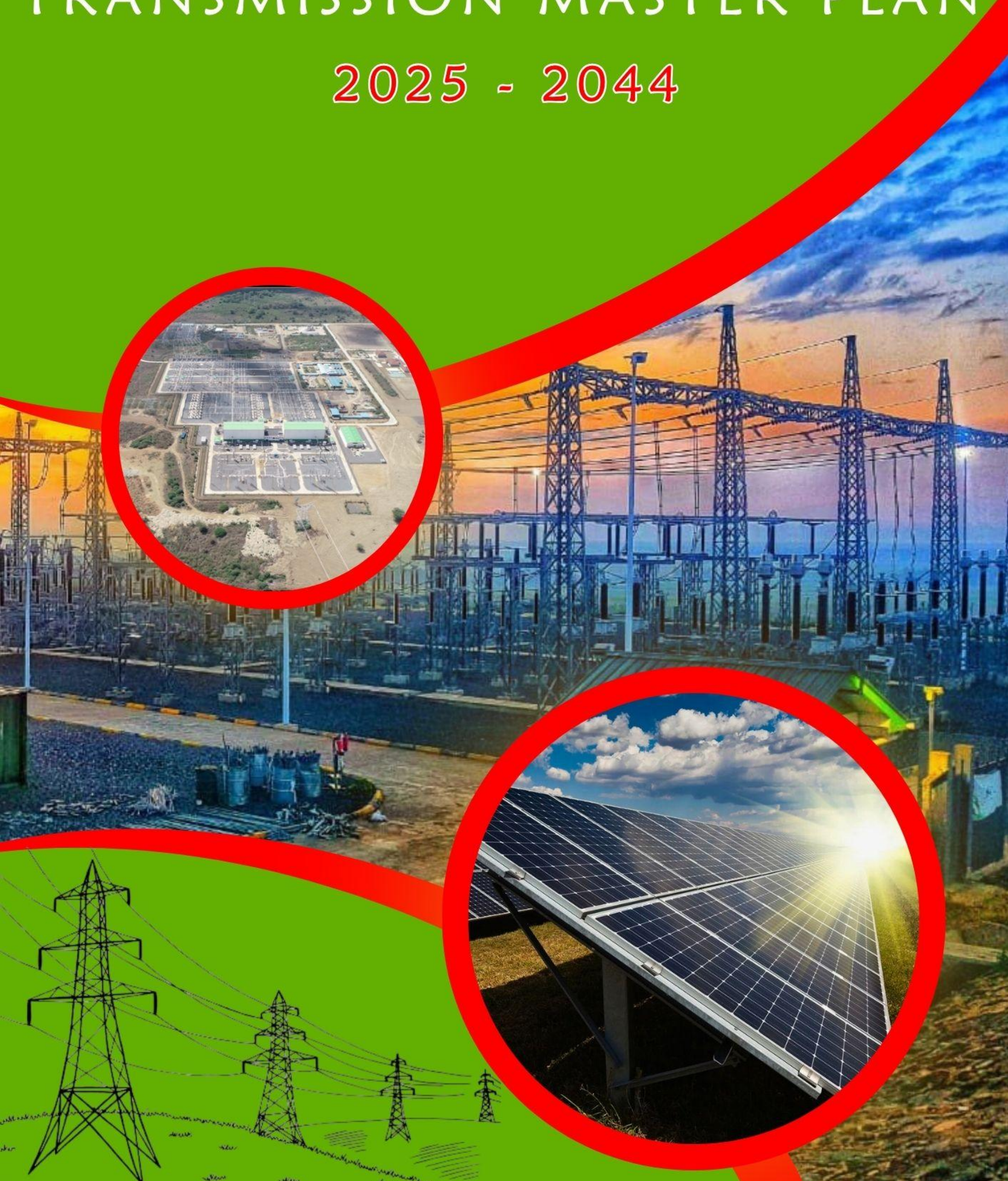
KETRACO
Kenya Electricity Transmission Company Limited
"Stable Power Grid - Mfumo Thabiti wa Umeme"

TRANSMISSION MASTER PLAN

2025 - 2044



Disclaimer

The Transmission Master Plan (TMP) has been developed and published to provide stakeholders with a clear, comprehensive overview of the planned developments within KETRACO's transmission network. It serves as a strategic roadmap, outlining proposed expansions and upgrades aimed at enhancing grid reliability, enabling regional power trade, and integrating renewable energy sources.

The TMP is a dynamic document that will continue to evolve in response to new data, changing demand trends, and shifting sectoral priorities. It is intended solely for informational purposes and serves to enhance transparency, promote knowledge sharing, and facilitate stakeholder engagement across all phases of planning, design, construction, operation, and maintenance of high-voltage transmission infrastructure. The contents of this document do not constitute legal, financial, or investment advice.

KETRACO based its plans on the best available data at the time of publication of this document to ensure stakeholders are kept informed of developments across the transmission network.

Cost estimates provided in the TMP are indicative and subject to revision. These figures are sensitive to fluctuations in global economic conditions, including foreign exchange rates and commodity prices.

For future transmission network expansion, KETRACO will conduct the necessary feasibility studies and pursue development within the framework of its capital investment process. All such investments will be undertaken in accordance with the relevant public procurement laws and regulations of the Government of Kenya.

Executive Summary

The Kenyan energy sector has undergone significant transformation over time as a result of government reforms and legislation. These reforms have resulted in growth in the country's power generation, transmission, and distribution. Electricity demand grew moderately from a peak of 2,149 MW in the financial year 2022/23 to 2,177 MW in the year 2023/24, an estimated 1.3% increase. The current peak demand of 2,316 MW was recorded in February 2025. This rise has been steered by growth in the manufacturing, agricultural and other sectors that propel GDP growth as well as population growth and urbanization. The number of households connected to the grid in the country increased significantly from 9,218,754 in the financial year 2022/23 to 9,660,005 in the financial year 2023/24, a 4.9% growth resulting to an electricity access rate of over 75%.

Over the last five years, installed generation capacity has expanded significantly, rising from 2,840MW in June 2019 to 3,243 MW in June 2024 inclusive of off-grid capacity, equivalent to a 14.19% increase over the period. The current contracted capacity is 3,056 MW.

There are several network issues that need to be resolved. These include, increased technical losses, over-voltages, overloading, and low voltages in some sections of the country, such as Kenya's western region. Diversifying power sources, building new transmission lines, installing reactors, and strengthening transmission and substations are all necessary solutions to these challenges. With the goal of rectifying all existing and future network issues, this Transmission Master Plan evaluated the existing network and considered future demand and generation estimates. The plan follows the National Transmission Grid Code's standards.

The Transmission Master Plan (TMP) embeds inclusive stakeholder engagement and sustainability at its core. It provides a structured framework for transparent, continuous participation across government, communities, civil society, and the private sector tailored to the needs of programs, plans, and projects. Environmental, social, and climate change considerations are mainstreamed through the application of safeguards, promoting biodiversity, land stewardship, and socioeconomic inclusion. The TMP supports low-carbon development by facilitating renewable energy integration, reducing losses, and enhancing climate resilience through principles like redundancy and robustness. It also outlines strategies for climate finance, carbon markets, and resilient PPP models.

The system peak demand is forecasted to grow at an average of 6.92% from 2,288 MW recorded in 2024 (base year) to 8,710 MW in 2044 under the reference scenario. The vision and low scenarios project the peak demand to reach 14,786 MW and 5,209 MW, an average growth of 9.81% and 4.21%, respectively. Electricity consumption is expected to rise from 10,763 GWh in 2024 to 36,328 GWh in the reference scenario, 65,525 GWh in the Vision scenario and 24,996 GWh in the low scenario by 2044.The effective/contracted capacity is projected to increase from 3,058 MW in 2024 to 12,819 MW by the year 2044.

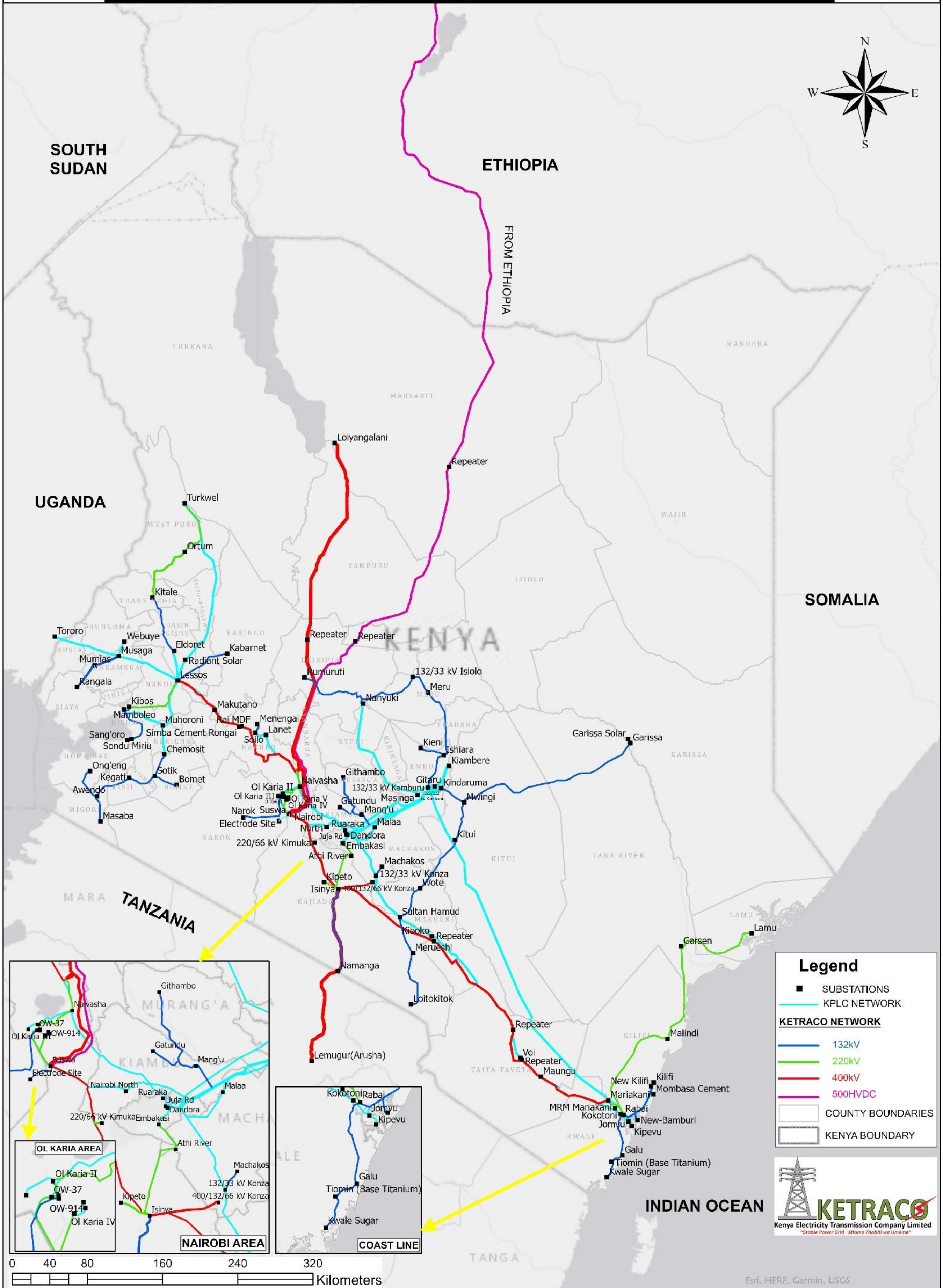
The power transmission network is currently operating at 132kV, 220kV, 400kV and 500kV DC. The size of the transmission network by circuit length is approximately 9,718 km of which **6,016** (62%) is owned and operated by KETRACO. This includes 1,308 km of 132kV lines, 835 km of 220kV lines, 2,590 km of 400kV and 1,282km of 500kV lines. In addition, KETRACO has completed and commissioned 44 new substations with 6,487 MVA capacity and 26 substations' bay extensions.

The total ongoing and planned projects sum up to 6,385.50 km in route length (10,666 km in circuit length) of transmission lines and 19,051 MVA in transformation capacity of substations.

The total investments requirement for the Transmission Master Plan is estimated at **USD 4,788 Million** out of which approximately **USD 411.17 Million** has been secured/committed through development partners' assistance and EPC +Financing framework. This implies that the financing gap is approximately **USD 4,376.82 Million**.

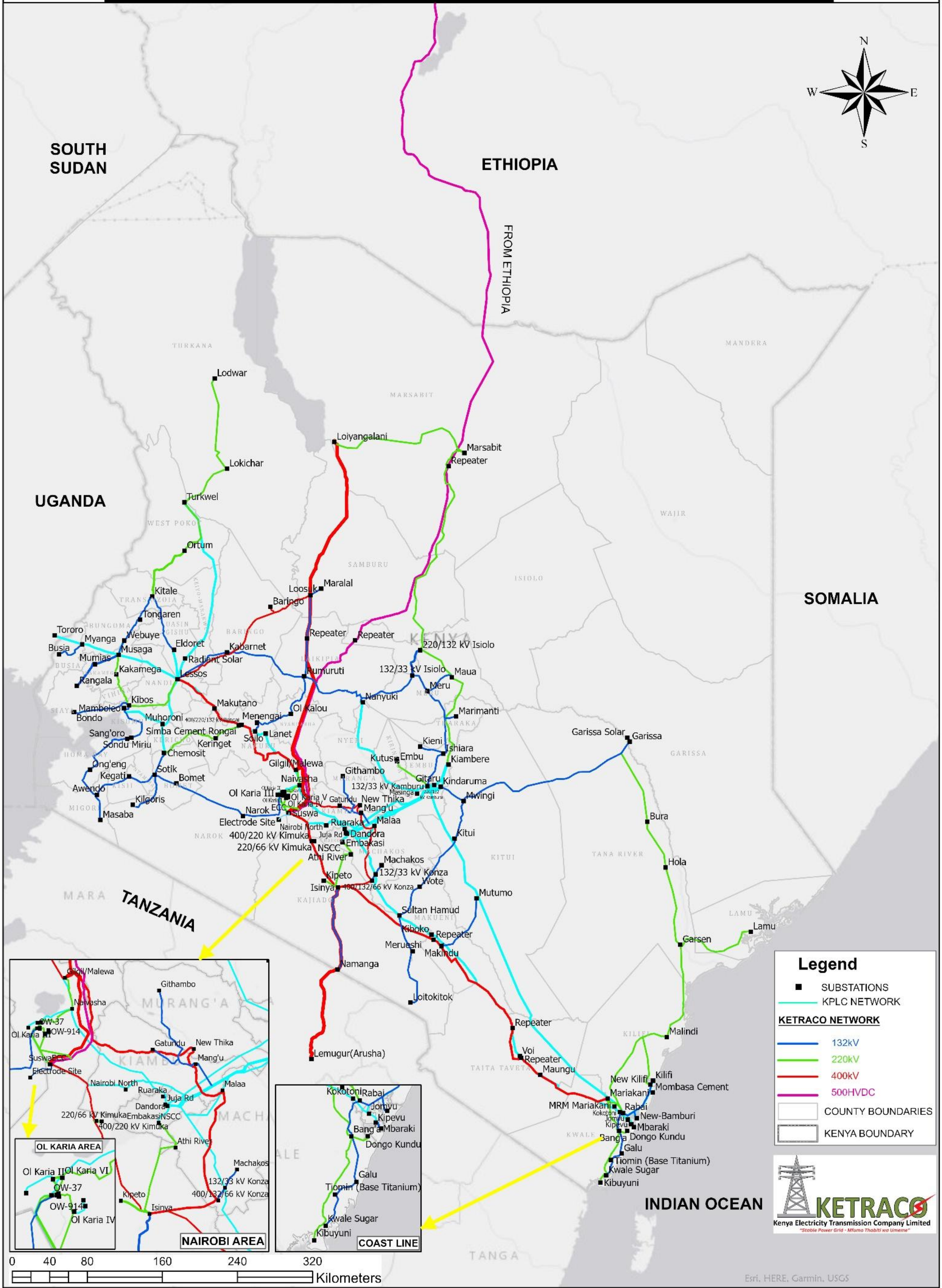
The maps in the next pages illustrate the national transmission grid network in 2025, and 2029 and 2044.

PROJECTED TRANSMISSION GRID NETWORK BY 2025



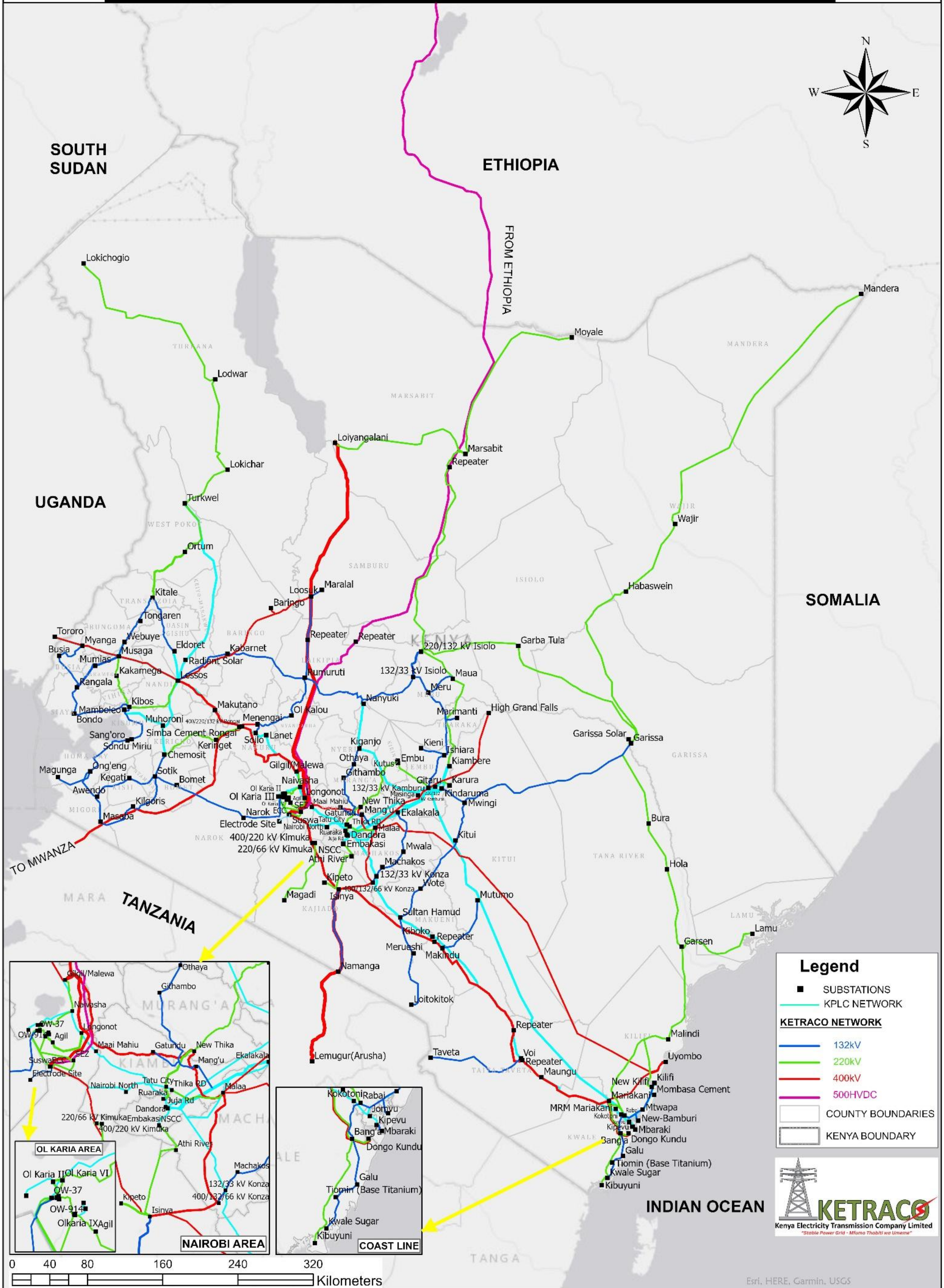
Date: 29/05/2025

PROJECTED TRANSMISSION GRID NETWORK BY 2029



Date: 29/05/2025

PROJECTED TRANSMISSION GRID NETWORK BY 2044



Date: 29/05/2025

Abbreviations & Acronyms

BETA	Bottom-Up Economic Transformation Agenda
BROP	Budget Review Outlook Paper
CIDP	County Integrated Development Plan
COD	Commercial Operation Date
CS & GM LS	Company Secretary & General Manager Legal Services
CS MOE	Cabinet Secretary Ministry of Energy
DGE	Deemed Generated Energy
DOSH	Directorate of Occupational Health and Safety
EAC	East African Community
EAPP	Eastern Africa Power Pool
EHS	Environmental, Health & Safety
EPC	Engineering, Procurement & Construction
EPRA	Energy and Petroleum Regulatory Authority
ESIA	Environmental & Social Impact Assessment
FiT	Feed in Tariff Policy
FOREX	Foreign Exchange
GDC	Geothermal Development Company
GDP	Gross Domestic Product
GM D&C	General Manager, Design & Construction
GM F	General Manager Finance
GM HRAD	General Manager Human Resource and Administration
GM PDS	General Manager, Project Development Services
GM SO & PM	General Manager, System Operations & Power Management
GM SRC	General Manager, Strategy, Research & Compliance
GoK	Government of Kenya
GPOBA	Global Partnership on Output Based Aid
GT	Gas Turbine
GWh	Giga Watt hours
HVDC	High voltage direct current
ICNIRP	International Commission on Non
IEEE	Institute of Electrical & Electronics Engineers
IPP	Independent Power Producers
KenGen	Kenya Electricity Generating Company Limited
KESS	Kenya Electricity System Studies
KETRACO	Kenya Electricity Transmission Company Ltd
KM	Kilometers
KPLC	Kenya Power and Lighting Company Limited
kV	Kilo Volt
LCPDP	Least Cost Power Development Plan
LILO	Line In Line Out
LV	Low voltage
MAED	Model for Analysis of Energy Demand
MEAL	Monitoring, Evaluation, Accountability and Learning
MECCF	Ministry of Environment, Climate Change, and Forestry
M KES	Million Kenya Shillings
MoEP	Ministry of Energy and Petroleum
MOU	Memorandum of Understanding
MSD	Medium Speed Diesel

MTEF	Medium Term Expenditure Framework
MTP	Medium Term Plan
MUSD	Million US Dollars
MV	Medium Voltage
MVA	Mega volt amp
MW	Mega Watt
NCCAP	National Climate Change Action Plan
NEMA	National Environmental Management Authority
NTEP	National Treasury and Economic Planning
NELSAP	Nile Equatorial Lakes Subsidiary Action Programme
ODPP	Office of Director of Public Prosecutions
PB	Parsons Brinckerhoff
PPA	Power Purchase Agreement
PPRA	Public Procurement Regulatory Authority
PPP	Public Private Partnership
RAP	Resettlement Action Plan
SAPP	Southern Africa Power Pool
SDG	Sustainable Development Goals
SIL	Surge Impedance Loading
SM IA	Senior Manager Internal Audit
SM SCM	Senior Manager Supply Chain Management
STATCOMS	Static Compensators
ToC	Theory of Change
TL	Transmission Line
TMP	Transmission Master Plan
VRE	Variable Renewable Energy
WHO	World Health Organization
ZTK	Zambia Tanzania Kenya

Table of Contents

List of Figures

List of Tables

1 Introduction and Background

Kenya Electricity Transmission Company Ltd (KETRACO) is a state corporation fully owned by the Government of Kenya, and is mandated to plan, design, construct, operate and maintain high voltage power lines, aimed at meeting different electricity needs in the country and Eastern Africa region. The needs include power evacuation from generation points to areas of demand, strengthening the existing power grid, enhancing reliability, and connecting previously unserved load centres through network expansion. This aligns with the Kenya Vision 2030 initiatives of economic, social, and political transformation towards competitive and prosperous Kenya. The LCPDP technical team has developed a medium term Least Cost Power Development plan 2025-2029 highlighting key projects in generation and transmission that are required to meet demand growth over this period.

Since 2008, the company has expanded its transmission infrastructure from 50km to approximately 6,016 kms of circuit length and 44 High Voltage substations with 6,486 MVA capacity as of May 2025. As the demand for electricity continues to rise, coupled with the need to extend and strengthen the national power grid and support regional economic integration, there is a need to establish a long-term Transmission Master Plan (TMP) to guide the implementation of grid expansion. Recognizing the significance of strategic planning, the KETRACO Board and Management identified the necessity for KETRACO to develop and annually review a 20-year TMP, to incorporate any future changes in demand, technology, policy and regulatory changes, risks and other socio-economic factors.

The TMP outlines KETRACO's long-term transmission grid expansion sequence, the associated cost implications, risk mitigation strategies, and financing options for the period between 2025-2044. Additionally, it seeks to provide support for the company's role in operation and maintenance, power system operations, and power market transactions. The transmission plan considers demand projections and the generation plan in the 2025-29 MTP and the 2024-2043 LCPDP.

This plan serves as a roadmap that will outline the Company's long-term transmission network investment strategy for the period between 2025-2044. The TMP will be reviewed, and if deemed necessary, updated annually to guide strategic planning, investment strategies, resource mobilization, and budgeting.

1.1 Objective of the Transmission Master Plan

The plan will guide the Company in:

a. Aligning all the transmission investment requirements to electricity sector priorities;
b. Prioritization of the identified power transmission projects
c. Mobilizing/ sourcing for the financing of the identified projects and aligning with the budget process.

1.2 Scope of Work

The specific scope of work includes undertaking the following activities:

a. Desktop review of the Medium Term LCPDP 2025-2029. Updating forecasted demand and generation expansion sequence over the planning period.
b. Updating planned transmission projects and those under implementation. This provides details of sources and status of financing of the projects.
c. Identify investment requirements for the planning period
d. Preparing resilience and risk mitigation strategies, and a review of the pertinent legislative and compliance framework of the Transmission masterplan.
e. Integrating sustainability and environmental considerations to the plan.
f. Prepare a 20-year Transmission Master Plan document.

The content of this Plan is arranged as follows;

a. Introduction and background
b. Current situation of the Power Sector
c. Electricity demand and generation
d. Transmission expansion plan
e. Resilience and risk mitigation strategies
f. Investment and financing plan
g. Technology and Innovation roadmap
h. Implementation Strategy
i. Stakeholder engagement and public consultation
j. Sustainability and environmental considerations
k. Monitoring, evaluation and review mechanisms.
l. Conclusion and recommendations.
m. Appendices and supporting documentation.

1.3 Policy and regulatory framework

In today's regulatory environment, organizations must navigate a complex web of laws and regulations to maintain compliance and avoid penalties. A policy and regulatory framework comprising of Laws, Regulations, Policies, Procedures, and Controls have been structured to help KETRACO adhere to Legal, Regulatory, and Industry-specific standards while minimizing risks and ensuring ethical business operations. Implementing a robust compliance framework involves risk assessment, policy development, training, and continuous monitoring.

KETRACO is committed to upholding the highest standards of integrity and accountability. By adhering to regulatory requirements, we not only mitigate legal risks but also foster trust among our stakeholders, including customers, employees, and regulatory bodies.

2 Current Situation of the Power Sector

2.1 Electricity Demand & Access

Over the years, Kenya has continued to experience a steady upward trajectory in electricity demand, with peak demand rising from 2,149MW in 2023 to 2,177MW as of June 2024, a reflection of 1.3% increase. Notably, a new peak of 2,316 was recorded in February 2025 underscoring the sustainable growth of energy consumption. The trend in peak demand over the period 2018/19 to 2023/24 is illustrated in Figure 1 below:

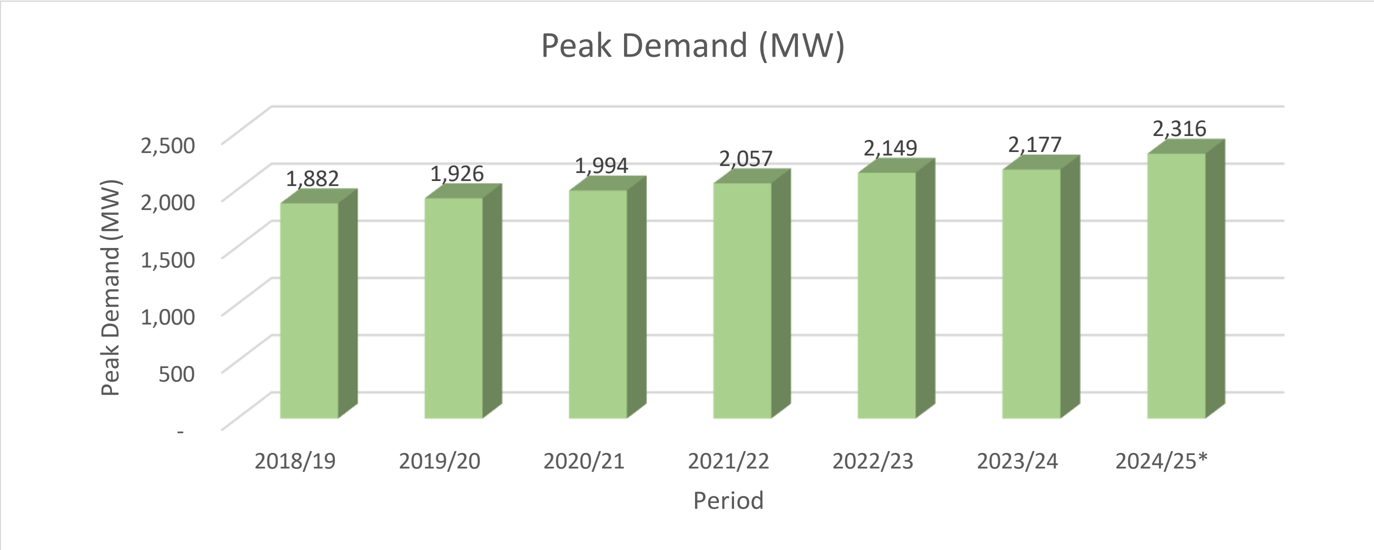


Figure 1: Historical Peak Demand (*Provisional peak demand for the financial year 2024/25)

Source: MTP 2025 - 2029KPLC

The annual growth in peak demand is driven by organic economic and population growth, industrial expansion, urbanization, and expanded grid access. Government initiatives and flagship projects have boosted electricity consumption.

The annual surge in peak demand can be attributed to organic economic growth, industrial expansion, heightened investment, urbanization, and deliberate policies aimed at enhancing electricity access. Through the various government-led initiatives like the Rapid Results Initiative that was launched in October 2023 towards domestic connections through Last Mile Connectivity and targeted government interventions that is aimed at achieving universal access by 2030, the number of consumers connected to the grid in the country increased significantly from 9,218,754 in the financial year 2022/23 to 9,660,005 in the financial year 2023/24, reflecting a 4.9% growth.

The total energy purchased increased from 13,290GWh in the financial year 2022/23 to 13,684GWh in the financial year 2023/24, a 3% growth. Trends in energy purchased from different technologies are highlighted in Table 1 below.

Table 1: Historical Energy Purchased in GWh

Technology Type	**2019/20**	**2020/21**	**2021/22**	**2022/23**	**2023/24**
Hydro	3,693	4,141	3,349	2,569	3,396
Geothermal	5,352	5,034	4,953	6,035	5,708
Thermal	882	940	1,648	1,396	1,127
Cogeneration	0.29	0.33	0.38	0.21	0.11
Solar	91	88	313	444	474

Technology Type	2019/20	2020/21	2021/22	2022/23	2023/24
Wind	1,284	1,700	2,052	2,202	1,781
Imports	161	197	338	644	1,199
Total	11,462	12,101	12,653	13,290	13,684

Source: Kenya Power Annual Report for the year ending June 2024

In the financial year 2023/24, electricity sales grew from 10,233GWh in 2022/23 to 10,516GWh, marking a 2.8% rise. The figure below illustrates the trend in total electricity sales and peak demand over the five-year period.

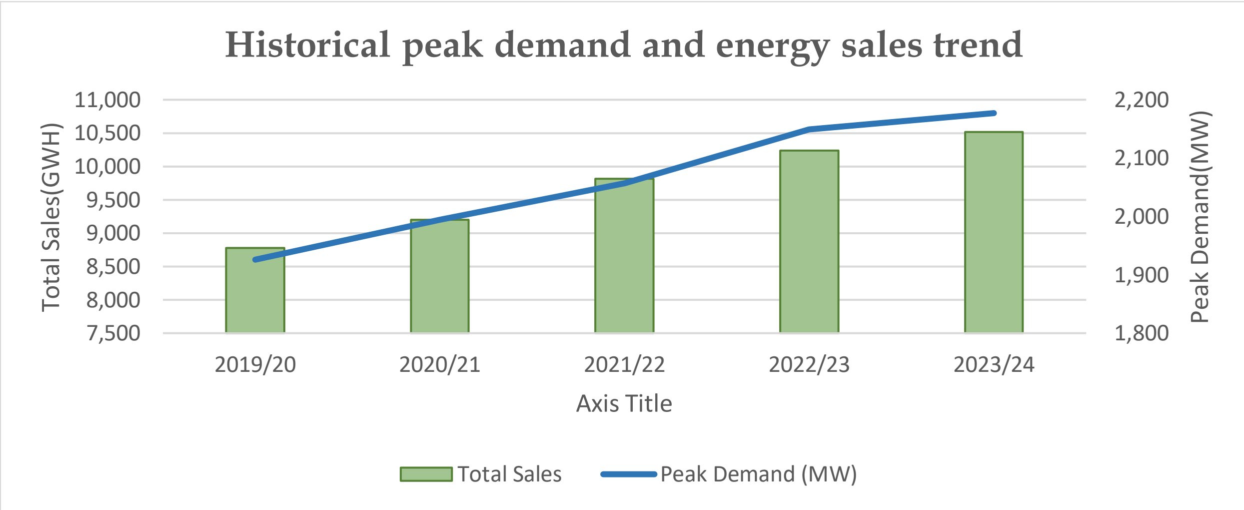


Figure 2 Historical peak demand and energy sales trends

Source: Kenya Power Annual Report for the year ending June 2024

2.2 Electricity Generation

For the past five-year period, Kenya's total installed generation capacity (including off-grid) expanded from 2840 to 3,243MW; the grid installed capacity slightly rising from 3,238MW in 2022/23 to 3,243MW in 2023/24. The cumulative effective/contracted capacity stands at 3,056MW, compared to 3112MW of 2022/23. Table 2-2 shows the installed and effective capacity by technology type as of June 2024.

Table 2: Installed, effective and captive power capacity as of 30th June 2024

Technology	Installed	Effective*/ Contracted	% (effective)	% (Installed)
Hydro	838.2	810.2	25.85%	26.51%
Geothermal	940	876.1	28.99%	28.67%
Thermal (MSD)	513	506	15.82%	16.56%
Thermal (GT)	60	0	1.85%	0.00%
Wind	435.5	425.5	13.43%	13.92%
Biomass	2	2	0.06%	0.07%
Solar	210.3	210.3	6.48%	6.88%
Import	200	200	6.17%	6.54%

Technology	Installed	Effective*/ Contracted	% (effective)	% (Installed)
Interconnected System	3,199	3,030	98.64%	99.15%
Off grid thermal	41	24.2	1.26%	0.79%
Off-grid Solar	2.3	1.7	0.07%	0.06%
Off-grid Wind	0.55	0	0.02%	0.00%
Total Off-grid	43.85	25.9	1.35%	0.85%
Total Capacity MW	**3,243**	**3,056**	**100.00%**	**100.00%**

Source: Kenya Power Annual report for the FY ending June 2024

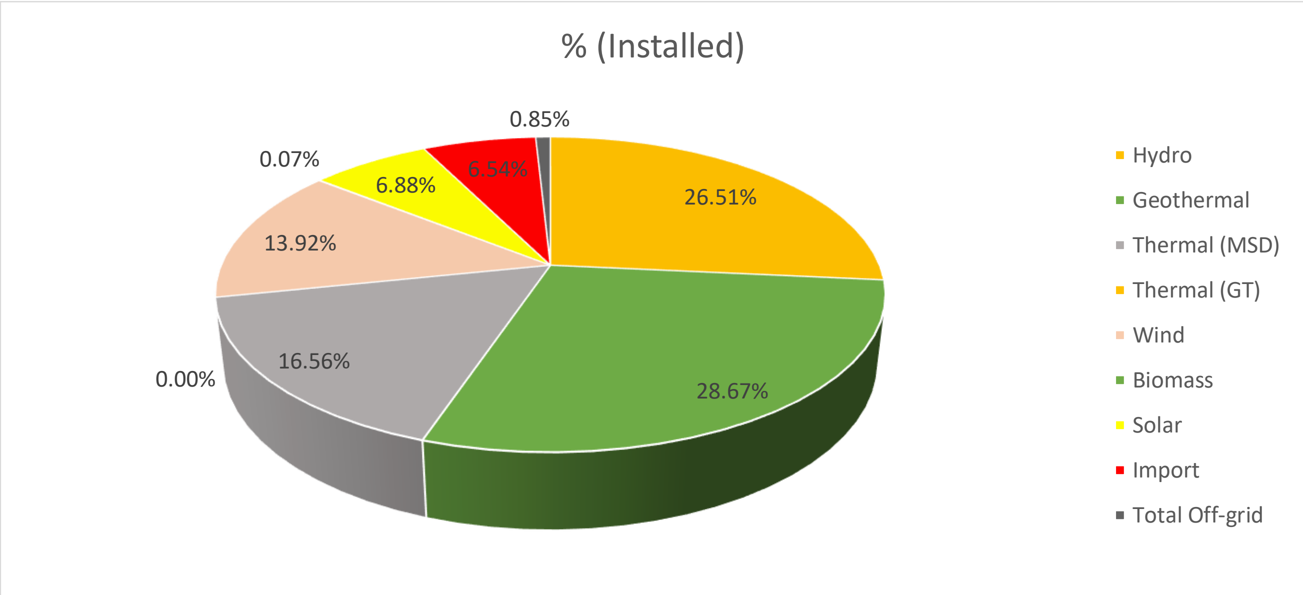


Figure 2: Installed capacity by technology as of June 2024

The Energy generation mix for the financial year ending June 2024 comprised of 41.71% of geothermal, 24.81% hydro, 8.24% fossil fuels, 13.01% wind, 3.46% solar and 8.76% imports. Evolution of energy mix is given on Figure 2

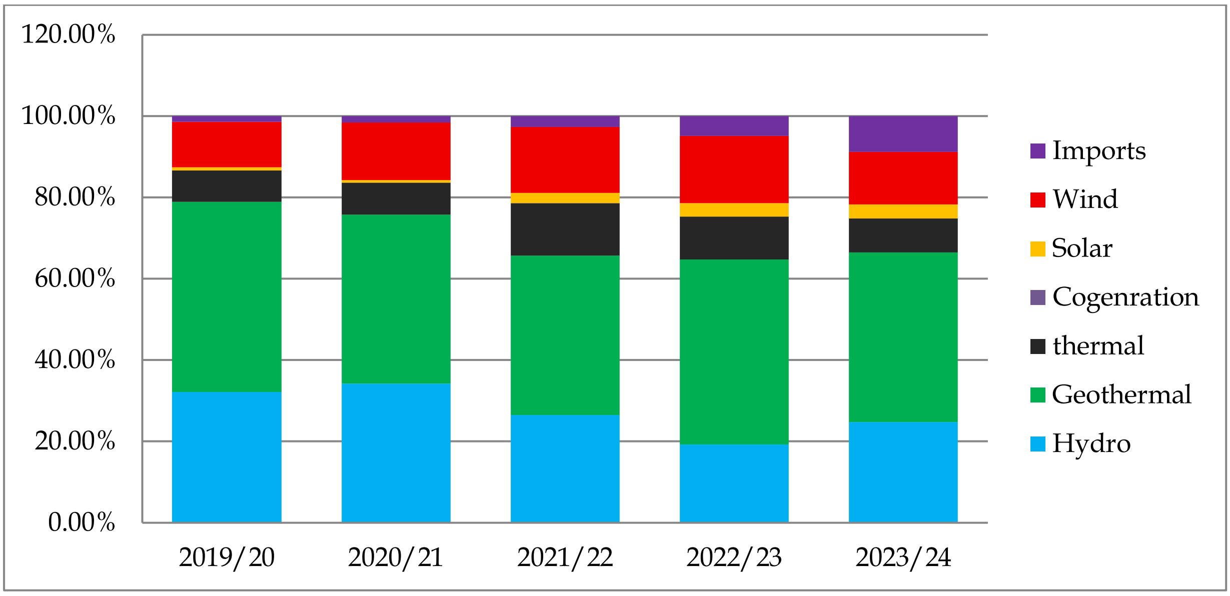


Figure 3 :Historical Generation mix

Source: Kenya Power

The distribution of power generators is as shown in Table 3.

Table 3: Distribution of power generators

Company	**Installed**	**Effective/Contracted**	**% Installed**	**% Effective**
KenGen	1786	1628	55.07%	53.27%
Offgrid	44	26	1.36%	0.85%
IPP	1163	1152	35.86%	37.70%
REREC	50	50	1.54%	1.64%
Imports	200	200	6.17%	6.54%
Total	3243	3056	100.00%	100.00%

Additionally, Captive power generation as approved by EPRA have an installed capacity of 533 MW that use hydro, geothermal thermal, solar, bioenergy, and Waste Heat Recovery Cycle (WHRC) technology according to EPRA Energy and Petroleum Statistics Report FY 2023-2024

2.3 Transmission Network

The power transmission network is currently operating at 132, 220kV, 400kV & 500kV DC. The size of transmission network (400kV, 220kV and 132kV) by circuit length is approximately 9,717 km of which 6,016(62%) is owned and operated by KETRACO. This includes 1,308km of 132kV lines, 835km of 220kV lines, 2,590km of 400kV and 1,282km of 500kV lines. In addition, KETRACO has completed and commissioned 44 new substations with 6,487 MVA capacity and30 bay extensions.Table 4 provides a list of KETRACO completed projects since inception.

Table 4: KETRACO Completed Projects as at May 2025

TRANSMISSION LINES					SUBSTATIONS				Year
S. No	**kV**	**Name**	**Route (KM)**	**Circuit (KM)**	**S. No**	**Name**	**MVA**	**Bays**	
1	132	Kilimambogo-Mang'u	19	38	1	132/66kV Mang'u (2x60MVA)	120		
2	132	Mang'u -Githambo	58	58	2	132/33kV Githambo	23		
3	132	Thika(Mang'u)-Gatundu	30	30	3	132/33kV Gatundu	23		
4	132	Sondu – Kisumu	50	50	4	132kV Sondu			Jul-07
						Kisumu 132kV Bay Ext		1	
5	132	Chemosit – Kisii	62	62	5	132/33 Kisii (2X23)	46		Mar-10
						Chemosit 132kV Bay Ext		1	
6	132	Kisii-Awendo	44	44	6	132/33 kV Awendo (2X23)	46		Dec-17
						Kisii 132kV Bay Ext		1	
7	132	Rabai – Galu	48	48	7	132/33kV Galu (2X23)	46		Mar-10
						Rabai 132kV Bay Extension		1	
8	132	Kamburu- Meru	122	122	8	132/33kV Meru (2X23)	46		Sep-10
						Kamburu 132kV Bay Ext		1	
9	132	Sangoro- Sondu	5	5	9	132/33kV Sangoro SS			Jun-12
						Sondu 132kV Bay Extension		1	
10	132	Mumias-Rangala	34	34	10	132/33kV Rang'ala SS	23		Jun-12
						Mumias 132kV Bay Ext		1	

TRANSMISSION LINES					SUBSTATIONS				Year
S. No	**kV**	**Name**	**Route (KM)**	**Circuit (KM)**	**S. No**	**Name**	**MVA**	**Bays**	
11	220	Rabai-Malindi	128	128	11	220/33KV Malindi SS	23		Jun-13
						Rabai 220kV Bay Ext		1	
12	220	Malindi-Garsen	104	104	12	220/33kV Garsen SS	23		Jun-13
13	220	Garsen-Lamu	96	96	13	132/33kV Lamu	23		Jun-13
14	132	Eldoret-Kitale	66	66	14	132/33kV Kitale (2X23)	46		Jun-16
						Eldoret 132kV Bay Ext		1	
15	132	Meru-Isiolo	26	26	15	132/33kV Isiolo	23		Sep-15
						Meru 132kV Bay Ext		1	
16	132	Kindaruma-Mwingi	29	29	16	132/33kV Mwingi	23		May-16
						Kindaruma 132kV Bay Ext		1	
17	132	Mwingi-Garissa	204	204	17	132/33kV Garissa	8		May-16
						132/11kV Garissa	8		
18	220	Suswa -Olkaria 1AU	25	51	18	220kV Olkaria 1 AU SS	105		Jun-16
19	220	Suswa- Olkaria IV	18	37	19	220kV Suswa	-		
20	220	Olkaria II- Olkaria 1AU	3	6	20	220kv Olkaria IV	-		Aug-16
						Olkaria II 220kV Bay Ext		2	
21	132	Sotik-Bomet	26	26	21	132kV Sotik	-		Aug-16
					22	132/33kV Bomet	23		

TRANSMISSION LINES					SUBSTATIONS				Year
S. No	kV	Name	Route (KM)	Circuit (KM)	S. No	Name	MVA	Bays	
22	132	Ishiara - Kieni	33	33	23	132kV Ishiara Switching Station	-		Dec-16
					24	132/33kV Kieni	23		
23	132	Machakos-Konza	13	13	25	132/33 kV Konza	23		Nov-16
					26	132/33 kV Machakos	23		
24	132	Menengai-Soilo	13	13	27	132kV Menengai	-		Dec-16
						Soilo 132kV Bay Ext		2	
25	132	Awendo-Ong'eng	37	37	28	132/33kV Ong'eng	23		May-18
						Awendo 132kV Bay Ext		1	
26	400	Suswa-Isinya	103	206	29	Isinya 400/220 kV(4x200MVA)	800		Jun-17
						Isinya 220/132 kV	110		
					30	Isinya 132/33 kV	23		
27	400	Athi river-Isinya	44	88					
28	400	Isinya-Mariakani	404	807		Rabai 220kV Bay Ext		2	Jun-17
29	220	Mariakani-Rabai	24	48					
30	400	Loiyangalani-Suswa	436	871	31	Loiyangalani 400kV	-		Aug-18
31	220	Embakasi-Athi River (Cable section repairs circuit I) 220kV	7	14		Embakasi 220kV Bay Ext		2	
32	220	Embakasi-Athi River (Overhead section 220kV)	12	23					

TRANSMISSION LINES					SUBSTATIONS				Year
S. No	kV	Name	Route (KM)	Circuit (KM)	S. No	Name	MVA	Bays	
22	132	Wote – Sultan Hamud	42	42	32	Wote 132/33 1x23MVA	23		Feb-19
					33	132/33 kV Sultan Hamud	23		
34	220	Olkaria IV –Olkaria V	2	3	34	Olkaria V 220kV	-		
35	132	Mwingi-Kitui	46	46	35	Kitui 132/33 kV	23		Sep-20
						220kV Nairobi North Bay Extension (220/66 1x90MVA)	90	1	Oct-20
36	400/220/ 132	Olkaria-Lessos-Kisumu	309	618	36	Kibos 220/132/33 1x150MVA, 2x 45MVA	240		Jun-21
						Olkaria II 220kV Bay Ext (Two Bays)		2	
						Kisumu (Mamboleo) 132kV Bay Ext (Two Bays)		2	
37	132	Olkaria- Narok	68	68	37	Narok 132/33 1x23MVA	23		Jul-22
38	500	Ethiopia-Kenya Interconnector 500kV HVDC (from Suswa to Border)	641	1,282	38	Suswa 500/400kV 4 x 588.3(196.1/Ph)MVA	2,353		Nov-22
						Suswa 400/220kV 3 x 350(117/Ph)MVA	1,050		
					39	Athi River 220kV/66kVSubstation 2 x 200MVA	400		Oct-22
					40	Kimuka 220/66 2x200MVA	400		Mar-24

TRANSMISSION LINES					SUBSTATIONS				Year
S. No	**kV**	**Name**	**Route (KM)**	**Circuit (KM)**	**S. No**	**Name**	**MVA**	**Bays**	
39	220	Turkwel Ortum	68	68	41	220/33kV Ortum (1x23)	23		Dec-23
						Turkwel 220kV Bay Ext (One Bay)			
40	132	Isinya(Kajiado) – Namanga 132kV	94	94	42	132/33kV Namanga (1x23)	23		Feb-24
41	220	Ortum – Kitale	78	78	43	220/132kV Kitale (1x90)	90		Sep-24
42	132	Sultan Hamud – Merueshi-Loitoktok 132kV	107.5	107.5	44	132/33kV Loitotok (1x23)	23		Oct-24
						132kV Sultan Hamud One Bay		1	
43	400	Kenya – Tanzania Interconnector 400kV	96	192					Dec-24
TOTAL			**3,874.5**	**6,015.5**		**Total**	**6,487**	**26**	

The completed transmission lines have realized a range of desired objectives, ranging from power evacuation and supplying new load centers, connecting regions that initially were not connected to the grid, reinforcing/ strengthening the existing transmission network for increased system reliability and transmission efficiency.

KETRACO is currently developing additional transmission projects consisting of power evacuation projects, grid strengthening and regional interconnectors. The projects are at various stages of completion. Table 5 presents the on-going projects currently under implementation.

Table 5: KETRACO Ongoing Projects

S/n	Transmission Line Name	Route Length (Km)	Circuit Length (Km)	Substation Name	MVA	Estimated Total Cost (MUSD)	Outstanding Project Cost (USD Million)
				YEAR 2025			
1	Nairobi Ring substations (Isinya, Athi River, Kimuka, Malaa)	-	-	Malaa 220/66kV 2x200MVA	400	47.76	4.63
2	Mariakani 400/220kV substation	-	-	Mariakani 400/220kV 4x200MVA	800	27.00	-
3	Awendo- Isebania 132kV	50	50	Isebania 132/33kV 1x23	23	129.69	-
4	Isinya-Konza 400KV	45	90	Konza 400/132kV 2x350MVA	700		
5	Rabai-Kilifi 132kV (with inter link to existing 132/33kV SS)	67	67	Kilifi 132/33kV 2x45MVA (new Site)	90	30.15	5.02
6	Rabai-Bamburi-Msa Cem-Vipingo- Kilifi 132kV	76	76				
8	Nanyuki – Isiolo 132kV	70	70			50.96	16.77
9	Nanyuki – Rumuruti 132kV 14.5 km UG cable	14.5	29			17.82	1.69
10	Nanyuki – Isiolo 132kV 5 km UG cable	5	5				
11	Lessos – Kabarnet 132kV	65	65	Kabarnet 132/33kV 1x23MVA	23	109.59	6.01
12	Kitui – Wote 132kV	66	66				
7	Nanyuki – Rumuruti 132kV	79	79	Rumuruti 132/33kV 23MVA	23		
13	Restoration of Longonot Towers						
				Lessos Tx 3 220/132kV 75MVA	75	Cost borne by KPLC	
TOTALS 2025		**537.5**	**597**		**2,134.00**	**412.97**	**34.12**
				YEAR 2026			
1	Narok – Bomet 132kV	88	176	Bomet 132/33kV 23MVA	23	27.07	24.18
				Narok 132/33kV 23 MVA	23		
2	Sondu (Thurdibuoro) – Ongeng (Homa Bay/Ndhiwa) 132kV	69	69			18.84	3.67
				Bomani 132/33kV 23MVA	23	Cost borne by KPLC	
				Kibos 20MVAr reactor	20		
TOTALS 2026		**157**	**245**		**89.00**	**45.91**	**27.85**

S/n	Transmission Line Name	Route Length (Km)	Circuit Length (Km)	Substation Name	MVA	Estimated Total Cost (MUSD)	Outstanding Project Cost (USD Million)
YEAR 2027							
1	Mariakani – Dongo Kundu 220kV Line	55	110	Dongo Kundu 220/33kV 2x75MVA	150	53.03	27.68
2	Garsen -Hola –Bura-Garissa 220kV	240	240	Bura 220/33kV 1x23MVA	23	94.99	52.34
				Hola 220/33kV 1x23MVA	23		
				Garissa 220/132kV 1x60MVA	60		
3	Makindu substation LILO - 400kV	1	4	Makindu 400/132kV 2x90MVA	180	55.37	55.37
	Makindu substation LILO - 132kV	1	4				
4	Rumuruti – Kabarnet 132kV	111	111	Rumuruti Tx2 132/33kV 1x23MVA	23	31.68	31.68
				Kabarnet Tx2 132/33kV 1x23MVA	23		
5	Malindi – Kilifi 220kV	48.5	97	Kilifi 220/132kV 2x90MVA	180	55.67	55.67
6	Malindi -Weru (Circuit II) 220kV	22	22	Malindi 220/33kV 45MVA	45	27.13	27.13
				Olkaria I 11/132kV 1x25MVA (Unit 1and 2)		Cost to be borne by KenGen	
				Olkaria I 11/132kV 1x25MVA (Unit 3)			
7	LILO on Juja/Naivasha 132kV- Maai Mahiu			Maai Mahiu 132/66kV 2x60MVA	120	12.06	12.06
8	Olkaria 1 AU-Olkaria IV /V 220KV	8	16	-		14.76	14.76
	-			STATCOMs (Coast, Nairobi).Suswa 120MVAr ,2x100MVAr STATCOM/DRPC)	Suswa STATCOM 120, MSR 2x100MVAr	100.00	100.00
9	400kV Kimuka - LILO on Suswa– isinya 400kV	2	4	Kimuka 400/220kV 2x200MVA	400	28.59	27.82
TOTALS 2027		**488.5**	**608**		**1,227.00**	**473.28**	**404.51**
YEAR 2028							
1	Loiyangalani – Marsabit 220kV	136	272	Loiyangalani 400/220 2x200MVA	400	126.81	122.46
2	Kamburu-Embu 220KV	150	300	Embu 220/132 2x90MVA	180	40.50	17.25
3	Isiolo - Marsabit 220kV	240	480	Marsabit 220/33kV 2x23MVA	46	127.72	120.63
				Isiolo 220/132kV 1x90MVA	90		
4				National System Control Centre		94.62	67.58
TOTALS 2028		**526**	**1052**		**716.00**	**389.65**	**327.92**
GRAND TOTAL		**1709**	**2502**		**4,166.00**	**1,321.81**	**794.40**

2.4 Distribution Network

The distribution network consists of Medium Voltage (MV) lines of 66kV, 33kV, and 11kV and low voltage (LV) lines of 415/240V and 433/250V. The circuit length of the MV network has grown from 76,161km in June 2019 to 86,212km by June 2024. This includes 1,313km of 66kV lines, 39,940km of 33kV lines, and 44,959km of 11kV lines. The circuit length of the LV lines has grown from 152,799km in June 2019 to 225,413km by June 2024. The total installed capacity of transformers in distribution substations grew from 4,480MVA in June 2019 to 4,956MVA in June 2024.

The system losses, which include both technical and non-technical losses, reduced from 23.7% in June 2019 to 21.2% in June 2024. These losses were in part caused by constraints in the grid due to aging equipment, theft and vandalization of electricity infrastructure, distribution capacity limitations, inadequate supply of meters, faulty metering, and reduced reliability in power supply due to underinvestment.

2.5 Existing Transmission Network Issues/Challenges

According to System Operations Daily Analysis (SODA), the existing system is experiencing challenges related to voltage and frequency instabilities, which pose difficulties in maintaining system stability during operations. These constraints encompass over-voltages, under-voltages, over-frequency, under-frequency, as well as overloading of transmission lines and power transformers.

Some teething issues and operational challenges have been experienced in the operation of the recently commissioned the Kenya-Tanzania 400kV line and the interconnection between the two systems. System disturbances in one country are propagated across the line and affecting the smooth operation of the interconnector. Protection configurations/settings have since been harmonized despite this, over frequency, swing in frequency and reactive power exchange continue to be experienced as a result of inadvertent changes in dispatch attributed to intermittency of Solar and wind resources and inadequate spinning reserves.

The transmission infrastructure has experienced increasing maintenance costs and power supply insecurity due to incidents of vandalism and isolated terror attacks.

There is a deficiency in obtaining monthly meter readings for installed transmission lines and transformers. This affects the ability of the system operator to determine actual transmission losses in the network and may limit system operation data for postmortem analysis. These are summarized in Table 5.

Table 6: Summary of Existing Transmission Line Challenges

S. No	Challenges	Causes	Mitigation
1.	Poor quality of supply as a result of : Over voltages and under voltages at receiving ends.	• Long transmission lines to load centres from generation locations. • Low loads during off peak periods. • Increasing penetration of intermittent renewable energy sources.	• A reactive power compensation study was carried out. The study recommended the installation of reactive power compensation devices including reactors, capacitor banks, STATCOMs and Static Var Generators (SVGs). These are planned to be implemented at Suswa, Rabai, Kibos

S. No	Challenges	Causes	Mitigation
		• Low voltages at peak due to voltage drop as a result of overloading and increasing technical losses	• Use of BESS technology to resolve the voltage challenges due to intermittency. • Segmentation of long transmission lines; Loosuk, Gilgil on Suswa Loiyangalani; Makindu and Voi for Isnya Mariakani and Mutomo for Rabai-Kiambere.
2.	High loading of transmission infrastructure and curtailment of generation.	Insufficient transmission capacities	• Fast track completion of ongoing projects: - Ndhiwa- Sondu, Narok Bomet, Nanyuki-Rumuruti Nanyuki-Isiolo, Rabai-Bamburi-Kilifi • Uprating and expansion of identified transmission infrastructure. • Installation of transmission devices i.e phase shifting transformers on Suswa-Nairobi North line to direct power flows and improve utilization of the existing infrastructure. • Synchronize the protection settings and design transfer capacities for optimal performance in the operation of the transmission line network.
3.	The renewable generation is intermittent, and this will be a challenge to the weak system. The renewables are now significantly penetrating the power system and if not properly managed might lead to system instability.	Increased penetration of uncompensated Renewable Energy Plants.	• Management of entry of the renewables. • Installation of Fast acting reactive compensation devices i.e., STATCOMs/Static Var Generators (SVGs). • Increasing Spinning reserves • Ensuring intermittent FITs projects contribute to the reactive requirements. • Continuous training on dispatch of renewables for NSCC officers • More accurate forecasting methods for wind and solar plants and use of updated renewable energy resource atlas • Installation of battery storage systems for frequency regulation.
4.	Limited generation at the Coast Region and West Kenya. This affects the voltage profiles and system response in the event of system disturbances. Increase interruption to customers connected to 132kv lines on faults occurring on distribution lines	Inadequate transmission capacity and low generation at the Coast region and West Kenya.	• Increase generation at Coast and West Kenya • Installation of Fast acting reactive compensation devices i.e., STATCOMs/Static Var Generators (SVGs). • Investment in new transmission capacity and reactive power compensation devices.

S. No	Challenges	Causes	Mitigation
5.	• Insufficient transformation capacity • Lack of required transmission infrastructure • High cost of infrastructure • Weak electricity infrastructure in West and Coast regions	• New load centres consuming more than anticipated, Garissa 132/11kV, Soilo132/33kV, Ortum 220/33kV substation. • Need to meet Electricity access target of 100% by 2030 • Minimum investments in transmission sector. • Increased evacuation requirement for RE sources	• Transmission reinforcements and substation upgrades (Garissa, Ortum, Rongai, Soilo, Lessos) • Construction of new transmission lines • Completion of Malaa 220/66 kV substation. • Establish 66kV feeders. at Kimuka and Malaa • Ensuring adequate investment for transmission to cater for evacuation of renewable energy sources
6.	Inadequate system security and reliability	Lack of alternative supply paths for generation and key load centres.	• Completion of a link between Olkaria IV /V to Olkaria I AU • Restoration of Loiyangalani-Suswa line to double circuit. • Completion of ongoing 220kV Nairobi Ring (Malaa 220kV Substation) and planned greater 400kV ring. • Completion Narok- Bomet, Kabarnet – Rumuruti, Kitui-Wote loop, Lessos - Loosuk, Operation of the 500kV HVDC link in bi-polar mode.
7.	Vandalism of transmission lines and also high voltage cables.	Vandalism and terrorism	• Co-ordinate with regional and county commissioners • Engage critical infrastructure police unit (CIPU) and the Energy Police Unit • Sensitise local communities on protecting/policing power infrastructure. • Establish toll number to report vandalism cases for immediate action. • Keeping a stock of ERS (mobile substations, and emergency restoration towers). • Maintenance of rich inventory of critical spares and inventory system
8.	Deficiency in obtaining monthly meter readings for installed transmission lines and transformers	Lack of meters on some transmission infrastructure Incompatible meters from different manufacturers. They have not undergone calibration or programming. some meters lack the essential functionalities.	• Installation of meters where they are not available • Replacement and re-configuration of incompatible meters. • Develop standardised specifications for meters. • Establishment of centralized metering system.

2.6 Review of the Implementation of the Previous Plan

This section reviews the status of implementation of the medium-term period of the 2024-2043 TMP. Therefore, the section will consider the actual timeliness of the ongoing and planned projects. Several ongoing projects expected to be completed in 2024 have been deferred to the end of 2025 due to challenges in completion of construction activities, and delays in acquisition of right of way.

The 220kV Turkwel-Ortum-Kitale transmission line was completed with the energization of the Ortum – Kitale section and addition of the 90MVA transformer at Kitale substation. However, it was noted the completed Ortum substation transformer is already fully utilized and the transformer capacity needs to be enhanced.

The 400kV Kenya-Tanzania (Namanga border) project was energized following completion of pending works on the Tanzania side. This project will allows for power exchange between the two countries and promote regional power trade.

The 132kV Sultan Hamud – Loitoktok project was completed and energized. This project will serve to connect Loitoktok and its environs to the high voltage network reinforcing the existing 33kV network and improving reliability of power in Loitoktok and its environs.

Implementation of some projects experienced delays due to the long process of securing financing and long turnaround time in the project preparatory processes.

The expected completion dates for Rumuruti – Kabarnet and Malindi- Kilifi projects have been deferred to 2027 due to long project preparatory processes.

STATCOMs (Rabai and Suswa) and 400kV Kimuka substation projects have been deferred to 2027 to allow sufficient time for project procurement and implementation. However, earlier completion is targeted.

A number of projects have been deferred by a year to allow for preparation, appraisal and sourcing of financing. Table 7 summarizes the implementation of projects in the 2024-2043 KETRACO TMP.

Table 7: Summary of Projects Implementation status

S/n	TL / Substation Name	Projected Commissioning (TMP 2024)	Implementation Status (May 2025)	Remarks-Challenges affecting Project Implementation
1	220kV Malaa substation	2024	Ongoing-96%	Financial challenges with the contracting firm.
2	132kV Kitui-Wote	2024	Ongoing-90%	Inadequate budget allocation affected wayleaves acquisition and payment to the contractor.
3	132kV Lessos-Kabarnet	2024	Ongoing-94%	Inadequate budget allocation affected wayleaves acquisition
4	400/220kV Mariakani substation	2024	Ongoing-99%	Addition of scope
5	132kV Rabai – Bamburi - Mombasa Cement – Vipingo - Kilifi	2024	Ongoing-76%	Addition of scope Court order on LILO section stopping works. Most of the Project Affected Persons (PAPs) are squatters hence difficult in compensation as a result lack of documents
6	14.5km 132kV Nanyuki - Rumuruti UG cable	2024	Ongoing- 68. 7%	Delay in mobilization by the contractor
7	5km 132kV Nanyuki-Isiolo UG cable	2024	Ongoing – 68.7%	Delay in mobilization by the contractor

3 Electricity Demand and Generation Projection

Electricity demand projections and the generation expansion plan adopted in this plan is in line with the forecast/projections in the following Electricity Sub-Sector plans;

i. Medium Term Plan 2025-2029 for the period ending 2029
ii. LCPDP 2024-2043 for the period beyond 2029 to the end of the planning period.

This Transmission Master Plan therefore is aligned to the demand and generation projections from the LCPDP planning process.

3.1 Electricity Demand

Electricity demand in Kenya is primarily driven by economic growth, population growth, urbanization, key government priority projects, upcoming technologies, and rising household consumption.

The main factors influencing demand growth considered were demography, GDP growth, Specific Vision 2030 Flagship projects, E-cooking, and E-Mobility.

Kenya Vision 2030 Flagship Projects

Energy Plays a significant role in achieving the goals as outlined in the Kenya Vision 2030. The vision highlights several flagship projects anticipated to significantly influence the country's electricity demand. The government has since been implementing generation, transmission, and distribution projects with primary objectives of increasing electricity access, strengthening the grid, and enhancing power supply reliability.

Flagship projects considered both in the reference and vision scenario, years of consideration and load requirements are indicated in Table 8.

Table 8: Electricity Demand Forecast of Key Flagship Projects

Project	Reference scenario				Vision scenario			
	First year of operation	Initial load [MW]	Year of total load	Total load [MW]	First year of operation	Initial load [MW]	Year of total load	Total load [MW]
Electrified Mass rapid transit system for Nairobi	2029	1	2044	50	2028	1	2035	50
Data Centre (IX Africa)	2025	40	2025	40	2025	40	2025	40
Oil Pipeline and Port Terminal (LAPSSET)	2026	1	2040	35	2025	1	2030	35
Special Economic Zones (Tatu City, Athi River, Eldoret)					2025	5	2039	60
Special Economic Zones (Kedong, Dongo Kundu, Konza)	2025	5	2042	60	2025	5	2040	60
E-Mobility	2024	23.5	2030	219.2	2024	23.5	2030	273
Special Economic Zones (KenGen, Marathon Data Centre)	2026	30	2028	100	2026	30	2028	100

Project	Reference scenario				Vision scenario			
E-Cooking	2024	1.2	2030	34.7	2024	1.2	2030	45.7

Source: MTP 2025-2029

Government Priority areas

Electricity demand in Kenya is expected to grow steadily in the coming years driven by various government-led development initiatives that aim to transform and sustain the economy. Strategic programs target housing, industrialization, digitalization, and energy transition, which intend to significantly increase Kenya's energy consumption.

Demand Forecast Results

Peak Demand

Demand in electricity consumption is growing owing to the various demand drivers. The projected growth in system peak demand over the planning period increases from 2,288MW in 2024 to 2,847MW in 2029 in the reference scenario and 8,710MW in 2044. In the vision and low scenarios, the peak demand is forecasted to reach 3,493MW and 2,532MW by 2029 and 14,786MW and 5,209MW by 2044 respectively as indicated in Figure 6 below. The average growth rate over the planning period for reference, vision and low scenarios is 6.92%, 9.81% and 4.21% respectively.

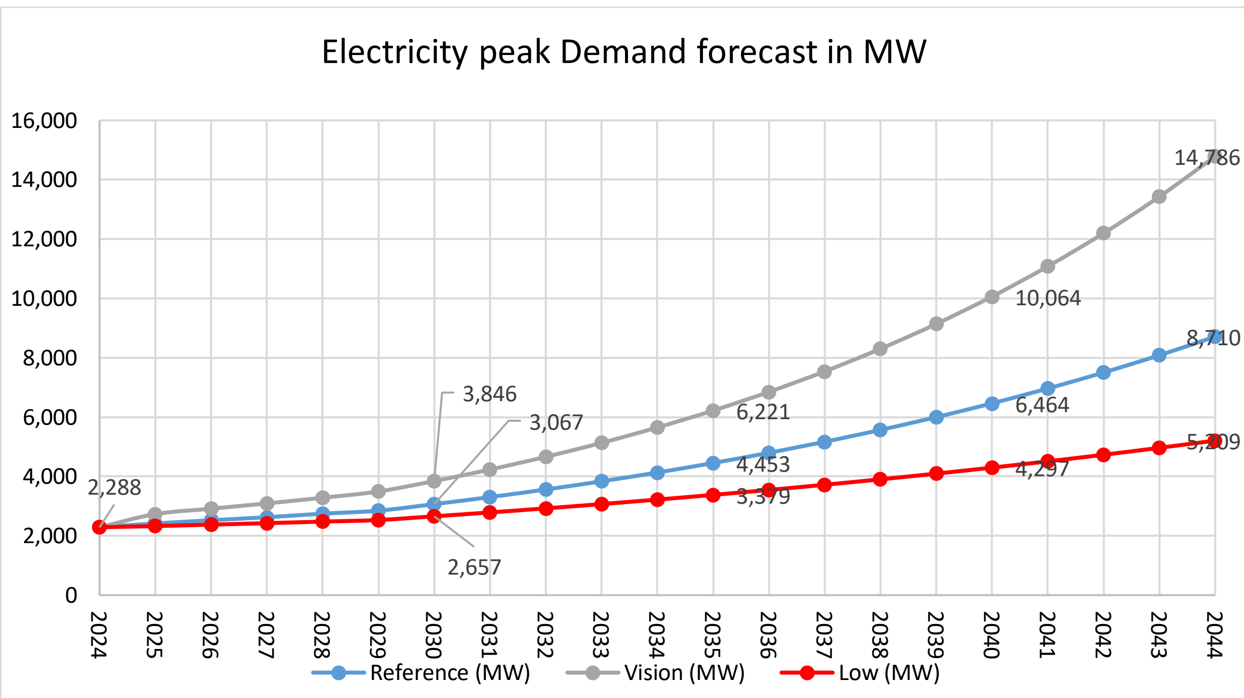


Figure 4: Electricity peak Demand forecast in MW

Source: LCPDP 2024-2043 and MTP 2025-20029

Electricity consumption is expected to rise from 10,763 GWh in 2024 to 13,595 GWh in 2029 in the reference scenario, 16,548 GWh in the Vision scenario and 12,934 GWh in the low scenario by 2029, and 36,328GWh, 65,525GWh and 25,996GWh by 2044 as indicated in figure 7

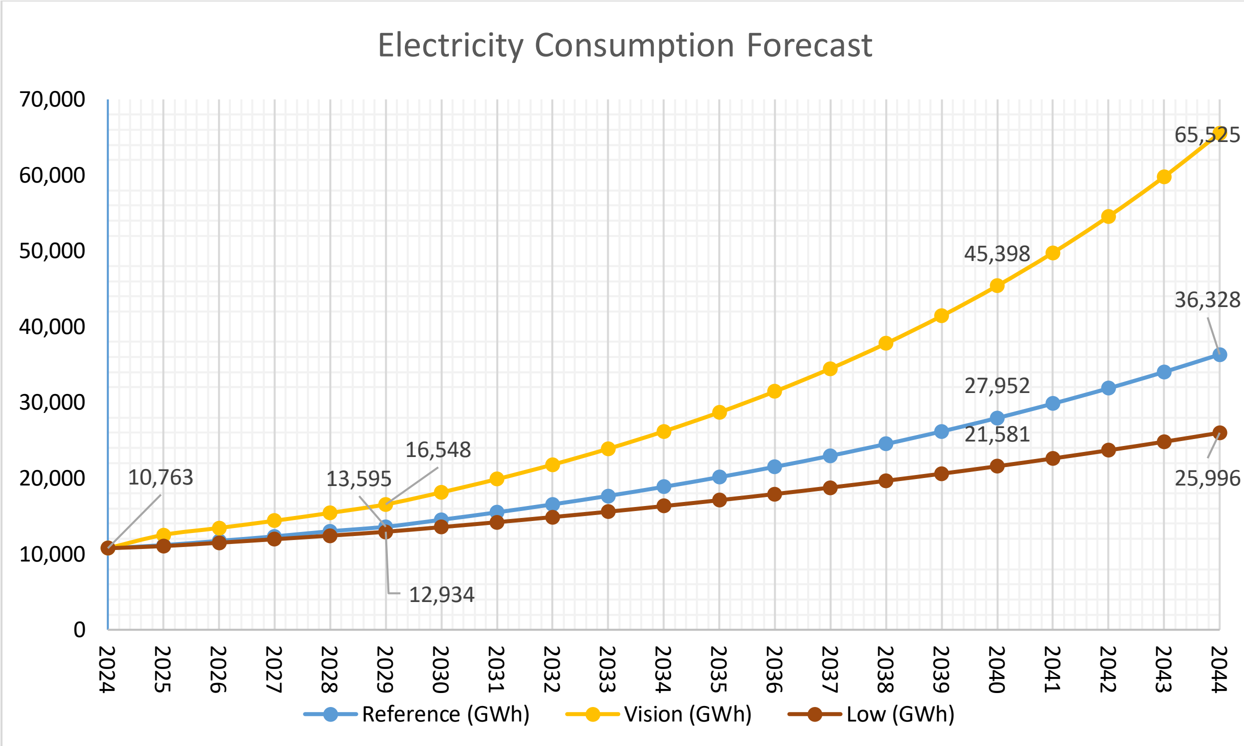


Figure 5: Electricity Consumption

Source: Least Cost Power Development Plan 2024-2043 and MTP 2025-2029

3.2 Generation Projection

The total interconnected effective capacity is projected to grow from 3,058 MW in 2024 to 4,719 MW in the medium term (2029) and to 12,819 MW by 2044 in the reference scenario. This growth in installed capacity is expected to meet the forecasted growth in peak demand plus reserve margin of 9,217 MW by 2044. From the results, Geothermal energy is anticipated to be the largest contributor to total firm capacity, averaging 40% annually over the planning period. One of the key recommendations in the medium term is to fast-track additional 200MW Ethiopia import scheduled for 2027 and LNG power plant in 2027 to address the projected peaking capacity gaps under the reference demand scenario. Battery Energy Storage Systems (BESS) and pumped storage will also play crucial roles in ensuring grid stability, together contributing 18% of the firm capacity mix by 2044. Nuclear power is expected to be introduced in 2034, reaching up to 9% of the total firm capacity mix by the end of the planning period. Renewable energy sources will account for 63% of the firm capacity mix, with variable renewable energy (VRE) sources representing 5% of this total by the end of the planning period. All existing diesel and gasoil power plants are slated for decommissioning by 2035.

There is a supply gap in 2025 and 2026 of 286 MW and 322 MW respectively. The average reserve margin over the planning period is 13%. Details of the reverse margin by year are in the Annexes. Table 8 shows the 20-year generation expansion sequence.

Table 9: 20-year Generation Expansion Sequence

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
End of 2024				**3,081.8**	**2,371**	**2,288**		
2025	KTDA - Nyambunde, Nyakwana	Small Hydro	0.5		0.13		Kegati 132/33kV	Cost of connection will be borne by the developer
2025	Marco Borero Co Ltd.	PV	1.5		-		Kiganjo 132/33kV	Cost of connection will be borne by the developer
2025	REA Vipingo Plantations Ltd (DWA Estates Ltd)	Biomass	1.44		0.72		Kiboko 132/33kV	Cost of connection will be borne by the developer
End of 2025			**3.44**	**3,085.2**	**2,372**	**2,416**		
2026	KTDA Ltd, Lower Nyamindi	Small Hydro	0.8		0.2		Kutus132/33kV	Cost of connection will be borne by the developer
2026	KTDA Ltd, South Maara (Greater Meru Power Co.)	Small Hydro	1.5		0.38		Kieni132/33kV(Marima33/11kV)	Cost of connection will be borne by the developer
2026	KTDA Ltd, Iraru	Small Hydro	1		0.25		Meru132/33kV(Kanyakine33/11)	Cost of connection will be borne by the developer
2026	Mt Kenya Community Based Organisation	Small Hydro	0.6		0.15		Meru 132/33kV (Meru 33/11)	Cost of connection will be borne by the developer
2026	Kleen Energy Limited	Small Hydro	6		1.5		Kutus 132/33kV (Embu 33/11kV)	Cost of connection will be borne by the developer
2026	Menengai 1 Phase I - Stage 1 (Quantum)	Geothermal	35		35		Menengai 132kV	Additional cost of connection will be borne by the developer
2026	Menengai 1 Phase I - Stage 1 (Orpower22)	Geothermal	35		35		Menengai 132kV	Cost of connection will be borne by the developer
2026	KPRL	Diesel	8.3		8.3		Awendo 33kV	Cost of connection will be borne by KenGen
2026	Kipevu I	Diesel	50		50		Hilltop 132kV	Cost of connection will be borne by KenGen
2026	Gogo Existing small hydro	Small Hydro	-1.6		-0.4		Decommissioning	N/A
2026	Muhoroni GT 1	Gas turbines (gasoil)	-26		-26		Decommissioning	N/A
2026	Muhoroni GT 2	Gas turbines (gasoil)	-26		-26		Decommissioning	N/A

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
End of 2026			**84.6**	**3,169.8**	**2,450**	**2,523**		
2027	Tindinyo Falls Resort	Small Hydro	2.4		0.6		Cheptulu ex Kisumu 33kV feeder	Cost of connection will be borne by the developer
2027	Olkaria 1 - Unit 1 Rehabilitation	Geothermal	20		20		Olkaria I 132kV	The additional cost of connection will be borne by KenGen as part of the project
2027	Olkaria 1 - Unit 2 Rehabilitation	Geothermal	20		20		Olkaria I 132kV	The additional cost of connection will be borne by KenGen as part of the project
2027	Olkaria 1 - Unit 3 Rehabilitation	Geothermal	20		20		Olkaria I 132kV	The additional cost of connection will be borne by KenGen as part of the project
2027	Baringo Silali - Paka I&II	Geothermal	100		100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Loosuk-Baringo-Lessos 400kV line must be ready
2027	Menengai II-Stage I (Modular)	Geothermal	10		10		Menengai 132kV	Cost of connection will be borne by the developer
2027	Prunus	Wind+ BESS	50		12.5		Kimuka 220/66kV	Cost of connection will be borne by the developer
2027	Chania Green	Wind +BESS	50		12.5		Kimuka 220/66kV	Cost of connection will be borne by the developer
2027	Aperture	Wind+ BESS	50		12.5		Limuru 66/11kV	Cost of connection will be borne by the developer
2027	Tarita Green (Kaptagat)	PV+BESS	40		-		Lessos-Kabarnet132kVline	Cost of connection will be borne by the developer
2027	Kisumu Solar One	PV+BESS	40		-		Kibos220/132/33kVsubstation	Cost of connection will be borne by the developer
2026	Kopere Solar Park Limited	PV+BESS	40		-		Lessos-Muhoroni 132kV line	Cost of connection will be borne by the developer
2027	Kenergy Renewables Ltd-Rumuruti	PV+BESS	40		-		Rumuruti 132/33kV	Additional cost of connection will be borne by the developer-Nanyuki-Rumuri 132kV line must be ready
2027	Kibwezi One Energy Limited	PV+BESS	40		-		Kiboko 132/33kV	Cost of connection will be borne by the developer
2027	Hannan Arya Energy (K) Ltd	PV+BESS	10		-		Kajiado 132/33kV	Cost of connection will be borne by the developer
2027	Seven Forks (Kamburu) Solar Power Plant	PV	42.5		-		Kamburu 220/132kV	cost of connection will be borne by KenGen

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2027	HVDC Ethiopia2	Import	200		200		Suswa Converter Station	Installation of STATCOM required at Suswa as this necessitates switching of 2nd Filter
2027	BESS_1	BESS	100		50		Embakasi 220kV	Cost of connection will be borne by the developer
2027	BESS_3	BESS	50		25		Kegati 132/33kV	Cost of connection will be borne by the developer
End of 2027			**924.9**	**4,094.7**	**2,933**	**2,626**		
2028	Raising Masinga	Hydropower	-		-			
2026	Gogo upgrade	Small Hydro	8.6		2.15		Awendo 132/33kV	Cost of connection will be borne by KenGen
2028	Olkaria 7	Geothermal	80		80		Olkaria 1AU 220kV	Cost of connection will be borne by the developer
2028	Olkaria 1 AU 4 & 5 uprating	Geothermal	20		20		Olkaria1AU220kV	No new investment
2028	Olkaria IV Uprating	Geothermal	20		20		OlkariaIV220kV	No new investment
2028	Electrawinds Bahari	Wind+ BESS	50		12.5		Garsen-Lamu 220kV line	Cost of connection will be borne by the developer
2028	BESS_2	BESS	100		50		Lessos 220/132kV	Cost of connection will be borne by the developer
2028	Isiolo Power (Greenmillenia Energy) Limited	PV+BESS	40		-		Isiolo 132/33kV Substation	Cost of connection will be borne by the developer
2028	KenGen LNG	LNG	200		200			The additional cost of connection will be borne by KenGen as part of the project
2028	KenGen Olkaria Wellheads I	Geothermal	-44.6		-44.6		Decommissioning	N/A
End of 2028			**474**	**4,568.7**	**3,273**	**2,745**		
2029	KTDA Chemosit	Small Hydro	0.25		0.06		Chemosit 132/33kV	Cost of connection will be borne by the developer
2029	Frontier Investment Management/ Nithi Hydro	Small Hydro	5.6		1.4		Kieni 132/33kV(Marima 33/11kV)	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2029	Gem Gen Power Company Limited	Small Hydro	9.5		2.38		Rangala 132/33kV (Nyamninia 33/11kV)	Cost of connection will be borne by the developer
2029	Power Technologies (Gatiki Small Hydro Plant)	Small Hydro	9.6		2.4		Kiganjo 132/33kV Substation (Karatina-Mukurweini 33kV line)	Cost of connection will be borne by the developer
2029	Rieke Ltd (Kaiuthi SHPP-Sagana I)	Small Hydro	20		5		Kutus-Kiganjo 132kV line	Cost of connection will be borne by the developer
2029	Rieke Ltd (Ithanji SHPP-Sagana II)	Small Hydro	20		5		Kutus-Kiganjo 132kV line	Cost of connection will be borne by the developer
2029	Global Sustainable-Kaptis	Small Hydro	14.7		3.68		Cheptulu ex Kisumu 33kV feeder	Cost of connection will be borne by the developer
2029	Global Sustainable Ltd-Buchangu	Small Hydro	4.5		1.13		Webuye 132/33kV	Cost of connection will be borne by the developer
2029	Mutunguru Hydroelectric Company Ltd	Small Hydro	7.8		1.95		Meru 132/33kV (Kenyakine 33/11)	Cost of connection will be borne by the developer
2029	Khalala Hydro Power Kenya Limited (Coastal Energy Ltd, Navakholo)	Small Hydro	20		5		Musaga 132/33kV	Cost of connection will be borne by the developer
2029	Ventus Energy Ltd	Small Hydro	7.7		1.93		Webuye 132/33kV	Cost of connection will be borne by the developer
2029	Olkaria II Extension (Olkaria 6)	Geothermal	140		140		Olkaria II 220kV	Cost of connection will be borne by the developer
2029	Ol-Danyat Energy	Wind+ BESS	10		2.5		LILO on Matasia-Magadi 66kV line	Cost of connection will be borne by the developer
2029	Marsabit Phase I - KenGen	Wind+ BESS	200		50		Loiyangalani 400/220kV Substation	Cost of connection will be borne by Kengen
2029	Kwale Int. Sugar Co. Ltd	Biomass	10		5		Kwale Sugar 132kV Substation	Cost of connection will be borne by the developer-Base Titanium-Kwale Sugar 132kV line must be completed
2029	Tana Biomass Generation Limited (Biogas-Solar Hybrid)	Biomass	20		10		Garsen 220/33kV	Cost of connection will be borne by the developer
2029	Olkaria 2	Geothermal	-101		-101		Decommissioning	N/A
End of 2029			**398.65**	**4,967.4**	**3,410**	**2,847**		

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2030	Thika Way Investments (Homa Bay Biogas One)	Biomass	8		4		Sondu 132/33kV Substation	Cost of connection will be borne by the developer
2030	UETCL Import2	Import	150		150		Tororo 220/132kV Substation	Lessos-Tororo 220kV line and asspociated substations must be ready
2030	BESS_4	BESS	50		12.5		Rabai 220/132kV	Cost of connection will be borne by the developer
2030	Makindu solar ltd	PV+BESS	30		0		Makindu 132kV	Cost of connection will be borne by the developer
2030	Greenlight Holdings/ Rianjue/Gichuki Ventures	Small Hydro	1.5		0.375		Kutus 132/33kV	Cost of connection will be borne by the developer
2030	Pumped hydro storage - Unit 1	Pumped storage	300		300		Ortum 220kV/33kV	Cost of connection will be borne by the developer
2030	Kenya Solar Energy	PV+BESS	40		-			Cost of connection will be borne by the developer
2030	Mwikhupo-Mwibale Hydro Power Kenya	Small Hydro	7		1.75		Musaga 132/33kV	Cost of connection will be borne by the developer
2030	Virunga Power Holdings Ltd, R. Sossio, Kaptama	Small Hydro	4.5		1.125		Webuye 132/33kV	Cost of connection will be borne by KenGen
2030	Njega/Rukenya Hydro Power Limited (Rights transfer)	Small Hydro	3.5		0.875		Githambo 132/33kV	Cost of connection will be borne by the developer
2030	Western Hydro	Small Hydro	10		2.5		Webuye 132/33kV	Cost of connection will be borne by the developer
2030	Kibisi Kinetic Energy Limited/Virunga Power Holdings	Small Hydro	6.5		1.625		Webuye 132/33kV	Cost of connection will be borne by the developer-More 220/132kV Transformers required at Kitale and the Kitale-Webuye 132kV line
2030	Kirogori Electrification Project	Small Hydro	7		1.75		Githambo 132/33kV	Cost of connection will be borne by the developer
2030	KTDA R. Chemosit, Chemosit	Small Hydro	2.5		0.625		Chemosit 132/33kV	Cost of connection will be borne by the developer
2030	Rareh Nyamindi Hydro Ltd- Mbiri	Small Hydro	5.2		1.3		Kutus 132/33kV	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2030	Rareh Nyamindi Hydro Ltd- Kiamutugu	Small Hydro	9.4		2.35		Kutus 132/33kV	Cost of connection will be borne by the developer
2030	Rareh Nyamindi Hydro Ltd-Gitie	Small Hydro	6		1.5		Kutus 132/33kV	Cost of connection will be borne by the developer
2030	VSHydro Kenya Ltd	Small Hydro	9.1		2.275		Kieni 132/33kV	Cost of connection will be borne by the developer
2030	Roadtech Solutions Ltd	Biomass	10		5		Kajiado 132/33kV	Cost of connection will be borne by the developer
End of 2030			**660.2**	**5,627.6**	**3,899**	**3,067**		
2031	High Grand Falls Stage 1+2	Hydropower	693		549.7		High Grand Fall then 400kV line to Malaa Substation	Cost of connection will be borne by the developer. High Grand Falls-Malaa 400kV line and Malaa 400kV Substation required
2031	Karuga Gitugi Electrification Project	Small Hydro	2.7		0.68		Githambo 132/33kV	Cost of connection will be borne by the developer
2031	KTDA Chemosit, Kiptiget	Small Hydro	3.3		0.83		Chemosit 132/33kV	Cost of connection will be borne by the developer
2031	KTDA Ltd, Yurith, Chemosit	Small Hydro	0.9		0.23		Chemosit 132/33kV	Cost of connection will be borne by the developer
2031	KTDA R. Rupingazi, Rutune	Small Hydro	1.8		0.45		Kutus 132/33kV	Cost of connection will be borne by the developer
2031	KTDA, R. Itare, Chemosit	Small Hydro	1.3		0.33		Chemosit 132/33kV	Cost of connection will be borne by KenGen
2031	KTDA, R. Yala, Taunet	Small Hydro	2.8		0.7		Cheptulu ex Kisumu 33kV feeder	
2031	Tridax Limited	Small Hydro	4.2		1.05		Kutus 132/33kV	Cost of connection will be borne by the developer
2031	Truck city ltd	Small Hydro	5.3		1.33		Webuye 132/33kV	Cost of connection will be borne by the developer
2031	Rabai Diesel (CC-ICE)	Diesel engines	-88.6		-88.6		Decommissioning	N/A
End of 2031			**626.7**	**6,254.3**	**4,366**	**3,305**		
2032	Karura	Hydropower	90		70.68		Karura	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2032	Eburru 2	Geothermal	25		25		Eburru/Naivasha	Cost of connection will be borne by the developer
2032	Chevron Africa Limited	Small Hydro	7.8		1.95		Meru 132/33kV	Cost of connection will be borne by the developer
2032	Dominion Farms	Small Hydro	1		0.25		Rangala 132/33kV	Cost of connection will be borne by the developer
2032	Webuye Falls-KenGen	Small Hydro	40		10		Webuye 132/33kV	Cost of connection will be borne by KenGen
2032	Viability Africa (Northern Energy Limited)	Biomass	2.4		1.2		Garissa 132/33/11kV	Cost of connection will be borne by the developer
2032	Cummins Cogeneration Kenya Limited	Biomass	8.4		4.2		Kabarnet 132/33kV	Cost of connection will be borne by the developer
2032	Baringo Silali Paka II	Geothermal	100		100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Cost of connection will be borne by the developer
2032	Suswa I	Geothermal	100		100		Suswa 220kV	Cost of connection will be borne by the developer
2032	Electrawinds Bahari Phase 2	Wind+ BESS	40		10		Garsen-Lamu 220kV line	Cost of connection will be borne by the developer
2032	Meru Phase 1	Wind+ BESS	80		10		Isiolo 132/33kV Substation	Cost of connection will be borne by the developer
2032	BESS_5	BESS	150		37.5		Weru 220kV	Cost of connection will be borne by the developer
2032	Kipevu 3	Diesel engines	-115		-115		Decommissioning	Cost of connection will be borne by the developer
2032	KenGen Olkaria Wellheads II & Eburru	Geothermal	-27.5		-27.5		Decommissioning	Cost of connection will be borne by the developer
End of 2032			**502.1**	**6,756.4**	**4,594**	**3,561**		
2033	Olkaria II Rehabilitation	Geothermal	105		105		Olkaria II 220kV Substation	Cost of connection will be borne by KenGen
2033	Olkaria 8	Geothermal	140		140		Longonot/Olkaria II/Naivasha	Cost of connection will be borne by the developer
2033	Menengai I Stage II	Geothermal	60		60		Menengai 132kV	Cost of connection will be borne by the developer

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2033	Njumbi Hydropower Plant Ltd (Hydroneo)	Small Hydro	9.6		2.4		Githambo 132/33kV	Cost of connection will be borne by the developer
2033	Hydel	Small Hydro	5		1.25		Githambo 132/33kV	Cost of connection will be borne by the developer
2033	VR Holding AB-Local Trade Ltd	Biomass	3		1.5		Musaga 132/33kV	Cost of connection will be borne by the developer
End of 2033			**322.6**	**7,079.0**	**4,891**	**3,836**		
2034	Nuclear Unit 1	Nuclear	291.3		291		Kilifi 400kV	Cost of connection will be borne by NUPEA (GoK)-Kilifi-Mariakani 400kV line required
2034	Meru Phase II	Wind+BESS	100		25		Isiolo 132/33kV Substation	Cost of connection will be borne by the developer
2034	Generic small hydro	Small Hydro	22		5.5		Githambo 132/33kV	Cost of connection will be borne by the developer
2034	West Kenya Sugar Company Limited	Biomass	6		3		Musaga 132/33kV	Cost of connection will be borne by the developer
2034	Biogas Holdings Ltd	Biogas	0.3		0.15			Cost of connection will be borne by the developer
2034	Generic PV	PV+BESS	40		-		Narok	Cost of connection will be borne by the developer
End of 2034			**459.6**	**7,538.6**	**5,216**	**4,133**		
2035	Menengai IV	Geothermal	100		100		Menengai 400kV	Menengai 400kV Substation and Menengai-Rongai 400kV line required
2035	Baringo Silali - Korosi /Chepchuk I	Geothermal	100		100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Cost of connection will be borne by the developer
2035	AGIL Longonot Stage 1	Geothermal	35		35		Longonot/Olkaria II/Naivasha	Cost of connection will be borne by the developer
2035	AGIL Longonot Stage 2	Geothermal	35		35		Longonot/Olkaria II/Naivasha	Cost of connection will be borne by the developer
2035	AGIL Longonot Stage 3	Geothermal	35		35		Longonot/Olkaria II/Naivasha	Cost of connection will be borne by the developer
2035	Marsabit Phase II - KenGen	Wind+ BESS	200		50		Loiyangalani 400/220kV Substation	Loosuk-Baringo-Lessos 400kV line must be ready

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2035	Generic small hydro	Small Hydro	22		5.5		Kiganjo 132/33kV	Cost of connection will be borne by the developer
2035	Generic Wind	Wind+ BESS	50		12.5		Kipeto 220kV Extension	Cost of connection will be borne by the developer
2035	Generic PV	PV+BESS	40		0		Isiolo 132/33kV Substation	Cost of connection will be borne by the developer
2035	Generic Biomass	Biomass	18		9		Sondu-Ndhiwa-Awendo 132kV line	Cost of connection will be borne by the developer
2035	Regional Trade 1 A	Import	100		100		Ethiopia-Kenya/Kenya-Tnzania/Kenya-Uganda	N/A
2035	Regional Trade 1 B	Import	100		100		Ethiopia-Kenya/Kenya-Tnzania/Kenya-Uganda	N/A
2035	Athi River Gulf	Diesel engines	-80.32		-80.32		Decommissioning	Cost of connection will be borne by the developer
2035	Iberafrica 2	Diesel engines	-52.5		-52.5		Decommissioning	Cost of connection will be borne by the developer
2035	Thika (CC-ICE)	Diesel engines	-87		-87		Decommissioning	Cost of connection will be borne by the developer
End of 2035			**615.18**	**8,153.7**	**5,578**	**4,453**		
2036	Olkaria 9	Geothermal	140		140		Longonot/Olkaria II/Naivasha	Cost of connection will be borne by KenGen
2036	Nuclear Unit 2	Nuclear	291.3		291.3		Kilifi 400kV	Cost of connection will be borne by the developer
2036	Generic small hydro	Small Hydro	22		5.5		Webuye 132/33kV	Cost of connection will be borne by the developer
2036	Generic Biomass	Biomas	18		9		Malindi (Kakuyuni) 220kV	Cost of connection will be borne by the developer
2036	Generic PV	PV+BESS	40		-		Ndhiwa 132/33kV	Cost of connection will be borne by the developer
2036	Ngong 1, Phase II	Wind	-20.4		-5.1		Decommissioning	Cost of connection will be borne by KenGen
2036	Triumph (Kitengela)	Diesel engines	-83		-83		Decommissioning	N/A
End of 2036			**407.9**	**8,561.6**	**5,936**	**4,798**		

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2037	AGIL Longonot Stage 4	Geothermal	35		35		Longonot/Olkaria II/Naivasha	Cost of connection will be borne by the developer
2037	Pumped hydro storage - Unit 2	Pumped storage	300		300		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Loosuk-Baringo-Lessos 400kV line must be ready
2037	Meru Phase III	Wind+ BESS	220		55		Isiolo 220kV Substation	Cost of connection will be borne by the developer
2037	Generic small hydro	Small Hydro	22		5.5		Cheptulu ex Kisumu 33kV feeder	Cost of connection will be borne by the developer
2037	Generic Wind	Wind+ BESS	50		12.5		Isiolo 132/33kV Substation	Cost of connection will be borne by the developer
2037	Generic Biomass	Biomas	18		9		Sultan Hamud 132/33kV	Cost of connection will be borne by the developer
2037	Generic PV	PV+BESS	40		-		Rumuruti 132/33kV	Cost of connection will be borne by the developer
End of 2037			**685**	**9,246.6**	**6,353**	**5,169**		
2038	Suswa II	Geothermal	100		100		Suswa 220kV	Cost of connection will be borne by the developer
2038	Nuclear Unit 3	Nuclear	291.3		291.3		Kilifi 400kV	Cost of connection will be borne by NUPEA (GoK)-Kilifi-Mariakani 400kV line required
2038	Generic small hydro	Small Hydro	22		5.5		Meru 132/33kV	Cost of connection will be borne by the developer
2038	Generic Biomass	Biomas	18		9		Ruai 66kV	
2038	Generic PV	PV+BESS	40		-		Nanyuki 132/33kV	Cost of connection will be borne by the developer
2038	OrPower4 Plant 2	Geothermal	-39.6		-39.6		Decommissioning	N/A
End of 2038			**431.7**	**9,678.3**	**6,719**	**5,569**		
2039	Baringo Silali (Silali) II	Geothermal	100		100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Loosuk-Baringo-Lessos 400kV line must be ready
2039	BESS Generic 1	BESS	150		37.5		Embakasi 220kV/Lessos 132kV/Kegati 132kV	Cost of connection will be borne by the developer
2039	Menengai V	Geothermal	100		100		Menengai 400kV	Menengai 400kV Substation and Menengai-Rongai 400kV line required

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2039	Suswa III	Geothermal	100		100		Suswa 220kV	N/A
2039	Regional Trade 2	Import	200		200		Ethiopia-Kenya/Kenya-Tnzania/Kenya-Uganda	N/A
2039	Generic small hydro	Small Hydro	22		5.5		Kutus 132/33kV	Cost of connection will be borne by the developer
2039	Generic Wind	Wind+ BESS	50		12.5		Meru 132/33kV	Cost of connection will be borne by the developer
2039	Generic Biomass	Biomass	18		9		Meru/Thika	Cost of connection will be borne by the developer
2039	Generic PV	PV+BESS	80		-		Turkwel 220kV	Cost of connection will be borne by the developer
2039	BESS_1	BESS	-100		-25		Decommissioning	N/A
2038	BESS_3	BESS	-50		-12.5		Decommissioning	N/A
2039	REA Garissa	PV	-50		-		Decommissioning	
2039	Strathmore	PV	-0.25		-		Decommissioning	
2039	Lake Turkana - Phase I, Stage 1	Wind	-100		-25		Decommissioning	
2039	Lake Turkana - Phase I, Stage 2	Wind	-100		-25		Decommissioning	
2039	Lake Turkana - Phase I, Stage 3	Wind	-100		-25		Decommissioning	N/A
End of 2039			**319.75**	**9,998.1**	**7,171**	**6,000**		
2040	Olsuswa 70MW unit 1	Geothermal	70		70		Loiyangalani-Suswa 400kV line	Cost of connection will be borne by the developer
2040	Marine Power Akiira Stage 1	Geothermal	70		70		Longonot/Olkaria II/Naivasha	Cost of connection will be borne by the developer
2040	Generic Geothermal Unit 2	Geothermal	140		140		Loiyangalani-Suswa 400kV line	Cost of connection will be borne by the developer
2040	Baringo Silali (Korosi/Chepchuk) II	Geothermal	100		100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	Cost of connection will be borne by the developer
2040	Baringo Silali (Paka) III	Geothermal	100		100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2040	Baringo Silali (Silali) III	Geothermal	100		100		Baringo 400kV (tied to Lessos-Loosuk 400kV line-PPP)	
2040	Arror	Hydropower	59		47.12		Proposed Kapsowar 132/33kV Substation	Cost of connection will be borne by the developer
2040	Nandi Forest	Hydropower	50		39.27		Proposed Chavakali 132/33kV Substation	Cost of connection will be borne by the developer
2040	Generic small hydro	Small Hydro	22		5.5		Musaga 132/33kV	Cost of connection will be borne by the developer
2040	Generic Wind	Wind+ BESS	300		75		Loiyangalani 400/220kV Substation	Loosuk-Baringo-Lessos 400kV line must be ready
2040	Generic Biomass	Biomass	18		9		Kibos 220/132kV	Cost of connection will be borne by the developer
2040	Generic PV	PV+BESS	80		-		Baragoi	Loosuk-Baringo-Lessos 400kV line must be ready
2040	Olkaria I Unit 4-5	Geothermal	-140		-140		Decommissioning	N/A
2040	Olkaria 4	Geothermal	-140		-140		Decommissioning	N/A
2040	OrPower4 Plant 3	Geothermal	-17.6		-17.6		Decommissioning	N/A
End of 2040			**811.4**	**10,809.5**	**7,629**	**6,464**		
2041	Generic Geothermal	Geothermal	400		400		TBD	Cost of connection will be borne by the developer
2041	BESS Generic 3	BESS	100		25		TBD	Cost of connection will be borne by the developer
2041	Generic Biomass	Biomass	18		9		Kakamega 220kV	Cost of connection will be borne by the developer
2041	Generic Wind	Wind	200		50		Kipeto 220kV Extension	Cost of connection will be borne by the developer
2041	Generic PV	PV+BESS	80		-		Lodwar 220kV	Cost of connection will be borne by the developer Turkwell-Lokichar-Lodwar 220kV line required
2041	Generic small hydro	Small Hydro	22		5.5		Chemosit 132/33kV	Cost of connection will be borne by the developer
2041	BESS_2	BESS	-100		-25		Decommissioning	N/A
End of 2041			**720**	**11,529.5**	**8,094**	**6,965**		

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2042	Pumped hydro storage - Unit 3	Pumped storage	650		650		TBD	Cost of connection will be borne by the developer
2042	Generic small hydro	Small Hydro	22		5.5		Kegati 132/33kV	Cost of connection will be borne by the developer
2042	Generic Wind	Wind+ BESS	100		25		Kipeto 220kV Extension	Cost of connection will be borne by the developer
2042	Generic Biomass	Biomass	18		9		Muhoroni 132kV	Cost of connection will be borne by the developer
2042	Generic PV	PV+BESS	80		-		Magadi	Cost of connection will be borne by the developer
2042	Orpower 4 Plant 4	Geothermal	-29		-29		Decommissioning	N/A
2042	Kipeto - Phase I	Wind	-50		-12.5		Decommissioning	N/A
2042	Kipeto - Phase II	Wind	-50		-12.5		Decommissioning	N/A
2042	Selenkei (Radiant)	PV	-40		-		Decommissioning	N/A
2042	Eldosol (Cedate)	PV	-40		-		Decommissioning	N/A
End of 2042			**661**	**12,190.5**	**8,729**	**7,504**		
2043	BESS Generic 2	BESS	50		12.5		Rabai 220/132kV	Cost of connection will be borne by the developer
2043	Generic Geothermal Unit 3	Geothermal	300		300		TBD	Cost of connection will be borne by the developer
2043	Regional Trade 3	Import	200		200		Ethiopia-Kenya/Kenya-Tnzania/Kenya-Uganda	Cost of connection will be borne by the developer
2043	Generic small hydro	Small Hydro	22		5.5		Kieni 132/33kV	Cost of connection will be borne by the developer
2043	Generic Wind	Wind+ BESS	150		37.5		Bubisa/Marsabit 220kV	Cost of connection will be borne by the developer
2043	Generic Biomass	Biomass	18		9		Lanet 132/33kV	Cost of connection will be borne by the developer
2043	Generic PV	PV+BESS	80		-		North Horr	Cost of connection will be borne by the developer
2043	BESS_4	BESS	-50		-12.5		Decommissioning	N/A

Year considered for system integration	Plant name	Type	Net capacity [MW]	Effective Capacity [MW]	Firm Capacity (MW)	Peak Load (MW)	Connection Point (Substation)	Remarks/Status of enabling infrastructure beyond point of connection
2043	Malindi Solar Ltd	PV	-40		-		Decommissioning	Cost of connection will be borne by the developer
2043	Orpower 4 Plant 1 (Expanded)	Geothermal	-63.8		-63.8		Decommissioning	N/A
End of 2043			**666.2**	**12,856.7**	**9,217**	**8,085**		
			0		0			
End of 2044			**0**	**12,856.7**	**9,217**	**8,710**		

Source: LCPDP 2024-2043 and MTP 2025-2029

4 Transmission Expansion Plan

Meeting growing electricity demand reliably and efficiently requires strategic expansion and modernization of transmission and distribution networks, with meticulous planning essential to ensure cost-effectiveness, system stability, and seamless integration of renewable energy sources given the complexity and capital-intensive nature of grid development. Transmission planning plays a pivotal role in shaping the future of power systems, particularly in the context of evolving power markets, cross-border electricity trade, and advanced grid technologies, and is categorized into medium-term and long-term planning, each addressing distinct objectives.

Long-term transmission planning focuses on strategic grid development, ensuring alignment with national and regional energy goals by identifying necessary investments to accommodate future generation (including renewables), load growth, and cross-border interconnections particularly within the EAPP and SAPP. Short and medium-term planning evaluates immediate system needs, including generation evacuation, network reinforcement, and smart grid solutions to improve reliability and resilience, leveraging real-time data and advanced analytics to optimize grid performance under current and near-future conditions.

This section outlines the planning objectives and methodology used to develop a pipeline of transmission projects, including cost estimates for the period 2025–2044.

4.1 Objectives of transmission planning

The main objectives of the transmission-planning are:

a) To identify and evaluate transmission network solutions up to the 2044 planning horizon, enabling the selection of an optimized target grid that will serve as the foundation for the transmission expansion plan
b) To identify transmission development options/sequences for comparison and determination of the least cost option through detailed technical studies and economic analysis.
c) To determine project cost estimates for the planned investments.

4.2 Planning Methodology

The transmission expansion plan was developed using inputs from demand forecasts and generation expansion planning to ensure alignment with future power system requirements.

The planning process involved comprehensive transmission network modeling for existing and future scenarios, allocation of incremental demand based on distribution master plans, mapping of generation facility locations and regional demand-supply balances, and determination of inter and intra-regional power transfer requirements to establish a functional network model.

The project schedule was updated based on the current implementation status of ongoing transmission projects, updated demand forecasts, and planned/ongoing generation projects as detailed in Chapter 3.

The following models were developed:

i. Existing transmission network model (base model for medium term planning)
ii. End of 2025 model (existing network model with all ongoing projects with 2025 as target completion date)
iii. End of year models for 2026, 2027, 2028 and 2029. These models included committed and planned projects expected in the respective years.
iv. Target network model – the 2044 model (base model for long term planning) containing the planned projects building up on the medium-term model. This contained all the planned network expansions including the proposed reinforcements as planned in the previous planning period.

System simulations were conducted to verify compliance with the National Transmission Grid Code, with corrective measures (such as revised concepts or additional reinforcements) incorporated where deficiencies were identified, followed by confirmatory simulations.

Both the target network approach for long-term vision and the alternatives approach for flexible, scenario-based solutions, with both methods applied under the LCPDP framework to ensure cost-effective, optimal and coordinated grid development. In both approaches, the minimization of the costs was realized by comparing transmission system development options where required.

4.2.1 Alternatives approach:

Using PSS/E, the solution for the current network model was determined while introducing additional network segments required to resolve underlying network constraints and challenges and/or to meet a specific objective within the short to medium term.

4.2.2 Target network approach:

Given that no changes were proposed in the long term, only confirmatory simulations and analysis were conducted for long term, anti-chronologically, starting with target network 2044 and ending with 2030 model.

4.3 Grid Expansion Process

The process involved:

(i) Determining the location of future generation facilities and demand supply points. Starting from the schedule of generation investments described in chapter 3, the future plant locations were selected considering the nature of each generation plant and its basic requirements, its existing resource development plans and its established policies. Similarly, and where applicable, the location of government priority projects including BETA Legacy projects and key vision 2030 flagship projects was also considered.

(ii) Splitting the power network into regions, determining the regional power balances and estimating future potential flows between regions. In Kenya, six regions were defined as follows: -
   a) Nairobi
   b) Mt. Kenya
   c) Coast

d) West Kenya
e) Central Rift
f) North Rift

Other regions such as Uganda, Tanzania and Ethiopia were also considered. These formed the external interconnected regions outside Kenya.

(iii) Estimating the number of transmission lines to plan within and between the regions. 220kV and 400 kV were adopted as the backbone transmission voltage in the short and medium terms. 400kV was adopted as the backbone for long term and for conformity with the current regional standards. Thermal rating and surge impedance loading were used to determine transfer capacity limits for transmission lines.

The transmission distances and level of system demand were also considered, and the power transfer capability of transmission lines was estimated as follows:

a) For short transmission lines, the thermal capacity (IEEE Standards) was considered as the transfer limit.
b) For lines spanning lengths of over 500km, the transfer limit was much lower than the thermal limit and was assumed to be equal to SIL (Surge Impedance Loading), For instance the SIL for 400kV is estimated at 680 MW per circuit.
c) Medium length lines (spanning between 200 and 499) km were assumed to be capable of transmitting up to 1.5 SIL.
d) For EHV lines spanning between 80-199 km were assumed to transmit 2.0 times the SIL.

For the long term, network models for each of the snapshot years, i.e. 2030, 2035, 2040, 2044 were further optimized through load flow, contingency and short circuit studies to ensure transmission criteria was complied with at every stage. Any new project was included as part of the plan. Movement in scheduling where necessary was also effected.

Detailed studies were carried out for average hydrology peak load and minimum load, for each of the snapshot years. Whereas peak load studies were required to establish equipment and conductor ratings, minimum load studies confirmed voltage criteria and established reactive compensation requirements.

In case of alternative investment strategies, they were formulated based on the initial target network options. Each strategy, evaluated annually, accounted for reinforcing transmission lines and substations, determining reactive compensation needs, and assessing transmission losses.

Where required, and for comparison purposes, the cost of transmission losses calculated at the Long Run Marginal Cost (LRMC) of energy for each option was determined. This cost was added to the total investment expenses. To establish the most cost-effective transmission plan, the annual costs of each investment sequence were discounted back to the base year (2025) at a rate of 12.8% as gazetted by EPRA. Further, the Operation & Maintenance (O&M) cost was calculated as 2.5% of the Investment Cost.

The Present Value (PV) of cost for the investment strategy is then calculated by summing up these discounted annual investments. Where different investment strategies are involved, the strategy demonstrating the lowest PV of cost is recommended as the most economical option for expanding the transmission network.

4.4 Planning Assumptions, Criteria and Catalogue of Equipment

4.4.1 Planning Assumptions

In preparation of the transmission expansion plan the following basic assumptions were made:

a) Future generation plans as detailed in chapter 3 will be developed across the country.

b) Firm power imports will be available only from Ethiopia. However surplus power exchange and trans-border wheeling within the region are envisaged hence regional interconnections with Uganda and Tanzania are considered in the transmission development plan. In the simulations, the following cross-border power transactions are assumed:
   (i) Kenya imports 200 MW from Ethiopia, an additional 100MW in 2025 and another 100MW in 2027[1] (total of 400MW beyond 2027).
   (ii) 100MW will be wheeled from Ethiopia to Tanzania through Kenya from the year 2025.

c) Due to anticipated right of way challenges and demand growth, major transmission lines will be designed as double circuits (and at higher system voltages) for higher transmission capacity, with a possibility of initial operation at lower voltage levels to reflect existing system strength and limit requirements for other line equipment.

4.4.2 Planning Criteria

Kenya National Grid Code requirements formed the primary basis of the planning criteria which are briefly highlighted below: -

4.4.2.1 System Voltage

Under normal conditions all system voltages from 132 kV and above (i.e. 132kV and 220kV) were set to be within ± 5% of the nominal value and should not exceed ±10% at steady state following a single contingency. For a 400kV system, the voltage magnitude should not exceed ± 5%. In order to maintain a satisfactory voltage profile deployment of both static and dynamic reactive power compensation equipment will be deployed as required and noted for consideration as new investments.

4.4.2.2 Equipment Loading

Under normal conditions and at steady state, all transmission equipment should not exceed 100% of their designed continuous rating. However, during contingency conditions loading was allowed to increase to 120%, which is a threshold justified by the fact that the equipment can withstand this level for about 20 minutes, assumed as the period within which the operator will be able to apply remedial actions and bring the system back to a normal or quasi normal condition.

[1] Additional imports subject to completion of Kimuka 400/220kV substation and Suswa STATCOMs.

4.4.2.3 Voltage Selection

Transmission development during the planning horizon was based on 132 kV, 220 kV and 400 kV. To enhance system operation and optimize wayleaves cost all future inter-regional transmission lines and regional interconnections were designed as 400 kV but may be initially operated at 220 kV. To limit corona losses and enhance transfer capacity, 400 kV and some 220 kV lines are designed with bundled conductors.

In determining voltage levels for new power evacuation lines, consideration for all power plants to be developed in any given location was taken into account to optimize overall transmission cost.

4.4.2.4 Reliability Criteria

The future transmission system was planned to operate satisfactorily under the condition of a single element contingency (N-1) for transmission lines and transformers. However, in assessing system reliability, a double circuit line was considered as two separate circuits.

4.4.2.5 Fault Levels

The system is planned to ensure maximum fault levels do not exceed 80% of the maximum rated fault current interrupting capacity of the circuit breakers. This criterion led to either the replacement of some breakers (i.e. upgrade) or to the identification of mitigation actions for limiting the fault levels.

4.4.2.6 Power Losses

The transmission system is planned to operate efficiently, with transmission power losses (technical losses) not exceeding 5% at the system peak and transmission energy losses not exceeding 2.5% at system peak.

4.4.3 Catalogue of Equipment

Standard equipment and materials (e.g. transformers, conductors, capacitors, substation diameters and bays etc.) were recommended for electricity transmission grid infrastructure development for reasons that:

(i) They offer economic and monetary value due to bulk purchase for future developments using established designs.
(ii) These equipment and materials are easily stocked for replacement in cases of failure and redundancy: standardization allows a large degree of interchangeability and a reduction of the amount of spare parts holding.
(iii) It offers ease in operation and maintenance owing to its uniformity and commonality.
(iv) It makes it easier for KETRACO to train and build capacity for its technical staff on the standard equipment.
(v) Lower costs could be incurred due to there being a reduced level of design input and no obligation to undertake type testing.
(vi) It makes it easier to up-rate certain equipment by substituting them with others that may be recovered for deployment elsewhere.

The updated catalogue of equipment and materials used in the development of the transmission plan and their estimated unit costs are summarized in Annex 6. The standardization principle was based on the 2012 Kenya Electricity System Studies (KESS) Report by Parsons Brinckerhoff (PB) for ERC (now EPRA). The equipment selection was based on the prevailing KETRACO practice.

These costs will be used as basis for preparing project cost estimates. The unit costs are reviewed and updated in every planning period to include equipment made available in the market and installed in the system. The wayleaves costs assume a highly populated and built-up area that represents the worst-case scenario.

4.5 Simulations Result for Network Planning

4.5.1 Load Data

In disaggregating the national load forecast to individual substations in the regions, the following assumptions were made:

i. Load distribution and growth rates in Kenya power system regions as projected in the reference scenario of the forecast.
ii. Vision 2030 flagship projects as detailed in Table 8, and with their indicative points of connections given Table 10.
iii. Uniform load growth rate in individual regions as per the demand forecast.

Table 10: Key Flagship Projects and their points of connection

S/n	Project	First year of operation	Max Initial load [MW]	Year of total load	Max Total load [MW]	Remarks and Point of Connection
1	Electrified Mass rapid transit system for Nairobi	2028	1	2035	50	Distribution Network
2	Data Centre (IX Africa)	2025	40	2025	40	TBA
3	Oil Pipeline and Port Terminal (LAPSSET)	2025	1	2030	35	LAPPSET Corridor Power Supply Projects (Isiolo-Garba Tula-Garissa)
4	Special Economic Zones (Tatu City, Athi River, Eldoret))	2025	5	2039	60	Tatu City: Malaa-Tatu City-ThikaRd/Dandora LILO Athi River : Athi River 220/66kV Eldoret : TBA
5	Special Economic Zones (Kedong, Dongo Kundu, Konza)	2025	5	2040	60	Kedong: Maai Mahiu, Suswa, Dongo Kundu: 220/33kV Dongo Kundu SS Konza: Konza 400/132/66kV and Konza 132/33kV
6	E-Mobility	2024	23.5	2030	273	TBA
7	Special Economic Zones (KenGen, Marathon Data Centre)	2026	30	2028	100	KenGen: Olkaria Complex Marathon Data Centre: TBA
8	E-Cooking	2024	1.2	2030	45.7	Organic Growth incorporated in regional SS loads.

The forecast for the peak load was distributed per region as indicated in Table 11. In developing the distributed forecast, it was assumed that peak demand occurs simultaneously in all regions.

Table 11: Peak Load as Distributed Per Region

Region	**2025**		**2029**		**2035**		**2040**		**2044**	
	MW	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**	**MW**	**MVAr**
Nairobi	1148.8	377.8	1374.2	451.7	2193	442.1	2938.4	441.5	3984.69	508.7
Coast	368.9	119.7	457.6	150.6	736.5	153.4	960.5	153.4	1273.1	172.3
Mt. Kenya	226.9	74.6	275.3	90.5	475.9	96.	635.7	96.0	853.9	108.7
C Rift	228.1	75	284.3	93.4	369.2	74.6	490.4	74.6	925.3	166.2
N Rift	130.5	42.9	252.8	83.1	326.2	65.2	438.2	65.2	389.3	47.5
Western	213.5	70.2	150..5	49.5	216.3	41.9	289.5	41.9	590.2	73.9
Grand Total	**2316.7**	**760.2**	**2794.7**	**912.2**	**4317.1**	**873.2**	**5752.7**	**872.6.2**	**8016.4**	**1077.3**

Detailed distributed forecast by substation is provided in Annex 4.

4.5.2 Generation Data 2025 -2044

The dispatch for system generation plants as described in Table 9 in Chapter 3 were distributed into the Kenya power system regions as given in Annex 3. Detailed distributed forecast by substation is provided in Annex 4. This also includes the tentative evacuation substation (point of connection).

4.5.3 Regional Power Balance Statement

As per the load and generation plan, it is noted that Coast, Central Rift, North Rift, Mt Kenya regions continue to dominate as generation and remain net exporters, while Nairobi and West Kenya dominate as net importers. The regional power balance as simulated for the year 2044 is given on Table 12.Table 13 gives the regional power exchange across the various regions.

Table 12: Year 2044 Regional Power Balances (MW)

Power Balance			
Region	**Generation Dispatch**	**Demand (Peak Load)**	**Surplus/ Deficit (As per assumed dispatch)**
NAIROBI	253.33	4032.11	-3,778.77
COAST	2,182.05	1,367.35	814.7
MT KENYA	1,648.81	862.01	786.80
C RIFT	1,858.64	925.34	933.30
W REGION	292.80	707.96	-415.16
N RIFT	1,830.46	390.26	1,440.2
ETHIOPIA(Imports)	600.7	-	-
EKT(Exports)	-200	200	-
Totals	**8,710**	**8,448.7**	

Table 13: Year 2044 Regional Power Exchange (MW)

REGION		NAIROBI	COAST	MT KENYA	C RIFT	W KENYA	N RIFT	UGANDA	ETHIOPIA	TANZANIA
NAIROBI	MW	-	-842	-1347	-1377	0	-	-	-590	200
	MVAr	-	243	61	236	0	-	-	268	-21
COAST	MW	842	-	-6	-	-	-	-	-	-
	MVAr	-243	-	-29	-	-	-	-	-	-
MT KENYA	MW	1347	6	-	-386	-	-236	-	-	-
	MVAr	-61	29	-	-113	-	37	-	-	-
C RIFT	MW	1347	-	386	-	-80	-922	-	-	-
	MVAr	-236	-	113	-	11	155	-	-	-
W KENYA	MW	0	-	-	-80	-	-208	-30	-	-
	MVAr	0	-	-	-11	-	76	-12	-	-
N RIFT	MW	-	-	236	922	208	-	30	-	-
	MVAr	-	-	-37	-155	-76	-	-16	-	-
UGANDA	MW	-	-	-	-	30	-30	-	-	-
	MVAr	-	-	-	-	12	16	-	-	-
ETHIOPIA	MW	590	-	-	-	-	-	-	-	-
	MVAr	-255	-	-	-	-	-	-	-	-
TANZANIA	MW	-200	-	-	-	-	-	-	-	-
	MVAr	-21	-	-	-	-	-	-	-	-

Source: Authors

4.5.4 Target network Candidates for 2025-2044

In the 2022 – 2041 planning period, candidate projects were selected to resolve challenges in the network. These projects aimed at: de-loading 132kV Dandora – Juja line by providing alternative supply to Juja Road substation; reducing reliance on 220kV Suswa – Nairobi North lines; providing alternative supply to Maralal and Mtwapa; and de-loading Soilo 132/33kV substation.

In the 2024-2043 planning period, target network candidates were identified to: assist in decongesting the Suswa Complex; mitigate the risk of increasing the short circuit fault level of equipment at Suswa; evacuate planned generation at Agil and Olkaria IX; and provide an alternative evacuation path from Olkaria complex.

In the current planning period, there were no new emerging targeted objectives beyond what was assessed in the previous planning period.

4.5.5 Establishment of Sequence of Investments

The investment sequences was established by creating and optimizing network models for each year for the planning period.

For the medium term, the investment sequence considered all ongoing projects, projects with committed financing and any other project that compliments the transmission of bulk power to and from 220 /400kV ring for increased efficiency and system reliability in the short and medium term.

Additional Projects in the medium term included:

1. Additional 23MVA at Ortum Substation
2. 23MVA at Ishiara Substation
3. 20MVAr Reactor at Kibos

Detailed investment analysis for the plan is given in Annex 6.

4.5.6 Transmission System Expansion Plan 2025-2044

Table 14 gives the list of planned transmission projects and also gives the details of the transmission investment required within the planning period 2025-2044.

Table 14: Planned Transmission Projects

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
YEAR 2026							
1					Mobile 220/33kV 1x30MVA and 132/33kV 1x30MVA	60	15.00
2					Mobile 220kV reactor 1x20MVAr and 132kV reactor 1x20MVAr.	-	11.60
3					SAS Upgrade, CCTV& Access Control, SCADA Upgrade, new Metering System, KETRACO WAN	-	16.00
4	Intertie between Konza 400/132 and Konza 132/33kV	5.5	11	97	-		3.97
TOTALS 2026		**5.5**	**11**	**97**		**60**	**46.57**
YEAR 2027							
1					Kibos 20MVAr reactor	20	3.24
2					Ortum 220/33 45MVA	45	3.87
3					Garissa 132/11kV 23MVA	23	3.20
4					Kisii 132/33kV 2x45MVA	90	3.30
5					Installation of Phase Shifting Transformers (PST) at Suswa		9.80
6	Kipevu - Mbaraki 132kV	6.5	13	97	Mbaraki 132/33kV 2x45MVA	90	14.44
7	Rongai Substation 132/33kV	1.5	6	97	Rongai 132/33kV 2x45MVA	90	17.56
8					Olkaria I 11/132kV 1x25MVA (Unit 1and 2)	78	Cost to be borne by KenGen
9					Olkaria I 11/132kV 1x25MVA (Unit 3)		
10	Olkaria 1 AU-Olkaria IV /V 220KV	8	16	324	-		14.76
11	Webuye -Tongaren - Kitale 132kV	73	73	97			24.82
12	Musaga-Webuye 132KV conversion to steel towers	18	18	97			1.96
13	Juja-Ruaraka 132KV conversion to steel towers including associated substation extension and modification	6.5	6.5	97			11.21
14					Kibos 220/132kV 150MVA	150	5.60
15					SS Ext. Garsen 220/33kV 23MVA	23	3.90

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
16					Kitale 220/132kV 110MVA	110	5.20
17					Machakos 132/33kV 23MVA	23	2.89
18					Kyeni 132/33kV 23MVA	23	2.89
19					Kutus 132/33kV 2x45MVA	90	3.78
TOTALS 2027		**113.5**	**132.5**	**809**		**855**	**132.42**
YEAR 2028							
1	Gilgil-Thika-Malaa-Konza 400kV	205	410	1,600	Thika 400/220 2x400MVA	800	262.59
2					Malaa/Nairobi East 400/220 2x400MVA	800	
3					Gilgil 400/220 2x400MVA	800	
5	Sotik – Kilgoris 132kV	50	100	97	Kilgoris 132/33kV 2x23MVA	46	22.00
6	Loiiyangalani/Suswa LILO - Loosuk 400kV	180	360	1,600	Loosuk Switch 400kV substation	-	166.00
					Lessos 400/220kV 2x400MVA	800	
7	Kisumu (Kibos) - Kakamega – Musaga 220kV	73	146	324	Kakamega 220/33 2x45MVA	90	71.17
8					Musaga 220/132 2x90MVA	180	
9	Rongai 400/220 LILO	2	8	1,600	Rongai 400/220 2x200MVA	400	34.05
11	Rongai 220/132 LILO	2	8	97	Rongai 220/132 2x90MVA	180	18.85
12	Kibos - Bondo 132kV	61	61	97	Bondo 132/33 2x23MVA	46	23.53
13	Rongai - Keringet - Chemosit 220kV	96	192	324	Keringet 220/33 2x60MVA	120	100.00
14					Chemosit 220/132kV 2x90MVA	180	
15	400/220kV SS at Baringo and LILO to Loosuk/Lessos line	3	12	1,400	Baringo 400/220kV 2x400MVA	800	35.24
16					Garissa 220/132kV 1x110MVA - second TX	110	5.20
17					Chemosit 132/33kV 2x45/60MVA	90	2.18
18					Githambo 132/33kV 23MVA - second TX	23	2.89
19					Mwingi 132/33kV 23MVA	23	2.89
20					Wote 132/33kV 23MVA	23	2.89
21					Thurdibuoro 132/33kV 23MVA	23	10.08
22					Kitui 132/33kV 23MVA	23	2.89
TOTALS 2028		**672**	**1,297**	**7,139**		**5,557**	**762.45**

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
YEAR 2029							
1	Meru - Maua 132kV	35	70	97	Maua 132/33kV 2x23MVA	46	25.63
2	Kiambere - Maua – Isiolo 220kV	145	290	324	Maua 220/132kV 2x90MVA	180	120.94
3	Menengai - Olkalou – Rumuruti 132kV	70	140	97	Olkalou 132/33kV 2x23MVA	46	34.34
4	Rumuruti - Maralal/Loosuk 132kV	148	296	97	Loosuk 132/33kV 1x23MVA	23	48.84
5	Ishiara - Meru LILO - Marimanti 132kV	13	26	97	Marimanti 132/33kV 2x23MVA	23	13.35
					Ishiara 132/33kV 1x23MVA	23	2.89
6	220kV Kiambere/Rabai LILO - Mutomo	1.5	3	324	Mutomo 220/132kV 2x90MVA	180	36.86
7	132kV Mutomo- Makindu	69	138	97	Mutomo 132/33kV 2x23MVA	46	
8	Turkwel – Lokichar – Lodwar 220kV	120	240	324	Lokichar 220/66kV 2x23MVA	46	100.00
					Lodwar 220/33kV 2x23MVA	46	
9	Kwale LILO (Mariakani/Dongo Kundu) -Kibuyuni (including switch station at Bang'a) and 132kV intertie to existing network	77	154	324	Shimoni/Kibuyuni 220/132kV 2x90MVA	180	84.90
10	Second Circuit LILO Nakuru West –Lanet 132KV	1.5	3	97			1.91
TOTALS 2029		**680**	**1,360**	**1,878**		**839**	**469.66**
YEAR 2030							
1	Ndhiwa (Ongeng) - Magunga (Karungu Bay/Sindo) 132kV	50	50	97	Magunga 132/33 1x23MVA	23	21.24
2	Machakos – Mwala – Sarara (T-off of Kindaruma – Juja line) 132kV	78	156	97	Mwala 132/33 2x23MVA	46	33.21
3	Mtwapa 132/33kV off Rabai-Kilifi 132kV	1.5	3	97	Mtwapa 132/33 2x45MVA	90	10.63
4	Githambo - Othaya-Kiganjo 132kV	72	144	97	Othaya 132/33 2x23MVA	46	28.03
5	LILO on Nairobi – Mombasa 400kV system -New Voi 400/132kV ss	3	12	1,400	Voi 400/132kV 2x150MVA	300	18.24
	Reinforcement of Nairobi – Mombasa 132kV system at Voi 132kV intertie	7	14	97	New Voi 132/33kV 2x23MVA	46	10.91
6	Garissa – Habaswein/Dadaab – Wajir 220kV	330	330	324	Habaswein 220/33 2x23MVA	46	176.18
					Wajir 220/33 2x23MVA	46	
7	Isiolo – Garba Tula – Garissa 220kV	320	640	324	Garba Tula 20/33 2x60MVA	120	177.99
8					-200MVAr, +150MVAr STATCOM/DRPC at Western Kenya region, Nairobi Region and Coast region	-200 and +150 MVAr	135.00

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
9	Malaa – Tatu City and LILO Dandora/Thika Road 220kV	30	60	324	Switch Station at Tatu City	-	30.11
10	Thika/Malaa – HG Falls 400kV	200	400	800	-	-	134.84
11	Kiambere/Malaa LILO-Karura 220kV	10	20	324	-	-	10.44
12	Conductoring of KPTSIP lines with second circiuit: i. 132kV Olkaria - Narok ii. 132kV Sotik-Bomet iii. 132kV Sultan Hamud- Wote-Kitui-Mwingi iv. 132kV Ishiara- Kieni v. 132kV Nanyuki-Rumuruti		353		Substation Extension of KPTSIP SS to accomdate second circuits: i. 132kV Olkaria - Narok ii. 132kV Sotik-Bomet iii. 132kV Sultan Hamud- Wote-Kitui-Mwingi iv. 132kV Ishiara- Kieni v. 132kV Nanyuki-Rumuruti		31.40
13	Voi - Taveta 132kV	110	220	97	Taveta 132/33 2x23MVA	46	34.76
14	400kV Kenya-Uganda Interconnector	132	264	1400	220/132kV Lessos 75MVA	75	161.83
TOTALS 2030		**1,343.5**	**2,666**	**5,478**		**884**	**1,014.81**
YEAR 2031							
1	Supply to Mandera County and environs (220kV Wajir-Mandera or link from Ethiopia	250	500	324	Mandera 220/33kV 1x23MVA	23	161.10
2					Garissa 132/33kV 23MVA (second tx)	23	2.89
TOTALS 2031		**250**	**500**	**324**		**46**	**163.99**
YEAR 2032							
1	220kV Marsabit-Moyale	180	360	324	Moyale 220/33 1x23	23	119.94
TOTALS 2032		**180**	**360**	**324**		**23**	**119.94**
YEAR 2033							
1	Olkaria VIII 220KV Evacuation (through Olkaria VI)	5	10	324			13.34
2	Menengai – Rongai 400kV	45	90	1,600	Menengai 400/132 2x150	300	76.08
TOTALS 2033		**50**	**100**	**1,924**		**300**	**89.42**
YEAR 2034							
1					SS Ext Dandora 220/66kV 2x200MVA	400	13.62
2					SS Ext Voi 132/33 2x45MVA uprating	90	3.09
3					SS Ext Galu 132/33 2x45MVA uprating	90	3.09

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
4					SS Ext Jomvu 132/33 2x45MVA uprating	90	3.09
5					SS Ext Rabai 132/33 1x45MVA additional	45	5.87
6					SS Ext Webuye 132/33 1x23MVA additional	23	5.23
7					SS Ext Naivasha 132/33 1x45MVA additional	45	5.87
TOTALS 2034		**0**	**0**	**0**		**783**	**39.86**
YEAR 2035							
1	NPP TI 1	80	160	1,600	Div 1 SS 3x350MVA	1,050	110.23
2	NPP TI 2	418	836	1,600	Div 2 SS 3x350MVA	1,050	316.10
3	New Thika - Ruaraka 220kV UG cables	27	54	324	Ruaraka 220/132kV 2x150MVA	180	81.06
4	Kilgoris – Masaba (Isebania/Kehancha) 132kV	45	90	97			13.37
5	Longonot Substation including LILO on Gilgil Thika 400kV line	40	80	1,600	Longonot 400/220kV 2x400MVA	400	58.03
6					New Bamburi 132/33 45MVA upgrade	45	1.79
7	Olkaria IX - Longonot 220kV (Evacuation)	25	50	324			13.69
TOTALS 2035		**635**	**1,270**	**5,545**		**2725**	**594.27**
YEAR 2036							
1	Myanga- Busia-Rangala – Bondo-132kV	91	91	97	New Substation at Busia 2x23MVA	46	27.21
TOTALS 2036		**91**	**91**	**97**		**46**	**27.21**
YEAR 2037							
1					Namanga 132/33 1x23MVA additional	23	5.23
2					Rabai 132/33 1x45MVA additional	45	5.87
3					Thika 132/66 1x60MVA additional	60	5.97
4					Gatundu 132/33 1x23MVA additional	23	5.23
5					Soilo 132/33 2x45MVA uprating	90	3.09
6					Chemosit 132/33 1x45MVA additional	45	5.87

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
7					Eldoret 132/33 1x45MVA additional	45	5.87
8					Kitale 132/33 2x45MVA uprating	90	3.09
9					Isiolo 132/33 1x23MVA additional	23	5.23
TOTALS 2037		**0**	**0**	**0**		**444**	**45.45**
YEAR 2038							
1		-	-		Lessos 132/33 2x45MVA	90	3.16
2	400kV Mariakani-Dongo Kundu	60	120	1600	Dongo Kundu 400/220kV 4x200MVA	800	86.16
TOTALS 2038		**60**	**120**	**1,600**		**890**	**89.32**
YEAR 2039							
1	Agil 220KV Evacuation	8.5	8.5	324	Agil SS (by Deveeloper)	-	4.66
2	Agil - Olkaria IX	25	25	324	Agil SS (by Deveeloper)	-	13.69
TOTALS 2039		**33.5**	**33.5**	**648**		**0**	**18.35**
YEAR 2040							
1	132kV Kwale Sugar-Titanium reconductoring	31.5	31,5	165			0.95
2	132kV Webuye-Musaga reconductoring	18	18	135			1.80
3					City Centre 150MVAr Capacitor	150MVAr	4.61
4					City Centre 220/66 1x200MVA additional	200	9.92
5					Isinya 220/66kV 2x200MVA	400	13.44
6					Nanyuki 132/33 2x45MVA uprating	90	3.09
7					Meru 132/33 2x45MVA uprating	90	3.09
8					Kisii 132/33 2x45/60MVA uprating	90/120	3.09
9					Kitale 220/132 1x90MVA additional	90	5.01
TOTALS 2040		**49.5**	**18**	**300**		**870**	**45.00**
YEAR 2041							
1	Suswa - Naivasha SEZ				Naivasha SEZ 220kV	-	43.00
2	Rongai - Kilgoris (Part of Lake Victoria Ring) 400kV	235	470	1,600	Kilgoris 400/132 2x150MVA	300	219.00

S/n	Transmission Line Name	Length (KM)	Cct Length	MVA /CCT	Substation Name	MVA	Estimated Total Cost (MUSD)
3	Ngong (Kimuka) – Magadi 220kV	88	88		Magadi 220/66 2x60MVA	60	60.10
4					Loosuk 400/132 2x90MVA	180	12.77
5	Lokichar/Lodwar – Lokichoggio 220kV	190			Lokichoggio 220/33 1x23 MVA	23	
TOTALS 2041		**513**	**588**	**1,697**		**563**	**334.87**
GRAND TOTAL		**4,676.5**	**8,517**	**27860**		**14,885**	**3,993.59**

5 Resilience and Risk Mitigation Strategies

5.1 Risk Assessment

A comprehensive analysis of the anticipated risks that may impact the implementation of this Master Plan has been conducted. The assessment covers risks likely to affect Project Funding, Feasibility Studies, Pre-Construction Activities, Construction Phases, Commissioning, and Operations and Maintenance processes. Each identified risk has been ranked, and appropriate mitigation measures have been proposed, with clear assignment of responsibility to the relevant offices.

Addressing emerging risks in the implementation of the Transmission Master Plan is essential in ensuring the long-term success, sustainability, and resilience of power infrastructure development. As the energy sector evolves rapidly due to technological advancements, climate change, regulatory shifts, and geopolitical uncertainties, anticipating and managing these emerging risks becomes critical. Proactively identifying such risks enables KETRACO to adapt its strategies, safeguard investments, and avoid costly disruptions during project planning, implementation, and operations. It also strengthens the organization’s capacity to respond to unexpected challenges, enhances stakeholder confidence, and supports the delivery of reliable and secure transmission services across the country. The details of the risks assessment and mitigation measures are outlined in Table 14.

Table 15:Risk Assessment and Mitigation Measures

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
1.	**Strategic Risks** • The inability to implement the Transmission Master plan • Inadequate capacity to undertake and manage system studies	• Changes in the government/ sector priorities and policies. • Inadequate funding to implement projects. • Lengthy process for mobilization of funds. • Regulatory changes which may affect the feasibility and implementation of the plan. • Market volatility impacting projects financing and costs estimates. • Limited availability of real-time or historical data necessary for accurate stability assessments	• Underutilized / Idle Transmission infrastructure. • Inefficient operations resulting to sub optimal operations of the transmission grid. • Missed opportunities for innovation, renewable energy integration. • Loss of revenue from wheeling charges due to delays in project completion. • Increase cost of project implementation.	**High**	• Continuous consultation and alignment of all upstream and downstream stakeholders • Implement robust monitoring mechanisms to track key risk indicators throughout the implementation process. • Leverage on the PPP model to finance projects and close the deficit. • Explore the Assets Monetization strategy for funds mobilization. • Investing in projects that ensure redundancy of transmission lines (N-1 criterion is met). • Invest in data integration systems and improve data collection processes to ensure availability of accurate information for system modelling.	**GM-PDS** **GM-FINANCE**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
2.	**Environmental and Social Risks** • Inability to undertake SESA studies. • Inability to complete ESIA studies on time • Inability to meet development partners' conditions within stipulated timelines. • Human rights violations	• Destruction of habitat through deforestation during clearing land for TL corridors • Extreme weather conditions such as flooding and other extreme temperatures causing service disruptions. • Risk of non-compliance with all environmental licenses, detailed permits and environmental authorizations required for the project. • The risk associated with the project impact on project affected persons including unrest, protests and resettlement.	• Possible litigation by aggrieved PAPs • Delayed project commencement • Damaged reputation • Regulatory Penalties and stoppage orders affecting the project delivery timelines. • Reputational damage • Social displacement of communities and disruption of livelihoods • Potential conflicts with indigenous communities or local stakeholders over land use and rights • Reputational damage, gender discrimination and	**High**	• Mainstreaming SESA into institutional programs, and plans such as master plans and strategic plans. • Development of sound environmental and social risk management plans. • Continuous Stakeholder engagement • Strengthen partnership and rapport between Ketraco & other relevant Lead Agencies • Establish clear communication channels to incorporate stakeholder input and feedback from planning through to implementation. • Plan and undertake Environmental and Social Audits to operational impact of projects and assess the efficacy of the operational phase ESMP • Adhere to labour laws, ensure safe working conditions, provide regular training, and establish grievance mechanisms. • Develop a human rights approach in implementation of projects including undertaking of Human	**GM-PDS**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
		• Lack of recognition of Vulnerable groups in Resettlement planning. • Demographic Changes: Shifts in population dynamics and workforce composition	potential Gender-based violence		Rights Action Plan, Gender Action Plan among others.	
3.	**Governance Risks** Risk of potential threats or challenges that arises from deficiencies or weaknesses in governance structures, processes, or practices.	• Changes in the company governance structure • Political instability, economic downturns and shifting government priorities which affect the implementation of the plan. • Geopolitical tensions.	• Delays in projects implementation and cost over runs • Compromised project quality. • Reputational damage • Supply chain disruptions. • Security threats to the transmission infrastructure	**High**	• Continuous stakeholder engagement. • Strengthening oversight controls to closely monitor implementation of the plan. • Close monitoring of geopolitical developments. • Continuous engagement with CIPU to enhance power infrastructure security.	**CS, GM-LEGAL SERVICES**
4.	**Operational Risks** • Risk of failures or disruptions in information technology systems or transmission infrastructure.	• Supply chain Disruptions resulting to delays or shortages affecting project timelines. • Grid instability due to inadequate	• Project implementation delays and cost overruns. • Reduced grid reliability and stability as a result	**High**	• Leverage on technical expertise by collaborations to explore emerging technologies, best practices and innovative solutions for optimizing the transmission infrastructure. • Maintain buffer stocks for critical materials.	**ALL HODs**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
	• Risk of deficiencies in internal processes and procedures	transmission capacity of some of the transmission lines. • Theft and Vandalism of Transmission infrastructure. • Equipment failure due to unexpected malfunctions resulting to network disruptions. • Extreme weather events such as flash floods, river floods and strong winds hindering maintenance activities.	of delay in transmission and transformation implementation. • Possible loss of transmission network • Loss of revenue and unplanned costs of spares. • Reputation damage		• Conduct a risk assessment and implement disaster management framework. • Enhance security system and operations.	
5.	**Human Resources Risks** Issues arising out of human capital issues and people management as well as talent management that are likely to impact the implementation of the TMP.	• Limited personnel with the required technical expertise and experience in Transmission planning, design and implementation. • Brain Drain/High Staff Turnover- Loss of institutional	• Project execution Delays and increased project costs due to shortage of skilled personnel. • Compromised quality of work, errors and omissions	**High**	• A staff skills audit to be carried out to identify personnel and expertise required to deliver the TMP. • Recruitment and training of personnel to equip them with the skills and competencies required. • Establish and implement knowledge management systems and processes to capture, document	**GM-HRA**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
		knowledge and expertise due to retirements, resignations or talent poaching by competitors.	throughout the project life cycle resulting to reworks and cost overruns. • Increased risk of accidents, injuries and fatalities during construction and operations • Reputation damage.		and transfer institutional knowledge and best practices in the company. • Develop and implement Succession plans to identify and groom personnel within the company to ensure continuity and stability in critical roles. • Leverage on collaborations and partnerships for knowledge sharing and access best practices.	
6.	**Project Risks** Inability to complete projects within the required scope, time and quality.	• Delays in acquisition of right of way • Expansion and Design changes from the original plan within the life of the projects. • Communication challenges between new and existing equipment due to differences/changes in technology. • Lengthy procurement	• Increased project costs and delays in project completion. • Unrealised Wheeling Revenue. • Lack of access to project sites. • Legal suits and costs • Reputational damage	**High**	• Monitor procurement performance, delivery timelines and contractual obligations to mitigate procurement risks. • Ensure the standards and specifications for the new or upgraded equipment are compatible with the existing equipment. • Develop and implement a project management framework. • Evaluate project resource availability, skills and expertise requirements and develop contingency plans for resource shortages.	**GM-D&C**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
		processes and contracts non-performance. • Inadequate risk assessments exposing the projects to unforeseen risks and uncertainties. • Stakeholder resistance or conflicts affecting project alignment and execution due to diverging interest, expectations and insufficient stakeholder involvement. • Under-performance of contractors.			• Effective communication, collaboration and engagement between all the project stakeholders throughout the project lifecycle.	
7.	**Financial Risks** • Financial Resilience - It encompasses all risks financial in nature including but not limited to Liquidity and cashflow risks. Risk	• Overreliance on exchequer funding • Overreliance on uncertain donor financing • Inadequate funding for projects.	• Incomplete projects/Delays in project implementation. • Unexpected increases in project costs affecting financial viability.	**High**	• Continuous engagement with the NT for early disbursements of funds. • Consider hedging strategies to cushion the company on adverse FX fluctuations.	**GM-FINANCE**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
	arising out of financial operations.	• Exchange rate fluctuations • Budget Constraints • Delayed disbursement of funds from National Treasury. • Misalignment between budgetary allocation and disbursement	• Reputational damage.		• Explore revenue diversification sources to reduce over reliance on exchequer. • Implement a monitoring and evaluation system that helps in providing realtime reports on actual disbursements and budgeted allocations.	
8.	**Technology Risks** These are technologically oriented risk and refers to all issues of information and Communication technology	• Obsolescence of equipment due to new emerging technologies, exposing the network to potential attacks (Technical Vulnerabilities) • Cyber security threats compromising systems integrity and data security. • Lack of a fully featured test environment and documentation of the	• Service disruptions due to unauthorized access and data breaches. • Increased maintenance costs and costly upgrades. • Incompatibility between different systems resulting to inefficiencies.	**High**	• Conduct regular technology audits and vulnerability tests to identify outdated systems and potential vulnerabilities. • Update Business Continuity plans, ICT Disaster Recovery plans and testing. • Implement robust cyber security measures to safeguard the systems against cyber threats and data breaches. • Develop comprehensive backup and recovery strategies to minimize data loss in case of system failures. • Training and capacity building for all staff to ensure efficient system operations.	**GM-SRC**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
		recovery and continuity processes. • Lack of systems replication or offsite backup to offer failover • Lack of integration between systems.			• Collaboration with technical experts for guidance on emerging trends and best practices.	
9.	**Legal and Compliance Risks** • Noncompliance to existing laws/ regulations and other statutory requirements • Inadequacies in contract management/Breach of Contract by third parties • Inability to effectively acquire land and right of way for projects.	• Complexities in Land acquisition and right of way for transmission infrastructure • Inadequate contract management processes. • Contractual ambiguity and non-performance by contractors. • Knowledge gaps in application of financial standards and regulations (IFRS, PFM Act, IPSAS, NT Circulars, etc)	• Legal Disputes and increased litigation costs. • Delays in Project implementation. • Cost overruns • Reputational damage • Increases in contingent liabilities	**High**	• Monitor performance metrics, milestones and remedies for non-performance to ensure accountability and project continuity. • Training project staff on contracts management. • Monitoring of contact implementation during the project lifecycle. • Regular assessment on project staff knowledge of financial standards through regular simulations and assesements.	**CS, GM-LEGAL SERVICES** **GM-SRC**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
10.	**Health and Safety Risks** • Potential hazards to staff/contractors and the public by accidents or incidents involving high voltage transmission installations.	• Non-Compliance to safety standards and contract provisions. • Inadequate enforcement of Contractual obligations. • Inadequate safety equipment. • Excessive Workload	• Public opposition to transmission projects due to safety concerns may derail or delay the project implementation. • Injuries, illnesses and fatalities among employees and contractors. • Increased insurance costs for the company and potential legal liabilities.	**High**	• Routine project site audits and routine risk assessments to identify potential hazards and implement corrective actions proactively. • Regularly review and update the safety policies and procedures to ensure compliance with industry standards and regulations. • Implement emergency response plans and train staff and contractors to ensure a prompt response in case of emergencies. • Activate the incident management plan. • Community engagement and outreach with local communities to raise awareness on health and safety risks associated with the transmission infrastructure.	**GM-SOPM**
11.	• **New and Emerging Risks** A risk that is evolving in areas and ways where the body of available knowledge is weak.	• Climate Change impacts leading to extreme weather events and grid vulnerabilities. • Disruptive Technologies: Rapid advancements in AI,	• Damage of transmission lines, towers and substations resulting to power outages and disruptions.	**High**	• Climate Resilience planning by conducting vulnerability assessments and developing adaptation strategies. • Developing emergency response plans and contingency measures to mitigate the impact of climate related disasters on the transmission infrastructure.	**All HoDs**

No.	Risk Description	Cause	Impact	Risk Rating	Proposed Mitigation/ Action plan	Risk Owner
		blockchain, and other technologies. • Geopolitical Instability: Political unrest and changes in international relations			• Collaborating with sector stakeholders and local communities to raise awareness and implement climate resilient practices. • Horizon scanning-Regularly monitor global trends and developments to identify potential risks early.	

6 Investment and Financing Plan

6.1 Ongoing projects

Approximately 1,709km in route length (2,502km in circuit length) of transmission lines and 4,166 MVA of substation capacity are currently under construction and are expected to be complete by the year 2030. The total outstanding investment requirements for these projects sums to about **USD 794.40 Million**. Approximately **USD 411.17**Million of outstanding investments have been secured/committed through development assistance and EPC + Financing arising from Government-to-Government memoranda of understanding. This implies that there is a financing gap of **USD 383.23** Million that relates to the 400kV Lessos-Tororo, 220kV Garsen-Hola-Bura-Garissa, 220kV Isiolo-Marsabit, 220kV Kamburu-Embu-Thika, 132kV Makindu Substations, 220kV Olkaria 1 AU-Olkaria IV /V, LILO on Juja/Naivasha 132kV- Maai Mahiu and 220kV Loiyangalani-Marsabit projects.

6.2 Planned Projects

Between the period 2025 - 2044, about 4544km in route length (7,900km in circuit length) of transmission lines and 14,764 MVA of substation capacity are planned. The investment requirement is approximated at USD 3,800.36 Million without funding commitment.

6.2.1 Planned Projects with Potential Financing

The following planned transmission infrastructure projects have potential funding by development partners.

1. Substations upgrade; Garissa, Kisii and phase shifting transformers at Suswa
2. Mobile 220/33kV substations
3. 73 km 132kV Webuye -Tongaren - Kitale
4. 18 km 132kV Musaga-Webuye conversion to steel towers
5. 72km 132kV Githambo-Othaya-Kiganjo
6. 190km 132 kV Kibos-Bondo-Rangala-Busia-Myanga

6.2.2 PPP Projects

Among the projects with potential financing, the following projects have been considered for possible procurement through PPP, both solicited and unsolicited.

7. 73km 220kV Kisumu-Kakamega-Musaga
8. 179km 400kV Lessos Loosuk
9. 53 km 220kV Kwale -Shimoni (Kibuyuni)
10. 145 km 220 kV Kiambere-Maua-Isiolo
11. 7km 132 kV Kipevu-Mbaraki
12. 132kV Meru- Maua

In addition, the company has received expression of interest on the following projects which are at various stages of PIP.

1. 70km 132kV Mutomo-Makindu
2. 148km 132kV Rumuruti - Maralal/Loosuk
3. 1.5km 220kV Kiambere/Rabai LILO – Mutomo
4. 69km 132kV Mutomo- Makindu
5. 50km 132kV Sotik-Kilgoris
6. 3km LILO on Nairobi – Mombasa 400kV system -New Voi 400/132kV ss
7. 7km 132kV Reinforcement of Nairobi – Mombasa 132kV system at Voi intertie
8. 110km 132kV Voi - Taveta

7 Technology and Innovation Roadmap

The National Energy Policy provides an overarching framework for the deployment of innovative grid technologies. It emphasizes the modernization of transmission infrastructure, improved efficiency, environmental sustainability, and the need for a smart grid transition. The policy encourages adoption of climate-resilient infrastructure, advanced monitoring systems, and technologies that support decentralization and digitalization. These principles are directly in line with the priorities identified in KETRACO's roadmap.

In line with evolving system requirements and the increasing complexity of the transmission grid, KETRACO has embarked on integrating new technologies to achieve the following objectives.

- Expand transmission capacity and access by reducing losses.
- Enhance grid reliability by enabling automated fault detection, isolation, and restoration without human intervention.
- Increase operational efficiency by transitioning to real-time system visibility.
- Support grid decarbonization and climate adaptation by aligning infrastructure planning with Kenya's national climate commitments.

Table 16 provides a summary of emerging technologies in the high voltage infrastructure.

Table 16:Emerging technologies.

Item	Emerging Technologies	Description	Relevance	Application/Implementation Status
1	**Advanced Energy Storage Solutions** BESS	- Battery Energy Storage Systems receive power from the grid and store it for later use.	- Energy stored in BESS is utilized during fluctuations of power demand and supply - Resolve voltage challenges due to intermittency of renewable energy sources	- BESS planned for installation in the network by various IPPs Nairobi , Central and Western and Coast region by 2027. - Inter-sectoral trainings ongoing in preparation for operation and adoption .
2	**Flexible AC Transmission Systems** (FACTS) STATCOM Static Variable Generators.	- FACTS inject and/or absorb reactive power into the grid voltage by correcting the imbalance between real and reactive power.	- Improve the operational reliability of long transmission corridors, reduce congestion, and defer costly infrastructure upgrades	- STATCOMs expected to be installed at Rabai and Suswa substations by 2027
3	**Asset Management Technologies** Intelligent Inspection Technologies Visualized Corridor Monitoring Tower Foundation Security	- For real-time monitoring of transmission infrustructure to improve safety, disaster prevention, and asset utilization. enhance operational efficiency and reliability while minimizing risks to personnel.	- Traditionally, inspection, monitoring, and maintenance of high voltage transmission lines and substations involved manual climbing, helicopter flyovers, or ground patrols, which are time-consuming, hazardous, and limited in reach. - **Drones** equipped with high-resolution cameras, thermal imaging sensors, LiDAR, and	- KETRACO has acquired drones to monitor the Nanyuki – Isiolo and Nanyuki - Rumuruti UG line..

Item	Emerging Technologies	Description	Relevance	Application/Implementation Status
	Drone Technology		other advanced payloads drones offer a safer, faster, and more cost-effective alternative, enabling utilities to enhance operational efficiency and reliability while minimizing risks to personnel. - **Intelligent Inspection Technologies** leverage AI and machine vision to analyze imagery for anomalies such as corrosion, conductor damage, or vegetation encroachment, allowing for predictive maintenance and automated defect detection. - **Visualized Corridor Monitoring** systems provide continuous, high-resolution surveillance of transmission pathways, detecting risks such as large machinery, fire, or encroachment, and transmitting real-time alerts to control centers. - **Tower Foundation Security solutions** -deploy fixed cameras and sensors with motion and intrusion detection capabilities	

Item	Emerging Technologies	Description	Relevance	Application/Implementation Status
			around critical tower bases to prevent vandalism, theft, or unauthorized access.	
4	**Automated Climate Information** Climate sensors Dynamic line rating (DLR) and Grid Enhancing Technolgies (GETs) Biodiversity Monitoring Avian Protection Avian Monitoring	- Integration of real-time weather data into decision-making processes. They utilize digital platforms and predictive analytics to inform infrastructure planning, risk assessment, and operational strategies. - By continuously capturing localized data, these sensors provide utilities with the necessary information to assess risks and optimize infrastructure performance in response to environmental changes.	- By accurately assessing real-time conditions, DLR can increase the capacity of transmission lines beyond static ratings, allowing more power to be transmitted without the need for costly upgrades. Thus, DLRs optimize the use of existing infrastructure, reduce congestion, and enhance grid reliability. - Motion-activated cameras, acoustic sensors, and GPS tracking devices enable real-time monitoring of animal movements near transmission corridors to track and mitigate the effects of transmission infrastructure on wildlife particularly electrocution, habitat fragmentation, and collision risks. - In areas of high infrared camera systems are being used to detect	- Planning and adaptation of transmission infrastructure in vulnerable regions Parts of Kenya experiencing extreme weather patterns (intense rainfall, high temperatures, and localized flooding) - It guides route selection, structural reinforcements, and the scheduling of maintenance activities based on environmental conditions. For example, projects near Lake Victoria or the Tana Basin can integrate flood data into their design to ensure uninterrupted service during the rainy season. - KETRACO has developed detailed guidelines and best practices for the readiness and implementation of bird diverter programs. Bird diverters have

Item	Emerging Technologies	Description	Relevance	Application/Implementation Status
			avian hotspots which are zones where birds are likely to collide with overhead lines or towers. These systems can operate day and night, allowing for continuous monitoring and providing crucial data for risk assessment and mitigation planning	been installed in the 132kV Sultan Hamud – Loitoktok line completed in 2024.
5	Mobile Reactors/Substations	- Mobile reactors and substations are self-contained, portable power infrastructure units that offer a flexible solution for temporary or emergency grid support. - They are pre-assembled on trailers or skids to enable the temporary restoration of power in areas affected by natural disasters, substation outages, or delayed construction.	- They provide rapid, flexible solutions for grid reinforcement, emergency response, and planned maintenance without the lead times and civil works associated with permanent installations. - Serve as interim solutions during substation upgrades or system reconfiguration, minimizing disruption to customers and maintaining system reliability. - Can be deployed adaptively to balance loads and stabilize voltage	- Planning and finance sourcing for the procurement of mobile substations to be used in Coast, Nairobi and Western region by 2027
6	Monopoles	- Monopoles are vertically oriented, single-shaft	- They offer a smaller footprint, simplified design, and	- Monopoles can be considered for regions with space constrictions

Item	Emerging Technologies	Description	Relevance	Application/Implementation Status
		transmission line structures used as alternatives to traditional lattice towers.	aesthetically cleaner appearance reducing wayleave requirements.	for example within the cities of Nairobi, Nakuru, and Mombasa as well as where the cost of acquiring wayleave is higher than the cost of installing a monopole.
7	Advanced Grid Management Phasor Measurement Units PMUs	- Phasor Measurement Units (PMUs) are specialized high-speed sensors that provide time-synchronized measurements of voltage and current across various points in the power grid.	- They offer real-time visibility into grid dynamics, enabling rapid identification of oscillations, frequency variations, voltage instability, and power angle changes.	- The ongoing NSCC project is adopting advanced systems
8	GIS/Hypact	- Gas insulated switch gear are switch gear that use SF6 gas or equivalent gas as insulating media between live parts and non live parts of the equipment.	- Gas-Insulated Switchgear and Hypact technologies offer advanced switchgear solutions for space-constrained or high-performance substation environments.	- HYpact systems have been used at 220kV Rabai and Soilo Substation. - Gas Insulated Substations may be considered in design of future projects in areas with space constraints.
9	Augmented GIS	- Augmented Geographic Information Systems (GIS) fuse traditional spatial mapping with Augmented Reality (AR) tools to improve	- Through AR-enabled devices such as smart glasses or mobile tablets, technicians can visualize sub-surface utilities, asset metadata, or maintenance history overlaid onto	- Augmented GIS may be implemented in future

Item	Emerging Technologies	Description	Relevance	Application/Implementation Status
		field operations and asset management.	real-world environments in real time.	

8 Stakeholder Engagement and Public Consultation

Stakeholder engagement and public participation are vital for sustainable development and inclusive decision-making in project planning. Rooted in Article 10 and Article 69 of Kenya's Constitution, as well as key environmental and county laws, this process ensures transparency, accountability, and the integration of national values like equity, inclusiveness, and public involvement. It allows communities to shape project design, express concerns, and foster local ownership. The main goals are to build trust, ensure fair representation, reduce conflict, incorporate local knowledge, and protect the interests of vulnerable groups.

8.1 Guiding Principles

Guiding Principles for stakeholder engagement and public participation:

- **Inclusivity**: Actively engage all stakeholder groups, including women, youth, Indigenous Peoples, persons with disabilities, and other vulnerable populations.
- **Transparency**: Share relevant information in a timely and accessible manner to enable informed participation.
- **Participation**: Provide meaningful opportunities for stakeholders to influence decisions that affect them.
- **Accountability**: Establish clear mechanisms for feedback, monitoring, and grievance redress.
- **Respect for Rights**: Uphold constitutional rights to a clean and healthy environment, public participation, and equitable access to development benefits.

8.2 Stakeholder Identification and Mapping

Effective electricity transmission planning requires early and continuous engagement with various stakeholders. Project planners must undertake systematic stakeholder mapping to identify those affected by or interested in electricity transmission development. This TMP categorizes multiple stakeholders based on their roles, influence, interests, and potential impact or benefit to the project. The lists provided are not conclusive. Due to the dynamic nature of individual projects, conclusive project-specific stakeholder mapping and stakeholder engagement plans should be developed during project individual project conceptualization and dully updated as the projects progress.

8.3 Entries of stakeholder engagement and public participation

Entries of public participation, stakeholder engagement and disclosure in the project cycle are as indicated in the Table 17:

Table 17: Entries of Stakeholder Engagement and public participation

Phase	Objective of Public Participation	Disclosure Modalities
Identification & Conceptualization	Align projects with national priorities, sectoral priorities, community priorities, socio-economic and environmental realities.	Concept notes, high level engagement meetings, project flyers, public barazas, local radio, noticeboards.
Feasibility, Planning & Design (Merged Feasibility,	Identify risks and opportunities, design inclusive and sustainable solutions, and validate safeguards and project layout.	ToRs for feasibility studies, safeguard plans, project briefs, SEP, shared online and locally;

Phase	Objective of Public Participation	Disclosure Modalities
ESIA/RAP Scoping, and Detailed Design)		public hearings; gazette notices; dailies and radio adverts
Financing & Approval	Promote transparency, integrate stakeholder feedback, and build ownership before final approval.	Final safeguard plans, stakeholder meeting reports disclosed on financier and government portals.
Implementation (Construction & Commissioning)	Ensure ongoing oversight, minimize disruption, and resolve grievances effectively.	Construction schedules, grievance redress mechanisms, contractor ESMPs, community posters, local language materials.
Operation, Maintenance & Evaluation	Promote long-term accountability, monitor impact, and support inclusive service delivery.	Monitoring and evaluation reports, satisfaction surveys, and sector performance scorecards.

8.4 Stakeholder mapping

The Table 18 gives broad classification and categorization of stakeholders and their significance to electricity transmission.

Table 18:Stakeholder Mapping

Stakeholder Category	Relevance to TMP	Level of Impact	Level of Influence	Level(s) of Engagement
Ministries, Departments and Agencies (MDAs)	**Ministries and Departments:** Strategic policy leadership, public investment coordination, energy policy execution e.g. MoEP	Low to High	High	Inform, Consult, Collaborate
	Agencies: Approve and guide routing in sensitive and protected zones Inform project planning e.g KENGEN, KPLC, REREC	Low to High	High	Inform, Consult, Collaborate
	Regulatory Authorities: Approve compliance (technical, environmental, social); set grid codes, tariffs	Low	High	Consult, Collaborate, Empower
County Governments	Land use approvals, grassroots	Medium	Medium	Inform, Consult, Involve

Stakeholder Category	Relevance to TMP	Level of Impact	Level of Influence	Level(s) of Engagement
	mobilization, devolved functions			
Financial Institutions	Financing, policy influence, safeguards requirements	Low	High	Collaborate, Involve, Inform
Affected Communities/Individual Stakeholders (PAPs)	Experience direct local impacts (land, employment, access)	High	Low to Medium	Inform, Consult, Involve, Empower
Media (Mainstream & Social)	Influence public opinion, perception, and project acceptance or resistance	Medium	High (Emerging)	Inform, Consult, Monitor
Civil Society Organizations (CSOs)	Advocate for accountability, fairness, and inclusiveness Monitor environmental compliance, advocate for ecosystem protection, and just transition	Medium	Medium	Consult, Involve, Collaborate
Private Sector (IPPs, PPPs, suppliers, contractors)	Power generation, Project design, financing, construction, O&M, supply of material	Medium	High	Collaborate, Involve, Consult
Power Consumers (residential, commercial, industrial)	Depend on grid reliability and tariffs; shape demand-side planning	Medium	Low	Inform, Consult, Monitor

8.5 Emerging Stakeholders

The energy transmission landscape is changing due to increased digitalization, climate focus, and private sector participation. New actors are gaining relevance:

- Kenya Meteorological Department (KMD): Provides critical climate risk data.
- Climate change crusaders: Push for climate justice, emissions tracking, just transition.
- Private Sector & Innovators: Catalysts for PPPs and tech-driven solutions.
- Transactional Actors: Crucial in structuring, regulating, and arbitrating PPP agreements.
- Media (Mainstream & Social): Evolving from informers to influential watchdogs shaping public perception and legitimacy.

8.6 Stakeholder Metamorphosis Under PPPs

When projects shift to Public-Private Partnerships (PPPs), the significance of traditional stakeholders' changes. Communities and affected people cease to be recipients of government compensation as they become active participants with rights, expectations, and high influence on the privately led process. This change happens because private companies now play a bigger role in building and running projects. As a result, engagement must be more inclusive, transparent, and fair to build trust, ensure benefits are shared, and avoid delays or conflict.

9 Sustainability and Environmental Considerations

The mainstreaming of environmental, socio-economic considerations and climate change is justified by the significant associated risks these factors pose to electricity transmission projects. Effective management of these risks is essential to protect communities, ecosystems, and investments in the sector. By integrating these environmental, socio-economic safeguards and climate change into its masterplan demonstrates commitment to sustainable and responsible operations for long-term success of projects. This also builds investor confidence and supports Kenya's broader sustainable development goals.

The chapter draws its regulatory context from EMCA 1999 (and 2015 revisions); Climate Change Act 2016 (and 2023 revision); other sectoral laws and international commitments like Paris Agreement 2015, and Kenya's Nationally Determined Contributions (NDCs), reinforcing the country's dedication to a low-carbon, climate-resilient energy future.

9.1 Integrated Environmental and Socio-Economic Consideration

Effective management of environmental and socio-economic mainstreaming begins with comprehensive project screening and assessment, which is critical for determining appropriate safeguard instruments and management plans for each transmission project. These processes are guided by Kenya's national legislation and aligned with international best practices.

9.1.1 List of Safeguard Plans and Tools

Depending on the outcome of the initial screening and scoping process, a suite of environmental, social, and climate safeguard instruments may be triggered, including but not limited to: -

Table 19: List of potential safeguards

Safeguard Tool / Plan	Trigger Condition	Purpose & Relevance
Environmental and Social Impact Assessment (ESIA)	All high-risk projects (electricity transmission infrastructure) under EMCA Section 58	Identifies, evaluates, and proposes mitigation for environmental and social impacts; forms the basis for project approval and licensing
Environmental and Social Management Plan (ESMP)	A management plan resultant of ESIA	Outlines specific mitigation measures, monitoring, and institutional actions for managing identified impacts throughout the project lifecycle
Strategic Environmental Assessment (SEA)	Long-term plans or programs (e.g., transmission masterplans, strategic plans)	Assesses broad, cumulative, and long-range environmental and climate risks; supports strategic decision-making
Resettlement Action Plan (RAP)	Land acquisition, physical or economic displacement	Ensures fair compensation, relocation support, and livelihood restoration for affected persons
Vulnerable and Marginalized Groups Plan (VMGP)	Impact on Indigenous Peoples or marginalized populations	Guarantees culturally appropriate engagement, benefit-sharing, and protection of rights
Livelihood Restoration Plan (LRP)	Economic displacement without physical relocation	Restores or improves income sources and living standards of affected persons or communities

Cumulative Impact Assessment (CIA)	Overlapping impacts from other infrastructure or development projects in the area	Identifies and manages combined, synergistic, or additive environmental and social effects beyond a single project scope
Cultural Heritage Management Plan (CHMP)	Proximity to sites of cultural, historical, or spiritual significance	Protects and manages both tangible and intangible cultural assets
Gender Action Plan (GAP)	Gender-based disparities or risks (e.g., GBV, exclusion)	Promotes equitable participation, addresses gender-specific impacts, and supports gender mainstreaming
Community and Occupational Health and Safety Plan (COHSP)	Public or workers' safety risks during construction or operation	Protects health and safety of communities and workers in compliance with labor and health standards
Stakeholder Engagement Plan (SEP)	Required for all projects, especially with public interest or risks of opposition	Ensures inclusive, transparent, and ongoing stakeholder consultation and grievance redress
Biodiversity Management Plan (BMP)	Project area intersects sensitive habitats or protected species	Avoids, minimizes, or offsets biodiversity loss and ecosystem degradation
Labour Management Procedures (LMP)	Engagement of workers, contractors, or community labor	Establishes fair labor practices, OHS provisions, and worker grievance mechanisms
Traffic Management Plan (TMP)	Projects requiring large-scale movement of construction materials or equipment	Ensures road safety, manages congestion, and minimizes disturbance to local transport systems
Emergency Response Plan (ERP)	Potential for environmental, health, or security emergencies	Prepares for effective and coordinated responses to accidents, spills, or disasters

Appendix 8 indicate the entry of these considerations through the project implementation cycle.

9.2 Climate Change and Transmission Infrastructure

Climate change presents both immediate and long-term risks to electricity transmission infrastructure in Kenya. As the country faces an increase in the frequency and intensity of extreme weather events the reliability, operational efficiency, and long-term sustainability of the transmission system are increasingly threatened. Addressing these risks requires incorporation of climate change adaptation to protect infrastructure and climate change mitigation to support national low-carbon development goals.

The electricity transmission sector is central to Kenya's commitment to a low-carbon economy as committed to both Nationally Determined Contributions (NDC) 2.0 and NDC 3.0 Kenya targets a 100% transition to renewable energy by 2030 and 2035 respectively. The NDCs 2.0, 3.0 and National Adaptation Plan (2015-2030) also commit to enhanced climate adaptation in the energy sector.

9.2.1 Climate Mitigation

Transmission infrastructure serves as the critical link between Kenya's abundant renewable energy generation and load centers. With 93% of the current energy mix (as of 2025) derived from renewable sources, an efficient and robust transmission network is essential to evacuate this clean energy. By facilitating access to this rich mix, transmission infrastructure reduces reliance on fossil-fuel-based generators, minimizes curtailment of green energy, and directly contributes to lowering national greenhouse gas emissions.

To support Kenya's climate mitigation goals, the transmission masterplan emphasizes several key strategies:

i. Grid reinforcement and development of ancillary infrastructure to accommodate higher integration of renewable energy.
ii. Increased system reliability.
iii. Modernization of the transmission network, including deployment of advanced conductors, integration of smart grid systems, and adoption of digital monitoring technologies.
iv. Reduction of energy losses, targeting a 1% reduction in transmission losses within the 2025–2029 Medium-Term Plan period, as per the LCPDP.

Tree-growing initiatives within project areas to offset the carbon footprint associated with wayleave clearance during transmission line development.

9.2.2 Climate Adaptation

Climate adaptation is guided the principles of resilience redundancy, rapidity, resourcefulness, and robustness. These principles ensure that transmission infrastructure can withstand and recover from climate-induced disruptions. By applying the redundancy principle, the system maintains reliability through multiple electricity pathways. Rapid restoration of operations after extreme events is prioritized, while the ability to mobilize diverse resources ensures effective response and recovery. Structural and operational robustness further enhances the system's capacity to endure a wide range of climate-related shocks, securing long-term energy stability.

The following strategies are proposed: -

i. Institutionalizing climate risk assessments early in project planning from feasibility studies and route selection to detailed engineering designs.
ii. Integrating climate modelling and downscaled climate projections into transmission planning to inform adaptive infrastructure designs.
iii. Partnering with Kenya Meteorological Department (KMD) to access localized climate projections, climate information, and risk analytics.
iv. Building internal technical capacity in climate risk assessment, modelling, cost-benefit analysis, and adaptive engineering practices.
v. Updating technical design manuals to incorporate climate-informed parameters such as wind loading, temperature thresholds, corrosion risk, and hydrological stress.
vi. Developing disaster risk management and emergency response plans to ensure rapid restoration of transmission services after climate-related events.
vii. Incorporation early warning systems as part of project design in areas where vulnerability and infrastructure exposure are highly significant.

Appendix 9 shows the impact of climate change on the functionality of electricity transmission infrastructure.

9.2.3 Climate Change Mainstreaming Opportunities

The opportunities in Table 20 have been identified as a result of mainstreaming of climate change.

Table 20: Climate Change Mainstreaming Opportunities

Opportunity Area	Description	Strategic Benefit
Multilateral, Bilateral, and Blended Finance	Access climate-aligned financing from institutions These funds can be blended with private capital or concessional loans to de-risk investments in transmission infrastructure and integrate climate resilience and mitigation measures.	Unlocks large-scale, concessional, and blended finance aligned with Kenya's NDCs; enables bankable, low-carbon, and climate-resilient transmission projects; attracts private capital.
Green Bonds and Sustainable Finance	Issue green or sustainability-linked bonds to mobilize capital for low-carbon, climate-resilient transmission infrastructure.	Broadens investor base; promotes transparency and accountability in climate-related expenditures.
Carbon Markets	Develop carbon credit-generating projects from grid efficiency, transmission loss reduction, and renewable energy integration; tap into voluntary and compliance carbon markets.	Provides long-term revenue streams for reinvestment in clean infrastructure and climate programs.
Feasibility Studies	Conduct technical and financial studies to assess carbon revenue potential and project bankability	Enhances project attractiveness to climate financiers and readiness for carbon credit registration.
Capacity Building for Carbon Projects	Develop institutional frameworks and skills to design, implement, and manage carbon-credit projects in the transmission sector.	Strengthens in-house sustainability expertise and ensures ongoing access to carbon and climate finance.
Climate-Resilient PPP Models	Structure PPPs using availability-based payments that are linked to climate resilience outcomes (e.g. continued line availability during extreme weather events or post-disaster recovery timelines). These models offer predictable cash flows while embedding performance incentives for climate-proof design and maintenance.	Enhances infrastructure longevity and reliability under climate stress; incentivizes private sector to invest in resilient transmission networks.

9.2.4 Decision-Making Support Tools

To support the mainstreaming of climate change in project planning the following tools are key to facilitate project-based decisions.

Table 21: Decision-Making Support Tools

Opportunity Area	Description
GIS-Based Risk Mapping	Use spatial tools (hydro-meteorological, drought/flood hazard maps) to guide siting and routing decisions.
Climate Scenario Modelling	Apply worst to assess long-term climate risks and impacts on the transmission network. Leverage KMD for localized projections, early warnings, and hazard assessment.
Cost-Benefit Analysis	Quantify economic impacts of adaptation measures to support efficient climate investment decisions.
Early Warning Systems	Incorporate climate forecasting and sensors to enhance system responsiveness to extreme weather events.

10 Monitoring, Evaluation, Accountability and Learning Framework

KETRACO's investments in transmission lines and substations are designed to ensure a reliable and efficient power supply to support national development. Adequate and stable electricity is a critical enabler for achieving Kenya's Vision 2030 and the Bottom-Up Economic Transformation Agenda (BETA). For example, manufacturing is one of the key drivers of economic growth and employment relies heavily on uninterrupted and quality power supply.

KETRACO is implementing a comprehensive monitoring program across multiple transmission lines and substation projects. These projects are categorized as follows:

i. **Projects with both baseline and post-commissioning data**: These allow for full evaluation of project outcomes. The transmission projects include 132kV Isinya-Namanga, 132kV Awendo-Masaba & 220kV Kimuka Substation

ii. **Projects completed before baseline data were collected**: Baseline data is currently being collected retrospectively for projects expected to be completed by 2028. The transmission projects include 132kV Mwingi-Kitui, 400/220/132kV Olkaria-Lesso-Kisumu

iii. **Inception Projects Lacking Baseline or Post-Commissioning Data:** These projects were completed 10 years ago, and there is a need to assess the impacts resulting from the energization of these transmission projects. The projects include: 220kV Rabai-Malindi-Garsen-Lamu, 132 kV Sondu Miriu-Kisumu, Chemosit-Kisii (Kegati), Rabai-Galu, Kamburu-Meru, Sangoro-Sondu, Mumias-Rangala, Kilimambogo-Thika-Githambo , Thika (Mangu)- Gatundu, and Meru-Isiolo

iv. **Committed, Planned, and Ongoing projects (up to Medium-Term Plan 2029)**: These will be fully integrated into the M&E framework from the outset. The transmission projects include 132kV Rumuruti Kabarnet ,132kV Kilifi-Malindi, 132kV Narok- Bomet,132kV Nanyuki-Isiolo & 132kV Nanyuki- Rumuruti.

Table 22 gives a summary of outcomes indicators for a number of completed projects evidenced from data collected during the MEAL activities.

Table 22:Project Outcomes for completed projects

Project	Company	Pre-project energization	Post Project energization
132kV Isinya-Namanga	Namanga One Border Post (NOBP)	NOBP experienced **730 power outage incidents** between 2022 and 2023, resulting in **122 hours of downtime** and the consumption of approximately **9,600 liters of diesel fuel** for backup power over a 24-month period.	In 2024,after energization of the transmission line, NOBP experienced only **10 power outage incidents**, totaling just **1 hour of downtime**. This reflects a **98.6% reduction in the number of outages** and a **99.2% decrease in total outage duration**, substantially minimizing reliance on diesel generators and supporting more efficient operations.
220 kV Turkwel-Ortum-Kitale	Cemtech Sebit Clinkerization	The plant was not in operation until Dec 2024 when KETRACO's transmission line was energized.	The Plant consumes **16MW of power** to run heavy-duty industrial motors.

			It produces **3,000 metric tons of clinkers daily**, with an energy efficiency rate of **65 kWh per ton**. **Significant socio-economic benefits-** The plant has created employment for **300 staff**, including local youth who were previously engaged in cattle rustling. This shift has contributed to enhanced **community stability, reduced insecurity, and improved livelihoods** in the region.

By comparing baseline conditions with post-energization data, KETRACO has gained critical insights into the true performance and socio-economic impact of its infrastructure beyond physical completion. This analysis provides valuable evidence to inform:

- Internal decision-making and capital investment planning
- Engagement with financers and development partners
- Identification of persistent grid challenges requiring strategic interventions

Details of operationalization of MEAL framework and strategis employed in KETRACO is given in Appendix 10.

11 Conclusion and Recommendations

11.1 Conclusion

This Transmission Master Plan highlights KETRACO's medium and long-term power infrastructure investment, priority power transmission projects and the required financial resources. The network as planned over the years was modelled using Power System Simulator for Engineers (PSSE) and simulations of the planned future power system were carried out to ensure the transmission network adequately meets the projected demand/load and evacuate planned generation, as required by the National Transmission Grid Code.

The demand forecast and generation expansion planning undertaken in the 2024-2043 Least Cost Power Development Plan and 2025-2029 Medium Term Plan formed the basis of the planning. The system peak demand is forecasted to grow at an average of 6.92% from 2,177 MW recorded in 2024 (base year) to 8,710 MW in 2044 under the reference scenario. The vision and low scenarios project the peak demand to reach 14,786 MW and 5,209 MW, an average growth of 9.81% and 4.21% respectively. Electricity consumption is expected to rise from 10,763 GWh in 2024 to 36,328 GWh in the reference scenario, 65,525 GWh in the Vision scenario and 25,996 GWh in the low scenario by 2044.

The effective/contracted capacity is projected to increase from 3,058 MW in 2024 to 12,819 MW by the year 2044. Geothermal capacity is expected to contribute the highest to the total firm capacity at an annual average of 40% over the planning period. There is a contribution from BESS and pumped storage for grid stability, amounting to a total of 18% of the firm capacity mix from both technologies by 2044. All existing diesel and gasoil power plants are expected to be decommissioned by 2035 while capacity from nuclear is projected to come in from 2034, contributing up to 9% of the total firm capacity mix by the end of the planning period. In 2044, Renewable Energy resources are forecasted to contribute 63% of the firm capacity mix with Variable Renewable Energies (VREs) representing 5% of this total. The average reserve capacity over the planning period is 13%.

Simulated results project transmission power (technical) losses to reduce from 2.87% by end of 2025 to 2.86% by 2029. In the long-term, the transmission losses (technical power losses) are expected to be about 3.64 % by the year 2044.

KETRACO will regularly monitor risk management activities and the effectiveness of mitigation strategies so as to build a robust risk management framework that enhances resilience in implementation of the Transmission Master Plan.

The company has institutionalized a MEAL framework to ensure that its investments yield both technical and socio-economic benefits. The system tracks improvements in power quality, reliability, and access, while also evaluating the broader impacts of transmission projects such as increased productivity and industrial growth. These evaluations are key to validating project success and guiding future investment.

Electricity transmission plays a crucial role in enabling the integration of renewable energy, expanding access to clean electricity, and strengthening the resilience of the power system against climate-related risks. This aligns directly with Kenya's NDCs, and broader sustainable development goals focused on a low-carbon future. Furthermore, embedding environmental, socio-economic safeguards alongside inclusive stakeholder engagement is essential to ensure sustainability while reducing social conflicts and environmental impacts.

KETRACO is currently constructing 1,709 km in route length (2,502 km in circuit length) of transmission lines and 4,166MVA in transformation capacity of substations which are expected to be complete by the year 2030. The total outstanding investment requirements for these projects amount to USD 794.40 Million with a financing gap of USD 383.23 Million.

The planned projects for the period 2025 – 2044 comprise 4,676.5 km in route length (8,517 km in circuit length) of transmission lines and 14,885 MVA in transformation capacity for substations. The investment requirement is approximated at USD 3,993.59 Million with no funding commitment. The total ongoing and planned projects sum up to 6,385.50 km in route length (10,666 km in circuit length) of transmission lines and 19,051 MVA in transformation capacity of substations. The total investment requirement for all the projects in the 20-year planning period are estimated to be USD 4,787.99 Million of which approximately USD 411.17 Million is secured/committed leaving an estimated financing gap of about USD 4,376.82 Million.

11.2 Recommendations

In order to implement the planned power transmission projects on time, there is need to timely secure the requisite financing. The ongoing and planned projects have a financing gap of USD 4,376.82 Million. The financing of these projects needs to be prioritized by involvement of both Government and the private sector through available frameworks and guidelines. The following measures /strategies should be explored:

i. Advocate for financing Right of Way associated costs from various other sources besides exchequer funds- sources that could be explored include retail tariffs and development assistance.
ii. Continuously promote the participation of private sectors in development of transmission grid through PPP framework.
iii. Continuous engagement with Government and development partners for more funding
iv. Leverage climate financing opportunities and strengthen institutional capacity to develop bankable project proposals and effectively manage their implementation.
v. Enhance integration of climate risk assessment into planning and design supported by climate modelling and GIS- based vulnerability assessments.
vi. Continuously improve the monitoring and evaluation of project outcomes with a view of promoting accountability and document lessons learnt through the MEAL framework.

12 Appendices and Supporting Documentation

(Refer to Volume II)

Kenya Electricity Transmission Company Limited
P. O. Box 34942 - 00100
Nairobi, Kenya.
Kawi Complex, Block B,
Popo Lane, Off Red Cross Road, South C ,
Nairobi, Kenya.
info@ketraco.co.ke

https://ketraco.co.ke