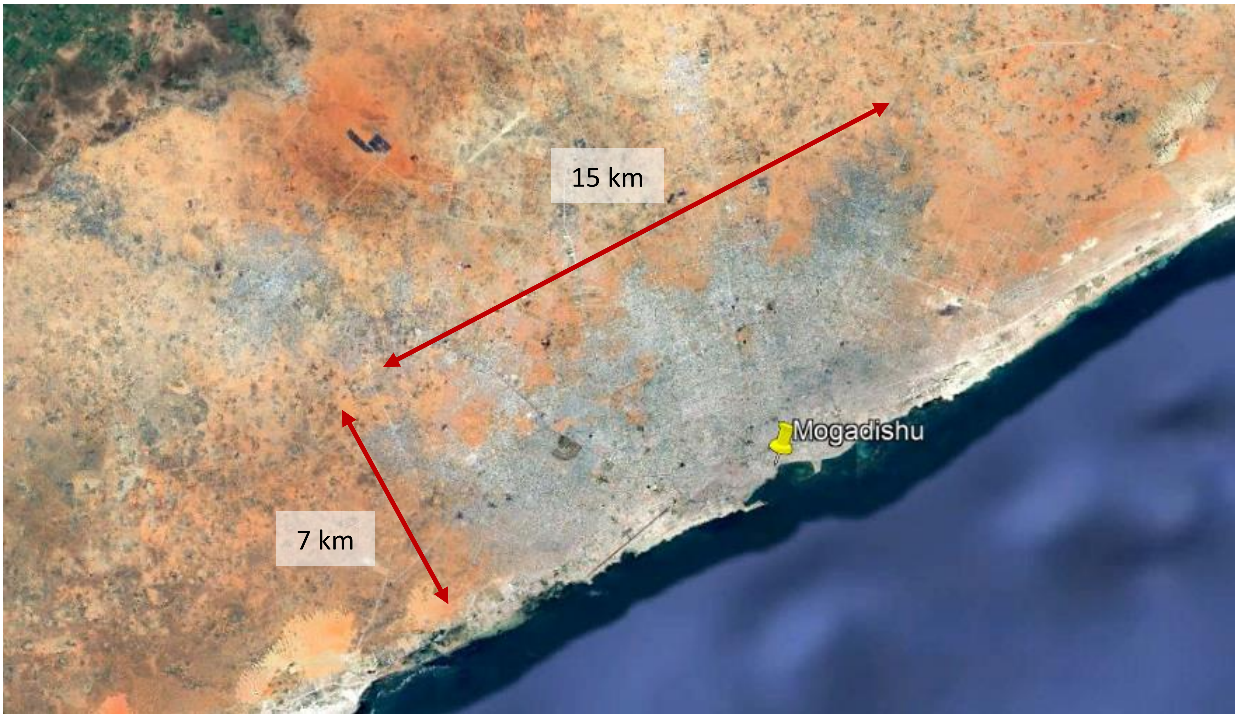


Figure 5-10 – Mogadishu area

For these reasons, the city of Mogadishu requires more injection points at the EHV level to supply the expected load evolution for the future.
In addition to the first S/S making part of the Ethiopia-Somalia interconnection project, two other 500/230kV injection points have been identified in the framework of this Transmission Plan:

- Mogadishu West 500/230/132 kV, since 2035
- Mogadishu North 500/230/132 kV, since 2045

The idea is to create a sort of EHV Transmission Ring around Mogadishu to have enough transmission capacity to:

- Supply the electricity consumption,
- Connect the expected future generation, particularly conventional generation, which is expected to be relevant in the long-term period thanks to the presence of the most important port of the country.

As a result, the following figure reports the indicative scheme of the future Mogadishu Ring that is expected to be developed in the long-term period.

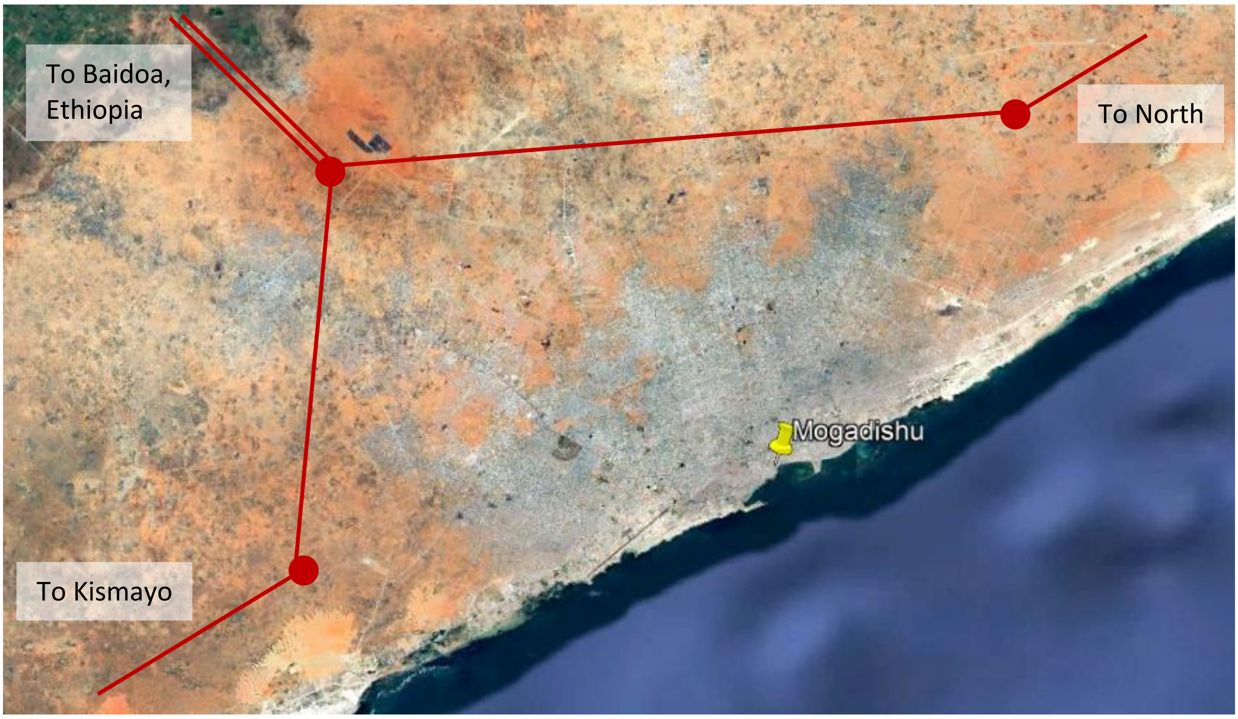


Figure 5-11 – Future 500kV Mogadishu Ring – indicative scheme

Furthermore:

- 230 kV and 132 kV S/S and lines are expected to be developed in the area of Mogadishu to supply the local demand. In the urban area, the 230 kV and 132 kV lines can be also partially developed with underground cables due to problems of space availability
- Dedicated connections for the development of the local generation can be realized and connected to the indicated S/S in the area.

Coal and Nuclear power development

In accordance with the generation expansion plan, Mogadishu is the most favourable location for the development, in the long-term period, for new coal and nuclear power plants.
The structure of the transmission grid here suggested, i.e., the realization of a ring around the city, represents one of the strongest configuration that a transmission grid can have, since a ring structure allows several ways to evacuate significant amount of generation.

With particular reference to the nuclear power plant, its development is possible only if the transmission grid is strong since there are many security protocols and standards to be respected, and the grid must be strong enough to always ensure:

- A stable and reliable connection of the power plant. Periodical disconnections are not allowed,
- Enough transmission capacity to evacuate the whole capacity of the power plant, since its production cannot be changed in real time as for the other type of power plants (like GT, CCGT, etc.),
- A significant amount of load in the area makes more reliable the realization of a nuclear power plant that is expected to produce a significant amount of generation.

The exact location of the Nuclear power plant will be objective of dedicated and careful evaluations, but indicatively the areas close to Mogadishu can represent suitable locations for its development in the future.

5.2.3.6 Project alternatives

As already anticipate, the Transmission Development Plan of Somali is performed considering several alternatives involving both transmission facilities and generating units. The alternatives considered in the power system analyses are described here below.
It is worth mentioning that all these alternatives are related to the target year 2050, for the intermediate years the development of the transmission grid will not be enough to assure the feasibility of all these alternatives.

Voltage levels
The identification of the most appropriate voltage level for the EHV backbone has been already performed in the framework of the Ethiopia-Somalia interconnection project.
Therefore, in this Transmission Expansion Plan, the 500kV is considered.
The other voltage levels considered for the development of the transmission grid aimed to connect cities and allow the electrifications of villages and towns are 230 kV and 132 kV.

Configuration of the EHV north-south backbone
The topology of the EHV north-south backbone can be:

- Single circuit configuration
- Double circuit configuration

Nevertheless, considering the following aspects:

- the internal backbone is not very critical, since there are also other transmission facilities that connect the load centres to the transmission grid,
- the expected electricity consumptions in Somalia are not so high to justify two circuits between north and south,
- the objective is to perform a least-cost expansion plan,

the EHV backbone inside Somalia will be considered in single circuit configuration. The management of the N-1 security criterion will be assured by the connection in both directions of the Somali grid in the long-term period.
On the contrary, the interconnections with Ethiopia are kept in double-circuit configuration for reliability reasons: for these interconnections, the double-circuit configuration is justified by the fact that, during the scenarios of high-power import or high-power export, the trip of one circuit (N-1) could cause the back-out of the whole Somali power system.

Location of the main EHV backbone
As already mentioned, for the northern part of Somalia the two alternatives illustrated in the Figure 5-12 have been evaluated. Nevertheless, with the objective to create a complete north-south backbone

minimize the costs, the alternative towards Garoowe is much more convenient in comparison with the alternative towards Bosaso because the first one reduces in a significant way the total length of the infrastructure, with a significant cost reduction (least-cost solution).

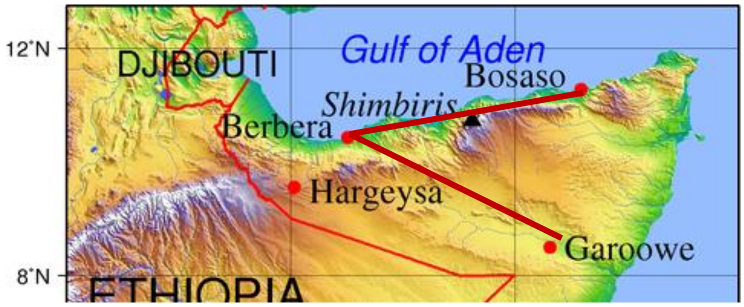


Figure 5-12 – Alternatives of the EHV backbone in Northern Line

Technology

The EHV backbone internal to Somalia is considered in AC technology.
The DC technology is not considered for the following reasons:

- it will make more complex the construction and the operation of the transmission grid, with the need to carefully control the power flow on the DC link to make balance the systems
- to be economically justified, an infrastructure in DC current shall be quite long but, in this case, the HVDC would not allow the widespread electrification of the territory, which in any case represents the main purpose of the Transmission Expansion Plan
- in order to allow the widespread electrification of the territory, the HVDC shall be quite short, but this solution does not find an economic justification. The realization of intermediate converter station and thus the realization of a multi-terminal HVDC is not considered because too complicated, too much costly and not practically to supply load centres with a limited amount of electricity demand

The HVDC solution or, as alternative, the adoption of a Back-to-Back configuration, as already described in the paragraph 5.2.3.3, will be adopted for the development of the interconnection with Kenya, due to the need to avoid the synchronization of Kenya and Ethiopia power system through Somalia.

5.2.4 Transmission Expansion Plan for Somalia

This sub-section reports the proposal of the transmission expansion plan for Somalia, including the development of interconnections with other countries.
The purposes of the transmission expansion plan are:

- Allow the electrification of Somalia and increase the access to electricity,
- Allow the development of new load centers and new types of loads, such as the industrial loads,
- Allow the development of the new generation facilities, both conventional and renewables.

The criteria adopted for the Somalia Transmission Expansion Plan are the following:

- The internal network development starts from the main cities of the country, i.e., Mogadishu and Hargeisa. These two cities are also the locations where the interconnections with Ethiopia are expected to be developed: considering that the appropriate operation of the interconnections with Ethiopia must be coordinated with the development of the internal grid in Somalia, it is of outmost importance to begin the development of the internal transmission grid in Somalia in these areas, to be coordinated with the Ethiopia-Somalia interconnection projects.
- In about 15 years, the objective is to develop an internal network able to substantially reach the majority of load centers in Somalia.

- The capitals of all regions in Somalia will be reached with the 500kV voltage level.
- The internal transmission grid foresees the development of a backbone at 500 kV, then other transmission lines are derived at lower voltage levels, such as:
  - 230 kV level for the connections between cities,
  - 132 kV level for developing the sub-transmission grid close to cities and for connecting minor load centers for short distances.

5.2.4.1 2030 transmission network expansion (short-term period)

2030 represents the first target year of development of the Somalia transmission grid.
At this stage, it is reasonable to consider the transmission grid internal to Somalia not yet developed, with the only infrastructures realized to make possible the electrification of the areas close to the main cities of the country, namely Mogadishu and Hargeisa. Furthermore, the development of the transmission grid in these areas is required to make possible the operation of the future interconnections with Ethiopia, since the development of the interconnections with Ethiopia and the development of the internal grid in Somalia must be coordinated between them.
At the target year 2030, the interconnections with Ethiopia are not yet considered in operation, due to a delay in comparison with the time schedule considered in the Ethiopia – Somalia interconnection project [1].

Transmission lines:

- 1475 km of 500kV transmission lines
- 175 km of 230 kV transmission lines

Table 5-1 – transmission lines expected in 2030

Operating year	*Vnom [kV]*	*Name*	*Length [km]*	*Type*
2030	500	Berbera-Burao	125	Single circuit
2030	500	Burao-Laascaanod	250	Single circuit
2030	500	Laascaanod-Garoowe	130	Single circuit
2030	500	Garoowe-Qardho	185	Single circuit
2030	500	Qardho-Bosaso	220	Single circuit
2030	500	Mogadishu-Afgooye	40	Single circuit
2030	500	Afgooye-Baraawe	180	Single circuit
2030	500	Baraawe-Kismayo	250	Single circuit
2030	500	Mogadishu-Jowhar	95	Single circuit
2030	230	Hargeisa-Burao	175	Single circuit

Substations (9 S/S):

- Afgooye 500/230/132 kV
- Baraawe 500/230 kV
- Kismayo 500/230 kV
- Burao 500/230/132 kV
- Laascaanod 500/230/132 kV
- Garoowe 500/230 kV
- Qardho 500/230/132 kV
- Bosaso 500/230 kV
- Jowhar 500/230/132 kV

All S/S, also where not explicitly mentioned, are equipped with transformers to MV level to feed the local loads in the city/town where they are located and in the suburbs.

Figure 5-13 shows the transmission grid in Somalia at the target year 2030.

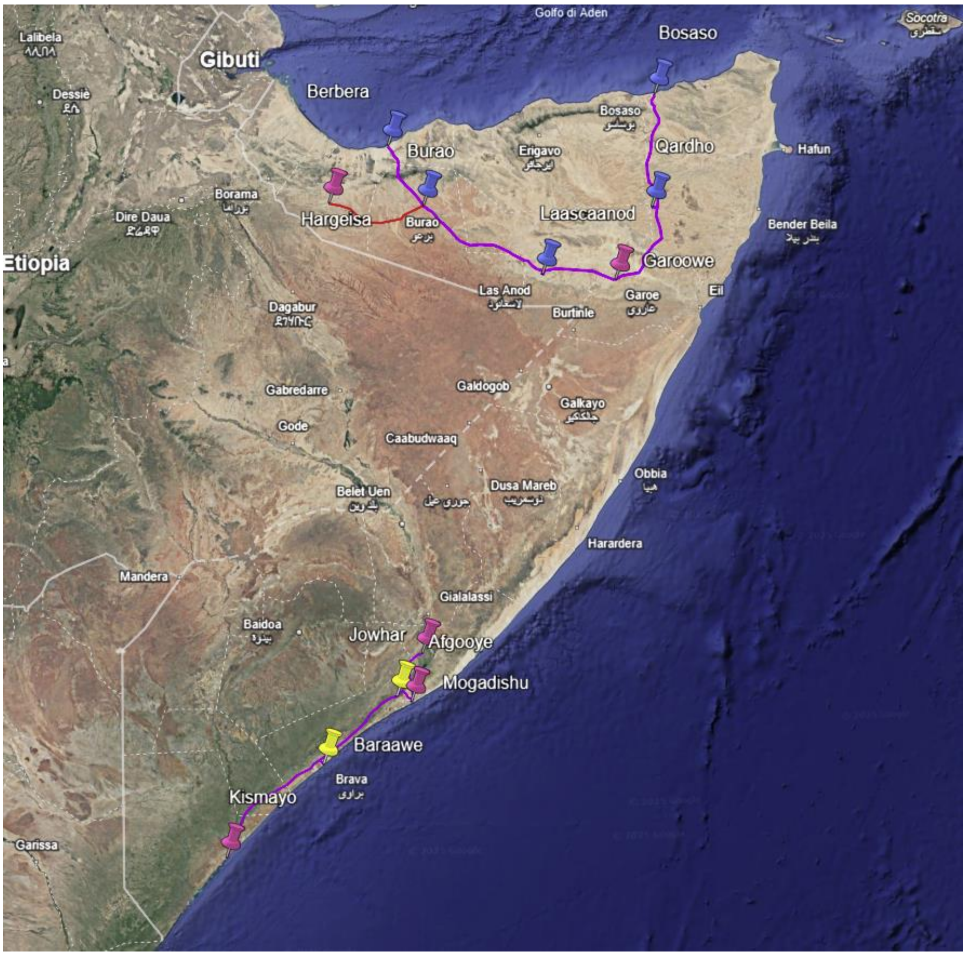


Figure 5-13 – Somalia-2030 transmission grid

5.2.4.2 2035 transmission network expansion (mid-term period)

2035 represents the second target year of development of the Somalia transmission grid.
At this stage, the interconnections with Ethiopia are considered in operation (both the northern interconnection and the southern interconnection). The hypothesis is that the interconnections with Ethiopia will be in operation in 2032.
Interconnections with other countries are not considered at this stage.
At this target year the national grid is continuously expanding through the connection of other main cities and the evolution of local grids in the central area of the country.
In 2035 the transmission grid in Somalia is still separated in two main parts, with a central isolated grid, not yet connected between them.
Concerning Mogadishu, due to the increase in the load, a new injection point represented by the new 500/230/132 kV S/S developed since 2030.

Note: the interconnections with Ethiopia and the associated S/S are included in the transmission expansion plan of Somalia, but they are not included in the costs associated to the transmission expansion since they are part of another project.

Transmission lines:

- 830 km of 230 kV transmission lines

- 270 km of 132 kV transmission lines

Table 5-2 – additional transmission lines expected in 2035

Operating year	Vnom [kV]	Name	Length [km]	Type
2035	230	Hargeisa-Gabiley	55	Single circuit
2035	230	Gabiley-Boroma	60	Single circuit
2035	230	Gabiley-Wajaale	35	Single circuit
2035	230	Ceeldahir-Badhan	85	Single circuit
2035	230	Badhan-Erigavo	110	Single circuit
2035	230	Jowhar-Jalalaqsi	75	Single circuit
2035	230	Jalalaqsi-BuloBurti	60	Single circuit
2035	230	BuloBurti-Beletweyne	110	Single circuit
2035	230	Baidoa-Xudur	125	Single circuit
2035	230	Baidoa-Dinsoor	115	Single circuit
2035	132	Galkayo-Abaarey	35	Single circuit
2035	132	Galkayo-Bandiiradley	65	Single circuit
2035	132	Duusamareeb-Godinlabe	45	Single circuit
2035	132	Duusamareeb-Guriceel	65	Single circuit

Interconnections with Ethiopia (in operation since 2032):

Table 5-3 – Northern interconnection with Ethiopia

Operating year	Vnom [kV]	Name	Length [km]	Type
2035	400	Ethiopia border - Hargeisa	105	Double circuit
2035	500	Hargeisa - Berbera	175	Double circuit

Table 5-4 – Southern interconnection with Ethiopia

Operating year	Vnom [kV]	Name	Length [km]	Type
2035	400	Ethiopia border - Dollow	5	Double circuit
2035	500	Dollow – Baidoa	220	Double circuit
2035	500	Baidoa - Mogadishu	210	Double circuit

Substations (22 S/S):

- Mogadishu West 500/230/132 kV
- Jilib 500/230 kV
- Merca 500/230/132 kV
- Ceeldahir 500/230/132 kV
- Sheikn 500/230 kV
- Jalalaqsi 230/33 kV
- BuloBurti 230/132 kV
- Beletweyne 230/132 kV
- Badhan 230/132 kV
- Erigavo 230/132 kV
- Gabiley 230/132 kV
- Boroma 230/132 kV
- Wajaale 230/132 kV

- Xudur 230/33 kV
- Dinsoor 230/33 kV
- BeledHawo 132/33 kV
- Duusamareeb 132/33 kV
- Godinlabe 132/33 kV
- Guriceel 132/33 kV
- Galkayo 132/33 kV
- Abaarey 132/33 kV
- Bandiiradley 132/33 kV

Substations associated to the Ethiopia interconnection project (in operation since 2032):

- Hargeisa 500/400/230/132 kV
- Berbera 500/230/132 kV
- Dollow 500/400/132 kV
- Baidoa 500/230 kV
- Mogadishu 500/230/132 kV

All S/S, also where not explicitly mentioned, are equipped with transformers to MV level to feed the local loads in the city/town where they are located and in the suburbs.
Figure 5-14 shows the transmission grid in Somalia at the target year 2035.

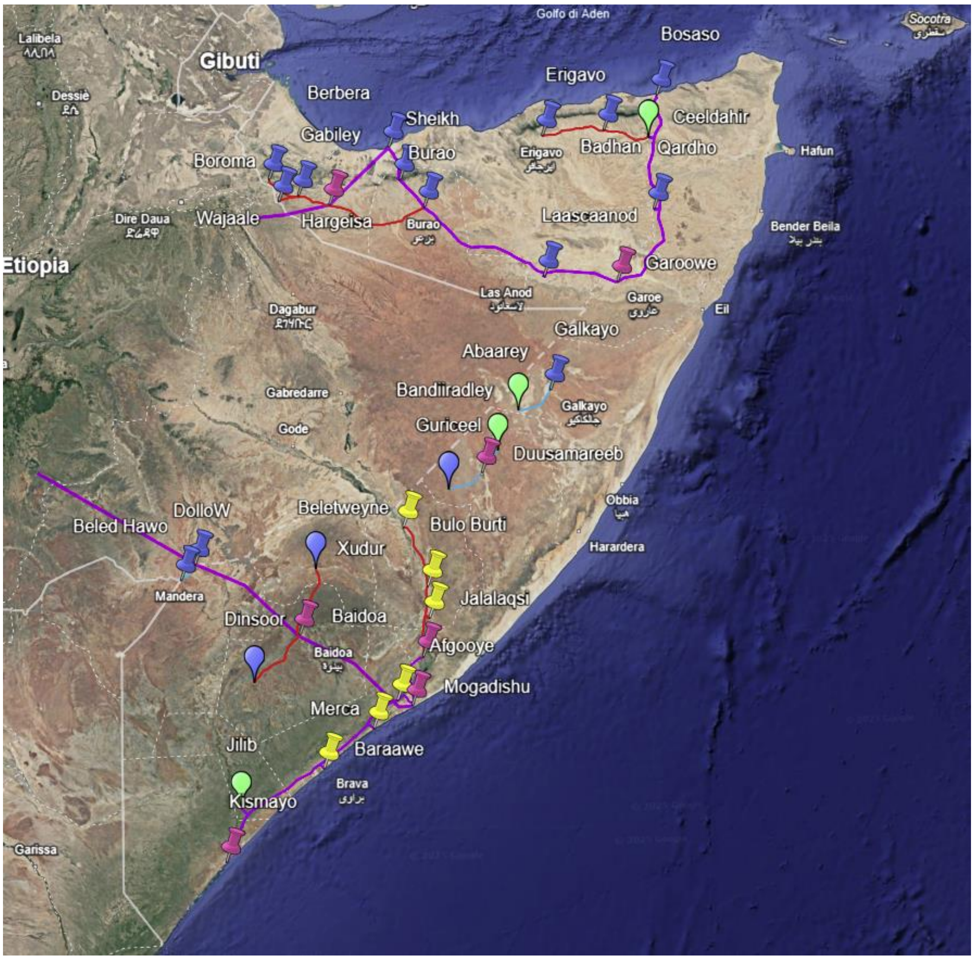


Figure 5-14 – Somalia-2035 transmission grid

5.2.4.3 2040 transmission network expansion (mid-term period)

2040 represents the third target year of development of the Somalia transmission grid and represents the end of the mid-term period considered for the development of the transmission expansion plan.
At this stage, all 7 region capitals and main cities are connected to the National Grid that, up to now, is still divided in two parts.
Main drivers for the development of the transmission grid are the electrification of rural areas and the creation of a backbone for the significant development of the RES potential (both solar PV and wind), for which dedicated connection aimed to collect especially offshore wind generation are foreseen.

Transmission lines:

- 165 km of 500 kV transmission lines
- 530 km of 230 kV transmission lines
- 1185 km of 132 kV transmission lines

Table 5-5 – additional transmission lines expected in 2040

Operating year	*Vnom [kV]*	*Name*	*Length [km]*	*Type*
2040	500	Garoowe-Eil	165	Single circuit
2040	230	Berbera-BulloXaar	65	Single circuit
2040	230	Baidoa-Buurhakaba	60	Single circuit
2040	230	Xudur-Wajid	80	Single circuit
2040	230	Dinsoor-Bardheere	80	Single circuit
2040	230	Jilib-Buale	90	Single circuit
2040	230	Jilib-Afmadow	80	Single circuit
2040	230	Kismayo-BulloXaaji	75	Single circuit
2040	132	Boroma-Quljeed	30	Single circuit
2040	132	Boroma-Baki	30	Single circuit
2040	132	Wajaale-Kalabeydh	20	Single circuit
2040	132	Kalabeydh-Dilla	20	Single circuit
2040	132	Gabiley-Arabsiyo	15	Single circuit
2040	132	Arabsiyo-Abaarso	15	Single circuit
2040	132	Hargeisa-BalliCabane	60	Single circuit
2040	132	Hargeisa-Awbarkhadle	30	Single circuit
2040	132	Burao-Oodweyne	55	Single circuit
2040	132	Laascaanod-Widhwidh	70	Single circuit
2040	132	Widhwidh-Buuhoodle	50	Single circuit
2040	132	Laascaanod-Oog	80	Single circuit
2040	132	Laascaanod-Xudun	100	Single circuit
2040	132	Qardho-XiinGalool	100	Single circuit
2040	132	Qardho-Taleh	100	Single circuit
2040	132	Qardho-Yake	30	Single circuit
2040	132	Ceeldahir-Armo	10	Single circuit
2040	132	Badhan-Hadaaftimo	30	Single circuit
2040	132	Beletweyne-Matabaan	70	Single circuit
2040	132	Jowhar-Qalimow	25	Single circuit
2040	132	Mogadishu-Balcad	35	Single circuit
2040	132	Dollow -Luuq	65	Single circuit
2040	132	Dollow -BeledHawo	40	Single circuit
2040	132	Galkayo-Galdogob	60	Single circuit
2040	132	Abaarey-Bacaadweyn	15	Single circuit

Operating year	***Vnom [kV]***	***Name***	***Length [km]***	***Type***
2040	132	Godinlabe-Cadaado	30	Single circuit

Substations (33 S/S):

- Eil 500/230 kV
- Buurhakaba 230/132 kV
- Wajid 230/33 kV
- Bardheere 230/33 kV
- Buale 230/33 kV
- Afmadow 230/33 kV
- BulloXaaji 230/33 kV
- BulloXaar 230/33 kV
- Qalimow 132/33 kV
- Balcad 132/33 kV
- Luuq 132/33 kV
- Matabaan 132/33 kV
- Cadaado 132/33 kV
- Galdogob 132/33 kV
- Bacaadweyn 132/33 kV
- Yake 132/33 kV
- XiinGalool 132/33 kV
- Taleh 132/33 kV
- Armo 132/33 kV
- Hadaaftimo 132/33 kV
- Oodweyne 132/33 kV
- Xudun 132/33 kV
- Oog 132/33 kV
- Widhwidh 132/33 kV
- Buuhoodle 132/33 kV
- Kalabeydh 132/33 kV
- Dilla 132/33 kV
- Arabsiyo 132/33 kV
- Abaarso 132/33 kV
- BalliCabane 132/33 kV
- Awbarkhadle 132/33 kV
- Quljeed 132/33 kV
- Baki 132/33 kV

All S/S, also where not explicitly mentioned, are equipped with transformers to MV level to feed the local loads in the city/town where they are located and in the suburbs.
Figure 5-15 shows the transmission grid in Somalia at the target year 2040.

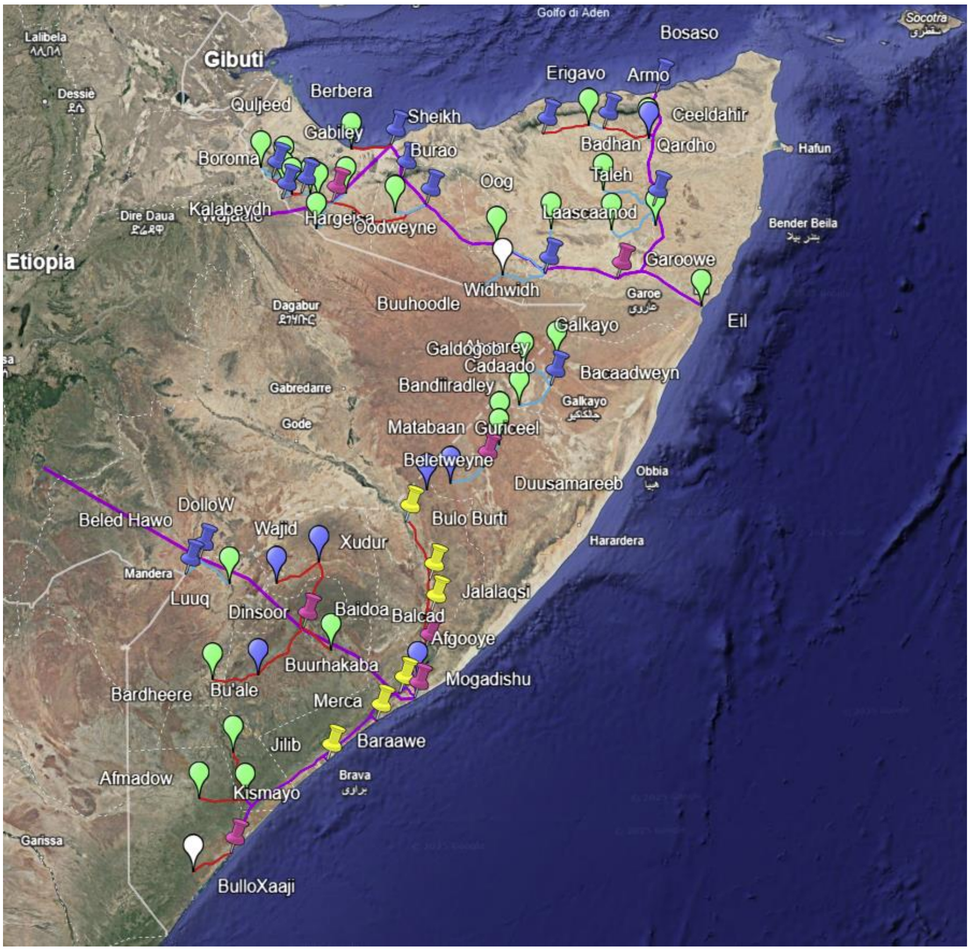


Figure 5-15 – Somalia-2040 transmission grid

5.2.4.4 2045 transmission network expansion (long-term period)

2045 represents the fourth target year of development of the Somalia transmission grid, and beginning of the long-term period considered for the development of the transmission expansion plan.

Main drivers for the development of the transmission grid are again the electrification of rural areas and the refurbishment of a backbone for the development of the significant RES potential (both solar PV and wind).

Concerning Mogadishu, due to the increase in the load, a new injection point represented by the new 500/230/132 kV S/S developed since 2045.

At the target year 2045 the EHV north-south backbone is not yet fully developed but significantly increased.

Transmission lines:

- 765 km of 500 kV transmission lines
- 465 km of 230 kV transmission lines
- 1030 km of 132 kV transmission lines

Table 5-6 – additional transmission lines expected in 2045

Operating year	Vnom [kV]	Name	Length [km]	Type
2045	500	Bosaso-Bargaal	215	Single circuit
2045	500	Garoowe-Galkayo	220	Single circuit
2045	500	Jowhar-Maxaas	200	Single circuit
2045	500	Maxaas-Duusamareeb	130	Single circuit
2045	230	BulloXaar-Lughaya	60	Single circuit
2045	230	Xudur-Beletweyne	195	Single circuit
2045	230	BulloXaaji-Burgabo	75	Single circuit
2045	230	Afmadow-Qoqani	50	Single circuit
2045	230	Qoqani-Dhobley	85	Single circuit
2045	132	Quljeed-Bown	15	Single circuit
2045	132	Bown-Xariirad	35	Single circuit
2045	132	Lughaya-GarboDadar	60	Single circuit
2045	132	Hargeisa-Darasalaam	35	Single circuit
2045	132	Awbarkhadle-Dacarbudhuq	30	Single circuit
2045	132	Dacarbudhuq-Madheera	25	Single circuit
2045	132	BalliCabane-Faraweyne	35	Single circuit
2045	132	BalliCabane-Baligubadle	25	Single circuit
2045	132	Buuhoodle-Ballidhiig	50	Single circuit
2045	132	Buuhoodle-Qorilugud	40	Single circuit
2045	132	Oog-Caynabo	25	Single circuit
2045	132	Erigavo-CeelAfweyn	85	Single circuit
2045	132	CeelAfweyn-GarAdag	65	Single circuit
2045	132	Bacaadweyn-Xarfo	20	Single circuit
2045	132	Xarfo-Burtinle	40	Single circuit
2045	132	Abaarey-Bursaalax	35	Single circuit
2045	132	BuloBurti-Halgan	40	Single circuit
2045	132	BuloBurti-Buqdaaqable	45	Single circuit
2045	132	Mogadishu-Warsheikh	60	Single circuit
2045	132	Qalimow-Hawadley	15	Single circuit
2045	132	Afgooye-Wanlaweyn	60	Single circuit
2045	132	Merca-Qoruooley	30	Single circuit
2045	132	Buurhakaba-Beerdale	35	Single circuit
2045	132	Dinsoor-Qansaxdheere	60	Single circuit
2045	132	Luuq-Garbahaarey	65	Single circuit

Substations (32 S/S):

- Mogadishu North 500/230/132 kV
- Maxaas 500/230 kV
- Bargaal 500/230 kV
- Lughaya 230/132 kV
- Burgabo 230/33 kV
- Qoqani 230/33 kV
- Dhobley 230/33 kV
- Hawadley 132/33 kV
- Wanlaweyn 132/33 kV
- Qoruooley 132/33 kV
- Beerdale 132/33 kV

- Garbahaarey 132/33 kV
- Qansaxdheere 132/33 kV
- Warsheikh 132/33 kV
- Halgan 132/33 kV
- Buqdaaqable 132/33 kV
- Bursaalax 132/33 kV
- Xarfo 132/33 kV
- Burtinle 132/33 kV
- CeelAfweyn 132/33 kV
- GarAdag 132/33 kV
- Qorilugud 132/33 kV
- Ballidhiig 132/33 kV
- Caynabo 132/33 kV
- Faraweyne 132/33 kV
- Baligubadle 132/33 kV
- Dacarbudhuq 132/33 kV
- Madheera 132/33 kV
- Darasalaam 132/33 kV
- Bown 132/33 kV
- Xariirad 132/33 kV
- GarboDadar 132/33 kV

All S/S, also where not explicitly mentioned, are equipped with transformers to MV level to feed the local loads in the city/town where they are located and in the suburbs.
Figure 5-16 shows the transmission grid in Somalia at the target year 2045.

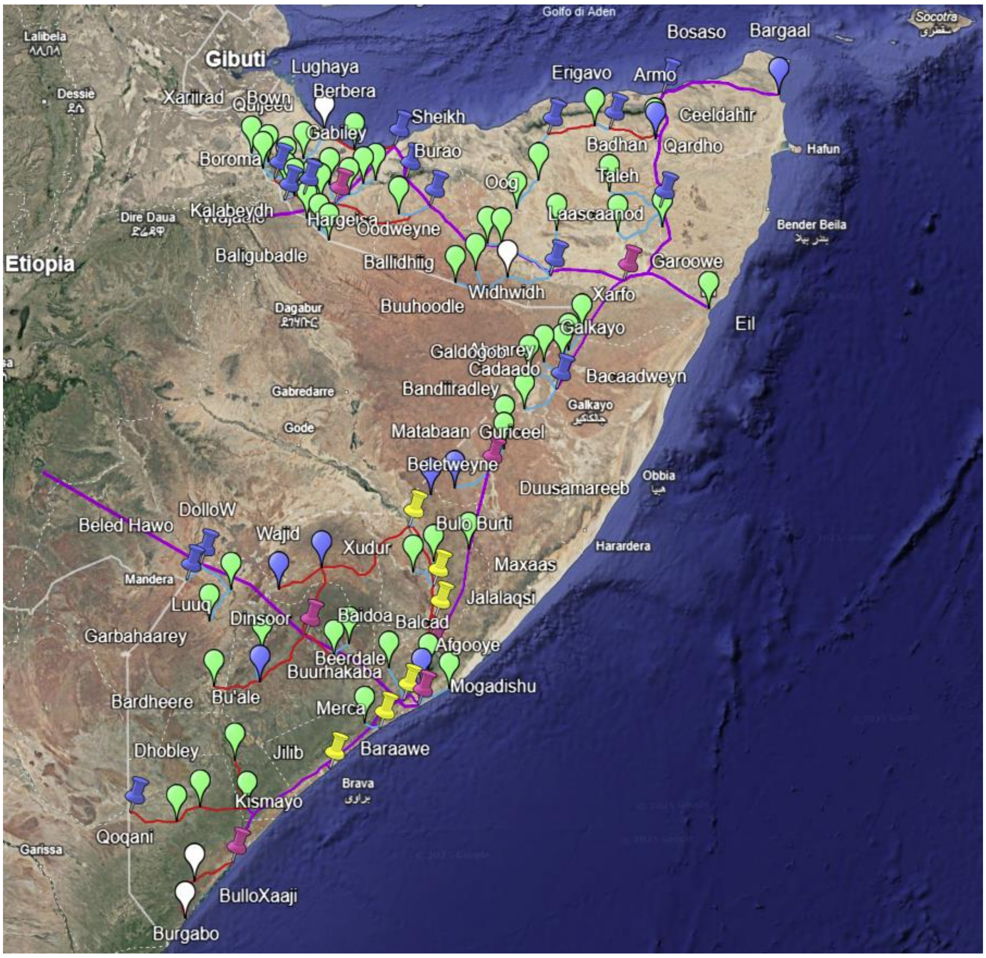


Figure 5-16 – Somalia-2045 transmission grid

5.2.4.5 2050 transmission network expansion (long-term period)

2050 represents the fifth and the last target year of development of the Somalia transmission grid, and representative of the long-term period considered for the development of the transmission expansion plan.
At this stage, the EHV backbone is completed and the grid developed in the north is connected to the network developed in the south.
Main drivers for the development of the transmission grid are again the electrification of rural areas and the further deployment of the RES potential (both solar PV and wind).

Transmission lines:

- 410 km of 500 kV transmission lines
- 1110 km of 230 kV transmission lines
- 280 km of 132 kV transmission lines

Table 5-7 – additional transmission lines expected in 2050

Operating year	*Vnom [kV]*	*Name*	*Length [km]*	*Type*
2050	500	Qardho-BenderBeila	200	Single circuit
2050	500	Duusamareeb-Baxdo	100	Single circuit
2050	500	Baxdo-Galkayo	110	Single circuit

Operating year	***Vnom [kV]***	***Name***	***Length [km]***	***Type***
2050	230	Lughaya-Zeila	95	Single circuit
2050	230	Burao-HajiSalah	120	Single circuit
2050	230	Galkayo-Garacad	210	Single circuit
2050	230	Baxdo-Obbia	155	Single circuit
2050	230	Maxaas-Mareeg	155	Single circuit
2050	230	Xudur-Eelbarde	85	Single circuit
2050	230	Buale-Bardheere	130	Single circuit
2050	230	Bardheere-BurAche	160	Single circuit
2050	132	Zeila-Lawyacado	25	Single circuit
2050	132	Lughaya-Geerisa	60	Single circuit
2050	132	Faraweyne-Alleybadey	20	Single circuit
2050	132	Baligubadle-Salaxley	25	Single circuit
2050	132	Duusamareeb-Balanbale	70	Single circuit
2050	132	Cadaado-Caabudwaaq	45	Single circuit
2050	132	Garbahaarey-Buurdhuubo	35	Single circuit

Substations (16 S/S):

- Baxdo 500/230 kV
- BenderBeila 500/230 kV
- Zeila 230/132 kV
- Eelbarde 230/33 kV
- BurAche 230/33 kV
- Mareeg 230/33 kV
- Obbia 230/33 kV
- Garacad 230/33 kV
- HajiSalah 230/33 kV
- Buurdhuubo 132/33 kV
- Balanbale 132/33 kV
- Caabudwaaq 132/33 kV
- Alleybadey 132/33 kV
- Salaxley 132/33 kV
- Geerisa 132/33 kV
- Lawyacado 132/33 kV

All S/S, also where not explicitly mentioned, are equipped with transformers to MV level to feed the local loads in the city/town where they are located and in the suburbs.
Figure 5-17 shows the transmission grid in Somalia at the target year 2050.

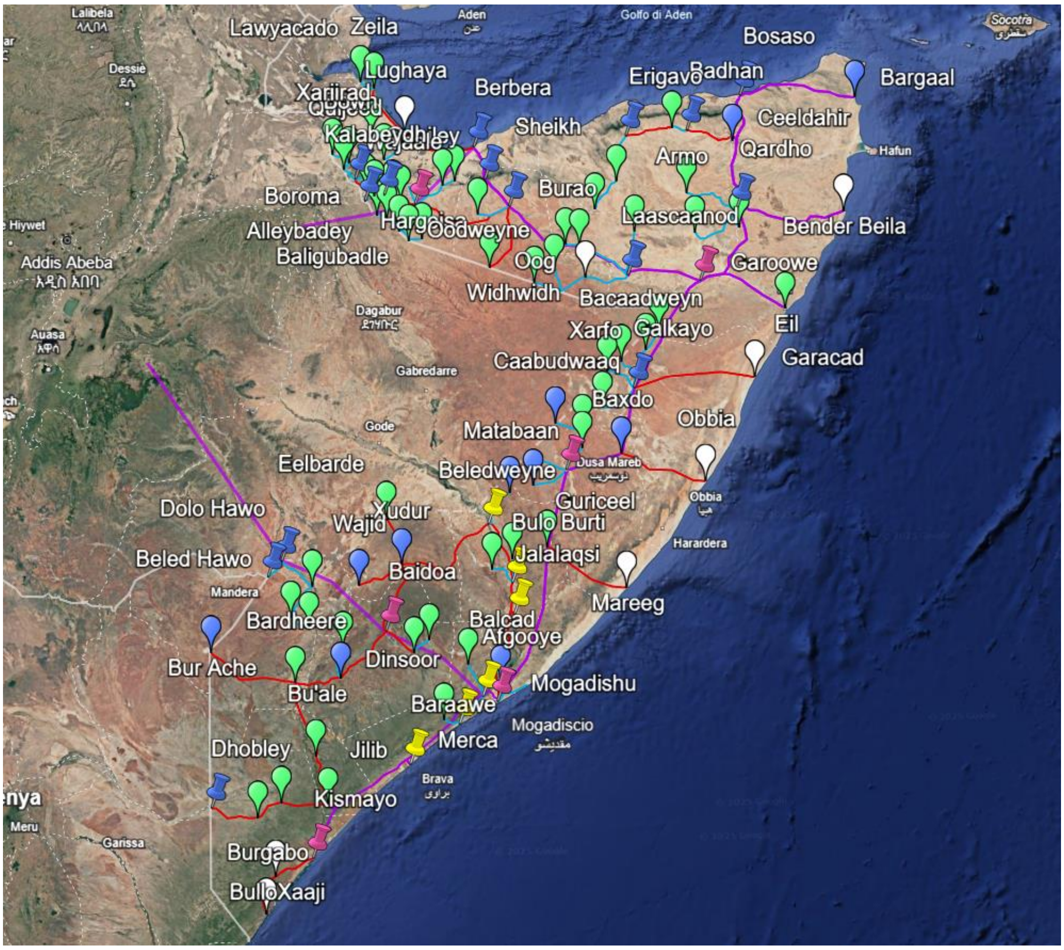


Figure 5-17 – Somalia-2050 transmission grid

5.2.4.6 Conclusions

The transmission expansion plan developed in this section represents a possible development of the transmission grid in Somalia taking into account some main objectives:

- Increase as fast as possible the electrification rate of the country,
- Coordinate the development of the internal transmission grid with the planned interconnections with Ethiopia, to be able to import a significant amount of cheap generation from Ethiopia in the first phase of the development process,
- Promote the development of the internal resources in Somalia, with particular reference to the high potential for PV and wind technologies.

As a result, the transmission master plan includes the development of:

- 2800 km of transmission lines at 500kV level (excluding the interconnections with Ethiopia), aimed to:
  - connect all capitals of the country,
  - create the north-south EHV backbone aimed to collect conventional and renewable generation and transmit it to the main load centres of the country
  - allow the power exchange with neighbouring countries, especially with Ethiopia, but also with Djibouti and Kenya in the future.
- 3200 km of transmission lines at 230kV level, aimed to:
  - Connect cities between them,
  - Supply the load centres located at a certain distance from the main EHV backbone,

    - Collect part of the renewable generation.
- 2760 km of transmission lines at 132kV level, aimed to electrify the country, reaching towns and villages also in remote areas.

In addition to that, the development of 112 substations at different voltage levels is foreseen.

The investments in transmission lines here reported does not include:
- The interconnections with Ethiopia, making part of a dedicated project,
- The subtransmission and distribution infrastructures that are not part of a Transmission Development Plan.

5.3 Power system analysis

Power system analyses of the transmission development plan described in the previous section are reported in the following paragraphs.
The purposes of these analyses are:

- Perform power flow calculations in normal (N) conditions, to identify possible criticalities in terms of voltage profiles, component loading and quantify the losses estimation,
- Perform power flow calculations in case of contingencies (N-1), to identify possible criticalities in the grid topology,
- Calculate the expected highest fault currents in the system, with the objective to identify the characteristics of the circuit breakers that should be selected in the transmission system planning.

The analyses are performed in the most relevant operating conditions for each type of calculation, in order to consider the most binding scenarios for the transmission network.
To cover the total internal demand, generating units are considered in accordance with the results of the generation expansion plan.

5.3.1 Rules of exploitation

Since Somalia does not have own Grid Code, the rules of exploitation considered for the planning of the transmission grid are the ones included in the EAPP guidelines.
Until Somalia will not have its own Grid Code, the EAPP prescriptions represent in fact the reference for the operation and the planning of the power system. In any case, also the future Somali Grid Code shall be in compliance with the regional prescriptions defined by EAPP.

Normal (N) Conditions
The basic assumptions related with N-criterion of transmission network are:

- The loading levels of all transmission lines and substation Equipment are within normal capacity ratings (thus, assuming 100% in normal condition).
- Operating voltage range of 0.95 to 1.05 per unit in steady state normal conditions for nominal voltage used in the Eastern Africa Power Pool (EAPP) interconnected transmission system.
- The Grid Frequency is within the limits of 49.5 Hz and 50.5 Hz.

Contingency (N-1) Conditions

- Operating voltage range of 0.90 to 1.10 per unit after single contingency
- 100% of overload allowed in N-1 for transmission lines
- 100% of overload allowed in N-1 for transformers

The following contingencies must be considered in N-1:

- A single transmission line
- A single generating unit or combination of generating units
- A single transformer
- A voltage compensation installation
- An HVDC link considered as either a generating unit or a large user

Multiple contingencies
Multiple contingencies can be defined, and possible limits are the following:

- 120% of overload allowed in N-2 for lines and transformers.
- Operating voltage range from 0.85 to 1.20 per unit a multiple contingency or severe systems stress.

Multiple contingencies will not be considered in this analysis.

Short circuit currents

According to EAPP prescriptions:

- Each TSO shall calculate where appropriate the short-circuit currents at each node of its National System taking into account the contributions of Neighbouring Systems to the short circuit current. TSOs of Neighbouring Systems shall exchange the data required for short circuit calculations.
- Each TSO shall operate its National System such that, at any node of the EAPP Interconnected Transmission System, short-circuit currents do not exceed the breaking capacity of the switchgear installed at that node, so that failure to clear a fault does not lead to cascading Outages. The TSO shall use an appropriate protection strategy to ensure selectivity and to provide backup protection in case of failure of the main protection system to isolate a fault

Considering that Somalia has not yet standards for circuit breaker limits, the short circuit currents calculated in this project have only the purpose to identify the characteristics of the circuit breaker that are expected to be installed in the different S/S.

5.3.2 Load flow analysis

The aim of the load flow calculation is the examination of balanced steady-state operation of the transmission systems of Somalia in the target years, to assure that is planned reliably within equipment and power system thermal limits, and voltage limits.

The power flow analysis is performed in normal operating conditions (N situation), i.e., with all network components in operation, in order to assess the violation of thermal limits on network elements, to identify network conditions that are outside of required control limits or to indicate controlling equipment and possible violations and conflicts associated with those controls.

The purpose of such analysis is to check future network operation, identify possible constraints and to define the appropriate set of transmission network components and the most appropriate transmission grid configuration to ensure the secure operation of the system avoiding overloads and voltage violations.

5.3.2.1 Load flow analysis for the target year 2030

The target year 2030 is analysed in order to figure out whether the system on one hand is adequate to balance the internal load at its peak demand by itself since any interconnection with foreign countries is in operation and in the other hand is operated in a secure and safe way.

Balance between generation and internal demand is reported in Table 5-8 with also details regarding losses and reactive power contributions.

Table 5-8 - Peak load scenario target year 2030

Balance	*Active Power* [MW]	*Reactive Power* [MVar]
Generation	596.7	7.6
Internal Demand	596.1	82.6
Bus Shunt	0	571.1
Line Shunt	0	749.3
Line Charging	0	1432.3
Grid Losses	0.62 (0.2%)	36.82

It is worth noticing how the system behaves and the main indexes to figure this out are the voltages in all the nodes of the network and the loading of the different elements. Thanks to Figure 5-20 it is possible to conclude that, since all the voltages in the network are safely within the 5% interval with respect to the nominal value, the system is in a stable and safe condition. This is confirmed also by Figure 5-18 and Figure 5-19 where it is shown that the network is quite unloaded since all the network elements have a loading percentage lower that 50%

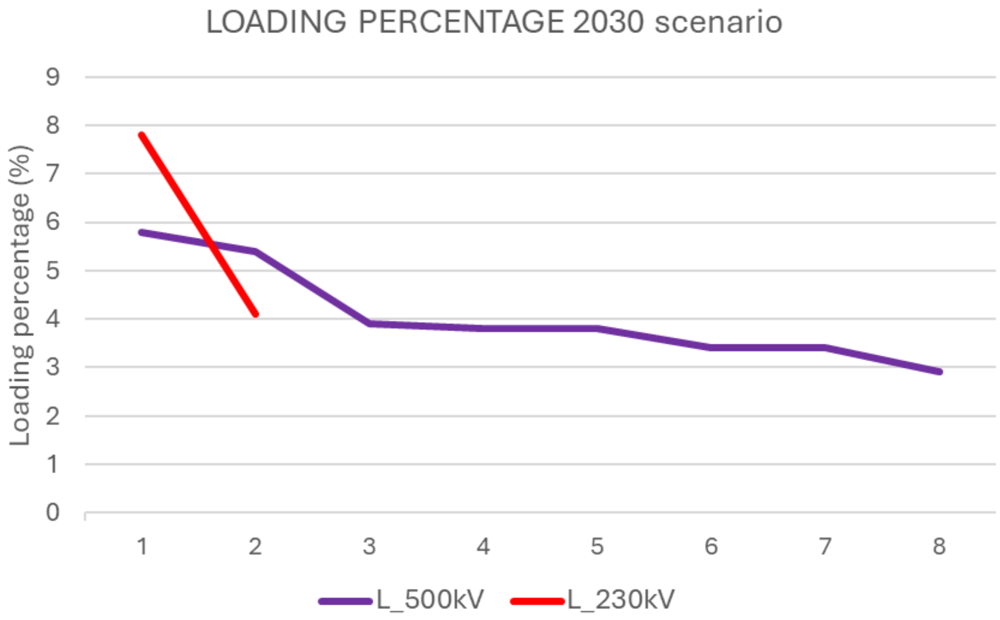


Figure 5-18 - Loading percentage of the branches - year 2030

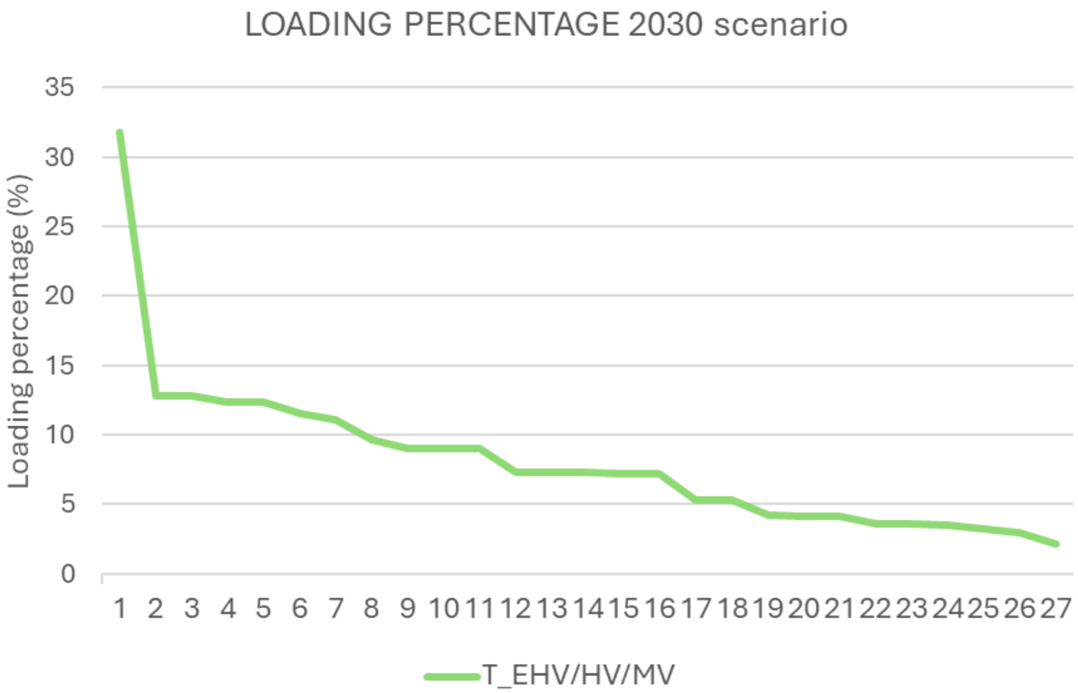


Figure 5-19- Loading percentage of the transformers - year 2030

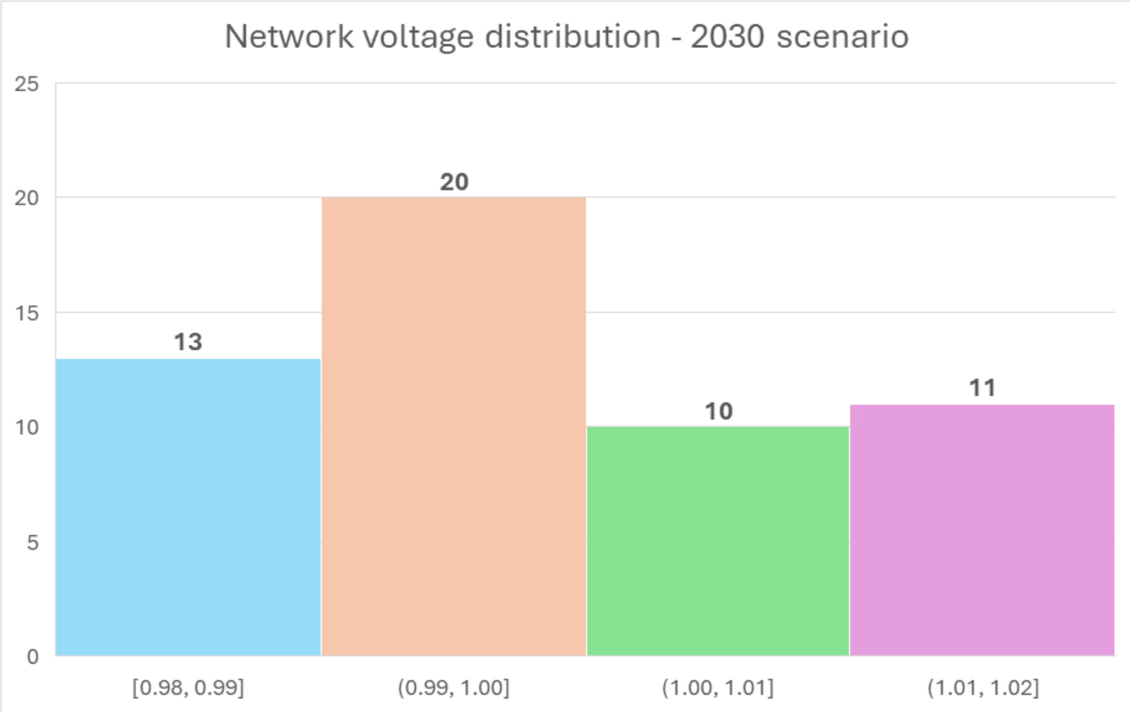


Figure 5-20 - Distribution of the voltages in the network, year 2030

5.3.2.2 Load flow analysis for the target year 2035

The target year 2035 is important since it is the first target year where the two interconnections between Somalia and Ethiopia are in operation and thus there is the possibility to mutually exchange power between the two countries. In order to reproduce a conservative situation, the peak internal demand of Somalia in year 2035 is covered primarily by local generation and only partially by the power coming from Ethiopia, in fact the interconnection lines are utilized well below their potential). From the Somalia perspective, it is a significant assessment since its national system must be adequate to balance the internal load demand without relying excessively on power imports from Ethiopia.

Balance between generation and internal demand is reported in Table 5-9 with also details regarding losses and reactive power contributions.

Table 5-9 - Peak load scenario target year 2035

Balance	*Active Power [MW]*	*Reactive Power [MVar]*
Generation	1198.5	-129
Internal Demand	1196.2	218.2
Bus Shunt	0	1296.9
Line Shunt	0	1185.9
Line Charging	0	2913.7
Grid Losses	2.31 (0.2%)	83.65

In order to figure out how the system behaves, focus is made on the main indexes of the systems such as the voltages in all the nodes of the network and the loading of the different elements, reported respectively in Figure 5-21, Figure 5-22 and Figure 5-23. Voltage values are very important because, as reported in Figure 5-23, since they are all within the ±5% interval with respect to the nominal value, the system is well operated, and voltage regulation is under control. The system is operated in a safe way also from the loading perspective since all network elements are loaded under 50% of their nominal power, as illustrated in Figure 5-21 and Figure 5-22.

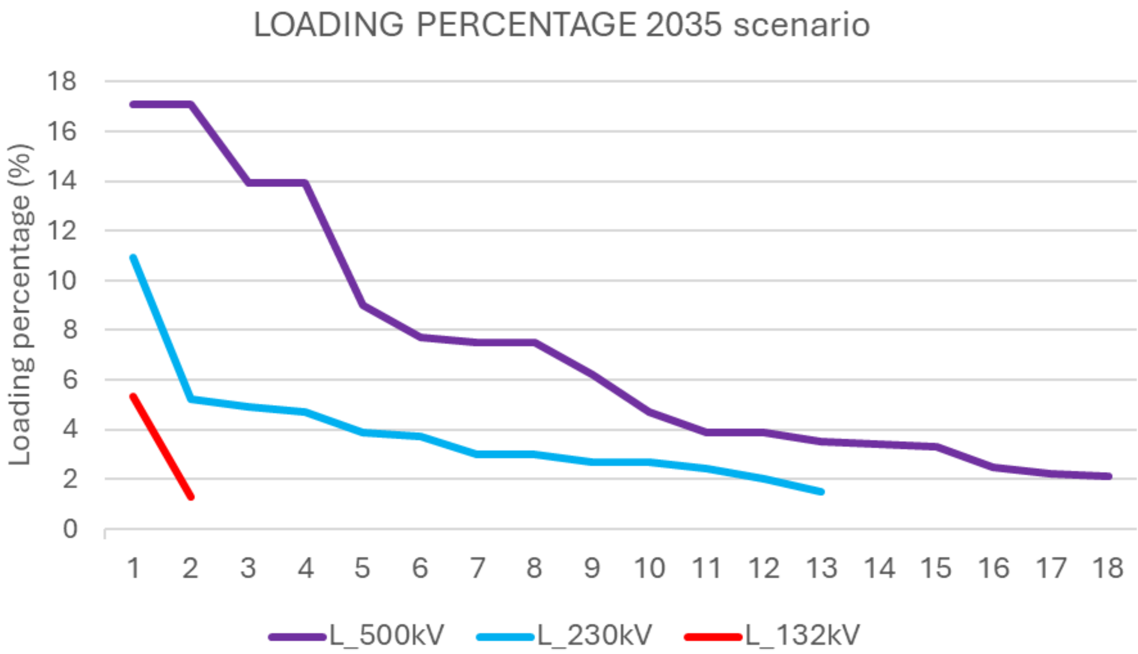


Figure 5-21- Loading percentage of the branches - year 2035

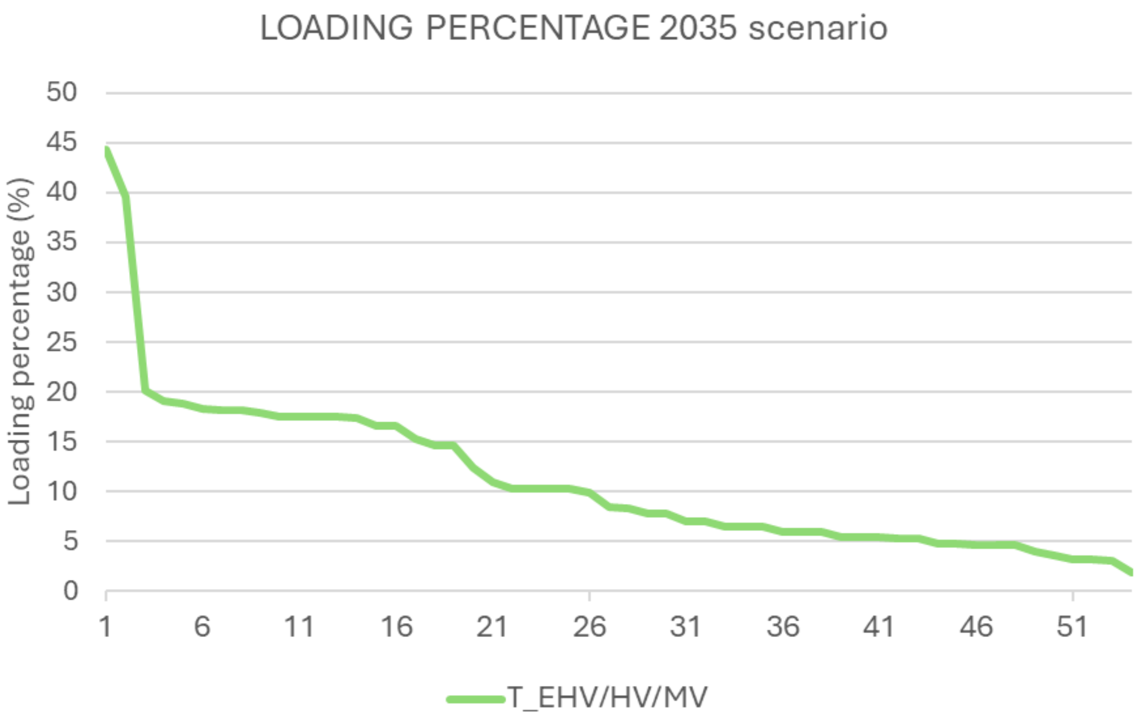


Figure 5-22- Loading percentage of the transformers - year 2035

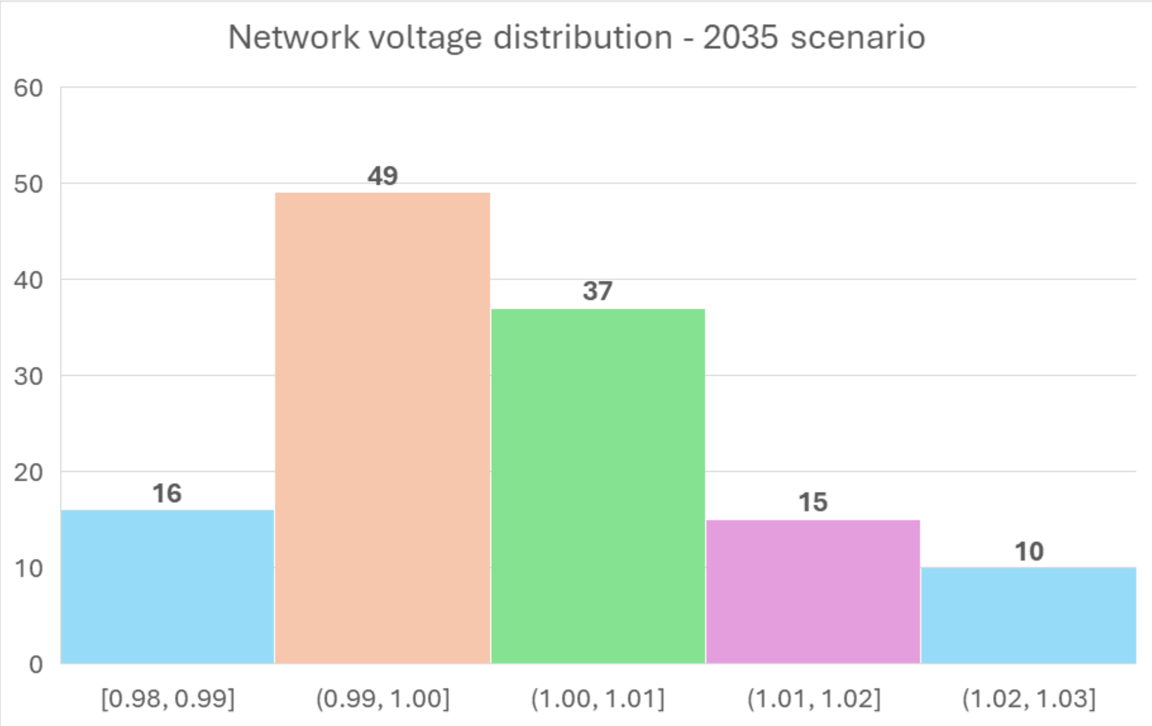


Figure 5-23 - Distribution of the voltages in the network, year 2035

5.3.2.3 Load flow analysis for the target year 2040

The target year 2040 represents a step forward in the evolution of the Somalia National Transmission system since the internal demand starts increasing significantly and to deal with this growth generation and transmission must cooperate together to install new generation capacity and reach further area of the country not yet electrified. As in the previous target year, the power exchange between Somalia and Ethiopia is kept well below its potential in order to reproduce the most conservative situation and thus the peak demand is primary covered by local generation installed in Somalia.

Balance between generation and internal demand is reported in Table 5-10 with also details regarding losses and reactive power contributions.

Table 5-10 - Peak load scenario target year 2040

Balance	***Active Power [MW]***	***Reactive Power [MVar]***
Generation	2290.6	-284.8
Internal Demand	2286.1	485.3
Bus Shunt	0	1011.6
Line Shunt	0	1307.9
Line Charging	0	3308.2
Grid Losses	4.53 (0.2%)	218.63

Voltage of the system and loading percentage of the network elements are two important factors since they are able to give a first glance of the behaviour of the system since they are able to tell how the system behaves. As shown in Figure 5-26, if voltages of all the network are within the ±5% interval with respect to the nominal value, the system is operating in a safe and secure way. This is confirmed also looking at Figure 5-24 and Figure 5-25 where the loading percentage of all the network is reported, and they are manageable since the rated power of all the elements is respected.

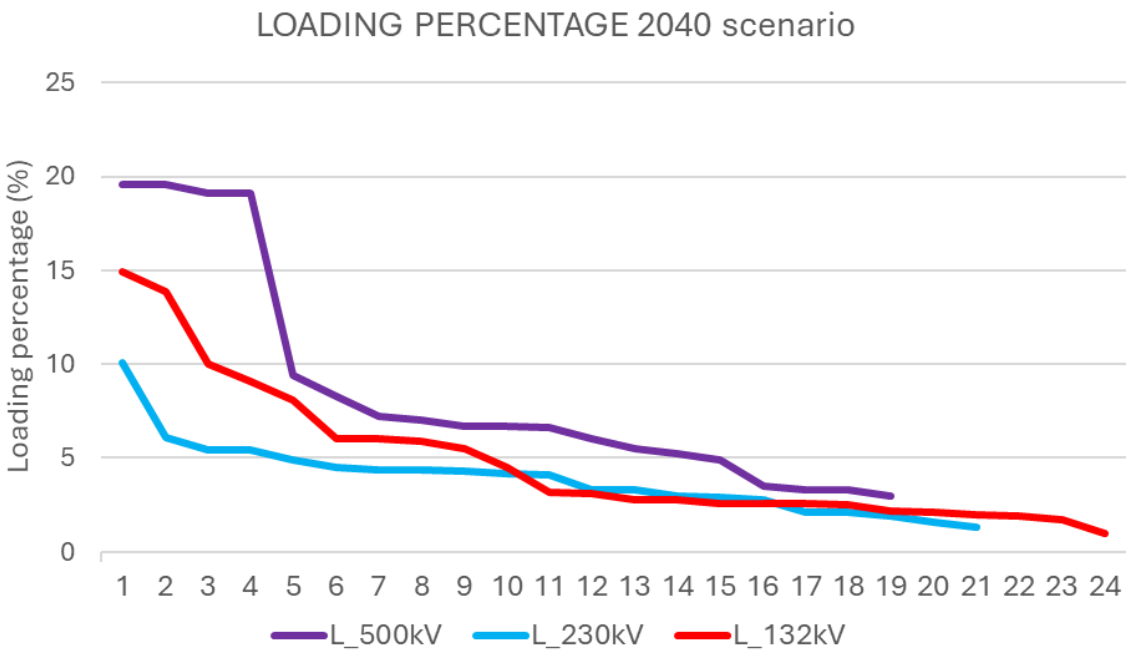


Figure 5-24 - Loading percentage of the branches - year 2040

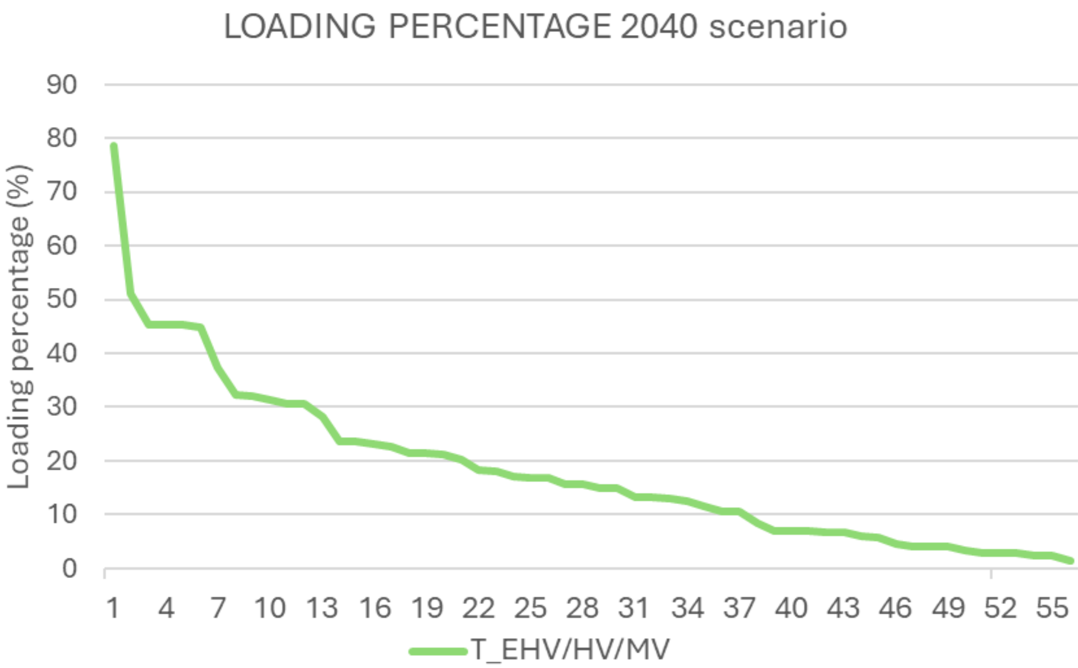


Figure 5-25 - Loading percentage of the transformers - year 2040

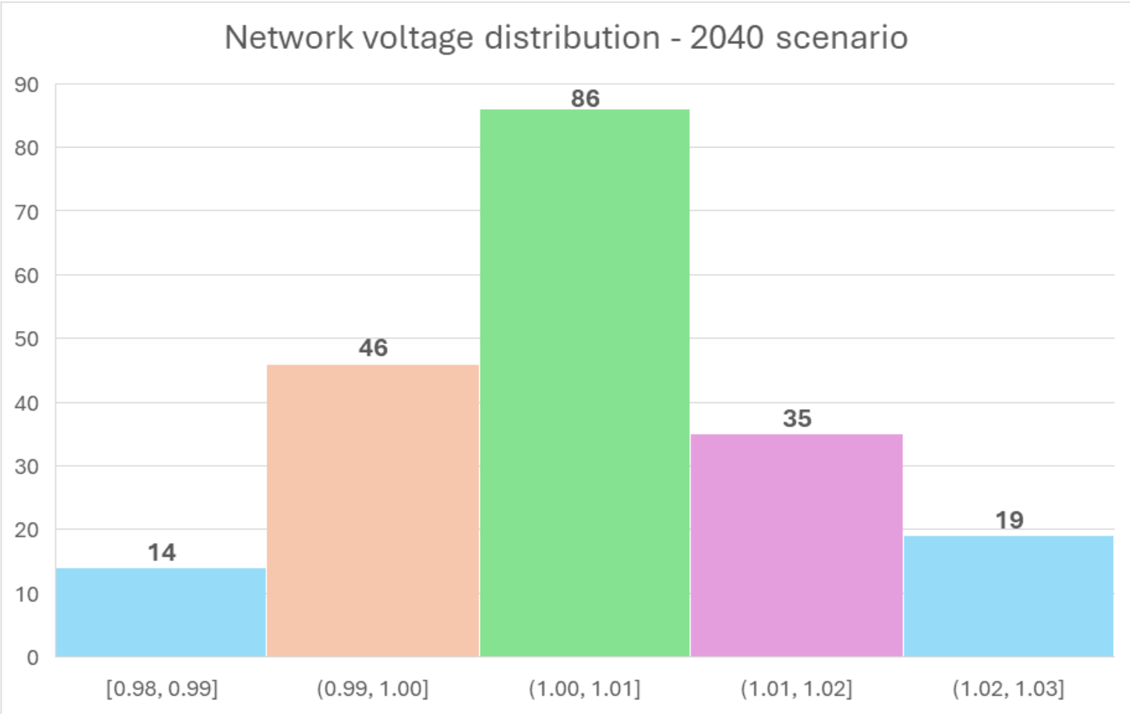


Figure 5-26 - Distribution of the voltages in the network, year 2040

5.3.2.4 Load flow analysis for the target year 2045

The target year 2045 brings important and crucial evolutions in the towards the goal of the unification of the Somalia National Transmission system thanks to the realization of an internal EHV back-bone: the first steps for the realization of such corridor are present in this target year together with the spread of electrification in the rural areas.
Similarly to the previous scenarios, regarding the power exchange, the interconnections are used well below their rated capacity in order to reproduce a more conservative solution and thus local generation installed in Somalia is used to primary cover the peak demand of the country.

Balance between generation and internal demand is reported in Table 5-11 with also details regarding losses and reactive power contributions.

Table 5-11- Peak load scenario target year 2045

Balance	***Active Power [MW]***	***Reactive Power [MVar]***
Generation	3970.7	51.4
Internal Demand	3962.0	911.5
Bus Shunt	0	958.8
Line Shunt	0	1802.6
Line Charging	0	4252.9
Grid Losses	8.74 (0.2%)	631.42

To figure out whether the system is operating in a safe and secure way, loading percentage of the network elements and voltages of all the nodes of the network are investigated since they are representative of the operating condition of the National grid. In fact, for instance looking at the voltages reported in Figure 5-29, it is possible to conclude that the system in operated in a safe condition since all the voltages of all the network are within the ±5% interval with respect to the nominal value.

Furthermore, concerning the usage of the elements, the loading percentage of the different elements starts increasing across the whole network but it remains moderate and under control as confirmed by looking at Figure 5-27 and Figure 5-28.

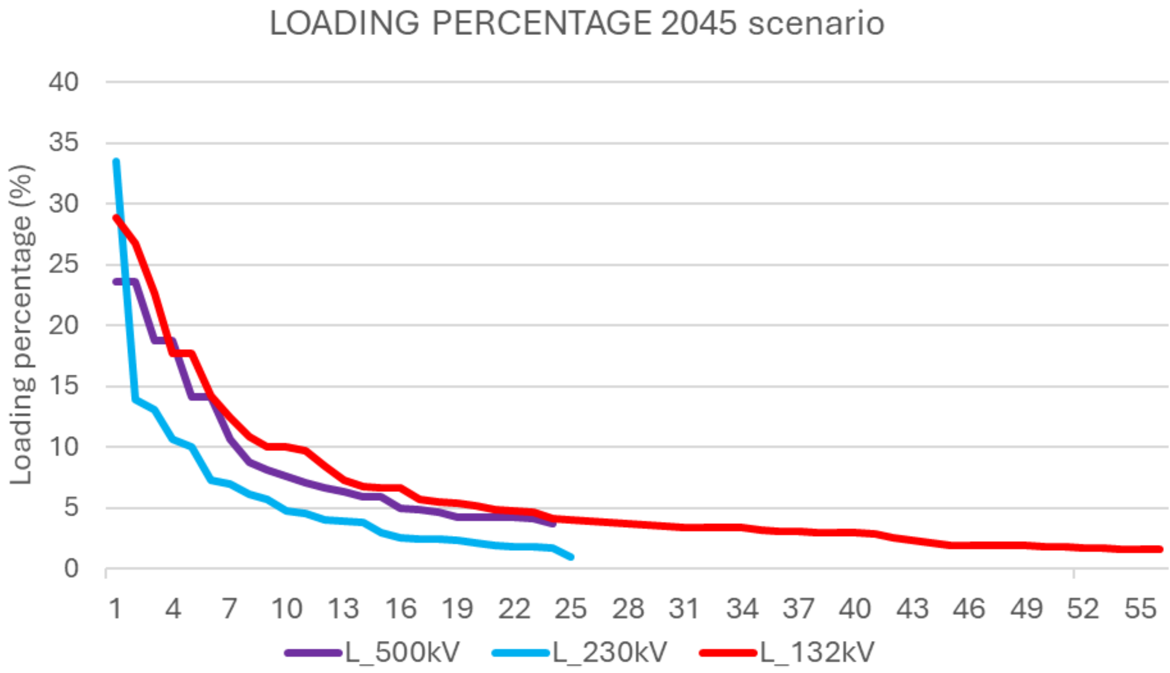


Figure 5-27 - Loading percentage of the branches - year 2045

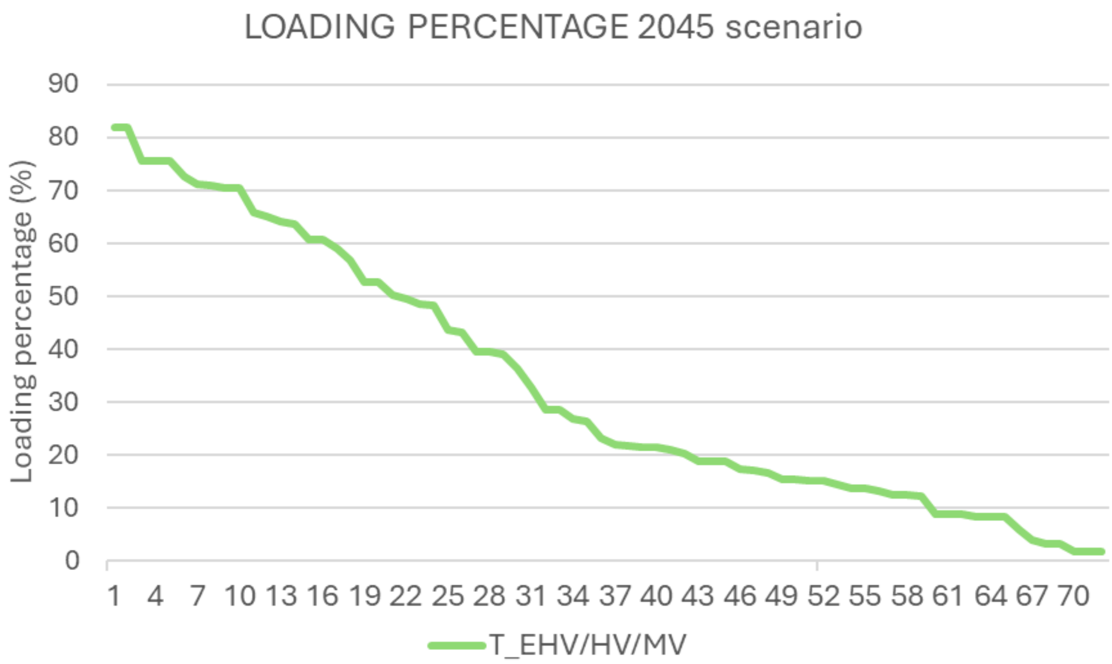


Figure 5-28 - Loading percentage of the transformers - year 2045

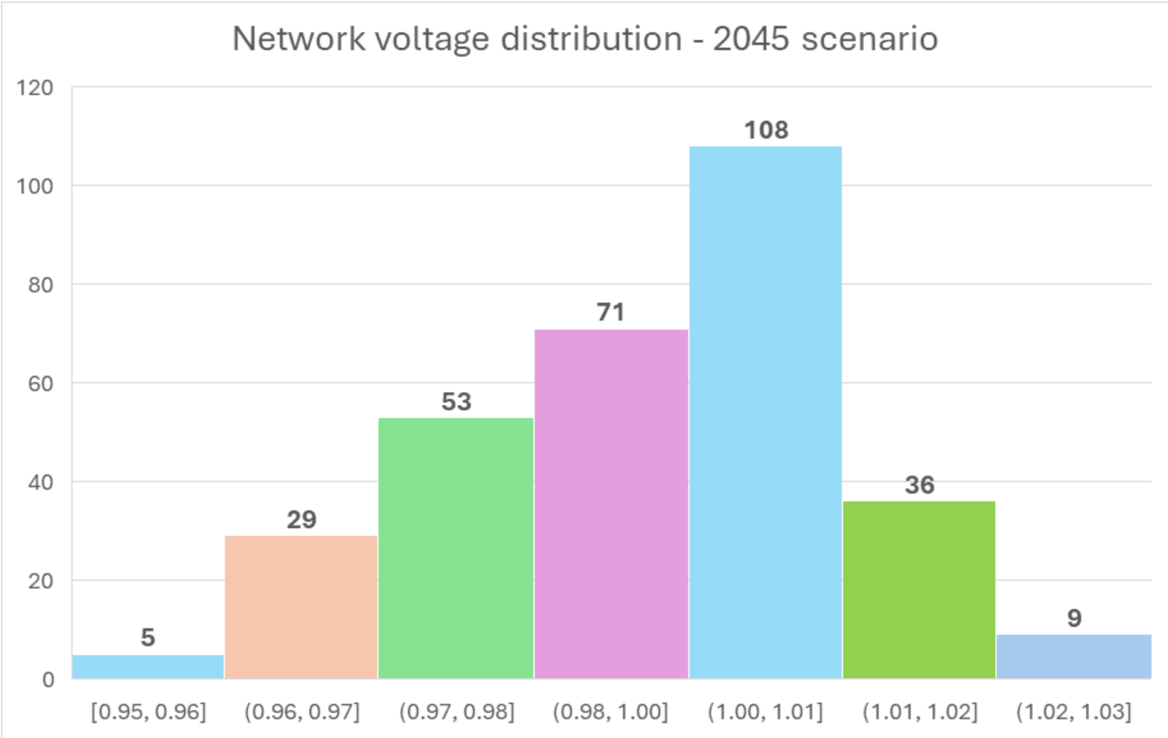


Figure 5-29 - Distribution of the voltages in the network, year 2045

5.3.2.5 Load flow analysis for the target year 2050

The target year 2050 represents the final year of the evolution of the National Transmission grid and it is very significant since it represents the conclusion of the internal EHV back-bone of Somalia as also the finalization of the process of rural electrification. In order to assess the behaviour of the system in the most conservative situation, the power exchange between Somalia and Ethiopia is kept limited and well below its rated capacity in order to verify that the generation capacity of Somalia is able to cope with its peak demand.

Balance between generation and internal demand is reported in Table 5-12 with also details regarding losses and reactive power contributions.

Table 5-12- Peak load scenario target year 2050

Balance	***Active Power* [MW]**	***Reactive Power* [MVar]**
Generation	5558.8	542.8
Internal Demand	5512.1	1283.1
Bus Shunt	0	773.8
Line Shunt	0	1924.8
Line Charging	0	4798.4
Grid Losses	46.66 (1%)	1359.55

Loading percentage of the network elements and voltage of the system's nodes are two important indicators to verify the performance of the system and figure out whether the system is stable, and it is operating in a safe condition or not. Looking at the voltages in the network reported in Figure 5-32 it is possible to conclude that the system is operating well: all the voltages of the nodes in the network are under control since the majority of them has a voltage value within the ±5% interval with respect to the nominal value. Only few of them exceed this limit however they are acceptable violations since the extent of the violation is quite low and they are all associated to nodes where loads are connected. Concerning loading percentage of the different network elements, in general terms the system is quite unloaded even if some critical loadings are present but the system is operating in a safe and secure condition as shown in Figure 5-30 and Figure 5-31.

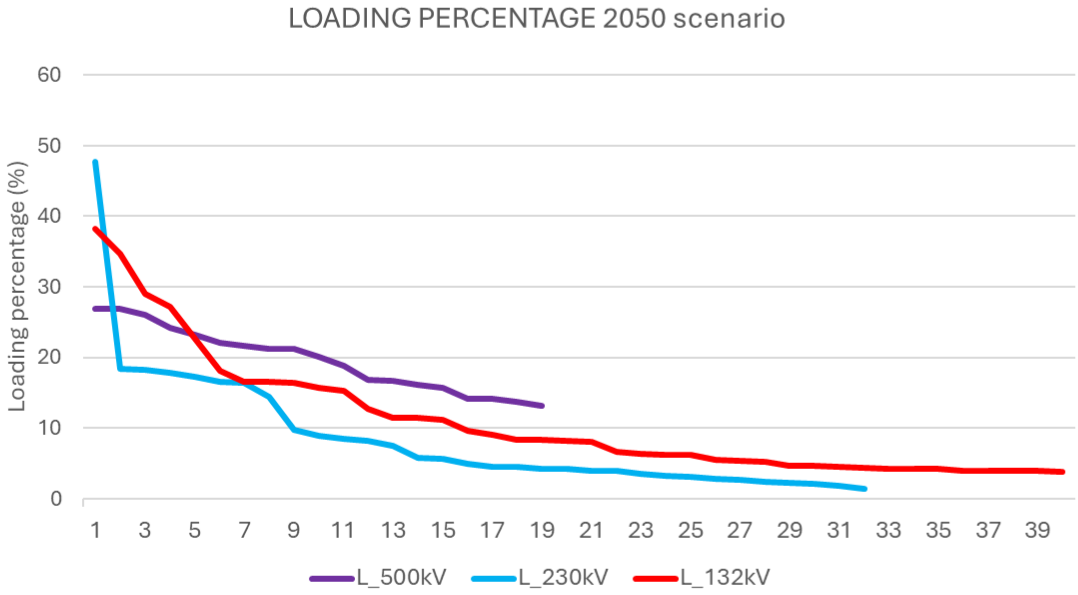


Figure 5-30 - Loading percentage of the branches - year 2050

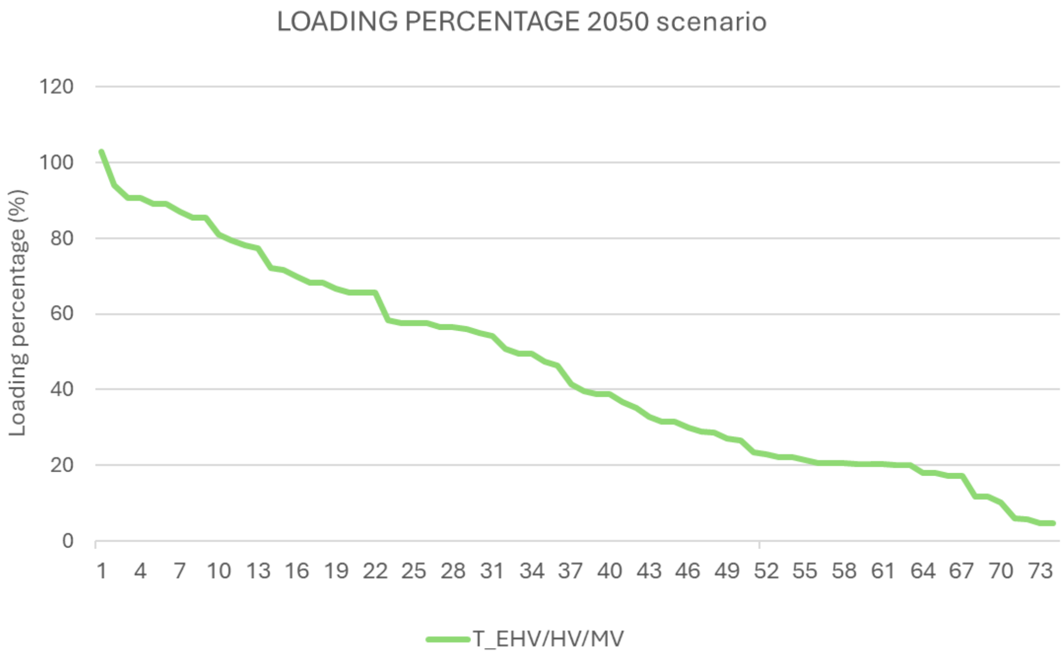


Figure 5-31 - Loading percentage of the transformers - year 2050

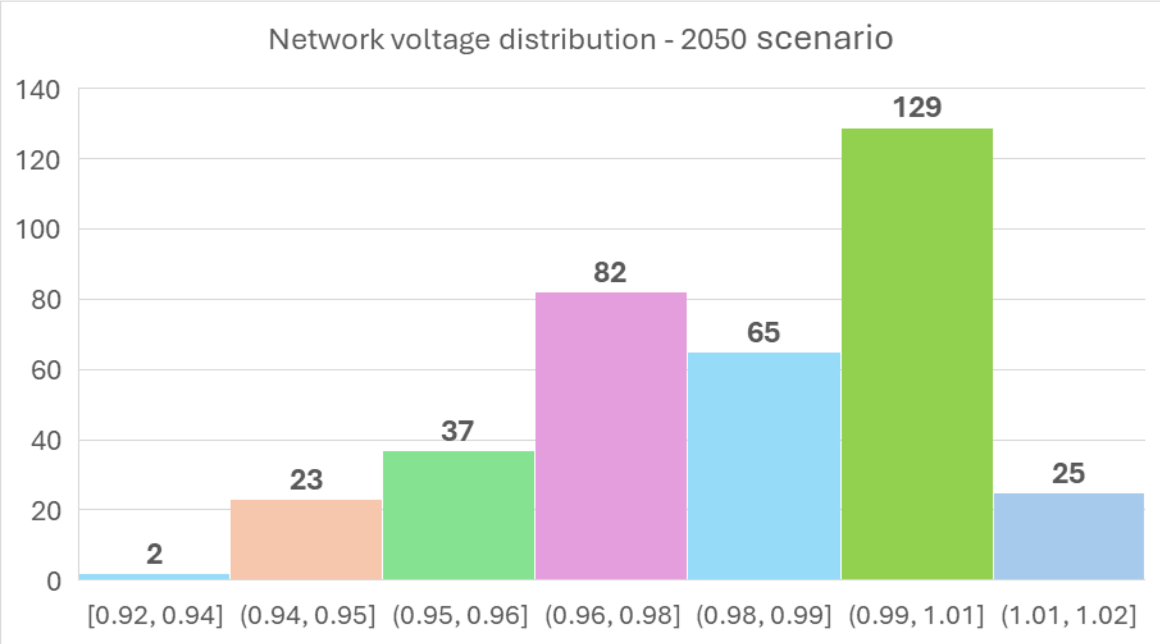


Figure 5-32 - Distribution of the voltages in the network, year 2050

5.3.3 Static security analysis

Steady-State Contingency Analysis (N-1 analysis) is applied to assess static security for the Somalia power system in the same scenarios already investigated in N conditions. This type of study comprises the outage of system elements and an examination of voltage and loading conditions both prior to and subsequent to the outage (contingency). The same target years and base cases selected in load flow analysis are analysed.
Contingency analysis method is based on the common planning criteria, consisting of simulation of element outages by a deterministic approach. Considering that the transmission grid of Somalia will be developed from scratch, there will be the possibility that the N-1 security criteria cannot be respected in some target years and for some transmission lines: these situations are highlighted indicating appropriate justifications based on technical and economic criteria.

5.3.3.1 Static security analysis for the target year 2030

In the target year 2030 Somalia National Grid is at its embryonic stage of development thus the N-1 security criteria cannot be guaranteed since the network is basically starting from stretch and the main drivers at the beginning are different with respect to the security criteria. Main issues associated to contingency analysis performed in this stage are not associated to problems of undervoltage events, that actually are limited and under control but are related to load isolation: since the network is mainly radial, in case of a continency event, the healthy portion of the network may not be able to fulfil the entire load.

CONTINGENCY > OPEN LINE FROM:	***BUS***	***BUS NAME***	***Vnom***	***V-CONT***	***V-INIT***
BUS 100000 [MOGADISHU 500.00] TO BUS 100005 [AFGOOYE 500.00]	100000	MOGADISHU	500	**0.932**	1.010
BUS 100000 [MOGADISHU 500.00] TO BUS 100005 [AFGOOYE 500.00]	100002	MOGADISHU	132	**0.949**	1.006

5.3.3.2 Static security analysis for the target year 2035

In the target year 2035 Somalia National Grid starts spreading from the 7 region capitals and main cities to the neighbouring major cities and load centers. Furthermore, thanks to the presence of the two interconnections with Ethiopia, in operation since 2032, the electricity network grows significantly. However, also the main driver that pushes this evolution is the rapid electrification of the areas of the country having in mind economic and financial aspects and thus it is accepted that N-1 security criteria has only a secondary priority. In any case, contingency analysis shows that there are no criticalities in terms of overloads and voltage issues, expect few overvoltage occurrences that are still manageable, however main concerns are related to load isolation since, after the contingency occurred, the healthy portion of the network may not be always able to supply the entire load.

CONTINGENCY > OPEN LINE FROM:	*BUS*	*BUS NAME*	*Vnom*	*V-CONT*	*V-INIT*
100001 [MOGADISHU 500.00] TO BUS 500050 [JOWHAR 500.00]	100050	JOWHAR	230	**1.050**	1.011
100001 [MOGADISHU 500.00] TO BUS 500050 [JOWHAR 500.00]	100103	JALALAQSI	230	**1.058**	1.024
100001 [MOGADISHU 500.00] TO BUS 500050 [JOWHAR 500.00]	100106	BULOBURTI	230	**1.061**	1.029
100001 [MOGADISHU 500.00] TO BUS 500050 [JOWHAR 500.00]	100107	BULOBURTI	132	**1.060**	1.028
100001 [MOGADISHU 500.00] TO BUS 500050 [JOWHAR 500.00]	100110	BELETWEYNE	230	**1.055**	1.030
100001 [MOGADISHU 500.00] TO BUS 500050 [JOWHAR 500.00]	100111	BELETWEYNE	132	**1.054**	1.029
100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100103	JALALAQSI	230	**1.101**	1.024
100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100106	BULOBURTI	230	**1.099**	1.029
100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100107	BULOBURTI	132	**1.098**	1.028
100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100110	BELETWEYNE	230	**1.085**	1.030
100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100111	BELETWEYNE	132	**1.084**	1.029
100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100106	BULOBURTI	230	**1.063**	1.029
100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100107	BULOBURTI	132	**1.062**	1.028
100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100110	BELETWEYNE	230	**1.057**	1.030
100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100111	BELETWEYNE	132	**1.056**	1.029

5.3.3.3 Static security analysis for the target year 2040

In the target year 2040 Somalia National Grid keeps growing following the increase in the load demand and therefore the need to connect new generation capacity to supply the internal demand. This evolution is performed dealing always with objective of optimizing the investments costs: it means that priority is given to accelerate the electrification of the rural area and connect the new generation capacity needed to cover the demand. This leaves to the possibility that during contingency events load isolation is possible since the healthy portion of the network may not be always able to supply the entire load. Nevertheless, contingency analysis shows that there are no criticalities in terms of overloads in the network elements and some overvoltage issues are reported but they are all not severe.

CONTINGENCY > OPEN LINE FROM:	***BUS***	***BUS NAME***	***Vnom***	***V-CONT***	***V-INIT***
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100103	JALALAQSI	230	**1.096**	1.019
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100106	BULOBURTI	230	**1.095**	1.026
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100107	BULOBURTI	132	**1.093**	1.025
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100110	BELETWEYNE	230	**1.083**	1.030
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100111	BELETWEYNE	132	**1.083**	1.030
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100211	MATABAAN	132	**1.083**	1.030
BUS 100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100106	BULOBURTI	230	**1.067**	1.026
BUS 100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100107	BULOBURTI	132	**1.065**	1.025
BUS 100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100110	BELETWEYNE	230	**1.061**	1.030
BUS 100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100111	BELETWEYNE	132	**1.061**	1.030
BUS 100103 [JALALAQSI 230.00] TO BUS 100106 [BULOBURTI 230.00]	100211	MATABAAN	132	**1.061**	1.030

5.3.3.4 Static security analysis for the target year 2045

In the target year 2045 the Somalia National Grid represents the first step towards the realization of a unified National Transmission Network thanks to the realization of the internal EHV back-bone. In parallel with it, the network is starting to be loaded especially during contingency events, and this implies that some reinforcements are necessary.
In any case, contingency analysis highlights that the system does not show particular problems in terms of voltage issues, neither overvoltage nor undervoltage concerns. However, due to the network's characteristics implemented in order to contain investments costs, the main issue is associated to the fact that load isolation is possible since the portion of the network that remains healthy may not be always able to supply the entire load.

CONTINGENCY > OPEN LINE FROM:	***BUS***	***BUS NAME***	***Vnom***	***V-CONT***	***V-INIT***
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100103	JALALAQSI	230	**1.059**	1.009
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100106	BULOBURTI	230	**1.059**	1.015
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100107	BULOBURTI	132	**1.057**	1.014
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100110	BELETWEYNE	230	**1.050**	1.020
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100306	HALGAN	132	**1.056**	1.012

CONTINGENCY > OPEN LINE FROM:	BUS	BUS NAME	Vnom	V-CONT	V-INIT
BUS 100050 [JOWHAR 230.00] TO BUS 100103 [JALALAQSI 230.00]	100309	BUQDAAQABLE	132	**1.058**	1.014

5.3.3.5 Static security analysis for the target year 2050

Target year 2050 represents the final year where the Somalia National Grid is eventually completed thanks to the realization of the internal EHV backbone that represents also the final step towards the electrification of the rural area of the whole country. Contingency analysis emphases that the network is starting to be used to its full potential.

Nonetheless, contingency analysis reports that, except few situations that are still acceptable, voltage in the whole network is quite robust with respect to both overvoltage and undervoltage events. In any case, main concerns associated to N-1 events are related to the possibility of load isolation: in order to contain investments costs, the system is designed in such a way that, in case of particular contingency events, the portion of the network that remains healthy may not be always able to supply the entire load.

CONTINGENCY > OPEN LINE FROM:	BUS	BUS NAME	Vnom	V-CONT	V-INIT
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100124	DINSOOR	230	0.878	1.009
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100125	DINSOOR	132	0.874	1.007
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100137	JILIB	230	0.870	1.009
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100230	BARDHEERE	230	0.853	1.008
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100233	BUALE	230	0.841	1.010
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100236	AFMADOW	230	0.882	1.016
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100327	QANSAXDHEERE	132	0.874	1.007
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100333	DHOBLEY	230	0.895	1.018
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100336	QOQANI	230	0.888	1.019
BUS 100010 [BARAAWE 500.00] TO BUS 100136 [JILIB 500.00]	100388	BURACHE	230	0.860	1.019
BUS 100022 [BERBERA 500.00] TO BUS 100068 [SHEIKH 500.00]	100029	BURAO	132	0.892	0.976
BUS 100022 [BERBERA 500.00] TO BUS 100068 [SHEIKH 500.00]	100168	OODWEYNE	132	0.889	0.974
BUS 100027 [BURAO 500.00] TO BUS 100032 [LAASCAANOD 500.00]	100094	DUUSAMAREEB	132	0.887	0.968
BUS 100027 [BURAO 500.00] TO BUS 100032 [LAASCAANOD 500.00]	100097	GODINLABE	132	0.883	0.965
BUS 100027 [BURAO 500.00] TO BUS 100032 [LAASCAANOD 500.00]	100100	GURICEEL	132	0.888	0.969
BUS 100027 [BURAO 500.00] TO BUS 100032 [LAASCAANOD 500.00]	100208	CADAADO	132	0.883	0.965

CONTINGENCY > OPEN LINE FROM:	***BUS***	***BUS NAME***	***Vnom***	***V-CONT***	***V-INIT***
BUS 100027 [BURAO 500.00] TO BUS 100032 [LAASCAANOD 500.00]	100292	DUUSAMAREEB	230	0.895	0.974
BUS 100027 [BURAO 500.00] TO BUS 100032 [LAASCAANOD 500.00]	100376	CAABUDWAAQ	132	0.882	0.965
BUS 100027 [BURAO 500.00] TO BUS 100032 [LAASCAANOD 500.00]	100379	BALANBALE	132	0.887	0.969
BUS 100027 [BURAO 500.00] TO BUS 100068 [SHEIKH 500.00]	100027	BURAO	500	0.898	1.008
BUS 100027 [BURAO 500.00] TO BUS 100068 [SHEIKH 500.00]	100028	BURAO	230	0.856	0.999
BUS 100027 [BURAO 500.00] TO BUS 100068 [SHEIKH 500.00]	100029	BURAO	132	0.823	0.976
BUS 100027 [BURAO 500.00] TO BUS 100068 [SHEIKH 500.00]	100168	OODWEYNE	132	0.820	0.974
BUS 100027 [BURAO 500.00] TO BUS 100068 [SHEIKH 500.00]	100358	HAJISALAH	230	0.861	1.006
BUS 100032 [LAASCAANOD 500.00] TO BUS 100037 [GAROOWE 500.00]	100094	DUUSAMAREEB	132	0.893	0.968
BUS 100032 [LAASCAANOD 500.00] TO BUS 100037 [GAROOWE 500.00]	100097	GODINLABE	132	0.888	0.965
BUS 100032 [LAASCAANOD 500.00] TO BUS 100037 [GAROOWE 500.00]	100100	GURICEEL	132	0.893	0.969
BUS 100032 [LAASCAANOD 500.00] TO BUS 100037 [GAROOWE 500.00]	100208	CADAADO	132	0.888	0.965
BUS 100032 [LAASCAANOD 500.00] TO BUS 100037 [GAROOWE 500.00]	100376	CAABUDWAAQ	132	0.887	0.965
BUS 100032 [LAASCAANOD 500.00] TO BUS 100037 [GAROOWE 500.00]	100379	BALANBALE	132	0.893	0.969

5.3.4 Fault current study

Aim of this analysis is to assess the maximum short circuit currents in main S/S of the transmission networks of Somalia over the planning period 2030-2050.
Short circuit currents are determined for the buses of the main substations.
To define the maximum short circuit currents expected in the transmission system, the assessment has been executed:

- in peak load conditions,
- with all transmission elements in operation (N conditions),
- in accordance with the international standards IEC 60909.

The following quantities are calculated:

- initial symmetrical short-circuit current,
- peak short-circuit current,
- symmetrical short-circuit breaking current,
- decaying (aperiodic) component of short-circuit current (DC time constant of the breaking current).

5.3.4.1 Methodology

As known, a complete calculation of short-circuit currents should give the currents as a function of time at the short-circuit location from the beginning of the short-circuit event up to its end. In Figure 5-33 and Figure 5-34 I''k represents the initial symmetrical short-circuit current, ip represents the peak short-circuit current and Ik represents the steady-state short-circuit current. In our calculation, the attention will be concentrated on the initial symmetrical short-circuit current, which represents the main parameters for the identification of the circuit breakers and for the characteristics of the protection system.

In order to estimate the value of I''k, IEC 60909 standard adopts the following simplifications:

- for the duration of the short-circuit there is neither change in the type of short-circuit nor in the structure of the network,
- the impedance of the transformers is referred to the tap-changer in the main position,
- arc resistances are not taken into account,
- all line capacitances, shunt admittances, and non-rotating loads are neglected.

Furthermore, the contribution of rotating loads like synchronous or asynchronous motors is neglected, according to common experience in short-circuit analyses on transmission networks. According to IEC 60909 standard, the rotating loads contribution should be considered to evaluate the short circuit current near the motor itself. Indeed, since information about rotating loads is not available, it is assumed that motors present in the system are on the distribution network, so electrically far from the buses of transmission and sub-transmission network represented in the model under exam.

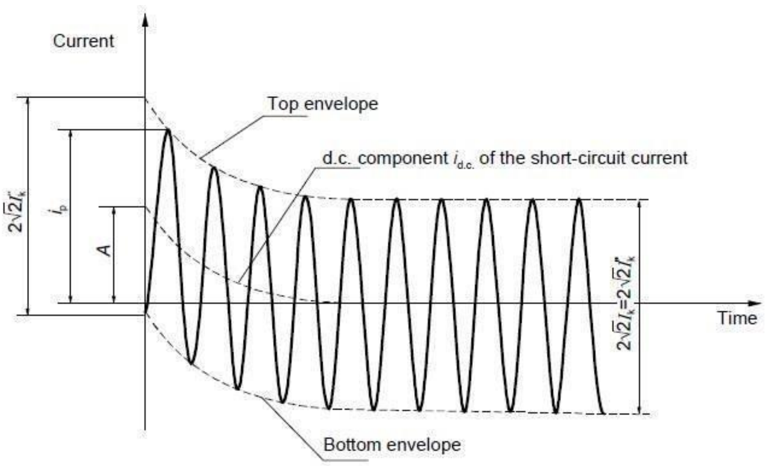


Figure 5-33 – Short-circuit current of a far-from-generator fault

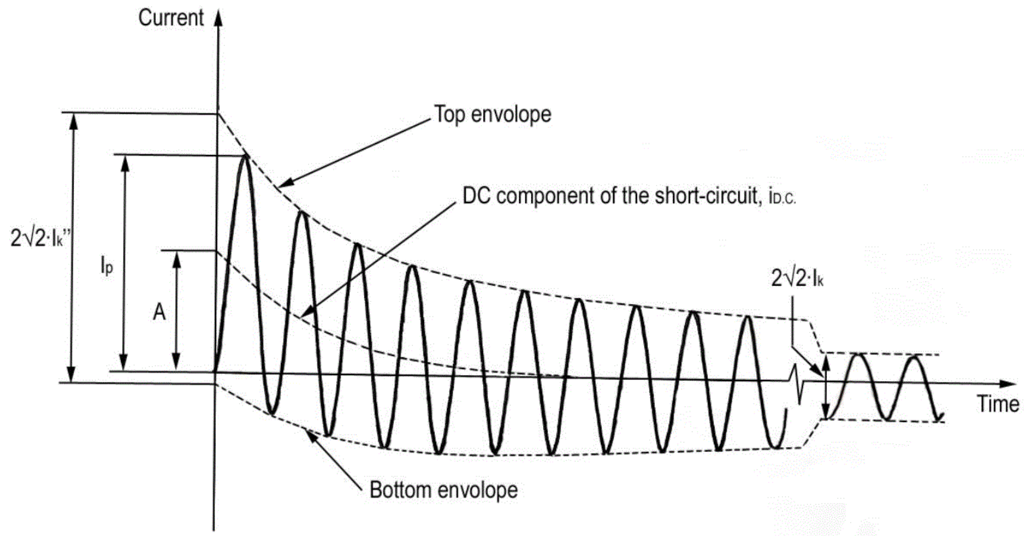


Figure 5-34 – Short-circuit current of a near-to-generator fault

The method used for the calculation is based on the introduction of an equivalent voltage source at the short-circuit location: this represents the only active voltage of the system since all network feeders, synchronous and asynchronous machines are replaced with their internal impedance. Furthermore, in three-phase AC systems the calculation of short-circuit currents is simplified using symmetrical components.

Figure 5-35 shows an example of the positive-sequence equivalent circuit obtained from a system diagram following the above-mentioned approach. An equivalent voltage source is placed at the short-circuit location "F" as the only active voltage of the system, the network feeder is represented by its internal impedance Zqt transferred to the LV-side of the transformer and the transformer is represented by its impedance referred to the LV-side. Line capacitances and passive loads are not considered in the equivalent circuit.

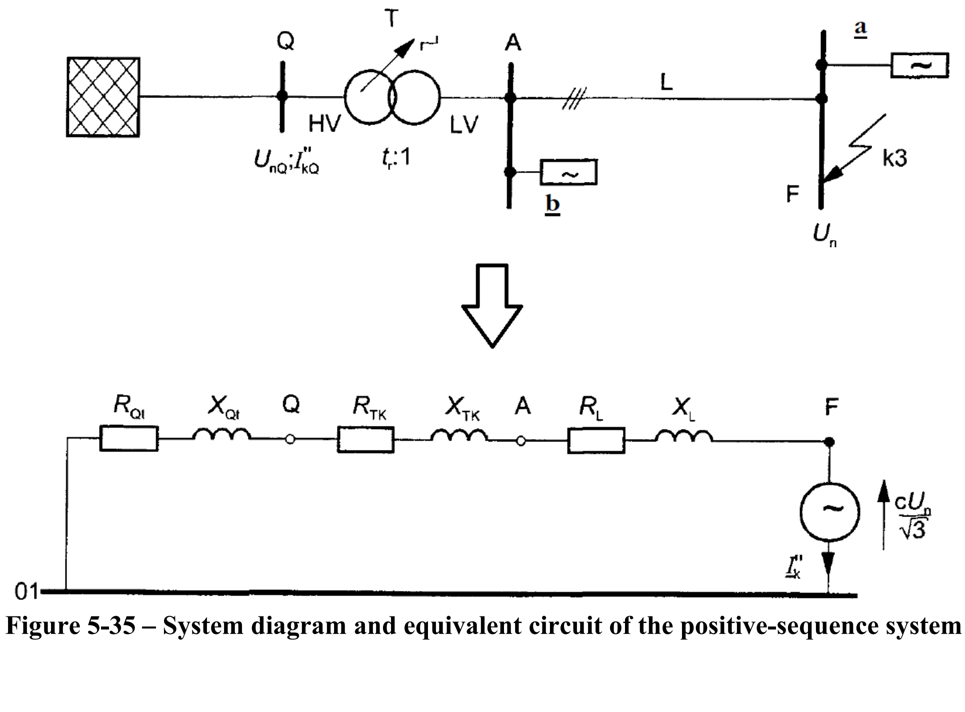


Figure 5-35 – System diagram and equivalent circuit of the positive-sequence system

In order to prudentially represent the state of the network, IEC 60909 suggests choosing a voltage factor "c" according to Table 5-13, considering that the highest voltage in a normal system does not differ, on average, by more than approximately +5%
(some LV systems) or +10% (some HV systems) from the nominal system voltage Un. Based on that, maximum short circuit analysis is performed using a c factor equal to 1.10, minimum short circuit analysis is performed using a c factor equal to 1.00.

Finally, IEC 60909 introduces impedance correction factors KG, KT, and KS when calculating short-circuit currents with the equivalent voltage source at the short-circuit location. These correction factors are applied to generators (G), network transformers (T) and power station units (S).

Table 5-13 - Forced and maintenance unavailability rates for Ethiopia and Somalia

Voltage factor *c*

Nominal voltage U_n	*Voltage factor c for the calculation of*	
	maximum short-circuit currents c_{max} [1)]	*minimum short-circuit currents* c_{min}
Low voltage 100 V *to* 1 000 V (IEC 60038, *table* I)	1,05[3)] 1,10[4)]	0,95
Medium voltage >1 kV *to* 35 kV (IEC 60038, *table* III)	1,10	1,00
High voltage[2)] >35 kV (IEC 60038, *table* IV)	1,10	1,00

(1) $c_{max}U_n$ should not exceed the highest voltage U_m for equipment of power systems.

(2) If no nominal voltage is defined $c_{max}U_n = c_{min}U_n = 90 \times U_m$ should be applied.

(3) For low-voltage systems with a tolerance of +6 %, for example systems renamed from 380 V to 400 V.

(4) For low-voltage systems with a tolerance of +10 %.

The PSS/E functionality called "activity IECS" allows to carry out short-circuit analyses in compliance with IEC60909. "Activity IECS" calculates the impedance correction factors, applies automatically the "c" factor for the maximum and minimum fault currents and performs the short-circuit analysis following the calculation method described above. For this purpose, "Activity IECS" neglects the following devices in positive and negative sequences: non-rotating loads, fixed and switched shunts, line charging susceptances.
Finally, "Activity IECS" allows either to consider or not the initial condition of the network considering (or not considering) the effect that the presence of shunts and/or loads has on the initial condition of the network.
As described at the beginning of this section, once the maximum short-circuit currents is known, then it is possible to check that current values are less than the opening capability of the installed equipment.
In the following paragraphs only the main results of the short circuit analysis are reported. The relevant maximum values for all network buses are reported in the ANNEX 4.1 – SHORT CIRCUIT RESULTS.

For Somalia, since a standard is not defined, short circuit currents are useful to understand the characteristics of the circuit breakers that shall be adopted in the future.

5.3.4.2 *Results for the target year 2030*

Considering the maximum short circuit current, the S/S associated to the main region capitals have always limited short circuit currents.

Bus Numbers	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100000	[MOGADISHU 500.00]	500	807.03	931.9	2620.8	1169.7	874.4
100001	[MOGADISHU 230.00]	230	845.93	2123.5	5976.3	2706	1965.8
100002	[MOGADISHU 132.00]	132	675.28	2953.6	8320.9	3843.3	2862.3
100014	[KISMAYO 500.00]	500	753.45	870	2429.4	942.9	823.3
100015	[KISMAYO 230.00]	230	745.74	1872	5233.9	2081.5	1766.1
100018	[HARGEISA 230.00]	230	379.38	952.3	2593.8	613	952.3
100019	[HARGEISA 132.00]	132	340.77	1490.5	4074.9	1036.7	1490.5
100037	[GAROOWE 500.00]	500	668.76	772.2	2149.6	775.3	738.5
100038	[GAROOWE 230.00]	230	477.83	1199.5	3354.1	1327.8	1196.8

Considering the minimum short circuit current, the following tables report the values calculated in the same operating conditions.

Bus Numbers	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100041	[BOSASO 500.00]	500	658.8	760.7	2118.8	790.6	722
100045	[QARDHO 500.00]	500	661.72	764.1	2125.8	763.2	729.4
100046	[QARDHO 230.00]	230	474.23	1190.4	3327.4	1311.1	1184.1
100033	[LAASCAANOD 230.00]	230	495.33	1243.4	3480.2	1404.6	1240.3
100047	[QARDHO 132.00]	132	369.53	1616.3	4529.5	1880.5	1616.3
100034	[LAASCAANOD 132.00]	132	382.22	1671.8	4690.3	1987.8	1671.8

5.3.4.3 *Results for the target year 2035*

Considering the maximum short circuit current, the S/S associated to the main region capitals have always limited short circuit currents.

Bus Numbers	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100000	[MOGADISHU 500.00]	500	1681	1941	5449	2347	1880
100001	[MOGADISHU 230.00]	230	1564	3927	11036	4883	3776
100002	[MOGADISHU 132.00]	132	1066	4663	13132	6039	4634
100014	[KISMAYO 500.00]	500	1214	1402	3829	1001	1369
100015	[KISMAYO 230.00]	230	1134	2845	7812	2237	2761
100054	[HARGEISA 500.00]	500	1115	1287	3591	1394	1259
100055	[HARGEISA 400.00]	400	1094	1579	4411	1743	1552
100018	[HARGEISA 230.00]	230	969	2432	6795	2724	2411
100019	[HARGEISA 132.00]	132	751	3286	9207	3874	3286
100037	[GAROOWE 500.00]	500	993	1147	3159	922	1124
100038	[GAROOWE 230.00]	230	623	1565	4352	1550	1565
100114	[BAIDOA 500.00]	500	1621	1872	5232	2070	1831
100115	[BAIDOA 230.00]	230	1168	2933	8197	3383	2925

Considering the minimum short circuit current, the following tables report the values calculated in the same operating conditions.

Bus Numbers	*Bus Name*	*Vnom [kV]*	*SC [MVA]*	*I''krms [A]*	*ip(B) [A]*	*DC IbC [A]*	*Sym Ib [A]*
100041	*[BOSASO 500.00]*	*500*	917	1059	2909	876	1026
100080	*[CEELDAHIR 500.00]*	*500*	938	1083	2978	893	1054
100076	*[ERIGAVO 230.00]*	*230*	427	1071	2887	582	1071
100072	*[BADHAN 230.00]*	*230*	539	1352	3699	985	1352
100077	*[ERIGAVO 132.00]*	*132*	340	1488	4048	971	1488
100118	*[MERCA 132.00]*	*132*	370	1620	4390	923	1620

5.3.4.4 Results for the target year 2040

Considering the maximum short circuit current, the S/S associated to the main region capitals have always limited short circuit currents.

Bus Numbers	*Bus Name*	*Vnom [kV]*	*SC [MVA]*	*I''krms [A]*	*ip(B) [A]*	*DC IbC [A]*	*Sym Ib [A]*
100000	*[MOGADISHU 500.00]*	*500*	3486	4025	11274	4653	3913
100001	*[MOGADISHU 230.00]*	*230*	2593	6509	18262	7980	6378
100002	*[MOGADISHU 132.00]*	*132*	1461	6391	17994	8333	6391
100014	*[KISMAYO 500.00]*	*500*	1952	2254	6057	1211	2221
100015	*[KISMAYO 230.00]*	*230*	1671	4195	11399	2742	4110
100054	*[HARGEISA 500.00]*	*500*	1830	2113	5822	1877	2090
100055	*[HARGEISA 400.00]*	*400*	1782	2572	7109	2393	2553
100018	*[HARGEISA 230.00]*	*230*	1600	4016	11127	3890	4008
100019	*[HARGEISA 132.00]*	*132*	1101	4817	13433	5248	4817
100037	*[GAROOWE 500.00]*	*500*	1901	2195	6038	1775	2183
100038	*[GAROOWE 230.00]*	*230*	1065	2674	7471	2943	2674
100114	*[BAIDOA 500.00]*	*500*	3041	3511	9707	3103	3480
100115	*[BAIDOA 230.00]*	*230*	2043	5128	14215	5100	5115

Considering the minimum short circuit current, the following tables report the values calculated in the same operating conditions.

Bus Numbers	*Bus Name*	*Vnom [kV]*	*SC [MVA]*	*I''krms [A]*	*ip(B) [A]*	*DC IbC [A]*	*Sym Ib [A]*
100041	*[BOSASO 500.00]*	*500*	1556	1797	4897	1341	1764
100198	*[EIL 500.00]*	*500*	1579	1823	4948	1144	1822
100076	*[ERIGAVO 230.00]*	*230*	617	1548	4120	657	1548
100220	*[WAJID 230.00]*	*230*	786	1973	5158	553	1970
100174	*[BUUHOODLE 132.00]*	*132*	238	1043	2779	404	1043
100186	*[XIINGALOOL 132.00]*	*132*	254	1109	2960	447	1109

5.3.4.5 *Results for the target year 2045*

Considering the maximum short circuit current, the S/S associated to the main region capitals have always limited short circuit currents even if more significant than in the previous target years.

Bus Numbers	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100000	[MOGADISHU 500.00]	500	6568	7584	21285	9262	7470
100001	[MOGADISHU 230.00]	230	6787	17037	48014	22709	15993
100002	[MOGADISHU 132.00]	132	2242	9805	27700	13596	9805
100014	[KISMAYO 500.00]	500	2500	2887	7661	1337	2849
100015	[KISMAYO 230.00]	230	2099	5268	14205	3129	5157
100054	[HARGEISA 500.00]	500	3595	4152	11381	3312	4152
100055	[HARGEISA 400.00]	400	3110	4488	12392	4021	4488
100018	[HARGEISA 230.00]	230	2440	6124	16975	5968	6124
100019	[HARGEISA 132.00]	132	1456	6368	17799	7223	6368
100037	[GAROOWE 500.00]	500	2698	3116	8391	1805	3109
100038	[GAROOWE 230.00]	230	1224	3071	8535	3098	3071
100114	[BAIDOA 500.00]	500	4698	5424	14763	3493	5422
100115	[BAIDOA 230.00]	230	2573	6459	17756	5695	6450

Considering the minimum short circuit current, the following tables report the values calculated in the same operating conditions.

Bus Numbers	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100285	[BARGAAL 500.00]	500	1627	1879	5014	1106	1872
100289	[GALKAYO 500.00]	500	1768	2041	5372	693	2041
100333	[DHOBLEY 230.00]	230	666	1671	4409	717	1640
100076	[ERIGAVO 230.00]	230	677	1699	4514	745	1699
100270	[BALLIDHIIG 132.00]	132	194	849	2242	266	849
100273	[QORILUGUD 132.00]	132	203	888	2346	285	888

5.3.4.6 *Results for the target year 2050*

Considering the maximum short circuit current, the S/S associated to the main region capitals have always limited short circuit currents even if more significant than in the previous target years.

Bus Numbers	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100000	[MOGADISHU 500.00]	500	8353	9645	26511	9330	9550
100001	[MOGADISHU 230.00]	230	7308	18344	51393	22861	17301
100002	[MOGADISHU 132.00]	132	2296	10041	28316	13631	10041
100014	[KISMAYO 500.00]	500	4765	5502	14983	4945	5475
100015	[KISMAYO 230.00]	230	5871	14738	40894	16195	13713
100054	[HARGEISA 500.00]	500	3966	4579	12397	3567	4579
100055	[HARGEISA 400.00]	400	3475	5016	13730	4431	5016
100018	[HARGEISA 230.00]	230	2856	7170	19774	6996	7170
100019	[HARGEISA 132.00]	132	1601	7001	19532	8023	7001
100037	[GAROOWE 500.00]	500	5411	6249	16538	2635	6249

100038	*[GAROOWE 230.00]*	*230*	1488	3734	10409	3963	3734
100114	*[BAIDOA 500.00]*	*500*	5408	6244	16692	3327	6243
100115	*[BAIDOA 230.00]*	*230*	2745	6891	18817	5606	6882

Considering the minimum short circuit current, the following tables report the values calculated in the same operating conditions.

Bus Numbers	***Bus Name***	***Vnom [kV]***	***SC [MVA]***	***I''krms [A]***	***ip(B) [A]***	***DC IbC [A]***	***Sym Ib [A]***
100361	*[BENDERBEILA 500.00]*	*500*	2722	3143	8181	933	3143
100198	*[EIL 500.00]*	*500*	3337	3854	10084	1436	3854
100285	*[BARGAAL 500.00]*	*500*	3476	4013	10773	2666	3995
100388	*[BURACHE 230.00]*	*230*	611	1534	3951	297	1534
100333	*[DHOBLEY 230.00]*	*230*	689	1729	4558	727	1699
100076	*[ERIGAVO 230.00]*	*230*	728	1827	4837	721	1827
100270	*[BALLIDHIIG 132.00]*	*132*	205	895	2357	264	895
100279	*[GARADAG 132.00]*	*132*	214	936	2474	360	936
100273	*[QORILUGUD 132.00]*	*132*	214	938	2472	284	938

5.3.4.7 Conclusions

Throughout the short circuit analysis performed for the different target years, it was possible to observe that SC power and currents are limited especially in the first years where the network is weak and not extremely developed. In the two final target years, a significant variation is visible, and it is worth noticing an increment in the SC power in the whole network.

5.4 Optimization of the future power system (generation and transmission)

Based on the results of the previous analyses, the objective of this section is to clearly identify physical generation and transmission line equipment and the sequence of their investments required for the generation development plan and the transmission master plan and the associated investment plan aiming at showing the yearly expenditure for each project/cluster of projects. The yearly expenditure is evaluated starting from the commissioning dates of the various projects and estimating the time for their implementation and the distribution of expenses over the time of implementation.

The costs that are considered include:

- The costs of power plants and associated further developments, subdivided by technology (renewable, conventional, hydro, geothermal, etc.) and for rate,
- The cost of the transmission lines,
- The cost of the transformers,
- The cost of the line and transformer bays,
- The costs of substations,
- The costs of Var compensation devices (reactors, SVCs, STATCOMs, capacitors, …),
- The costs of automation systems,
- The costs of all other relevant components.

The costs estimated in this section are the base for the cost-benefit analysis reported in the section 5.5.

5.4.1 Cost database for generation technologies

The table below presents the main sources consulted to gather the necessary data for the analysis. In cases where specific information was unavailable or incomplete, internal expertise and experience were used to fill the gaps and ensure consistency and reliability across all parameters.

Table 5-14: Sources

Sources		
Name	**Note**	**Link**
Lazard	For CAPEX, OPEXT, Lifetime	https://www.lazard.com/research-insights/levelized-cost-of-energyplus/
IEA		Net Zero by 2050 - A Roadmap for the Global Energy Sector

The tables below summarize the key technical and economic parameters required to evaluate the investment costs and operational performance of both thermal and renewable generation technologies. These parameters are essential inputs for long-term planning models and cost-benefit analyses.

The main characteristics considered include:

- Fuel type: The primary energy source used by the technology (e.g., diesel, natural gas, solar, wind).
- Capital Expenditure (CAPEX): Expressed in $/kW, this represents the upfront investment cost required to install one kilowatt of capacity.
- Fixed Operational Expenditure (Fixed OPEX): Annual fixed costs in $/kW/year, covering maintenance, staffing, and other non-variable expenses.
- Variable Operational Expenditure (Variable OPEX): Costs in $/MWh that vary with the amount of electricity generated, such as fuel and consumables.
- Thermal Efficiency: For thermal power plants, efficiency is expressed in Gcal/MWh, indicating the amount of fuel energy required to produce one megawatt-hour of electricity.
- Investment Lifetime: The expected operational lifespan of the asset.

For thermal power plants, a single CAPEX value is provided, reflecting current market estimates. In contrast, for renewable technologies (such as solar PV and wind) and battery energy storage systems (BESS), the analysis includes projected cost reductions over the planning horizon (2030–2050), in line with global technology learning curves and market trends.

Table 5-15: cost database for thermal power plants

Technology	size	Fuel	CAPEX	F-OPEX	V OPEX	η	Life
	MW	-	$/kW	$/kW/year	$/MWh	Gcal/MWh	Years
HSDG	1	Diesel	1440	10	10	2.23	8
Diesel MSDG 10 MW	10	Diesel	1500	10	5	2.05	10
HFO MSDG 10 MW	10	HFO	1500	10	5	2.10	10
HFO MSDG 20 MW	20	HFO	1400	10	5	2.00	10
Diesel OCGT	30	Diesel	1000	10	4	2.39	20
LNG OCGT 40 MW	40	LNG	1200	10	2	2.26	20
LNG OCGT 100 MW	100	LNG	1050	10	2	2.26	20
LFO OCGT 40 MW	40	LFO	1200	10	2	2.26	20
LFO OCGT 100 MW	100	LFO	1050	10	2	2.26	20
LNG CCGT 1+1 60 MW	60	LNG	1350	15	2	2.10	30
LNG CCGT 2+1 120 MW	120	LNG	1200	15	2	1.80	30
LNG CCGT 1+1 150 MW	150	LNG	1150	15	2	1.95	30
LNG CCGT 2+1 300 MW	300	LFO	1000	15	2	1.95	30
LFO CCGT 1+1 60 MW	60	LFO	1350	15	2	2.10	30
LFO CCGT 2+1 120 MW	120	LFO	1200	15	2	1.80	30
LFO CCGT 1+1 150 MW	150	LFO	1150	15	2	1.95	30
LFO CCGT 2+1 300 MW	300	LFO	1000	15	2	1.95	30
Coal	200	Coal	5000	50	5	2.39	30
Nuclear	300	Nuclear	10’000	120	10	2.46	60
Existing Hydro	4.6	-	100	10	1	80%	40
New Hydro	150	-	1000	10	1	80%	40

Table 5-16: cost database for renewable power plants

	CAPEX 2030	CAPEX 2040	CAPEX 2050	F-OPEX	V OPEX	Lifetime
	$/kW	$/kW	$/kW	$/kW/year	$/MWh	years
PV	700	650	500	7	0	25
Wind On shore	1500	1400	1300	20	0	30
Wind off shore	2200	2100	2000	50	0	30
BESS (4h)	800	480	360	0	0	15

5.4.2 Cost database for transmission grid facilities

Table 5-17 shows the details of the unitary investment costs for transmission equipment considered for the estimation of the investment costs for the transmission facilities.
The costs have been considered in line with the ones assumed in the Ethiopia-Somalia interconnection feasibility project [1].

Considering that Somalia does not have the transmission grid, no references for the costs of the components are available. This fact, of course, increases the uncertainties for the cost estimation of the new infrastructures, but these unitary costs represent in any case a valid reference for the estimation of the total costs of the transmission expansion plan.
Comparing the costs of the lines in single and double circuit configuration, it is possible to note that the least-cost solution is obtained considering the single-circuit configuration.

Table 5-17 – Unit investment costs for transmission equipment

Equipment	Unit	Total cost (USD'000)
Transmission lines		
500 kV single circuit quad Condor	km	511
230 kV single circuit twin Ash	km	313
132 kV single circuit Ash	km	237
500 kV double circuit quad Condor	km	787
230 kV double circuit twin Ash	km	450
132 kV double circuit Ash	km	330
Transformers		
500/230kV 500MVA	Transformer	6300
500/230kV 250MVA	Transformer	5500
500/230kV 150MVA	Transformer	4500
230/132kV 250MVA	Transformer	4300
230/132kV 150MVA	Transformer	3200
230/33kV 100MVA	Transformer	3000
230/33kV 50MVA	Transformer	2580
132/33kV 100MVA	Transformer	2500
Switchgear		
500kV switchgear	circuit	4190
230kV switchgear	circuit	1500
132kV switchgear	circuit	850
Reactive compensation		
reactor	Mvar	15
capacitor bank	Mvar	25

5.4.3 Investment plan for generation expansion

The table below reports the outcomes of the optimal generation expansion plan in terms of new installed capacity. The values are consistent with the revised demand forecast scenario (baseline growth).

Table 5-18 – Outcomes of the optimal generation expansion plan in terms of new installed capacity

MW	HSDG	MSDG	Diesel OCGT	LNG OCGT	LNG CCGT	Hydro	WTE	BESS	PV	WND
2030	5	20	0	0	0	4.6	0	5	160	0
2031	18	0	0	100	0	0	0	15	38	40
2032	0	10	0	100	0	0	0	10	73	14
2033	2	0	0	0	300	0	0	20	33	18
2034	2	0	0	100	0	0	0	5	28	7
2035	0	0	0	200	0	150	10	10	38	8
2036	0	10	0	0	600	0	0	15	21	67
2037	-6	20	30	0	300	0	0	5	61	38
2038	-7	0	0	0	0	0	0	45	11	69

MW	HSDG	MSDG	Diesel OCGT	LNG OCGT	LNG CCGT	Hydro	WTE	BESS	PV	WND
2039	-8	20	30	0	300	0	0	20	45	33
2040	0	0	60	0	300	0	10	0	12	56
2041	0	20	0	100	0	0	0	20	45	195
2042	0	0	0	0	300	0	0	40	103	342
2043	-2	0	15	0	300	0	0	5	12	239
2044	0	0	0	0	0	0	0	60	30	469
2045	-4	0	0	0	300	0	0	35	520	430
2046	0	0	30	0	0	0	0	125	610	405
2047	0	0	30	0	0	0	0	280	870	380
2048	0	0	0	0	0	0	0	0	650	360
2049	0	0	0	0	0	0	0	450	450	173
2050	0	0	0	0	0	0	0	105	300	287

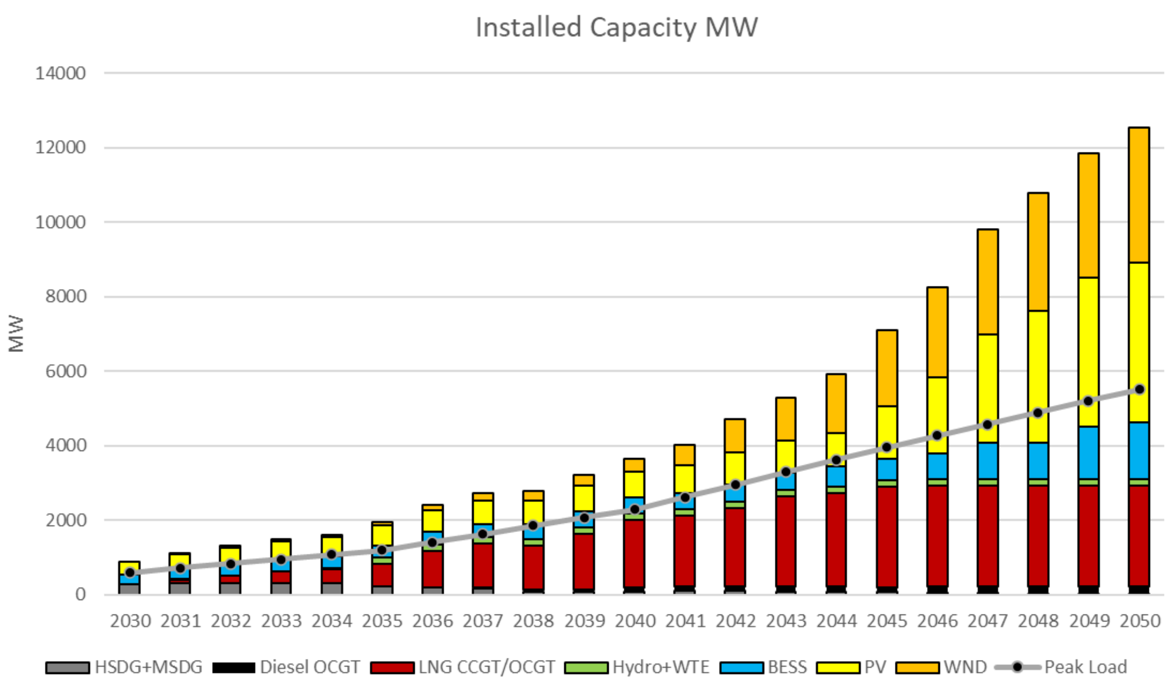


Figure 5-36: Yearly installed capacity

Based on the optimal installed capacity identified through the generation expansion analysis, it is possible to evaluate the total expected investment costs.

The total system costs presented in this analysis have already been adjusted to reflect the expected Weighted Average Cost of Capital (WACC) and inflation rates over the planning horizon. This adjustment ensures that all investment and operational expenditures are expressed in real economic terms, allowing for a more accurate and consistent comparison across different scenarios and timeframes.

By incorporating WACC, the analysis accounts for the time value of money and the opportunity cost of capital, which are critical for evaluating long-term infrastructure investments. Similarly, adjusting for inflation ensures that cost projections are not distorted by changes in purchasing power, enabling a realistic assessment of future financial commitments.

Table 5-19: Financial assumptions, reference scenario

Financial assumptions	
Inflation Rate	2.0%
WACC (nominal)	10.0%
WACC real (includes inflation)	7.8%

Table 5-20: CAPEX and OPEX disbursement – reference scenario (values not actualized)

Year	CAPEX [M$]	OPEX [M$]	TOTAL [M$]
2030	578	575	1153
2031	218	585	803
2032	189	627	816
2033	148	454	602
2034	131	350	481
2035	455	219	675
2036	679	242	921
2037	327	275	602
2038	102	304	406
2039	411	342	753
2040	486	394	880
2041	433	443	876
2042	710	439	1149
2043	615	479	1095
2044	671	695	1367
2045	1052	773	1825
2046	936	854	1790
2047	1071	915	1987
2048	790	998	1788
2049	591	1131	1722
2050	561	1349	1910
TOTAL	**11157**	**12443**	**23600**

5.4.4 Investment plan for transmission expansion

Based on the unitary costs of the transmission components reported in the paragraph 5.4.2, the objective of this paragraph is to provide the sequence of investments, in terms of transmission lines and substations, for each target year, and the associated value of expenditures.

5.4.4.1 Transmission Lines short/mid-term period

Table 5-21, Table 5-22 and Table 5-23 report respectively the list of the transmission lines expected for the target year 2030, 2035 and 2040.

More in detail, the expected investment costs amount to:

- USD 808.5 million up to the target year 2030
- USD 309.6 million for the period 2031 – 2035

- USD 531.1 million for the period 2036 – 2040

The total expected investment costs for the short/mid-term period amount to: USD 1,644.6 million for the transmission lines.

Table 5-21 – Transmission lines: sequence of investments and associated investment costs up to 2030

Year	Vnom [kV]	Line	Length [km]	Type	M$
2030	500	Berbera-Burao	125	Single circuit	63.88
2030	500	Burao-Laascaanod	250	Single circuit	127.75
2030	500	Laascaanod-Garoowe	130	Single circuit	66.43
2030	500	Garoowe-Qardho	185	Single circuit	94.54
2030	500	Qardho-Bosaso	220	Single circuit	112.42
2030	500	Mogadishu-Afgooye	40	Single circuit	20.44
2030	500	Afgooye-Baraawe	180	Single circuit	91.98
2030	500	Baraawe-Kismayo	250	Single circuit	127.75
2030	500	Mogadishu-Jowhar	95	Single circuit	48.55
2030	230	Hargeisa-Burao	175	Single circuit	54.78
		TOTAL 2030 [M$]			**808.50**

Table 5-22 – Transmission lines: sequence of investments and associated investment costs period 2031-2035

Year	Vnom [kV]	Line	Length [km]	Type	M$
2035	230	Hargeisa-Gabiley	55	Single circuit	17.22
2035	230	Gabiley-Boroma	60	Single circuit	18.78
2035	230	Gabiley-Wajaale	35	Single circuit	10.96
2035	230	Ceeldahir-Badhan	85	Single circuit	26.61
2035	230	Badhan-Erigavo	110	Single circuit	34.43
2035	230	Jowhar-Jalalaqsi	75	Single circuit	23.48
2035	230	Jalalaqsi-BuloBurti	60	Single circuit	18.78
2035	230	BuloBurti-Beletweyne	110	Single circuit	34.43
2035	230	Baidoa-Xudur	125	Single circuit	39.13
2035	230	Baidoa-Dinsoor	115	Single circuit	36.00
2035	132	Galkayo-Abaarey	35	Single circuit	8.30
2035	132	Galkayo-Bandiiradley	65	Single circuit	15.41
2035	132	Duusamareeb-Godinlabe	45	Single circuit	10.67
2035	132	Duusamareeb-Guriceel	65	Single circuit	15.41
		TOTAL 2035 [M$]			**309.56**

Table 5-23 – Transmission lines: sequence of investments and associated investment costs period 2036-2040

Year	Vnom [kV]	Line	Length [km]	Type	M$
2040	500	Garoowe-Eil	165	single circuit	84.32
2040	230	Berbera-BulloXaar	65	single circuit	20.35
2040	230	Baidoa-Buurhakaba	60	single circuit	18.78
2040	230	Xudur-Wajid	80	single circuit	25.04
2040	230	Dinsoor-Bardheere	80	single circuit	25.04
2040	230	Jilib-Buale	90	single circuit	28.17
2040	230	Jilib-Afmadow	80	single circuit	25.04
2040	230	Kismayo-BulloXaaji	75	single circuit	23.48
2040	132	Boroma-Quljeed	30	single circuit	7.11

Year	Vnom [kV]	Line	Length [km]	Type	M$
2040	132	Boroma-Baki	30	single circuit	7.11
2040	132	Wajaale-Kalabeydh	20	single circuit	4.74
2040	132	Kalabeydh-Dilla	20	single circuit	4.74
2040	132	Gabiley-Arabsiyo	15	single circuit	3.56
2040	132	Arabsiyo-Abaarso	15	single circuit	3.56
2040	132	Hargeisa-BalliCabane	60	single circuit	14.22
2040	132	Hargeisa-Awbarkhadle	30	single circuit	7.11
2040	132	Burao-Oodweyne	55	single circuit	13.04
2040	132	Laascaanod-Widhwidh	70	single circuit	16.59
2040	132	Widhwidh-Buuhoodle	50	single circuit	11.85
2040	132	Laascaanod-Oog	80	single circuit	18.96
2040	132	Laascaanod-Xudun	100	single circuit	23.7
2040	132	Qardho-XiinGalool	100	single circuit	23.7
2040	132	Qardho-Taleh	100	single circuit	23.7
2040	132	Qardho-Yake	30	single circuit	7.11
2040	132	Ceeldahir-Armo	10	single circuit	2.37
2040	132	Badhan-Hadaaftimo	30	single circuit	7.11
2040	132	Beletweyne-Matabaan	70	single circuit	16.59
2040	132	Jowhar-Qalimow	25	single circuit	5.93
2040	132	Mogadishu-Balcad	35	single circuit	8.3
2040	132	Dollow -Luuq	65	single circuit	15.41
2040	132	Dollow -BeledHawo	40	single circuit	9.48
2040	132	Galkayo-Galdogob	60	single circuit	14.22
2040	132	Abaarey-Bacaadweyn	15	single circuit	3.56
2040	132	Godinlabe-Cadaado	30	single circuit	7.11
		TOTAL 2040 [M$]			**531.05**

5.4.4.2 Transmission Long-term period

Table 5-24 and Table 5-25 report respectively the list of the transmission lines expected for the target year 2045 and 2050.

More in detail, the expected investment costs amount to:

- USD 780.6 million up to the period 2041 – 2045
- USD 623.3 million for the period 2046 – 2050

The total expected investment costs for the long-term period amount to: USD 1,444.7 million for the transmission lines.

Table 5-24 – Transmission lines: sequence of investments and associated investment costs period 2041-2045

Year	Vnom [kV]	Line	Length [km]	Type	M$
2045	500	Bosaso-Bargaal	215	single circuit	109.87
2045	500	Garoowe-Galkayo	220	single circuit	112.42
2045	500	Jowhar-Maxaas	200	single circuit	102.20
2045	500	Maxaas-Duusamareeb	130	single circuit	66.43
2045	230	BulloXaar-Lughaya	60	single circuit	18.78
2045	230	Xudur-Beletweyne	195	single circuit	61.04
2045	230	BulloXaaji-Burgabo	75	single circuit	23.48
2045	230	Afmadow-Qoqani	50	single circuit	15.65
2045	230	Qoqani-Dhobley	85	single circuit	26.61

Year	Vnom [kV]	Line	Length [km]	Type	M$
2045	132	Quljeed-Bown	15	single circuit	3.56
2045	132	Bown-Xariirad	35	single circuit	8.3
2045	132	Lughaya-GarboDadar	60	single circuit	14.22
2045	132	Hargeisa-Darasalaam	35	single circuit	8.3
2045	132	Awbarkhadle-Dacarbudhuq	30	single circuit	7.11
2045	132	Dacarbudhuq-Madheera	25	single circuit	5.93
2045	132	BalliCabane-Faraweyne	35	single circuit	8.3
2045	132	BalliCabane-Baligubadle	25	single circuit	5.93
2045	132	Buuhoodle-Ballidhiig	50	single circuit	11.85
2045	132	Buuhoodle-Qorilugud	40	single circuit	9.48
2045	132	Oog-Caynabo	25	single circuit	5.93
2045	132	Erigavo-CeelAfweyn	85	single circuit	20.15
2045	132	CeelAfweyn-GarAdag	65	single circuit	15.41
2045	132	Bacaadweyn-Xarfo	20	single circuit	4.74
2045	132	Xarfo-Burtinle	40	single circuit	9.48
2045	132	Abaarey-Bursaalax	35	single circuit	8.3
2045	132	BuloBurti-Halgan	40	single circuit	9.48
2045	132	BuloBurti-Buqdaaqable	45	single circuit	10.67
2045	132	Mogadishu-Warsheikh	60	single circuit	14.22
2045	132	Qalimow-Hawadley	15	single circuit	3.56
2045	132	Afgooye-Wanlaweyn	60	single circuit	14.22
2045	132	Merca-Qoruooley	30	single circuit	7.11
2045	132	Buurhakaba-Beerdale	35	single circuit	8.3
2045	132	Dinsoor-Qansaxdheere	60	single circuit	14.22
2045	132	Luuq-Garbahaarey	65	single circuit	15.41
		TOTAL 2045 [M$]			**780.57**

Table 5-25 – Transmission lines: sequence of investments and associated investment costs period 2046-2050

Year	Vnom [kV]	Line	Length [km]	Type	M$
2050	500	Qardho-BenderBeila	200	single circuit	102.2
2050	500	Duusamareeb-Baxdo	100	single circuit	51.1
2050	500	Baxdo-Galkayo	110	single circuit	56.21
2050	230	Lughaya-Zeila	95	single circuit	29.74
2050	230	Burao-HajiSalah	120	single circuit	37.56
2050	230	Galkayo-Garacad	210	single circuit	65.73
2050	230	Baxdo-Obbia	155	single circuit	48.52
2050	230	Maxaas-Mareeg	155	single circuit	48.52
2050	230	Xudur-Eelbarde	85	single circuit	26.61
2050	230	Buale-Bardheere	130	single circuit	40.69
2050	230	Bardheere-BurAche	160	single circuit	50.08
2050	132	Zeila-Lawyacado	25	single circuit	5.93
2050	132	Lughaya-Geerisa	60	single circuit	14.22
2050	132	Faraweyne-Alleybadey	20	single circuit	4.74
2050	132	Baligubadle-Salaxley	25	single circuit	5.93
2050	132	Duusamareeb-Balanbale	70	single circuit	16.59
2050	132	Cadaado-Caabudwaaq	45	single circuit	10.67
2050	132	Garbahaarey-Buurdhuubo	35	single circuit	8.3
		TOTAL 2050 [M$]			**623.30**

5.4.4.3 Substations Short/Mid-term period

Table 5-26, Table 5-27 and Table 5-28 report respectively the list of substations expected for the target year 2030, 2035 and 2040.
More in detail, the expected investment costs amount to:

- USD 238.8 million up to the target year 2030
- USD 329.1 million for the period 2031 – 2035 for new substations and upgrades of existing ones
- USD 265.0 million for the period 2036 – 2040 for new substations and upgrades of existing ones

The total expected investment costs for the short/mid-term period amount to: USD 796.7 million for the substations.

Table 5-26 – Substations: sequence of investments and associated investment costs up to 2030

Substation	*M$*
Afgooye 500/230/132 kV	29.72
Baraawe 500/230 kV	25.32
Kismayo 500/230 kV	21.13
Burao 500/230/132 kV	31.22
Laascaanod 500/230/132 kV	29.72
Garoowe 500/230 kV	25.32
Qardho 500/230/132 kV	29.72
Bosaso 500/230 kV	21.13
Jowhar 500/230/132 kV	25.53
TOTAL 2030 [M$]	**238.81**

Table 5-27 – Substations: sequence of investments in new substations and associated investment costs period 2031-2035

Substation	*M$*
Mogadishu South 500/230/132 kV	47.46
Jilib 500/230 kV	25.32
Ceeldahir 500/230/132 kV	31.22
Merca 500/230/132 kV	29.72
Sheikn 500/230 kV	25.32
Jalalaqsi 230/33 kV	9.75
BuloBurti 230/132 kV	14.15
Beletweyne 230/132 kV	12.65
Badhan 230/132 kV	14.15
Erigavo 230/132 kV	12.65
Gabiley 230/132 kV	15.65
Boroma 230/132 kV	12.65
Wajaale 230/132 kV	12.65
Xudur 230/33 kV	8.25
Dinsoor 230/33 kV	8.25
BeledHawo 132/33 kV	6.45
Duusamareeb 132/33 kV	7.30
Godinlabe 132/33 kV	6.45
Guriceel 132/33 kV	6.45
Galkayo 132/33 kV	7.30
Abaarey 132/33 kV	6.45

Substation	***M$***
Bandiiradley 132/33 kV	6.45
TOTAL 2035 [M$]	**326.69**

Table 5-28 – Substations: sequence of investments in new substations and associated investment costs period 2036-2040

Substation	***M$***
Eil 500/230 kV	21.13
Buurhakaba 230/132 kV	12.35
Wajid 230/33 kV	7.83
Bardheere 230/33 kV	7.83
Buale 230/33 kV	8.25
Afmadow 230/33 kV	8.25
BulloXaaji 230/33 kV	8.25
BulloXaar 230/33 kV	7.83
Qalimow 132/33 kV	6.15
Balcad 132/33 kV	6.15
Luuq 132/33 kV	6.15
Matabaan 132/33 kV	6.15
Cadaado 132/33 kV	6.15
Galdogob 132/33 kV	6.15
Bacaadweyn 132/33 kV	6.15
Yake 132/33 kV	6.15
XiinGalool 132/33 kV	6.15
Taleh 132/33 kV	6.15
Armo 132/33 kV	6.15
Hadaaftimo 132/33 kV	6.15
Oodweyne 132/33 kV	6.15
Xudun 132/33 kV	6.15
Oog 132/33 kV	6.15
Widhwidh 132/33 kV	7.00
Buuhoodle 132/33 kV	6.15
Kalabeydh 132/33 kV	7.00
Dilla 132/33 kV	6.15
Arabsiyo 132/33 kV	7.00
Abaarso 132/33 kV	6.15
BalliCabane 132/33 kV	6.15
Awbarkhadle 132/33 kV	6.15
Quljeed 132/33 kV	6.15
Baki 132/33 kV	6.15
TOTAL 2040 [M$]	**238.02**

5.4.4.4 Substations Long-term period

Table 5-29 and Table 5-30 report respectively the list of the substations expected for the target year 2045 and 2050.
More in detail, the expected investment costs amount to:

- USD 373.5 million up to the period 2041 – 2045 for new substations and upgrades of existing ones

- USD 177.1 million for the period 2046 – 2050 for new substations and upgrades of existing ones

The total expected investment costs for the long-term period amount to: USD 546.4 million for the substations.

Table 5-29 – Substations: sequence of investments in new substations and associated investment costs period 2041-2045

Substation	*M$*
Mogadishu North 500/230/132 kV	47.46
Maxaas 500/230 kV	25.32
Bargaal 500/230 kV	21.13
Lughaya 230/132 kV	13.50
Burgabo 230/33 kV	8.25
Qoqani 230/33 kV	9.75
Dhobley 230/33 kV	8.25
Hawadley 132/33 kV	6.45
Wanlaweyn 132/33 kV	6.45
Qoruooley 132/33 kV	6.45
Beerdale 132/33 kV	6.45
Garbahaarey 132/33 kV	6.45
Qansaxdheere 132/33 kV	6.45
Warsheikh 132/33 kV	6.45
Halgan 132/33 kV	6.45
Buqdaaqable 132/33 kV	6.45
Bursaalax 132/33 kV	6.45
Xarfo 132/33 kV	7.30
Burtinle 132/33 kV	6.45
CeelAfweyn 132/33 kV	7.30
GarAdag 132/33 kV	6.45
Qorilugud 132/33 kV	6.45
Ballidhiig 132/33 kV	6.45
Caynabo 132/33 kV	6.45
Faraweyne 132/33 kV	6.45
Baligubadle 132/33 kV	6.45
Dacarbudhuq 132/33 kV	7.30
Madheera 132/33 kV	6.45
Darasalaam 132/33 kV	6.45
Bown 132/33 kV	7.30
Xariirad 132/33 kV	6.45
GarboDadar 132/33 kV	6.45
TOTAL 2045 [M$]	**298.31**

Table 5-30 – Substations: sequence of investments in new substations and associated investment costs period 2046-2050

Substation	*M$*
Baxdo 500/230 kV	26.82
BenderBeila 500/230 kV	21.13
Zeila 230/132 kV	13.50
Eelbarde 230/33 kV	7.83
BurAche 230/33 kV	7.83

Substation	*M$*
Mareeg 230/33 kV	7.83
Obbia 230/33 kV	8.25
Garacad 230/33 kV	8.25
HajiSalah 230/33 kV	8.25
Buurdhuubo 132/33 kV	6.15
Balanbale 132/33 kV	6.15
Caabudwaaq 132/33 kV	6.15
Alleybadey 132/33 kV	6.15
Salaxley 132/33 kV	6.15
Geerisa 132/33 kV	6.15
Lawyacado 132/33 kV	6.15
TOTAL 2045 [M$]	**152.74**

5.4.4.5 Total capital expenditures

Table 5-31 summarizes the expected expenditures related to the investment costs for the transmission facilities.
Note: the cost estimation here reported does not include the investment costs of the interconnections with Ethiopia, as well as the costs of other interconnections with neighbouring countries.

Table 5-31 – Cost estimation for transmission facilities – CAPEX subdivision

	Capital Expenditure [M$]					
	2030	2035	2040	2045	2050	**TOTAL**
Transmission Line	808.50	309.56	531.05	780.57	623.30	**3052.98**
Substations	238.81	329.04	265.01	373.54	177.06	**1383.46**
TOTAL	**1047.31**	**638.60**	**796.06**	**1154.11**	**800.36**	

Figure 5-37 reports the expected behaviour of the cumulative investment expenditures over the planning period, from 2030 to 2050, including both transmission lines and S/S. as it is possible to see, the expected investment disbursements for the transmission facilities are expected to be quite distributed over the planning period.

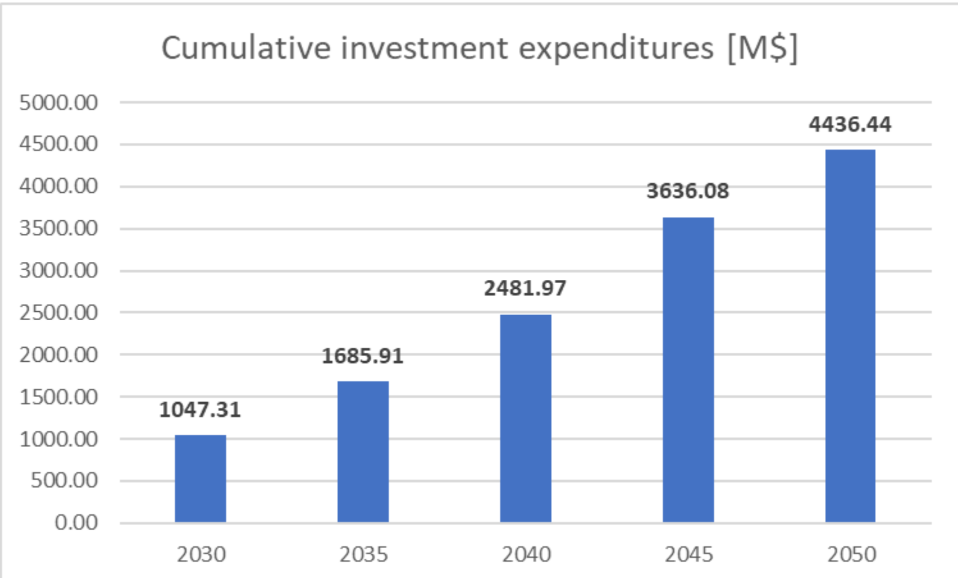


Figure 5-37 – Cumulative investment expenditures [M$]

5.4.4.6 *Total operational expenditures*

Two types of operational costs shall be considered:

- The fixed operational and maintenance (O&M) costs, calculated as a percentage of the investment costs,
- The cost of losses, whose economic value shall reflect the generation production cost of the power system.

Focusing the attention on the fixed operational and maintenance (O&M) costs, Table 5-32 reports the cumulative quantification of these costs assuming a total value of 1%/year of the total CAPEX.

Table 5-32 – O&M Cost estimation for transmission facilities – cumulative quantification

	Cumulative O&M Expenditure [M$/year]				
	2030	2035	2040	2045	2050
Transmission Line	8.09	11.18	16.49	24.30	30.53
Substations	2.39	5.68	8.33	12.06	13.83
TOTAL	**10.47**	**16.86**	**24.82**	**36.36**	**44.36**

5.4.4.7 *Costs of the interconnections with Ethiopia*

The values here reported are based on the calculations performed in the framework of the Ethiopia-Somalia interconnection feasibility project.
The subdivision of the Project costs for all infrastructures necessary for the full operation of the new Ethiopia – Somalia northern interconnection between countries is reported here below.

Table 5-33 – Cost estimation - Total CAPEX for country – Northern interconnection

Project costs	Somalia
AC Double circuit line	172,550
Hargeisa S/S	67,200
Berbera S/S	36,100
Rural electrification	2,800
Consultancy Supervision Services	9113
Regional coordination & monitoring	1139
Contingencies	41378
Total Project Costs for Somalia	**330,280**

From the figures reported in the previous tables, it is possible to note that the expected Project costs are well subdivided between the two countries, since:

- Ethiopia has approximately the 54.3% of the total project costs
- Somalia has approximately the 45.7% of the total project costs

In terms of operation expenditures, about US$ 6.1 million of O&M costs are expected for each year of the project lifetime.

The subdivision of the Project costs for all infrastructures necessary for the full operation of the new Ethiopia – Somalia southern interconnection between countries is reported here below.

Table 5-34 – Cost estimation - Total CAPEX for country – Southern interconnection

Project costs	Somalia
AC Double circuit line	282,300
Dollow S/S	52,450
Baidoa S/S	28,400
Mogadishu S/S	46,540
Rural electrification	2,000
Consultancy Supervision Services	12,781
Regional coordination & monitoring	1,598
Contingencies	57,779
Total Project Costs for Somalia	**483,848**

From the figures reported in the previous table, it is possible to note that the expected Project costs are mainly associated to Somalia because of the costs of S/S. More precisely:

- Ethiopia has approximately the 36.2% of the total project costs
- Southern Line has approximately the 63.8% of the total project costs

In terms of operation expenditures, about US$ 6.4 million of O&M costs are expected for each year of the project lifetime.

5.5 Overall cost-benefit analysis

The purpose of this section is to perform an overall cost-benefit analysis of the grid master plan through the following steps:

a) Estimation of the investment and operational costs related to the generation and transmission grid infrastructures
b) Estimation of the benefits arising from the identified power system development.
c) Evaluation of the typical economic indexes, such as:
    - The Net Present Value (NPV),
    - The Economic Internal Rate of Return (IRR),
    - The Benefit/Cost Ratio (B/C) of the proposed project.

Actually, considering that this project is referred to the development of the whole power system of Somalia (Generation and Transmission infrastructures), the cost-benefit analysis is performed considering the system as a whole, so like a cluster of projects that cannot be identify and evaluated individually, but all together to reach the objectives of such investments, i.e., the economic growth of the country, the increase of the social welfare and the improvement of the life quality for the population.

5.5.1 Methodology and assumptions

5.5.1.1 Overall objectives

The development of the transmission grid in Somalia, including the interconnections with neighbouring countries, presents a series of technical and technological challenges. Nevertheless, potential benefits, such as the availability of electricity, the enhancement of power trade, the integration of Somalia into EAPP and the mitigation of geopolitical risks of supply, all provide strong incentives to assess the opportunity to deploy these critical infrastructures.
Key economic benefit stems from the flexibility of building new power plants at favourable locations, promote the massive development of renewable generation to be used for internal consumption and for export, and possibility to use more economical power plants with most favourable energy resources based on economic exchange. As a result, the development of a structured electric power system allows optimum use of available resources and reduces the need for investment in peak capacity. Improved power systems reliability in comparison with the current situation consisting in the presence of several isolated grids will increase the electricity availability, the quality of service and a reduction in power interruptions. It may also permit the introduction of bigger size units in the power system, including both conventional and renewables, thereby capturing economies of scale and creating many new job opportunities for local communities.
Investment in generation and transmission capacity generally increases the total sum of the individual surpluses by enabling a larger proportion of demand to be met by cheaper generation units that were not available before development.

This sub-section describes the methodology, assumptions and results of the overall cost-benefit analyses that have been carried out based on the data provided from market simulation analysis.

5.5.1.2 Methodology

Economic analysis of generation/transmission development is conducted from the perspective of the national economy of Somalia through a comparison of the project economic costs with project economic benefits. The economic analysis, including measures such as Economic Internal Rate of Return (EIRR), Economic Net Present Value (ENPV) and Benefit to Cost Ratio (BCR) is based on streams of benefits and costs, to be identified and quantified in the best possible way, resulting from the installation and operations of the project components, over their economic lives.

The main methodological benchmark adopted in this analysis is represented by the ENTSO-E Guidelines for Cost Benefit Analysis of Grid Development Projects.
The ENTSO-E Guidelines include, for the scope of computing the economic indicators of the project, three main categories of items: Benefits, Costs and Residual Impacts, see Figure below.

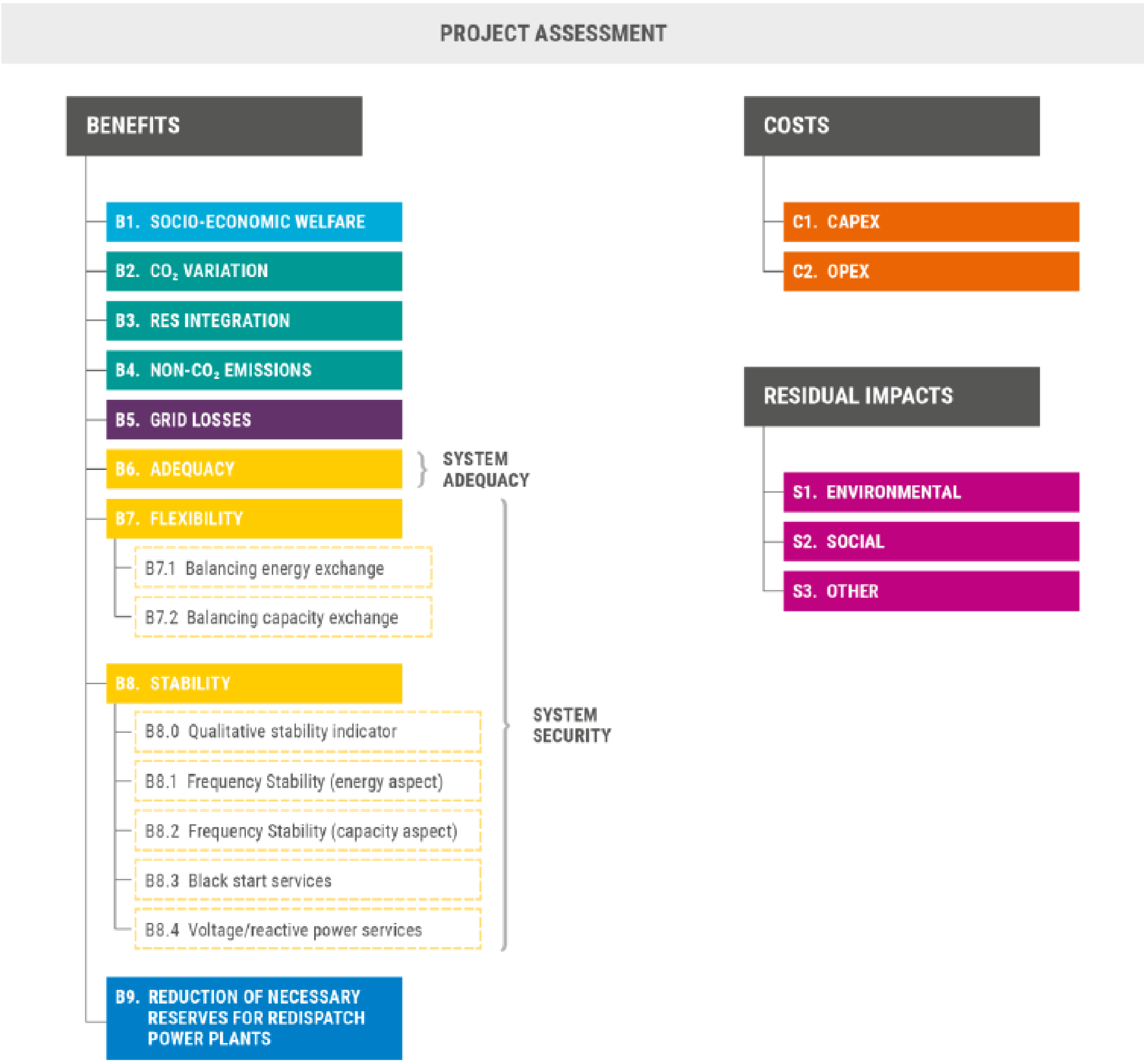


Figure 5-38: ENTSO-E indicators, 2024.

Benefits describe the positive contributions made by the project. Costs describe the cost of the project or investment, i.e., CAPEX and OPEX. Residual Impacts describe the impacts of investments that are not addressed by any of the identified mitigation measures. This to ensure that all measurable costs associated are considered, without any double counting.

The Project costs (outflows) include all the Project related costs, including physical costs (such as capital costs during installations, including design and project management costs, projected operation and maintenance costs) and other costs over the economic life of the project components. The potential project benefits are estimated over the expected economic life (40 years) by comparing the situations with-project and without-project, or alternatively by estimating incremental net gains due to the proposed project.

In alignment with the ENTSO-E Guidelines, the key expected **Economic Benefits** from the Project include the following:

- **B1–Socio-Economic Welfare (SEW)**. The project makes it possible to increase commercial exchanges, so that electricity markets can trade power in a more economically efficient manner. This benefit is the Socio-Economic Welfare (SEW) provided by the project and is expressed in millions of dollars a year. It is calculated as the sum of the short-run economic surpluses of electricity consumers, producers, and transmission owners. The main benefit is quantified in accordance with the ENTSO-E, i.e., Socio-Economic Welfare (SEW) that is measured through the following benefits:
  - Change in social economic welfare based on total surplus approach, where the producer and the consumer surplus for the bidding areas of interest, as well as the congestion rent between them, are calculated with and without the project. This evaluation is carried out in the market study analysis and monetized in this analysis. The total SEW benefit for each year is calculated for the period lifespan of 25 years.
  - In the context of our analysis, we use the results of the **Least Cost Generation and Transmission Expansion Plans**.
- **B2–CO2 Variation**. It is a consequence of changes in generation dispatch and the unlocking of renewable generation potential. CO2 emissions, the main greenhouse gas produced by the electricity sector, and other GHG emissions are displayed, and monetary benefit of their reductions is described using societal costs for carbon.
  - In the context of our analysis, we use the results of the **Least Cost Generation and Transmission Expansion Plans**.
- **B–6 Adequacy**. Adequacy to meet demand is characterized by the project's impact on the ability of a power system to provide an adequate supply of electricity to meet demand over an extended period. Adequacy metrics are computed, including the expected energy not served.
  - In the context of our analysis, we use the results of the **Least Cost Generation and Transmission Expansion Plans.**
- **Other benefits and impacts** of a project. Although ENTSO-E guidelines intend to monetize as many of the indicators as possible, in some cases the required data is not always available or quantifiable. For the scope of this analysis:
  - **B3–RES Integration**. This specific component is not included, as per modelling assumption. The generation expansion is consistently described via the Base Case + Scenario Modelling, as input data for the power flow simulations.
  - **B4–Non-CO2 Emissions**. This category of emissions (e.g. COX, NOX, SOX, PM 2, 5, 10) is not included. However, given the reduction of HFO and diesel generation in Somalia, this benefit is qualitatively highlighted.
- **B9 Reduction of necessary reserves**: the development of interconnections with other countries allows the reduction of generation investments the quantification of the economic benefits due to due avoided CAPEX/OPEX is reported in this analysis.

The key expected Costs from the Project include the following:

- **C1–Capital expenditures** (CAPEX) comprise the cost of equipment, installation and civil works, system commissioning, etc.; these are cost that will be under the EPC contracts and are included in the analysis; costs of preparation, implementation, including for conducting feasibility studies as well as additional studies, seabed survey, obtaining rights-of-way, ground, preparatory work, designing, etc. that are typically under Owner responsibility are not included in the computation.
- **C2–Operating and maintenance expenditures** (OPEX or O&M costs) include the annual operating and maintenance expenses associated with the investment and expressed in dollars per year.

All costs and benefits are expressed and evaluated at constant prices.

Residual impact indicators refer to the impacts that remain after impact mitigation measures have been taken. These generally represent additional negative (or cost) components. The indicators, defined as follows, are not included in the computation:

- **S1–Residual Environmental Impact** refers to the (residual) project impact on the environment and aims to provide a measure of the environmental sensitivity related to the project. This shall be overall evaluated in the Environmental & Social Study, but it is not monetized in this analysis.
- **S2–Residual Social impact** refers to the (residual) project impact on the (local) population affected by the project and aims to provide a measure of the social sensitivity associated with the project.
- **S3–Other Impacts** represent the remaining indicators of all other impacts of a project.

5.5.1.3 Other assumptions

Modelling assumption used in this economic analysis are the following:

- Constant price approach, economic figures are expressed in US dollars real terms.
- Base Year 2025.
- Commissioning Year of the first projects 2030.
- Project Economic Life 25 years, with a residual value of the project of an additional 25 years.
- CAPEX instalment schedule planned across years uniformly spread in the four years before the implementation of the projects operated in a certain target year.
- Forecasted costs and benefits for each investment are represented annually. The benefits are accounted for from the first year after commissioning.
- No Taxation assumption. The impact of taxation is not considered in the project economic assessments, so the values are to be represented as pre-tax values.
- The Shadow Cost of Carbon has been taken as per ENTSO-E guidelines.
- Discount Rate: the economic discount rate of 7.8% in real terms has been used for the base case of the economic analysis, considering the accelerated economic growth of Somalia.

5.5.2 Economic benefits

The four monetized benefits of the generation/transmission projects were estimated as follows.

5.5.2.1 Socio-Economic Welfare (SEW): Benefit B1

Change in social economic welfare was measured using the total surplus approach where producer and consumer surplus for the market areas of interest.

- The Surplus to Producers is the difference between the System Marginal Price (SMP) received for each unit of electricity produced and the Short Run Marginal Cost (SRMC) of producing that unit of electricity as represented by the upward sloping supply curve.
- The Surplus to Consumers is the total electricity demand in a country multiplied by the difference between the Value of Lost Load (VoLL) and the System Marginal Price – SMP for electricity.

The sum of these two elements yields the Total SEW.

The cost-benefit analysis is a differential analysis; hence the value of the power system development is the difference in the SEW without the generation/transmission system and the SEW with the generation/transmission system.

To carry out the economic analysis, which is based on marginal cost curves and SMP, we need to make some assumptions on hourly equilibrium; this implies the creation of a load duration curve within each stage. To do this, there are two options: the first one is to keep a constant load level within each time stage; the second one is to create a load profile based on the load factor of all active generating units within the stage. If we have a power plant that has a load factor of 20%, then in the first case we imagine that it has produced all hours of the period, well below its full capacity. In the second option, instead, we make the hypothesis that it has operated at full capacity, hence it has produced only a certain number of hours. The tables below represent the different outcome of these two options in terms of SMP.

Table 5-35: Option 1 for the load duration curve within a stage

UNIT	MWH	MC	MW	HOURS
Fuel oil	10	150 $/MWh	5	10
HP	100	5 $/MWh	10	10
Implicit hourly equilibrium				
Demand		11		
Fuel oil		1		
HP		10		
AVERAGE SMP		**150 $/MWH**		

In this first case, we imagine that the fuel oil plant produces all the hours within the stage. This implies that it sets the prices all the hours within the period. Hence, the average SMP of the stage is equal to the marginal cost of the fuel oil and precisely 0.15 $/kWh.

In the second case, instead, the fuel oil plant produces at full capacity for 2 hours; then it stops. This implies a peak demand within the block of 15 MW for 2 hours and then a demand of 10 in the other eight hours. Hence, in the remaining hours the price is set by the hydropower plant and the average SMP of the stage is 0.034 $/kWh.

Table 5-36: Option 2 for the load duration curve within a stage

UNIT	LOAD FACTOR	HOURS
Fuel oil	20%	2
Hydro Power	100%	10
Hourly equilibrium first 2 hours		
Demand	15	
Fuel oil	5	
Hydro Power	10	
SMP	150 $/MWh	
Hourly equilibrium other 8 hours		
Demand	10	
Hydro Power	10	
SMP	5 $/MWh	
AVERAGE SMP	**34 $/MWH**	

Below we show the two different load duration curves. Using the second approach, we can calculate a load-factor based weighted average SMP for each 12 stages within a year, which is the starting value for computing welfare in all scenarios under consideration.

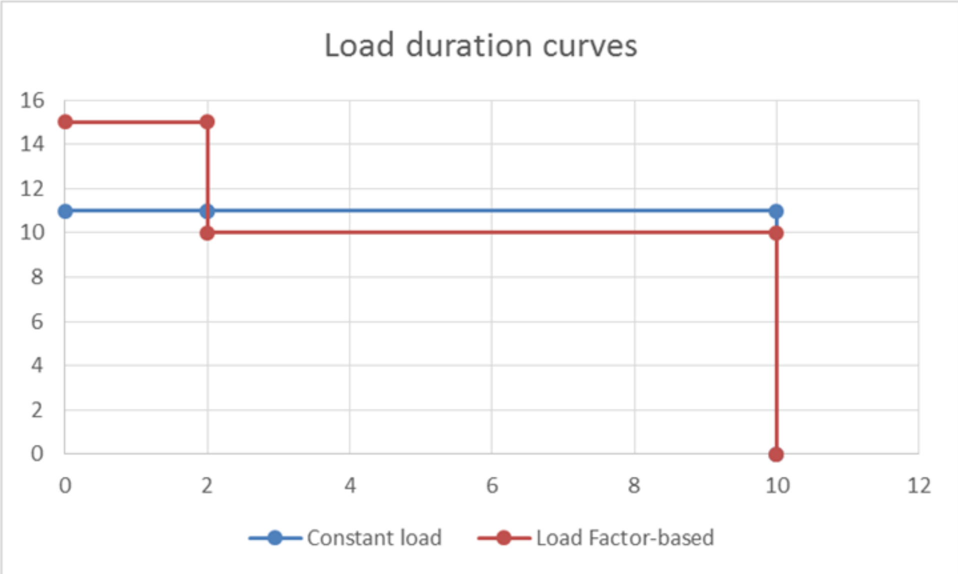


Figure 5-39: Hypothesis on the load duration curves within each stage

5.5.2.2 Societal benefit due to net GHG reductions: Benefit B2

Greenhouse gas (GHG) emissions refer to the change in CO2 and non-CO2 emissions (e.g., COX, NOX, SOX, PM 2.5, 10) in the power system due to the project. They are a consequence of changes in generation dispatch and the unlocking of renewable generation potential.
The direct CO2 emissions from the generation mix and dispatching schedule were calculated in the Generation Expansion.
The data on costs of carbon used for the purposes of economic analysis were taken from the most recent ENTSO-E / TYNDP document.

For the economic analysis, the social cost of carbon has been used, and the values are presented in the graph below.

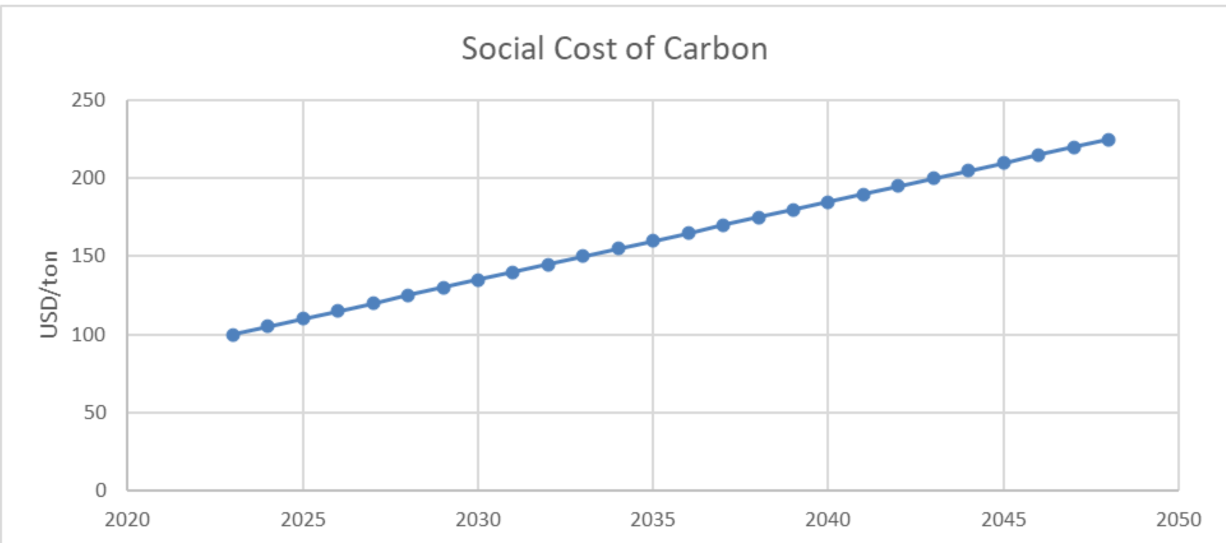


Figure 5-40: Evolution of the Social Cost of Carbon. EPA, 2024.

5.5.2.3 *Security of Supply (Adequacy): Benefit B6*

The development of a national generation and transmission grid, including the development of interconnections with neighbouring countries, reduces the EENS. The Value of lost load to monetize the expected energy not served is determined at 400 $/MWh, considered to be the full generation cost of an independent diesel gen-set.

5.5.2.4 *Reduction of necessary reserves (avoided investments): Benefit B9*

The results of the simulations performed in the framework of the Ethiopia-Somalia interconnection project [1] indicate that part of the generation investments can be avoided thanks to the development of the transmission system, and in particular of the interconnections with Ethiopia.
The outcomes in terms of economic benefits, implemented in the CBA, are reported in the following table:

Table 5-37: Avoided investments in Somalia

PLANT NAME	PP TYPE	PP FUEL	CAPACITY		
			MW	USD Million	Year avoided
SL_MSD4	MSD	Diesel_SL	10	15	2028
SL_MSD5	MSD	Diesel_SL	5	7.75	2028
SL_MSD6	MSD	Diesel_SL	5	7.75	2028
SL_MSD7	MSD	Diesel_SL	5	7.75	2028
SL_MSD8	MSD	Diesel_SL	5	7.75	2028
SL_MSD9	MSD	Diesel_SL	5	7.75	2028
SL_MSD10	HSDG	Diesel_SL	5	7.75	2028
HSDG 1	HSDG	Diesel_SL	30	45	2025
HSDG 2	HSDG	Diesel_SL	5	7.5	2037
HSDG 3	HSDG	Diesel_SL	10	14	2037
MSD 1	MSD	Diesel_SL	30	45	2033
MSD 7	MSD	Diesel_SL	30	45	2029
MSD 9	MSD	Diesel_SL	20	30	2033
PL_HSDG5	HSDG	Diesel_PN	0.5	0.85	2025
PL_HSDG6	HSDG	Diesel_PN	0.5	0.85	2025
HR_HSDG2	HSDG	Diesel_HR	0.5	0.85	2025
SW_MSD2	MSD	LFO_HR	20	28	2028
SW_MSD3	MSD	Diesel_SW	5	7.75	2028
SW_MSD4	MSD	Diesel_SW	5	7.75	2028
SW_HSDG9	HSDG	Diesel_SW	2	3	2028
SW_HSDG10	HSDG	Diesel_SW	2	3	2028
MSD 6	MSD	Diesel_SW	25	38.75	2030
MSD 4	MSD	Diesel_JB	30	45	2032
MSD 5	MSD	Diesel_JB	40	60	2033
TOTAL			**294**	**443.8**	

5.5.2.5 *Other benefits: Specific issues concerning increased availability of electricity in rural areas*

Developing an economic analysis that includes the development of a generation/transmission systems in area without or with a limited access to electricity implies the quantification of economic benefits associated with the increase availability and reliability of electricity-related services in rural areas.

In fact, the electrification of rural areas brings about not just a reduction of energy costs (e.g. the switch from kerosene lamps to electric bulbs or the switch from diesel generation to grid), but it also increases the quantity and quality of many electricity-related services (electric lighting is better in terms of luminosity than other options), their availability (lumen/hours increase), while reducing negative effects of less advanced energy sources (e.g. smoke, smell and noise).

The increase in quality and quantity of these services brings an increase in people's utility: better lighting means that children can study at night or that people feel safer walking around the village. Increased energy availability means that people can use refrigerators, can watch TV for longer hours, etc.…

In terms of economic activities in rural areas, electrification allows for increased productivity. For instance, cheaper water pumping and storage of fresh produce increase the value of agricultural activities.

The following paragraphs illustrate how electricity enables a wide range of services that increase people's well-being[6].

Figure 5-41: Services and benefits derived from electricity use7.

The benefits derived from these services can be quantified and monetized and hence summed up together to determine the benefits of the connection of rural areas to the main grid. Below, we provide few examples of how these benefits can be converted into money.

Lighting: Its value may be evaluated in terms of quality (measured in Lumen-Flux provided by a fluorescent lamp with respect to a candle) or in terms of reliability (being connected to the grid means having a continuous provision of the service). Moreover, together with an improved service, the dweller will enjoy an increase in real income due to the lower cost of the service and higher efficiency.

Education: It is a long-term consequence of lighting. In fact, children gain more flexibility in timing as they can better keep-up with peers. It follows that enrolment rates to the secondary school are higher

[6] Source: Meier, P., Peter, V., Barnes, D. F., Bogach, S. V., & Farchy, D. (2010). Peru: National survey of rural household energy use.
[7] Source: Woodruff, A. (2007). An economic assessment of renewable energy options for rural electrification in Pacific Island Countries. Suva: SOPAC, 2007.

whenever students have access to reliable electricity. Moreover, energy access allows schools to be equipped with modern technologies, providing a better service.

Communication and entertainment: With the advent of cheaper energy access, television is more accessible to consumers. Their value may be estimated by the increase time of usage. Grid electricity also makes easier charging mobile phones easing communication and empowering rural businesses.

Productivity: businesses are empowered through the time-saving resulting from the use of electrical appliances. Per unit of output, electrified enterprises expenditure on energy is significantly lower.

Health: Improvements in health levels are a consequence of a multitude of factors. For instance, the possibility to operate water pumps allows an increase in hygienic standards; the reduced use of kerosene lamps, instead, reduces respiratory illnesses, relieving private and public healthcare.

Hence, it is clear that it is fundamental to take all these benefits into account when performing a cost benefit analysis for projects including the electrification of rural areas and the increasing of the electrification rate of the country. This can be possible if and only if we can forecast how household will change their behaviour once they have electricity from the grid.

5.5.3 Cost-benefit analysis

The previous section provided a theoretical overview of the cost-benefit analysis (CBA) framework commonly adopted at the international level to assess infrastructure investments. In the specific context of Somalia, a tailored quantification has been carried out to estimate the total achievable benefits of implementing a coordinated generation and transmission expansion plan.

The analysis is based on a comparative approach between two scenarios:

3. Reference Scenario: This scenario includes all planned investments in generation and transmission infrastructures, as defined by the optimal expansion strategy. It accounts for the full spectrum of capital expenditures (CAPEX) and operational expenditures (OPEX) associated with new generation technologies (including renewables and flexible thermal units), as well as the costs of developing and reinforcing the transmission network.
4. Business-as-Usual (BAU) Scenario: In this counterfactual scenario, no coordinated expansion plan is implemented. Instead, the expected load growth is assumed to be met exclusively through the deployment of Medium-Speed Diesel Generators (MSDGs). These units are characterized by relatively high fuel costs and emission factors. The BAU scenario includes only the CAPEX and OPEX of MSDGs, with no additional investment in transmission infrastructure.

5.5.3.1 First model: Reference scenario supplied by local generation

By comparing the total system costs and emissions between these two scenarios, the analysis aims to quantify the economic and environmental benefits of pursuing a structured and forward-looking expansion strategy. These benefits include:

- Reduced fuel consumption and operating costs
- Lower greenhouse gas emissions
- Improved system reliability and resilience
- Enhanced integration of renewable energy sources

Assumptions are reported in table below.

Table 5-38: assumption for the cost benefit analysis – first model

MSDG CAPEX	$/kW	1500
MSDG efficienry	Gcal/MWh	2.05

Diesel CO2 emissions	t/Gcal	0.33
CO2 costs	$/ton	80
ENS costs	$/MWh	1000
ENS with only MSDG	% of load	0.01%
ENS with gull development of G&T	% of load	0.0001%

The associated investment and operational costs of the As Usual scenario are the following:

Table 5-39: investment and operational costs of the As Usual scenario - first model (actualized values)

Year	CAPEX [M$]	OPEX [M$]	CO2 emissions [M$]	ENS [M$]	Transmission [M$]	NPC [M$]
2030	491	627	176	3.4	0	1 298
2031	199	697	196	3.8	0	1 095
2032	610	774	212	4.1	0	1 600
2033	343	833	225	4.3	0	1 405
2034	688	874	235	4.5	0	1 801
2035	451	908	242	4.7	0	1 605
2036	914	997	266	5.1	0	2 182
2037	711	1073	284	5.5	0	2 075
2038	1 083	1136	299	5.8	0	2 525
2039	890	1185	310	6.0	0	2 391
2040	1 144	1222	318	6.2	0	2 690
2041	1 052	1312	338	6.5	0	2 709
2042	1 250	1377	354	6.8	0	2 988
2043	1 158	1441	365	7.1	0	2 972
2044	1 306	1480	373	7.2	0	3 167
2045	1 205	1504	378	7.3	0	3 094
2046	1 306	1523	378	7.3	0	3 214
2047	1 208	1549	376	7.3	0	3 140
2048	1 284	1535	373	7.2	0	3 199
2049	1 190	1516	368	7.1	0	3 081
2050	1 247	1495	361	7.0	0	

The associated investment and operational costs of the Reference scenario are the following:

Table 5-40: investment and operational costs of the Reference scenario - first model (actualized values)

Year	CAPEX Gen [M$]	OPEX Gen [M$]	CO2 emissions [M$]	ENS [M$]	CAPEX Transmission [M$]	NPC [M$]
2027 2030	578	575	146	0.03	1047	2 346
2031	203	542	126	0.04	439	871
2032	163	539	108	0.04		810
2033	118	363	75	0.04		556
2034	97	259	45	0.05		401

<table>
<tr><th>Year</th><th>CAPEX Gen [M$]</th><th>OPEX Gen [M$]</th><th>CO2 emissions [M$]</th><th>ENS [M$]</th><th>CAPEX Transmission [M$]</th><th>NPC [M$]</th></tr>
<tr><td>2035</td><td>313</td><td>151</td><td>30</td><td>0.05</td><td></td><td>932</td></tr>
<tr><td>2036</td><td>433</td><td>154</td><td>30</td><td>0.05</td><td rowspan="5">376</td><td>618</td></tr>
<tr><td>2037</td><td>193</td><td>163</td><td>36</td><td>0.05</td><td>392</td></tr>
<tr><td>2038</td><td>56</td><td>167</td><td>44</td><td>0.06</td><td>267</td></tr>
<tr><td>2039</td><td>209</td><td>174</td><td>52</td><td>0.06</td><td>435</td></tr>
<tr><td>2040</td><td>229</td><td>186</td><td>59</td><td>0.06</td><td>850</td></tr>
<tr><td>2041</td><td>190</td><td>194</td><td>64</td><td>0.07</td><td rowspan="5">374</td><td>448</td></tr>
<tr><td>2042</td><td>288</td><td>178</td><td>62</td><td>0.07</td><td>529</td></tr>
<tr><td>2043</td><td>232</td><td>180</td><td>66</td><td>0.07</td><td>478</td></tr>
<tr><td>2044</td><td>235</td><td>243</td><td>87</td><td>0.07</td><td>564</td></tr>
<tr><td>2045</td><td>341</td><td>251</td><td>90</td><td>0.07</td><td>1 056</td></tr>
<tr><td>2046</td><td>281</td><td>257</td><td>84</td><td>0.07</td><td rowspan="5">178</td><td>622</td></tr>
<tr><td>2047</td><td>299</td><td>255</td><td>84</td><td>0.07</td><td>639</td></tr>
<tr><td>2048</td><td>204</td><td>258</td><td>88</td><td>0.07</td><td>551</td></tr>
<tr><td>2049</td><td>142</td><td>272</td><td>94</td><td>0.07</td><td>507</td></tr>
<tr><td>2050</td><td>125</td><td>300</td><td>106</td><td>0.07</td><td>710</td></tr>
</table>

Table 5-41: Cost and Benefit comparison for the Reference scenario - first model (actualized values)

Year	Cost	Benefit	Cost-Benefit
2027-2030	- 2 346	1 298	- 1 049
2031	- 871	1 095	224
2032	- 810	1 600	790
2033	- 556	1 405	849
2034	- 401	1 801	1 400
2035	- 932	1 605	673
2036	- 618	2 182	1 564
2037	- 392	2 075	1 683
2038	- 267	2 525	2 258
2039	- 435	2 391	1 956
2040	- 850	2 690	1 841
2041	- 448	2 709	2 262
2042	- 529	2 988	2 459
2043	- 478	2 972	2 494
2044	- 564	3 167	2 602
2045	- 1 056	3 094	2 038
2046	- 622	3 214	2 592
2047	- 639	3 140	2 502
2048	- 551	3 199	2 648
2049	- 507	3 081	2 573
2050	- 710	3 110	2 401

In order to assess the economic viability of infrastructure investments—such as generation and transmission projects—three key financial indicators are commonly used:

- Net Present Value (NPV): represents the difference between the present value of all expected benefits (cash inflows) and the present value of all costs (cash outflows) over the lifetime of a project, discounted using a specified rate (typically the Weighted Average Cost of Capital, or WACC). A positive NPV indicates that the project is expected to generate net economic value and is therefore considered financially viable.
- Internal Rate of Return (IRR): is the discount rate at which the NPV of a project becomes zero. It represents the expected annualized rate of return generated by the investment. If the IRR exceeds the discount rate (WACC), the project is considered economically attractive. IRR is particularly useful for comparing projects with different scales or durations.
- Benefit-Cost Ratio (B/C): The Benefit-Cost Ratio is the ratio between the present value of total benefits and the present value of total costs. If B/C > 1, the project delivers more benefits than costs and is considered economically justified. If B/C < 1, the project is not cost-effective.

These metrics provide a quantitative basis for comparing alternative scenarios and prioritizing projects based on their expected economic performance.

Table 5-42: Results of the cost-benefit analysis - first model

NPV [M$]	36,760
Benefit/Cost	3.52
IRR	64%

As it is possible to see, the economic figures obtained by this first approach determine significant benefits, for Somalia, due to the investments in generation and transmission infrastructures.

5.5.3.2 Second model: monetization of the additional electricity consumption

The second approach quantify the economic benefits considering the following assumptions:

- Without the investments in generation and transmission facilities, the electricity consumption remains the ones quantified in the BAU scenario of the load forecast analysis, supplied by diesel and a limited PV capacity,
- With the investments in generation and transmission facilities, the electricity consumption is the one considered in the previous Reference Scenario, supplied by the generation mix identified in the generation expansion plan,
- Without considering the monetization of the CO2 emissions.

The benefits in this case are:

- The economic growth rate of the country, due to the availability of electricity, as well as benefits in terms of education health, life quality, etc.
- Lower specific greenhouse gas emissions
- Improved system reliability and resilience
- Enhanced integration of renewable energy sources

The data related to the BAU scenario, in terms of demand, generation supply and generation costs are reported in the following table.

Table 5-43: Data of the BAU scenario - second model (values not actualized)

Year	Demand BAU		Generation		
	GWh	MW	Investment cost M$	PV generation [GWh]	Operational cost [M$]
2025	642	113	0	315.4	98
2026	687	121	11.9	315.4	111
2027	735	129	12.7	315.4	126
2028	786	138	13.5	315.4	141
2029	843	148	15.0	315.4	158
2030	900	158	15.0	315.4	175
2031	964	170	16.9	332.9	189
2032	1,031	181	17.7	341.6	207
2033	1,103	194	19.0	354.8	224
2034	1,181	208	20.6	374.5	242
2035	1,264	222	21.9	404.1	258
2036	1,350	238	22.7	448.4	270
2037	1,447	255	25.6	501.6	284
2038	1,549	273	26.9	576.1	292
2039	1,655	291	28.0	654.4	300
2040	1,771	312	30.6	756.0	304
2041	1,895	334	32.7	844.2	315
2042	2,028	357	35.1	950.0	323
2043	2,172	382	38.0	1076.9	329
2044	2,323	409	39.9	1153.0	351
2045	2,485	437	42.8	1236.8	374
2046	2,660	468	46.2	1328.9	399
2047	2,844	501	48.6	1430.3	424
2048	3,044	536	52.8	1541.8	451
2049	3,257	573	56.2	1664.4	478
2050	3,485	613	60.2	1799.3	506

The data referred to the Reference scenario are reported in the following table. These values have been obtained:

- Monetizing the increase of the electricity consumption equal to 400 $/MWh, representative of the above-mentioned benefits coming from the development of generation and transmission infrastructures
- Considering the progressively exclusion of the investments in the diesel generation required in the BAU scenario and the associated operational costs

Table 5-44: Data of the Reference scenario - second model (values not actualized)

	Net Supplied Demand	Losses	Dconsump	Benefit Energy	Benefit Investment diesel	Benefit operational diesel	Total benefit
year	GWh	GWh	GWh	M$	M$	M$	M$
2025	642	108	0	0	0	0	0
2026	687	115	0	0	0	0	0
2027	735	122	0	0	0	0	0
2028	787	127	1	0	0	0	0

	Net Supplied Demand	Losses	Dconsump	Benefit Energy	Benefit Investment diesel	Benefit operational diesel	Total benefit
year	GWh	GWh	GWh	M$	M$	M$	M$
2029	843	134	0	0	0	0	0
2030	3 031	364	2 131	852	1.0	11.7	865
2031	3 662	417	2697.6	1079	2.3	25.2	1107
2032	4 284	478	3253.2	1301	3.5	41.4	1346
2033	4 898	548	3794.8	1518	5.1	59.9	1583
2034	5 496	633	4315.4	1726	6.9	80.7	1814
2035	6 039	774	4775	1910	8.8	103.2	2022
2036	7 175	884	5824.6	2330	10.6	126.2	2467
2037	8 298	1006	6851.2	2740	13.7	151.3	2905
2038	9 416	1 134	7866.8	3147	16.2	175.1	3338
2039	10 504	1 291	8849.4	3540	18.7	200.1	3759
2040	11 551	1 490	9780	3912	22.5	223.3	4158
2041	13 291	1 654	11395.6	4558	26.2	252.2	4837
2042	15 001	1 847	12973.2	5189	30.4	280.3	5500
2043	16 652	2 100	14479.8	5792	35.5	306.6	6134
2044	18 375	2 280	16052.4	6421	39.9	351.0	6812
2045	20 058	2 501	17573	7029	42.8	374.5	7446
2046	21 667	2 657	19006.8	7603	46.2	399.3	8048
2047	23 227	2 862	20382.6	8153	48.6	424.1	8626
2048	24 874	2 979	21830.4	8732	52.8	450.7	9236
2049	26 497	3 121	23240.2	9296	56.2	477.8	9830
2050	28 097	3 286	24612	9845	60.2	505.7	10411

The results of this second approach for the quantifications of the economic viability of the Somalia investments in generation and transmission facilities are the following:

Table 5-45: Results of the cost-benefit analysis - second model

NPV [M$]	17,319
Benefit/Cost	2.779
IRR	37.1%

As it is possible to see, also the economic figures obtained by this second approach determine significant benefits, for Somalia, due to the investments in generation and transmission infrastructures.

5.6 ANNEX 4.1 – SHORT CIRCUIT RESULTS

In this paragraph, short circuit results are reported for the all the buses of the whole network for each target year. They are grouped by voltage levels starting from the highest value to the lowest one.

Short circuit results for the whole network – target year 2030

Bus Number	*Bus Name*	*Vnom [kV]*	*SC [MVA]*	*I''krms [A]*	*ip(B) [A]*	*DC IbC [A]*	*Sym Ib [A]*
100000	*[MOGADISHU 500.00]*	*500*	807.03	931.9	2620.8	1169.7	874.4
100005	*[AFGOOYE 500.00]*	*500*	800.48	924.3	2596.6	1131	869
100010	*[BARAAWE 500.00]*	*500*	775.9	895.9	2507.2	1008	847.1
100014	*[KISMAYO 500.00]*	*500*	753.45	870	2429.4	942.9	823.3
100027	*[BURAO 500.00]*	*500*	689.01	795.6	2223.6	877.9	757.7
100022	*[BERBERA 500.00]*	*500*	685.18	791.2	2211.5	880.3	751.5
100032	*[LAASCAANOD 500.00]*	*500*	676.35	781	2176.6	804.6	746.6
100037	*[GAROOWE 500.00]*	*500*	668.76	772.2	2149.6	775.3	738.5
100045	*[QARDHO 500.00]*	*500*	661.72	764.1	2125.8	763.2	729.4
100041	*[BOSASO 500.00]*	*500*	658.8	760.7	2118.8	790.6	722
100001	*[MOGADISHU 230.00]*	*230*	845.93	2123.5	5976.3	2706	1965.8
100015	*[KISMAYO 230.00]*	*230*	745.74	1872	5233.9	2081.5	1766.1
100023	*[BERBERA 230.00]*	*230*	683.48	1715.7	4802.1	1961.3	1618.3
100042	*[BOSASO 230.00]*	*230*	660.2	1657.2	4621.9	1767.5	1563
100006	*[AFGOOYE 230.00]*	*230*	621.99	1561.3	4392.7	1972.9	1534
100050	*[JOWHAR 230.00]*	*230*	616.6	1547.8	4231.1	1062.7	1524.8
100028	*[BURAO 230.00]*	*230*	533.54	1339.3	3755.9	1584.6	1329.8
100011	*[BARAAWE 230.00]*	*230*	530.14	1330.8	3736.6	1609.6	1328.2
100033	*[LAASCAANOD 230.00]*	*230*	495.33	1243.4	3480.2	1404.6	1240.3
100038	*[GAROOWE 230.00]*	*230*	477.83	1199.5	3354.1	1327.8	1196.8
100046	*[QARDHO 230.00]*	*230*	474.23	1190.4	3327.4	1311.1	1184.1
100018	*[HARGEISA 230.00]*	*230*	379.38	952.3	2593.8	613	952.3
100002	*[MOGADISHU 132.00]*	*132*	675.28	2953.6	8320.9	3843.3	2862.3
100024	*[BERBERA 132.00]*	*132*	567.59	2482.6	6960.9	2940.3	2416.1
100007	*[AFGOOYE 132.00]*	*132*	453.47	1983.4	5588.2	2583.7	1983.4
100051	*[JOWHAR 132.00]*	*132*	450.62	1971	5436.9	1638.8	1971
100029	*[BURAO 132.00]*	*132*	404.57	1769.6	4972.7	2185.2	1769.6
100034	*[LAASCAANOD 132.00]*	*132*	382.22	1671.8	4690.3	1987.8	1671.8
100047	*[QARDHO 132.00]*	*132*	369.53	1616.3	4529.5	1880.5	1616.3
100019	*[HARGEISA 132.00]*	*132*	340.77	1490.5	4074.9	1036.7	1490.5

Short circuit results for the whole network – target year 2035

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100000	[MOGADISHU 500.00]	500	1681	1941	5449	2347	1880
150000	[MOGADISHU_SO500.00]	500	1666	1923	5393	2271	1864
100005	[AFGOOYE 500.00]	500	1622	1873	5236	2069	1819
100114	[BAIDOA 500.00]	500	1621	1872	5232	2070	1831
100128	[DOLLOW 500.00]	500	1498	1729	4798	1646	1709
100010	[BARAAWE 500.00]	500	1407	1625	4481	1345	1590
100136	[JILIB 500.00]	500	1314	1517	4162	1150	1486
100014	[KISMAYO 500.00]	500	1214	1402	3829	1001	1369
100022	[BERBERA 500.00]	500	1146	1323	3700	1493	1286
100068	[SHEIKH 500.00]	500	1133	1308	3652	1413	1275
100027	[BURAO 500.00]	500	1116	1289	3592	1332	1258
100054	[HARGEISA 500.00]	500	1115	1287	3591	1394	1259
100032	[LAASCAANOD 500.00]	500	1030	1189	3285	1009	1165
100037	[GAROOWE 500.00]	500	993	1147	3159	922	1124
100045	[QARDHO 500.00]	500	956	1104	3034	879	1078
100080	[CEELDAHIR 500.00]	500	938	1083	2978	893	1054
100041	[BOSASO 500.00]	500	917	1059	2909	876	1026
100129	[DOLLOW 400.00]	400	1439	2076	5771	2041	2061
100055	[HARGEISA 400.00]	400	1094	1579	4411	1743	1552
100001	[MOGADISHU 230.00]	230	1564	3927	11036	4883	3776
150001	[MOGADISHU_SO230.00]	230	1283	3220	9047	3962	3194
100115	[BAIDOA 230.00]	230	1168	2933	8197	3383	2925
100015	[KISMAYO 230.00]	230	1134	2845	7812	2237	2761
100023	[BERBERA 230.00]	230	1061	2663	7461	3125	2575
100006	[AFGOOYE 230.00]	230	1041	2614	7339	3159	2614
100050	[JOWHAR 230.00]	230	1022	2565	6934	1395	2554
100018	[HARGEISA 230.00]	230	969	2432	6795	2724	2411
100042	[BOSASO 230.00]	230	888	2230	6149	1956	2146
100103	[JALALAQSI 230.00]	230	846	2124	5677	908	2116
100028	[BURAO 230.00]	230	834	2093	5813	2195	2087
100121	[XUDUR 230.00]	230	817	2050	5516	1014	2044
100106	[BULOBURTI 230.00]	230	782	1963	5231	804	1950
100110	[BELETWEYNE 230.00]	230	766	1923	5142	914	1892
100011	[BARAAWE 230.00]	230	765	1919	5353	2024	1919
100137	[JILIB 230.00]	230	755	1895	5270	1884	1895
100060	[GABILEY 230.00]	230	750	1884	5142	1272	1884
100069	[SHEIKH 230.00]	230	736	1846	5182	2228	1846
100124	[DINSOOR 230.00]	230	674	1691	4526	739	1691
100064	[WAJAALE 230.00]	230	656	1647	4452	893	1647
100033	[LAASCAANOD 230.00]	230	655	1643	4580	1696	1643
100081	[CEELDAHIR 230.00]	230	653	1639	4552	1618	1636
100038	[GAROOWE 230.00]	230	623	1565	4352	1550	1565
100046	[QARDHO 230.00]	230	608	1527	4242	1491	1527
100056	[BOROMA 230.00]	230	602	1512	4063	722	1512

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100072	*[BADHAN 230.00]*	*230*	539	1352	3699	985	1352
100076	*[ERIGAVO 230.00]*	*230*	427	1071	2887	582	1071
100002	*[MOGADISHU 132.00]*	*132*	1066	4663	13132	6039	4634
150002	*[MOGADISHU_SO132.00]*	*132*	927	4056	11417	5186	4056
100130	*[DOLLOW 132.00]*	*132*	813	3556	9965	4138	3556
100024	*[BERBERA 132.00]*	*132*	805	3523	9894	4322	3482
100019	*[HARGEISA 132.00]*	*132*	751	3286	9207	3874	3286
100007	*[AFGOOYE 132.00]*	*132*	658	2880	8108	3692	2880
100051	*[JOWHAR 132.00]*	*132*	634	2775	7630	2155	2775
100029	*[BURAO 132.00]*	*132*	556	2434	6802	2810	2434
100107	*[BULOBURTI 132.00]*	*132*	533	2331	6330	1399	2331
100111	*[BELETWEYNE 132.00]*	*132*	526	2299	6255	1505	2291
100061	*[GABILEY 132.00]*	*132*	518	2266	6254	1917	2266
100133	*[BELEDHAWO 132.00]*	*132*	472	2063	5577	1092	2063
100065	*[WAJAALE 132.00]*	*132*	471	2062	5644	1458	2062
100034	*[LAASCAANOD 132.00]*	*132*	471	2058	5760	2321	2058
100082	*[CEELDAHIR 132.00]*	*132*	470	2055	5735	2237	2055
100047	*[QARDHO 132.00]*	*132*	446	1952	5447	2099	1952
100057	*[BOROMA 132.00]*	*132*	443	1937	5276	1228	1937
100125	*[DINSOOR 132.00]*	*132*	420	1838	5020	1245	1838
100073	*[BADHAN 132.00]*	*132*	408	1783	4915	1515	1783
100118	*[MERCA 132.00]*	*132*	370	1620	4390	923	1620
100077	*[ERIGAVO 132.00]*	*132*	340	1488	4048	971	1488

Short circuit results for the whole network – target year 2040

Bus Number	*Bus Name*	*Vnom [kV]*	*SC [MVA]*	*I''krms [A]*	*ip(B) [A]*	*DC IbC [A]*	*Sym Ib [A]*
150000	*[MOGADISHU_SO500.00]*	*500*	3496	4037	11311	4696	3920
100000	*[MOGADISHU 500.00]*	*500*	3486	4025	11274	4653	3913
100005	*[AFGOOYE 500.00]*	*500*	3343	3860	10757	3996	3771
100114	*[BAIDOA 500.00]*	*500*	3041	3511	9707	3103	3480
100010	*[BARAAWE 500.00]*	*500*	2729	3151	8639	2383	3111
100128	*[DOLLOW 500.00]*	*500*	2492	2878	7833	1871	2878
100136	*[JILIB 500.00]*	*500*	2365	2731	7418	1742	2700
100014	*[KISMAYO 500.00]*	*500*	1952	2254	6057	1211	2221
100022	*[BERBERA 500.00]*	*500*	1916	2212	6105	2002	2175
100068	*[SHEIKH 500.00]*	*500*	1909	2204	6070	1855	2176
100027	*[BURAO 500.00]*	*500*	1904	2199	6045	1756	2176
100037	*[GAROOWE 500.00]*	*500*	1901	2195	6038	1775	2183
100032	*[LAASCAANOD 500.00]*	*500*	1870	2160	5918	1566	2150
100054	*[HARGEISA 500.00]*	*500*	1830	2113	5822	1877	2090
100045	*[QARDHO 500.00]*	*500*	1753	2024	5543	1552	2004
100080	*[CEELDAHIR 500.00]*	*500*	1685	1946	5331	1587	1917
100198	*[EIL 500.00]*	*500*	1579	1823	4948	1144	1822
100041	*[BOSASO 500.00]*	*500*	1556	1797	4897	1341	1764
100129	*[DOLLOW 400.00]*	*400*	2268	3273	8954	2346	3273
100055	*[HARGEISA 400.00]*	*400*	1782	2572	7109	2393	2553
150001	*[MOGADISHU_SO230.00]*	*230*	2995	7518	21150	9516	7195
100001	*[MOGADISHU 230.00]*	*230*	2593	6509	18262	7980	6378
100115	*[BAIDOA 230.00]*	*230*	2043	5128	14215	5100	5115
100015	*[KISMAYO 230.00]*	*230*	1671	4195	11399	2742	4110
100023	*[BERBERA 230.00]*	*230*	1638	4113	11425	4161	4002
100006	*[AFGOOYE 230.00]*	*230*	1629	4090	11492	5029	4090
100018	*[HARGEISA 230.00]*	*230*	1600	4016	11127	3890	4008
100011	*[BARAAWE 230.00]*	*230*	1586	3981	11151	4609	3829
100042	*[BOSASO 230.00]*	*230*	1394	3500	9603	2906	3415
100050	*[JOWHAR 230.00]*	*230*	1358	3408	9066	1330	3406
100137	*[JILIB 230.00]*	*230*	1323	3320	9114	2850	3309
100060	*[GABILEY 230.00]*	*230*	1267	3180	8673	2313	3180
100081	*[CEELDAHIR 230.00]*	*230*	1255	3149	8771	3340	3139
100124	*[DINSOOR 230.00]*	*230*	1228	3082	8207	1227	3082
100199	*[EIL 230.00]*	*230*	1224	3074	8457	2505	3074
100223	*[BUURHAKABA 230.00]*	*230*	1223	3071	8198	1306	3071
100028	*[BURAO 230.00]*	*230*	1201	3014	8279	2693	3014
100121	*[XUDUR 230.00]*	*230*	1198	3007	8000	1302	2973
100233	*[BUALE 230.00]*	*230*	1159	2910	7833	1598	2880
100230	*[BARDHEERE 230.00]*	*230*	1132	2843	7573	1217	2839
100164	*[BULLOXAAR 230.00]*	*230*	1111	2789	7528	1567	2751
100103	*[JALALAQSI 230.00]*	*230*	1070	2686	7064	826	2682
100038	*[GAROOWE 230.00]*	*230*	1065	2674	7471	2943	2674
100064	*[WAJAALE 230.00]*	*230*	1061	2664	7187	1558	2664

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100239	[BULLOXAAJI 230.00]	230	992	2489	6566	824	2488
100106	[BULOBURTI 230.00]	230	975	2447	6419	737	2439
100069	[SHEIKH 230.00]	230	964	2420	6762	2687	2420
100110	[BELETWEYNE 230.00]	230	964	2420	6374	896	2390
100056	[BOROMA 230.00]	230	947	2378	6375	1234	2378
100033	[LAASCAANOD 230.00]	230	919	2306	6426	2380	2306
100072	[BADHAN 230.00]	230	914	2295	6240	1526	2278
100046	[QARDHO 230.00]	230	891	2238	6230	2333	2238
100236	[AFMADOW 230.00]	230	838	2104	5600	890	2104
100220	[WAJID 230.00]	230	786	1973	5158	553	1970
100076	[ERIGAVO 230.00]	230	617	1548	4120	657	1548
150002	[MOGADISHU_SO132.00]	132	1581	6914	19499	9219	6914
100002	[MOGADISHU 132.00]	132	1461	6391	17994	8333	6391
100019	[HARGEISA 132.00]	132	1101	4817	13433	5248	4817
100024	[BERBERA 132.00]	132	1100	4811	13444	5414	4790
100130	[DOLLOW 132.00]	132	1008	4411	12300	4662	4411
100007	[AFGOOYE 132.00]	132	845	3698	10423	4865	3698
100061	[GABILEY 132.00]	132	809	3540	9811	3418	3540
100051	[JOWHAR 132.00]	132	750	3279	8962	2249	3279
100065	[WAJAALE 132.00]	132	730	3193	8778	2615	3193
100082	[CEELDAHIR 132.00]	132	728	3185	8929	3811	3185
100224	[BUURHAKABA 132.00]	132	707	3092	8454	2166	3092
100029	[BURAO 132.00]	132	699	3058	8503	3276	3058
100214	[BALCAD 132.00]	132	683	2989	8022	1348	2989
100057	[BOROMA 132.00]	132	671	2936	8029	2168	2936
100073	[BADHAN 132.00]	132	659	2883	7948	2454	2845
100158	[AWBARKHADLE 132.00]	132	646	2824	7623	1504	2824
100152	[ARABSIYO 132.00]	132	644	2818	7693	1968	2818
100192	[ARMO 132.00]	132	631	2760	7649	2578	2760
100107	[BULOBURTI 132.00]	132	616	2696	7264	1401	2696
100111	[BELETWEYNE 132.00]	132	612	2676	7231	1552	2673
100034	[LAASCAANOD 132.00]	132	604	2640	7395	3043	2640
100125	[DINSOOR 132.00]	132	585	2557	7025	1958	2557
100047	[QARDHO 132.00]	132	582	2544	7122	2942	2544
100149	[KALABEYDH 132.00]	132	558	2441	6610	1436	2441
100133	[BELEDHAWO 132.00]	132	531	2324	6240	1061	2324
100155	[ABAARSO 132.00]	132	530	2319	6266	1280	2319
100217	[QALIMOW 132.00]	132	529	2314	6214	1070	2314
100183	[HADAAFTIMO 132.00]	132	524	2290	6248	1630	2237
100140	[QULJEED 132.00]	132	464	2027	5442	979	2027
100143	[BAKI 132.00]	132	464	2027	5442	979	2027
100161	[BALLICABANE 132.00]	132	461	2017	5377	825	2017
100146	[DILLA 132.00]	132	453	1981	5317	960	1981
100077	[ERIGAVO 132.00]	132	451	1972	5331	1135	1972
100195	[YAKE 132.00]	132	419	1833	5010	1261	1833
100118	[MERCA 132.00]	132	419	1832	4938	933	1832

Bus Number	*Bus Name*	*Vnom [kV]*	*SC [MVA]*	*I''krms [A]*	*ip(B) [A]*	*DC IbC [A]*	*Sym Ib [A]*
100227	*[LUUQ 132.00]*	*132*	410	1794	4771	659	1794
100168	*[OODWEYNE 132.00]*	*132*	377	1648	4421	786	1648
100177	*[WIDHWIDH 132.00]*	*132*	325	1420	3829	727	1420
100211	*[MATABAAN 132.00]*	*132*	313	1370	3616	455	1370
100171	*[OOG 132.00]*	*132*	291	1273	3411	555	1273
100180	*[XUDUN 132.00]*	*132*	258	1127	3006	443	1127
100186	*[XIINGALOOL 132.00]*	*132*	254	1109	2960	447	1109
100189	*[TALEH 132.00]*	*132*	254	1109	2960	447	1109
100174	*[BUUHOODLE 132.00]*	*132*	238	1043	2779	404	1043

Short circuit results for the whole network – target year 2045

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100000	[MOGADISHU 500.00]	500	6568	7584	21285	9262	7470
150000	[MOGADISHU_SO500.00]	500	6425	7419	20768	8537	7310
160000	[MOGADISHU _NO500.00]	500	5868	6776	18799	6498	6695
100005	[AFGOOYE 500.00]	500	5761	6652	18398	5866	6601
100114	[BAIDOA 500.00]	500	4698	5424	14763	3493	5422
100022	[BERBERA 500.00]	500	4415	5098	14227	5856	5049
100068	[SHEIKH 500.00]	500	3906	4510	12391	3575	4510
100010	[BARAAWE 500.00]	500	3841	4435	11946	2444	4398
100054	[HARGEISA 500.00]	500	3595	4152	11381	3312	4152
100027	[BURAO 500.00]	500	3587	4142	11281	2658	4142
100128	[DOLLOW 500.00]	500	3402	3928	10488	1768	3928
100136	[JILIB 500.00]	500	3174	3665	9799	1839	3633
100032	[LAASCAANOD 500.00]	500	2815	3251	8723	1577	3249
100037	[GAROOWE 500.00]	500	2698	3116	8391	1805	3109
100302	[MAXAAS 500.00]	500	2514	2903	7611	783	2903
100014	[KISMAYO 500.00]	500	2500	2887	7661	1337	2849
100045	[QARDHO 500.00]	500	2368	2735	7354	1651	2719
100080	[CEELDAHIR 500.00]	500	2254	2603	7028	1870	2576
100041	[BOSASO 500.00]	500	2081	2403	6478	1714	2370
100198	[EIL 500.00]	500	2043	2360	6271	1071	2360
100291	[DUUSAMAREEB500.00]	500	1940	2240	5818	489	2240
100289	[GALKAYO 500.00]	500	1768	2041	5372	693	2041
100285	[BARGAAL 500.00]	500	1627	1879	5014	1106	1872
100055	[HARGEISA 400.00]	400	3110	4488	12392	4021	4488
100129	[DOLLOW 400.00]	400	2953	4263	11491	2306	4263
100001	[MOGADISHU 230.00]	230	6787	17037	48014	22709	15993
100023	[BERBERA 230.00]	230	5595	14046	39424	17563	13023
150001	[MOGADISHU_SO230.00]	230	4032	10122	28505	13132	9804
160001	[MOGADISHU _NO230.00]	230	3880	9740	27316	11598	9422
100115	[BAIDOA 230.00]	230	2573	6459	17756	5695	6450
100018	[HARGEISA 230.00]	230	2440	6124	16975	5968	6124
100015	[KISMAYO 230.00]	230	2099	5268	14205	3129	5157
100164	[BULLOXAAR 230.00]	230	2047	5138	13546	1789	5107
100006	[AFGOOYE 230.00]	230	2016	5061	14210	6147	5061
100050	[JOWHAR 230.00]	230	1832	4598	11970	1136	4598
100042	[BOSASO 230.00]	230	1756	4408	12014	3603	4324
100011	[BARAAWE 230.00]	230	1742	4373	12220	4854	4220
100028	[BURAO 230.00]	230	1647	4135	11326	3561	4135
100060	[GABILEY 230.00]	230	1635	4104	11079	2418	4104
100137	[JILIB 230.00]	230	1599	4014	10969	3241	3986
100199	[EIL 230.00]	230	1442	3619	9853	2492	3619
100081	[CEELDAHIR 230.00]	230	1430	3589	9961	3694	3579
100223	[BUURHAKABA 230.00]	230	1395	3503	9262	1248	3503
100124	[DINSOOR 230.00]	230	1385	3477	9164	1137	3477

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100121	*[XUDUR 230.00]*	*230*	1352	3393	8925	1221	3361
100233	*[BUALE 230.00]*	*230*	1317	3307	8825	1563	3277
100103	*[JALALAQSI 230.00]*	*230*	1299	3261	8432	709	3258
100064	*[WAJAALE 230.00]*	*230*	1295	3250	8672	1513	3250
100286	*[BARGAAL 230.00]*	*230*	1281	3215	8751	2470	3215
100251	*[LUGHAYA 230.00]*	*230*	1271	3191	8304	861	3190
100239	*[BULLOXAAJI 230.00]*	*230*	1265	3176	8395	1310	3140
100230	*[BARDHEERE 230.00]*	*230*	1260	3163	8346	1143	3161
100069	*[SHEIKH 230.00]*	*230*	1255	3152	8839	3756	3152
100038	*[GAROOWE 230.00]*	*230*	1224	3071	8535	3098	3071
100106	*[BULOBURTI 230.00]*	*230*	1137	2853	7374	650	2846
100056	*[BOROMA 230.00]*	*230*	1124	2822	7484	1171	2822
100033	*[LAASCAANOD 230.00]*	*230*	1089	2733	7580	2576	2733
100110	*[BELETWEYNE 230.00]*	*230*	1084	2720	7077	831	2690
100046	*[QARDHO 230.00]*	*230*	1019	2558	7085	2490	2558
100236	*[AFMADOW 230.00]*	*230*	1016	2551	6793	1181	2529
100072	*[BADHAN 230.00]*	*230*	1009	2532	6859	1619	2515
100303	*[MAXAAS 230.00]*	*230*	1005	2523	6918	1829	2523
100339	*[BURGABO 230.00]*	*230*	953	2391	6308	1077	2340
100292	*[DUUSAMAREEB230.00]*	*230*	910	2284	6204	1354	2284
100290	*[GALKAYO 230.00]*	*230*	888	2228	6083	1540	2228
100220	*[WAJID 230.00]*	*230*	849	2132	5526	514	2130
100336	*[QOQANI 230.00]*	*230*	841	2111	5590	891	2087
100076	*[ERIGAVO 230.00]*	*230*	677	1699	4514	745	1699
100333	*[DHOBLEY 230.00]*	*230*	666	1671	4409	717	1640
100002	*[MOGADISHU 132.00]*	*132*	2242	9805	27700	13596	9805
100024	*[BERBERA 132.00]*	*132*	2094	9161	25836	12360	9161
150002	*[MOGADISHU_SO132.00]*	*132*	1829	8000	22583	10878	8000
160002	*[MOGADISHU _NO132.00]*	*132*	1797	7860	22144	10259	7860
100019	*[HARGEISA 132.00]*	*132*	1456	6368	17799	7223	6368
100130	*[DOLLOW 132.00]*	*132*	1116	4883	13575	4837	4883
100007	*[AFGOOYE 132.00]*	*132*	949	4150	11697	5457	4150
100061	*[GABILEY 132.00]*	*132*	924	4041	11169	3654	4041
100051	*[JOWHAR 132.00]*	*132*	875	3827	10394	2299	3827
100029	*[BURAO 132.00]*	*132*	830	3632	10105	3951	3632
100065	*[WAJAALE 132.00]*	*132*	818	3577	9794	2680	3577
100214	*[BALCAD 132.00]*	*132*	816	3571	9507	1333	3571
100082	*[CEELDAHIR 132.00]*	*132*	783	3424	9585	4061	3424
100158	*[AWBARKHADLE 132.00]*	*132*	776	3394	9142	1736	3394
100224	*[BUURHAKABA 132.00]*	*132*	761	3329	9071	2191	3329
100057	*[BOROMA 132.00]*	*132*	744	3256	8865	2182	3256
100252	*[LUGHAYA 132.00]*	*132*	735	3214	8665	1708	3214
100152	*[ARABSIYO 132.00]*	*132*	714	3122	8493	1993	3122
100073	*[BADHAN 132.00]*	*132*	701	3065	8435	2582	3026
100258	*[DARASALAAM 132.00]*	*132*	682	2984	7983	1271	2984
100107	*[BULOBURTI 132.00]*	*132*	677	2962	7932	1360	2962

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100192	*[ARMO 132.00]*	*132*	671	2936	8121	2683	2936
100034	*[LAASCAANOD 132.00]*	*132*	671	2935	8203	3240	2935
100111	*[BELETWEYNE 132.00]*	*132*	658	2878	7731	1515	2876
100047	*[QARDHO 132.00]*	*132*	633	2770	7734	3092	2770
100125	*[DINSOOR 132.00]*	*132*	618	2704	7406	1957	2704
100149	*[KALABEYDH 132.00]*	*132*	607	2655	7160	1417	2655
100088	*[GALKAYO 132.00]*	*132*	590	2582	7135	2273	2582
100094	*[DUUSAMAREEB132.00]*	*132*	589	2578	7103	2073	2578
100217	*[QALIMOW 132.00]*	*132*	588	2574	6870	1041	2574
100155	*[ABAARSO 132.00]*	*132*	576	2521	6786	1266	2521
100315	*[WARSHEIKH 132.00]*	*132*	561	2455	6470	724	2455
100133	*[BELEDHAWO 132.00]*	*132*	560	2449	6552	1036	2449
100183	*[HADAAFTIMO 132.00]*	*132*	545	2386	6496	1657	2332
100261	*[DACARBUDHUQ 132.00]*	*132*	531	2322	6179	931	2322
100161	*[BALLICABANE 132.00]*	*132*	511	2234	5929	818	2234
100077	*[ERIGAVO 132.00]*	*132*	499	2182	5900	1303	2182
100140	*[QULJEED 132.00]*	*132*	497	2175	5813	952	2175
100143	*[BAKI 132.00]*	*132*	497	2175	5813	952	2175
100312	*[HAWADLEY 132.00]*	*132*	492	2151	5708	760	2151
100146	*[DILLA 132.00]*	*132*	484	2118	5662	935	2118
100324	*[BEERDALE 132.00]*	*132*	478	2090	5576	847	2090
100118	*[MERCA 132.00]*	*132*	456	1993	5371	1026	1993
100195	*[YAKE 132.00]*	*132*	445	1947	5305	1271	1947
100227	*[LUUQ 132.00]*	*132*	427	1867	4951	642	1867
100245	*[BOWN 132.00]*	*132*	426	1865	4959	721	1865
100306	*[HALGAN 132.00]*	*132*	422	1848	4877	598	1848
100321	*[WANLAWEYN 132.00]*	*132*	419	1831	4904	782	1831
100264	*[MADHEERA 132.00]*	*132*	417	1825	4828	648	1825
100085	*[ABAAREY 132.00]*	*132*	414	1811	4902	1023	1811
100168	*[OODWEYNE 132.00]*	*132*	412	1801	4819	800	1801
100309	*[BUQDAAQABLE 132.00]*	*132*	403	1765	4653	556	1765
100267	*[BALIGUBADLE 132.00]*	*132*	398	1739	4587	543	1739
100248	*[GARBODADAR 132.00]*	*132*	385	1682	4447	589	1682
100097	*[GODINLABE 132.00]*	*132*	371	1621	4355	742	1621
100202	*[BACAADWEYN 132.00]*	*132*	368	1609	4334	816	1609
100255	*[FARAWEYNE 132.00]*	*132*	365	1598	4206	477	1598
100318	*[QORUOOLEY 132.00]*	*132*	357	1561	4171	671	1561
100177	*[WIDHWIDH 132.00]*	*132*	342	1496	4022	717	1496
100327	*[QANSAXDHEERE132.00]*	*132*	339	1481	3945	569	1481
100205	*[GALDOGOB 132.00]*	*132*	330	1444	3867	631	1444
100211	*[MATABAAN 132.00]*	*132*	325	1421	3737	441	1421
100296	*[XARFO 132.00]*	*132*	321	1404	3762	643	1404
100242	*[XARIIRAD 132.00]*	*132*	320	1400	3693	447	1400
100091	*[BANDIIRADLEY132.00]*	*132*	318	1393	3725	590	1393
100100	*[GURICEEL 132.00]*	*132*	318	1392	3716	557	1392
100299	*[BURSAALAX 132.00]*	*132*	313	1369	3662	585	1369

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100171	*[OOG 132.00]*	*132*	306	1337	3574	546	1337
100208	*[CADAADO 132.00]*	*132*	297	1300	3462	492	1300
100282	*[CEELAFWEYN 132.00]*	*132*	284	1240	3301	551	1240
100180	*[XUDUN 132.00]*	*132*	269	1177	3132	434	1177
100330	*[GARBAHAAREY 132.00]*	*132*	264	1154	3027	307	1154
100186	*[XIINGALOOL 132.00]*	*132*	263	1150	3061	442	1150
100189	*[TALEH 132.00]*	*132*	263	1150	3061	442	1150
100276	*[CAYNABO 132.00]*	*132*	261	1143	3038	413	1143
100293	*[BURTINLE 132.00]*	*132*	250	1092	2900	407	1092
100174	*[BUUHOODLE 132.00]*	*132*	248	1084	2879	396	1084
100279	*[GARADAG 132.00]*	*132*	210	919	2434	366	919
100273	*[QORILUGUD 132.00]*	*132*	203	888	2346	285	888
100270	*[BALLIDHIIG 132.00]*	*132*	194	849	2242	266	849

Short circuit results for the whole network – target year 2050

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100000	[MOGADISHU 500.00]	500	8353	9645	26511	9330	9550
150000	[MOGADISHU_SO500.00]	500	8136	9395	25754	8512	9304
160000	[MOGADISHU _NO500.00]	500	7588	8762	23829	6725	8685
100005	[AFGOOYE 500.00]	500	7247	8368	22680	5719	8340
100041	[BOSASO 500.00]	500	5461	6306	17258	6021	6272
100037	[GAROOWE 500.00]	500	5411	6249	16538	2635	6249
100114	[BAIDOA 500.00]	500	5408	6244	16692	3327	6243
100010	[BARAAWE 500.00]	500	5218	6025	16063	2791	6010
100080	[CEELDAHIR 500.00]	500	5064	5847	15722	3573	5847
100022	[BERBERA 500.00]	500	4850	5601	15338	5578	5601
100136	[JILIB 500.00]	500	4845	5595	14971	2953	5593
100045	[QARDHO 500.00]	500	4797	5539	14674	2307	5539
100014	[KISMAYO 500.00]	500	4765	5502	14983	4945	5475
100032	[LAASCAANOD 500.00]	500	4569	5276	13902	1972	5276
100068	[SHEIKH 500.00]	500	4509	5206	14041	3542	5206
100027	[BURAO 500.00]	500	4354	5027	13437	2694	5027
100302	[MAXAAS 500.00]	500	4324	4994	13014	1398	4994
100289	[GALKAYO 500.00]	500	4150	4792	12480	1394	4790
100368	[BAXDO 500.00]	500	4028	4652	12102	1338	4646
100291	[DUUSAMAREEB500.00]	500	3979	4594	11929	1200	4593
100054	[HARGEISA 500.00]	500	3966	4579	12397	3567	4579
100128	[DOLLOW 500.00]	500	3729	4306	11339	1697	4306
100285	[BARGAAL 500.00]	500	3476	4013	10773	2666	3995
100198	[EIL 500.00]	500	3337	3854	10084	1436	3854
100361	[BENDERBEILA 500.00]	500	2722	3143	8181	933	3143
100055	[HARGEISA 400.00]	400	3475	5016	13730	4431	5016
100129	[DOLLOW 400.00]	400	3185	4597	12261	2237	4597
100001	[MOGADISHU 230.00]	230	7308	18344	51393	22861	17301
100042	[BOSASO 230.00]	230	6122	15367	42806	17875	14367
100023	[BERBERA 230.00]	230	5972	14990	41845	18091	13968
100015	[KISMAYO 230.00]	230	5871	14738	40894	16195	13713
150001	[MOGADISHU_SO230.00]	230	4416	11086	31003	13200	10768
160001	[MOGADISHU _NO230.00]	230	4305	10807	30117	11948	10490
100286	[BARGAAL 230.00]	230	2973	7464	20672	7562	7159
100018	[HARGEISA 230.00]	230	2856	7170	19774	6996	7170
100115	[BAIDOA 230.00]	230	2745	6891	18817	5606	6882
100006	[AFGOOYE 230.00]	230	2155	5410	15123	6200	5410
100199	[EIL 230.00]	230	2138	5368	14638	3856	5368
100164	[BULLOXAAR 230.00]	230	2112	5301	13946	1857	5271
100239	[BULLOXAAJI 230.00]	230	1898	4764	12472	1517	4728
100050	[JOWHAR 230.00]	230	1867	4688	12165	1120	4688
100011	[BARAAWE 230.00]	230	1860	4670	13057	5267	4517
100137	[JILIB 230.00]	230	1790	4494	12328	4077	4467
100081	[CEELDAHIR 230.00]	230	1784	4479	12516	5068	4469

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100028	[BURAO 230.00]	230	1783	4476	12177	3652	4476
100060	[GABILEY 230.00]	230	1778	4464	11972	2486	4464
100033	[LAASCAANOD 230.00]	230	1578	3960	11015	4010	3960
100369	[BAXDO 230.00]	230	1537	3858	10635	3203	3828
100038	[GAROOWE 230.00]	230	1488	3734	10409	3963	3734
100223	[BUURHAKABA 230.00]	230	1444	3626	9542	1215	3626
100124	[DINSOOR 230.00]	230	1443	3621	9501	1103	3621
100290	[GALKAYO 230.00]	230	1420	3565	9824	2951	3565
100303	[MAXAAS 230.00]	230	1415	3551	9798	3001	3551
100233	[BUALE 230.00]	230	1406	3528	9398	1625	3498
100121	[XUDUR 230.00]	230	1384	3474	9102	1205	3442
100064	[WAJAALE 230.00]	230	1379	3462	9181	1523	3462
100103	[JALALAQSI 230.00]	230	1318	3308	8532	701	3306
100230	[BARDHEERE 230.00]	230	1315	3300	8675	1124	3299
100251	[LUGHAYA 230.00]	230	1313	3295	8573	941	3294
100069	[SHEIKH 230.00]	230	1306	3278	9156	3765	3278
100046	[QARDHO 230.00]	230	1284	3223	8962	3268	3223
100362	[BENDERBEILA 230.00]	230	1276	3203	8796	2520	3203
100339	[BURGABO 230.00]	230	1211	3039	7934	1081	2988
100292	[DUUSAMAREEB230.00]	230	1191	2990	8240	2491	2990
100056	[BOROMA 230.00]	230	1185	2976	7850	1171	2976
100106	[BULOBURTI 230.00]	230	1151	2890	7453	645	2883
100072	[BADHAN 230.00]	230	1139	2860	7729	1658	2843
100110	[BELETWEYNE 230.00]	230	1098	2756	7154	826	2726
100236	[AFMADOW 230.00]	230	1083	2718	7237	1267	2697
100372	[OBBIA 230.00]	230	944	2369	6394	1532	2369
100336	[QOQANI 230.00]	230	883	2218	5866	924	2193
100382	[MAREEG 230.00]	230	868	2179	5873	1342	2179
100220	[WAJID 230.00]	230	862	2163	5594	509	2162
100385	[EELBARDE 230.00]	230	842	2114	5462	489	2113
100358	[HAJISALAH 230.00]	230	822	2063	5392	618	2063
100342	[ZEILA 230.00]	230	798	2003	5165	454	2003
100365	[GARACAD 230.00]	230	782	1962	5277	1233	1962
100076	[ERIGAVO 230.00]	230	728	1827	4837	721	1827
100333	[DHOBLEY 230.00]	230	689	1729	4558	727	1699
100388	[BURACHE 230.00]	230	611	1534	3951	297	1534
100002	[MOGADISHU 132.00]	132	2296	10041	28316	13631	10041
100024	[BERBERA 132.00]	132	2145	9382	26411	12503	9382
150002	[MOGADISHU_SO132.00]	132	1904	8329	23441	10915	8329
160002	[MOGADISHU _NO132.00]	132	1883	8237	23146	10429	8237
100019	[HARGEISA 132.00]	132	1601	7001	19532	8023	7001
100130	[DOLLOW 132.00]	132	1146	5013	13894	4808	5013
100007	[AFGOOYE 132.00]	132	977	4273	12023	5487	4273
100061	[GABILEY 132.00]	132	962	4206	11602	3746	4206
100051	[JOWHAR 132.00]	132	883	3862	10478	2291	3862
100082	[CEELDAHIR 132.00]	132	876	3833	10777	4861	3833

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100029	[BURAO 132.00]	132	863	3776	10480	4017	3776
100065	[WAJAALE 132.00]	132	846	3700	10109	2717	3700
100034	[LAASCAANOD 132.00]	132	825	3610	10121	4289	3610
100214	[BALCAD 132.00]	132	823	3602	9578	1326	3602
100158	[AWBARKHADLE 132.00]	132	813	3554	9546	1767	3554
100088	[GALKAYO 132.00]	132	781	3416	9525	3605	3416
100224	[BUURHAKABA 132.00]	132	776	3392	9224	2172	3392
100057	[BOROMA 132.00]	132	768	3357	9120	2202	3357
100073	[BADHAN 132.00]	132	753	3294	9066	2690	3256
100252	[LUGHAYA 132.00]	132	748	3273	8827	1804	3273
100192	[ARMO 132.00]	132	738	3229	8953	3017	3229
100152	[ARABSIYO 132.00]	132	736	3219	8737	2014	3219
100047	[QARDHO 132.00]	132	727	3178	8902	3715	3178
100258	[DARASALAAM 132.00]	132	712	3116	8313	1289	3116
100094	[DUUSAMAREEB132.00]	132	696	3044	8479	3149	3044
100107	[BULOBURTI 132.00]	132	682	2985	7984	1355	2985
100111	[BELETWEYNE 132.00]	132	663	2901	7784	1510	2900
100125	[DINSOOR 132.00]	132	629	2753	7529	1951	2753
100149	[KALABEYDH 132.00]	132	622	2722	7324	1422	2722
100217	[QALIMOW 132.00]	132	592	2590	6906	1037	2590
100155	[ABAARSO 132.00]	132	591	2584	6941	1271	2584
100183	[HADAAFTIMO 132.00]	132	572	2501	6803	1655	2448
100133	[BELEDHAWO 132.00]	132	567	2481	6625	1028	2481
100315	[WARSHEIKH 132.00]	132	565	2470	6503	721	2470
100261	[DACARBUDHUQ 132.00]	132	547	2392	6352	935	2392
100161	[BALLICABANE 132.00]	132	543	2375	6302	915	2375
100343	[ZEILA 132.00]	132	541	2365	6276	928	2365
100077	[ERIGAVO 132.00]	132	525	2296	6199	1296	2296
100140	[QULJEED 132.00]	132	507	2220	5922	952	2220
100143	[BAKI 132.00]	132	507	2220	5922	952	2220
100085	[ABAAREY 132.00]	132	497	2173	5887	1231	2173
100312	[HAWADLEY 132.00]	132	494	2162	5733	758	2162
100146	[DILLA 132.00]	132	494	2159	5762	934	2159
100195	[YAKE 132.00]	132	489	2140	5830	1355	2140
100324	[BEERDALE 132.00]	132	483	2115	5633	839	2115
100118	[MERCA 132.00]	132	461	2018	5431	1020	2018
100245	[BOWN 132.00]	132	434	1898	5038	719	1898
100227	[LUUQ 132.00]	132	431	1886	4992	638	1886
100202	[BACAADWEYN 132.00]	132	431	1885	5075	934	1885
100264	[MADHEERA 132.00]	132	427	1867	4930	648	1867
100306	[HALGAN 132.00]	132	424	1857	4896	596	1857
100267	[BALIGUBADLE 132.00]	132	424	1856	4900	638	1856
100321	[WANLAWEYN 132.00]	132	424	1854	4960	776	1854
100168	[OODWEYNE 132.00]	132	420	1836	4902	798	1836
100346	[LAWYACADO 132.00]	132	416	1818	4791	598	1818
100097	[GODINLABE 132.00]	132	410	1794	4837	902	1794

Bus Number	Bus Name	Vnom [kV]	SC [MVA]	I''krms [A]	ip(B) [A]	DC IbC [A]	Sym Ib [A]
100309	[BUQDAAQABLE 132.00]	132	405	1773	4671	555	1773
100248	[GARBODADAR 132.00]	132	388	1697	4487	604	1697
100205	[GALDOGOB 132.00]	132	382	1672	4476	711	1672
100255	[FARAWEYNE 132.00]	132	381	1669	4390	514	1669
100177	[WIDHWIDH 132.00]	132	376	1645	4407	740	1645
100349	[GEERISA 132.00]	132	374	1637	4315	520	1637
100296	[XARFO 132.00]	132	367	1605	4297	706	1605
100091	[BANDIIRADLEY132.00]	132	367	1604	4287	658	1604
100318	[QORUOOLEY 132.00]	132	360	1576	4206	668	1576
100299	[BURSAALAX 132.00]	132	358	1567	4185	643	1567
100355	[SALAXLEY 132.00]	132	350	1529	4025	496	1529
100100	[GURICEEL 132.00]	132	347	1517	4061	649	1517
100327	[QANSAXDHEERE132.00]	132	342	1496	3980	565	1496
100171	[OOG 132.00]	132	334	1462	3895	560	1462
100379	[BALANBALE 132.00]	132	334	1461	3904	605	1461
100211	[MATABAAN 132.00]	132	326	1427	3749	440	1427
100352	[ALLEYBADEY 132.00]	132	326	1426	3741	406	1426
100242	[XARIIRAD 132.00]	132	324	1418	3737	445	1418
100208	[CADAADO 132.00]	132	322	1408	3760	566	1408
100180	[XUDUN 132.00]	132	291	1273	3376	441	1273
100282	[CEELAFWEYN 132.00]	132	291	1271	3380	541	1271
100276	[CAYNABO 132.00]	132	282	1233	3267	418	1233
100186	[XIINGALOOL 132.00]	132	278	1214	3229	443	1214
100189	[TALEH 132.00]	132	278	1214	3229	443	1214
100293	[BURTINLE 132.00]	132	277	1210	3208	426	1210
100330	[GARBAHAAREY 132.00]	132	265	1161	3043	306	1161
100174	[BUUHOODLE 132.00]	132	265	1159	3071	398	1159
100376	[CAABUDWAAQ 132.00]	132	243	1065	2818	350	1065
100391	[BUURDHUUBO 132.00]	132	220	962	2514	237	962
100273	[QORILUGUD 132.00]	132	214	938	2472	284	938
100279	[GARADAG 132.00]	132	214	936	2474	360	936
100270	[BALLIDHIIG 132.00]	132	205	895	2357	264	895

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