Consultancy Services for the Power Market Study in the Electric Power Sub- Sector

Final Report

Prepared for:

Ministry of Energy

Energy and Petroleum Regulatory Authority

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Mercados–Aries International.

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Revisions

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To:
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Madrid, 17 November 2021

Dear Maj.Gen (Rtd) Dr. Kihalangwa

Consultancy Services for a Power Market Study in the Electric Power Sub-Sector – Final Report

Please accept the submission of our Final Report for the above-mentioned study, which is being carried out under the contract signed on 12 February 2021 between the Ministry of Energy and Mercados Aries International.

Yours sincerely,

Leonardo Lupano
Director Policy Regulation and Strategy

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List of Acronyms

AE	Allocated energy
AIC	Average Incremental Cost
AP	Allocated capacity
BC	Bilateral Contract
BESS	Battery Energy Storage System
CC	Capacity Charge
CIP	Census of Industrial Production
COSS	Cost of Service Study
CP	Capacity Payment
CPCS	Canadian Pacific Consulting Services
CTM	Cost of Transition to the Market
DAM	Day Ahead Market
DSCR	Debt Service Coverage Ratio
EPC	Engineering, Procurement and Construction
EPRA	Energy & Petroleum Regulatory Authority
FC	Free Customers
FERFA	Foreign Exchange Fluctuation Adjustment

FIT	Feed in Tariff
FX	Foreign Exchange
GDC	Geothermal Development Company
GDP	Gross Domestic Product
Genco	Generation company
GWh	Gigawatt hour
HEP	Hourly Energy Price
INEP	Integrated National Energy Plan
INFA	Inflation Adjustment
IPP	Independent Power Producer
ISO	Independent System Operator
ISMO	Independent System and Market Operator
ITP	Independent Transmission Provider
KEM	Kenya Electricity Market
KEMP	Kenya Electricity Modernisation Programme
KETRACO	Kenya Electricity Transmission Co. Ltd
KNBS	Kenya National Bureau of Statistics
KNES	Kenya National Electrification Strategy
KNTGC	Kenya National Transmission Grid Code
KPLC	Kenya Power and Lighting Company PLC
KSh	Kenya Shillings
kV	Kilovolt
LCPDP	Least Cost Power Development Plan
LRMC	Long Run Marginal Cost
MCC	Metering Control Center
MO	Market Operator
MOE	Ministry of Energy
MP	Market Participant
MW	Megawatt
OPEX	Operational Expenditures
O&M	Operations and Maintenance
PPA	Power Purchase Agreement
PV	Photovoltaic
REA	Rural Electrification Agency
REREC	Rural Electrification and Renewable Energy Corporation
RES	Renewable Energy Sources
RFP	Request for Proposal
RTP	Real Time Price
SC	Services Company

SCADA	Supervisory Control and Data Acquisition
SDDP	Stochastic Dual Dynamic Programming
SHS	Solar Home Systems
SMO	System and Market Operator
SMP	System Marginal Price
SO	System Operator
TNSP	Transmission Network Service Provider
VRE	Variable Renewable Energy

Executive Summary

This Final Report sets out key findings on the development of a power market in Kenya.

Review of policy and related documents

Several policy and contextual documents have been reviewed, starting from the Sessional Paper №4 on Energy of 2004, and concluding with the Feed-in-Tariff Policy and Renewable Energy Auctions Policy of January 2021. Over the past 15-20 years several policy measures have been implemented, which represent important building blocks towards the introduction of competition arrangements. These include structural separation of the electricity sector, regulatory and institutional development, introduction of private capital in KenGen, resource diversification and upcoming regional interconnection. However, several challenges are raised in this material, including:

- A lack of systematic least cost planning over time and a tendency to base planning decisions on over-optimistic demand forecasts.
- Relatively weak take up of capacity under the Feed-in-Tariff (FIT) regime, partly due to finance issues and partly due to confidence in the off-take arrangements.
- Slower progress with rural electrification than anticipated, with remaining costs potentially higher than planned, which could have cost implications for KPLC.
- A need to minimise tariff cross-subsidies to ensure customer decisions to seek alternative supplies are based on efficiency and do not create potential stranded costs to KPLC.
- The extent to which existing PPA arrangements can be renegotiated (if required).
- The need for any market arrangements to reflect the important capacity costs (including stranded costs) to KPLC, which would need to be fully remunerated. These costs are potentially higher than necessary due to challenges in least-cost capacity contracting and delays in transmission projects.

The recent revision to the FIT regime, and the creation of renewable energy auction is a positive step in ensuring new supply commissioned by KPLC is at an efficient cost.

Legal review

A legal review has highlighted that there are no major impediments that prevent the establishment of different forms of competitive markets. The Constitution provides inherent rights to the counties over reticulation, though it is not foreseen that this would be a disbarment or constraint from a market perspective. Moreover, neither the Competition Act nor the Public Private Partnership Act appear to create barriers, though it would be prudent for clarity to be sought, and potentially a memorandum of understanding agreed with the competition authorities once details on the market arrangements are known.

Key concerns from a market perspective centre around the Energy Act, 2019 and especially what is clearly provided for, and what areas are less clear. The absence of licensing of the upstream supply side (as opposed to the retail side) is surprising, although this is tempered somewhat by the approval requirement for all buying and selling, and the possibility for the Minister to issue market related regulations (although the scope and extent of these rules are not specified at all). In addition, the existing PPAs may also pose problems, especially around breach and Government obligations should breach occur.

Planning arrangements

In general, the overall governance framework for planning appears appropriate, with procedures that can transition into the Integrated National Energy Plan as envisaged in Energy Act. A key weakness of the recent Least Cost Power Development Plans (LCPDPs) has been the tendency to overestimate demand growth, potentially due to the incorporation of aspirational goals on economic growth and development that have not been realised in full. As a credible demand forecast is critical for planning a review of demand forecasting approaches is recommended.

The detailed technical approach to planning was recently reviewed by Mott MacDonald, who highlighted a need to update planning software to be able to adequately capture variable renewable energy (VRE) and change certain practices in generation and transmission planning. We support these recommendations, some of which have already been implemented in the 2020-40 and 2021-30 LCPDPs.

Key constraints to the development of a market

A financially and operationally sustainable off taker (KPLC) is essential for any durable market arrangements. However, several risk factors need to be addressed prior to the initiation of any electricity market.

The high cost of existing PPAs, notably those signed with IPPs, creates important risks:

- KPLC's exposure to contracts that may no longer be economic creates a risk that it cannot recover its fixed costs of supply where customers seek alternative supply of energy – either through self-generation as is currently the case, or participation in a future wholesale market.
- KPLC's exposure risk may augment over time given that alternative supply sources in Kenya (especially with solar) are reducing in price, creating an increasing gap between costs available to customers considering alternative arrangements and the overall cost of KPLC's power purchase portfolio.

Moreover, a limited reduction in capacity supplied under existing PPAs is envisaged over the period to 2030, meaning key cost burdens will persist for several years. To support any market arrangement and protect KPLC, uneconomic contracts, or more specifically the fixed costs of supply (capacity costs and take-or-pay costs of renewable PPAs) will need to be considered as restructuring costs to be spread across participants in any market arrangements. Even if some renegotiation of some PPA contracts is possible, an important cost burden cannot be removed entirely.

Adequate protection to KPLC from existing competition from solar PV is essential. The installation of solar PV by customers creates an added risk to KPLC in recovering its revenue requirements and ensuring financial viability:

- The limited spread of two-part tariffs exposes KPLC to the risk that customers who take up solar PV but maintain connection to the grid are not paying towards the cost of network capacity.
- Potential cross-subsidies in the tariff structure may create artificial incentives for some customers to seek solar PV solutions.

Both these factors reduce the revenue base to KPLC, creating conditions for what is often referred to as a "death spiral" for the utility. In general tariff and regulatory reform is required to protect KPLC. The proposed introduction of a net metering policy can help address this difficulty and should be introduced as soon as feasibly possible. Under best practice the policy should:

- Allow KPLC to recover the costs of capacity provided to Distributed Energy Resources (DER) customers, by either a) implementing 2-part tariffs or other network related charges as a pre-condition for customers to install DER, or b) introducing gross billing where all energy produced is directly metered and charged separately to energy consumed from the grid.
- Ensure that energy supplied to the KPLC network is remunerated at the value of that energy generated, which will be much lower than the retail tariff (net of network costs) and potentially much lower at off-peak hours when most electricity produced by solar PV facilities is injected into the grid.
- Permit transition to time-of-use remuneration, which can also provide incentives for customer storage solutions to develop, in line with broader market developments.

Ensuring KPLC's sustainable performance more generally requires that other factors are addressed, including:

- Enhancing its performance on key operational variables. This is particularly relevant for losses, which have been increasingly gradually over recent years, but also relevant for outages: while KPLC's performance on outages has improved over the past 6-year, recent data suggests improvements have stalled.
- Ensuring it has a cost-reflective tariff that allows it to operate efficiently within a context of least cost planning that minimises the overall cost of supply over time.

Simplified modelling of KPLC's financial performance over the following 5-year period, suggests that KPLC will face problems in debt repayment and liquidity, even assuming full cost recovery tariffs are in place over this period. This suggests that KPLC's overall financial performance and capital expenditure program needs close review to ensure any structural factors affecting its financial performance (e.g., debt capacity) are addressed in the transition to any market arrangements. Moreover, it is essential to enhance its governance structures.

This report has been developed without access to legacy PPAs, though some information is available in the Presidential Taskforce on PPAs. The standardised RES PPAs foresee the possibility of a changed electricity market and provide that KPLC must transfer its transmission, distribution and purchase rights and obligations to any successor in title. This demonstrates that the parties to these PPAs acknowledge that such changes may occur, and tasks KPLC with ensuring that this happens. However, this does not mean that should such transfer of rights and obligations take place it would take away the right of the sellers to invoke change of law or breach provisions should their commercial rights be negatively impacted, and the same principles should hence be applied that market rules should not negatively impact the commercial rights or obligations of the contractual parties in the first place.

Wheeling tariffs and market tranches

A pre-requisite for formal electricity market arrangements, and precursor arrangements like allowing customers to develop solar PV plants away from their point of consumption through forms of virtual net-metering, is a system of wheeling tariffs. Wheeling rates have been estimated, with end-user tariffs simultaneously estimated.

A first key step is to estimate the sector revenue requirement, and specifically for wheeling purposes, the distribution and transmission revenue requirement. A key principle used in developing the wheeling tariffs is that network costs are estimated by voltage level, with calculations starting from the voltage level estimates of Long Run Marginal Cost. Wheeling tariffs are considered as equivalent to network tariffs, so that a customer wheeling across the 33kV network will also have to pay the costs of higher voltage levels as would a customer connected to the 33kV network, while simultaneously receiving energy from generators connected to the High Voltage network.

Wheeling tariffs have been developed using the coincident peak methodology to allocate the key capacity costs of the distribution and transmission networks. Losses are then added, including non-technical losses at Low Voltage. Based on this methodology, the following cost-reflective wheeling charges are estimated for the commercial and industrial categories CI1 to CI6. Two alternatives are provided – a fully energy based wheeling charge, and a capacity-based wheeling charge with an energy-based component for losses.

Table 1: Estimated wheeling charge – coincident peaks methodology 2020-21)

	1-part option: Energy Charge Wheeling Rate (KSh/kWh)	2-part option a) Capacity charge Wheeling Rate (KSh/kVA)	2-part option b Energy component (KSh/kWh)
LV			
Commercial and Industrial CI1	8.25	2,541	0.77
MV			

Commercial and Industrial CI2	5.38	1,699	0.38
Commercial and Industrial CI3	4.07	1,607	0.38
HV			
Commercial and Industrial CI4	3.56	1,189	0.26
Commercial and Industrial CI5	3.51	1,102	0.26
Commercial and Industrial CI6	2.11	981	0.26

Source: Own analysis

It is proposed that eligibility for customers to participate in the Kenyan Electricity Market (KEM) will be staged and based on existing customer tariff categories. An advantage of the current tariff system is that it is clearly segmented by voltage level, with the amount of consumption within these bands relatively well spaced out. This allows for a gradual opening based on tariff categories working from the highest voltages (220 and 132kV) downwards. Data has not been seen on maximum demand, which is the most plausible alternative at least for the largest customers. However, a strong correlation between maximum demand and voltage level is envisaged, which further supports application of the use of customer categories. A suggested approach is to apply four bands as follows:

- CI6, CI5, CI4 and CI3 (33 kV and above) - representing 172 customers in 2020 and 16.81% of the total consumption.
- CI2 (11kV) – 480 customers and 13.59% of total consumption
- CI1 (240/415V) – 2983 customers and 17.88% of total consumption.
- Domestic and street lighting (240/415V) – mass market opening with 7.2 million customers and 36.27% of total consumption.

Market design

Pre-requisites

A critical pre-requisite for moving to any formal market design arrangement is to address the key constraints highlighted earlier, many which affect KPLC.

These following **tariff reform** measures are proposed:

- Continued transition towards cost-reflective tariffs allowing KPLC, where operating efficiently, to fully recover its efficient revenue requirement and ensure that tariffs are properly indexed and adjusted to keep the cost reflective level any time
- Wider implantation of two-part tariffs, including for all commercial customers over time and for high usage domestic customers who subsequently take up supply from solar PV at its premises or through wheeling arrangements. Specifically, all commercial customers above a certain size (10kW) should have 2-part tariffs.
- Development of a net metering policy that is compatible with above steps by ensuring customers with solar PV or other DER facilities pay for the cost of network services provided by KPLC, and energy supplied to the grid is remunerated in relation to the value that energy provides to the grid. Where 2-

part tariffs are cost reflective this can be under net-billing arrangements, otherwise gross-billing is recommended.

Stabilisation in KPLC's financial performance is critical for developing market arrangements where key additional aspects of this situation (to those above) include:

- Enhancement of all aspects of KPLC's financial performance more generally. A review of financial performance with a time-limited action plan is proposed to ensure it moves to sustainable financial operations. This should be supported with enhanced governance arrangements and a more proactive role for its public and private shareholders.
- Develop clear targets for enhancing operational performance to ensure the recent increase in reported losses is reversed, and improvements in service quality can be made on a systematic basis.

In a fully functioning market, the role of generation **least cost planning** is indicative in nature, with a key aim being to provide signals to investors to guide investment decisions. However, enhancement of planning arrangements is required in any transitional period, where planning is necessary to identify projects and key needs. Enhancements that need to be introduced include proposed updates to planning software, enhancement of demand forecasting, and ensuring strong complementarity between generation and transmission planning.

Assumptions

Reflecting the limited information on PPAs, assumptions on PPAs have been made in developing a market design. Key assumptions include:

- Existing PPAs can be characterized as capacity contracts, with the operational costs (fuel costs) remunerated on a pass-through basis. This means that the energy of these PPAs can be subject to economic dispatch, based on the fuel costs of the plants of the PPA holders.
- Existing PPAs are sufficiently flexible that the introduction of a market does not trigger change of law or breach provisions.
- In the case of the standardized PPAs related to RES, there is payment for the produced and delivered energy, but not a capacity payment.
- The PPAs have clauses that ensure a proper reliability of the provided capacity.

Principles

A fundamental principle of any feasible market design should be to respect the existing PPAs, without threatening the solvency of energy sellers or the rights of energy buyers. However, stranded costs arise, which are considered as the fixed (capacity) components to the selling parties of the PPAs as well as any take-or-pay obligations for RES.

A key principle for the proposed Kenya Electricity Market (KEM) is that the full amount of stranded costs is allocated and passed through to the market participants, namely the buyers (consumers) of electricity, which includes purchases for the non-competitive market and purchases under competitive arrangements. The stranded costs of the existing PPAs are to be allocated to all consumers proportionally based on their consumption (energy or peak demand) through transition payments that will be included in the wheeling or end-user tariffs paid by consumers.

The report of the Presidential Taskforce on PPAs (September 2021) recommends renegotiating existing PPAs where practical. While any downward revision to PPA prices would support market development by reducing stranded costs, the extent to which this is possible may be limited, and even then, will incur costs to KPLC and/or the Kenyan Government due to the legally binding nature of these agreements. In the absence of significant capacity to renegotiate PPA prices, the main tools available to reduce purchase costs are contracting new capacity at economic prices, which will reduce the per-unit stranded cost, and the use of direct subsidies to the sector.

Creation of a System and Market Operator

A System and Market Operator (SMO) will be the key entity to manage the operation of the Kenya's power system and the future market. This represents an important change from current arrangements, where system operation (SO) functions are vested in KPLC.

A first key issue is whether it is most efficient to have a single entity that carries out both SO and Market Operation MO, or whether it is sufficient to have separate SO and MO functions. Combining the two entities into an SMO is recommended for three key reasons:

- **Coordination** – SO and MO activities will need to be coordinated, especially in phases of the KEM with a day-ahead market, which creates the need for synchronisation of several key activities over a period of a few hours.
- **Cost** - Separate entities will require more resources and cost to operate.
- **Single database** - which means less risk of incongruencies and errors, as well as a single source of information for market participants.

A second key issue is whether to create a fully independent SMO (ISMO) or use one of the existing sectors participants as SMO. KPLC is currently the SO, though as the Energy Act, 2019 prohibits the SO from being involved in the direct or indirect buying or selling of electrical energy, the only plausible entity from within existing sector participants is KETRACO. In this case the SMO functions could be undertaken within a ring-fenced department within KETRACO (KSMO). Each of the two alternatives - ISMO or KSMO - has advantages and disadvantages in key evaluation areas like conflict of interest, information transparency, priorities, integration of independent transmission providers (ITPs), governance, costs, and implementation time.

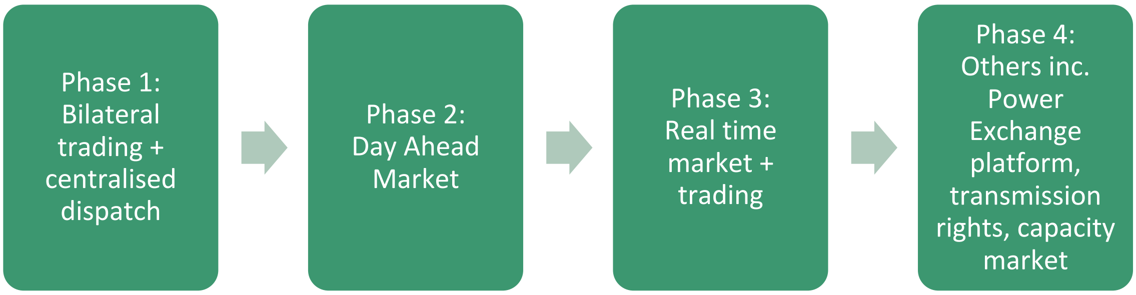
Strict technical arguments support the development of an ISMO, especially if a decision is taken to initiate the process towards the development of market arrangements and introduction of ITPs. Where the recommended end point is an ISMO, then the most applicable intermediate point is to designate an independent SO to perform system operation functions in the period prior to market formation, after which the ISO would transition into an ISMO.

The findings of the Presidential Taskforce on PPAs are consistent with the above, as it recommended that KETRACO suspend work on ISO infrastructure until a decision on the location of the SO functions is made. Moreover, it recommended that in the interim period the SO function be performed by a team of experts from KPLC and KETRACO working under EPRA and MOE.

Proposed model

A four-phase market model is proposed, in which the switch from one phase to the next will occur when it is considered that the previous phase is running smoothly and efficiently.

Figure 1: Proposed four phase model for wholesale competition



In the **first phase** energy will be traded through bilateral contracts or through a centralized economic dispatch determined on a day-ahead basis and carried out by the SMO. A key aim of the economic dispatch will be to minimize the variable cost to meet the day ahead forecasted demand. Other key features are that:

- Ancillary services are centrally allocated to market participants and paid with a regulated tariff.
- On an ex-post basis, the SMO will calculate the energy consumed for each supplier and free customer for each hour.
- The demand side of the market will be responsible to pay a transition charge (CTM) reflecting the fixed cost obligations under the PPAs and their share of overall capacity (AP).
- Additional capacity will be subject to a Capacity Charge (CC) set by EPRA and applied to their actual maximum annual power demand (capacity demand) minus the AP.

The **second phase** will involve the introduction of a day-ahead market (DAM). The DAM allows multilateral trading among market participants and produces 24-hourly schedules for the production and consumption of electricity the day before the operating day. The DAM ensures the optimal use of the available generation to meet the forecasted load. The DAM will be financially binding, which means that the differences between the scheduled and measured generation and demand will be settled with a procedure defined in the KEM's market rules.

In the **third phase**, additional possibilities include:

- A real time market will be introduced, based on offers presented by generators or loads at request of the SMO, and a real time price based on the accepted offers for upward or downward regulation.
- Allowing Free Customers to participate in the real time market with demand side bids.
- Introduction of traders as MPs.

In the **fourth phase**, the following additional possibilities will be introduced:

- Depending on the evolution of new investments, the capacity payment may be eliminated for new entrants, or replaced by a competitive capacity market.
- Introduction of a power exchange platform where Market Participants can trade standardized products (e.g., peak energy, baseload energy, etc.) as futures or options.
- Introduction of transmission rights for bilateral contracts, that will allow to optimize the use of the available transmission capacity, allocating the available capacity to the bilateral contract parties through auctions.

Pace of transition

The pre-requisites to introducing the market, which revolve around having a financially sustainable electricity sector, are significant. However, providing the market pre-requisites can be addressed, fast implementation of the KEM should be possible, providing there is political willingness to develop and implement in a short period the rules and procedures for the operation of the KEM and decide on the location of the SMO. Specifically, there are no technical obstacles for a fast implementation of the KEM, though several institutional changes and operational steps need to be made, which are included in the **Action Plan** included in this report.

The switch from one phase to the following will occur when it is considered that the previous phase is running smoothly and efficiently. In the proposed plan, the transition will be proposed by EPRA to the MOE who will make the final decision.

A key aim of the proposed principles to market reform and approach is to ensure that KPLC is protected from power purchase risk and can recover all its fixed costs related to energy purchase. For this reason, there is no in-principal reason why transition cannot commence as soon as KPLC's financial situation is stabilised. However, this assumption may need reviewing as further information in the PPAs is made available.

1 Introduction

This Final Report for the project, "Consultancy Services for the Power Market Study in the Electric Power Sub- Sector" sets out key findings and conclusions of the study, which was developed between February 2021 and November 2021.

This Report is structured as follows:

- Section 2 reviews key contextual and policy documents of relevance to the study (Task 1 of the Study).
- Section 3 assesses the legislative and regulatory framework (Task 2).
- Section 4 reviews Least Cost Planning Development Plans (LCPDPs) issued in Kenya in recent years (Task 3).
- Section 5 outlines barriers to the development of a wholesale market (Task 4).
- Section 6 considers several issues regarding the operational and financial performance of sector entities (Task 5).
- Section 7 considers market design and develops an Action Plan (Task 6).
- Section 8 considers training needs (Task 7).
- Section 9 sets out conclusions.

In addition, the following annexes are included:

- Annex 1, with details of the calculations underpinning the estimation of the revenue requirement of the sector participants.
- Annex 2, setting out details of the tariff calculations, and
- Annex 3, containing proposals for optimising the dispatch of hydro plants under market arrangements.

2 Review of existing documentation – policy and contextual documents

This section reviews several documents that have importance for the Kenyan electricity sector and draws out key implications for the development of competitive market arrangements.

This review includes consideration of the following policy documents:

- Vision 2030 (2008).
- Sessional Paper No.4 of 2004 on Energy
- National Energy and Petroleum Policy, 2015
- National Energy Policy, 2018, including the National Treasury and Planning, Policy on the Issuance of Government Support Measures in Support of Investment Programmes, 2018.
- Revised Feed in Tariff Policy
- Renewable Energy Auctions Policy, 2021

Following this, the following studies and initiatives are evaluated:

- Study on Options for the Development of a Power Market in Kenya (CPCS study), 2012.
- Study for USAID on the Open Access Market Framework (2019).
- Previous tariff reviews and studies conducted by Fichtner GmbH (2007) and SNC Lavalin (2013).
- The Kenya Electricity Modernisation Programme (KEMP), including the Kenya National Electricity Strategy, 2018.
- Terna/CESI Gap analysis report for KETRACO 2014.

For each document, a brief explanation of the key objectives is set out, followed by key relevant findings and implications for the introduction of competitive markets and/or other issues of relevance to this study.

2.1 Sessional Paper No.4 of 2004 on Energy

Policy objectives

The objective of the Sessional Paper on Energy was to lay the policy framework upon which cost-effective, affordable, and adequate quality energy services was to be made available to the domestic economy on a sustainable basis over the period 2004-2023.

2.1.1 Key findings and conclusions

Sessional Paper Nº4 represents a key building block in the development and modernisation of the Kenyan electricity sector. It highlights several key constraints at the time: a weak power transmission and distribution infrastructure caused by limited investments; resulting power system losses estimated at 20% of net generation; extreme voltage fluctuations and high intermittent power outages causing material damage and losses in production; and high cost of power from IPPs, all of which contributed to high cost of business for customers.

Sessional Paper Nº4 was the forerunner to the Energy Act Nº12 of 2006, foreshadowing:

- Establishment of a single independent energy regulator under the Energy Act with adequate mandate to regulate all sector players.
- Establishment of a State-owned Geothermal Development Company (GDC) responsible for geothermal resource assessments and sale of steam to future IPPs and KenGen for electricity generation.
- Privatisation of KenGen over time starting with an Initial Public Offering of 30% of its equity through the Nairobi Stock Exchange.
- Creation of a Rural Electrification Authority to accelerate the pace of rural electrification in the country.
- Unbundling of KPLC into two entities, one for transmission which will be a 100% state owned and the other for distribution which will be private sector owned.
- *Promoting privately or community owned vertically integrated entities either operating renewable energy power plants or hybrid systems, to coexist with licensed electricity distributors.*
- *Allowing power generation companies to access bulk electricity consumers through the power transmission network.*
- *Creation of a domestic power pool with a provision for wholesale and retail markets to create competition and thus reduce the cost of electricity.*
- Privatisation or concession of isolated power stations to reduce operating costs and thus free up resources for rural electrification expansion.
- An increase in the lifeline tariff applicable to domestic consumers of up to 50 kWh per month to at least recover the cost of electricity generation, and
- Transfer of the rural electrification assets within the interconnected electricity network to licensed electricity distributors at cost consistent with the law.

The above list also includes several provisions pre-supposing the development of competitive markets (in italics). Reflecting the proposed development, the Paper later states the need for transmission and distribution charges to be developed, which will be regulated by the regulator.

2.1.2 Implications

Many of the provisions in Sessional Paper Nº4 have been implemented in full (e.g., 30% share offering of KenGen, creation of REA, creation of GDC, creation of independent regulator) or implemented indirectly (e.g., creation of KETRACO instead of unbundling of KPLC).

However, the provisions related to the creation of competition are largely untouched, except to some degree in off-grid rural electrification. In part this reflects inherent difficulties in implementing market arrangements. Moreover, the nature of the starting point (in 2004) was significantly more prejudicial to the creation of wholesale markets and similar arrangement than presumed at the time, especially related to the performance of the transmission and distribution networks.

2.2 Vision 2030 (2008)

Programme objectives

The Kenya Vision 2030 aims to transform Kenya into a newly industrializing, middle-income country providing a high quality of life to all its citizens by 2030 in a clean and secure environment. It has 3 main pillars:

- Economic – aiming to achieve annual GDP growth of 10% per annum from 2012
- Social – building a just and cohesive society with social equity in a clean and secure environment
- Political – realise a democratic political system that respects the rule of law

2.2.1 Key findings and conclusions

Kenya Vision 2030 places an important role on the energy sector in driving the economic transformation process. In addition to identifying several energy-intensive new projects creating important demand for electricity, the Vision highlights several needs for the energy sector. These include:

- Increased generation at lower cost.
- Increased efficiency in energy consumption.
- Creation of a strong regulatory framework.
- Encouragement of the private sector to develop generation.
- Separation of generation and distribution activities.
- Development of new sources of energy, including geothermal, coal and renewable energies, and
- Connection to the energy systems of surplus countries.

The Vision 2030 document does not set out explicit capacity and energy forecasts for the electricity sector, though forecasts drawing upon the Vision are reflected in subsequent LCPDPs. For example, the Plan developed for the period 2011-30 includes the following core forecasts for energy and peak demand.

Table 2: Estimates of energy and peak demand growth, 2010-2030 (2011 LCPDP)

	2010	2020	2030
Energy production (GWh)	7,296	25,512	91,946
Ave growth (% p.a.)		14.5% (2010-20)	12.2% (2020-30)
Peak demand (MW)	1,227	4,755	15,026
Ave growth (% p.a.)		14.5% (2010-20)	12.2% (2020-30)

Source: Republic of Kenya, Updated Least Cost Power Development Plan, Study Period 2011-31, March 2011.

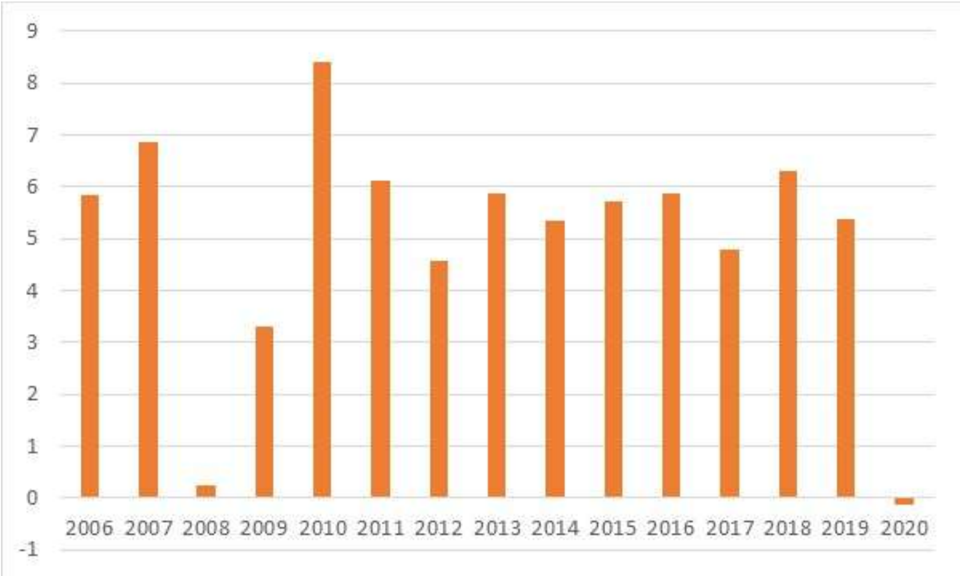
The above forecasts include an estimated 6,394GWh additional energy needs and 876MW additional capacity associated with major flagship projects underpinning the Vision 2030 programme.

2.2.2 Implications

The Vision 2030 qualitative objectives for the electricity sector are sound and have to a large degree been implemented: KenGen is separated from KPLC, the regulatory framework has developed, interconnections are being built, the resource mix is being diversified, including through the involvement of the private sector. All these developments support the introduction of competitive arrangements for power supply.

However, a key legacy of Vision 2030 for the electricity sector has been a tendency to overestimate electricity demand and subsequent capacity needs, and in some cases significantly so. For example, actual generation production and purchase in 2019/20 was 11,462GWh, less than 40% of that forecast in the 2011 LCPDP for 2020. Similarly reported peak demand for 2020 at 1972MW was around 42% of the value forecast in the 2011 LCPDP for 2020. In practice, energy growth has not been stagnant, averaging 4.6% per annum between 2010 and 2020, but forecast rates around 14.5% have been shown to be unachievable and highly aspirational. Part of the reason has been the overestimation of GDP growth used in the demand forecasts: the 2011 LCPDP envisaged GDP growth of 10 percent per annum from 2012, when in practice it grew around 6 percent per annum.

Figure 2: GDP constant prices, national currency, annual growth rate 2006-2020



Source: IMF World Economic Outlook Database, April 2021 (2020 estimated value)

The tendency to overestimate demand has been a notable feature of subsequent LCPDPs and is considered in greater detail in Task 3 (Section 4).

2.3 National Energy and Petroleum Policy (2015)

Policy objective

The overall objective of the energy and petroleum policy is to ensure affordable, competitive, sustainable, and reliable supply of energy to meet national and county development needs at least cost, while protecting and conserving the environment.

2.3.1 Key findings and conclusions

The National Energy and Petroleum Policy was the first main policy document for the electricity sector following the introduction of the Constitution. The policy was drafted consistent with the desire for greater devolution of powers in the sector.

The Policy places a strong emphasis on the development of renewable energies and reflects the different needs of each renewable energy type. It presupposes private sector involvement in small hydro, waste-to-energy, biogas, and residential and commercial premises for solar PV facilities. A key vehicle proposed is continued use of the Feed-in-tariff (FiT) as under the FiT Policy 2012, where several challenges were raised:

- Insufficient data and analytical tools to inform the level of tariffs for different technologies.
- Lack of awareness on FiT among the potential investors.

- No clear guidelines on PPA negotiations.
- Inadequate technical and financial capacity.
- Tariffs charged do not generate sufficient revenues to cover capital, operation, and maintenance costs of the projects.

An additional complicating factor raised in the policy for investment in renewable energy was insufficient local credit schemes and financing mechanisms.

Consistent with the Vision 2030 document, large increases in capacity and energy demand are predicted in the Policy, with peak demand anticipated to increase from 1,468MW in 2013/14 to 3,400MW in 2016 and 5,359MW by 2018 – that is, a more than three-fold increase in little over 4 years. The supporting generation growth was anticipated to result in a reduction in the average cost of generation from 11.3c/kWh in 2013 to 7.41c/kWh in 2017, with the associated end-user tariffs reducing from 14.14c/kWh to 9c/kWh for commercial/industrial customers and from 19.78c/kWh to 10.45c/kWh for domestic customers. Important roles for geothermal, thermal and coal fired plants were identified for meeting the increased demand, with plans included to develop a nuclear power plant by 2024. Matching augmentation of the transmission network is set out, as are interconnections with Tanzania, Ethiopia, and Uganda.

Several challenges are outlined for distribution, including:

- Weak distribution network characterized by limited redundancy and aging assets.
- Frequent and prolonged supply interruptions.
- High distribution system losses.
- Illegal power line connections and theft of electricity.
- High costs of rural electrification projects
- High electricity connection charges, with most consumers unable to afford upfront connection costs.

2.3.2 Implications

The policy raises several challenges in the use of FiT. The FiT Policy of 2012 is well articulated, but limited capacity has been commissioned, including after publication of the 2015 Energy Policy. Highlighted constraints are broad, including technical and financial ones, with the latter including difficulties for project proponents to obtain credit from commercial banks at a rate that supports project viability. In practice, many of these issues are subsequently superseded by the FiT Policy of January 2021, which is considered later in this section.

A proposed greater role for geothermal and interconnections in the policy has largely transpired. On the other hand, as for Vision 2030, the forecasts for peak demand are notably higher than what transpired during the same period, while several difficulties identified for distribution have not been fully mitigated.

2.4 National Energy Policy (2018)

Policy objective

The overall objective of the Energy Policy is to ensure affordable, competitive, sustainable, and reliable supply of energy at the least cost to achieve the national and county development needs, while protecting and conserving the environment for inter-generational benefits.

2.4.1 Key findings and conclusions

The National Energy Policy is the successor document to the 2015 Policy and sets out several important goals for renewable investment:

- Continued government funding of the Geothermal Development Company (GDC) to manage exploration risk and attract investors.
- Transformation of the Rural Electrification Authority into the Rural Electrification and Renewable Energy Corporation (REREC) to be the lead agency for development of renewable energy resources other than geothermal and large hydroelectric sources.

As with the 2015 Policy an important role is given to the FiT regime to develop capacity for smaller renewable projects.

Other key Government decisions in the Policy include:

- Develop and monitor implementation of electricity master plans for the country and the Eastern African Region.
- Support the development by KETRACO of new transmission lines: about 5,000 km in the short term and 16,000 km by 2031.
- Facilitate open access to the transmission and distribution networks, designate a System Operator and encourage regional interconnections to enhance regional electricity trade.
- Provide incentives for development of robust distribution networks to ensure efficient and safe provision of distribution services to reduce power supply interruptions and improve the quality of supply and service.
- Formulate and implement a National Electrification Strategy to accelerate connection with a view to achieving universal access to electricity by 2020.
- Continue funding the development of distribution networks through REREC.

2.4.2 Implications

The policy contains various aspirational measures – for example, an increase in installed capacity from 2,336MW in December 2017 to more than 6,700MW in 2024; and universal access by 2020. In this sense it is aligned to other documents written following Vision 2030, which stress targets that appear unachievable, at least in the timeframe specified.

The policy continues to stress the importance of the FiT regime. It also notes significant interest expressed from the private sector to develop capacity (4,608MW in the 2018 Policy and 1,781MW in the 2015 Policy). However, very little of this interest has translated into project operating under FiT tariffs. The policy reflects that an important constraint to the development of private projects operating under FiTs is finance, which has implications that are wider than simply the FiT. The policy mentions the following challenges:

1. Inadequate funding for the energy sector.
2. Low foreign investment from a highly competitive international finance market.
3. High initial capital outlay for energy projects.
4. Inadequate institutional capacity to negotiate energy contracts.
5. Inadequate local content in energy projects.
6. Foreign exchange fluctuations.
7. Unpredictable fiscal regime.

Of critical importance from the above is the need for a strong off-taker (for contracts signed with a Single Buyer) and investor confidence in the Government. Following development of the Policy, the National Treasury and Planning issued its Policy on the Issuance of Government Support Measures in Support of Investment Programmes (2018). The policy focuses on potential areas of support, principally for private investors signing contracts with Government owned entities – like an IPP signing a PPA with KPLC. Various measures are foreseen, including the following benefiting the private sector: political risk cover, sovereign guarantees, letters of support, project-based guarantees, partial risk guarantees, Government Notes and Letters of Exchange, and co-investment arrangements.

While the above measures are not directly applicable to market-based arrangements (e.g., private generator selling directly to a customer), ensuring strong policy support to private-state contracts is critical to continue developing confidence in the sector, ensuring private parties participate in the market, and subsequently evolve towards direct participation without sovereign guarantees or similar arrangements. Availability of supportive local funding for project developers is also an important constraint in other markets where development of renewable projects by the private sector is being promoted.

2.5 Feed in Tariffs policy (January 2021)

Study objectives

The policy represents an update of the previous FIT policy, which was published in December 2012.

2.5.1 Key findings and conclusions

This policy represents the first major review of the FIT policy since December 2012 and should be read in conjunction with a parallel policy issued on Renewable Energy Auctions (subsequent sub-section).

Key broad features of the revised policy are:

- Removal of solar PV and wind projects from access to the FIT.
- No consideration of geothermal, with these projects to be procured under the Policy on Licensing of Geothermal Greenfields.
- Cap of 20MW on capacity eligible for the FiT for all other technologies.
- Total capacity under the FiT arrangements to not exceed 10% of total system-wide generation capacity.

Key contractual and tariff arrangements are:

- The application of a 20-year PPA period.
- Non-dispatchable nature of the plants.
- Fixing the FiT in US dollar terms unless requested by a developer, with the O&M component indexed to the US CPI.
- Cost of connection to be borne by the developer.
- Prices to be energy based (no capacity component).

The following prices are specified:

Table 3: PPA Prices specified in Feed-in-Tariff policy 2021

Technology	Capacity (MW)	Price	Scalable component
Hydro	0.5*	9.00	8%
	10-20	8.20	8%
Biomass	0.5-20	9.50	15%
Biogas	0.2-20	9.50	15%

Note *: interpolation applied for hydro capacity between 0.5MW and 10MW.

2.5.2 Implications

The scope of the FiT has been scaled down for several reasons: difficulties in contracting expected capacity under the previous scheme, evidence that customers are installing solar facilities independent of charging regimes, and the success that renewable energy auctions are having in several countries, especially for solar PV and wind, which leave a FiT policy for those technologies inefficient. For this reason, the FiT has been refocused on areas where it potentially can support electrification (e.g., mini-hydro) and technologies where there is less international competition and potentially community-based schemes (biomass, biogas). While volumes under the FiT are expected to be lower, it is still important that expected projects are captured in the LCPDP process.

2.6 Renewable Energy Auctions Policy (January 2021)

Policy objectives

The primary objective of the policy is to procure RE capacity at competitive prices and aligned to the Least Cost Power Development Plan/Integrated National Energy Plan

2.6.1 Key findings and conclusions

This policy forms a fundamental component of the transition of the FIT policy considered above. Under this Policy, all solar PV and wind, and all other RE project above 20MW will be procured via auction. Approved wind and solar PV projects with an Expression of Interest (EOI) but no signed PPA will be transitioned to an auction process.

Key broad features of the auction arrangements are:

- Availability of land to be decided by the MOE.
- A two-stage bidding process will be used with the first stage pre-qualification and the second stage the financial and technical proposals.
- All bids to be on a $/kWh basis.
- All costs of connection to be borne by the developer.
- The policy to be reviewed every five years.

2.6.2 Implications

The move to the use of auctions for RE, especially solar PV and wind reflects best international practice and provides important opportunities for significant reductions in energy costs. Benefits have occurred in Africa, where Ethiopia obtained a price of $0.025/kWh for 250MW of solar PV in June 2019, and Zambia a price of $0.044/kWh for 120MW of solar PV in April 2019. Since this date prices have reduced further with values less than $0.02/kWh seen in several countries in the Middle East and Central Asia. These values compare with $0.12/kWh in the previous version of the FiT policy.

In practice, the intermittent nature of variable RE plus take or pay provisions in the PPAs mean that there is need to ensure system balance and that all relevant costs of doing so are fully recovered in the tariff by KPLC as they will be the counterpart to the signed PPAs.

2.7 Study on Options for the Development of a Power Market in Kenya (CPCS study), 2012

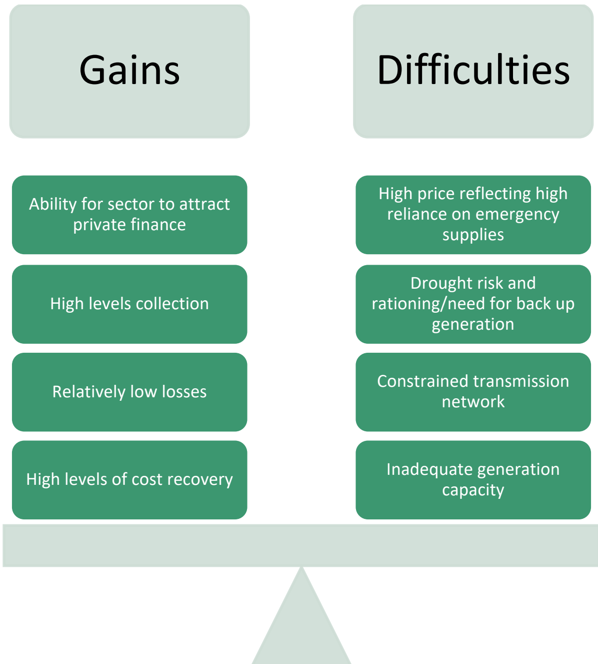
Study objectives

In its 2012 study for the Ministry of Energy, CPCS in collaboration with Castalia Strategic Advisors, were asked to look at ways to increase competition in the electricity market, with its detailed tasks involving: providing guidelines for the entry of additional generation capacity to the network; identifying and evaluating approaches for large eligible customers to gradually be allowed to choose their electricity provider while ensuring financial sustainability of the sector; providing recommendations for KETRACO to assume the role of independent system operator; and preparing regulations for supply contracts between eligible consumers and authorised generators and for the use of the network by eligible customers

2.7.1 Key findings and conclusions

The CPCS undertook an extensive review of the electricity sector, highlighting several difficulties and areas of gains. These are summarised below.

Figure 3: Summary of status review Kenyan electricity sector, CPCS study



Source: Own adaptation from text in pages 43-44 of CPCS (2012).

The report did not explicitly review the performance of KPLC, but several of the gains listed above are attributed to its operations. A key conclusion of the study was that

Kenya was not at the stage to readily accommodate competitive wholesale and retail electricity markets.

Key constraints highlighted include:

- A critical need for additional generation capacity.
- Presence of transmission constraints.
- Frequent and prolonged outages.
- Need for development of a balanced fuel mix to ensure security of supply to reduce the overdependence on hydroelectricity (then 48% of installed capacity).
- Limited horizontal competition, with KenGen owning 72% of available capacity.

Part of CPCS's concern regarding generation capacity relates to the proposed capacity additions in the then prevailing LCPDP, that of 2011 which concluded that 1,874MW of new capacity was required between 2011 and 2015 and 3,381MW between 2016 and 2020.

However, the study noted several facilitating factors. These included the forthcoming development of geothermal resources, which would address resource shortage and diversity in supply; an existing sector structure with generation activities separated from transmission activities; and several IPPs and large customers willing to enter the market.

Its key recommendations are consistent with a view that a phased introduction of competition is possible. These include:

- Announcing the reform process at least five years from the time of commitment to the commencement of a competitive market structure to help develop the new institutional structure and procedures and allow time for participants to acquire new business cultures
- Start the transition process using the single buyer market model with bypass arrangements to allow large consumers to trade with generators. Large customers would enter the market in tranches matched approximately to the rate of growth of free load available in the market. This is designed to ensure that KPLC always has a captive customer load that is greater than its Take or Pay Contracts.
- A corresponding balancing market will be developed with offers made by KenGen into this market being regulated until sufficient market competition was present.
- Ensuring KPLC and KenGen are not exposed to stranded costs.
- Building flexibility in the PPAs to allow for a smooth transition to a competitive market.
- Commencing competition by allowing large consumers to enter the market under flexible PPA structures.
- KETRACO to take over the role of operation and maintenance of the transmission system and system operation, including development and construction of a modern automated computerised load dispatch centre to facilitate the transition to a competitive market.

The recommendations for PPAs to become more flexible has several angles:

- Allow the IPP to sell power to other buyers or in the market while the contractual buyer (KPLC) remains obligated to buy the contracted capacity. In this arrangement the contracted capacity is temporarily reduced by the amount IPP sells to other customers for the same duration. This provides certainty to an IPP and its lenders while leaving flexibility for its integration into a competitive wholesale market.
- Restructuring of existing PPA contracts that are near the end of their life to reduce the Take or Pay requirements and allow more flexible non-exclusive terms.
- Allowing IPPs or KenGen to reduce take or pay commitments voluntarily where they wish to be allowed to sell to eligible customers directly.

While noting the important role of geothermal development, CPCS stressed the need for Government to explore PPP options for proposed coal and LNG plants, and the need to invite more private investors for the geothermal expansion programme.

The authors undertook analysis of the impact of phased competition on KPLC. They concluded that due to significant capacity developing and limited existing tariff cross-subsidies, the financial impact on KPLC of competition would be minimal providing a cost reflective transmission (and distribution) tariff is developed. While its revenue would reduce with competition, so would costs allowing it to maintain profitability.

2.7.2 Implications

The study raises several factors that need to be revisited in this Study: generation capacity and balance, nature of the PPAs, extent of horizontal competition in generation and supply, averting stranding assets, financial impact on KPLC, appropriate role for system operation and planning, and the feasibility of smooth tranches for competition.

However, there are many differences between the situation in 2021 than in 2012, including:

- Greater overall supply availability due to resource development outstripping growth in demand in recent years.
- The presence of new forms of competition driven by technological development: notably those of customers bypassing the utility through its own solar PV supplies, combined with the role of battery storage.
- Much greater levels of rural electrification, which has important implications on KPLC's cost structure.
- Potential regional aspects to market competition with the development of new interconnections to Tanzania, Uganda, and Ethiopia.
- A larger volume, and range of prices, of PPAs.

CPCS broadly supported allowing competition equal to incremental demand. As demand growth has turned out to be lower than envisaged, with forecasts reduced, the extent to which this strategy can be employed would need to be scaled down.

Moreover, it is unclear that all CPCS's proposed mechanisms can be invoked:

- Where existing PPA costs are higher than potential market-based costs of new supply, allowing flexibility in PPA arrangements, even if agreed, may not result in much greater sale of energy outside the PPA (see section 2).
- The willingness of parties to restructure existing PPAs may be limited.

Further consideration on the legal implications of the proposals made by CPCS are seen in the following section.

2.8 USAID Study for EPRA – Open Access Market Framework, 4C Report (2019)

Study objectives

The objective of the 4C Report reviewed is to propose an Open Access Framework that paves the way for the gradual introduction of open access in Kenya's electricity market

2.8.1 Key findings and conclusions

The report proposes a market development model, applying a mechanism – specifically, a capacity certificate scheme - to manage and phase out existing PPAs.

The proposals revolve around a capacity market, which aims to allow a smooth transition from existing PPA arrangements to a mechanism compatible with a competitive wholesale energy market, by ensuring that:

a) current contractual arrangements will not be affected severely, and
b) the possibility of limited liquidity in an energy-only wholesale market, will not negatively impact entry of new generating capacity and system adequacy.

The proposed reforms/ interventions are proposed to take place in two phases.

The first phase is a transitional phase that may last between 10-12 years. It incorporates the following elements:

a) **System operation**: Dispatching and scheduling of units is performed through a 'central dispatching' model allowing bilateral contracts to run in parallel with a process based on the generating units' merit order.
b) **T&D Networks**: Application of cost-of-service regulation for determining allowed remuneration.
c) **Wholesale market arrangements – Energy**: Introduction of a market-based mechanism (pool/merit order).

d) **Wholesale market arrangements - Capacity**: new suppliers wishing to enter the market to serve existing load are obliged to buy certificates through this mandatory "pool of certificates". The capacity remuneration would be set by EPRA, considering the PPA obligations of KPLC. This set up aims to provide cash neutrality for KPLC, but also provides a stable investment environment for new players, having a clear view of how capacity will be paid in the future market arrangements. Specifically:
   a. If the need for a new generation capacity certificate arises due to expiration of previously existing PPAs, new plants will be obliged to place their certificates in the "pool" and thus receive a regulated remuneration for their capacity availability.
   b. If the need for new generation capacity arises due to new economic activity (e.g., a new manufacturing factory) new plants will be allowed to exchange their certificates outside the "certificate pool", bilaterally with suppliers.

e) **Tariffs**: It is important to ensure that the tariff for each activity is cost-reflective.

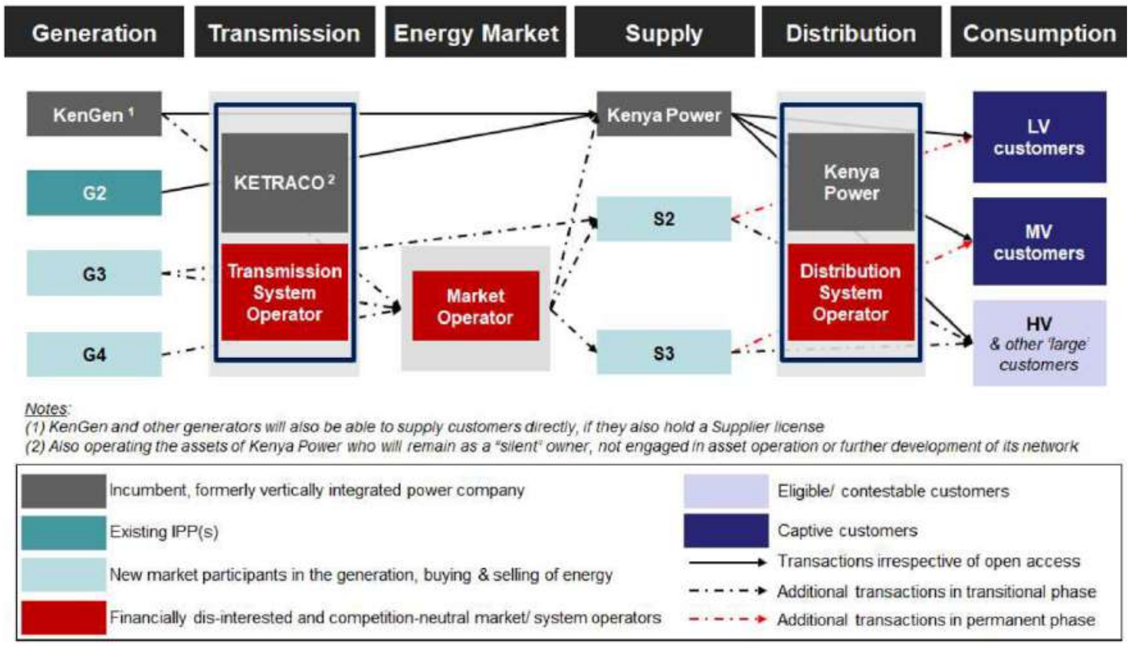
f) **Eligible customers**: Customers can freely choose their supplier.

In the second (Permanent) phase, as demand for electricity is growing and the old PPAs are expiring, the need for the "certificates pool" and regulated certificate prices is reduced, with the idea that the price to KPLC becomes more cost reflective. Specifically:

- Gradually, an increasing number of certificates will be exchanged outside the "certificate pool", bilaterally between producers and demand (suppliers and consumers). Once a liquid and efficient market for capacity certificates is established, the need for a "certificates pool" and for regulated remuneration of certificates diminishes and the market will determine freely the price for all new capacity certificates, outside the pool.
- Open access is extended to MV customers.
- Open access is gradually extended also to LV customers.

The following figure illustrates the proposed open access framework described above.

Figure 4: Proposed Open Access market framework



Source: USAID (2019), Technical Assistance to EPRA to Develop an Open Access Market Framework and Rule, Report 4C.

2.8.2 Implications

The study in effect proposes separate capacity and energy markets. This is an option that warrants further investigation with several potential advantages:

- It reflects the high proportion of capacity-related costs in the generation sector,
- It would allocate the costs of capacity to the demand side,
- It can promote the entry of firm capacity, for example the use of battery storage by solar PV.

An implication is that, for example, a party wishing to install a solar PV plant for wheeling may require capacity certificates unless it were to install battery storage. In addition, greater complexity may be needed in the setting of wheeling tariffs.

2.9 Previous cost of service studies by Fichtner (2007) and SNC Lavalin (2013)

Study objectives

In 2007 Fichtner developed an Electricity Tariff study for the Electricity Regulatory Board with the following specific objectives: i) develop an appropriate transmission pricing model and the proposed Transco's revenue requirements and recommend an appropriate wheeling tariff ii) review the unbundled KPLC's revenue requirements and recommend new retail customer tariffs; and iii) determine KenGen's revenue requirements and recommend new bulk tariff structure taking into account the sources of generation.

In 2013 SNC Lavalin developed a Cost-of-Service study for the Ministry of Energy. Its objective was to assist the Energy Regulatory Commission determine system charges, namely generation, transmission, and distribution wheeling charges, and rates for various categories of consumers, which recover costs and send appropriate price signals to consumers about the cost of generating and delivering the electric services while addressing social and equity concerns.

2.9.1 Key findings and conclusions

Fichtner study

Fichtner estimated a need for average tariffs charged by KPLC to rise from 8.22KSh/kWh in 2006 to 9.45KSh/kWh by 2011 (constant prices). An important increase was due to fuel costs, driven by an increased share of thermal power generation at constant fuel prices.

On the generation side Fichtner:

- Noted the sensitivity of bulk generation costs to drought conditions, for which it proposed the use of a stabilisation fund to smooth out costs to customers.
- Noted additional risks to KPLC in a drought if service must be cut, and if emergency generation is required, for which Government support with fixed costs was considered necessary.
- Supported revisions to the KenGen hydro PPAs to have capacity payments linked to effective capacity and penalty payments for forced outages in critical periods (dry season, peak periods).

The study estimated a tariff shortfall of around 21% to reach cost recovery levels, with a large part of this gap attributed to fuel costs. It found an important cross subsidy from commercial and industrial customers to domestic customers, with the average tariff to the latter group needing to rise by 72%, while tariffs to the larger industrial users were too high by around 32%.

SNC Lavalin study

The SNC Lavalin study was undertaken at a similar date to that of CPCS, though its findings are not wholly aligned with the tariff related conclusions of CPCS. The study found:

- A need for average tariff increases of around 30% between 2013 and 2018, incorporating increases in the generation tariff (from 7.46c/kWh to 9c/kWh) and the implicit transmission (2c/kWh to 3.39c/kWh) and distribution wheeling charge (3.10c/kWh to 3.84c/kWh) to support investment and other needs in the sector.
- Shortfalls in the revenue collection from all sectors, with this being greater for high voltage customers (37.9%) and medium voltage customers (38.7%) than for low voltage customers (25.5%). The relative shares imply the presence of a cross subsidy from low voltage customers to medium and high voltage customers.
- Important levels of volatility in the fuel price component.
- Generally competitive electricity tariffs for larger customers than in the closest regional markets.

The authors considered the potential for introducing time of use tariffs to change load patterns. However, they concluded that due to capacity and energy constraints the conditions to introduce such tariffs were not met.

2.9.2 Implications

The two studies were published in different market circumstances, yet their format, and especially that of SNC Lavalin is consistent with the current deliberations in developing transmission and distribution wheeling charges, while its focus on tariff shortfalls and cross-subsidies are also important. The two studies show a general tendency for tariffs to fall below cost recovery levels at time of study development, and for inter-category cross subsidies to be prevalent, though the exact nature of the cross-subsidy is not common between the two studies.

2.10 The Kenya Electricity Modernisation Programme (KEMP)

Project objectives

Key objectives of the World Bank financed programme (including a loan of $250 million) are to support the sector to:

- Increase access to electricity.
- Improve reliability of electricity service.
- Strengthen KPLC's financial situation.

The Kenya National Electricity Strategy is also a component of KEMP but is considered separately below given it has many specific issues.

2.10.1 Key findings and conclusions

The project was initiated with four main components:

- Improvement in service delivery and reliability - encompassing:
  - Upgrades to the supervisory control and data acquisition/energy management system.
  - Distribution system enhanced flexibility.
  - Enhanced maintenance practices to improve reliability of supply.
- Revenue protection for sales to large and medium customers, ensuring that large users are billed according to accurately metered consumption and thus reduce non-technical losses. The component includes:
  - Creation of one or more Metering Control Centres (MCCs) with investments in IT infrastructure needed to operate them.
  - Incorporation of Meter Data Management software and training of staff in the MCCs in its proper use.
  - Supply and installation.
- Electrification program, providing grant financing for the connection of new households, with two main subcomponents:
  - Peri-urban electrification, where the program finances the design, materials and construction works required to electrify all households and businesses in high population density peri-urban areas located close to existing electricity networks.
  - Off-grid electrification.
- Technical assistance and capacity building.

The project also includes an International Development Association guarantee of $200 million to support the refinancing of KPLC´s short-term commercial debt obligations with longer dated debt with the objective of strengthening its financial position.

The project was originally scheduled for completion in June 2020 and has been extended to the end of December 2021. The World Bank report the following challenges:

- Delays in getting budgetary allocations from the Government of Kenya for aspects of co-finance.
- A backdrop of increases in losses: An envisaged objective of the project was to reduce commercial losses from an estimated 6.7% (out of total losses of 18.1%) to 3.7%, whereas in practice total losses in 2018/19 rose to 23.7%, of which 9.1% were estimated as commercial losses. This means the end objective of the project for commercial losses was revised upwards from 3.7% to 6.1%.

However, the World Bank note some positive factors independent of the project: Important overall reductions in SAIDI, increase in substations connected to SCADA and an increase in customers connected to Automated Metering Infrastructure.

2.10.2 Implications

An effectively functioning distribution sector and KPLC more generally, is critical for the development of competition, and not just for those projects connected to the distribution network. For these reasons, the KEMP project plays a strong facilitating role for preparing Kenya for electricity competition. However, observations from the project since its commencement reinforces a view that current developments within KPLC are mixed in nature, with enhancements in supply quality and digitalisation of the network offset by higher losses. Strong enhancement in performance across most indicators is essential to protect KPLC's revenue, allow it to maintain and grow its customer base even with competition, and operate sustainably over time.

2.11 Kenya National Electricity Strategy, 2018

Strategy objectives

The Kenya National Electrification Strategy (KNES) is the roadmap to achieving universal access to electricity as a key plank of powering the Country's development agenda.

2.11.1 Key findings and conclusions

The KNES was developed in conjunction with the World Bank supported KEMP programme and provides a roadmap to universal electricity access by identifying the least cost and most effective solutions for electrification coverage given available supply options and demand for energy service. The supply options considered are grid intensification and densification, grid expansion, and off-grid supply solutions - both mini-grids and solar home systems (SHS).

An investment programme costing almost $2.75 billion through public and private investment is identified to obtain universal access by 2022. This does not include investment needed for grid substations or for strengthening medium voltage distribution networks, which is critical to ensure service reliability and quality do not suffer with a large increase in the number of customers. The Strategy considers that as investments in grid substations and medium voltage feeders are essential elements for the Last Mile Connectivity Program to work, such investments should also be treated in the same manner as the Last Mile and be eligible for subsidy by the Government.

Of the total of $2.75 billion, $2.3 billion is earmarked as public investment, based on a cost of grid connection of $1,000, with an additional $458 million of private investment in SHSs or off-grid service foreseen for households scattered throughout the country that are unlikely to be served by the national grid or small mini-grids.

KNES places an important focus on off-grid solutions for rural and remote areas. It notes that pay-as-you-go SHSs that provide basic lighting and cell-phone charging have achieved high market penetration, including in Kenya (more than 700,000 households). A key challenge highlighted is to devise a strategy for systematic service delivery to off-grid areas that can achieve scale (that is, reach many consumers efficiently) and at the approved level of energy delivery.

The strategy notes that multiple interventions are required to leveraging the knowledge and capacity of existing market participants and stimulating investment by offering incentives for service provision in difficult-to-reach areas.

A critical issue raised is the financing of any subsidies for off-grid systems, especially under a uniform tariff system. The strategy estimates that with KPLC annual sales of 7,000 GWh, a $19.5 million annual subsidy would add $0.0028/kWh to KPLC's grid-connected consumers' tariffs.

Table 4: Estimated subsidy needs for mini grids and Solar Home Systems in KNES

System	Households	Annual subsidy ($)
Mini grids	35,000	3,377,500
Solar Home Systems	1,070,000	16,050,000
Total	1,105,000	19,427,500

Source: Kenya National Electrification Strategy (2018)

2.11.2 Implications

It is understood that the programme set out in the KNES is on the one hand ambitious by expecting to spend $2.75 billion over three years, but on the other hand has been found to be insufficient to permit universal access as rates of electrification across the country are potentially lower than has been previously understood. An important implication is that the need for new connection to KPLC's network under electrification programmes is far from complete, which may place greater strain on its financial situation.

At the same time, the development of alternative business models, in terms of SHSs and off-grid developments, permit the entry of private sector entities, and in the case of SHSs, without necessarily the full need for guarantees as in the case of larger IPP projects.

2.12 Terna/CESI Gap analysis report for KETRACO (2014)

Study objectives

In its "Capacity building and technical assistance component for 220 kV Nairobi ring transmission line project" report for KETRACO (Deliverable 3), Terna and CESI made recommendations on the development of the system operation and market operations functions in the country.

2.12.1 Key findings and conclusions

The project provided recommendations on the development of system operation and market operations.

Its recommendations on system operations included: the creation of targeted KPIs for benchmarking and planning purposes; enhancements to primary and secondary Frequency Control; introduction of operational security analyses; introducing simulation tools to support operational planning; development of an Emergency Operations plan; operational training and introduction of software and tools to support the system operator and planners.

Of most relevance for the study is its recommendations for market operations, where the authors assumed two parallel markets: a regulated/captive market; and a Free Market for the eligible consumers who can manage by themselves to obtain their own contracts for electricity.

Terna/CESI recommend that:

- Planning is performed by an independent body (Planning Institute) or by a special division of the Ministry of Energy, with this entity performing mandatory central coordinated planning for generation and transmission.
- The expected new generation and transmission facilities in the LCPDP are implemented via auctions and not via bilateral negotiations. In the case of generation, the auctions will result in long-term PPA contracts for quantity and reliability, while the result of the transmission auctions will be the guaranteed remuneration of the assets according to the regulatory framework and the enlargement of the asset base with the auctioned transmission facilities.
- System Operation and Market Operation are performed by a ring-fenced division within KETRACO.
- Commercial & Industrial customers are proposed to be eligible.
- KPLC distribution activities are to be split into 4 different companies.
- KenGen should not be allowed to participate in the generation auctions until certain concentration limits for supply are met.

2.12.2 Implications

The recommendations of Terna/CESI are broadly in line with other options regarding the use of two types of market, separating planning into a separate unit of the Ministry, combining System Operation and Market Operation within the same entity, having auctions for new generation, and permitting larger commercial and industrial customers to become contestable first. Various other recommendations raise issues to be resolved:

- The proposal for transmission auctions for expansion related capital expenditure would allow the entry of Independent Transmission Providers should KETRACO not be the winning bidder. This model represents an important divergence from the current practices and would require: the expansion of the licensing regime; clear checks on financial standing of the company (over and above that required for licensing); provisions to prevent conflicts of interest in the bidding process; as well as the creation of contractual documents and ensuring there is a fall-back operator in the case of default. The potential for this model will be reviewed subsequently in this project, including through stakeholder consultation.
- It makes sense for the system operator and market operator to be the same entity in Kenya. Advantages and disadvantages arise whether this role is kept within KPLC (current System Operator), performed by KETRACO, or vested in a separate organisation.
- The separation of KPLC into four distribution business is outside the scope of this study. However, any plan to restructure KPLC will need to ensure that its fundamental financial situation is sound, which is currently not certain.

2.13 Summary of key issues raised in the review

A summary of key issues raised in this review with implications for this study is provided below.

Table 5: Summary of key implications from literature review

Area	Issue
Planning	Implementation of a market needs to be premised on realistic demand forecasts – too often aspirational values have been used
Feed in Tariff	Take up has historically been low. As a tool its scope has change to support certain technologies (mini-hydro, biomass, biogas), while the potential for auctions and competition makes it role redundant for solar PV and wind
Financing	Finance has historically been a constraint for the private sector to engage in merchant arrangements, though it appears several providers are finding ways to address this (see Task 4).
Strong off-taker and Government support	Measures taken to enhance confidence in the off-taker and Government role are critical for purchases made by the single buyer, especially given finance risk (above).
Rural electrification	Electrification is going slower than anticipated and potentially is costing more than planned. Could have important implications on KPLC
Tariffs	Extent of cross subsidies is an evolving issue but one that needs clear resolution to prevent stranded costs to KPLC and to ensure there is no cherry picking by certain customers categories
Renegotiation of PPAs	There may be a limit to which these can be renegotiated (if required) or to which the holders of PPA will wish to sell outside the PPA

Market model	The combined use of capacity and energy markets is proposed and warrants further investigation. With rapid technical change, especially for renewables, flexibility in the market model is necessary, while ensuring firm capacity is made available.
System Operator	A decision is required on who takes on this role. If a dedicated Market Operator is required, it may be efficient for the same entity to take on the two roles

3 Legislative review

This section reviews key legislative and regulatory material, with the objective of considering what is already permitted and where legislative gaps are for certain models of competition.

In doing so, the following documents have been considered:

- Constitution of Kenya.
- Energy Act, 2019.
- The Competition Act №12 of 2010.
- Energy Act No. 12 of 2006.
- Public Private Partnerships Act, 2013
- Public Private Partnerships Regulations, 2014
- Public Private Partnerships (Project Facilitation Fund) Regulations, 2017
- Draft Public Private Partnerships Bill, 2021.
- Draft Energy (Electricity Market, Bulk Supply and Open Access) Regulations 2022.

3.1 Introduction – CPCS study

The adequacy of the sector policy, regulatory and legal environment needs to be assessed to determine its adequacy of these to support the development of the electricity supply industry market in Kenya. However, assessing the adequacy requires a clear vision of what the market should look like and to this end, this review starts from the CPCS Study of 2012, which made the following key elements or observations:

- The CPCS Study advocates a phased approach to a competitive market as opposed to a "big-bang" type approach.
- Key amongst the recommendations (based on the 2004 Sessional Paper on Energy policy) was transforming the power transmission system into an open access system that would allow large electric power consumers to contract with generators of their choice.
- It also proposes the creation of a domestic pool with a provision for wholesale and retail markets to create competition and thus reduce the cost of electricity.

The CPCS study envisages three stages to achieve this, namely:

- A Pre-transition Phase – Preparation for market (legal, institutional, commercial structures)
- A Transition Phase - Beginning of the competitive wholesale electricity market, marked by large commercial and industrial customers (eligible customers) having a choice of contracting directly with generators for the supply of electricity and a simple balancing market in place. Retail suppliers or retail supply aggregators and other end-supply options would theoretically be possible. All KPLC/KETRACO activities would need to be ringfenced.

- Medium Term Phase - More customers becoming eligible customers and generators are competing for dispatch in a pool market. There is still a degree of retail price regulation for the remaining captive customers and some central coordination of the procurement of additional capacity.
- Long Term Phase - All customers should theoretically be eligible for a competitive supply; all generation entry is competitive, and all generators compete for dispatch.

The Study recommends that initially the focus should only be on the pre-transition and transition Phases, these are:

- Preparation for a market from a legal, institutional, and commercial perspective; and
- Beginning of the competitive wholesale electricity market, with a) large commercial and industrial customers (eligible customers) having a choice of contracting directly with generators for the supply of electricity; b) a simple balancing market in place and c) retail suppliers or retail supply aggregators and other end-supply options d) all KPLC/KETRACO activities need to be ringfenced.

We note that since the CPCS Study was published in 2012, various market related developments took place that impact the views held in the study, amongst others:

- A customer buying direct from an IPP for either its own use or a combination of own use may want to supply its own customer base located near its point of connection. A customer building its own generation on its site for its own use and/or supplying to customers at this physical location.
- A customer building its own generation away from its own site and developing a wheeling relationship with KETRACO or KPLC for the wheeling of its power ("off-site" own generation)
- The purchase and sale of electricity by power/electricity merchants who may not own any assets but wish to participate in a power market.
- A customer buying at a Commercial/Industrial tariff from KPLC and then distributing to residential customers nearby.
- The potential for new industrial zones to develop their own supply arrangements and potentially sell to customers outside the boundaries of the industrial zone.
- Smaller distributed generation and net metering arrangements for customers connected to the distribution network.

Accordingly, both the CPCS Study recommendations as well as the above potential market developments were taken into consideration in reviewing the adequacy of policy, legislation, and regulations. The Consultants also looked at the Final Access to Open Market framework document prepared under the auspices of USAID, particularly the concept of new players at wholesale level buying into existing capacity to participate in the market.

It is noted as per the CPCS study and other policy documents referred to, sector policy is generally conducive to enabling a competitive electricity market.

Accordingly, this section first and foremost looks at key legislation impacting market reform, which has been identified as the Constitution of Kenya, 2010, the Energy Act, 2019, the Competition Act, 2010 and the Public Private Partnerships Act, 2013. Whilst there is other legislation that will inevitably be important, these are mostly ancillary by its nature and are hence not addressed at this point.

3.2 The Constitution, 2010

As the highest law in the land, the Constitution forms an important cornerstone that could impact market reform as all other legislation is bound to its terms.

While it does not address electricity markets as such, it does provide for inherent powers and functions of county governments – which in Schedule 4 thereof includes "electricity reticulation".

This term is not defined in the Constitution but could, by logical deduction as to what "reticulation" means within the context of a county government, include distribution and supply activities from a planning, construction. and service provision perspective.

Interestingly, the Energy Act, 2019 provides a definition for "reticulation", namely "…reticulation means the planning and construction of the network consisting of low and medium voltage electric supply lines together with service lines to enable a consumer get supply of electricity". Notably, it excludes electricity supply and related activities. Furthermore, the Energy Act also prescribes what are deemed to be national functions, and lists the following:

a) Regulation and licensing of production, conversion, distribution, supply, marketing and use of renewable energy.
b) Regulation and licensing of generation, importation, exportation, transmission, distribution, retail and use of electrical energy.
c) Approval of energy purchase agreements, network service contracts as well as contracts for common user facilities.

Whilst it is doubtful if the Energy Act can really limit the Constitution as to what "reticulation" means it accordingly does provide some legislative guidance in that it *de facto* acknowledges that county governments would have jurisdiction over planning and construction of medium and low voltage infrastructure but that everything that is set out in paragraphs (a) to (c) would effectively fall within the ambit of the national government. Whilst market design and operation is not pertinently mentioned in these paragraphs, one could through the regulation and licensing of the mentioned activities possibly develop and design the market approach to be used on a national level. In other words, market design would thus be a national prerogative. It could also mean that local counties could impact on the ability of transmission and distribution licensees to plan and construct distribution infrastructure in its areas of jurisdiction, as it now has authority over such activities, and hence could thus potentially impact on the functioning of a market, albeit indirectly.

Given that legislative directives are preferable to policy it is advisable that all market approaches, rules and the like should be prescribed by statutory instruments (i.e.

national legislation and regulations) and not be left to policy or be open to ambiguity, as this would in addition to the national jurisdiction categories as set out in in paragraphs (a) to (c) above provide clear guidance on how the market would be structured and how market rules are to be implemented.

3.3 The Energy Act, 2019

The Energy Act, 2019 is the primary instrument for governing the electricity supply industry and of paramount importance in market design.

Key to the suite of regulatory instruments provided for in the Energy Act is the licensing of activities. According to the Act, licences are required for the following activities:

- Generation licence– authorising a person to construct, operate and maintain a generation facility to generate electricity and allow for connection to a distribution or transmission network. Generation for own use less than 1 MW is excluded from the requirement to hold a licence. The law also provides for net-metering (consumers for own use that sell surplus to the grid, not exceeding 1MW installed capacity), as well as distributed generation (small generators not more than 10kW installed capacity supplying directly into a distribution grid)
- Transmission licence– authorising the licensee to construct, operate and maintain its network and connect to another transmission or distribution network. Transmission licensees must provide non-discriminatory open access to third parties to its network. The law also importantly provides that a transmission licensee can be designated as the system operator, responsible for matching consumer's requirements or demand with electrical energy availability or supply, maintaining electric power system security, arranging for the dispatch process, and operating the National Control Centre. The system operator is "independent" and may not be involved in the buying and selling of energy.
- Distribution licence- A distribution licence authorizes the licensee to plan, construct, operate and maintain a distribution system. It also allows a county to plan for and construct distribution systems. Distribution licensees must also provide non-discriminatory open access to third parties to the distribution network, whether for supply or for wheeling purposes.
- Retail supply licence - A retail licence authorizes a person to supply electricity to consumers through a series of commercial activities including procuring the energy from other licensees, metering, selling, billing, and collecting revenue. A retail supply area could be linked to the licence, or the licence could be limited to a particular premise[1]. Every electricity supply agreement between a retailer and another licensee for the procurement of electrical energy by a retailer for resale to consumers must be submitted to the regulator before execution.

[1] A "retail supply licence" is defined as "… any document or instrument authorizing a person to supply electrical energy in the manner described in such document or instrument *to any premises* and such licence shall also entitle the licensee to *receive a bulk supply* from another licensee. In other words, it envisages end supply to a consumer to a particular premise, based on bulk supply received (presumably) from a generator. It thus seems clear that "retail supply" does not extend to "bulk supply", i.e. a "retail supply licence" does not include the bulk supply component.

- Import and export licences – Import and/or export of electricity also requires a licence. It is not clear in the Act who would qualify for such licences (e.g., if it is the *de facto* single buyer or whether an IPP could for example export directly).

Besides the licensing requirements set out above, it should be noted that wholesale supply activities (e.g., for single buyer/modified single buyer/market purposes) as opposed to retail supply licences) are apparently not licensed, which seems to be an anomaly compared to other regional legislation that typically requires both wholesale and retail supply (or wholesale and retail trading) to be licensed. Ideally wholesale supply (similar to retail supply), especially in the absence of a fully competitive market, should be a licensed activity, with the market platform or operator licensed. This anomaly is somewhat mitigated by the following:

- All contracts for the sale of electrical energy as well as provision of transmission and distribution network services, between and among licensees, and between licensees and eligible consumers must be submitted to the regulator for approval – this provides for some regulatory oversight - although this could also be seen as a hindrance to a market where the market operation may determine prices, and not the regulator.
- Key licence conditions include the approval of bulk and retail tariffs or charges for electrical energy and capacity for different types of licensees and classes of consumers – although it is not totally clear how tariffs of a bulk supplier are approved (and made compulsory or subject to regulatory oversight) if there is no underlying licence.
- Wheeling charges are provided for (charges for use of the transmission and distribution network services).
- Compulsory third party access and wheeling across both transmission and distribution is provided for.

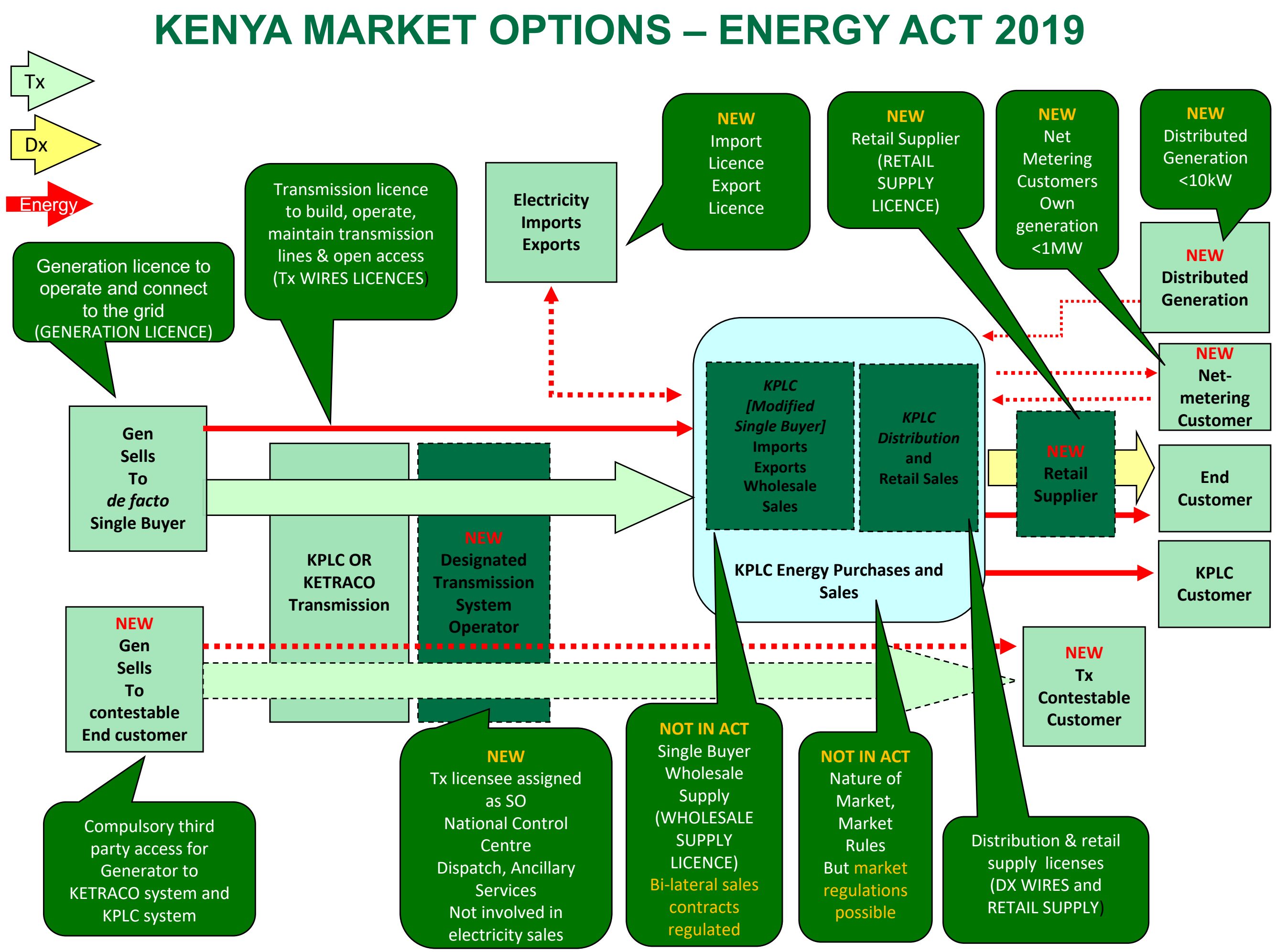
A further aspect to note is that although the Energy Act requires that the regulator in consultation with the cabinet secretary review the "… electricity market on a regular basis…" (with a view to enhancing competition, improving efficiency, increasing reliability and security of supply, and improving the quality of service by all licensees), the Act does not specify at all what a "market" is to begin with. Nor does it set any parameters or requirements as to what a market should comply to.

Nevertheless, it is noted that the Act provides that the Cabinet Secretary on recommendation of the regulator may publish regulations for the operation of the "electricity market". Whilst we have noted draft regulations marked "2022" relating to the market have been prepared, it is not that clear what type of market is envisaged and the exact status of these drafts. Having regard to the definition of "electricity market", which is defined as "….the market where licensees who are authorized to generate, import or export electric power offer to sell electrical energy to *retail licensees* for resale to consumers….." the exact scope of the market rules is also open to some doubt and could be seen to not automatically include the *wholesale* component of the market, which would be particularly problematic for any market designed to deal with that particular aspect.

This aspect will be further investigated and discussed with role-players as the project progresses, particularly to get a good understanding of what the regulations envisage and how market players are to be regulated, and to get a better understanding if it may be preferable to establish a market operator and related rules through dedicated legislation.

Accordingly, we have mainly interpreted the law as it stands to determine what market arrangements are possible under the current provisions. Our understanding of what the law clearly contemplates (as opposed to how this could possibly be expanded, for example as per the Final Access to Open Market framework document or the “2022” market regulation draft. The operation of the Energy Act and what it currently provides for is illustrated below:

Figure 5: Market structures permitted under the Energy Act 2019



From the above illustration, the following electricity market options or approaches can thus be foreseen as possible:

- Ring-fencing of the different activities performed by a licensee (e.g., a distribution licence also providing retail supply services can be undertaken providing that entity is licensed (and ring-fenced) for both activities).
- A dedicated System Operator (SO) is provided for by designating a transmission licensee as such. The language used is "designated", hence implying that one of the existing transmission licensees should be used.
- Direct sales by generators (IPPs) to eligible contestable transmission customers is possible and clearly provided for.
- Linked to third party access to common transmission and distribution that would be needed to give effect to direct sales by generators, compulsory third party access to both transmission and distribution infrastructure is allowed.
- The possibility of retail suppliers that supply to end consumers is introduced.
- Net-metering is introduced.
- Small, distributed generation is provided for.

Of course, whilst the above options are possible under the law, there are also some challenges with the above scenarios, especially regarding the following:

- Developing the market further than allowing for some sales past the de facto single buyer is difficult - the law does not in any manner describe in any detail the nature, content or regulation of any wholesale market, pool market or other market platform save for providing for rules that can be made for such a "market". Whilst rules could indeed provide for market design and operation, it is doubtful if rules could, for example, override existing contractual provisions relating to bi-lateral PPAs, or in any manner force compliance by unlicensed role-players if voluntary participation is not forthcoming, especially in the context that wholesale supply is currently not a licensed activity under the Act (and hence not inherently subject to the regulator's control). Ideally, we believe the law should at least provide detail about what rules could be promulgated (i.e., set out the scope or ambit of the rules), who they apply to and provide a broad oversight over what the market would entail.
- Establishing a dedicated System Operator (SO) – whilst the Act provides that an existing transmission licensee can be mandated for this role, the Act does not describe or provide how this should happen, save to say that the SO may not be involved in the commercial buying and selling of electricity. By default, that excludes KPLC in its current format, which means that KETRACO would need to fulfil this role. The commercial and institutional arrangements to facilitate this are however not provided for in the law at all. Dedicated legislation may potentially be needed to operationalise an SO and statutorily deal with matters that otherwise cannot be dealt with (e.g., transfer of staff, pension funds, taxation, assets etc).
- Consequently, low hanging fruit in opening the market may lay more towards the initial stages as proposed in the CPCS study (direct bilateral sales from generators to transmission customers) and on the consumer side/own

generation side (distributed generation, net metering), than on a competitive wholesale or other type market.

The above point can be illustrated by the following examples that are all possible:

- A customer buying direct from an IPP for its own use, or a combination of own use and supplying its own customer base located near its point of connection.
- A customer building its own generation on its site for its own use and/or supplying to customers at this physical location would be possible under the Energy Act.
- A customer building its own generation away from its own site and developing a wheeling relationship with KETRACO or KPLC for the wheeling of its power ("off-site" own generation) would be feasible under the Energy Act, subject to development of access and wheeling charges.
- The purchase and sale of electricity by power/electricity retailers who may not own any assets but wish to participate in a power market is feasible.
- A customer buying at a commercial/industrial tariff from KPLC and then distributing to residential customers ("reselling") is certainly possible.
- The potential for new industrial zones to develop their own supply arrangements and potentially sell to customers outside the boundaries of the industrial zone would also be possible.
- Smaller distributed generation is allowed up to 10kW.
- Net metering arrangements for customers connected to the distribution network is also provided for up to 1MW installed capacity.

In summary, whilst the Energy Act in our opinion goes quite far towards the establishment of a competitive market, it is currently lacking in key aspects necessary to move much further than the list as set out above. Concerns relate to the possible scope and ambit of the market rules and the ability to govern through such rules in the absence of dedicated legislation, as well as the commercial and institutional establishment and operationalisation issues around the establishment of an Independent System Operator.

3.4 The Competition Act, 2010

Provision of electricity forms part of "goods" as contemplated under the Act and hence electricity supply is also subject to its jurisdiction. The Competition Act also applies to Government and Government institutions and would hence apply to both KPLC and KETRACO.

Both entities could fall thus in principle fall foul of provisions of Competition Act (e.g., dominant position, sole service provider) in exercising their functions under the Energy Act.

The Competition Act does provide for co-operation between the competition authority and the energy regulator, but in case of conflicts the Competition Act prevails. Accordingly, it is crucial that any proposed market structure/functioning is discussed with the competition authority and that any non-competitive aspects are governed by agreement between the two regulators.

This is especially important for those aspects that are not directly regulated under the Energy Act but indirectly, for example wholesale supply that is not licensed. In the electricity market context, any regulations relating to the market that can be developed would thus also be crucial to provide clarity and certainty.

3.5 Public Private Partnerships Act, 2013

This Act sets down rules that apply for PPP transactions – i.e., for any project that involves the private sector that performs a “public function” or a “public service”. Accordingly, for a project to qualify, the project would need to fall under the ambit of “a public function” or perform a “public service”. In terms of the regulations published under the Act, smaller transactions (less than 75 000 000 Shillings) would be excluded from the ambit of the Act.

Accordingly, it is a question to what extent the Act would apply to different segments/private sector participants in the electricity market (on the generation, transmission or distribution infrastructure or wholesale or retail sales side) to determine if such functions are “public”, and hence if the Act and regulations would apply and what its impact would be on any such activities.

Currently this is not easy to determine without knowing exactly what activities are foreseen to be covered under the market rules, although it can be expected that some larger transactions (e.g., the establishment of new transmission concessions in the national interest) may fall under its ambit, while other may not (e.g., an IPP selling exclusively to a private client). It is suggested that this is further reviewed later in the project once proposed market options are put forward. This would also ensure that any changes foreseen under the new Public Private Partnership Bill, 2021, are taken into consideration if it is passed into law.

3.6 Existing PPAs

The Consultants have requested access to existing PPAs to determine what hurdles these may pose towards a new market structure.

The contents of these PPAs are particularly important in the context of the breach thereof and Government support mechanisms contained therein should breach occur, as contravention of these agreements (e.g., via the operation of new market rules) may lead to severe or unforeseen consequences if not properly addressed.

Nevertheless, it is proposed that these agreements be further investigated once a more concrete concept of the envisaged market is formed as that would also inform exactly what aspects of the agreements need to be studied in more detail.

3.7 Existing licences

Existing licences and licence conditions could impact the development of a competitive market structure, typically around the following aspects:

- Generation licences that authorise sales to specific customers (e.g., aligned to the PPA between the generator and off-taker) would need to be amended to accommodate sales to persons other than the identified off-taker.
- Transmission and distribution licences that do not deal with or do not adequately deal with third party access and wheeling of electricity.
- Distribution and supply licences that provide for sales within specific geographic areas could raise the question of exclusivity of supply in those areas and the resultant possibility of sales by other supply licensees which would impact on existing rights and obligations.

In this context, it should be noted that whilst the Energy Act, 2019 allows for the amendment of a licence condition on application by a licensee, it clearly also determines that "…..a licence issued under the Act may not be altered, revised, or modified, except with the consent of the licensee….". Accordingly, in so far as licence conditions may prove to be contrary to what a market requires, such licences will, under the current law, only be able to be amended on a voluntary basis and not unilaterally by the regulator. It is also doubtful if such amendments would be able to be introduced. As such, this would possibly not be of too much concern if the licensee wishes for its licence to be amended but could raise problems where a licensee does not want its licenced rights to be impacted. In turn, this could lead to the requirement that dedicated legislation may need to be enacted to deal with the envisaged market structure and market rules.

This aspect will be further investigated going forward as the proposed market models unfolds.

3.8 Summary

From a policy perspective, nothing seems to prevent the establishment of a competitive market that can take various shapes. Similarly, whilst the Constitution provides inherent rights to local counties over "reticulation", it is not foreseen that this would be a disbarment or constraint from a market perspective.

Given the nature of the Competition Act, the operation of an electricity market would fall within its ambit, and it would be prudent that EPRA and the competition authorities enter a memorandum of understanding regarding the nature and operation of such a market.

Similarly, depending on the nature of electricity transactions, and whether these are perceived to be of a public nature, the Public Private Partnership Act could apply. Whilst this is not problematic per se, it could be of importance in terms of how energy is procured, for example, and what procurement processes need to be followed. As for the Competition Act, it would thus be advisable that clarity is sought beforehand whether any market related transactions would be seen to fall under this Act. At this point in time, in the absence of detail market design, it is however not possible to make any definitive statements on this.

Key concerns from a market perspective thus centres around the Energy Act and especially what is clearly provided for, and what areas are less transparent. In this context especially the absence of licensing of the upstream supply side (as opposed to the retail side) is somewhat concerning, although this is tempered somewhat by the approval requirement for all buying and selling (which itself may pose problems for market operations) and the possibility for the Minister to issue market related regulations (although the scope and extent of these rules are not specified at all).

Lastly, the existing PPAs may also pose problems, especially around breach and Government obligations should breach occur. It is suggested that these stay on the agenda and be further investigated once a more concrete concept of the market has been developed, as that would inform what aspects of the agreements need to be further investigated in more detail.

4 Review of the LCPDPs and the KNTGC

Several Least Cost Power Development Plans (LCPDPs) or documents reviewing LCPDPs have been issued in recent years. These include:

- Mott McDonald VRE Grid integration study (Review of the LCPDP processes and Demand Forecast), February and March 2021.
- LCPDP 2021-2030, April 2021.
- Vision 2030, Updated LCPDP, Study Period 2020-2040, February 2021.
- Vision 2030, Updated LCPDP, Study Period 2019-2039, June 2020.
- Ministry of Energy, LCPDP Medium Term Plan 2018-2023, June 2019.
- Vision 2030: Updated LCPDP, Study period 2017-2037, June 2018.
- Lahmeyer International (for the Ministry of Energy and Petroleum), Development of a Power Generation and Transmission Master Plan, Kenya, Long Term Plan 2015 – 2035, October 2016.

Due to its important role in planning and market development, the Kenya National Transmission Grid Code (KNTGC) should be considered alongside these documents.

In this section, we consider the following:

- The importance of planning for market development,
- Processes undertaken in developing the LCPDPs,
- Performance against expectations in previous versions of the LCPDPs,
- An assessment of the current provisions of the KNTGC, and
- Implications of the LCPDP's and the KNTGC for assessing the needs of, and role of market arrangements.

4.1 Importance of planning in market development

Facilitating the energy transition, which includes permitting new and evolving forms of competition, requires ever more careful network planning that takes due account of new connections, both in transmission and distribution and ensures that there is sufficient host capacity for the integration of renewables located throughout the supply chain. At the same time, new forms of distributed generation complicate distribution planning given the possibility of bi-directional flows with the transmission network.

A key requirement for planning is to ensure flexibility, and allow the system to adapt to dynamic conditions, including balancing supply and demand with:

- An increased share of intermittent power sources,
- Reduced levels of inertia due to a corresponding reduction in the share of traditional thermal technologies,
- An increasing role for storage, and
- Evolving customer responses, including the use of their own power supplies and/or demand side management.

The increasing need for flexibility, together with important trade-offs between capital and operating expenditure places an important onus on effective planning to promote long-term reliability of the system. Moreover, planning needs to be linked to new procurement mechanisms, including markets for flexibility, and the role for the tariff system in promoting system stability.

The developments that result in network planning processes becoming more complicated also affect planning for generation adequacy. Greater resources connected to the distribution system or connected to the transmission system to meet customer own demand (either directly or through wheeling arrangements) impact the required level of reserves, and affect economic dispatch decisions, especially where renewables operate under must-run conditions and storage increasingly allows the penetration of energy generated by solar PV into peak periods.

Flexibility in new capacity development is increasingly required. Procuring an excess of new resources can result in unnecessary system and unit costs, especially if demand on aggregate does not grow as forecast or customers respond in different ways with the possibility of directly having new sources of energy, including through competitive arrangements. Permitting competition can promote flexibility on the generation side, but it also requires effective planning to allow participants – both current incumbents and IPPs - to take informed decisions on constructing new capacity.

4.2 Process in developing LCPDPs

Several LCPDPs have been developed in Kenya, with six long- or medium-term Plans produced in the past five years. This section reviews governance and technical aspects of the processes conducted in developing these LCPDPs. In doing so, it draws heavily on a recent report of Mott MacDonald for the MOE with World Bank support, which explicitly reviewed planning procedures adopted in the development of LCPDPs.

4.2.1 Governance processes

Key planning requirements are set out in Section 4 to 8 of Part II of the Energy Act 2019. Section 5 (“Integrated National Energy Plan”) states that:

1. The Cabinet Secretary shall in consultation with the relevant stakeholders develop, publish and review energy plans in respect of coal, renewable energy, and electricity so as to ensure delivery of reliable energy services at least cost.
2. Each national energy service provider shall develop and submit to the Cabinet Secretary plans for provision of energy services in accordance with its mandate.
3. Each County Government shall develop and submit a county energy plan to the Cabinet Secretary in respect of its energy requirements.

4. The Cabinet Secretary shall consolidate the plans contemplated in subsections (2) and (3) into an integrated national energy plan which shall be reviewed after every three years.
5. The energy plans shall—
    a. take into account the national energy policy,
    b. serve as a guide for energy infrastructure investments,
    c. take into account all viable energy supply options, and
    d. guide the selection of the appropriate technology to meet energy demand.
6. The Cabinet Secretary shall prescribe regulations on the content and timelines for the preparation of the energy plans.

The current process for developing LCPDPs is considered as a transitional step to the framework underpinning the Integrated National Energy Plan (INEP). Reflecting the role of each national energy service provider in developing the plan (consistent with sub-point 2 of the Act), LCPDPs have been developed by a technical team comprising key organisations in the sector, subject to oversight and quality assurance by a committee chaired by the Director General of EPRA as well as senior management of sector utilities. The technical team undertakes all relevant simulations, analysis and drafts the report for consideration by the Oversight committee. In addition, the MOE provides policy guidance to ensure the report meets key requirements for the provision of adequate, reliable, and affordable power in the country.

An important development to align with the INEP requirements is full integration of the role of the Counties.

Two typical common approaches for developing LCPDPs internationally are:

- Vest its development in the MOE, who produces the plan often with the support of external consultants.
- Vest its development with the System Operator.

The latter approach is not recommended as the System Operator may be biased towards the development of certain projects, especially where it is also the Transmission Service Operator. The first approach has the advantage of using independent expertise, though the Ministry in many countries is not always closely connected with the technical knowledge of sector participants. The approach adopted in Kenya is a variant of the first approach, with the breadth of knowledge within the sector substituting for external support and the MOE vesting its role in industry committees. The structure for developing the LCPDP, involving all sector stakeholders, allows for different views to be heard, should minimise the risk of bias, and promotes capacity development. In practice, several LCPDPs have been developed, suggesting that the model used has been successful in plan production.

4.2.2 Planning and technical processes

The analytical processes underpinning the development of the LCPDP were reviewed by Mott MacDonald in March 2021. The consultants made several findings, largely drawing on the results of the 2019-39 LCPDP, with them providing input into the 2020-40 LCPDP. For generation, key findings included:

- The modelling had an excessive reliance on committed projects, including in optimised scenarios. Mott MacDonald recommended that only those projects guaranteed to proceed at the time of study development should be considered as committed, and those project with a PPA signed, but not having reached financial close should be treated as candidates.
- Renewables were largely “forced in” and not fully optimised.
- No consideration was given for exports.
- No allowance was provided for batteries to offset renewable energy load, which was part of the reason for new coal plant to be proposed.
- Some improvements to the modelling of operational reserve were possible, particularly where related to renewables.

A key common feature affecting many of the above findings is that the modelling software used was dated and designed for traditional energy sectors. Notably, according to Mott MacDonald, the software used:

- Did not allow consideration of battery storage.
- Had difficulties in modelling “free” resources, which itself required renewables to be forced.
- Was limited in the customised constraints that could be included
- Had difficulties incorporating distributed generation and electric vehicles (though the latter could be treated in the demand forecast).

In the case of transmission planning, the authors noted that any errors in generation forecasting would have a flow on effect to transmission. Moreover, they found:

- In some cases, there was not complete alignment of the generation plan with the PSS/E files used to model transmission augmentation.
- Significant system strengthening projects (400kV, 220kV, 132kV) were proposed that may not be fully justified, with overplanning and underloading of some of the new lines at all voltage levels.
- It was unclear what system stability studies were undertaken.
- The modelling of lines was potentially too complex, with a recommendation to separate the 400kV and 220kV lines from 132kV lines for modelling purposes due to the growth and expansion of the network.
- Capital costs were considered high, with the treatment of O&M costs unclear.
- The approach to the treatment of committed projects was considered unclear.
- Battery storage does not appear to be incorporated.

The LCPDP 2020-40 and the LCPDP 2021-30 state that they take into consideration the views of Mott MacDonald, though it appears that several issues raised, particularly those related to software upgrades, were not able to be addressed at the time of preparing the Plans due to software challenges. In the LCPDP 2021-30 Battery Energy Storage Solutions (BESSs) are incorporated using characteristics of thermal plants that serve as peaking plants due to limitations of the software used (LIPS-XP/OP planning tool).

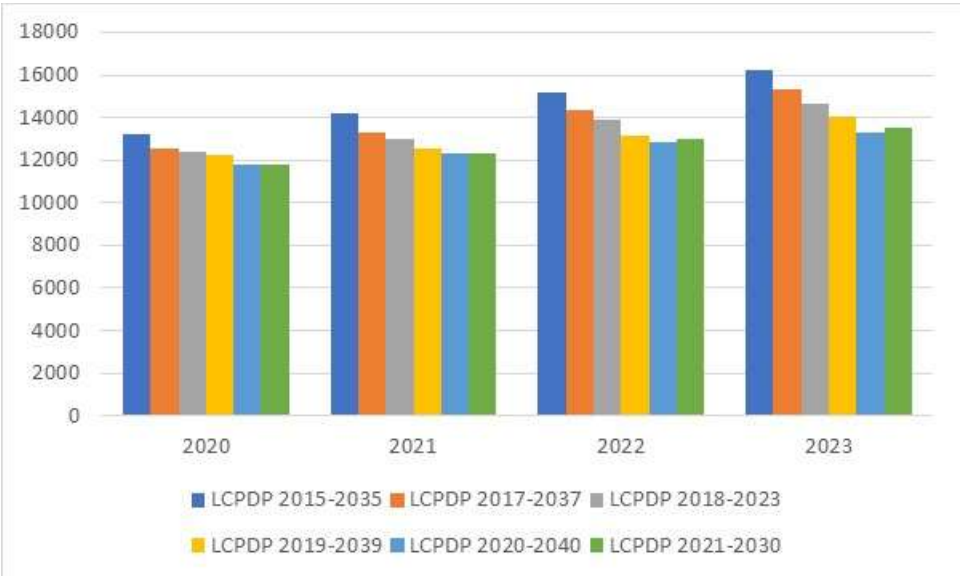
4.3 Performance against expectations

A key feature of previous LCPDPs has been an overestimation of demand. The tendency to overestimate demand is evident following publication of the Vision 2030 document in 2008 and has been a common feature since. In section 2 it was noted that:

- The reference scenario of the 2011 LCPDP forecast that electricity demand in 2020 would be 28,795 GWh, whereas in 2019/20 energy demand was 11,462GWh, less than 40% of that forecast in the 2011 LCPDP for 2020.
- Reported peak demand for 2020 at 1972MW was around 42% of the value forecast in the 2011 LCPDP for 2020.

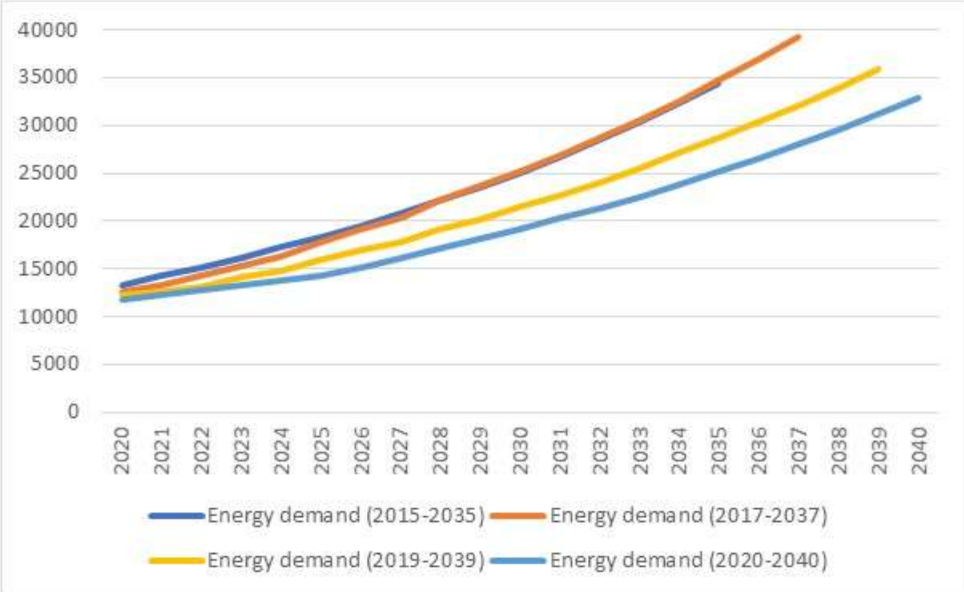
In subsequent plans, except for the recent LCPDP 2021-30, there has been a regular (downward) revision of the demand forecast. This trend can be seen using the reference case estimate for energy consumption for the years 2020 to 2023 in the latest 6 plans.

Figure 6: Forecasts of electricity consumption 2020-23 (GWh) by LCPDP, Reference scenario



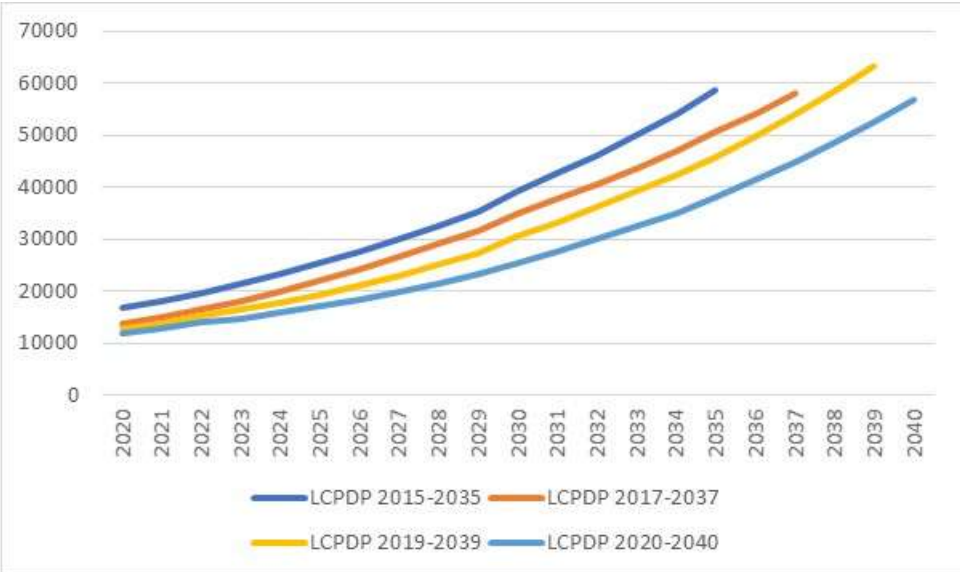
Considering longer dated data, a marked difference is evident between the forecast in the 2017-39 LCPDP and the two subsequent LCPDPs. For the year 2030, the forecast in the 2015-35 LCDP is 30% higher than that in the 2020-40 LCPDP. By 2035 the difference between the value forecasted in the 2017-37 LCPDP and the 2020-40 LCPDP rises to 38%.

Figure 7: Electricity consumption forecast 2020-40 by LCPDP (GWh), Reference Scenario



The same trends are evident in the Vision scenarios.

Figure 8: Electricity consumption forecast 2020-40 by LCPDP (GWh), Vision Scenario



Several factors may account for demand not growing as fast as anticipated, including:

- Over-optimistic forecasts of flagship projects and/or the time necessary to bring the projects to fruition.
- Demand under rural electrification not growing as high as previously anticipated.
- Continuation of constrained demand, including through network difficulties.
- Use of forecasts for GDP that turn out to be too high.

However, the above factors, by themselves, do not account for systematic over-forecasting of demand. A potential key driver for over-forecasting is over-optimism regarding the achievement of national targets for connection, flagship projects, eliminating suppressed demand and overall national economic growth. For example, both the reference and vision scenarios assume implementation of flagship projects in the medium term, even though the probability of several of these being constructed will be falling. In its review of the demand forecasting in the LCPDPs, Mott MacDonald questioned whether there may be double counting of flagship projects, as many of these additional demands may be expected to occur under more dynamic economic growth cases. If true, any overestimation of these demands would be magnified. In parallel they recommend a review of updates (capacity and expected completion dates) to the Flagship projects be applied to the Reference and Vision scenarios.

A key risk of overestimation of the demand forecast is sub-optimal capacity development, including over-supply of available capacity. The following graphs aim to evaluate at a high level whether there is a link between overestimation of demand and the generation projects that are deemed optimal under the planning simulation. The envisaged installed capacity in 2030 by LCPDP and share by technology is set out below.

Figure 9: Installed capacity in 2030 (MW), reference scenario by period of LCPDP

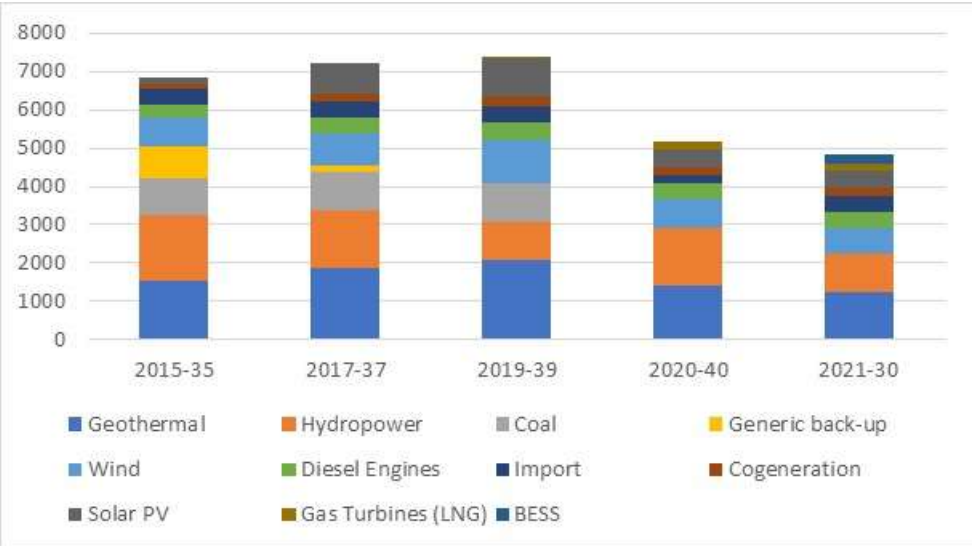
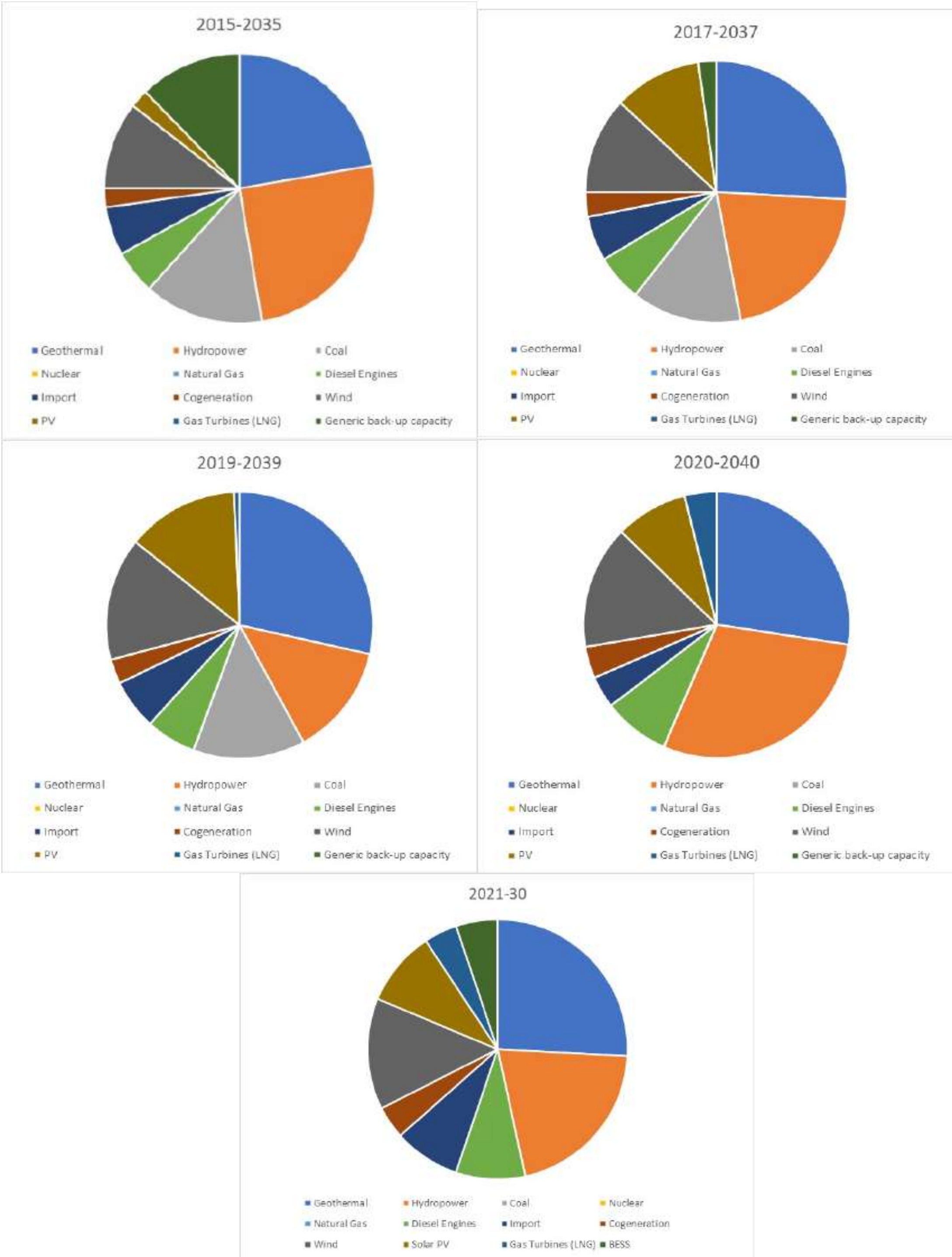


Figure 10: Share of installed capacity by technology in 2030 (%) by LCPDP



The high-level data is not conclusive but suggests the presence of evolving trends for the first three LCPDP, followed by a notable change in the 2020-40 LCPDP reflecting much lower overall capacity. Notable trends include:

- Important role for coal up to the 2019-39 LCPDP, which is deferred beyond 2030 in the 2020-40 and 2021-30 LCPDPs.

- Increasing importance for geothermal and declining importance of hydropower between the 2015-35 and 2019-39 LCPDPs, with a reversal of this trend from the 2020-40 LCPDP.
- Increasing share for wind and solar PV up to the 2019-39 LCPDP.
- Drop-off of generic back-up (important in the 2015-35 LCPDP) with specific plants in subsequent versions.

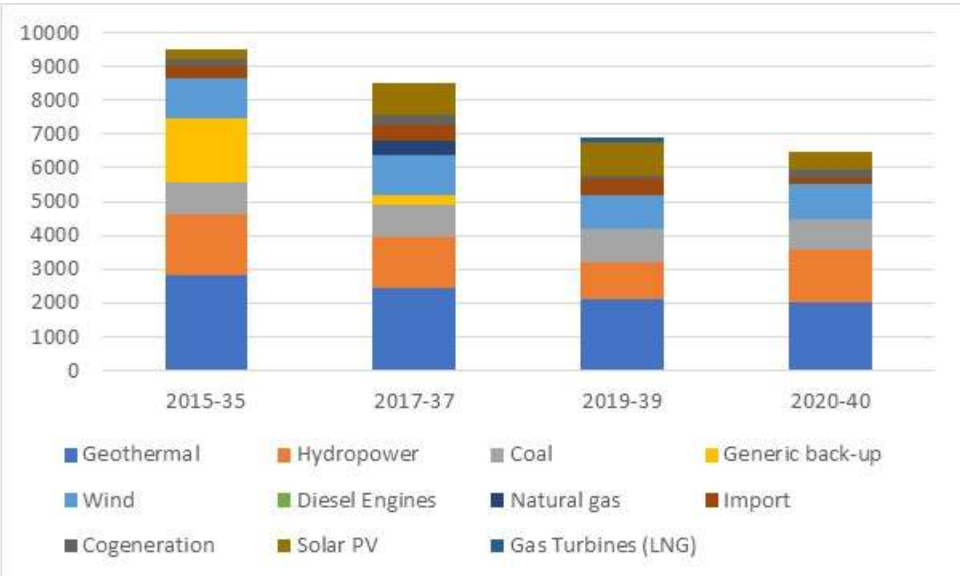
In part, reflecting some of the comments made by Mott MacDonald, the 2020-40 LCPDP has a notably different capacity profile in 2030, with:

- Reduced capacity of renewables, notably solar PV.
- Much higher share of hydropower.

Similar data for 2035 is presented below. In terms of capacity shares there is less break in findings than for 2030, with the following trends evident across the LCPDPs:

- Slightly more conservative assumptions for geothermal over time,
- Common view of the need for coal

Figure 11: Installed capacity in 2035 (MW), reference scenario by period of LCPDP



The share of each technology by LCPDP is illustrated below.

Figure 12: Share of installed capacity by technology in 2035 (%) by LCPDP

We have also reviewed whether plants either recently constructed or planned in the next 2 years in the LCPDP 2020-40 have a long history of being in previous plans. In general, this is the case for larger plants, though often there has been important slippage in commissioning dates. For small plants there is less consistency, though this reflects in part the nature of the FiT regime and in some cases the use of generic candidates for solar and wind in earlier plants. The following table summarises the plants above 10MW either recently constructed or included in the LCODP 2020-40 for commissioning by 2023.

Table 6: Recently commissioned or to be commissioned plants: treatment in previous LCPDPs, above 10MW facilities

Plant	Capacity (MW)	Planned date of commissioning	Current or exp. date of commissioning
KenGen Olkaria Wellheads II	28	LTP 2015-2035 (2016)	2016
Hydro Plant WEBUYE	10		2018
Olkaria 5	158	LTP 2015-2035 (2019) LTP 2017-2037 (2019) LCPDP 2019-2039 (2019)	2019
Lake Turkana	300	LTP 2015-2035 (2017) LTP 2017-2037 (2018)	2019
REA Garissa	50	LTP 2015-2035 (2019) LCPDP 2019-2039 (2019)	2020

Kensen Solar Energy	40	LCPDP 2019-2039 (2020)	2020
Olkaria 1 - Unit 6	83	LTP 2015-2035 (2019) LTP 2017-2037 (2020) LCPDP 2019-2039 (2021)	2021
Kipeto	100	LTP 2015-2035 (2018) LTP 2017-2037 (2020) LCPDP 2019-2039 (2021)	2021
Radiant/Selenki	40	LTP 2017-2037 (2020) LCPDP 2019-2039 (2019)	2022
Menengai I Phase 1	103	LTP 2015-2035 (2019) LTP 2017-2037 (2019) LCPDP 2019-2039 (2021)	2023
Municipal waste to energy	30		2023
Eldosol	40	LTP 2017-2037 (2020) LCPDP 2019-2039 (2021)	2023
Malindi Solar - Vateki	40	LTP 2015-2035 (2024) LTP 2017-2037 (2020) LCPDP 2019-2039 (2021)	2023

Source: Own analysis

4.4 Review of the KNTGC

In the preamble to the Kenya National Transmission Grid Code (KNTDC or Code), the objective of the Code is stated as follows:

> *The objective of the KNTGC is to improve the ability of Kenya's power system to be planned and operated safely, reliably, efficiently, and economically, in a transparent and non-discriminatory manner, while multiple independent parties use the power system. The KNTGC provides a framework of rules and regulations under which Users must operate and coordinate with each other and with the operators of the power system. The KNTGC is intended to establish the reciprocal obligations of Users of the Kenya National Transmission System (KNTS) and operation of the Eastern African Power Pool.*

This sub-section reviews the Code for its capacity to encourage private participation.

4.4.1 Overall comments

We have the following overall comments on the KNTGC and its applicability for a market with greater involvement of private investors.

1. **Private generation** - There appears an absence of major factors that can discourage the private participation in the expansion of generation in Kenya. The technical requirements are demanding, but compatible with international practices.

2. **Private participation in transmission** - There is no clear reference to private participation in expansion of the transmission system through independent transmission companies. Most of the KNTGC refers to the national transmission

company (TNSP); in some sections of the Code there are references to a single TNSP, and in others the reference is to TNSPs. However, in section 4.3.1, which deals with the composition of the KNTGC Review Committee board there is reference to private Transmission Licensees, private Distribution Licensees, and private Generation Licensees. Given the mixed messages it is recommended to clarify if the intention is to allow several TNSPs, in which case some sections of the KNTGC should be modified.

3. **Requirements on renewables** - In the case of renewables, specifically wind (WPP) and solar (SPP) there are requirements in relation with provision of voltage and frequency regulation. Although modern WPP and SPP can provide this type of regulation, it will increase the costs.

4. **Overlapping roles** - There are references to the System Operator (SO), Kenya National TSO and TNSP, with an unclear definition or overlapping of roles. Moreover, some sections appear a copy of the same conditions in the EAPP Grid Code. However, what is necessary in these sections is to clearly define the obligations of the SO and TNSP in relation to the internal operation and with the EAPP, which is a specific issue for Kenyan participants.

5. **Planning responsibility** - The KNTGC should define the organization responsible for the planning and development of the KNTS. Depending on the chapter, the responsibility seems to lie with the Ministry of Energy, the TNSP, or in other cases the Code states that it should be defined in the future (section 6.2). In chapter 20 on data exchange for planning, the role of information collection is allocated to TNSP and SO, without clarifying exactly which of both should provide or receive the information.

6. **Review Committee** - Section 4.3 sets out the role of the KNTGC Review Committee. In most countries there is no need for a permanent entity, with reliance placed on an ad-hoc working group. In this case this committee has majority of representatives from the state-owned companies. Voting is by a simple majority, so any private bodies would be necessarily in a minority position.

7. **Links to EAPP Grid Code** - Some chapters contain this paragraph: “This chapter contains requirements specific to both the EAPP IC and the KNTGC. If in any instance there is a difference in requirements, the more stringent requirement shall hold.”. In some cases, the identification of the “more stringent requirement” may be subjective, which supports greater case by case definition of the requirements.

8. **Operational Planning** - Section 8.2.7, “Operational Planning” mentions, “If a daily generation dispatch needs to be developed, it shall be done following the procedure guidelines shown below”. Generation dispatch is essential for the operation of power systems. It may be an economic dispatch, the results of a market clearing or other procedure, but it cannot be avoided. In case of a market,

the rules for dispatch are part of the Market Rules, but the KNTGC should define the technical aspects, including the feasibility of the dispatch taking into consideration security and quality requirements.

9. **Data requirements** - Section 8.2.9, “Transmission System Data Requirement” establishes that “the capability of transmission system components for both normal and emergency conditions shall be established by technical studies and operating experience”. The KNTGC should define how these studies should be undertaken, including methodology, load scenarios and data collection.

10. **Planning process** - Several additional comments are made in relation with the planning process:

- Section 5.1: EAPP IC Requirements - This section looks like as a copy of the EAPP Planning Chapter. This section identifies the obligations of Kenya (SO, Ministry, TNSP) in relation to the planning process of EAPP
- Section 5.2: KNTGC Requirements, states that “All the requirements presented in Section 5.1 EAPP IC Requirements shall apply in this Section 5.2 and in all other places in this Planning Chapter”. For clarity it would be convenient to specify which are those requirements as it is difficult to match the two sections.
- Section 5.2.2.1: Planning Process - The basis for a new planning process should be an updated load forecast and generation expansion schedule. Additionally, specific problems may launch an update of the plan.
- Section 5.2.4.1: Development Assessment Reports - This section seems to involve the TNSP in a key role in the planning. It would be more appropriate for the plan to be managed by the Ministry with a close cooperation of the TNSP. However, in subsequent sections, it seems that more responsibility is given to Ministry.
- Section 5.2.5.2: Other Targets for Long-term Planning Purposes - All the responsibility to provide information is assigned to TNSP. However, if independent transmission companies are ultimately permitted, these should also provide information.
- Chapter 6: This chapter looks like part of EAPP Grid Code. This chapter should describe the obligations of Kenya’s SO in relation to the internal power system and as part of EAPP.

4.5 Implications for the LCPDPs and the KNTGC in developing market arrangements

From the above assessment, key planning requirements that are critical for the development of market arrangements include:

- Update of planning software to ensure full functionality of the simulation models with the evolving nature of energy markets, especially the integration of renewables and potential role for storage.

- Undertake a detailed review of the approach to estimating electricity demand to ensure the core forecast reflects the best estimate of how demand will evolve independent of aspirational goals and policy targets that may not be feasible to introduce.
- Incorporation of all detailed recommendations of Mott MacDonald relating to generation and transmission planning.
- Ensuring that the text in the KNTGC is harmonised to facilitate any proposed market arrangements and that the planning provisions in the KNTGC are fully consistent with those employed in the LCPDP.

The 2020-40 LCPDP made several conclusions and recommendations. These are analysed in turn for their relevance for introduction of market arrangements.

Table 7: Conclusions and recommendations of 2020-40 LCPDP

№	Recommendation	Comment
a.	The optimised case to be adopted as the national long term generation expansion plan for the 2020-2040 period.	Agree with use of optimised scenarios. Critical for planning tools to be adequate to support optimisation.
b.	The proposed solar and wind projects which are likely to deliver higher intermittent capacity in the system than required should be spread to minimise energy curtailment.	These projects should be signalled where optimal and other technologies, like storage, incorporated to develop optimised plan that duly considers all the trade-offs.
c.	For Solar and Wind projects that do not have PPAs, it is recommended that they are migrated to renewable energy auctions.	Agree
d.	Peaking capacity power plants and Battery storage should be developed immediately to avert peak capacity shortfalls, absorb excess energy presented as vented steam during off-peak hours, provide system reserves, and prevent load shedding in Western Kenya in the short term as transmission projects are being implemented. In the long term the recommended projects for the same purpose are LNG gas turbines, Pumped Hydro Storage and peaking hydro plants	This is one of the aspects where the use of appropriate planning tools could provide a thorough analysis of the merits, costs, and risks of alternative solutions for the short and the long term.
e.	Demand side management relating to load shifting is recommended to enable optimal utilisation of the excess energy in the system during off-peak hours. This includes initiatives like strengthening the time of use tariff, electrification of the transport sector among others.	Role of tariff system should be investigated to see if it can result in load shifting and peak reductions (point d above). Market arrangements can facilitate these trends and provide efficient pricing signals.

f.	Demand creation efforts to be enhanced to support optimal use of the existing generation capacity and projects under implementation.	Demand creation should not substitute for weaknesses in demand forecasting. Tariff system can promote consumption where efficient.
g.	Negotiate for firm 200MW Ethiopia imports for at least 5 years to allow for development of local firm capacity in the medium term.	Duration and pricing of long-term firm contracts should be carefully evaluated to prevent relevant stranded cost once market arrangements are implemented.
h.	In the period between 2022 and 2024, there is a risk of firm capacity shortfalls if Ethiopia imports and the KenGen Olkaria I unit 6 plant are not realised as planned. This may necessitate extension of the plants scheduled for retirement.	Agree
I	Renegotiate Commercial Operation Dates and tariffs for projects that have PPAs but are yet to commence construction, to be integrated according to the dates given in the optimal plan. Respective contingent liabilities for the committed projects should be determined to inform proposals and negotiations.	Feasibility of renegotiation will depend on contractual conditions
j.	Carry out a comprehensive study on ancillary services requirements for the system, including battery storage, pumped storage, and reactive power compensation, with the increasing levels of intermittent renewable energy sources	Agree
k.	The Automatic Generation Control (AGC) to be implemented as a matter of urgency to improve the management of secondary reserves to ensure smoother system frequency control.	Agree
l.	Focus on sustainable technology for geothermal expansion that will minimize steam venting and enhance flexibility	Agree

5 Potential barriers to advancing electricity wholesale market opening

This section considers key barriers to advancing wholesale market opening.

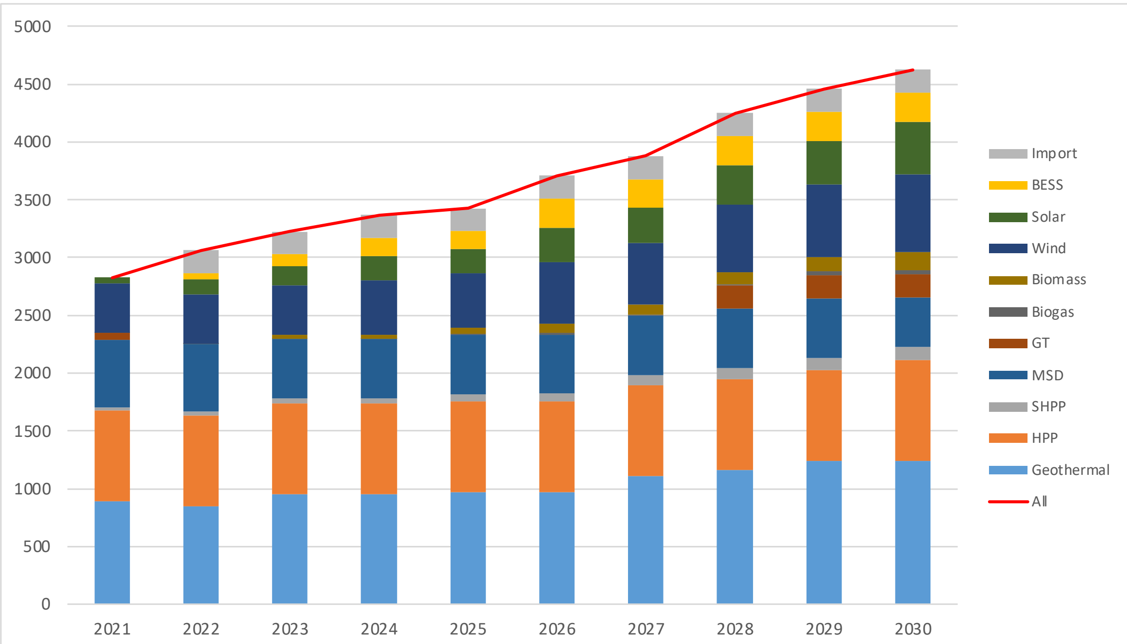
5.1 Market analysis

Simulation modelling of the Kenyan electricity market has been undertaken using the SDDP model, data in the 2021-30 LCPDP and information provided on PPA prices and coverage. As this analysis is based on capacity development included in the LCPDP, the capacity development outlined here is identical to that in the LCPDP of 2021-30 though dispatch will vary, as some differences in costs are anticipated, while the SDDP model used is run based on monthly dispatch as opposed to annual dispatch underpinning the LCPDP.

For a core analysis, the model is run assuming a largely closed domestic market but allowing 200MW of imports from Ethiopia in the medium term. Results have been developed up to 2030.

The following figure shows the trends in installed capacity, with a more than 60% increase envisaged between 2021 and 2030. Capacity increases are most apparent for solar PV (net increase of 404MW), geothermal (350MW), battery energy storage system (BESS, 250MW), wind (246MW) and imports (200MW) over the projection period.

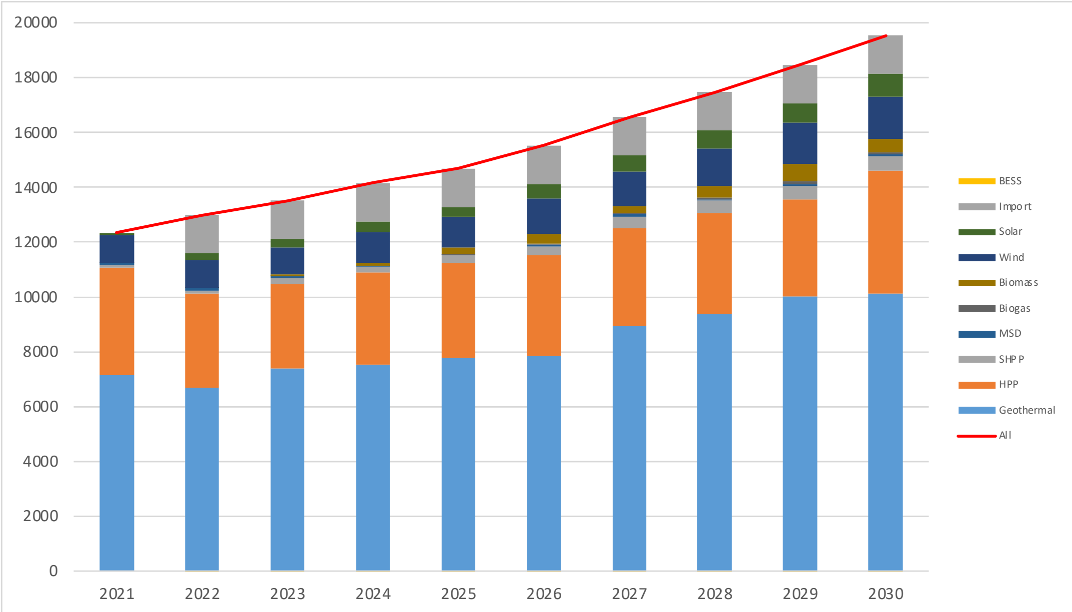
Figure 13: Installed capacity MW, 2021 to 2030 (MW)



Source: Own analysis from data in LCPDP 2021-30

Over the period generation volumes are envisaged to increase by just under 60% with the largest increases coming from geothermal (approx. 3000GWh/year), imports (1400GWh/year) and solar PV (750GWh/year).

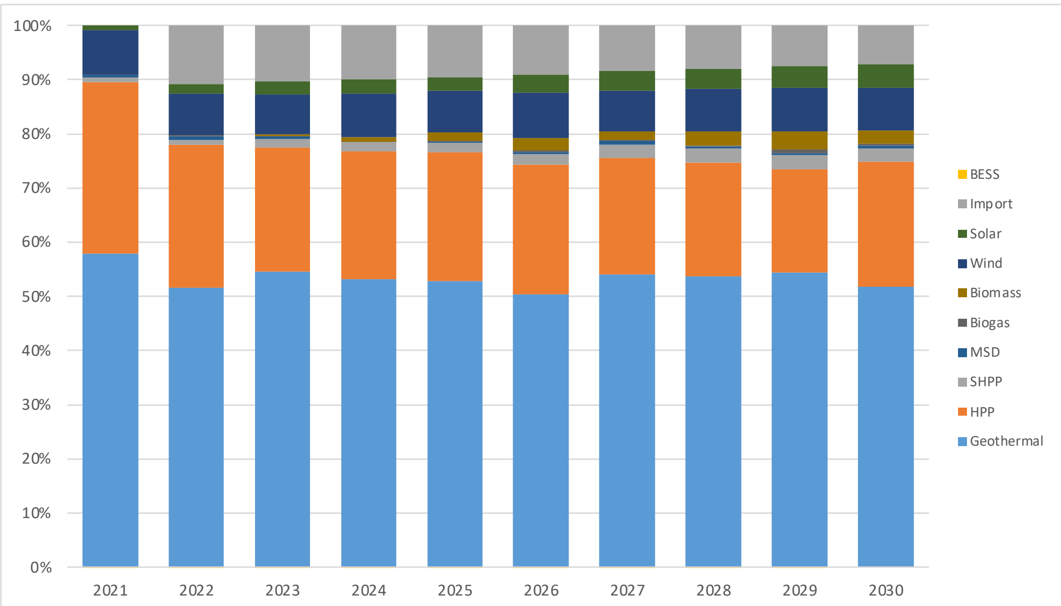
Figure 14: Annual generation (GWh), 2021 to 2030



Source: Own analysis from data in LCPDP 2021-30

Trends in generation share are illustrated below, with general fall in the share of hydro, geothermal largely remaining stable, with increases in the share of imports, wind, solar PV, and biomass.

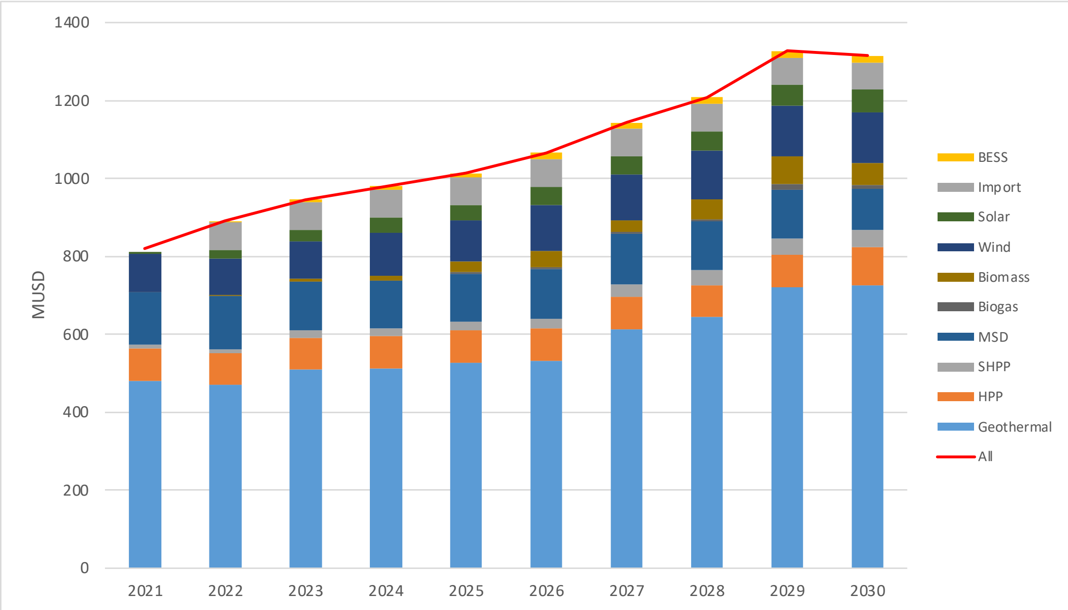
Figure 15: Share of generation by technology, 2021 to 2030 (%)



Source: Own analysis from data in LCPDP 2021-30

Overall system costs are expected to increase gradually over the period before levelling off in 2029. An important increase in geothermal costs is evident from 2026.

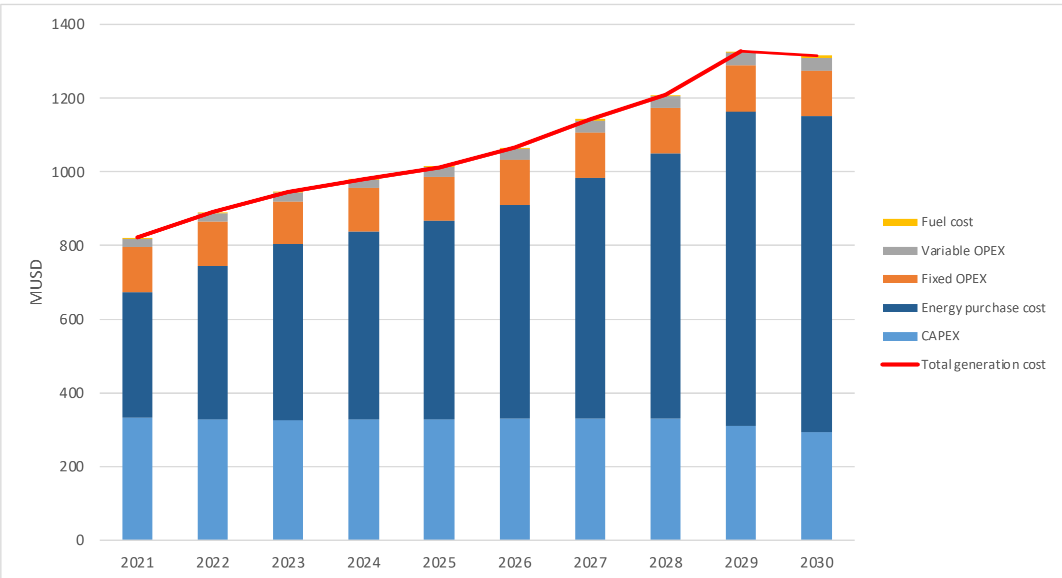
Figure 16: Total system cost ($ million), 2021 to 2030



Source: Own analysis from data in LCPDP 2021-30

Over the period the cost share evolves. At the start of the period most of the cost share can be accounted for by capital related costs and fixed operation and maintenance expenditure. However, as the period evolves there is a much greater share of energy purchase costs from IPPs and imports, much of which is envisaged as fixed from the standpoint of KPLC due to the presence of take-or-pay contracts.

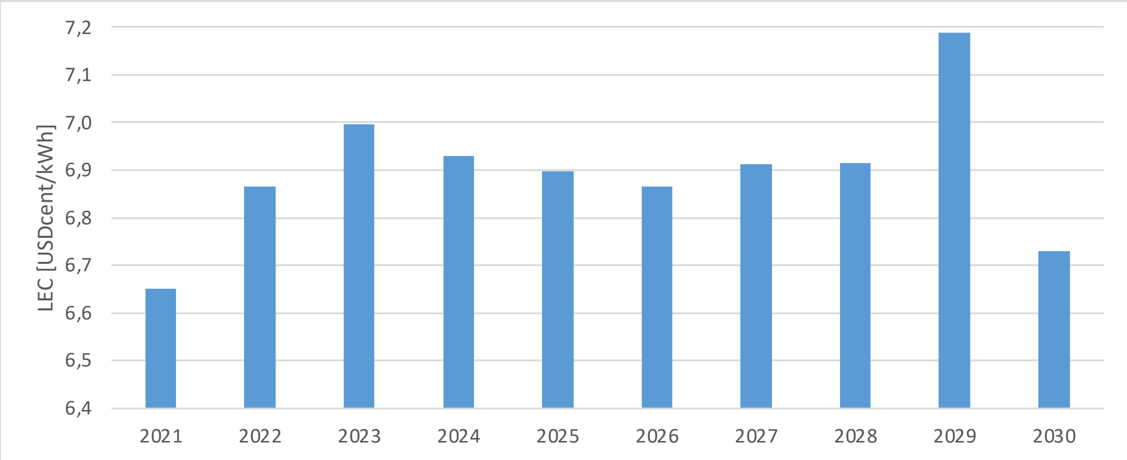
Figure 17: System cost by cost component ($ million), 2021 to 2030



Source: Own analysis from data in LCPDP 2021-30. CAPEX in this section refers to capital related costs.

Over the period the average system costs is generally within the range of 6.6 to 7.0c/kWh, with increases generally corresponding to the entry of new capacity. The costs assumed are based partly on information provided on new PPAs being signed, information in the Master Plan and own assumptions on the cost of new technologies and imports.[2]

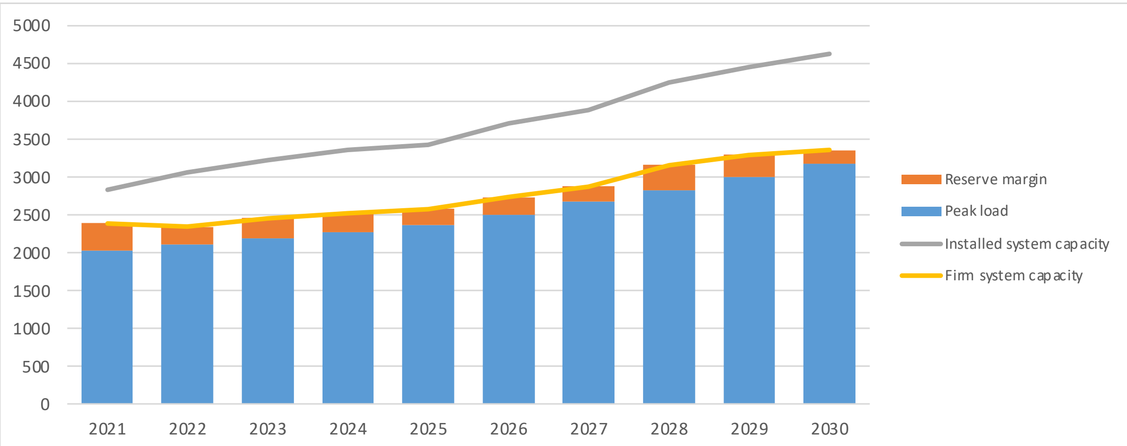
Figure 18: Average system costs per unit generation (c/kWh) 2021 to 2030



Source: Own analysis from data in LCPDP 2021-30.

The following graph compares the firm system capacity with peak demand. A generally adequate reserve margin is evident, including in the first few years of analysis, assisted by the assumed 200MW contract with Ethiopia.

Figure 19: Estimation of firm capacity and system load (MW)

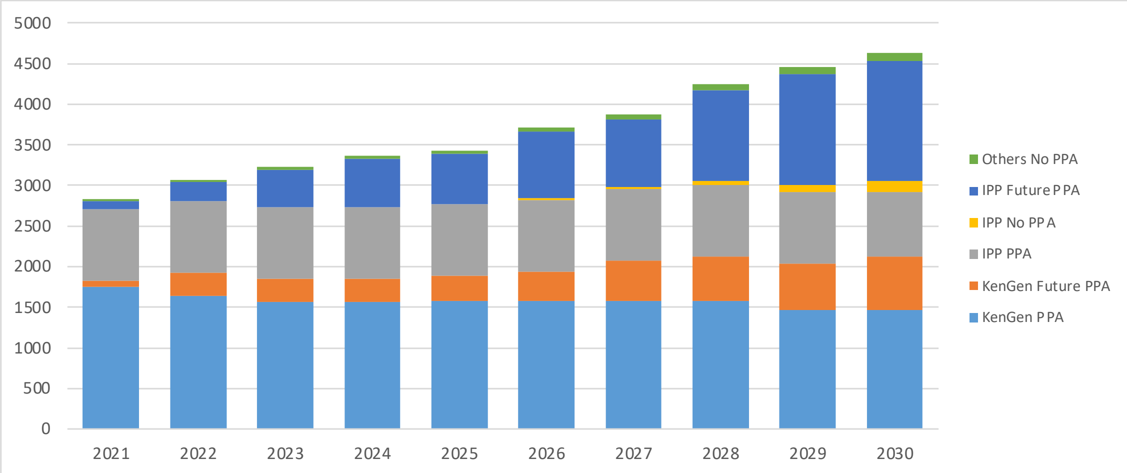


Source: Own analysis from data in LCPDP 2021-30

The impact of PPA arrangements is considered in subsequent graphs. The following graph of installed capacity shows that capacity increases are predominately concentrated in IPPs, with a smaller increase in plants to be operated by Kengen. However, limited retirement of plants with PPAs is envisaged up to 2030.

[2] For example, where a PPA price is not specified the following LCOE are assumed: solar 4c/kWh, wind 6c/kWh, biomass 7c/kwh, BESS capacity price $30.4/kW/year and $24.3/MWh/year, imports 5c/kWh.

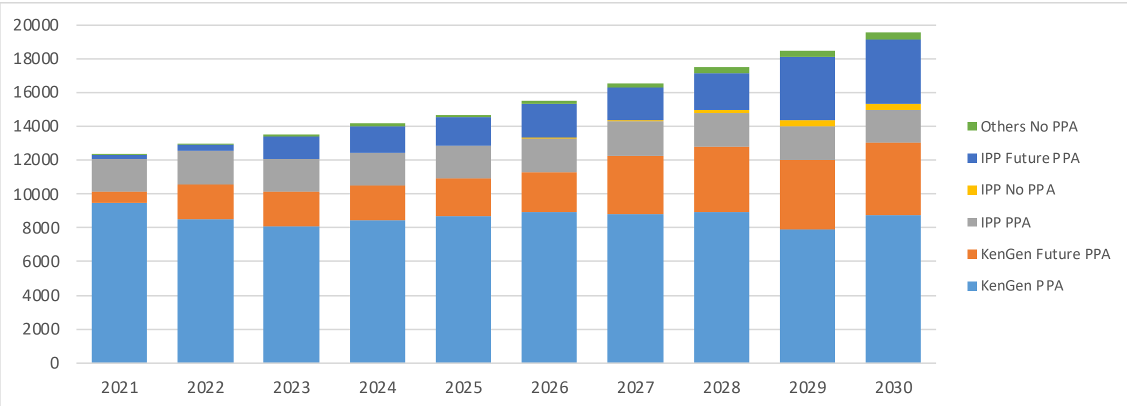
Figure 20: Installed capacity by ownership (MW)



Source: Own analysis based on data in LCPDP 2021-30

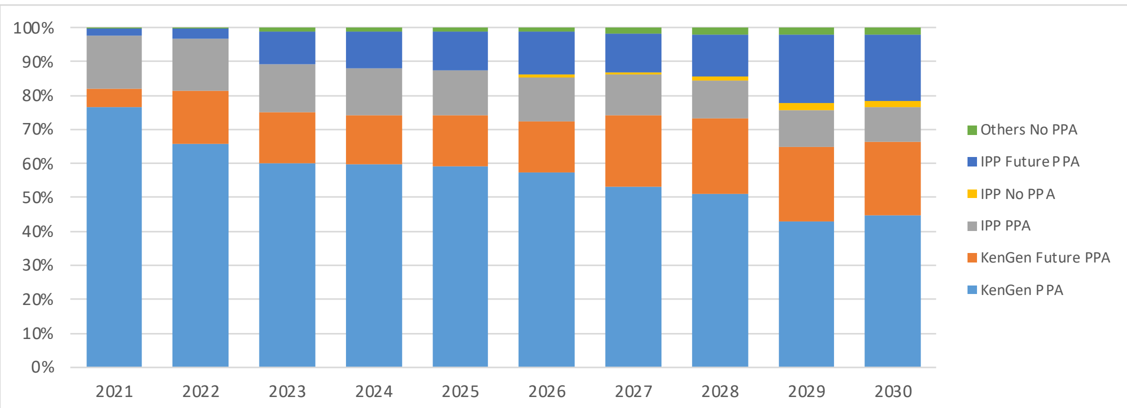
The following graphs show the annual generation and the share in annual generation by plant ownership. While the share of IPPs in overall generation rises, it generally rises less than its capacity share.

Figure 21: Annual generation (GWh) by plant ownership (GWh)



Source: Own analysis based on data in LCPDP 2021-30

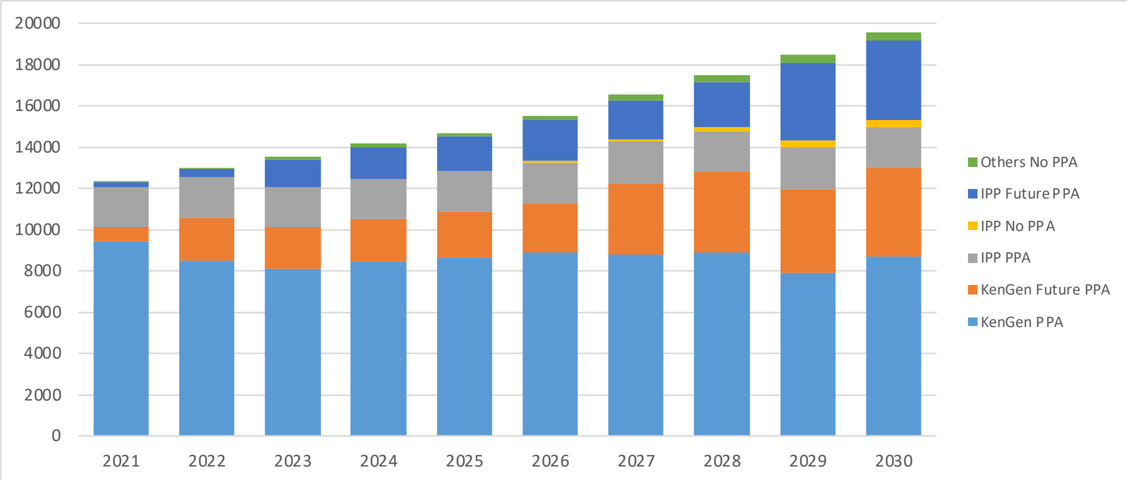
Figure 22: Share of annual generation by plant ownership (%)



Source: Own analysis based on data in LCPDP 2021-30

The subsequent graph shows the trend in annual generation costs by plant ownership. The actual value of KenGen's generation cost increases, while that of IPPs generally rises at a faster rate.

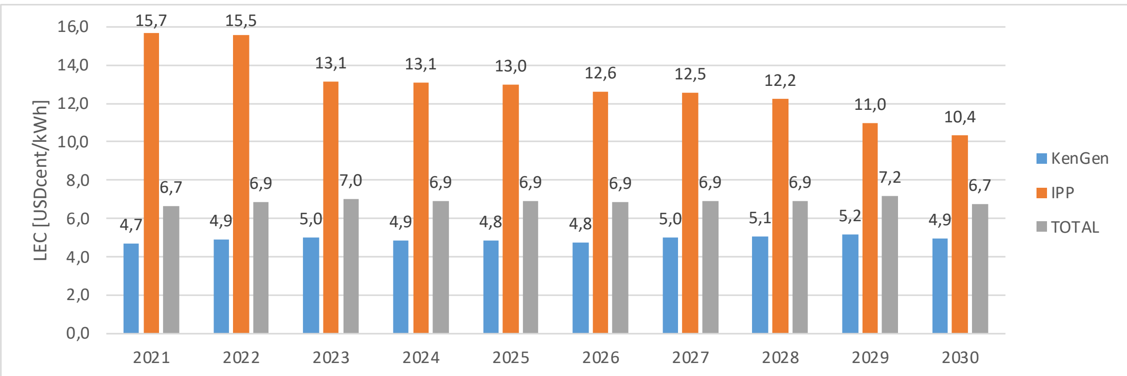
Figure 23: Annual generation cost by plant ownership ($ million)



Source: Own analysis based on data in LCPDP 2021-30

The overall average cost of PPAs signed with IPPs is significantly higher than those of KenGen, with the average cost of energy generated by IPPs estimated at more than double that of KenGen. This partly reflects the technologies applied by IPPs and existing pricing arrangements. Assuming that new PPAs are acquired at efficient cost, then the overall cost of energy supplied by IPPs should fall over the period, with these reductions offsetting greater envisaged costs to KenGen.

Figure 24: Average system cost – generation from IPPs and KenGen (c/kWh)



Source: Own analysis based on data in LCPDP 2021-30

Summary of key implications – market analysis
The cost of existing PPAs, notably those signed with IPPs, appears high on average, creating important risks, especially to KPLC:

- KPLC is exposed to high-cost contracts that may no longer be economic, creating a risk that it cannot recover its fixed costs of supply from customers, especially where some customers seek alternative supply of energy – either through self-generation or participation in a future bilateral or similar market.
- KPLC's exposure risk may augment over time given that alternative supply sources in Kenya (especially with solar) are reducing in price, creating an increasing gap between costs available to customers considering alternative arrangements and the overall cost of KPLC's power purchase portfolio.

Moreover, a limited reduction in capacity supplied from existing PPAs is envisaged over the period to 2030. As many of these PPAs involve fixed costs of capacity, and/or involve take-or-pay provisions, then key cost burdens that are independent from dispatch volumes will persist for several years.

At the same time, a more than 60% envisaged increase in installed capacity is envisaged over the period to 2030. This means that arrangements for the purchasing of new capacity are critical to support market development and the overall reduction in the overhanging cost burden. In particular, the prices and terms under which new PPAs are being signed prior to a more open market arrangement will also critically impact the form of these market arrangements, especially if this means that more than 100% of demand in future years are covered by PPAs.
To support any market arrangement and protect KPLC, there will be a need to ensure fair distribution of any restructuring costs – especially capacity costs and take-or-pay costs of renewable PPAs - across all participants in any market arrangement.

5.2 Development of private solar PV installations

There is increasing evidence that Kenyan customers are starting to migrate partially or fully off the grid, citing high power bills, unreliability, and attractive distributed generation options as main reasons to do so. Several large power consumers have recently commissioned solar power units on their properties. While reliability of grid power is improving, customer dissatisfaction remains a challenge, with solar PV able to bridge this gap.

In response to this situation significant commercial development is occurring.

5.2.1 New forms of business models

This shift in the market has encouraged the establishment of a new paradigm in Kenya's energy sector which has favoured the emergence of many active companies and different models of service delivery. This includes:

- Companies operating as EPC contractors like Solarcentury East Africa, who work primarily with developers. Recent installations include hybrid solar plant at Africa Logistics Properties (506kWp), Nairobi Garden City Mall (858kWp), International Centre of Insect Physiology and Ecology (900kWp), Williamson Tea (1MWp).

- Developers offering PPAs to customers – for example, Crossboundary Energy, who have a 12-year PPA with Nairobi Garden City Mall (installed by Solarcentury East Africa), a 15-year PPA with Unilever Tea Kenya (600kWp), and a 20-year PPA with Xflora rose farm for a roof and ground mount 425kW solar PV project.
- Developers working under arrangements where they build, operate, and maintain a plant and offer customers a discount on the KPLC tariff – for example, Equator Energy, including for Dormans's Coffee (936kW rooftop solar PV), Danco Plastics (900kW grid tied) and Spinners & Spinners (700kW grid-tied).
- Companies operating as a licensed distributor, like Astonfield, who has installed 1.2MW solar PV hybrid plant at Two rivers.
- Other companies specialising in solutions with Battery Energy Storage Solutions (BESS) like Ofgen, who has installed several combined solar PV/BESS systems in Serena Hotels.

5.2.2 Incumbents' reaction

In response to the competitive threat, and potential loss in market share, KPLC has responded and is starting to offer options to commercial customers, like the installation of Solar PV in private houses and office blocks, with the aim of guaranteeing supply, thereby minimising the risk that large clients will seek a private solution. This model proposes that a private sector investor be selected competitively through a request for proposal (RFP) with the scope of work to include solar energy resource assessment, design and grid interconnection studies, supply, installation, finance, test, and commission the solar PV projects that selected bidders will operate for 20 years.

At the same time KenGen, is considering the manufacturing of solar panels with an estimated annual production between 5 MW to 10 MW.

5.2.3 Off-grid systems

Other off-grid activity is proceeding at an important rate. Various lodges in the Kenya's National Parks and Conservation Centres have installed solar PV plus BESS in various lodges, while around 26 companies are providing Solar Home System (SHS) solutions. At the same time, there is also significantly support from international development agencies to support solar off-grid PV development generally, including:

- Support by the Agence Française de Développement to KPLC to retrofit 23 diesel-powered mini grids with renewable energy. The project is expected to introduce 9.6MW of solar photovoltaic capacity and 0.6MW of wind generation.
- The Kenya Off-Grid Solar Access Project (KOSAP) of the World Bank that aims to promote the wider use of Solar PV and clean cooking technologies by suppling 250,000 households with standalone SHSs and a further 150,000 households with clean cooking solutions.

5.2.4 Challenges

Despite increasing evidence of competitive pressures, enhanced diversification of supply as more customers are supplied by renewables and more companies being involved in on-grid and off-grid generation, challenges remain.

A key challenge is that practically all customers (excepting Serena Hotels) still maintain their connection to KPLC's network, which potentially creates a risk to KPLC that they are providing capacity services to these customers that are not adequately remunerated in tariffs, thereby adversely affecting KPLC's health and sustainability. This may be especially problematic for high energy customers on DC-2 and SC-2 tariffs who are billed based on energy consumption only.

Moreover, the decision to seek alternative supply options is potentially impacted by the tariff system and especially any cross-subsidies that may be incorporated in existing tariffs. Therefore, a continual review of KPLC tariffs is necessary to ensure that customers are taking use of alternative supply options where efficient and not simply due to incentives artificially created by the tariff system.

Summary of key implications – competitive developments

Current experience demonstrates that competition is already occurring in the Kenyan electricity market, with any market design roadmap needing to reflect this, and its implications.

In its current form, competitive arrangements create a key risk to KPLC in recovering its revenue requirements:

- Potential cross-subsidies in the tariff structure may create artificial incentives for some customers to seek solar PV solutions.
- The limited spread of two-part tariffs exposes KPLC to the risk that customers who take up solar PV but maintain connection to the grid are not paying towards the cost of network capacity.

Both these factors reduce the revenue base to KPLC, creating conditions for what is often referred to as a "death spiral" for the utility. In general tariff and regulatory reform is required to protect the utility, where the form of net metering policies is important. The Energy Act, 2019 allows for net metering, with a critical need being to develop a net metering policy that provides incentives for customers to install their own solar PV or other DER facilities (e.g., small hydro) where efficient, while ensuring KPLC recovers the full cost of services provided. An effective policy should be introduced as soon as possible. Under best practice the policy should:

- Allow KPLC to recover the costs of net capacity provided (either by 2-part tariffs or other changes).
- Ensure that energy supplied to the KPLC network is remunerated at the value of that energy generated, which will be much lower than the retail tariff (less network costs) and potentially much lower at off-peak hours when most electricity is produced by solar PV facilities, that at peak hours, when customers take energy from the grid. A transition to time-of-use remuneration can also provide incentives

for customer storage solutions to develop, in line with broader market developments.

5.3 Financial and operational performance of KPLC

A critical requirement for the introduction of any market arrangements, is to ensure that KPLC can operate efficiently and providing high quality of service, can meet all its obligations under PPAs, and that it is not left with a portfolio of PPA agreements that result in either stranded costs or undue costs that must be passed on to captive customers.

5.3.1 Financial performance

An important concern is that KPLC's financial situation has been gradually worsening over recent years. The following table includes key income Statement values for the past reported six financial years. This data shows that while gross profit has gradually increased, costs have increased at greater rate, resulting in a noticeable year-on-year worsening in profit, which became negative by 2019-20.

Table 8: KPLC Income Statement, 2014/15 to 2019/20 (KSh'000)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Operating Revenue	106,763,525	108,374,612	120,742,270	131,378,974	133,140,887	133,258,602
Total Power purchase costs	73,115,360	70,265,032	80,477,244	84,100,479	90,152,296	87,499,392
Gross profit	**33,648,165**	**38,109,580**	**40,265,026**	**47,278,495**	**42,988,591**	**45,759,210**
Total operating expenses	16,273,187	23,531,779	30,527,126	25,146,509	31,498,581	25,542,779
Depreciation and amortization	7,943,421	9,434,560	11,213,039	14,013,511	15,896,918	16,335,890
Operating income	**9,431,557**	**9,458,828**	**5,520,208**	**2,737,857**	**1,945,165**	**-2,075,261**
Operating profit	15,837,548	16,928,715	13,650,606	11,915,793	10,530,956	5,312,226
Profit before tax	**12,253,574**	**12,082,397**	**7,656,639**	**4,968,267**	**333,614**	**-7,042,014**
Profit for the year	**7,431,957**	**7,196,563**	**5,280,425**	**3,268,626**	**261,553**	**-939,482**

KPLC's balance sheet shows a gradual increase in assets, which is largely matched on the liabilities side by important increases in current liabilities

Table 9: KPLC Balance Sheet, 2014/15 to 2019/20 (KSh'000)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Assets						
Total non-current assets	206,223,607	247,532,363	269,942,846	282,035,008	283,783,986	282,640,420
Total current assets	66,062,475	50,009,817	61,293,386	50,234,335	44,710,629	42,626,939
Total assets	**272,286,082**	**297,542,180**	**331,236,232**	**332,269,343**	**328,494,615**	**325,267,359**
Equity and liabilities						
Total capital and reserves	59,204,080	64,021,813	63,333,617	60,622,423	56,230,862	54,896,799

Total non-current liabilities	167,482,820	182,605,464	189,074,030	165,399,598	156,583,263	152,894,799
Total current liabilities	45,599,182	50,914,903	78,828,585	106,247,322	115,680,490	117,475,761
Total liabilities	213,082,002	233,520,367	267,902,615	271,646,920	272,263,753	270,370,560
Total equity and liabilities	**272,286,082**	**297,542,180**	**331,236,232**	**332,269,343**	**328,494,615**	**325,267,359**

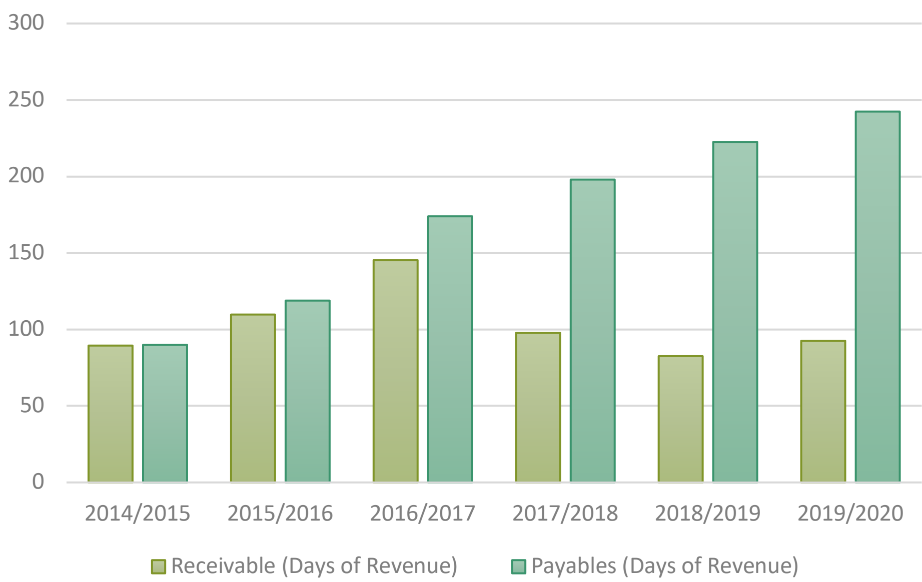
KPLC's cashflow position has also weakened in line with the worsening operating results, with its situation balanced through lower investment from its own cashflows.

Table 10: KPLC, Cashflow statement 2014/15 to 2019/20 (KSh'000)

	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20
Total cash flow from operating activities	27,610,077	25,677,042	28,158,540	28,266,650	26,839,031	23,561,211
Total cash flow from investing activities	-40,089,558	-48,842,869	-39,519,963	-27,733,224	-20,947,514	-16,240,814
Net cash from financing activities	34,100,955	438,219	4,700,867	-6,986,162	-3,626,532	1,977,372
Net increase in cash and cash equivalents	**21,621,474**	**-22,727,608**	**-6,660,556**	**-6,452,736**	**2,264,985**	**9,297,769**
Opening balance	6,609,188	28,230,662	5,503,054	-1,150,410	-7,603,146	-5,338,161
End of year balance	**28,230,662**	**5,503,054**	**-1,150,410**	**-7,603,146**	**-5,338,161**	**3,959,608**

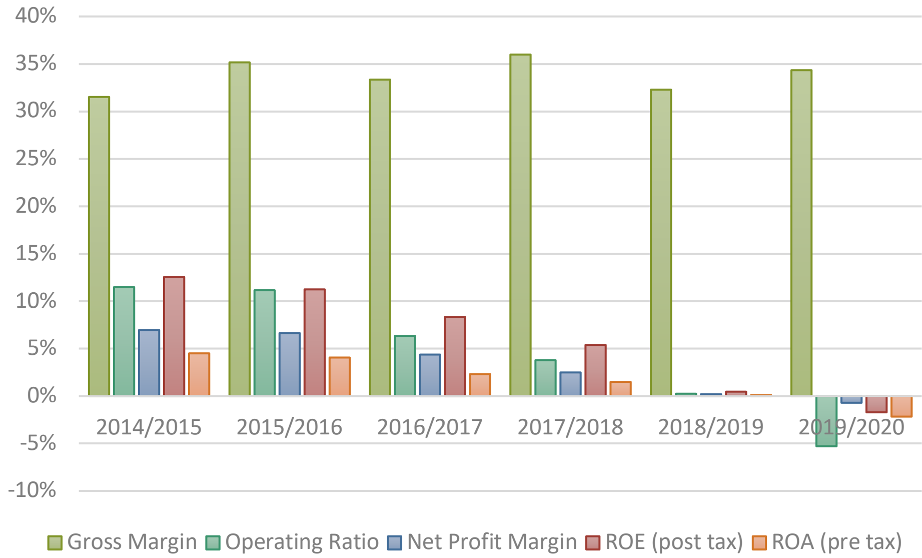
The evolving financial situation is seen in various ratios. Performance on receivables has improved since 2016/17, potentially reflecting the impact of pre-payment. However, payables have increased on a yearly basis reflecting almost 250 days of revenue by 2019/20.

Figure 25: Payables and receivables 2014/15 to 2019/20 (as days of revenue)



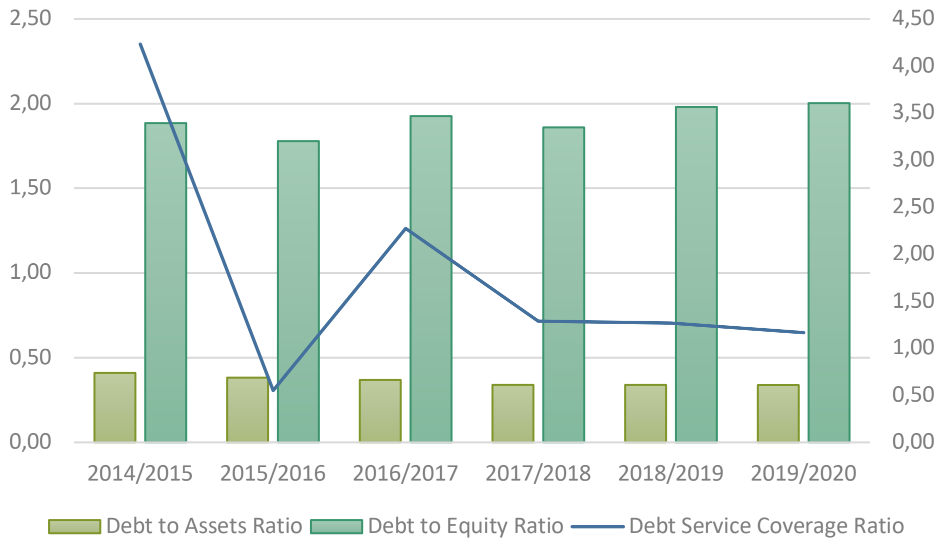
A worsening in profitability ratios is notable. The only exception is the gross margin, which has stayed broadly constant over the 6 years reviewed.

Figure 26: KPLC Profitability ratios, 2014/15 to 2019/20



Debt to assets and debt to equity have been relatively stable throughout the last 6 years, though a fluctuation in the debt service coverage ratio (DSCR) is evident. Values of the DSCR are at around expected benchmarks partly due to limited debt repayments and due to the gross profit holding up.

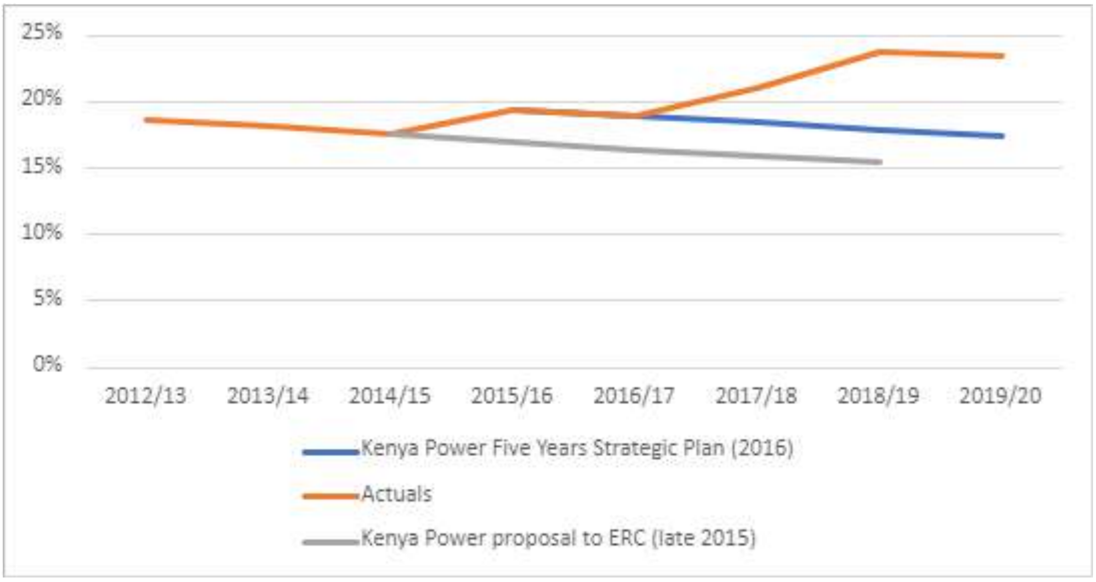
Figure 27: KPLC, Debt ratios 2014/15 to 2019/20



5.3.2 Operational performance

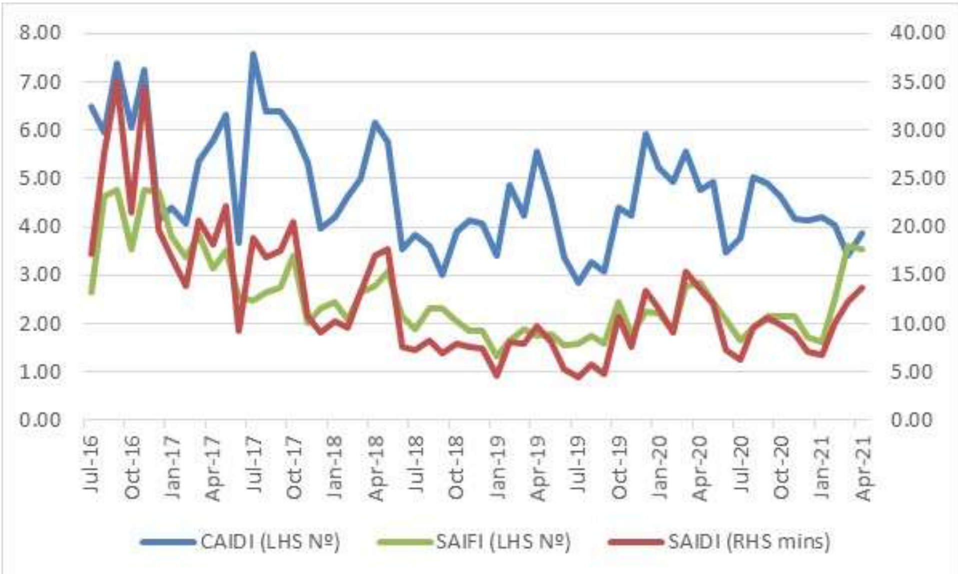
KPLC's operational data also highlights structural weaknesses. The following graph illustrates trends in total losses (technical plus commercial losses) as well as certain reported loss reduction initiatives. In general, losses have gradually risen since 2014/15, and that the plans and targets issued by KPLC have not been met.

Figure 28: KPLC, total losses 2012/13 to 2019/20 (%)



Other data on operational performance, namely outages, show improvements up to late 2019, though from this date the indicators show upward pressures.

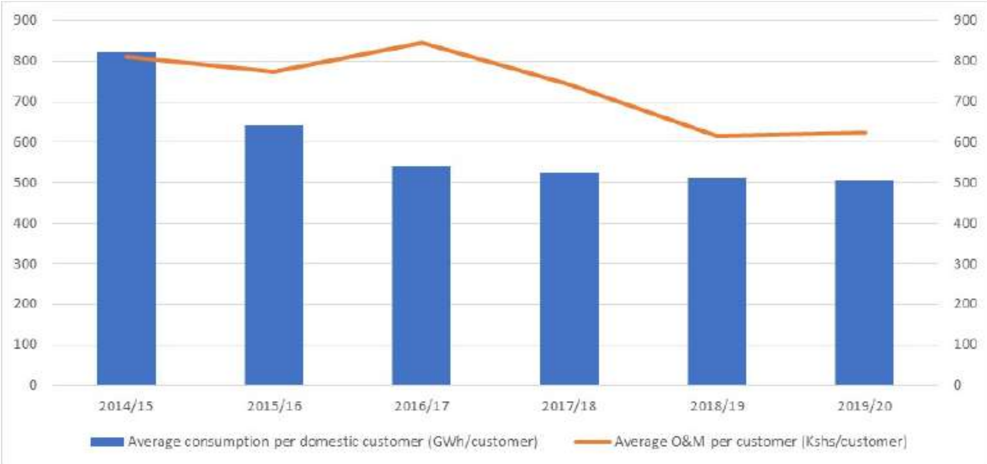
Figure 29: KPLC operating performance indicators



Source: KPLC

KPLCs worsening financial performance coincides with increased rural electrification, though whether this is a determining factor is unclear. An implication of the rapid growth in connections is a gradual reduction in average consumption for the domestic customer category, which is particularly notable from 2014/15 to 2016/17. Over the same period, network management related operating costs per customer have also reduced, suggesting some offsetting impacts on the cost side.

Figure 30: Consumption per customer (kWh) and network management O&M per customer 2014/15 to 2019/20 (KSh)



Source: Own calculations from data in KPLC annual reports

Another area of concern is the increasing exposure of KPLC to customers developing their own solar PV installations, while maintaining connection to the KPLC grid (see previous sub-section). These developments create a risk that the tariff system is not allowing KPLC to recover its network capacity costs, and hence customers currently installing solar PV on their properties are not paying the full cost they impose on KPLC.

5.3.3 Prospects

KPLC's financial and operational performance reflects important structural weaknesses that need to be addressed as part of any plan to introduce a greater spread of market-based arrangements. Programmes like KEMP are supporting KPLC, but its benefits are not rising as strongly as anticipated due to wider issues in areas like losses.

A related issue within KPLC is corporate governance and its willingness to implement necessary measures. For example, in September 2021 and relation to its weakening financial performance, the World Bank stated:[3]

> A financial recovery plan was agreed to in 2018, but the actions identified in the recovery plan remained largely unimplemented mainly due to lack of political will to implement some of the measures like adjustments in retail tariffs. Frequent changes in top management and the Board of KPLC also contributed to the loss of focus in implementing the measures.

[3] The World Bank, KE Electricity Modernization Project (P120014). Report Nº RES46812, Restructuring Paper on a Proposed Project Restructuring of Electricity Modernization Project Approved on March 31, 2015, to the Republic of Kenya, 10 September 2021.

Other reports have highlighted governance issues. The Presidential Taskforce on PPAs highlighted the need for governance reforms in KPLC. Its report was critical on information provided by KPLC to the Taskforce, even once the Board was involved,[4] and made several relevant comments on its internal operations:[5]

a. KPLC, whilst being a state corporation, is also a commercial enterprise listed in the Nairobi Securities Exchange and in this regard, the Board of Directors and the Company have obligations to all stakeholders in the business, including:
    i. The customer base and their desire and need for affordable and consistent electricity.
    ii. The company's direct lenders.
    iii. The company's public equity investors.
    iv. Suppliers, and
    v. Employees.
b. Lack of complete and satisfactory information on IPPs' compliance with laws and regulations. The monitoring of IPPs contracts and performance has not been efficient. KPLC has executed contracts with IPPs in instances where the commerciality of the geothermal resource has not been assessed resulting in long lead times in project implementation, and
c. The KPLC management structure does not appear to be operating efficiently and optimally in overseeing the power purchase and subsequent distribution and retailing to consumers.

Summary of key implications – KPLC financial and service performance
A critical requirement for key challenge is ensuring KPLC can operate sustainably, which has several angles: • Enhancing its performance on key operational variables. This is particularly relevant for losses, which have been increasingly gradually over recent years, but also relevant for outages: while KPLC's performance on outages has improved over the past 6-year, recent data suggests improvements have stalled. • Ensuring it has a cost-reflective tariff that allows it to operate efficiently within a context of least cost planning that minimises the overall cost of supply over time. • Reviewing the tariff structure to ensure that the customers who are installing solar PV are paying the costs that their consumption decisions impose on KPLC. This is especially important for solar PV customers who maintain the potential to be supplied via the grid, moreover if charged on DC-2 and SC-2 tariffs that are entirely energy based. • Ensuring the tariff structure does not have cross-subsidies that are unduly affecting customer decisions to seek alternative suppliers and affecting revenue recovery more generally. • Ensuring its governance is enhanced and supports KPLC's financial and operational recovery from the Board down to operational levels.

[4] Republic of Kenya, Report of the Presidential Taskforce on the Review of Power Purchase Agreements (PPAs), Chairperson Mr. John Ngumi, 29 September 2021, p. xxiii.
[5] Ibid, p.62.

5.4 Legal issues and nature of PPAs

Legal issues are considered in section 3 in greater detail, with the most pressing reflecting the Energy Act, 2019, the Competition Act, 2010, and based on the existing knowledge of the PPAs.

5.4.1 The Energy Act, 2019

Section 117 of the Energy Act, 2019 requires that a person who wishes to carry out the generation, exportation, importation, transmission, distribution, and retail supply of electricity must apply for a license. An exception is granted for the generation of electricity for own use where the capacity does not exceed one MW. Wholesale supply activities are not licensed under this section, which seems to be at odds with other regional legislation that typically requires both wholesale and retail supply (or wholesale and retail trading) to be licensed. Ideally wholesale supply (similar to retail supply), especially in the absence of a fully competitive market, should be a licensed activity, with the system operation and market platform or operator (SMO) separately licensed.

Having regard to the definition of "electricity market", which is defined in section 2 as "….the market where licensees who are authorized to generate, import or export electric power offer to sell electrical energy to *retail licensees* for *resale* to consumers….." the exact scope of the market rules could be open to interpretation as this could be seen to not automatically include the *wholesale* component of the market, and also do not talk to *direct sales*, for example to contestable end customers (as opposed to resale activities that are mentioned).

It should be noted that the law does not in any detail describe the nature, content or regulation of any market platform and related market rules, save for providing for rules that can be made for such a "market" (*viz* section 131). It is doubtful if such rules could override existing contractual provisions relating to contractually binding PPAs, or in any manner force compliance if voluntary participation by existing role-players are not forthcoming. It is also difficult to see how such rules could legally override existing licence conditions that govern current activities where changes to licence may be needed.

In addition, whilst the Act provides that an existing transmission licensee can be mandated for the SMO role (see section 138), the Act does not describe or provide how this should happen (save to say that the SMO may not be involved in the commercial buying and selling of electricity) – section 138(9). The commercial and institutional arrangements to facilitate the establishment of the SMO are not provided for in the law and hence would depend on the goodwill of industry role players. On the other hand, nothing prevents the SO from performing a market operation role (as long as it is not involved in the buying and selling of electricity) and hence the market rules developed under section 131 can provide for that.

Dedicated legislation may potentially be needed (or at least may be very useful) to force industry compliance to the new market regime, help operationalise an SMO and statutorily deal with matters that otherwise cannot be dealt with (e.g., transfer of staff, pension funds, taxation, transfer of assets, unilateral amendment of licences or licence conditions).

5.4.2 Competition Act, 2010

Provision of electricity forms part of "goods" as defined under the Competition Act, 2010 and hence electricity supply is also subject to its jurisdiction. The Act also applies to Government and Government institutions and would hence apply in principle to both KPLC and KETRACO insofar as the provision of electricity is concerned.

Both entities could fall thus potentially fall foul of provisions of Competition Act, 2010 (e.g., abuse of dominant position – Part IIIC) in exercising their functions under the Energy Act, 2019.

The Competition Act, 2010 does however provide for co-operation between the competition authority and the energy regulator, and it is crucial that any proposed market structure is discussed with the competition authority and that any potential non-competitive aspects inherent in such a market preferably be governed by agreement between the two regulators.

5.4.3 PPAs

Although access to legacy PPAs have not been granted and hence no definitive observations can be made, it follows from general principles that apply to most PPAs that any external actions that negatively impact the rights and obligations of the parties could have a contractual consequence.

This would be especially important for the commercial rights and obligations of the parties to a PPA, for example if the operation of the market impacts the viability of the PPA it can be expected that there will be contractual consequences. This would typically realise through reliance on force majeure, political force majeure and change of law provisions and could potentially lead to breach of contract and claims for damages or compensation. This is evidenced by the report of the Presidential Task Force on PPAs where it was highlighted that PPAs indeed had such clauses.

Hence it is important that market rules should as far as possible *not* affect inter party PPA rights and obligations, especially the existing commercial (buy and sell) rights and obligations between sellers and buyers so as not to inadvertently fall foul of contractual provisions that could have adverse effects.

In the case of the standardised RES PPAs it was noted that these foresee the possibility of a changed electricity market and provide that KPLC must transfer its transmission, distribution and purchase rights and obligations to any successor in title. This demonstrates that the parties to these PPAs acknowledge that such changes may occur. However, this does *per se* impact the rights and obligations of the seller who would continue to be able to invoke change of law or breach provisions should their commercial rights be negatively impacted.

Accordingly, the same principles should be applied to RES PPAs, i.e., that market rules should avoid impacting the contractual commercial rights or obligations of the parties. Should changes be necessary, these should be negotiated with the contractual parties to the PPAs. It should be noted that the report of the Presidential Task Force on PPAs follows the same approach, i.e., that amendments to PPA provisions should be negotiated and not unilaterally be enforced.

Summary of key implications – Legal issues and PPAs
• The Energy Act, 2019 does not licence wholesale activities which could have an impact on how licensing under a new market framework is designed and operationalised in the absence of such licences. • Compliance to the market rules under the Energy Act, 2019 may need voluntary buy-in from the relevant role-players as it is not clear if market rules by itself would be able to override PPAs, nor if it can unilaterally impact existing licensed rights and obligations of existing licensees. Alternatively, dedicated legislation may be helpful to deal with market related issues over and above what can be achieved through market rules. • The Energy Act, 2019 is silent on how any System/Market Operator (SMO) is to be operationalised and hence there may be challenges in transferring staff, assets, pension funds etc. A statutorily established SMO could be very helpful, also in addressing aspects that would otherwise require agreement and goodwill from industry players (e.g., changes to licences, PPAs) • Electricity supply falls under the mandate of the Competition Commission and hence any non-competitive aspects of a market would ideally need to be agreed between the energy and competition regulator beforehand. • Market rules should avoid impacting the commercial contractual arrangements between the parties to a PPA to minimize the risk of change of law and breach provisions being invoked. Transactions post PPAs should also not indirectly or inadvertently impact the commercial viability of the underlying PPAs.

6 Operational and Financial Performance of Sector Entities (Task 5)

6.1 Review of AF Mercados Cost of Service Study

AF Mercados Cost of Service Study of 2018 focused primarily on setting tariffs, while also considering a range of additional issues of relevance for the market study.

On the tariff side, it developed a range of scenarios for cost-reflective tariffs. The following table compares the tariffs gazetted in 2018 with the estimated tariffs for 2017-18 determined in the study, which were cost-reflective but adjusted to minimise transition effects. The figures exclude fixed charges, fuel costs, FERFA and INFA charges.

Table 11: Comparison with tariffs set in 2018 and those estimated in the Cost-of-Service Study

Tariff	Restrictions	Unit	Gazetted 2018	COSS 2017-18	Difference
DC1	Up to 100kWh	KSH/kWh	10.0	14.5	45%
DC2	Above 100kWh	KSH/kWh	15.8	39.55	150%
SC1	Up to 100kWh	KSH/kWh	10.0	18.61	86%
SC2	Above 100kWh	KSH/kWh	15.6	18.61	19%
CI1	Peak	KSH/kWh	12.0	14.47	21%
	Off-peak	KSH/kWh	6.0	6.37	6%
	Demand	KSH/kVA	800	1000	25%
CI2	Peak	KSH/kWh	10.9	13.17	21%
	Off-peak	KSH/kWh	5.45	5.8	6%
	Demand	KSH/kVA	520	800	54%
CI3	Peak	KSH/kWh	10.5	13.16	25%
	Off-peak	KSH/kWh	5.25	5.79	10%
	Demand	KSH/kVA	270	500	85%
CI4	Peak	KSH/kWh	10.3	12.38	20%
	Off-peak	KSH/kWh	5.15	5.45	6%
	Demand	KSH/kVA	220	551	150%
CI5	Peak	KSH/kWh	10.1	12.38	23%
	Off-peak	KSH/kWh	5.05	5.45	8%
	Demand	KSH/kVA	220	962	337%
SL	All units	KSH/kWh	7.5	16.34	118%

A gap between the set tariffs and those proposed for 2017-18 is evident for all tariff categories. While the gap is generally greater for domestic customers, there appears no a-priori evidence of clear inter-category cross subsidisation. If still applicable based on current data, this suggests that the issue with customers choosing to install solar PV panels to reduce bills may reflect fundamental structural issues raising the electricity tariff to all categories and not necessarily cross-subsidies.

The study also estimated the LRMC of transmission and distribution services. The Average Incremental Cost (AIC) approach was adopted to estimate these costs by voltage level, where AIC is the present value of the stream of least cost plans needed to satisfy the projected demand divided by the present value of the stream of demand itself, namely:

$$AIC_t = \frac{NPV(TOTAL\ EXPENDITURES)}{NPV(demand)}$$

To calculate the LRMC via AIC, three variables are required to be predicted: load, CAPEX, and OPEX. The AIC reduces as the sum of the AIC for capex and opex as follows

$$AIC_t = AIC_t^{MCC} + AIC_t^{MOC}$$

Where:

$$AIC_t^{MCC} = \frac{NPV(CAPEX)}{NPV(demand)}$$

$$AIC_t^{MOC} = \frac{NPV(OPEX)}{NPV(demand)}$$

For the distribution sector, a parametric model was developed to forecast CAPEX and OPEX over the period 2017-2030, with the following assumptions applied:

- Reliance on available information for CAPEX and OPEX predictions, applying econometric techniques along with the estimation of future demand.
- Assuming 70% of total CAPEX is load related, with a factor of 3% of CAPEX related to load growth added on a cumulative basis to account for related O&M.
- Discounting predicted costs to 2030 to the base year with a discount rate of 10%.
- Dividing the discounted value by the total discounted incremental demand stream to arrive at the marginal distribution investment and O&M cost per kW of incremental (peak) demand sustained into the future.
- Splitting the calculated LRMC by voltage levels (medium voltage and low voltage) based on an analysis of KPLC investments on a project-by-project basis.

For transmission a similar approach was adopted taking investment from KETRACO's then current expansion plan and applying 2% of CAPEX as OPEX. The following results across distribution and transmission applied:

Table 12: Estimate of LRMC in AF Mercados cost of service study, by voltage level

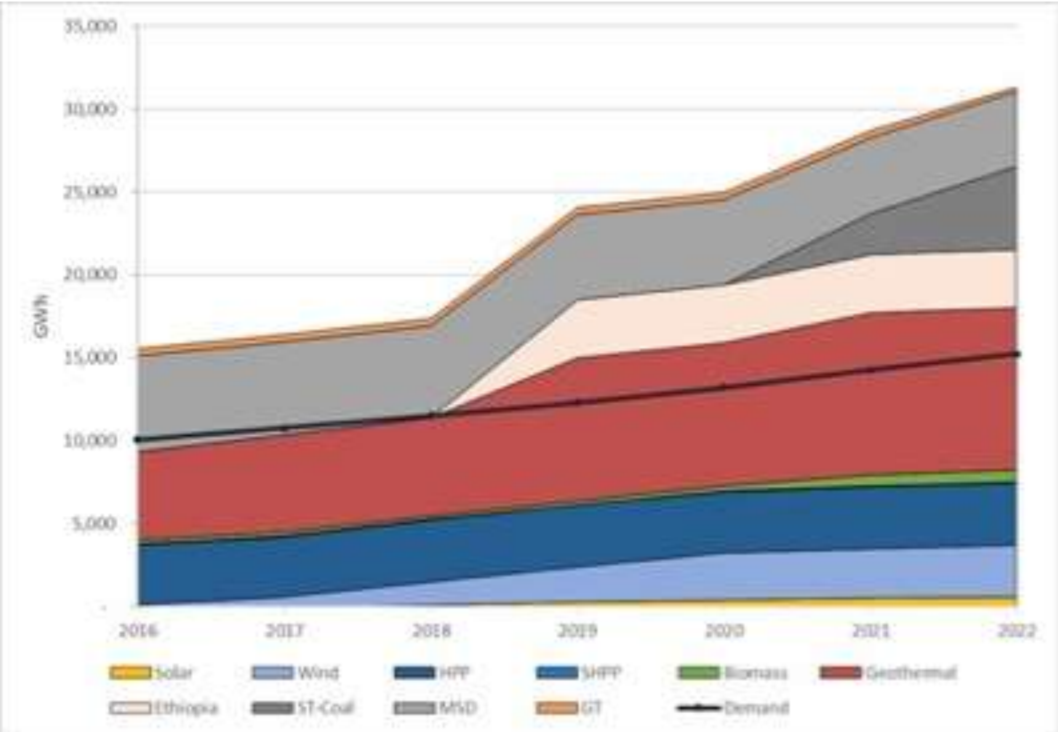
Voltage level	Discounted costs (KSh million)	Discounted peak demand (MW)	LRMC KSh/kW/year
LV	112,367	924	12,576
11kV	35,208	1,076	3,386
33kV	34,459	1,114	3,200
66kV	5,244	1,165	466
132kV	66,185	1,223	5,600
220kV	137,002	1,223	11,591
400kV	123,370	1,223	10,438

Source: AF Mercados Cost of Service Study, Final Report, March 2018

In general, it is expected that the LRMC will decrease from LV to HV. Up to 66kV this relationship held. However, proposed large investment on the transmission network reversed this relationship for 132kV and above. KPLC advised that the estimated values for LRMC on its voltage levels in this Study should still represent a good approximation of current LRMC. In practice, for tariff setting as there is revenue reconciliation, cost recovery is respected under all values of LRMC.

In the study, an important excess of supply was estimated, partly reflecting then anticipated imports from Ethiopia, and important increase in supply from geothermal.

Figure 31: Estimated energy available and demand, 2016-22 (GWh)



Source: AF Mercados Cost of Service Study, Final Report, March 2018

Notwithstanding the above, a suggested schedule for customer eligibility was developed based on the following data on consumption and consumers.

Table 13: Overview of number of customers and share of total consumption, 2016

Customer category	Voltage	Number of customers	Share of total consumption
LC CI5	132 kV	34	5.64%
LC CI4	66 kV	34	5.94%
LC CI3	33 kV	50	3.61%
LC CI2	11 kV	373	16.15%
LC CI1	415/240V	3,065	20.64%
Domestic Customers	415/240V	6,520,160	29.86%
Small Commercial	415/240V	313,059	17.48%

Source: AF Mercados Cost of Service Study, Final Report, March 2018

The following three tranches were suggested as possible for opening the market

- Consumers supplied at 66 kV and above – LC CI5 and LC CI4 - representing (then) 68 customers and 11.58% of the total consumption.
- Consumers supplied at 33 kV and 11kV – LC CI3 and LC CI2 – including 423 customers and 19.76% of total consumption.
- Commercial and Industrial consumers supplied at 415 volts three phase four-wire and whose consumption exceeds 15,000 kWh.

An alternative approach to opening the market could be by consumption (kWh) or demand (MW). These approaches were considered less preferable in the Study due to measurement issues. These measurement issues are still valid, and in any case, the approach of opening the market by customer category/voltage level is considered optimal in the current circumstances. These estimates are update in section 6.5.

6.2 Review of investment requirements

Well-functioning transmission and distribution networks are critical for market development, with effective investment in both networks important to meet proposed demand growth, ensure quality of supply and allow the connection of new generation facilities on the distribution and transmission networks.

In this context, the following investment profile is included in KETRACO's transmission Master Plan:

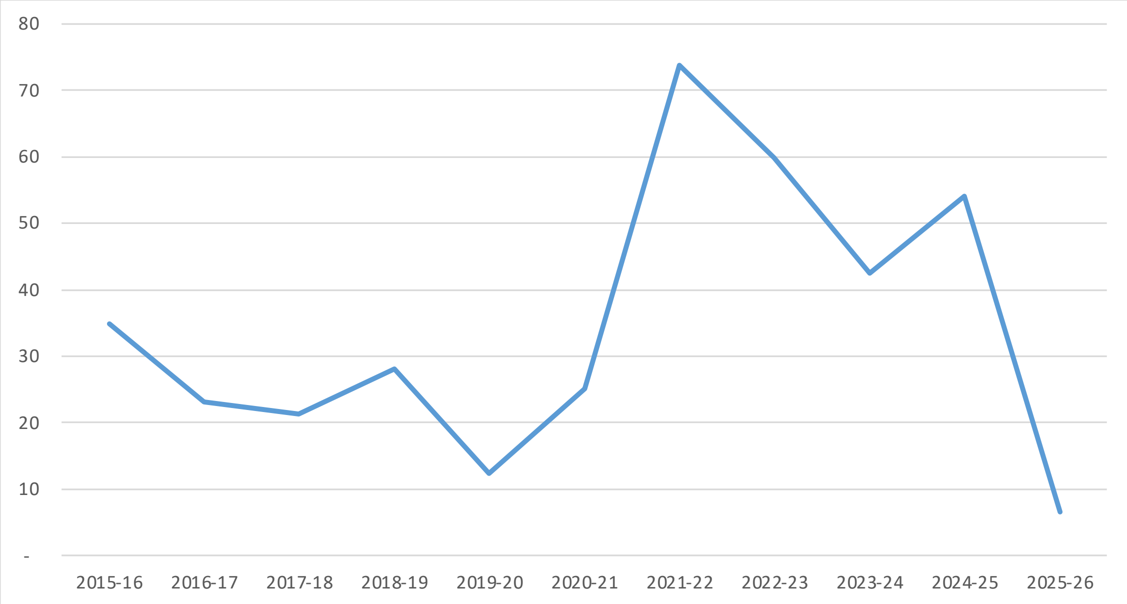
Table 14: High level summary of KETRACO's investment plan, 2020-21 to 2025-26 (KSh million)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Transmission	24,960	66,132	48,171	18,070	54,039	6,438
Substations	-	7,618	11,627	24,328	-	-
Others	74	74	74	74	74	74
Total	**25,034**	**73,823**	**59,871**	**42,472**	**54,113**	**6,512**

Source: Own calculations from data in KETRACO, Transmission Master Plan 2020-2040, May 2021

Overall, the capital expenditure plan is more aggressive than historical investment, as seen in the following simplified graph. However, the existence of a step change is misleading as KETRACO reports Capital Work in Progress in 2019-20 of KSh 96,579 million, indicating significant investment that has not been added to the asset base.

Figure 32: KETRACO Investment: Additions to Fixed Assets 2015-16 to 2019-20 and Forecast Expenditure 2020-21 to 2024-25 in its Transmission Master Plan (KSH million)



Source: Own calculations from data in KETRACO, Transmission Master Plan 2020-2040, May 2021

In the Master Plan, KETRACO notes that funding of approximately USD 1,266 million has been secured or committed through development partners or through EPC and financing approaches. Within the list of projects, the following are earmarked for potential private sector involvement, that is through Independent Transmission Providers (ITPs):

- Kwale Lilo – Kibuyuni 220kV, 134km, estimated costs $84.9 million.
- Kisumu (Kibos) - Kakamega – Musaga 220kV, 146km, estimated costs $79.45 million.
- Lessos-Loosuk 400kV 358km, estimated cost $202 million.
- Rongai – Keringet– Chemosit 220kV 192km, estimated cost $100 million.

A summary of the capex plan provided by KPLC is set out below. The plan is more rigorous for 2021-22, and hence may understate expenditure in 2020-21 and expenditure on non-project items (e.g., machinery, vehicles, furniture) in other years.

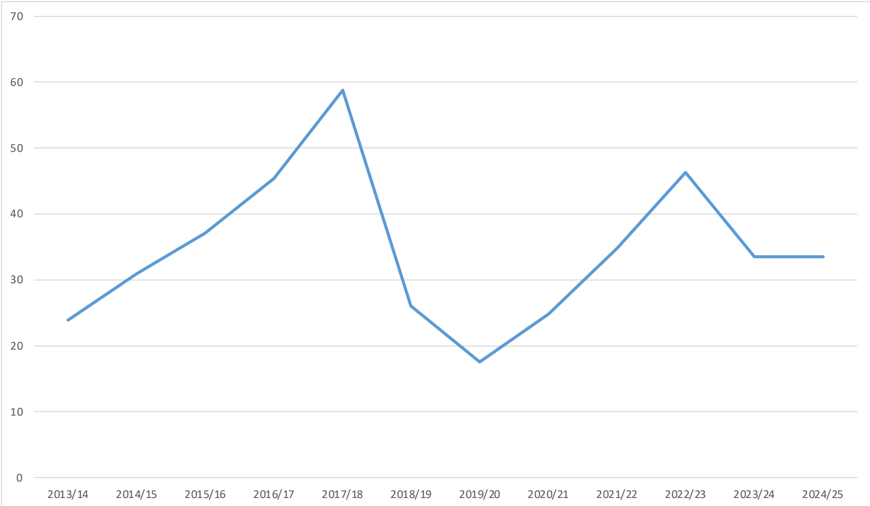
Table 15: High level summary of KPLC's capex plan, 2020-21 to 2025-26 (KSh million)

	2020-21	2021-22	2022-23	2023-24
Land	0	750	0	0
Transmission	-	3,686	5,250	5,250
Distribution	15,903	22,244	32,123	19,364
Machinery		3,561		
Motor Vehicles		950		
Furniture, equipment, and others		4,362		
Total	**15,903**	**35,553**	**37,373**	**24,614**

Source: Own calculations from data provided by KPLC

The following graph shows reported additions to KPLC's asset base over the period 2013-14 to 2019-20 and forecast expenditure to 2024-25.[6]

Figure 33: KPLC capital expenditure: reported additions 2013-14 to 2019-20 and estimated new expenditure 2020-21 to 2024-25 (KSh billion)



Source: Own estimates based on data in KPLC Annual Reports and data provided by KPLC

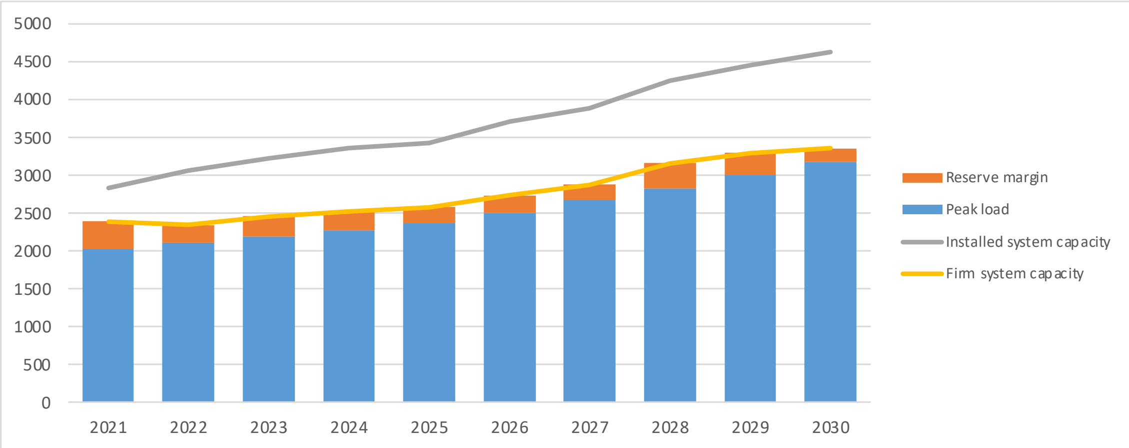
The data suggests that there has been an overall drop in KPLC capex in the period from 2017-18. This may reflect large scale investment related to rural electrification in the period to 2017-18, the pace of which has not been maintained subsequently.

6.3 Review peak demand against proposed generation plans

A review of peak demand against proposed generation plans is considered in the previous section. Based on this analysis, the graph below compares firm system capacity with peak demand. A generally adequate reserve margin is evident, including in the first few years of analysis, implying that at the level of capital the most recent generation plan reflects anticipated movements in peak demand.

[6] The estimates from 2020-21 assume that the anticipated expenditure on land, machinery, vehicles, furniture, equipment and other in 2021-22 is undertaken in other forecast years.

Figure 34: Estimation of firm capacity and system load (MW)



Source: Own analysis from data in LCPDP 2021-30

6.4 Review retail tariff categories

This section reviews the retail tariffs from the perspective primarily of the needs of a competitive market. For a competitive market, and more generally, the definition of consumer categories and tariff structure should be based on several principles:

- **Cost of supply**. The tariff rates should be cost reflective and consider all the costs required for supplying electricity to the final customer.
- **Efficient use of energy**. The tariff rates can incorporate a premium-punishment scheme to improve the efficient use of energy. The premium-punishment mechanism implies generating positive incentives for the users in the system that make efficient use of energy and negative incentives for those that do not. Tariffs in increasing blocks or by applying a significantly higher tariff to users that, in the case of Kenya exceed a pre-established consumption of 100 kWh, are widely used mechanisms.
- **Reflect the cost of alternative supplies**. For example, tariffs should reflect the alternative supply options available to customers, including self-supply.
- **Fairness to consumers and sensitiveness to social considerations**. Customers should be rated according to the way they use the electricity system although some considerations to social aspects can be considered.
- **Simplicity to administer**. When setting the tariff structure, simplicity should be considered to minimize administrative costs for both the regulator and the firm.
- **Easily understood by consumers**. Both the tariff structure and the tariff rates should be easily understood by customers.
- **Stable**. Generally, the tariff structure remains fixed for long periods.

At times the principles may not overlap, or be in conflict, which confirms the need for discretion and flexibility in their application.

Key features of the current tariff structure are summarised below.

Table 16: Summary of key tariff features by tariff category

Tariff category	Voltage	Restrictions	(Peak) energy charge (KSh/kWh)	Off-peak energy charge (KSh/kWh)	Demand (KSh/kVA)
DC-1	240/415V	<100kWh	10.00	-	-
DC-2	240/415V	>100kWh<15,000kWh	15.80	-	-
SC-1	240/415V	<100kWh	10.00	-	-
SC-2	240/415V	>100kWh<15,000kWh	15.60	-	-
CI1	240/415V	>15,000kWh	12.00	6.00	800
CI2	11kV	-	10.90	5.45	520
CI3	33kV	-	10.50	5.25	270
CI4	66kV	-	10.30	5.15	220
CI5	132kV	-	10.10	5.05	220
CI6	220kV	-	7.99	4.00	200
SL	240/415V	-	7.50		

Source: Schedule of tariff approved November 2018 as amended February 2020.

In addition, customers are subject to a fuel energy cost, foreign exchange adjustment (FERFA) and inflation adjustment (INFA).

Overall, the tariff system displays several supportive features, which are in conformity with the above-mentioned tariff principles:

- A system of voltage-based charging is well embedded, with customers effectively distinguished based on the voltage of supply.
- Demand charging is also well embedded for the commercial and industrial tariffs, with the higher charges at lower voltage levels reflecting the additive nature of charging (namely that the supply at low voltage it is necessary to also use medium and high voltage networks).
- Time-of-use charging is in place, partly reflecting the capacity costs of generation and providing strong signals to move consumption where possible to off-peak periods.
- Systems of social support are in place for low use domestic and commercial customers, who are generally low-income customers, with a higher second band for less discretional consumption.
- An explicit street lighting tariff is in place.

Moreover, while it is generally efficient for domestic customers to be charged a fixed component reflecting metering and other customer service costs, the high number of recently electrified pre-payment customers that have extremely low levels of consumption supports its removal.

The following changes are recommended to enhance the system further:

- There is a need to develop explicit distribution and transmission wheeling tariffs per voltage level.
- The domestic charge has the following two features:

- The lower bound is relatively high at 100kWh and more so than can generally be justified for essential use. We understand there are discussions to reduce this to 30kWh, which is in line with our recommendations in the 2018 Cost of Service Study.
    - There is a maximum value on the DC-2 tariff (15,000kWh). This appears to assume that any customer with this profile is in effect a relatively high using commercial customer who should be transferred to the CI1 tariff. An alternative, in line with the reduction of the lower band value, could be to introduce a 3-band increasing block tariff, with the first block up to 30kWh, a second up to 100kWh or a value slightly, and then a third block, with a charge higher than that currently for consumption above 100kWh.
- The current structure provides strong incentives for high-use residential and commercial customers that are below the 15,000kWh/month threshold to install solar PV solutions, as they can remain connected to the KPLC network, reduce energy-based charging significantly but without incurring a capacity charge. The proposed approach differs between domestic and commercial customers:
    - For domestic customers, access to net metering should be conditioned on the customer transferring to a two-part cost-reflective tariff, where the capacity component reflects the cost of connection to the transmission and distribution networks. A pre-requisite will be the need for a licensing regime (albeit simplified) for customers taking out net metering
    - For commercial customers below 15,000kWh/month a similar approach can be adopted, though due to the important benefits that 2-part tariffs can provide, a new tariff category is proposed for commercial customers above a certain capacity threshold (e.g., 10kW) that will be charged on a 2-part basis.
    - Over time all commercial customers should move towards 2-part pricing, which in effect involves gradually lowering the threshold.

6.5 Recommend criteria of eligible customers

Most systems of market design use a phased approach to allowing customers to access key features of the market. This is due to the large number of logistical, technical, organisational, and economic/financial issues that arise in market liberalisation. There are different approaches by which the electricity market can be progressively opened.

The main options to select eligible customers are the following:
- Consumption. Selection of customers based on its annual energy consumption.
- Voltage. Selection of customers based on their supply voltage.
- Maximum demand. Selection of customers based on their maximum demand.
- Consumer group. Selection of customers based on its consumer group (domestic consumers, industrial, commercial etc).

- Economic sector. Selection of customers based on its sector of activity (smelters, cement factories etc.,).

Information on voltage and consumer groups is readily available, as is total consumption within these consumer groups.

Table 17: Overview of number of customers and share of total consumption, 2019-20

Customer category	Voltage	Number of customers	Share of consumers	Share of total consumption	Cumulative consumption
LC CI5	132 kV	45	0.0006%	4,84%	4,84%
LC CI4	66 kV	52	0.0007%	6,64%	11,48%
LC CI3	33 kV	75	0.0010%	5,33%	16,81%
LC CI2	11 kV	480	0.0063%	13,59%	30,40%
LC CI1	415/240V	2,983	0.0394%	17,88%	48,28%
Small commercial	415/240V	399,783	5.2769%	15,45%	63,73%
Domestic	415/240V	7,156,429	94.4600%	35,42%	99,15%
Street Lighting		16,298	0.2151%	0,85%	100,00%

Source: Data provided by KPLC and KPLC Annual Report 2019-20, includes REP customers.

An advantage of the current tariff system is that it is clearly segmented by voltage level, with the amount of consumption within these bands relatively well spaced out. This allows for a gradual opening based on tariff categories working from the highest voltages (132kV) downwards.

Data is not available on maximum demand, which is the most plausible alternative at least for the largest customers. However, a strong correlation between maximum demand and voltage level is envisaged, which further supports application of the use of customer categories.

In section 6.1 a review of the approach taken to define contestable customers in the 2018 Cost of Service Study was undertaken. Notably, the data on the share of consumption and consumers by tariff category was similar, indicating stability in the consumption breakdown over time.

The number of tranches and the amount of tariff categories to group in each tranche is a decision to take once the market infrastructure and key constraints is best known. Simply considering the existing tariff structure, up to 7 tranches are possible (8 with street lighting). A possible approach that stages the energy to be included in the market could be to apply three bands prior to mass market opening as follows:

- CI5, CI4 and CI3 (33 kV and above) - representing 172 customers in 2020 and 16.81% of the total consumption.
- CI2 (11kV) – 480 customers and 13.59% of total consumption
- CI1 (240/415V) – 2983 customers and 17.88% of total consumption.
- Domestic and street lighting (240/415V) – mass market opening with 7.2 million customers and 36.27% of total consumption.

We understand that KPLC is introducing advanced metering for its largest customers. This is a critical step to facilitating market access, and which is in line with the above suggested approach. Any mass market opening should be restricted to the most advanced market stages (see later).

6.6 Propose wheeling tariffs for transmission and distribution networks

A pre-requisite for formal electricity market arrangements, and precursor arrangements like allowing customers to develop solar PV plants away from their point of consumption through systems of virtual net-metering, is a system of wheeling tariffs. Wheeling rates have been estimated, with end-user tariffs simultaneously estimated. This section contains a summary of the analysis set out in detail in Annex 1 and Annex 2.

6.6.1 Revenue requirement

A first key step to determining tariffs, is to estimate the sector revenue requirement, the details of which are in Annex 1. In these calculations, the sector revenue requirement has been estimated based on the following components:

- Generation – comprising revenue needs of KenGen and IPPs, imports and steam sales of the Geothermal Development Company (GDC).
- Transmission – encompassing the revenue requirement of KETRACO and transmission related business of KPLC.
- Distribution/Retail – encompassing KPLC's revenue needs for its distribution assets and the costs incurred by REREC associated with rural electrification.

The total revenue requirement is estimated to rise from KSh 175 billion in 2020-21 to KSh 240 billion by 2025-26. By sector roughly half of the total cost is accounted for by costs of generation as shown below.

Table 18: Total revenue requirement by sector 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Generation	91,583,243	99,366,907	105,477,803	109,389,096	113,000,812	118,853,099
Transmission	8,000,343	10,217,538	13,622,513	19,528,272	23,037,239	23,869,748
Distribution/retail	76,909,773	82,919,522	89,570,354	90,842,087	96,079,980	100,944,383
TOTAL RR	**176,493,360**	**192,503,967**	**208,670,671**	**219,759,455**	**232,118,031**	**243,667,230**

Source: Own analysis

6.6.2 Tariff setting

The model used to calculate the tariffs has been CALCUTTA, an in-house model developed for this purpose. Based on the revenue requirement calculations, the CALCUTTA model allows for two types of tariffs to been modelled:

- End-user tariffs, and
- Wheeling tariffs.

The wheeling tariffs are effectively an input to the end-user tariffs. Wheeling tariffs have been developed reflecting the network costs at each voltage level. In doing so, they are considered as equivalent to the stand-alone network tariff for that voltage level. This means that a customer that is connected at 11kV and purchases energy from a generator connected at 132kV will pay the same wheeling rate as a customer connected at 11kV and with an agreement for local generation at 11kV. This approach is preferred as it is revenue neutral for KPLC, simplifies calculations, and avoids artificial incentives for customer to contract energy from generators located at low voltage levels.

The wheeling charges represent the fixed costs of the system. These costs are evaluated through the LRMC of the transmission and distribution network. All users of the transmission and distribution facilities should pay for the network usage of the system following an efficient pricing mechanism that can recover the costs and allocate them to the users in a proper way. For this reason, this is the key charge that varies according to the tariff group. There is also a need to add losses by voltage level, including non-technical losses at low voltage.

The coincident peaks methodology has been used for the allocation of all the existing network costs. This methodology allocates the fixed costs depending on the participation of each group during the peak hours of the system. Based on this methodology, the following cost-reflective wheeling charges are estimated for the commercial and industrial categories CI1 to CI6. Two alternatives are provided – a fully energy based wheeling charge, and a capacity-based wheeling charge with an energy-based component for losses.

Table 19: Estimated wheeling charge – coincident peaks methodology 2020-21)

	1-part option: Energy Charge Wheeling Rate (KSh/kWh)	2-part option a) Capacity charge Wheeling Rate (KSh/kVA)	2-part option b Energy component (KSh/kWh)
LV			
Commercial and Industrial CI1	8.25	2,541	0.77
MV			
Commercial and Industrial CI2	5.38	1,699	0.38
Commercial and Industrial CI3	4.07	1,607	0.38
HV			
Commercial and Industrial CI4	3.56	1,189	0.26
Commercial and Industrial CI5	3.51	1,102	0.26
Commercial and Industrial CI6	2.11	981	0.26

Source: Own analysis

In developing end user tariffs, there is a need to include costs of retailing and generation. Retail costs have been allocated to distribution to reflect that currently a fixed customer service charge is not levied on customers. The resulting end-user tariffs were determined based on the adding these generation costs to the network/wheeling tariffs.

The tariffs that arise from this process are fully cost-reflective, that is, without any subsidy. For some of the domestic and small commercial customers, these tariffs result in significant variations in customer tariffs, which may not be socially acceptable. For this reason, the cost reflective tariffs are shown constraining the first band of the DC and SC groups to be 10KSh/kWh, with the cost reflective revenue recovered from the second band. The resulting tariffs are set out below.

Table 20: Final tariffs (potential adjustment) 2020-21 to 2025-26

	Unit	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
DC 0 - 100 kWh							
Energy charge	KSh/kWh	10.00	10.00	10.00	10.00	10.00	10.00
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
DC >100 kWh							
Energy charge	KSh/kWh	25.45	25.84	26.12	26.10	26.09	26.06
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
SC 0-100 kWh							
Energy charge	KSh/kWh	10.00	10.00	10.00	10.00	10.00	10.00
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
SC > 100 kWh							
Energy charge	KSh/kWh	23.24	23.58	23.82	23.80	23.79	23.77
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
Street lighting							
Energy charge	KSh/kWh	22.85	23.26	23.60	23.64	23.72	23.80
Monthly charges	KSh/kWh	0.01	0.03	0.02	0.01	0.01	0.02
CI1 TOU							
Energy charge peak	KSh/kWh	8.33	8.61	8.78	8.73	8.68	8.58
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.74	4.25	4.68	4.75	4.86	5.00
Monthly charge - o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	2,541	2,541	2,541	2,541	2,541	2,541
CI2 TOU							
Energy charge peak	KSh/kWh	8.19	8.47	8.64	8.59	8.54	8.44
Monthly charge - peak	KSh/kWh	0.00	0.00	0.00	0.00	0.00	0.00
Energy charge off-peak	KSh/kWh	3.68	4.18	4.61	4.67	4.79	4.92
Monthly charge – o/p	KSh/kWh	0.00	0.00	0.00	0.00	0.00	0.00
Demand charge	KSh/kVA	1,699	1,699	1,699	1,699	1,699	1,699
CI3 TOU							
Energy charge peak	KSh/kWh	8.19	8.47	8.64	8.59	8.54	8.44
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.68	4.18	4.61	4.67	4.79	4.92
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	1,607	1,607	1,607	1,607	1,607	1,607
CI4 TOU							
Energy charge peak	KSh/kWh	7.67	7.93	8.09	8.04	7.99	7.90
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.44	3.91	4.31	4.37	4.48	4.60
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	1,189	1,189	1,189	1,189	1,189	1,189

CI5 TOU							
Energy charge peak	KSh/kWh	7.67	7.93	8.09	8.04	7.99	7.90
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.44	3.91	4.31	4.37	4.48	4.60
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	1,102	1,102	1,102	1,102	1,102	1,102
CI6 TOU							
Energy charge peak	KSh/kWh	7.55	7.81	7.97	7.92	7.87	7.78
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.39	3.85	4.25	4.31	4.41	4.53
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	981	981	981	981	981	981

Source: Own analysis

6.7 Assess impact of tariffs on demand for electricity

The impact on demand of a change in tariff will depend on the changes in electricity tariff and the price elasticity of demand.

6.7.1 Changes in electricity tariff

Based on the modelling undertaken the average tariff will be lower for CI customers but higher for other customers. However, the following figures exclude the fuel cost component in the current tariffs, and hence for DC, SC and SL will overstate any price increase and understate any price reduction for CI customers. The summary values are provided below.

Table 21: Average tariff summary 2019-20 to 2025-26 (KSh/kWh)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26	Increase 2021
DC	14.52	22.08	22.39	22.59	22.56	22.56	22.55	52%
SC	15.10	22.08	22.39	22.59	22.56	22.56	22.55	46%
SL	7.50	22.86	23.30	23.62	23.65	23.72	23.82	201%
CI	12.65	12.11	12.93	13.50	13.49	13.56	13.63	-4%

In this simplified cross-subsidy adjustment, intra-group cross-subsidies have been applied for the DC and SC categories, that is, subsidies inside the same tariff group. Specifically, the first band of the DC and SC groups is constrained at 10KSh/kWh. Commercial and industrial tariff remain largely unchanged.

A comparison between current tariffs and those proposed for 2020-21 under the adjusted cost-reflective approach are set out below.

Table 22: Current and estimated cost-reflective tariffs for 2020-21

	Unit	Current	2020-21

DC 0 - 100 kWh			
Energy charge	KSh/kWh	10.00	22.05
Monthly charges	KSh/kWh		0.03
DC >100 kWh			
Energy charge	KSh/kWh	15.80	22.05
Monthly charges	KSh/kWh		0.03
SC 0-100 kWh			
Energy charge	KSh/kWh	10.00	22.05
Monthly charges	KSh/kWh		0.03
SC > 100 kWh			
Energy charge	KSh/kWh	15.60	22.05
Monthly charges	KSh/kWh		0.03
Street lighting			
Energy charge	KSh/kWh	7.50	22.85
Monthly charges	KSh/kWh		0.01
CI1 TOU			
Energy charge peak	KSh/kWh	12.00	8.33
Monthly - peak	KSh/kWh		0.04
Energy charge o/p	KSh/kWh	6.00	3.74
Monthly – off peak	KSh/kWh		0.01
Demand charge	KSh/kVA	800	2,541
CI2 TOU			
Energy charge peak	KSh/kWh	10.90	8.19
Monthly - peak	KSh/kWh		0.00
Energy charge o/p	KSh/kWh	5.45	3.68
Monthly – off peak	KSh/kWh		0.00
Demand charge	KSh/kVA	520	1,699
CI3 TOU			
Energy charge peak	KSh/kWh	10.50	8.19
Monthly - peak	KSh/kWh		0.04
Energy charge o/p	KSh/kWh	5.25	3.68
Monthly – off peak	KSh/kWh		0.01
Demand charge	KSh/kVA	270	1,607
CI4 TOU			
Energy charge peak	KSh/kWh	10.30	7.67
Monthly - peak	KSh/kWh		0.04
Energy charge o/p	KSh/kWh	5.15	3.44
Monthly – off peak	KSh/kWh		0.01
Demand charge	KSh/kVA	220	1,189
CI5 TOU			
Energy charge peak	KSh/kWh	10.10	7.67
Monthly - peak	KSh/kWh	5.05	0.04
Energy charge o/p	KSh/kWh		3.44
Monthly – off peak	KSh/kWh	220	0.01
Demand charge	KSh/kVA		1,102
CI6 TOU			
Energy charge peak	KSh/kWh	7.99	7.55
Monthly – peak	KSh/kWh		0.04
Energy charge o/p	KSh/kWh	4.00	3.39
Monthly charge	KSh/kWh		0.01
Demand charge	KSh/kVA	200	981

Source: Own analysis

6.7.2 Price elasticity of demand

The price elasticity of demand is defined as the percentage variation in the consumption of electricity in response to a unit variation in its price. In general, studies show that demand is inelastic in the short term; in other words, the reaction to changes in price is small. The exact value of the price elasticity depends on many factors including country specifications, specific customer group, the availability of subsidies, the income level and the proportion of the total expenditure dedicated to electricity. Without detailed field studies, it is not possible to accurately estimate the price elasticity for all consumer categories in Kenya. However, some general picture can be drawn, and previous studies can be analysed to get a high-level understanding of possible impacts of change in the level of electricity tariffs.

In the short term, industrial consumer groups are relatively insensitive to changes in electricity prices as electricity is a direct input for industrial process and there are few alternatives, if any, to replace electricity during these processes. Industrial consumers might have incentives to undertake one of two main alternatives:

- Take out alternative supplies of energy to grid supply. This may include self-generation or installing a plant in another location and using the grid for wheeling purposes. Measures of this nature are envisaged by the proposed market arrangements.
- Move their business to other neighbouring countries with lower electricity tariffs, which is considered in section 6.8. In practice, the scope to relocate an existing business depends on several factors and not just the electricity price, so in practice this mechanism may be most relevant for new businesses considering several locations for setting up operations.

Price elasticity may have a more critical role for household and small commercial consumers, particularly those with higher consumption and potentially more exposed to price increases. Some past studies in Kenya provide information on the price elasticity of demand for household and manufacturing consumers in Kenya:

- A study by Ngui, et al (2011)[7] uses a comprehensive survey of 3665 households sampled across Kenya, to estimate price and fuel expenditure elasticities of demand by applying the Linear approximate Almost Ideal Demand System. The study concludes that several fuels are price elastic, while electricity prices are inelastic for household consumers.
- A study by Onuonga et al (2011),[8] estimated the price elasticity of demand for oil and electricity in the Kenyan manufacturing sector over the period 1970 to 2005. The study found that oil and electricity were significant substitutes but that

[7] Ngui, et al., 2011, Household energy demand in Kenya: An application of the linear approximate almost ideal demand system (LA-AIDS).

[8] Susan Moraa Onuonga, S. Etyang, M. and Mwabu, G. "The Demand for Energy in the Kenyan Manufacturing Sector," The Journal of Energy and Development, Volume 34, Number 2, pp.265-276.

the substitution possibilities were low, and that electricity and oil were price inelastic.

- A study by Mabea, 2014,[9] employs the Engle and Granger two-step procedure and Error Correction method to a time series data over the period from 1980 to 2009 to analyse household electricity demand. The study concludes that the long-run price elasticity for residential electricity demand for Kenya is -0.095, and thus significantly inelastic.

A contrasting view is seen in a study published by CrossBoundary LLC in 2019, which reported that in trials in neighbouring Tanzania, customers supplied by mini-grids and facing high prices had high levels of price elasticity. The study concluded that for each $1.00 saved in electricity from lower prices, customers were willing to pay an extra $0.93 to increase consumption of electricity, and that this change in consumption pattern was sustainable over time.[10] The findings of this study may be consistent with the earlier studies finding low price elasticity of demand, given that in effect this study deals with customer decision-making in the dual circumstance of initial connection to electricity and at high prices, sensitivity which is expected to decline over time as usage patterns stabilise.

6.7.3 Implications

While many of the studies citied are dated, low price elasticity of demand for electricity is consistent with several international studies. This means that relatively small changes in the domestic tariffs may not have a noticeable impact on consumption. However, this does not mean that there will no other impacts on demand. Income effects are potentially more significant, that is, as income rises customers use of electricity will increase. Indeed, this is at the root of most findings that changes in GDP is the predominant driver in changes in electricity demand. Moreover, evidence of renewables development in Kenya suggests that customers will respond to high electricity prices by initiating measures to reduce the cost of this electricity, and potentially maintain consumption patterns but at a lower cost of energy.

More generally, the development of wholesale market arrangements and explicit access prices should have a neutral impact on the demand for electricity in the first instance. Where access prices are calculated on a cost-reflective basis and are equivalent for customers being supplied under a bundled tariff to those taking out competitive arrangements, any price impact on demand will be determined by potential savings in the generation component. Subsequent analysis in this report proposes that customers taking up competitive offers pay a transition charge, reflecting any excess costs in the generation sector, thereby reducing to some degree the price benefits available from taking out alternative supplies.

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[9] Mabea, 2014, Modelling Residential Electricity Demand for Kenya.

[10] CrossBoundary LLC 2019, Innovation Insight: The Price Elasticity of Power, May 2019 (https://www.crossboundary.com/wp-content/uploads/2020/04/Innovation-Insight-The-Price-Elasticity-of-Power.pdf)

Several measures that can be introduced alongside competitive markets, for example, greater time-of-use based charging, creating incentives for users of PV facilities to feed into the grid during times of peak usage (through differential pricing), and encouraging flexibility in the use of the distribution network to reduce demand peaks, can be seen as measures designed to increase price elasticity of demand and more specifically, increase the potential for substitution over time for the benefit of customers and the network owner. While these measures aim to increase flexibility in the timing of demand, it is unclear that these will result in a major shift in average demand patterns.

6.8 Assess competitiveness

An ongoing issue related to tariff reform and the impact that competitive markets may have on customer tariffs is the impact any change in tariff may have on competitiveness of companies operating in the country. Possible adverse impacts of price increases could arise through a reduction in productivity and exports of local companies. For companies or businesses where electricity is a key cost component, changes in tariffs could result in significant downward pressure on its profit. Conversely if competition permits downward pressure on prices the opposite impacts could arise. In principle, a large company could respond to an increase in tariff by relocating to a country where the electricity is cheaper, which would have further adverse impacts on the competitiveness and productivity of the host country.

To analyse the potential impact of new tariffs on competitiveness, it is necessary to understand which are the main sectors that contribute to GDP and exports, and then the sensitivity of these sectors to changes in the electricity price.

6.8.1 Key sources of exports

According to the Kenya National Bureau of Statistics (KNBS) Economic Survey 2020,[11] in 2019 Kenya exported goods and services with a total value of KSh 520,787 million. The principal contributors were:

- Horticulture – KSh 122,916 million (23.6%).
- Tea – KSh 113,551 million (21.8%).
- Articles of apparel and clothing accessories – KSh 34,768 million (6.7%).
- Coffee – KSh 20,310 million (3.9%).
- Iron and steel – KSh 15,678 million (3.0%).
- Titanium ore and concentrates – KSh 13,853 million (2.7%).
- Essential oils – KSh 13,391 million (2.6%).
- Tobacco and tobacco manufacturers – KSh 13,024 million (2.5%).

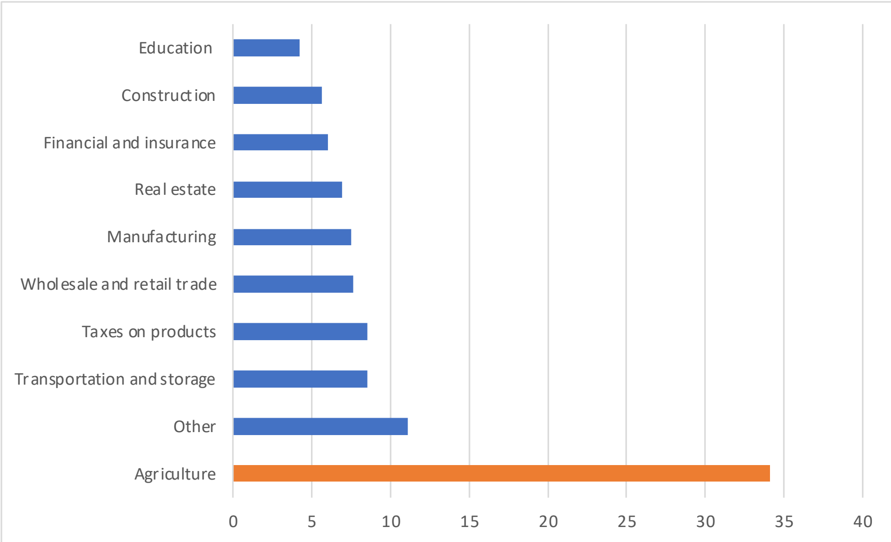
The combination of horticulture, tea, coffee, and tobacco accounted for more than 50% of the total value of exports. While the share of heavy industry is low, the figures show

[11] Kenya National Bureau of Statistics, Economic Survey 2020, p.100.

an increase in the share of iron and steel and titanium ore over the past 5 years, with a notable fall in the share of cement.

The role of agricultural industries in driving Kenya's GDP is also evident, with agriculture accounting for 34% of total GDP in 2019. However, the overall share of services is greater, indicating less reliance on agriculture than in previous years.

Figure 35: Share by key sectors in Kenya's GDP (%), 2019



Source: KNBS, Economic Survey 2020, p.27

6.8.2 Role of electricity in key sectors

The above data on exports and GDP highlights the critical role of agriculture for Kenya's economy. However, electricity is not the most critical variable for business performance. According to World Bank Kenya Economic Update of 2019, the sector's relatively low productivity reflected a range of factors independent to electricity supply and pricing, including lack of quality inputs, (seeds, breeds and fertilizers), distorted input and output markets, minimal adoption of modern production technologies (mechanization, greenhouse, ICT), high incidence of pests and diseases, poor soil health, poor delivery of extension services, and low investment in infrastructure (irrigation, drainage, rural roads)[12].

For other sectors, the role of electricity appears more critical. According to the KNBS 2018 Census of Industrial Production (CIP), for the manufacturing sector 52.9% of energy and utility costs (including petroleum) in 2017 were accounted for by electricity.[13] The same report reported that 47.1% of participants reported the high cost of electricity as a key factor in capacity underutilisation, second only to the high cost of materials.[14] Moreover, the World Bank has reported that high costs of production, in particular

[12] World Bank Group, Kenya Economic Update, April 2019, p.28.
[13] KNBS, Census of Industrial Production and Construction Report 2018, p.v.
[14] Ibid, p.36.

energy have been a major obstacle to manufacturing and may account why new business has been established in industries with low energy intensity.[15] However, the 2018 CIP reported that out of expenditure for industry and manufacturing of KSh 796.5 billion in 2017, KSh 31.3 billion was on electricity, representing 3.9% of total input costs, which appears relatively low given the high concern raised on electricity costs in the survey.

6.8.3 Benchmarking tariffs against key neighbours

To analyse the impact of electricity tariffs on the competitiveness of Kenyan businesses it is necessary to carry out a benchmarking analysis of tariffs against comparable countries. This exercise is needed to assess the possibility of a company looking for competitive advantages in terms of electricity prices in other countries and, consequently, change its location.

The countries included in the comparison are Ethiopia, Tanzania, Rwanda, Uganda, and South Africa. These countries have been selected for reasons of geography proximity, and potential alternative countries for energy-intensive businesses.

For comparative purposes, and broadly reflecting the potential eligibility blocks, the following profiles have been chosen:

- CI5 customer (connected at HV, 132kW) – with the following features:
  - Contracted capacity of 2,500kW,
  - Average consumption of 800,000kWh/month
  - Consumption 50% at peak times, 50% off-peak
  - High value of 12,500,000kWh/month and low value of 500.000kWh/month.
- CI3 customer (connected at MV, 33kV) – with the following features:
  - Contracted capacity of 1,500kW,
  - Average consumption of 500,000kWh/month
  - Consumption 60% at peak times, 40% off-peak
  - High value of 750,000kWh/month and low value of 300,000kWh/month.
- CI1 customer (connected at LV) – with the following features:
  - Contracted capacity of 120kW,
  - Average consumption of 40,000kWh/month
  - Consumption 75% at peak times, 25% off-peak
  - High value of 60,000kWh/month and low value of 20,000kWh/month.

For Kenya, the current tariffs and proposed tariffs based on the modelling in section 6.6 are used in the comparison. For the other countries the following data is chosen:

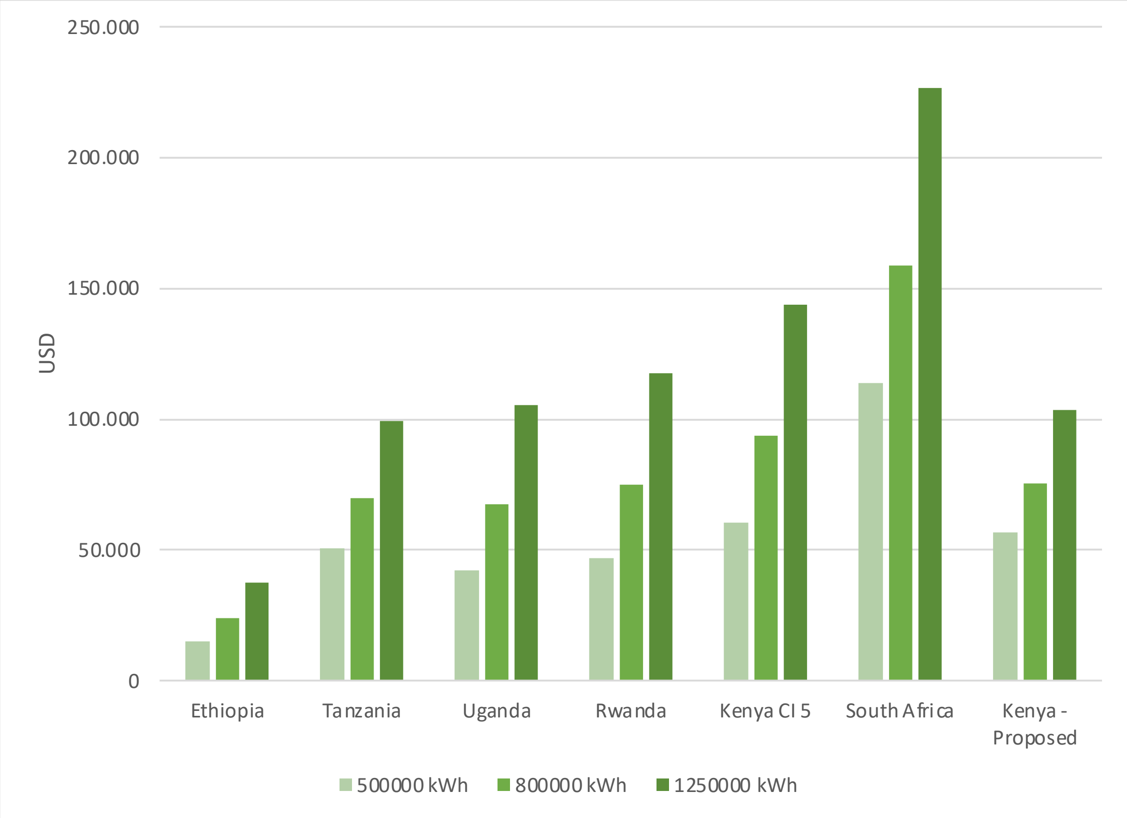
- Ethiopia: Existing tariffs of Ethiopian Electric Power and Ethiopia Electric Utility.[16]

[15] World Bank Group, Kenya Economic Memorandum, From Economic Growth the Jobs and Shared Prosperity, March 2016.
[16] Tariffs obtained from own sources.

- Tanzania: The Tanzania Electric Supply Company Limited ("TANESCO") Tariff Adjustment Order, 2016.[17]
- Uganda: Electricity Regulatory Authority, schedule of tariffs applicable for second quarter of 2021[18].
- Rwanda: Tariffs of Rwanda Energy Group, effective from January 2020[19].
- South Africa: Example of Citypower (Johannesburg), approved tariffs for 2020-21.[20]

The comparison for the CI5 tariffs is set out below.

Figure 36: Tariff comparison – High Voltage industrial customers



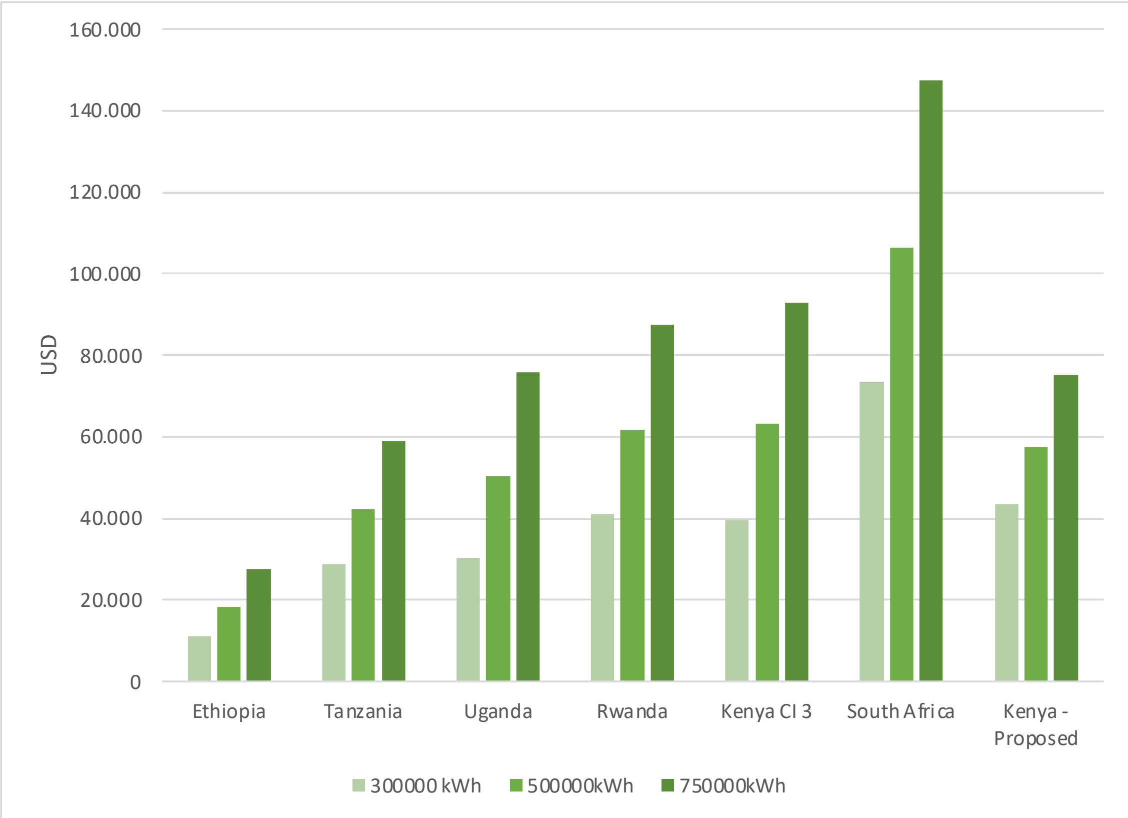
Source: Own analysis

The analysis shows that HV industrial tariffs are significantly lower than the South African comparator but generally higher than in the other countries. However, for high load factors (i.e., higher consumption for the same contracted capacity), the Kenyan tariffs compare more favourably to most of the comparators. An additional difference is that a significant reduction in the fuel charge is assumed in moving to the new tariffs.

[17] https://www.ewura.go.tz/wp-content/uploads/2021/04/TANESCO-Order-No.-2016-010-English.pdf
[18] https://www.era.go.ug/index.php/tariffs/tariff-schedules/630-schedule-of-end-user-tariffs-applicable-for-the-supply-of-electricity-by-umeme-limited-for-the-second-quarter-of-the-year-2021/download
[19] https://www.reg.rw/customer-service/tariffs/
[20] https://www.citypower.co.za/customers/Documents/City%20Power%20Approved%20Tariffs%20for%20FY%2020 21-22.pdf

The same ranking applies for CI3 customers, though the difference between current tariffs in Kenya and those in Rwanda is minimal, with less difference to those in Uganda as well.

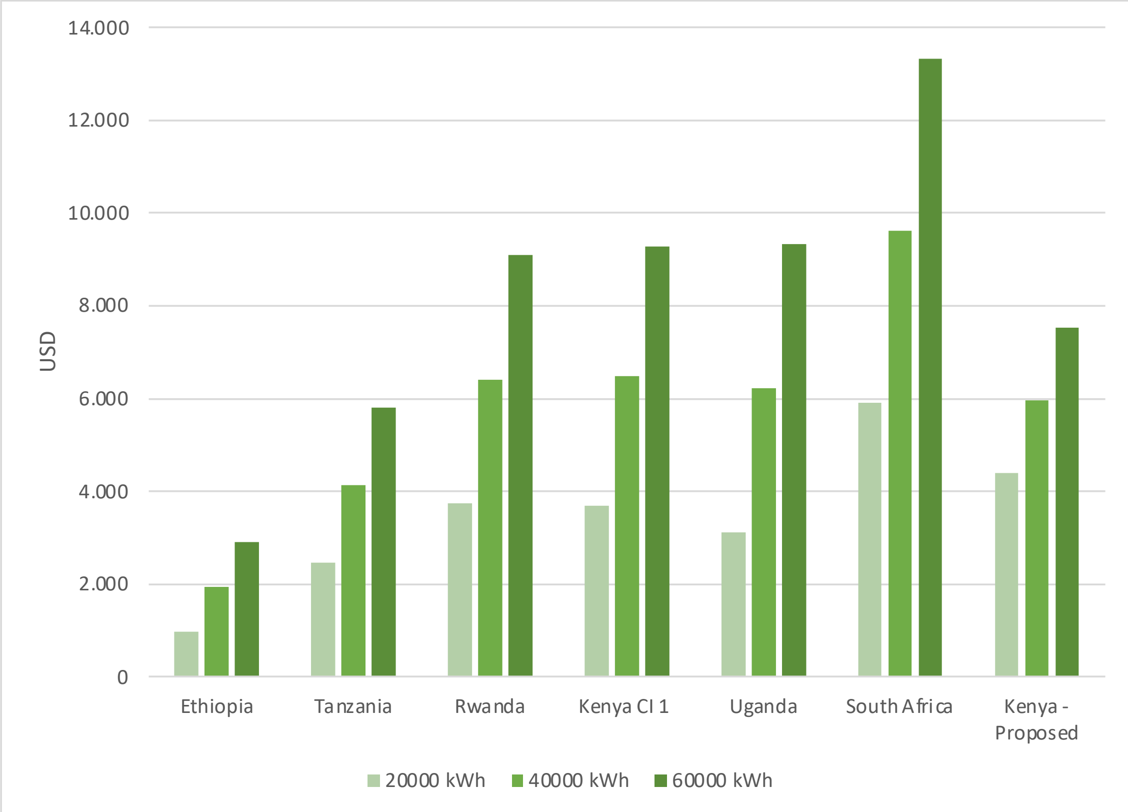
Figure 37: Tariff comparison – Medium Voltage industrial customers



Source: Own analysis

For CI1 customers, the existing tariffs in Kenya are much lower than those in South Africa, but generally identical to those in Rwanda and Uganda. For the proposed tariffs the comparison varies depending on the customer load factor. In the core case tariffs remain comparable to those in Rwanda and Uganda.

Figure 38: Tariff comparison – Low Voltage industrial customers



Source: Own analysis

6.8.4 Implications

The analysis in this section suggests that the current electricity tariffs calculated as part of the exercise to develop wheeling tariffs are generally higher than most comparators (except South Africa). However, it is unclear they will have a notable impact on competitiveness. In agricultural production, electricity is not highlighted as a critical issue. In industrial production, where the role of electricity appears more significant, available data suggests that electricity may represent little more than 4% of expenditure of intermediate consumption on average. However, surveys suggest the importance of electricity price and quality of supply is much more critical than the aggregate figures imply.

Should a company wish to change its location, or more likely, set up in a different country due to high input costs, the most likely destination would be a regional neighbour. Based solely on electricity tariffs, Ethiopia, Tanzania, Uganda, and Rwanda may provide some price advantages. However, the comparator values may not reflect the true cost of electricity in these countries: the cost of electricity in Ethiopia is low due to the use of hydroelectricity, which will need supplementing with more expensive sources of energy with EEP, the state owned generation and transmission entity, having a chronic financial situation; the tariffs for Tanzania shown are from 2016 suggesting a need for an important adjustment, while tariffs in Rwanda are understood to be below cost. However, in general, there is no strong basis to assume that changes in electricity tariffs, even those estimated as cost-reflective, would be sufficiently strongly to affect locational decisions and hence unduly affect industry performance and the competitiveness of the Kenyan economy.

6.9 Prepare financial projections

Financial projections for KETRACO and KPLC have been prepared based on the estimated revenue requirements. To the extent that they assume the recovery of full revenue needs from the starting year they may present an optimistic vision of the financial situation of both entities. However, even within this perspective, several features of underlying financial performance can be drawn out.

6.9.1 KETRACO

The revenue requirement methodology assumes that KETRACO is remunerated for its operating expenditure and financing costs, and in later years the costs associated with contracting capacity from ITPs.

The presence of a power market per-se should not unduly affect the modelling results. As noted above, the financial model allows for new capacity be constructed by ITPs. Some costs of System Operator (SO) functions are incorporated in these projections. In section 4 options are considered where the SO and Market Operation (MO) services are performed by an external body or by KETRACO. However, as the costs of adding these costs (or removing existing SO costs) are largely administrative in nature, no major difference in costs is envisaged. All other components of KETRACO's transmission business are assumed unchanged with no sale/purchase of energy.

In developing its income statement over a 5-year period the following assumptions are made:

- Estimates of its revenue requirement, administrative expenses, maintenance costs, interest costs and payments to ITPs are included directly into the statement.
- KETRACO receives two forms of grants: A small one that enters its income statement as revenue, and another reflecting the financing of capital projects. For modelling purposes, it is assumed that in the forecast period the amortization on the grants that are provided to finance capital expenditure are broadly equivalent to KETRACO's depreciation and amortization and credit loss (none of which are revenue requirement items).
- KETRACO has limited other income, with a small increase in its interest income.
- KETRACO is liable for corporate tax at 30%, though the financial loss reported in 2019-20 can be carried forward for tax purposes.

A summary income statement is set out below, with the latest reported value (2019-20) included for comparison basis.

Table 23: Simplified Income statement, KETRACO 2019-20 to 2025-26 (KSh'000)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Tariff Revenue	2,748,725	3,072,649	4,950,877	7,734,656	12,984,492	15,851,693	16,056,512
Recurrent grants	270,000	297,000	326,700	359,370	395,307	434,838	478,321
Capital grants	2,253,745	2,582,221	4,018,667	5,387,189	6,855,160	8,047,623	8,973,172
Other income	39	31,006	35,276	36,174	29,603	26,420	31,696
Total revenue	**5,252,509**	**5,982,877**	**9,331,520**	**13,517,389**	**20,264,563**	**24,360,573**	**25,539,701**
Operating expenses							
Administration costs	-1,094,074	-1,137,837	-1,183,350	-1,230,684	-1,279,912	-1,331,108	-1,384,353
Distribution costs (Maintenance)	-922,870	-1,548,715	-3,394,299	-4,891,076	-5,952,874	-7,305,700	-7,468,512
Credit loss expense	-1,476,012	-	-	-	-	-	-
Depreciation	-2,382,280	-2,400,591	-3,000,145	-4,823,712	-6,338,199	-7,410,722	-8,762,385
Amortization of intangible assets	-128,991	-128,991	-128,991	-128,991	-128,991	-128,991	-128,991
Payments to ITPs				-1,252,109	-5,402,945	-6,877,749	-6,877,749
Total operating expenses	**-6,004,227**	**-5,216,134**	**-7,706,786**	**-12,326,572**	**-19,102,922**	**-23,054,270**	**-24,621,991**
OPERATING PROFIT	**-751,718**	**766,743**	**1,624,735**	**1,190,817**	**1,161,641**	**1,306,303**	**917,710**
Finance income	207,025	215,306	223,918	232,875	242,190	251,878	261,953
Finance costs	-88,252	-111,134	-107,429	-103,848	-100,387	-97,040	-93,806
PRE-TAX PROFIT	**-632,945**	**870,916**	**1,741,223**	**1,319,844**	**1,303,444**	**1,461,140**	**1,085,857**
Tax loss BF		-571,442	-	-	-	-	-
Taxation charge	61,503	89,842	522,367	395,953	391,033	438,342	325,757
PROFIT FOR THE YEAR	**-571,442**	**781,074**	**1,218,856**	**923,891**	**912,411**	**1,022,798**	**760,100**

Source: Own analysis

The balance sheet has been developed with the following assumptions built in:

- All non-current assets that are not plant, property and equipment are rolled forward at 2019-20 values.
- Trade and other receivables increase annually by 10%.
- Trade and other payables increase annually by 10%.
- Amounts due to related parties remain constant.
- Capital expenditure related grants increase annually based on the amount of work-in-progress, with annual amortization rising from 1.5% to 2.6% by 2025-26.
- Provisions reduce over time. According to KETRACO's financial statements, most of these costs are associated with cost overruns and project delays. As the modelling assumes an important reduction in capital work in progress, it is expected that provisions related to project delay will reduce accordingly.

Table 24: Simplified Balance Sheet, KETRACO 2019-20 to 2025-26 (KSh million)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Non-current assets							
Plant, property, equipment	181,970	245,441	293,612	337,081	361,055	356,901	348,139
Others	997	997	997	997	997	997	997
Total non-current assets	**182,967**	**246,437**	**294,609**	**338,077**	**362,052**	**357,898**	**349,135**
Current assets							
Trade and other receivables	2,177	2,395	2,635	2,898	3,188	3,507	3,857
Amounts due related parties	6,785	6,612	6,612	6,612	6,612	6,612	6,612
Cash and bank balances	3,344	8,468	8,800	9,544	10,555	11,776	13,373

Total current assets	**12,306**	**17,476**	**18,047**	**19,054**	**20,355**	**21,895**	**23,843**
TOTAL ASSETS	**195,273**	**263,913**	**312,656**	**357,132**	**382,407**	**379,792**	**372,978**
Equity							
Total equity	**2,038**	**1,835**	**3,182**	**4,235**	**5,277**	**6,428**	**7,318**
Non-current liabilities							
Deferred grant incomes	170,013	233,930	279,646	321,183	343,172	337,189	327,290
Borrowings	2,995	7,974	7,708	7,451	7,203	6,963	6,731
Others	1,013	1,013	1,013	1,013	1,013	1,013	1,013
Total non-current liabilities	**174,021**	**242,917**	**288,367**	**329,647**	**351,389**	**345,165**	**335,034**
Current liabilities							
Deferred grant income	2,234	2,582	4,019	5,387	6,855	8,048	8,973
Trade and other payables	11,155	12,271	13,498	14,848	16,333	17,966	19,763
Provisions	4,494	3,595	2,876	2,301	1,841	1,473	1,178
Others	1,331	713	713	713	713	713	713
Total current liabilities	19,214	19,162	21,106	23,249	25,742	28,199	30,627
TOTAL LIABILITIES	**193,235**	**262,078**	**309,473**	**352,896**	**377,130**	**373,364**	**365,661**
TOTAL LIABILITIES AND EQUITY	**195,273**	**263,913**	**312,656**	**357,132**	**382,407**	**379,792**	**372,978**

Source: Own analysis

Notable features in the balance sheet include:

- A notable increase in fixed assets arising from the assumption that the capital program will be implemented in full.
- Corresponding increase in grant income reflecting the financing of these assets.
- An increase in cash balances in 2020-21, largely reflected by an assumed increase in borrowing.

The key calculated line items of the cashflow statement are set out below.

Table 25: Simplified Cashflow, KETRACO 2019-20 to 2025-26 (KSh million)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Cashflow – operating activities	-5,797	727	598	1.001	1.259	1.461	1.830
Cashflow – investing activities	-12,428	-25,034	-73,823	-59,871	-42,472	-54,113	-6,513
Cashflow – financing items	19,193	29,431	73,558	59,614	42,224	53,873	6,280
Change in cash balances	**968**	5,125	332	744	1,011	1,221	1,598
Opening value	2,375	3,344	8,468	8,800	9,544	10,555	11,776
Closing value	3,344	8,468	8,800	9,544	10,555	11,776	13,373

Source: Own analysis

Over the forecast period a positive cashflow is forecast, with a large increase in 2020-21 reflecting the inclusion of increased debt financing.

Corresponding financial ratios are set out below.

Table 26: Estimated financial ratios, KETRACO 2019-20 to 2025-26

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Current ratio	0.64	0.91	0.86	0.82	0.79	0.78	0.78
Cash ratio	0.17	0.44	0.42	0.41	0.41	0.42	0.44
Receivables (days revenue)	289.13	284.52	194.24	136.76	89.61	80.74	87.69
Payables (days of revenue)	1,481.32	1,457.67	995.14	700.67	459.12	413.68	449.25
Operating ratio	-23%	28%	35%	17%	10%	9%	7%
Net profit margin	-21%	25%	25%	12%	7%	6%	5%
Post tax return on equity	-28%	43%	38%	22%	17%	16%	10%
Pre-tax return on asset	0%	0%	1%	0%	0%	0%	0%

Debt to assets ratio	0.02	0.03	0.02	0.02	0.02	0.02	0.02
Debt service coverage ratio	(44.24)	1.88	1.60	2.77	3.61	4.33	5.61
Self-financing ratio	(0.47)	0.03	0.01	0.02	0.03	0.03	0.28

Source: Own analysis

The ratios are generally favourable, reflecting the assumption that KETRACO can recover a revenue that allows it to meet its costs. This said, the cash-related nature of the regulatory arrangements means that the return on assets is forecast around zero. The assumptions suppose a favourable trajectory for payables and receivables. Debt-related ratios are well above typical benchmarks reflecting the limited debt in the company.

6.9.2 KPLC

The revenue requirement methodology assumes that KPLC is remunerated for its activities based on a building blocks approach allowing for a return on capital, depreciation, operating expenditure, and taxation.

In principle, KPLC's financial projections will vary depending on the timetable for market development. To help inform this decision, and especially given its current weak financial situation, it is important to understand how KPLCs financial situation may evolve under current regulatory arrangements before taking a decision on a power market. In section 4 options for a power market are considered. However, as a key principle of these is to best ensure a neutral impact on KPLC's financial situation, including equal recovery of network costs, then no major difference in financial projections is perceived, with any reduction in retail revenues offset by equal reductions in generation purchase costs.

In developing KPLC's income statement over a 5-year period the following assumptions are made:

- Its core revenue is assumed to be the sector revenue requirement, excluding fuel payment and less revenue related to rural electrification customers, plus the fuel charge and foreign exchange receipts from customers.
- Its power purchase costs are payments to KenGen and IPPs, plus fuel costs and foreign exchange costs.
- Its operating expenditure is as per the revenue requirement, with costs of KETRACO (recovered in the core revenue) netted off
- Extrapolation of credit losses reported in 2019-20.
- Depreciation as calculated in the revenue requirement.
- No "other operating income", which has been significant in previous years.
- Inclusion of foreign exchange losses in the financing costs as per previous practice.

A summary income statement is set out below, with the latest reported value (2019-20) included for comparison basis.

Table 27: Simplified Income statement, KPLC 2019-20 to 2025-26 (KSh million)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Electricity sales	116,172	165,917	182,026	197,983	209,072	221,431	232,980
FX adjustment	924	-	-	-	-	-	-
Fuel sales	16,162	304	492	253	98	113	413
Operating revenue	**133,259**	**166,221**	**182,518**	**198,236**	**209,170**	**221,543**	**233,392**
Power purchase costs							
Non-fuel costs	74,445	91,279	98,875	105,225	109,291	112,888	118,440
FX costs	1,994	-	-	-	-	-	-
Fuel costs	11,061	272	416	212	80	96	345
Total power purchase cost	**87,499**	**91,551**	**99,292**	**105,437**	**109,371**	**112,984**	**118,786**
Gross profit	**45,759**	**74,670**	**83,226**	**92,799**	**99,799**	**108,559**	**114,607**
Operating expenses	-	-	-	-	-	-	-
Distribution/network management	3,784	4,341	5,119	6,244	6,921	7,599	8,277
Transmission inc. KETRACO	2,090	5,162	7,133	10,048	15,429	18,427	18,764
Commercial services	2,406	2,454	2,503	2,553	2,604	2,656	2,709
Administration	19,951	20,949	21,996	23,096	24,251	25,463	26,737
Expected credit losses	3,268	3,268	3,268	3,268	3,268	3,268	3,268
Total operating expense	**31,499**	**36,173**	**40,019**	**45,208**	**52,473**	**57,414**	**59,754**
Depreciation/amortization	16,336	15,227	17,090	18,376	16,393	18,525	20,401
Other operating income	7,387	-	-	-	-	-	-
Operating profit	**5,312**	**23,269**	**26,117**	**29,216**	**30,933**	**32,621**	**34,452**
Finance costs	-12,354	-10,071	-10,738	-11,641	-12,319	-12,562	-12,602
Profit before tax	**-7,042**	**13,199**	**15,379**	**17,575**	**18,614**	**20,059**	**21,850**
Taxation	6,103	-3,960	-4,614	-5,272	-5,584	-6,018	-6,555
NET PROFIT	**-939**	**9,239**	**10,765**	**12,302**	**13,030**	**14,041**	**15,295**

Source: Own analysis

A notable increase in operating profit is shown reflecting the full recovery of the revenue requirement. A change in revenue breakdown is evident based on the economic dispatch modelling that results in limited dispatch of fuel-fired plants.

The balance sheet has been developed with the following assumptions built in:

- All non-current assets that are not plant, property and equipment are rolled forward at 2019-20 values.
- Increase in inventories of 2.5% per annum
- Trade and other receivables increase annually by 5%.
- Trade and other payables increase annually by 5%.
- Deferred tax income, deferred income and bank overdraft remain constant
- Deferred income and leave provisions are maintained constant.
- New capital expenditure is 60% debt-financed over an average 8-year period, with expiring commercial loans rolled over under the same financing terms.
- All borrowings are treated as non-current for simplicity.

Table 28: Simplified Balance Sheet, KPLC 2019-20 to 2025-26 (KSh million)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Non-current assets							
Plant, property, equipment	276,860	297,186	327,091	342,952	360,795	376,507	356,106
Others	5,781	5,781	5,781	5,781	5,781	5,781	5,781
Total non-current assets	**282,640**	**300,761**	**330,666**	**346,527**	**364,370**	**380,082**	**359,681**
Current assets							
Inventories	4,831	4,952	5,076	5,203	5,333	5,466	5,603

Trade and other receivables	33,815	35,506	37,281	39,145	41,102	43,157	45,315
Other current assets	7,865	12,029	17,536	19,447	23,681	30,147	39,803
Total current assets	**42,627**	**52,487**	**59,893**	**63,795**	**70,116**	**78,771**	**90,721**
TOTAL ASSETS	**325,267**	**353,248**	**390,559**	**410,322**	**434,486**	**458,853**	**450,402**
Equity							
Share capital and premium	26,900	26,900	26,900	26,900	26,900	26,900	26,900
Retained earnings	27,997	56,801	74,318	68,937	76,799	85,416	60,781
Total equity	**54,897**	**83,701**	**101,217**	**95,837**	**103,699**	**112,316**	**87,681**
Non-current liabilities							
Trade and other payables	23,488	24,662	25,895	27,190	28,549	29,977	31,476
Borrowings	94,957	104,769	118,684	137,654	147,475	156,418	165,455
Other non-current liabilities	34,450	33,534	33,534	33,534	33,534	33,534	33,534
Total non-current liabilities	**152,895**	**162,965**	**178,114**	**198,379**	**209,558**	**219,929**	**230,465**
Current liabilities							
Trade and other payables	88,503	92,928	97,574	102,453	107,576	112,954	118,602
Other current liabilities	28,973	13,654	13,654	13,654	13,654	13,654	13,654
Total current liabilities	**117,476**	**106,582**	**111,228**	**116,107**	**121,229**	**126,608**	**132,256**
Total liabilities	**270,371**	**269,547**	**289,342**	**314,485**	**330,788**	**346,537**	**362,721**
TOTAL EQUITY AND LIABILITIES	**325,267**	**353,248**	**390,559**	**410,322**	**434,486**	**458,853**	**450,402**

Source: Own analysis

Notable features in the balance sheet include:

- Important increases in non-current assets up to 2024-25 reflecting the proposed expenditure profile.
- Increases in retained earnings, reflecting the higher net profit than has been achieved by KPLC.
- Increases in borrowings, reflecting the assumption of 60% debt finance of new capital expenditure and rollover of existing commercial loans.

The key calculated line items of the cashflow statement are set out below.

Table 29: Simplified Cashflow, KPLC 2019-20 to 2025-26 (KSh million)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Cash generated - operations	31,497	37,859	42,541	46,895	46,598	50,385	54,057
Finance costs	-7,757	-10,194	-10,861	-11,764	-12,442	-12,685	-12,725
Others (inc. income tax)	-179	-3,836	-4,491	-5,149	-5,461	-5,894	-6,432
Cashflow – operating activities	**23,561**	**23,829**	**27,189**	**29,982**	**28,695**	**31,805**	**34,900**
Purchase of property and equipment	-16,195	-25,526	-35,553	-46,996	-34,237	-34,237	-34,237
Other investments	-45	-45	-45	-45	-45	-45	-45
Cashflow – investing activities	**-16,241**	**-25,571**	**-35,598**	**-47,041**	**-34,282**	**-34,282**	**-34,282**
Proceeds of borrowing	14,632	30,998	31,729	38,595	27,903	27,903	25,555
Repayment of borrowing	-12,400	-21,187	-17,814	-19,625	-18,083	-18,960	-16,518
Other	-255	-	-	-	-	-	-
Cashflow – financing items	**1,977**	**9,812**	**13,915**	**18,970**	**9,820**	**8,943**	**9,037**
Change in cash balances	**9,298**	**8,070**	**5,506**	**1,911**	**4,234**	**6,466**	**9,656**
Opening value	-5,338	3,960	12,029	17,536	19,447	23,681	30,147
Closing value	3,960	12,029	17,536	19,447	23,681	30,147	39,803

Source: Own analysis

Over the forecast period a positive cashflow is forecast, though this is premised on recovery of a tariff that allows the estimated cost of service, including a return on equity of 12%. Corresponding financial ratios are set out below.

Table 30: Estimated financial ratios, KPLC 2019-20 to 2025-26

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Current ratio	0.36	0.49	0.54	0.55	0.58	0.62	0.69
Cash ratio	0.03	0.11	0.16	0.17	0.20	0.24	0.30
Receivables (days revenue)	92.62	77.97	74.55	72.08	71.72	71.10	70.87
Payables (days of revenue)	242.41	204.06	195.13	188.64	187.72	186.10	185.48
Gross margin	34%	45%	46%	47%	48%	49%	49%
Operating ratio	-5%	8%	8%	9%	9%	9%	9%
Net profit margin	-1%	6%	6%	6%	6%	6%	7%
Post tax return on equity	-2%	11%	11%	13%	13%	13%	17%
Pre-tax return on asset	-2%	4%	4%	4%	4%	4%	5%
Debt to assets ratio	0.34	0.30	0.30	0.34	0.34	0.34	0.37
Debt service coverage ratio	1.17	0.76	0.95	0.96	0.94	1.01	1.19
Self-financing ratio	1.45	0.93	0.76	0.64	0.84	0.93	1.02

Source: Own analysis

The profitability ratios are generally favourable, reflecting the assumption that KPLC can recover a revenue that allows it to meet its costs, including a return on capital. A gradual improvement in receivables and payables is also built into the calculations. However, the figures show:

- Current ratio and cash ratio well below 1, indicating in the first instance that current liabilities are much greater than current assets, and in the second instance that KPLC has limited cash on hand to pay off short term debts. The ratio potentially overstates the ratio based on the current assumptions as all debt is considered long term in nature in the balance sheet.
- Debt service ratios remain below accepted benchmarks, with the debt service coverage ratio projects to be less than 1.0 for the period up to 2024-25 and not rising above 1.2 in the whole period.

The above two factors indicate a structural weakness that cannot be simply resolved by higher tariff income, which supports that greater investigation into KPLC's financial situation is undertaken prior to initiating market reform.

6.10 Assess and propose appropriate tariff structure for rural-based community power generation and distribution systems

In Kenya, there are two broad models for new mini grids:

- Public ones, which are developed by Rural Electrification and Renewable Energy Corporation (REREC), and which are operated by KPLC.
- Private ones, which are developed by the private sector sometimes in conjunction with local communities.

The government has planned 158 mini-grids under the Kenya Off-Grid Solar Access Project (KOSAP) to be built and operated by REREC or KPLC. In addition, the private sector is planning over 130 mini-grids, currently at various stages of development. Therefore, over 280 mini-grids are planned to be constructed and commissioned before 2022 to achieve electrification targets.[21] Due to the increasing importance of mini-grids, and the role of the counties in approving these, it is important they are captured in least cost planning even if planning process are primarily focused on grid-supplied energy.

To support the development of the mini-grids, EPRA issued its Draft Energy (Mini-Grid) Regulations, 2021.

A key feature of the development of mini grids is that due to their location in remote areas, the cost of development (as measured by the Levelized Cost of Electricity) is generally much higher than where it is possible to supply new areas through incremental grid extension. This creates important tariff implications in that to be sustainable a mini grid generally requires a tariff above the cost of service of grid supplied energy. Where KPLC is the operator (public mini grid) the KPLC national uniform tariff is applied, allowing any additional costs over and above those of grid supply to be socialized across the customer base. In the case of private developers, a cost-reflective tariff is generally set – which is foreseen in the Draft Regulations - with price impacts mitigated to some extent by the availability of grants for various international organizations.

However, for any private developer there are several risks inherent in developing a mini grid:

- Mini grids have a high component of up-front costs, which increase the potential impact of cost and/or stranding risk.
- Their remote nature, and the customer base – often including a high number of lifeline customers – creates affordability issues and difficulties in introducing innovative payment options, both which affect revenue recovery.
- Maintenance may be generally more difficult, imposing costs and potential jeopardizing service quality.
- There is an important stranding risk created by the potential for grid extension (grid encroachment), allowing for KPLC (or another supplier) to offer a lower price to that paid by customers of the mini grid.

These risks are evident in most plausible technologies and hence there seems no reason to treat mini hydro any differently to say solar PV. In all cases, the above factors create important risks to developers. Allowing for sites for new mini grids to be tendered based on a required subsidy is one way to help mitigate this risk. A developer may wish to have a greater proportion of fixed charges, though this may conflict with affordability concerns.

Section 24 of the Draft Regulations includes provisions to reflect the potential of interconnection with the main grid:

[21] Energy and Petroleum Regulatory Authority, The Draft Energy (Mini-Grid) Regulations, 2021 (Pursuant to Sections 10, 11 and 208 of the Energy Act, 2019). Regulatory Impact Statement, p.3.

- Allowing the mini-grid operator to sell its assets to the Distribution Licensee (KPLC) negotiating compensation payable by REREC based on the remaining depreciated value of the assets, outstanding customer payments (24(8)). EPRA is nominated as an arbiter if agreement is not reached (24(9)).
- Allowing the mini-grid operator to become a power producer selling to the distribution licensee (KPLC), a power purchaser buying in bulk from the distribution licensee for all or part of its energy (24(1))(a) to (c).
- Any other model approved of by the Regulator (24(1)(d).

In the case that a developer wishes to sell its assets to KPLC, then through the above provisions it should recover its outstanding costs, previous mini-grid customers will potentially receive a lower tariff (that of grid supply), and with any compensation payable by REREC, KPLC will not be paying any upfront capital costs for the new connections. In this circumstance, the stranding risk is largely internalized.[22]

However, the regulations are less clear in cases where a mini-grid owner does not wish to sell its assets to KPLC. The option of *remaining* as a mini-grid (i.e., remain with the status quo or a variant (as allowed in 24(1)) does not seem to be provided for unless KPLC agrees, suggesting that the mini-grid (and its customers) have limited choice over its business model.[23] Also, the licensed area of supply does *not* seem to be exclusive, increasing the risk of losing the business to KPLC. While it may generally be in the customers interest to be supplied through the main distribution grid, situations where quality of supply is higher and/or price is lower in an off-grid setting – or a purchase/sale agreement between the mini-grid and KPLC is beneficial to the mini-grid customers - could plausibly arise.

There is also limited detail in the Draft Regulations as to what is taken into consideration for determining compensation. Moreover, should KPLC simply extend its grid and seek to capture the mini-grid customers (considered possible due to the non-exclusivity of the license), or starts developing an area immediately adjacent to the mini-grid, there does not seem to be a remedy *forcing them* to come to an agreement with the developer. Requiring negotiation is incorporated in the regulatory regimes in other countries, as for example, is the case with the Zambian Grid Encroachment regulation, which has been approved by the Energy Regulation Board, and could be option for consideration in this case.

[22] In practice, for the developer stranding risk may not be fully recovered as the compensation model does not take into account all the business risks associated with the development of the mini grid in the first place and the value of the customer base built up over time.
[23] Mini-grids often offer have tailor made packages/solutions that consumers prefer where they don't have such choices with grid supply, while mini-grids often have better quality of supply than customers sitting at the tail end of a distribution line in a remote rural area.

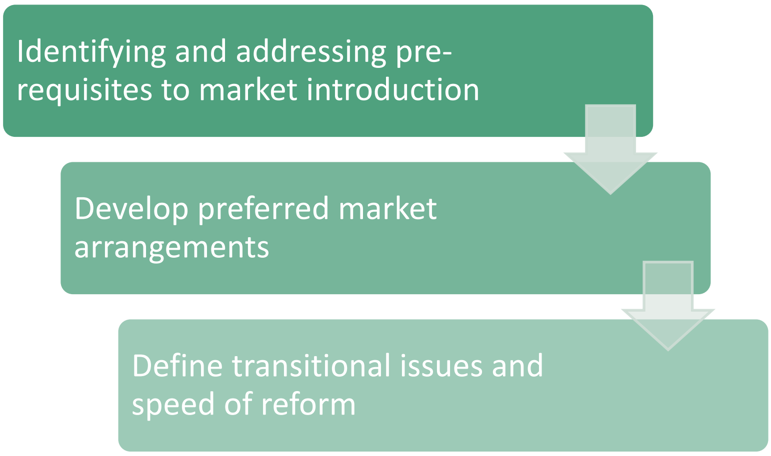
7 Market Design and Action Plan

7.1 Introduction

A three-step process is proposed for developing market design arrangements, involving:

- Identifying and addressing key legal, regulatory, tariff and other pre-requisites that must be addressed prior to allowing extension of competitive arrangements.
- Developing the preferred market design arrangements, including phases in a multi-phase arrangement. This step also incorporates identifying the documents and supporting arrangements that need to be put in place, institutions that need to be created, potential winners and losers and means to address any imbalances between participants.
- Defining transitional issues and the pace of reform.

Figure 39: Key steps in developing market design arrangements



In practice, as competition is already developing in the Kenyan electricity sector and having important impacts, an important question is the best way to permit competition to evolve over the reform timeframe regardless of whether or when a formal electricity market is introduced.

7.2 Pre-requisites to market introduction

The previous sections have highlighted several pre-requisites to the introduction of a market.

7.2.1 Tariff reform

The following key tariff reform needs have been identified in previous sections:

- A need for KPLC, operating efficiently, to fully recover its efficient revenue requirement, including the costs of its own distribution and transmission network, those of KETRACO and generation purchases.
- Continued transition towards cost reflective tariffs, in which cross-subsidies are minimised to those necessary to support social policy (e.g., increasing block tariff for domestic customers) and do not artificially impact on customer decisions to take out alternative energy sources.
- Wider implantation of two-part tariffs, including for all commercial customers over time and for high usage domestic customers who subsequently take up supply from solar PV at its premises or through wheeling arrangements.
- Development of a net metering policy that is compatible with above steps by ensuring:
    - Customers with solar PV facilities and other DER resources pay for the cost of network services provided by KPLC.
    - Energy supplied to the grid is remunerated in relation to the value that energy provides to the grid.
    - Over time, time-of-use pricing is incorporated to reflect the difference in value/cost of energy supplied to grid at off-peak periods and consumption from the grid at peak hours and provide incentives for customers with PV facilities to install storage solutions and provide flexibility to the network.

7.2.2 Sustainability of KPLC’s financial and operational performance

Stabilisation in KPLC’s financial performance is critical for developing market arrangements to ensure that it can: meet power purchase obligations, operate in a sustainable manner where service quality is prioritised, and provide confidence to market participants over the credibility of the market. Key aspects of this situation include:

- Development of cost reflective tariffs (see previous section).
- Enhancement of all aspects of KPLC’s financial performance more generally. While the share of debt in its financing is moderate, its borrowing costs including costs from foreign exchange exposure have increased disproportionally over time, while at the same time its debt service coverage ratio has been declining gradually over the past 5 years. A review of financial performance with a time-limited action plan is proposed to ensure it moves to sustainable financial operations.
- Develop clear targets for enhancing operational performance to ensure the recent increase in reported losses is reversed, and improvements in service quality can be made on a systematic basis.
- Ensuring clarity in institutional roles and ensuring KPLC is not covering costs of last mile connection and other activities that are outside its core roles.

- Enhancement of KPLC's governance processes.

In relation to governance, KPLC has undertaken steps to address its inherent problems. The Presidential Taskforce on PPAs reports that "the Board of Directors has initiated a business turnaround and transformation strategy to expeditiously improve the financial and operational aspects of the business, while balancing social responsibilities to enhance business sustainability". Evidence that benefits are being achieved and are sustainable is essential. Moreover, implementing the following Taskforce recommendations are supported, with additional strengthening for the private shareholder role in the Boards operations:[24]

a. The National Treasury to enhance its shareholder responsibility in KPLC, and: (i) set clear expectations on return on equity, (ii) pursue its social and public good mandate in line with sector policy.
b. That the Board of Directors takes responsibility to secure the competitive recruitment and hiring of a Chief Executive Officer of the company, or a management company, and sets the requisite performance targets to guide their function.
c. KPLC's Board of Directors to provide strategic leadership and oversight to the Company including driving a performance culture and holding management to account for results.

The Presidential Taskforce on PPAs also make several recommendations regarding KPLC's financial performance more generally, which include that: a) KPLC budgets be always premised on the current financial position of the Company. b) Government of Kenya moratorium for on lent loans to KPLC be extended by a further 2 years. c) KPLC to renegotiate and restructure commercial debts, and where possible convert debt to equity. d) KPLC to review RES agreements on the compensation, operations, and maintenance and the GoK last mile subsidy costing for CAPEX. e) KPLC to enhance revenue collection. f) National Treasury to provide resources to reimburse KPLC under the rural electrification scheme. g) EPRA to formulate and publish a realistic benchmark on return on equity and cost of funds.[25]

7.2.3 Enhancements to Least Cost Planning

In a fully functioning market, the role of least cost planning is indicative in nature, with a key aim being to provide signals to investors to guide investment decisions. This approach contrasts with the current arrangements, where planning aims is to provide the overarching framework from which projects are chosen to be developed, whether by an incumbent supplier or IPPs. Given the status of market arrangement in Kenya, enhancement of planning arrangements is required in the transitional period until a steady stream of projects are developed by private (merchant) means. In any case,

[24] Republic of Kenya, Report of the Presidential Taskforce on the Review of Power Purchase Agreements (PPAs), Chairperson Mr John Ngumi, 29 September 2021, p.150.
[25] Ibid, pp.150-151.

transmission planning will be an ongoing requirement. Enhancements that need to be introduced include:

- Update of planning software to ensure full functionality of the simulation models with the evolving nature of energy markets, especially the integration of renewables and potential role for storage.
- Undertake a detailed review of the approach to estimating electricity demand to ensure the core forecast reflects the best estimate of how demand will evolve independent of aspirational goals and policy targets that may not be feasible to introduce.
- Ensuring strong complementarity between generation and transmission planning – which can include undertaking the two exercises simultaneously, and
- Ensuring that the text in the KNTGC is harmonised to ensure that the planning provisions in the KNTGC are fully consistent with those employed in the LCPDP.

The Presidential Taskforce on PPAs recommended that KPLC take the lead in the formulation of the LCPDP. In section 4 we support the current approach in which the planning is developed by an industry committee working under the Ministry of Energy. As KPLC is directly involved in the purchase of energy, and given planning impacts on several sector entities, a broader group (while still involving KPLC) is preferred.

7.2.4 Framework for renewables fully implemented

The review of the policy and regulatory framework has shown that several important steps for the development of renewables have been implemented, including:

- Removing the feed-in-tariff regime for solar and wind projects and requiring all procurement that will be subject to a PPA to be subject to a tender/auction process.
- Reduce the scope for application of a feed-in-tariff regime to biomass, biogas, and small hydro projects below 20MW.

A critical ongoing gap is the development of a net metering policy to provide legislative and regulatory validity to current measures being developed and ensure that competition that it currently developing is efficient and doesn't unduly impact on KPLC. We have been advised that a draft policy has being prepared, though at the time of writing this has not been received. Key features that we recommend are incorporated in the policy include:

- The need for any customer subject to a net-metering arrangement to be subject to 2-part tariffs to ensure that it pays the full costs it imposes on KPLC as network operator for maintaining network connection.
- The payment made, or credit provided, for any energy injected into the grid should be based on the value of that energy to KPLC as single buyer. Energy injected by customer PV facilities generally occurs during daytime off-peak hours, while energy is consumed from the grid at peak hours unless storage solutions are also incorporated.

- In the first instance, a value for injection should be set that is significantly below the average generation cost. Over time, the tariff arrangements for customers on net metering arrangements should transition towards time-of-use charging to a) link any remuneration to the reflect the value of energy provided to the system, and b) provide incentives for flexibility solutions to develop like battery storage allowing either consumption at peak hours from energy produced during the day or injection to the grid at peak hours.

7.3 Proposed Market Design

7.3.1 PPA Constraints

The earlier legal review touched on the possibility that legacy PPAs could be affected by market design where new market rules impact on the existing rights and obligations of the parties to such agreements. The general rule of departure should be that such impacts should be minimised or avoided if possible.

Although access to legacy PPAs have not been granted and hence no definitive observations can be made, a new market could potentially trigger change of law or breach provisions where new market rules negatively impact the rights and obligations buyers or sellers. Hence it is important that market rules should as far as possible not affect such rights and obligations, especially the existing commercial rights and obligations between sellers and buyers.

This seems to be aligned to the underlying intention of section 138(9) of the Energy Act, 2019 that makes it clear that any SO should not be involved in the direct or indirect buying and selling of energy. In turn this implies that the commercial buying and selling obligations between legacy generators and KPLC as off-taker could or should remain as is under the PPAs, with essentially only the SO related aspects transferred or dealt with differently.

As such, the SO related aspects (less the commercial buying and selling aspects) should not be of major concern as PPAs typically do not deal with these directly (save perhaps from a force majeure or emergency perspective) and it hence should have a limited impact on the current commercial rights and expectations of either party to the PPA.

Any market rules on sales post the PPAs (i.e., how KPLC or a successor in title potentially deals with the on-sale of capacity and energy to customers) should not be the subject of the PPAs either and hence should not affect the ongoing commercial rights and obligations of the parties amongst themselves. Nevertheless, care should be taken that such further arrangements (or alternative arrangements, e.g., direct sales to contestable customers) do not impact the viability of the generators or off-taker *per se* and in such a manner impact the viability of the PPAs.

In the case of the standardised RES PPAs it was noted that these foresee the possibility of a changed electricity market and provide that KPLC must transfer its transmission, distribution and purchase rights and obligations to any successor in title.

This is helpful as it demonstrates that the parties to these PPAs acknowledge that such changes may occur, and tasks KPLC with ensuring that this happens. However, this does not mean that should such transfer of rights and obligations take place it would take away the right of the sellers to invoke change of law or breach provisions should their commercial rights be negatively impacted, and the same principles should hence be applied that market rules should not negatively impact the commercial rights or obligations of the contractual parties in the first place.

7.3.2 Assumptions for market design

This market design has been developed without access to the legacy PPAs, though some information is included in the Presidential Taskforce on PPAs. As the provisions of the PPAs may have important implications for forms of market design that can be introduced, certain assumptions have been made. As further information is made available, the proposed market design arrangements refined accordingly.

The main assumptions are:

- Existing PPAs can be characterized as capacity contracts, with the operational costs (fuel costs) remunerated on a pass-through basis.[26] This is a key assumption for the proposed market design. This means that the energy of these PPAs can be subject to economic dispatch, based on the fuel costs of the plants of the PPA holders. Contracts with this characteristic are subsequently referred to as "dispatchable contracts".
- Existing PPAs are sufficiently flexible that the introduction of a market does not trigger change of law or breach provisions, given that market operation may impact existing commercial rights and obligations, especially regarding dispatch and settlement.
- In the case of the standardized PPAs related to renewable energy sources (RES), there is payment for the deemed produced energy rather than on the delivered energy, but not a capacity payment.
- The standardized RES PPAs include clauses that foresee a transition to an energy market in that KPLC is tasked with ensuring that any new entity under a new dispensation tasked with transmission, distribution or purchase related activities is obliged to take over KPLC's transmission, distribution and purchase related obligations under the PPAs. This should facilitate the introduction of market rules to the extent that these rules impact the commercial rights of sellers under the RES PPAs.
- The PPAs have clauses that ensure a proper reliability of the provided capacity.

[26] This is mentioned in the Task 4.C report "Technical Assistance to the Kenya Energy and Petroleum Regulatory Authority (EPRA) to Develop an Open Access Market Framework and Rule", p. 27, October 2019 for USAID.

- For ancillary services, as there is not available information on the eventual obligations of the IPPs in relation with provision of these services, it is necessary to consider two possible alternatives in the market design, depending on how IPP's obligations are included in the PPAs:
  - The IPPs have obligation to provide frequency regulations reserves and to produce reactive power to support voltage in the buses where the plants are connected.
  - The IPPs do not have any obligation to provide ancillary services

  For future PPAs the first alternative is recommended.

It would be possible to cease procuring capacity and energy through new PPAs when the market becomes competitive enough that the privately commissioned investments are sufficient to meet the load with a reasonable security level.

The information that would be most useful to refine these assumptions can be broadly split by technical and legal aspects:

- From the technical side – information on the clauses related to the structure of payments (i.e., all type of payments that the IPP receives and the conditions to trigger the payments), mechanisms to dispatch the IPP's plants, IPP obligations on ancillary services provisions, and penalties that can be applied to the IPPs.
- From the legal side – the validity periods of the PPAs, exclusivity of supply/obligation to offtake (take or pay with one off-taker), change in law, any provisions relating to the possibility to cede/assign rights and obligations under the PPA, step in rights e.g., of financiers and the breach/consequences of breach provisions. Also, the linked agreements (if applicable) such as Implementation Agreements (e.g., if Government guaranteed the off-taker obligations) and fuel supply agreements (e.g., if there are agreements dependent on the PPA that could also be breached).

7.3.3 The System and Market Operator

The SMO will be the key entity to manage the operation of the Kenya's power system and the future Kenyan's Electricity Market (KEM). Two key issues that arise in its development is the nature of the organisation and the appropriate entity to run its operations.

a) Single or dual entities

A first key issue is whether it is most efficient to have a single entity that carries out both System Operation (SO) and Market Operation (MO), or whether it is sufficient to have separate SO and MO Functions.

Combining the two entities into an SMO is recommended for three key reasons:

- **Coordination** – the activities of the two entities will need to be coordinated, especially in phases of the KEM with a day-ahead market, which creates the need for synchronisation of several key activities over a period of a few hours, the potential for significant iterations to obtain a least cost schedule, which increases time and the risk of error. Some of the activities that require special coordination are the verification of the SO of the KEM clearing results, the information exchange on the accepted bids and offers, the metering information for the DAM settlement and the coordination with EAPP cross border exchanges.

- **Cost** – Separate entities will require more resources and cost to operate. Some positions will be duplicated (board, legal team, administration) as well as material resources like office equipment, software, communications, etc.
- **Single database** – which means less risk of incongruencies and errors. Moreover, market participants will have to access to a single source of information and data exchange.

In practice cost is not a crucial issue, as the benefits of an efficient SMO should outweigh those of separate SO and MO´s and at a lower cost.

b) Location of the SMO

The main alternative bodies to perform the functions of SMO involve either:

- The creation of a fully independent entity or independent SMO (ISMO),
- Use of one of the existing sectors participants as SMO.

KPLC is currently the SO. However, given it is currently the off taker to the existing PPAs, and given that also Article 138(9) of the Energy Act, 2019 states that the SO shall not be involved in the direct or indirect buying or selling of electrical energy, the only plausible entity from within the sector – that is, without creating a new entity – is KETRACO. In this case the SMO functions could be undertaken within a ring-fenced department within KETRACO (KSMO).

Each of the two alternatives – ISMO or KSMO – has advantages and disadvantages against key evaluation criteria.

- **Conflict of interest**: The SMO will provide instructions to the transmission companies, who are required to follow these instructions strictly, except in very exceptional circumstances. In case the transmission companies do not follow the instructions, the SMO should penalise them, or recommend penalties to the regulator. However, it is unlikely that if the SMO is integrated into the transmission company, this may occur. With an ISMO this potential conflict of interest is removed.
- **Information**: when a SMO is integrated in the transmission company, there is a single source of information on what is going on in the system and the market, which simplified information provision. With two different entities, the ISMO and the transmission company, the regulator, the market participants, and the Ministry of Energy will have two sources of information, which supports a much more transparent electricity market.

- **Priorities**: When the SMO is integrated in the transmission company, in some cases the staff of the SMO may be required to carry out activities not strictly related with the system and market operation, which may lead to neglect their key mission.
- **Independent Transmission Providers (ITPs)**: one measure that is currently proposed to be trialled, and which should be permitted in the proposed KEM is the introduction of ITPs, which will finance, build, and operate new transmission facilities. These new entities can perceive the incumbent transmission company as a competitor with several advantages. An ISMO can give them guarantees of a transparent a fair operation of their facilities. To some extent this can also apply to the new IPPs, who normally also prefer an independent institution on the transmission side.
- **SMO Governance**: An ISMO has an important advantage in that it can permit the inclusion of the market participants in its governance arrangements. This practice is common in several electricity markets, including some cases like some USA pools where the ISMO is fully managed by the market participants. This participation allows a more fluent operation of the market, as many potential conflicts are solved internally, and there is also possible a balanced governance power between electricity sellers and buyers.
- **Cost and resources**: an ISMO will require additional resources and staff, which is less acute for an existing institution. While KETRACO is currently not the designated SO, it is undertaking related activities, which will reduce the cost of designating it as a SMO: a) it already has a department responsible for O&M and Power Management (SO), which would only require strengthening through inter-organizational transfers; and b) it has already started construction of a modern Control Centre, which is an advantage in terms of preparedness to undertake the envisaged SMO functions.
- **Implementation time**: a KSMO should ordinarily be faster to implement, especially noting the above points. However, as it is not currently the SO, any benefits from taking advantage of exiting human and material resources may not be extensive.

Strict technical arguments support the development of an ISMO, especially if a decision is taken to initiate the process towards the development of market arrangements and introduction of ITPs. Where the recommend end point is an ISMO, then the most applicable intermediate point is to designate an independent SO to perform system operation functions in the period prior to market formation, after which the ISO would transition into an ISMO.

The findings of the Presidential Taskforce on PPAs are consistent with the above, as it recommended that KETRACO suspend work on ISO infrastructure until a decision on the location of the SO functions is made. Moreover, it recommended that in the interim period the SO function be performed by a team of experts from KPLC and KETRACO working under EPRA and MOE.

International experience of incorporating the SO and MO roles
International experience shows two typical models of organizing the entities that will perform the roles of SO and MO in a competitive market: 1. The Transmission System Operator (TSO) model, under which the TSO also performs the SO role. 2. The independent System and Market Operator (SMO) model. **The TSO model** is common within the European Union, where the power sector reform process led to the unbundling of the transmission services provider activity including the SO role that was previously embedded in the transmission company. With the development of the electricity markets the creation of a MO become necessary, and in most cases, it was done through creating an (relatively) independent entity. These are usually for-profit organization, and in several cases the TSO are shareholders of these entities. **The SMO model** is common in almost all the electricity markets in America, but with some differences between the model adopted in the United States (ISO or Regional Transmission Organisation – RTO), and the Latin America SMOs. An independent system operator (ISO) is an organization formed at the recommendation of the Federal Energy Regulatory Commission, which has jurisdiction on the interstate trade of energy. In the areas where an ISO is established, it coordinates, controls, and monitors the operation of the electrical power system, usually within a single US state, but sometimes encompassing multiple states. RTOs typically perform the same functions as ISOs but cover a larger geographic area. Their function generally also incorporates transmission expansion planning. ISOs/RTOs were formed to reduce government oversight, increase market competition, to advocate for economic efficiency and grid reliability, and to police all market participants to ensure their actions are unbiased and neutral. The ISO/RTOs are managed by the market participants and manages the electricity generation dispatch and the transmission operation in several states. In Latin America the creation of SMOs was a condition for the development of competitive electricity markets. In general, these SMOs are jointly governed by the market participants and the government, but with an independent professional staff. In some cases, the government representatives have veto power on some sensitive issues. In most of Latin America's electricity market there is an incumbent transmission company that owns the assets existing at the time of the reform and undertakes asset expansions, with the incumbent provider coexisting with independent transmission companies normally dedicated to build and operate some specific lines and substations. The incumbent transmission company and the independent transmission companies manage their assets following orders of the SMO.

7.3.4 Market Design Principles

To ensure the credibility of the market and its future development, a fundamental principal is to respect the existing PPAs, without threatening the solvency of energy sellers or the rights of energy buyers. However, due to the cost burden already considered, stranded cost will inevitably arise. These stranded costs are considered as the fixed (capacity) components to the selling parties of the PPAs as well as the take-or-pay obligations with PPAs for RES, based on the deemed produced energy.

A key proposed principle is that the full amount of stranded costs is allocated and passed through to the market participants, namely the buyers (consumers) of electricity in the KEM, which includes purchases for the non-competitive market and purchases under competitive arrangements. Potentially, the Government of Kenya (GOK) could decide to absorb part of the stranded costs; in this case, the amount of stranded costs to be allocated would reflect the difference between the total stranded costs and the part absorbed by the GOK.

The stranded costs of the existing PPAs are to be allocated to all consumers proportionally based on their consumption (energy or peak demand). These payments, named costs of transition to the market (CTM), will be included in the tariffs paid by end consumers. The capacity and energy (when applicable) provided by these PPAs will be also allocated to the consumers in the same proportion as the CTM payments. This is called the allocated capacity (AP) or allocated energy (AE). The obligations of the demand to pay for their maximum demand will be reduced in the AP, and the obligations to pay for the energy consumed will be reduced in the AE.

For the PPAs with capacity payments and dispatchable energy, only the capacity of the contract will be allocated to end consumers. In the case of PPAs for RES supply, the deemed produced energy will also be allocated to the end consumers. The AP and the AE will be deducted from the end consumer's actual power and energy demand.
In the case of RES, when deemed energy is different to the delivered energy, the cost will be transferred based on the payments to this volume of energy, but it will be considered that the energy effectively purchased is based on the delivered energy.

The report of the Presidential Taskforce on PPAs (September 2021) recommends renegotiating existing PPAs where practical. While any downward revision to PPA prices would support market development by reducing stranded costs, the extent to which this is possible may be limited, and even then, will incur costs to KPLC and/or the Kenyan Government due to the legally binding nature of these agreements. In the absence of significant capacity to renegotiate PPA prices, the main tools available to reduce purchase costs are contracting new capacity at economic prices, which will reduce the per-unit stranded cost, and the use of direct subsidies to the sector.

7.3.5 Eligible (free) Consumers

Eligible or Free Consumers (FCs) will be allowed to enter in direct contracts with generation companies (Gencos) to buy the part of their demand not covered by the AP and AE.

A consumer will be allowed to become a FC if:

- It is an end consumer, not a supplier.
- The consumer meets the thresholds for eligibility, which will be defined by the regulator and will be periodically reduced.
- It is connected to the national transmission system, or to a distribution system connected to the national transmission system

Considerations as to thresholds for allowing eligible customers are considered in greater detail in section 6.5, where an approach based on the customer category/voltage level is proposed.

As an alternative, to promote that end consumers become FC is that the FCs do not have the obligation to pay the CTM and consequently, not receive the AP and AE. In this case all the PPA costs are transferred to the regulated (non-FC) consumers.

In all cases, it is proposed that FC do not have to seek out market-based arrangements and can continue to be supplied by KPLC at least in the early stages of market development. KPLC will also need to act as the supplier of last resort in case a customer is left without supply (e.g., bankruptcy of a supplier). Adequate compensation in market-related fixed costs will also be required for any additional costs incurred by KPLC in providing this service.

7.3.6 Participants of the KEM

The proposed Market Participants (MPs) of the KEM will be:

- FCs.
- Suppliers to non-FC. Initially this will be the distribution company (KPLC in the current circumstances), though later in the reform program the supply activity should be unbundled from the distribution (network) activity.
- Generators (Gencos) and
- Traders (later in the reform program).

FCs will be free to enter direct contracts with Gencos, but this will be optional. If a person that qualifies as a FC does not opt for concluding a contract with a Genco, it will continue to pay a regulated tariff to its the respective Supplier (KPLC in the first instance).

Non-FC are not direct market participants and will be charged based on regulated tariffs that will include the allocation of the CTM.

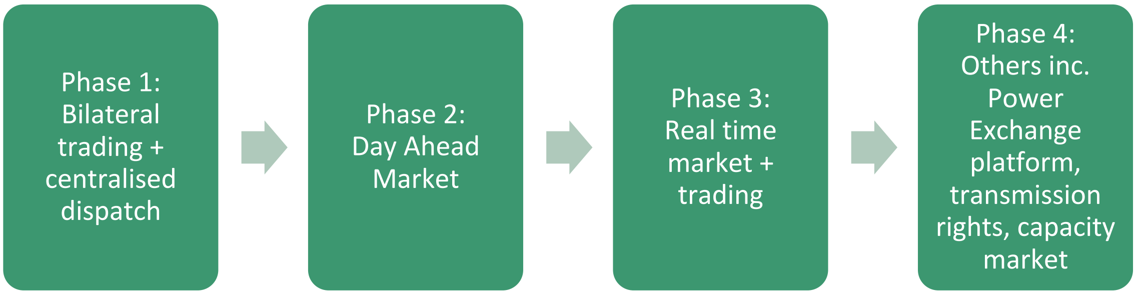
In the initial years of the market, distribution companies will be also suppliers. In some moment, when the market is liquid enough, the supply function to non-free customers may be unbundled from the distribution (wires) activity. Transmission companies should not be allowed to trade electricity any time.

7.3.7 KEM Development

The KEM will be developed in phases. The switch from one phase to the following will occur when it is considered that the previous phase is running smoothly and efficiently. The transition will be proposed by EPRA to the MOE who will make the final decision.

This proposal for the market design of the KEM assumes that the development of this market will be undertaken in four broad phases as illustrated below and considered in further detail.

Figure 40: Proposed four phase model for wholesale competition



7.3.7.1 Phase 1

The key principles adopted in this phase are:

- Energy is traded through bilateral contracts or in a centralized economic dispatch for the day ahead, carried out by the SMO.
- The economic dispatch aims to minimize the variable cost to meet the day ahead forecasted demand and will be based on the following approach:
    - Thermal plants are dispatched based on their actual fuel and other variable O&M costs. Fuel costs are calculated based on the units' efficiency and actual cost of the respective fuels.
    - Variable RES generation (wind and solar) is considered as must run and has priority in the dispatch.
    - The daily production of the hydroelectric plants with reservoirs will be optimized in a long-term horizon, therefore their daily production is established by the SMO (unless there is some clause in the PPAs that impedes this operational criterion). The general principles for the long-term optimization of hydro plants are included in Annex 3.
    - Geothermal plants are dispatched based on their variable O&M costs.
    - Gencos with a bilateral contract (BC) that requires to produce the committed energy (i.e., a physical contract) will be self-dispatched.
    - Imports will be considered as must run or with an energy price, depending on the PPA rules.
    - The economic dispatch will consider the start-up cost of thermal units and will allocate to generating units the margins for frequency regulations as well as some spinning reserve.
    - The dispatch will be run by the SMO the day ahead of the operation day. The scheduled generation will be an obligation for the involved Gencos. Non authorized deviations from the economic dispatch will be settled paying a deviation charge (if a PPA have a clause that limits this possibility, it may require a particular treatment of deviations).

    - The economic dispatch will consider the forecasted demand, the full representation of the transmission system, the must run requirement for system security or quality and any other constrains included in the regulations.
- The centralized economic dispatch will be the root of a future day-ahead market in the following phases
- Ancillary services are centrally allocated to MPs and paid with a regulated tariff. The general rules for ancillary services allocation are:
    - Gencos will have the obligation to provide a margin for primary frequency regulation (PPAs may have some restrictions to this obligation).
    - The SMO will enter in contracts with Gencos to provide secondary and tertiary frequency regulation. The price of these contracts will be regulated.
    - Gencos will have the obligation to produce reactive power within the limits of their capability curve, following the instructions of the SMO.
    - The SMO will enter in contracts with generators that can provide black start.
    - In case the deviations that arise from normal fluctuations of generation or demands cannot be balanced with the frequency regulation reserves in real time, the SMO will instruct generators that are providing spinning reserve to change generation to keep the system balance.
- After operation (on an ex-post basis), the SMO will calculate the energy consumed for each supplier and FC for each hour. It will be assumed that the difference between the hourly energy consumption and the energy bought through a BC that includes energy supply is bought at an hourly energy price (HEP) that will be calculated by the SMO. The HEP will be calculated as:
    - The sum of the hourly variable costs of all the dispatched generation plus the payments to RES, except for the energy committed in BCs, divided by corresponding energy i, plus
    - A services cost (SC) calculated as the sum of the start-up cost of the units plus the payments to secondary and tertiary reserve providers, divided by the daily energy production.
- Real time balance is based on instruction to Gencos to increase or decrease load, and the compensation is based on variable costs incurred to supply the additional energy or saved in case the Genco is instructed to reduce production.
- The MPs that are FCs or Suppliers will have to pay a Capacity Charge (CC) applied to their actual maximum annual power demand (capacity demand) minus the AP.
- The CC will be set out by EPRA and will be based in the fixed cost (CAPEX and OPEX) of a generating unit appropriate for covering the peak demand.
- FCs can enter in bilateral contracts with Gencos for their demand not covered by AP and AE or being supplied at the Capacity Charge.
- Suppliers can buy the capacity and energy not covered with the AP and AE through BCs awarded in competitive auctions. In these auctions suppliers can

buy only capacity or capacity and energy. The rest of their energy demand will be bought through the economic dispatch.

- Generators not involved in PPAs will have the option of selling their capacity to suppliers or FCs through BCs or by receiving a capacity payment (CP) based on their firm capacity and sell the energy through the economic dispatch.
- Therefore, some capacity that is not committed in BCs will receive a CP. The sum of all the CPs divided by the corresponding capacity will define the capacity charge (CC) that will be paid by suppliers and FCs proportionally to their capacity demand not covered by the AP or BCs.
- Therefore, each supplier and FC will cover its capacity demand through AP, contracts, or the CC.
- Each supplier and FC will cover their energy demand through the AE, energy bought through BCs on in the economic dispatch.
- The SMO will settle daily the payments of consumers based on their actual consumption at the HEP.
- At the beginning of each month the SMO will issue the invoices to consumers by the energy obtained from the economic dispatch. The consumers will make the payments in a bank account managed by the SMO.
- The SMO will use the payments of consumers to pay at the Gencos.

Simplified example of how the proposed CTM mechanism would work

This example is based on the following assumptions:

- The CTM allocation is based on the maximum demand of each supplier of FC and that these participants must cover their peak demand with the AP, contracts with Gencos or paying a capacity charge.
- The PPAs have a payment for the provided capacity and the energy is economically dispatched

Based on these assumptions, the example uses the following data:

Demand

- Supplier 1, maximum demand: 1000 MW
- Supplier 2, maximum demand: 500MW
- FC1, maximum demand: 200MW
- FC2, maximum demand: 150MW
- Total system demand: 2850MW

PPAs for which costs should be allocated:

- PPA1, capacity provided: 400MW at $80,000/MW-year
- PPA2, capacity provided: 300MW at $120,000/MW-year
- Total capacity provided by PPAs: 700 MW (400 + 300MW)

Unit cost of capacity provided by PPAs

CP = (400 * 80,000 + 300 * 120,000) / 700 = $97,000/MW-year

Other contracts:

- Supplier 1, contract with Genco 1 for 400MW
- FC2: contract with Genco 2 for 100MW

Capacity payment: demand not covered with AP pays a capacity charge of $60,000/MW-year

Allocation of capacity of PPAs:

- Supplier 1: AP1= 1000 *700 / 2850 = 245 MW
- Supplier 2: AP2= 500 *700 / 2850 = 123 MW
- FC1: AP3= 200 *700 / 2850 = 49 MW
- FC2: AP4= 150 *700 / 2850 = 37 MW

Allocation of PPAs cost to participants

- Supplier 1: AE1= AP1 * CP = 245 MW * $97,000/MW-year = $23,765,000/year
- Supplier 2: AE2= AP2 * CP = 123 MW * $97,000/MW-year = $11,931,000/year
- FC1: AE3= AP3 * CP = 49 MW * $97,000/MW-year = $4,753,000/year
- FC2: AE4= AP4 * CP = 37 MW * $97,000/MW-year = $3,589,000/year

The amount of demand (MW) that must pay the capacity charge is as follows:

- Supplier 1= 1000 MW – 245 MW – 400 MW = 355 MW
- Supplier 2 = 500 MW – 123 MW = 377 MW
- FC1: 200 MW – 49 MW – 100 MW = 51 MW
- FC2: 150 MW – 37 MW = 63 MW

In this example, Supplier 1 could be considered an incumbent (KPLC) which passes on these costs to customers based on a regulated tariff, while Supplier 2 could be a new retailer, which would be free to choose the form in which the capacity charges are passed through.

The preconditions for the launching of the phase 1 are:

- The rules for the operation of the system (Grid Code) and the market (Market Rules) have been developed and approved by EPRA (or MOE).
- The SMO is in place, with the minimum equipment necessary to start the operation of the KEM.
- The tariff adapted to the principles of the KEM has been developed and approved by EPRA.
- The future MPs have been trained to understand how to manage themselves in the KEM, including rights and obligations.
- Identification and purchase of the commercial software that the SMO would use for the economic dispatch and the settlement of transactions.
- PPAs have been consequentially adopted and acceded to by the contractual parties to the extent necessary to enable phase 1.

To avoid delays in the launching of the phase 1, a survey of existing equipment (metering, communications, control) should be carried out with transitional measures aiming to the initial operation of the KEM with minimum requirements on additional equipment defined.

7.3.7.2 Phase 2

Phase 2 will involve the introduction of a day-ahead market (DAM).

Why and how of the DAM

The DAM allows multilateral trading among MPs and produces 24-hourly schedules for the production and consumption of electricity the day before the operating day. The DAM ensures the optimal use of the available generation to meet the forecasted load. Most of the benefits of an electricity market arise from the existence of a DAM, therefore, its introduction in the KEM is a priority.

The DAM is based on offers of sellers to inject some volume energy at a given minimum price and bids of buyers to buy energy at a maximum price.

The DAM is cleared with a software (clearing engine) that select the offers and bids that maximizes the social welfare or minimizes the cost to meet the buying offers.
Using security constrained economic dispatch (SCED), the all the constraints are considered in the dispatch. The transactions arising from the economic dispatch (also Market Clearing) are settled at the day-ahead hourly locational marginal price. Deviations from the schedule of generation or demand are settled with the methodology described in the future KEM's market rules.

The DAM will be financially binding, which means that the differences between the scheduled and measured generation and demand will be settled with a procedure defined in the KEM's market rules. The settlement will be prepared by the SMO and submitted to the MPs.

The daily generation schedules that arise from the economic dispatch that are based on the following principles:

- The objective is to match the buying and selling demand bids and offers to maximize the social welfare, while keeping the system in balance and respecting physical, environmental and security constraints.
- The economic dispatch uses an optimization method (normally mixed integer linear or non-linear programming) to obtain the set of offers and bids to be accepted that will allow maximizing the social welfare, producing an hourly schedule of transactions between MPs.
- The clearing process assesses hourly offers and bids and establishes the wholesale cost of energy based on a nodal clearing price auction.

The KEM's DAM will provide the possibility of trading by means of bids and offers received from MPs formulated one day in advance prior to Gate Closure, i.e., the last time at which offers and bids can be presented. The matching between offers and bids will result in a set of awarded transactions between buyers and sellers of energy that will be scheduled for the day-ahead. Because the characteristics of the Kenya's transmission system, the clearing process should take into consideration the location of the nodes where the electricity is injected or withdrawn, leading to different prices in each node due to congestion (if any) and losses. The full representation of the transmission system allows maximizing the social welfare including the effect of losses.

The following operational principles will apply to KEM's DAM:

- Generators not involved in PPAs can present offers to sell the energy, instead of being dispatched based on their variable costs. Offers may have a price cap set out by EPRA. A high price cap is convenient to limit abuse, mainly at the beginning of the market, but it should be higher than the variable costs of the most expensive generating units. It is applied explicitly or implicitly in practically all the power markets in the world. Price caps set the marginal price like regular offers of generators.
- RES will have dispatch priority at zero offered price but will be paid at the tariff in their PPAs.
- The SMO will clear the market with the goal to minimize total supply costs, constrained by security and quality objectives. The KNTGC should establish these objectives.
- The price of the energy each hour will be based on the system marginal price (SMP), i.e., the marginal cost to supply an additional unit of energy in each node of the transmission system.
- Gencos not involved in PPAs or BCs with self-dispatch, will be paid at the hourly SMP for the energy not sold in the respective PPAs or BCs.
- Gencos with PPAs will continue being paid based on their fuel and other variable costs as established in the respective PPA.
- In real time the SMO will use the offers or variable costs (in case of PPAs) of Gencos to balance economically the system.
- Based on the resources used to balance the system, the SMO will calculate a real time price (RTP) for the upward and downward deviations.
- Deviations from the DAM schedule will be settled at the RTP (in the case of PPAs this possibility may be not considered in the respective PPAs).
- FCs can participate in the DAM as price takers, or present bids for their total or part of their demand.
- FCs can participate of the secondary frequency regulation offering downward regulation.
- Gencos with obligation to provide primary frequency regulation can transfer their obligations to other Gencos. This must be authorized by the SMO.
- The DAM's clearing software will include a full representation of the transmission system and will co-optimize the allocation of secondary and tertiary frequency regulation
- The following rules and entities for market governance will be introduced:
    - Dispute resolution procedure.
    - Market Surveillance activity by a dedicated working group under EPRA.
    - Enforcement procedures including penalization for breaching of the market rules.
    - Audits to the SMO.

The rest of the KEM will operate as in phase 1.

The rules for BCs will not change, but MPs will have the possibility to enter in financial contracts using the cleared DAM prices.

The preconditions for the launching of the phase 2 are:

- SMO will have available the full equipment and software necessary for the operation of the system and the KEM according with the approved market rules for this phase.
- All MPs have installed the commercial metering required by the Grid Code or accept a correction to the measures with other metering equipment that does not comply with the Grid Code requirements.
- The Supply activity is fully unbundled from the distribution activity.

7.3.7.3 Phase 3

In phase 3 the following possibilities will be introduced:

- A real time market will be introduced, based on offers presented by generators or loads at request of the SMO, and a real time price based on the accepted offers for upward or downward regulation.
- FCs can participate of the real time market offering downward energy.
- Secondary and tertiary frequency regulation will be awarded based on periodic auctions with free offers (eventually with a price cap). FCs can participate in the auctions.
- Co-optimization of energy and frequency regulation reserves will include the cost of these reserves.
- Introduction of traders as MPs.

All other provisions will be as per phase 2.

The preconditions for the launching of the phase 3 are:

- SMO will have available the full equipment and software necessary for the real time operation of the system.
- MPs have installed the communication and manoeuvre equipment necessary to receive orders from the SMO and proceed accordingly.

7.3.7.4 Phase 4

In phase 4 the following possibilities will be introduced:

- Depending on the evolution of new investments, the CP can be eliminated for new entrants, or replaced by a competitive capacity market.
- Introduction of a power exchange platform where MPs can trade standardized products (e.g., peak energy, baseload energy, etc.) as futures or options.
- FC will have to buy the energy not supplied by the AE or in physical BCs in the DAM.
- Introduction of transmission rights for BC, that will allow to optimize the use of the available transmission capacity, allocating the available capacity to the BC parties through auctions. Transmission rights can be physical or financial. The

physical transmission rights grant the holders the right to inject a value of power in a node of the transmission system and withdraws the same power in another node. Financial transmission rights grant the holders to receive (or pay) by the difference between the marginal price in a couple of nodes of the transmission system times a value of power. Financial transmission rights allow the parties of a BC to hedge against the differences in marginal prices between the nodes of injection and withdrawal of the BC.

The preconditions for the launching of the phase 3 are:

- Agreement of the MPs to create and fund the power exchange.
- The development and approval of rules by EPRA for an eventual capacity market.
- The development and approval of rules by EPRA for auctions to allocate transmission rights.
- SMO has all necessary equipment and software to operate the capacity market and the auctions to allocate transmission rights.

7.3.8 Some Criteria for the Transitions between Phases

The following criteria complement the proposed rules for the different phases of the KEM:

- FCs are consumers meeting the approved eligibility threshold. The threshold value will be reduced periodically by the regulator, based on the liquidity of the BCs market.
- The regulator will define the conditions that the KEM should comply with, to permit transition from one phase to the subsequent phase.
- CP will be received by the "firm capacity" of each generating unit. This is the capacity that a generating unit can provide during the monthly system peak with a high probability. Market rules will define the calculation methodology for the firm capacity of each generating unit.
- Firm capacity of the units can be reduced when there is an excess of capacity in the system.
- A criterion should be used to curtail demand in case of deficit of generation. It should be proportional to the capacity allocated to each demand by the different methods. Demand with BC with a Genco that is producing the committed capacity will not be curtailed by such capacity.
- If it is compatible with the PPAs, hydro plants will be centrally operated based in a long-term optimization of the use of water, as described in Annex 3. The central optimisation will start in phase 1 and continue in phase 2. EPRA will decide if in phase 3 onwards this operation criterion will continue, or hydro plants will present free offers in the DAM and the real time market.
- EPRA, on request of the SMO can decide on the introduction of intra-day market, to allow MPs to correct their position according with the evolution of the market.

- In principle firm capacity of variable RES will be zero. However, these plants can receive a fixed payment according with the respective contracts. In this case this payment will be part of the CTM.
- It should be possible to stop issuing PPAs when the market becomes competitive enough that the privately initiated investments are sufficient to meet the load with a reasonable security level.

7.3.9 KEM and EAPP

Kenya, as a member of the Eastern Africa Power Pool (EAPP) will have to adapt the rules of the KEM to the requirements of the EAPP market rules. These rules are currently being developed by a consulting firm as part of a project funded by the World Bank. Therefore, at present it is not possible to include these eventual requirements in the proposed KEM's design.

7.3.10 Similarities and differences with NARUC proposal for EPRA

Section 2.8 reviewed an approach to wholesale competition proposed by the National Association of Regulatory Utility Commissioners (NARUC). Key features are summarized in the box below.

Overview of NARUC market design proposal for EPRA

NARUC proposes a market development model, applying a capacity certificate scheme – to manage and phase out existing PPAs.

The proposals revolve around a capacity market, which aims to allow a smooth transition from existing PPA arrangements to a mechanism compatible with a competitive wholesale energy market, by ensuring that:

c) current contractual arrangements will not be affected severely, and
d) the possibility of limited liquidity in an energy-only wholesale market, will not negatively impact entry of new generating capacity and system adequacy.

The proposed reforms/ interventions are proposed to take place in two phases.

The first phase is a transitional phase that may last between 10-12 years. It incorporates the following elements:

g) **System operation**: Dispatching and scheduling of units is performed through a 'central dispatching' model allowing bilateral contracts to run in parallel with a process based on the generating units' merit order.
h) **T&D Networks**: Application of cost-of-service regulation for determining allowed remuneration.
i) **Wholesale market arrangements – Energy**: Introduction of a market-based mechanism (pool/merit order).
j) **Wholesale market arrangements – Capacity**: new suppliers wishing to enter the market to serve existing load are obliged to buy certificates through this mandatory "pool of certificates". The capacity remuneration would be set by EPRA, considering the PPA obligations of KPLC. This set up aims to provide cash neutrality for KPLC, but also provides a

stable investment environment for new players, having a clear view of how capacity will be paid in the future market arrangements. Specifically:

   a. If the need for a new generation capacity certificate arises due to expiration of previously existing PPAs, new plants will be obliged to place their certificates in the "pool" and thus receive a regulated remuneration for their capacity availability.
   b. If the need for new generation capacity arises due to new economic activity (e.g., a new manufacturing factory) new plants will be allowed to exchange their certificates outside the "certificate pool", bilaterally with suppliers.

k) **Tariffs**: It is important to ensure that the tariff for each activity is cost-reflective.

l) **Eligible customers**: Customers can freely choose their supplier.

In the second (Permanent) phase, as demand for electricity is growing and the old PPAs are expiring, the need for the "certificates pool" and regulated certificate prices is reduced, with the idea that the price to KPLC becomes more cost reflective. Specifically:

- Gradually, an increasing number of certificates will be exchanged outside the "certificate pool", bilaterally between producers and demand (suppliers and consumers). Once a liquid and efficient market for capacity certificates is established, the need for a "certificates pool" and for regulated remuneration of certificates diminishes and the market will determine freely the price for all new capacity certificates, outside the pool.
- Open access is extended to MV customers.
- Open access is gradually extended also to LV customers.

In practice, there are not substantial differences between NARUC's approach and that proposed in this section, though some aspects of implementation differ:

- **Dealing with existing PPAs**. A key issue in both approaches is how to deal with the existing PPAs. NARUC proposes a capacity certificates scheme, where all the demand should be covered by these certificates, from either by the firm capacity of the PPAs or other generators. The scheme considered here is based on capacity payments that fulfil the same objective, where all the demand pays for the available firm capacity. Furthermore, the NARUC report mentions this mechanism as an option. Any of these capacity mechanisms can solve the problem of the PPAs where the PPAs have a capacity payment and the energy is dispatchable.
- **Unbundling**. Both schemes propose the unbundling of the generation, transmission, distribution, and supply functions. In the proposal presented in this section, the unbundling of distribution and supply is not considered crucial and can be postponed without affecting the restructuring objectives.
- **Open access**. In both schemes open access is a key component of the reform. This includes allowing some categories of consumers to conclude contracts with generators and for IPPs to enter the market without a PPA.
- **Tariff restructuring**. In both schemes the tariffs should include components to pay for generation, transmission, and distribution, as well as supply when this activity is unbundled from the distribution.
- **Cross subsidies**. Both schemes require the elimination of cross subsidies to avoid creating inefficient incentives for users to enter contracts with generators. The proposal of NARUC is explicit, while previous analysis in this report proposes to set cost-reflective network tariffs and eliminate to the best extent possible cross-subsidies for customers who are supplied by KPLC.

- **System and Market Operator**. Both schemes propose an independent SO, but in this case, there are some differences:
    - In the NARUC proposal the SO also fulfils the role of MO, while the proposal in this section differentiates both activities, although both functions are allocated to a single entity, the SMO.
    - NARUC mentions as activities of the SO: Dispatching and scheduling of units is performed through a 'central dispatching' model allowing bilateral contracts to run in parallel with a process based on the generating units' merit order. This is similar to the proposal in this section for stage 1 of the reform.
    - The proposal outlined in this section allocates the SMO only the function of operation of the system and the market. The NARUC proposal goes further and includes that the SO will have "adequate financial and technical capacity to carry out the investment plan for the full electrification of the country and to ensure security of supply for the economy of Kenya."
- **Wholesale Market**. NARUC proposes the "introduction of a market-based mechanism (pool/ merit order) where energy might be freely exchanged, without the need for strict, bilateral long-term contracts." The proposal here is similar, with a staged development of this market. NARUC considers capacity certificates as part of the wholesale market, The proposal in this section considers this as a regulated mechanisms to protect the financial sustainability of the system. However, the result of both mechanisms would be similar if properly implemented.
- **Capacity issues**. NARUC considers that "Given the current situation of overcapacity, new generation capacity will not be allowed, unless the need for it, due to increasing peak load demand, is demonstrated (e.g., by the SO) through a generation adequacy assessment". This assessment is developed assumed relative balance in capacity, and that all new capacity should be admitted because demand is continued to increase. However, in case that an excess of capacity leads to an unaffordable increase of the tariffs, a proportional reduction of the payments to IPPs that are not parties of a PPA could be made. In this section the possibility of implementing a capacity market in the last stage of the market development to replace the capacity payments is included.

7.4 Transitional issues

Providing the market pre-requisites identified in section 7.2 can be addressed, fast implementation of the KEM should be possible, providing there is political willingness to develop and implement in a short period the rules and procedures for the operation of the KEM and make a decision on the location of the SMO.

Specifically, there are no technical obstacles for a fast implementation of the KEM. The proposed phase 1 can be mostly run with the existing technical resources. It is also possible to train the staff for the initial operation of the KEM in a short period of time, as the proposed phase 1 includes few new activities to those currently carried out.

A key aim of the proposed principles and approach is to ensure that KPLC is protected from power purchase risk and can recover all its fixed costs related to energy purchase. For this reason, there is no in-principal reason why transition cannot commence as soon as its financial situation is stabilised. However, this assumption may need reviewing as further information in the PPAs is made available.

For a fast launching of the KEM, a gap analysis is recommended to identify in detail the existing resources that can be used in the beginning of the phase 1, and any missing resources. A training program is also required for the initial staff of the ISMO.

7.5 Evaluating the level of competition

Various indicators can be developed to assess the level of competition at the wholesale and retail level once the market is in place.

Typical monitoring indicators on the wholesale side include:

- The number of participants in the wholesale market, both in the supply side and on the demand side.
- The number of participants who operate without a PPA, and the energy generated by these participants – who could be IPPs or KenGen.
- Prices reported in the Day Ahead Market and subsequent markets.
- Measures of concentration of the supply side.

Common indicators of market concentration include the share of the largest or x largest generators in capacity and energy, or estimation of the concentration ratio through the Herfindahl Hirschmann Index (HHI). The HHI is calculated by squaring the market share of each firm competing in a market (as a number, not a decimal) and then summing the resulting numbers. Its value can range from close to zero to its highest value of 100^2 = 10,000 where one firm supplies the whole market. The HHI is commonly used by anti-trust authorities to assess mergers but is also employed in electricity markets.

$$HHI = s_1^2 + s_2^2 + s_3^2 + \cdots s_n^2$$

In the above, s_1 is the market share of firm 1, s_2 the market share of firm 2 and successively down to firm n. In general, a HHI above 2,500 is considered an indicator of a highly concentrated market, a value between 1,500 and 2,500 of a moderately concentrated market, and a value below 1,500 of a competitive market.

In practice, while the HHI index provides useful information it is not sufficient as market conditions vary over the course of a day, season, or year, with concentration by capacity and energy also differing. For this reason, use of the HHI is often combined with more investigative analysis to determine if there are any pivotal generators that unduly influence price setting.

To evaluate retail market competition various indicators are used, including:

- Number of customers that take up market offers (including by its incumbent supplier as an alternative to a default tariff) and the energy sold to these customers
- Number and share of customers switching to an alternative supplier of energy.

These indicators are frequently combined with complementary analysis on prices available to customers, and how these are evolving over time.

7.6 Action Plan

The following Action Plan is proposed.

Table 31: Proposed Action Plan

Issue	Requirements	Milestones	Responsible entity	Date
Least Cost Planning	Update planning software to adequately allow modelling of VRE and its needs (e.g., ancillary services)	New software procured and staff fully trained to develop LCPDP	Industry group convened by EPRA under guidance of MOE	Software in place and staff trained by end of April 2022
	Enhance approach to demand forecasting, through initiation of a detailed review of how to enhance methodology and update on an annual basis	Detailed review of demand forecasting completed, and recommendations incorporated into LCPDP	Industry group convened by EPRA under guidance of MOE	Review to be completed by end June 2022
	Review planning provisions in KNTGC to ensure coherence with LDPDP processes	Revised draft of the KNTGC to incorporate revised planning requirements	EPRA	Revised draft to be developed by end of April 2022
Tariff setting	Remove any major inter-category cross subsidies through transitional process. Close monitoring to ensure no push back over time	Inter-category cross subsidies removed or minimised (depending on potential constraints).	EPRA/KPLC	All cross subsidies to be removed for tariffs to apply from January 2023
	Introduce new two-part tariffs for commercial customers below 15,000kWh/month	Revised tariff structure introduced with all fixed network costs recovered through capacity charge	EPRA/KPLC	For tariffs to apply from January 2023
	Require domestic customers taking up supply from solar PV to transfer to a two-part tariff	Revised tariff structure introduced for net metering customers, requiring them to cover cost-reflective costs of network connected through the capacity charge of a two-part tariff structure	EPRA/KPLC	For tariffs to apply once net metering regulation gazetted (mid 2022)
	Development of wheeling tariffs for transmission and distribution	Wheeling tariffs set	EPRA	For tariffs to apply from January 2022
Net metering policy	Development of net metering policy that is consistent with move to two-part pricing (above) and provides time-of-use signals for value of energy injected into the grid by customers with solar PV installations	Net metering regulations gazetted following supportive Regulatory Impact Assessment	EPRA	Gazettal by mid-2022

KPLC performance	Detailed review of KPLC's financial situation, potentially with support of external auditors	Study concluded with recommendations to streamline costs and liabilities	EPRA/KPLC	Study concluded by June 2022
	Implementation of recommendations of the Presidential Taskforce on PPAs on financial performance	Development of Board Policy Paper, National Treasury Letter, Performance Contract and 2022-23 Budget (as per the report of the Presidential Taskforce on PPAs)	National Treasury, KPLC Board of Directors, Chief Executive Officer EPRA	By end of November 2021
	Implementation of recommendations of the Presidential Taskforce on PPAs on corporate governance	Creation of HR instruments and employment of CEO	National Treasury Board of KPLC	By end of October 2021
	Development of revised loss reduction plan, including expenditure needs and efficient profile following closure of KEMP program (KPLC/World Bank) at end of December 2021	Loss reduction plan with investment profile finalised and agreed by EPRA	EPRA/KPLC	Findings to be incorporated in tariffs to apply from January 2022
	Revised targets for service quality, with timeframe for introduction of monitoring and incentive regime developed by EPRA	Service quality path, including investment needs, agreed between KPLC and EPRA	EPRA/KPLC	Agreement by end of June 2022
Creation of SMO	Decision taken on form of SO and MO functions (SO/MO or SMO), appropriate institutional set-up (independent or within KETRACO) and transitional arrangements given KPLC current SO	Decision taken together with creation of statutes and any accompanying legal/regulatory instruments to allow organisational (set-up) issues to commence	EPRA	Decision with any legislation instruments to be in place by December 2022
	Plans for staff and asset transfers from existing organisation(s) to be developed	Transfer plan agreed	EPRA (and potentially KPLC)	Staff and asset transfers approved by June 2023
	SMO staffed with all necessary equipment and software to undertake interim SO activities	SMO operational	EPRA/SMO	By September 2023
Market design – Phase 1	Approval of all necessary revised rules for the operation of the system (KNTGC) and the market (Market Rules), including ensuring consistency with proposed Rules being developed for EAPP and agreement	Revised KNTGC gazetted, and Market Rules gazetted	EPRA/MOE	By mid-2023

	by PPA parties to consequential changes needed to PPAs			
	Agreement between MOE/EPRA and Competition Regulator	Agreement on dealing with any non-competitive aspects of the market	EPRA/MOE/Competition Regulator	By mid-2023
	Amendment of licences and licence conditions to facilitate market establishment and operation	New licences developed/existing licences amended	EPRA/MOE/Existing Licensees	By September 2023
	Consequential amendments to PPAs	PPA rights and obligations assigned to correct parties if necessary	EPRA/PPA Parties	By September 2023
	Carry out survey of existing equipment (metering, communications, control) to facilitate the initial operation of the KEM with minimum additional requirements and cost	Consultant hired, with recommendations provided	EPRA/MOE	By April 2023
	Approval of Cost of Transition to the Market (CTM) payments and any detailed rules in their application (to complement Market Rules)	Determination of CTM payments and their application	EPRA/MOE	By September-2023
	Approval of other market charges, including capacity payments	Determination of charges and their application	EPRA/MOE	By September-2023
	Identification and purchase of the commercial software that the SMO will use for the economic dispatch and the settlement of transactions	Software identified and subsequently purchased through international tender	EPRA/MOE/SMO	By September 2023
	Training of all market participants on the operation of phase 1 of the KEM – how it works conceptually, logistically, and key obligations/requirements/rights	Implementation of training programs to all participants	EPRA/MOE	By December-2023
Market Design – Phase 2	Amendments to the Market Rules to facilitate DAM	Revisions to Market Rules	EPRA/MOE	6 months prior to start of phase
	Separation of retail activities from KPLC: a) creation of new legal entity, with new statutes and encompassing all existing retail activities of KPLC, b) development of	New retail entity created and functioning	EPRA/MOE	No less than 3 months prior to start of phase

	plan for staff and asset transfer, c) staff transferred to new entity			
	SMO has available the full equipment and software necessary for the operation of the system and the KEM according with the approved Market Rules for this phase. Incorporates purchase, installation, training and testing with existing market participants	Software in place and SMO staff trained to implement	EPRA/SMO	No less than 3 months prior to start of phase
	All MPs have installed the commercial metering required by the KNTGC (or accepts a correction to the measures with other metering equipment that does not comply with the Grid Code requirements).	All MP with appropriate metering equipment	SMO/MPs/EPRA	No less than 3 months prior to start of phase
Market Design – Phase 3	Amendments to the Market Rules to facilitate ancillary services market and other changes	Revisions to Market Rules	EPRA/MOE	6 months prior to start of phase
	SMO has available the full equipment and software for the real time operation of the system and the ancillary services market	Software in place and SMO staff trained to implement	SMO	No less than 3 months prior to start of phase
	MPs have installed the communication and manoeuvre equipment necessary to receive orders from the SMO and proceed accordingly	All MP with appropriate communications and manoeuvre equipment	MPs	No less than 3 months prior to start of phase
Market Design – Phase 4	Agreement of the MPs to create and fund the power exchange	Agreement in place	EPRA/MPs	No less than 6 months prior to start of phase
	Rules for an eventual capacity market developed and approved	Rules gazetted	EPRA/MOE	No less than 3 months prior to start of phase
	Rules for auctions to allocate transmission rights developed and approved	Rules gazetted	EPRA/MOE	No less than 3 months prior to start of phase
	SMO has available the equipment and software to operate the capacity market	Software in place and SMO staff trained to implement	SMO	No less than 3 months prior to start of phase

	and the auctions to allocate transmission rights.			

8 Training Needs for the SMO

Training is a critical activity for the SMO as it will need to perform two critical roles: first, be able to operate any electricity wholesale market; and second, be able to effectively train market participants to ensure smooth functioning of the KEM.

For training purposes, the activities of the SO and MO can be largely delineated. As the SO function is currently operational, with its role allocated to KPLC, then there should be sufficient staff trained in the operation of the transmission system. However, as the MO role is a new activity, staff allocated to this function will require training.

Several forms of training are suggested.

8.1 Specific in-house training courses

In house training will be required, with courses proposed at the SMO premises, or a nearby venue, to ensure maximum uptake of SMO staff. This course can cover basics of electricity markets and then more detailed issues that will arise in the phased market approach.

A suggested training course for future staff of the SMO that can be held in Nairobi and performed by a specialist consultancy/institution, is set out below.

Course 1: Economy and Regulation of Electricity Markets (1 week)

1. Review of Microeconomy Concepts
    a. Short-term and Long-term Marginal costs
    b. Fixed and Variable costs in power systems
    c. Theory of competition
    d. Social welfare
    e. Market Power
2. Electricity Market Institutions
    a. Energy Policy Authority (Ministry)
    b. Regulator
    c. System and Market operator
    d. Transmission Companies
    e. Market Participants
    f. Single buyer
    g. Planning responsibility

Course 2: Electricity Markets (2 weeks)

1. Description of electricity markets

    a. Structure
    b. Architecture
    c. Market Rules
2. Electricity markets models
    a. Single buyers in electricity markets
    b. Gross pools
    c. Net pools
    d. Regional markets
3. System Operation and Market Operation
    a. Coordination
    b. The Grid Code
    c. Security and quality criteria
    d. Operation Procedures
    e. Power system studies
    f. Operational planning
    g. Use of SCADA for system operation
    h. Calculation of available transmission capacity for bilateral contracts and the DAM
4. Transition from regulated system to electricity markets
5. The day-ahead market – description
    a. Offers and bids
    b. Treatment of variable renewable sources
    c. Optimal operation of hydroelectric plants
    d. Market clearing
    e. Market settlement
    f. Identification and settlement of deviations
6. Real time markets
7. Intra-day markets
8. Ancillary services
    a. Description of the necessary ancillary services
    b. Modalities to provide ancillary services
    c. Ancillary services markets
9. Bilateral Contracts in Electricity Markets
    a. Physical contracts
    b. Financial contracts
    c. Standardized contracts
10. Wholesale Electricity pricing
    a. Single pricing
    b. Zonal pricing
    c. Locational Energy Pricing
    d. Price of capacity
    e. Including Market Price of Electricity in End Users' tariffs
11. Cross border trading – EAPP rules
12. Software and Hardware for Electricity Markets Operation

8.2 Study Tours

It is also critical for staff of the SMO to see how similar institutions operate, especially the Market Operation functions. Study tours can allow participants to see first-hand how other markets work, ask questions and allow senior management to gain insights as to how the market organisations are structured and managed internally (organisational structures, staffing needs etc.,).

For Study Tours there are three main groups of organizations that could be visited, which will need to be prioritized based on budgets and specific common needs identified for a new KEM:

- Existing SMOs responsible for system operation and market operation. These can include ones in the United States and Canada as well as others in countries like Guatemala, El Salvador, Peru, Chile, and Argentina.
- Stand-alone MOs in Europe and countries in Asia-Pacific like Philippines, Singapore, and Australia
- Regional markets, including SAPP and Central America.

8.3 Training courses

Senior staff can also attend courses run by international organisations and other markets including:

- Florence School of Regulation.
- Council of European Regulators.
- European Association of Regional Regulators.
- On-line courses run by different universities (e.g., Duke University).

A limitation of these courses is that they may be unduly tailored towards the needs of a particular region, but most courses are currently run on-line, which will save in travel and transports costs.

In addition, it may be useful to some staff to participate in courses run by Market Operators for their own market to gain better insight into the type of training that the SMO can provide for its own market. Some courses are free, with examples including courses run by:

- The Australian Electricity Market Operator.
- Elexon, responsible for the Balancing and Settlement Code in the Great Britain electricity market
- California ISO

9 Conclusions

The analysis in this report highlights several pre-requisites that need to be met prior to introducing a wholesale market arrangement. Many of these revolve around the regulatory framework facing KPLC and its financial performance, including: the need for transition towards cost-reflective pricing and ensuring tariffs stay at this level; development of a tariff structure that enhances the use of two-part tariffs including for all commercial customers; development of a net metering policy that protects the ability for KPLC to recover its network costs as customers take up forms of DER; enhancing in service quality; and stabilisation in KPLC's financial performance.

Meeting these pre-requisites is not simple, and the analysis in this report suggests that even with a cost-reflective tariff, KPLC will face several financial issues for several years. However, with these pre-requisites overcome, there is no technical reason why Kenya cannot move quickly to more formal wholesale market arrangements. The fact that competition is already developing quickly suggests this is not something that can be deferred for years; in fact, many of the tariff reform issues proposed are essential to protect KPLC and its customer base from the competitive changes that are already taking place.

10 Annexes

10.1 Annex 1 – Revenue Requirement

10.1.1 Introduction

To estimate wheeling tariffs, a more comprehensive tariff-setting exercise has been undertaken incorporating two key steps: a) estimation of sector revenue requirements, and b) estimation of tariffs to recover these revenue needs, including the costs of connection to, and use of the transmission and distribution networks. A by-product of this exercise is that the revenue needs of the whole sector are estimated, which allows for the determination of tariffs for activities beyond wheeling (see Annex 2).

The sector revenue requirement has been estimated based on the following components:

- Generation – comprising revenue needs of KenGen and IPPs, imports and steam sales of the Geothermal Development Company (GDC).
- Transmission – encompassing the revenue requirement of KETRACO and transmission related business of KPLC.
- Distribution/Retail – encompassing KPLC's revenue needs for its distribution assets and the costs incurred by REREC associated with rural electrification.

The following documents and sources of information have been critical in developing the estimates of the revenue requirement:

- The Least Cost Power Development Plan of 2021-30 developed in April 2021.
- KETRACO's Transmission Master Plan 2020-2040 of 31 May 2021.
- KPLC's Investment Plan (provided by KPLC).
- REREC Strategic Plan 2018/19 to 2022/23.

10.1.2 Generation revenue requirement

An estimate of the generation revenue requirement has been made using the SDDP model and based on the following critical inputs:

- Demand forecast and capacity expansion plan included in the 2021-30 LCPDP.
- Information provided on the prices underpinning existing PPAs for which KPLC is the off taker and their coverage.
- Information on feed-in-tariffs previously signed.

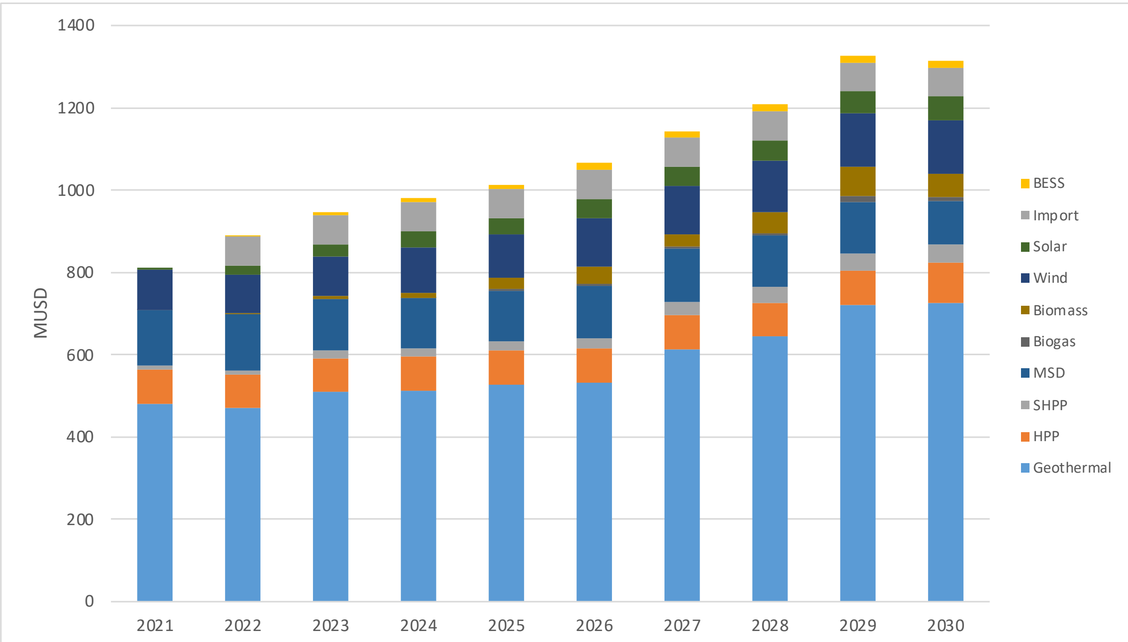
For plants to enter service up to 2030 and for which prices are not available, the following assumptions have been adopted on average purchase prices:

- Solar PV acquired through auctions - $40/MWh
- Wind acquired through auctions - $60/MWh
- Hydro IPP projects - $70/MWh
- Geothermal IPP projects - $70/MWh

The analysis takes the capacity development path included in the LCPDP as given, with dispatch simulated monthly using the SDDP model as opposed to annual dispatch underpinning the LCPDP. The model is run assuming a largely closed domestic market but allowing 200MW of imports from Ethiopia in the medium term.

The following cost breakdown by technology is determined by the SDDP model for the period 2021 to 2030:

Figure 41: Total sector costs by technology, 2021 to 2030 ($ million)



Source: Own analysis

Table 32: Breakdown of Generation revenue requirement 2020-21 to 2025-26 (KSh'000)

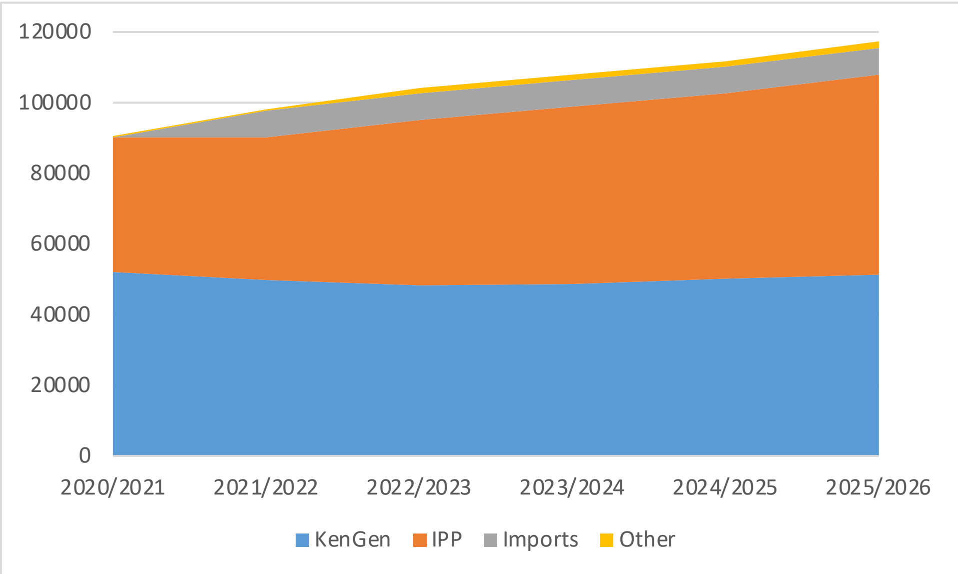
	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Ken Gen RR	**52,060,937**	**50,244,689**	**48.935,366**	**49,198,849**	**50,893,957**	**51,803,358**
KenGen - fuel	82,531	37,080	7,663	1,185	1,301	70,668
KenGen - energy	20,982,627	19,908,129	19.717,547	19,987,508	21,682,501	22,522,534
KenGen - capacity	30,995,778	30,299,480	29.210,156	29,210,156	29,210,156	29,210,156
IPP RR	**37,986,485**	**40,910,166**	**47.288,173**	**50,845,333**	**52,808,995**	**57,403,886**
IPP - fuel	217,443	454,428	245,090	96,889	111,283	341,996
IPP - energy	18,624,049	20,665,620	26.860,510	30,173,419	32,122,687	35,769,701
IPP - capacity	19,144,993	19,790,119	20.182,572	20,575,025	20,575,025	21,292,188
Net Imports	-	**7,817,226**	**7.817,165**	**7,817,165**	**7,817,204**	**7,817,277**

Other (largely steam)	342,869	394,826	1.437,100	1,527,749	1,480,655	1,828,579
TOTAL SECTOR	**90,390,290**	**99,366,907**	**105.477,803**	**109,389,096**	**113,000,812**	**118,853,099**
Total fuel	299,974	491,508	252,753	98,074	112,584	412,664
Total energy	39,606,676	40,573,748	46.578,057	50,160,927	53,805,187	58,292,235
Total capacity plus others	50,483,640	50,484,425	50.829,827	51,312,930	51,265,836	52,330,923
Imports	-	7,817,226	7.817,165	7,817,165	7,817,204	7,817,277

Source: Own analysis

The breakdown by key revenue blocks is illustrated below, with a notable increase in the share of revenue attributed to IPPs.

Figure 42: Estimate generation revenue requirement by block 2020-21 to 2025-26 (KSH million)



Source: Own analysis

10.1.3 Transmission revenue requirement (KETRACO)

The revenue requirement for KETRACO is based on the following assumed features of its regulatory regime:

- Most assets are grant financed, and for which KETRACO does not earn a return on capital or depreciation.
- In some cases, KETRACO has debt financing, for which KETRACO is allowed to recover its interest costs and loan repayments.
- Allowance is provided for operating expenditure related to all assets, and general administrative expenditure.

In addition, KETRACO proposes to finance some assets in the next five years through PPPs, namely using Independent Transmission Providers (ITPs). For project financed through these means it is assumed that the KETRACO will pay the ITP an annual annuity payment reflecting the capital cost of the project, operating expenditure, and the cost of capital/discount rate.

10.1.3.1 Capital expenditure

An estimate of KETRACO's capital expenditure needs is made based on the following key sources:

- KETRACO's Master Plan 2020-2040, which sets out proposed capital expenditure for new lines and other infrastructure.
- KETRACO's financial statement, which includes expenditure on other components of capital expenditure not generally included in investment plans (motor vehicles, furniture, computers). For this analysis we assume that expenditure on these items continues at the average of the last 4 years.

Based on data in these documents, the following capital expenditure breakdown is applied up to 2025-26.

Table 33: KETRACO - assumed capital expenditure profile 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Land	0	0	0	0	0	0
Transmission lines	24,959,779	66,131,814	48,170,500	18,069,515	54,038,993	6,438,499
Substations	0	7,617,551	11,626,554	24,328,423	0	0
Aircrafts	0	0	0	0	0	0
Motor vehicles	47,460	47,460	47,460	47,460	47,460	47,460
Machinery	0	0	0	0	0	0
Furniture / office equipment	5,508	5,508	5,508	5,508	5,508	5,508
Computers	21,044	21,044	21,044	21,044	21,044	21,044
TOTAL CAPEX	**25,033,790**	**73,823,376**	**59,871,065**	**42,471,948**	**54,113,003**	**6,512,509**

Source: Own analysis from KETRACO Master Plan 2020-40 and KETRACO annual reports

The above estimates exclude the capital costs associated with projects that are listed in the Plan to be undertaken using PPP approaches, namely construction through an IPT.

10.1.3.2 Operating expenditure

KETRACO operating expenditure is estimated as a sum of the following two items:

- Maintenance expenditure – starting from the 2019-20 estimate and then escalating this by 2.5% of the change in gross book value (GBV) of transmission assets.
- Administrative expenditure – assuming annual 4% growth over the reported 2019-20 value.

The estimated values are summarized below.

Table 34: KETRACO - assumed operating expenditure profile 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Maintenance	1,548,715	3,394,299	4,891,076	5,952,874	7,305,700	7,468,512
Administrative	1,137,837	1,183,350	1,230,684	1,279,912	1,331,108	1,384,353
TOTAL	**2,686,552**	**4,577,650**	**6,121,760**	**7,232,786**	**8,636,808**	**8,852,865**

Source: Own analysis

The important increase in estimated maintenance costs reflects the large increase in the GBV related to the capital expenditure program. Its evolution is set out below.

Table 35: Estimate of KETRACO Gross Book Value, 2019-20 to 2025-26 (KSh million)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Transmission lines	85,654	110,614	176,746	224,916	242,986	297,025	303,463
Substations	4,593	4,593	12,211	23,837	48,166	48,166	48,166
Airlines	804	804	804	804	804	804	804
Motor vehicles	190	237	284	332	379	427	474
Machinery	35	35	35	35	35	35	35
Furniture, fittings, and office equip.	154	159	165	170	176	181	187
Computers	186	207	228	249	270	291	312
Total	**91,616**	**116,650**	**190,473**	**250,344**	**292,816**	**346,929**	**353,442**

Source: Own analysis

10.1.3.3 Payments to Independent Transmission Providers

KETRACO's Transmission Master Plan 2020-2040 lists three projects that may be constructed in the period to 2025-26 under PPP arrangements, namely through contracting of the construction and operation of the lines to ITPs. Under these projects, it is assumed that KETRACO will pay an annual fee to the ITP to reflect the annualised capital-related costs that the project proponent will incur – namely return on capital and depreciation – and operating/maintenance costs. The finance mode differs from typical KETRACO projects as a private sector participant will need to recover its full costs, without availability of a grant payment.

The following three projects are identified in the Master Plan, with following date of service and estimated capital costs.

Table 36: Potential ITP project and estimated costs (KSh'000)

Project	Estimated commissioning	Estimated costs (KSh'000)
Kwale LILO (Mariakani/Dongo Kundu) -Kibuyuni (including switch station at Bang'a) 220kV	2023	9,346,989
Kisumu (Kibos) - Kakamega – Musaga 220kV	2024	8,746,976
Lessos-Loosuk (Through Baringo) 400kV	2024	22,239,008
Rongai – Keringet– Chemosit 220kV	2025	11,009,410

Source: KETRACO Transmission Master Plan 2020-2040. Costs converted to local currency.

For each project the following assumptions are applied to develop an annual (smoothed) cost annuity:

- Agreement period of 30 years, which assumes that private investors will seek a shorter period than the asset life.
- Weighted average cost of capital and discount rate of 10.13%, with simplified modelling ignoring any tax benefits.
- Operating expenditure applied at 2.5% of the asset cost.

The resulting estimated costs are set out below.

Table 37: Assumed payments to Independent Transmission Providers, 2022-23 to 2025-26 (KSh'000)

	2022-23	2023-24	2024-25	2025-26
Capital related costs				
Kwale LILO - Kibuyuni	1,015,350	1,015,350	1,015,350	1,015,350
Kisumu - Musaga		950,172	950,172	950,172
Lessos -Loosuk		2,415,792	2,415,792	2,415,792
Rongai-Keringet-Chemosti			1,195,936	1,195,936
Operating related costs				
Kwale LILO - Kibuyuni	236,759	236,759	236,759	236,759
Kisumu - Musaga		221,560	221,560	221,560
Lessos -Loosuk		563,313	563,313	563,313
Rongai-Keringet-Chemosti			278,868	278,868
TOTAL COST	**1,252,109**	**5,402,945**	**6,877,749**	**6,877,749**

Source: Own analysis

10.1.3.4 Borrowing costs

KETRACO currently holds loans for the following three projects (2019-20 end year balance in brackets based on information provided by KETRACO):

- Chemosit Kisii (KSh 1.182 million)
- Kamburu-Meru (KSh 1.633 million)
- Sondu Miriu-Kisumu (KSh 1.786 million).

An additional loan is anticipated to be allocated to KETRACO (from KPLC) for the Olkaria-Suswa project (KSh 4.601 million).

For the calculations, it is assumed that:

- The Olkaria-Suswa loan was incorporated during 2020-21
- Sondu Miriu - Kisumu is subject to an interest rate of 0.75% and a 30-year repayment (JICA)
- Olkaria-Suswa is subject to the same JICA borrowing conditions, with the others subject to an interest rate of 2.5% and 30-year repayment (Exim Bank, China).

Resulting borrowing costs are set out below.

Table 38: KETRACO – assumed borrowing costs 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Principal payments	274,964	265,799	256,939	248,374	240,095	232,092
Interest	111,134	107,429	103,848	100,387	97,040	93,806
TOTAL	**386,098**	**373,228**	**360,787**	**348,761**	**337,135**	**325,897**

Source: Own analysis

10.1.3.5 Total KETRACO revenue requirement

Based on the above analysis, and especially reflecting the large increase in capital expenditure, an important increase in KETRACO's revenue requirement is envisaged in the period to 2025-26.

Table 39: Estimate KETRACO revenue requirement, 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
OPEX	2,686,552	4,577,650	6,121,760	7,232,786	8,636,808	8,852,865
Borrowing costs	386,098	373,228	360,787	348,761	337,135	325,897
Payments to ITPs			1,252,109	5,402,945	6,877,749	6,877,749
TOTAL Rev Req	**3,072,649**	**4,950,877**	**7,734,656**	**12,984,492**	**15,851,693**	**16,056,512**

Source: Own analysis

10.1.4 KPLC revenue requirement (distribution and transmission)

The following approach has been applied to estimating the revenue requirement of KPLC and its subsequent division between distribution and transmission:

- Estimate its full revenue needs based on the typical building blocks approach derived from inclusion and/or projection of the following values:
  - Capital expenditure.
  - Regulatory asset base (RAB).
  - Depreciation.
  - Required return on capital (RAB x WACC)
  - Taxation
- Estimate the transmission revenue needs based on the following:
  - Allocate an appropriate share of capital assets to transmission (132kV) based on transmission projects identified in KPLC's capital expenditure plan and the fixed asset base in its Financial Statements.
  - Estimate the amount of return on capital and depreciation on these assets
  - Estimate the operating expenditure needs on the transmission assets.
- Subtract the estimated transmission revenue needs from the total revenue requirement to determine the distribution revenue requirement.

The above approach involves the allocation of all administrative and commercial costs, non-transmission related assets together with taxation and borrowing, to the distribution business. As most commercial and administrative activities are associated with distribution activities, and given other costs are not voltage-related, with the transmission business relatively small in KPLCs overall portfolio, the simplified approach is unlikely to create any distortion.

10.1.4.1 Capital expenditure

An estimate of KPLC's capital expenditure needs is made based on its Investment Plan. The Plan includes a detailed breakdown of all expenditure needs for 2021-22, including land, transmission, distribution, machinery, motor vehicles and furniture, equipment, and others. Planned expenditure on transmission and distribution projects for 2020-21, 2022-23 and 2023-24 is also included. For tariff calculation purposes this data has been extrapolated as follows:

- Proposed expenditure on distribution and transmission for 2023-24 is assumed to apply in 2024-25 and 2025-25, while
- Expenditure on land, machinery, motor vehicles and furniture, equipment, and others in 2021-22 is extrapolated in other years.

Based on the information provided and assumptions made, the following capital expenditure breakdown is applied up to 2025-26.

Table 40: KPLC - assumed capital expenditure profile 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Land	750,000	750,000	750,000	750,000	750,000	750,000
Transmission	-	3,686,000	5,250,000	5,250,000	5,250,000	5,250,000
Distribution	15,902,500	22,243,500	32,122,500	19,363,500	19,363,500	19,363,500
Machinery	3,561,000	3,561,000	3,561,000	3,561,000	3,561,000	3,561,000
Motor vehicles	950,000	950,000	950,000	950,000	950,000	950,000
Furniture, equipment others	4,362,000	4,362,000	4,362,000	4,362,000	4,362,000	4,362,000
TOTAL CAPEX	**25,525,500**	**35,552,500**	**46,995,500**	**34,236,500**	**34,236,500**	**34,236,500**

Source: Own analysis from KPLC Investment Plan. Shaded are assumed values

10.1.4.2 Regulatory asset base and depreciation

A key assumption adopted is that the depreciated value of fixed assets in KPLC's financial statements is a suitable proxy for the RAB, with the base value being the value of fixed assets reported in KPLC's 2019-20 Financial Statements. In rolling forward the RAB, the following approach is applied:

- Expenditure is assumed to enter the RAB in the year in which construction is to finalise, with approximately 1 year of capital expenditure in Capital Work in Progress (CWIP).
- For existing (pre-2020) assets, depreciation is applied by category based on the average depreciation rate applied in the last five financial years.

- For new assets (2020-21 and beyond), depreciation is applied based on rates stated by the Kenya Revenue Authority (KRA).
- CWIP is incorporated in the RAB for determination of the return on capital but not depreciation. No disposals are incorporated.

Based on the above, the following depreciation rates are applied:

Table 41: KPLC - assumed depreciation rates pre- and post-2020-21 assets (% per annum)

	Existing assets	New assets
Land	2.00%	2.00%
Transmission	2.97%	3.04%
Distribution	3.16%	3.15%
Machinery	4.09%	6.66%
Motor vehicles	4.63%	25.00%
Furniture, equipment others	10.50%	20.00%

Source: Own analysis and KRA

Based on the proposed capital expenditure path and the above depreciation rates, the following annual depreciation allowance is determined.

Table 42: KPLC - assumed depreciation profile 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Land	237,991	252,991	267,991	282,991	297,991	312,991
Transmission	981,772	981,772	1,093.826	1,253,426	1,413,026	1,572,626
Distribution	8,193,185	8,694,113	9,394,784	10,406,642	11,016,593	11,626,543
Machinery	49,273	286,436	523,598	760,761	997,924	1,235,086
Motor vehicles	359,845	597,345	834,845	1,072,345	1,309,845	1,292,115
Furniture, equipment others	5,404,738	6,277,138	6,260,548	2,617,200	3,489,600	4,362,000
TOTAL	**15,226,804**	**17,089,795**	**18,375,592**	**16,393,365**	**18,524,978**	**20,401,361**

Source: Own analysis

The corresponding end of year net book value (RAB) is set out below.

Table 43: KPLC - assumed end of year RAB 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Land	10,666,638	11,163,647	11,645,656	12,112,665	12,564,674	13,001,684
Transmission	20,199,701	22,903,930	27,060,104	31,056,677	34,893,651	38,571,025
Distribution	214,018,910	227,568,297	250,296,013	259,252,871	267,599,778	275,336,736
Machinery	4,450,944	7,725,508	10,762,909	13,563,148	16,126,225	18,452,138
Motor vehicles	2,493,995	2,846,650	2,961,805	2,839,460	2,479,615	2,137,500
Furniture, equipment others	14,282,487	12,367,348	10,468,800	12,213,600	13,086,000	13,086,000
Work in progress	31,072,925	42,515,925	29,756,925	29,756,925	29,756,925	-4,479,575
TOTAL	**297,185,600**	**327,091,305**	**342,952,213**	**360,795,347**	**376,506,869**	**356,105,508**

Source: Own analysis

10.1.4.3 Return on capital

The return on capital is calculated by applying a vanilla WACC to the RAB. The vanilla specification of the WACC is based on the pre-tax cost of debt and post-tax cost of equity, with each value weighted by the assumed gearing, namely the share of debt and equity respectively in company finance.

The vanilla WACC is developed under two key scenarios:

- The first, is based on an estimate of efficient financing values, though reflecting the fact that KPLC receives concessional debt financing,
- The second, is the same as the above but with the cost of equity constrained to be 12.5%, which we understand is regulatory practice in Kenya.

In both cases gearing of 60% is assumed. An in-depth review of the WACC was undertaken for the 2018 Cost of Service study, the values of which we use here, and which are the following:

Table 44: Estimate of the WACC (%)

	Efficient financing	Constrained cost of equity
Cost of debt	6.5%	6.50%
Gearing	60%	60%
US risk free rate	2.25%	
Equity Risk Premium	13.32%	
Mature Market Risk Premium	6.25%	
Country Risk Premium	7.07%	
Equity beta	1.0	
Post tax cost of equity	15.57%	12.50%
Vanilla WACC	**10.13%**	**8.90%**

Source: Own analysis, and AF-Mercados Cost of Service Study, Final Report 2018.

In the estimation of KPLC's return on capital the second approach is applied. The former is applied in estimating the capital costs for the ITPs.

10.1.4.4 Operating expenditure and tax

For KPLC's operating expenditure the following approach is applied:

- For O&M related to distribution assets, the base year is taken as the reported value for 2019-20, with the allowance increasing in subsequent years by the change in Gross Book Value multiplied by 3.5%.
- For O&M related to transmission assets, the base year is taken as the reported value for 2019-20, with the allowance increasing in subsequent years by the change in Gross Book Value multiplied by 2.5%.
- For commercial services, reflecting relatively stable trajectory over time, an annual increase of 2% is included.
- For administrative services, reflecting notable increases in recent years, annual growth of 5% is applied.

The resulting estimates are produced.

Table 45: KPLC - assumed O&M cost profile 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Distribution & network manag't	4,340,735	5,119,257	6,243,545	6,921,267	7,598,990	8,276,712
Transmission	2,089,846	2,181,996	2,313,246	2,444,496	2,575,746	2,706,996
Commercial services	2,453,748	2,502,823	2,552,879	2,603,937	2,656,015	2,709,136
Administration	20,948,829	21,996,271	23,096,084	24,250,889	25,463,433	26,736,605
TOTAL	29,833,158	31,800,346	34,205,754	36,220,588	38,294,184	40,429,448

Source: Own analysis

Estimated tax is calculated in the Financial Statements for each year based on the overall revenue requirement and estimated costs.

10.1.4.5 Total KPLC revenue requirement

Based on the above approach, the following overall revenue requirement for KPLC is determined:

Table 46: KPLC – Estimated revenue requirement by activity 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
D - return on capital	22,596,041	24,025,009	26,231,976	27,488,627	28,570,653	29,500,733
D - depreciation	14,245,032	16,108,024	17,281,766	15,139,939	17,111,952	18,828,735
D - opex	27,743,312	29,618,351	31,892,508	33,776,092	35,718,438	37,722,453
D - tax	4,121,143	4,403,579	4,839,229	5,112,554	5,354,061	5,567,587
TOTAL DISTRIBUTION	**68,705,528**	**74,154,962**	**80,245,479**	**81,517,212**	**86,755,105**	**91,619,508**
T - return on capital	1,856,076	2,102,893	2,480,785	2,845,858	3,196,775	3,533,614
T - depreciation	981,772	981,772	1,093,826	1,253,426	1,413,026	1,572,626
T - opex	2,089,846	2,181,996	2,313,246	2,444,496	2,575,746	2,706,996
T - tax	0	0	0	0	0	0
TOTAL TRANSMISSION	**4,927,694**	**5,266,661**	**5,887,857**	**6,543,780**	**7,185,547**	**7,813,236**
Return on capital	24,452,117	26,127,902	28,712,761	30,334,485	31,767,428	33,034,348
Depreciation	15,226,804	17,089,795	18,375,592	16,393,365	18,524,978	20,401,361
Opex	29,833,158	31,800,346	34,205,754	36,220,588	38,294,184	40,429,448
Tax	4,121,143	4,403,579	4,839,229	5,112,554	5,354,061	5,567,587
TOTAL KPLC	**73,633,222**	**79,421,622**	**86,133,337**	**88,060,992**	**93,940,652**	**99,432,744**

Source: Own analysis

10.1.5 REREC (distribution)

Allowance is included in the revenue requirement for O&M expenditure undertaken by KPLC on REREC's behalf. O&M expenditure for three classes of expenditure – network management, commercial services, and administration – are incorporated, consistent with the reporting in KPLC's annual reports.

An overall increase in O&M allowance is determined based on 2.5% of the increase in expenditure as set out in REREC's strategic plan. The total allowance is then divided between network management, commercial services, and administration as per the reported shares of each service in total O&M on assets constructed by REREC in 2019-20. The following values are calculated:

Table 47: Opex on assets constructed by REREC 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Identified capex	*16,009,000*	*16,009,000*	*16,009,000*			
Network management	4,106,807	4,387,285	4,667,762	4,667,762	4,667,762	4,667,762
Commercial services	2,696,122	2,880,255	3,064,389	3,064,389	3,064,389	3,064,389
Administration	1,401,316	1,497,020	1,592,724	1,592,724	1,592,724	1,592,724
TOTAL OPEX	**8,204,245**	**8,764,560**	**9,324,875**	**9,324,875**	**9,324,875**	**9,324,875**

Source: Own analysis

10.1.6 Total revenue requirement

The total revenue requirement is estimated to rise from KSh 176 billion in 2020-21 to KSh 244 billion by 2025-26. By sector roughly half of the total cost is accounted for by costs of generation as shown below.

Table 48: Total revenue requirement by sector 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Generation	91,583,243	99,366,907	105,477,803	109,389,096	113,000,812	118,853,099
Transmission	8,000,343	10,217,538	13,622,513	19,528,272	23,037,239	23,869,748
Distribution/retail	76,909,773	82,919,522	89,570,354	90,842,087	96,079,980	100,944,383
TOTAL RR	**176,493,360**	**192,503,967**	**208,670,671**	**219,759,455**	**232,118,031**	**243,667,230**

Source: Own analysis

By organization, the share of the revenue requirement accounted for by IPPs, KETRACO and imports rises, with that of KPLC relatively stable, and the share of KenGen declining.

Table 49: Total revenue requirement by organisation 2020-21 to 2025-26 (KSh'000)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
KenGen	52,748,026	50,244,689	48,935,366	49,198,849	50,893,957	51,803,358
IPPs	38,487,823	40,910,166	47,288,173	50,845,333	52,808,995	57,403,886
Other inc. imports	347,394	8,212,052	9,254,265	9,344,914	9,297,859	9,645,855
KETRACO	3,072,649	4,950,877	7,734,656	12,984,492	15,851,693	16,056,512
KPLC transmission	4,927,694	5,266,661	5,887,857	6,543,780	7,185,547	7,813,236
KPLC distribution	68,705,528	74,154,962	80,245,479	81,517,212	86,755,105	91,619,508
O&M for REREC	8,204,245	8,764,560	9,324,875	9,324,875	9,324,875	9,324,875
TOTAL	**176,493,360**	**192,503,967**	**208,670,671**	**219,759,455**	**232,118,031**	**243,667,230**

Source: Own analysis

Overall, an increase in the average revenue requirement to 2022-23 is forecast, after which the average value stabilizes.

Table 50: Average revenue requirement 2020-21 to 2025-26 (KSh/MWh)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Total RR (KSh'000)	176,493,360	192,503,967	208,670,671	219,759,455	232,118,031	243,667,230
Energy generated (GWh)	12,343	12,977	13,518	14,152	14,685	15,517
Average Rev Req (per unit generated)	**14,299**	**14,834**	**15,437**	**15,529**	**15,806**	**15,703**

10.2 Annex 2 – Tariff Modelling

The model used to calculate the tariffs has been CALCUTTA, an in-house model developed for this purpose. Based on the revenue requirement calculations, the CALCUTTA model allows for two types of tariffs to been modelled:

- End-user tariffs, and
- Wheeling tariffs.

The wheeling tariffs are effectively an input to the end-user tariffs. Wheeling tariffs have been developed reflecting the network costs at each voltage level. In doing so, they are considered as equivalent to the stand-alone network tariff for that voltage level. This means that a customer that is connected at 11kV and purchases energy from a generator connected at 132kV will pay the same wheeling rate as a customer connected at 11kV and with an agreement for local generation at 11kV. This approach is preferred as it is revenue neutral for KPLC, simplifies calculations, and avoids artificial incentives for customer to contract energy from generators located at low voltage levels.

Several inputs are required for the tariff modelling, following which calculations are undertaken.

10.2.1 Input data

10.2.1.1 Demand Forecast

The revenue requirement has been developed based on the (gross) demand forecast applied in the LCPDP 2021-30. For tariff setting, forecasts of consumption and losses at the level of customer category is required. Data on both these factors were provided by KPLC. A small adjustment has been made to reconcile the KPLC consumption forecast with the Master Plan generation forecast to maintain the loss reduction target assumed by KPLC. Resulting forecasts are set out below.

Table 51: Consumption forecast by customer category (GWh)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
SC	1,462	1,581	1,639	1,690	1,753	1,799	1,909
Dom	3,353	3,792	4,117	4,394	4,694	4,947	5,376
SL	80	96	109	120	132	142	158
CI-1	1,693	1,762	1,824	1,880	1,951	2,016	2,085
CI-2	1,286	1,317	1,342	1,358	1,384	1,405	1,453
CI-3	505	563	622	693	777	867	897
CI-4	629	644	657	665	678	688	711
CI-5	458	462	466	465	467	467	484
Total Consumption	**9,466**	**10,217**	**10,776**	**11,265**	**11,836**	**12,331**	**13,075**
Losses	1,996	2,126	2,201	2,253	2,316	2,354	2,442
TOTAL ENERGY	**11,462**	**12,343**	**12,977**	**13,518**	**14,152**	**14,685**	**15,517**
Losses (%)	17.42%	17.22%	16.96%	16.67%	16.36%	16.03%	15.74%

Source: Own estimates based on data in LCPDP 2021-30 and KPKC data. No demand is included in the CI-6 category.

10.2.1.2 Losses

The treatment of losses is a critical component of tariff setting as higher losses necessitate a higher tariff for the company to earn the same revenue requirement (all other things being equal). The system losses need to be defined for each voltage level. This data is used to calculate for each tariff group a “loss penalty” proportionally to the use of the grid. Thus, customers at low voltage have a loss penalty from high voltage, medium voltage, and low voltage, whereas customer connected at medium voltage have a loss penalty from high voltage and medium voltage only.

The following loss breakdown by voltage level is applied, based on KPLC data.

Table 52: Loss forecast by voltage level (%)

	2019-20	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Total system	23.7%	23.16%	22.66%	22.16%	21.66%	21.16%	20.66%
High Voltage	4.4%	4.22%	4.08%	3.94%	3.80%	3.66%	3.51%
Medium Voltage	6.4%	6.3%	6.2%	6.1%	5.9%	5.8%	5.7%
Low Voltage	12.9%	12.6%	12.4%	12.2%	11.9%	11.7%	11.4%

Source: KPLC

The forecast of losses includes both technical and commercial (non-technical) losses. If correctly set, this should be consistent with cost recovery, and provide strong incentives for efficiency on the part of KPLC. The following table shows the resulting estimates of technical losses per voltage level and capacity losses per voltage level used in the Calcutta model.[27]

[27] The numbers are not strictly additive as the LV figures show the losses related to demand on the LV network, the MV losses show that losses on the MV network plus those related to demand and losses on the LV network, while those on the HV relate to supplying all demand.

Table 53: CALCUTTA inputs. Technical energy losses and capacity losses per voltage level (%)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Technical losses						
LV	1.73%	1.82%	1.88%	1.94%	1.91%	1.86%
MV	6.30%	6.18%	6.06%	5.94%	5.82%	5.70%
HV	4.22%	4.08%	3.94%	3.80%	3.66%	3.51%
Capacity losses						
LV	2.64%	2.64%	2.64%	2.64%	2.64%	2.64%
MV	9.75%	9.75%	9.75%	9.75%	9.75%	9.75%
HV	6.61%	6.61%	6.61%	6.61%	6.61%	6.61%

Source: Own calculations

10.2.1.3 Time of use

The different time blocks in the load curve need to be defined to calculate appropriate ToU tariffs. Based on the current KPLC tariffs, published in November 2018, two blocks are defined: peak and off peak. Three different peak and off-peak blocks are defined depending on the day (weekday, Saturdays/holidays, and Sundays), however, the inputs for Calcutta define only an average day. For this reason, the definition for the weekdays has been chosen to define the ToU blocks:

- Off-peak hours: from 00:00 to 06:00 and from 22:00 to 00:00
- Peak hours: from 07:00 to 21:00.

The TOU component of the tariff is reflected in the energy charge, with this value varying by time-period. The evaluation of the energy charge for each timeframe is undertaken considering the energy mix and the PPAs of the dispatched units. The marginal technologies making the difference between the two different states, have their cost mainly reflected on the capacity charge of the PPA. For this reason, when calculating the energy charge of the tariff, both energy and capacity charge of the PPAs need to be considered.

10.2.1.4 Power Factor

The electric power is the rate, per unit time, at which electrical energy is transferred by an electrical circuit and is calculated as the product of the voltage drop across the element and the current flowing through it.

In DC power systems, the circuit behaves as resistive and the entire electrical power is dissipated in the form of heat, that is, inductor and capacitor are in steady state. This type of circuit causes no phase difference between current and voltage.

However, in the case of AC power systems, both the inductor and the capacitor offer certain amount of impedance. The inductor stores electrical energy in the form of magnetic energy and the capacitor stores electrical energy in the form of electrostatic energy. Neither of them dissipates it. Hence, when considering the entire circuit consisting of resistor, inductor and capacitor, there exists some phase between the source voltage and the current due to this energy dissipated and stored. For this reason, the electric power (apparent power) is divided into two terms, the real power, and the reactive power. While active power is the actual energy being used, reactive power is used to provide the voltage levels necessary for active power to do useful work. The power factor is the relation between apparent power and active power; thus, it is a measure of AC electrical systems efficiency. For CALCUTTA model, the power factor has been defined for each voltage level as follows:

- LV – 0.85
- MV – 0.90
- HV – 0.95

10.2.1.5 Customer numbers and energy consumption per tariff group

The forecast total number of customers is as per the estimates provided by KPLC. However, no information was provided on either the split of domestic customers and small commercial customer among their 2 sub-categories, nor the split of the five bands of commercial and industrial customers (CI1 to CI5).

To split the domestic customers, based on previous information that the domestic customers with a consumption lower than 50 kWh represented 69% of DC customers and consumed 15% of the total domestic energy, a polynomic regression was developed to estimate that the change of sub-category into bands above and below 100 kWh would result in 77% of the DC customers consuming less than 100kWh, with these customers representing 22% of total category consumption.

For small commercial customers, it is assumed that 35% of customer consume less than <100 kWh, accounting for 9% of total SC energy. This results in average consumption close to 100 kWh for the lower category, but without exceeding it.

Commercial and industrial customers are split based on the same average split between its sub-categories (CI1-CI5) in the previous period.

Resulting estimate of consumer numbers are set out below.

Table 54: Forecast of customer numbers 2020-21 to 2025-26 (million)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
LV	**8.1389**	**8.7009**	**9.2499**	**9.7859**	**10.3097**	**10.8450**
Domestic 0 - 100 kWh	5.9370	6.3630	6.7778	7.1826	7.5782	7.9823
Domestic >100 kWh	1.7734	1.9006	2.0246	2.1455	2.2636	2.3843
Small Commercial 0-100 kWh	0.1424	0.1447	0.1474	0.1503	0.1531	0.1560
Small Commercial > 100 kWh	0.2645	0.2687	0.2738	0.2791	0.2843	0.2897
Street lighting	0.0185	0.0208	0.0229	0.0250	0.0269	0.0288
Commercial and Industrial CI1	0.0031	0.0032	0.0034	0.0035	0.0036	0.0038
MV	**0.0006**	**0.0006**	**0.0006**	**0.0007**	**0.0007**	**0.0007**
Commercial and Industrial CI2	0.0005	0.0005	0.0005	0.0006	0.0006	0.0006

Commercial and Industrial CI3	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
HV	**0.0001**	**0.0001**	**0.0001**	**0.0001**	**0.0001**	**0.0001**
Commercial and Industrial CI4	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001
Commercial and Industrial CI5	0.0000	0.0000	0.0001	0.0001	0.0001	0.0001
TOTAL	**8.1396**	**8.7017**	**9.2507**	**9.7867**	**10.3105**	**10.8459**

Source: Own analysis from KPLC data. No consumers are included for CI6

The corresponding forecast of energy consumption by tariff block is set out below

Table 55: Energy consumption by tariff block 2020-21 to 2025-26 (GWh)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
LV	**7,231**	**7,689**	**8,084**	**8,530**	**8,904**	**9,529**
Domestic 0 - 100 kWh	834	906	967	1,033	1,088	1,183
Domestic >100 kWh	2,958	3,211	3,427	3,661	3,858	4,193
Small Commercial 0-100 kWh	142	148	152	158	162	172
Small Commercial > 100 kWh	1,439	1,492	1,538	1,595	1,637	1,738
Street lighting	96	109	120	132	142	158
Commercial and Industrial CI1	1,762	1,824	1,880	1,951	2,016	2,085
MV	**1,880**	**1,964**	**2,051**	**2,162**	**2,272**	**2,350**
Commercial and Industrial CI2	1,317	1,342	1,358	1,384	1,405	1,453
Commercial and Industrial CI3	563	622	693	777	867	897
HV	**1,107**	**1,123**	**1,130**	**1,145**	**1,155**	**1,195**
Commercial and Industrial CI4	644	657	665	678	688	711
Commercial and Industrial CI5	462	466	465	467	467	484
TOTAL	**10,217**	**10,776**	**11,265**	**11,836**	**12,331**	**13,075**

Source: Own analysis from KPLC data. No consumption is assumed for CI6

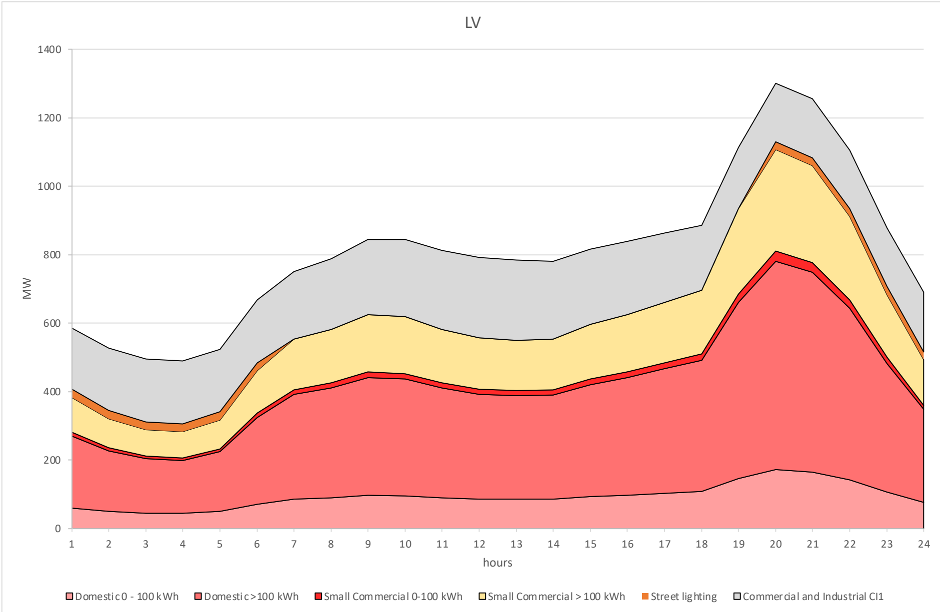
10.2.1.6 Load profile

The load profiles are used for different objectives, including:

- Calculating the capacity losses of the system.
- Calculate the different coefficients that will divide the total costs of the system between the different tariff groups.

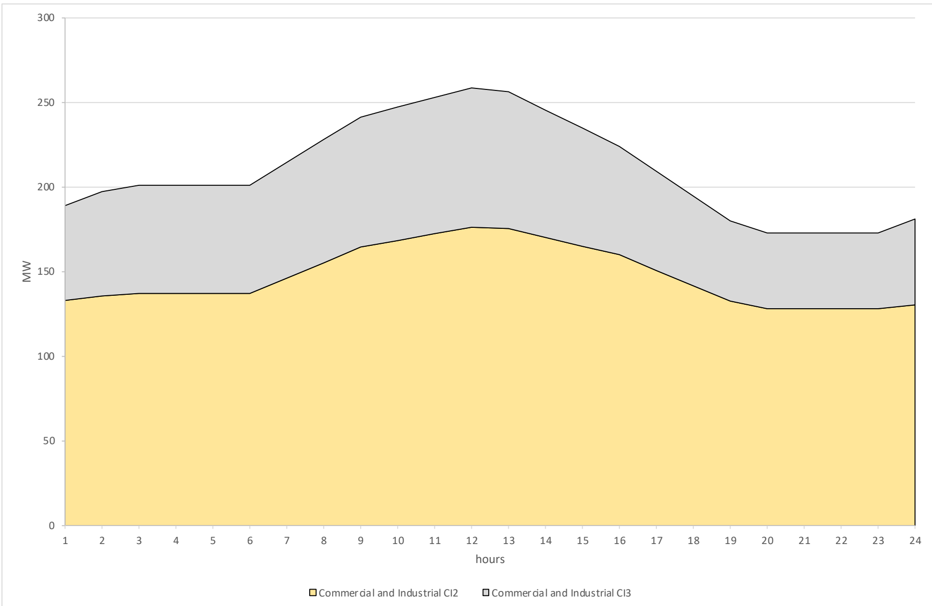
Information was received on the total load curve of the system. However, for tariff setting purposes specific information for each tariff group is needed. The same assumptions are applied as for the 2018 COSS to break-down the curve. The resulting load duration curves are set out below.

Figure 43: Load duration curve for LV customers (MW by hour)



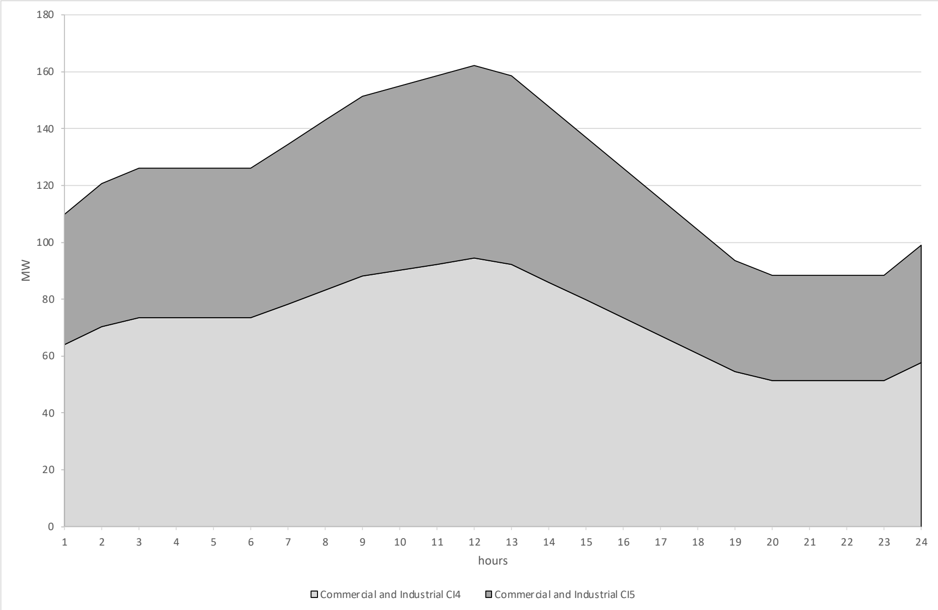
Source: Own assumptions based on total demand

Figure 44: Load duration curve for MV customers (MW by hour)



Source: Own assumptions based on total demand

Figure 45: Load duration curve for HV customers (MW by hour)



Source: Own assumptions based on total demand

10.2.1.7 Contracted Capacity

Typically, electricity tariffs are composed of up to three different charges:

- Fixed charge: amount charge to each consumer per billing period.
- Energy charge: amount charge to each consumer per unit consumed in each billing period.
- Demand charge: amount charge for demand supplied per kVA or kW in each billing period

Usually, the tariff for small consumers includes a fixed charge and an energy charge, though in this case a simple energy charge is applied. A demand charge is typically also included for large consumers. Therefore, it is necessary to know the capacity contracted or measured by each tariff group to divide proportionally the wheeling charges between large consumers.

The following table presents the capacity in kVA per large consumer in categories CI1 to CI5:

Table 56: Contracted capacity by tariff categories with demand component, 2020-21 to 2025-26 (kVA)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
LV	**5,891,378**	**6,301,166**	**6,730,353**	**7,179,527**	**7,646,280**	**8,136,866**
CI1	5,891,378	6,301,166	6,730,353	7,179,527	7,646,280	8,136,866
MV	**4,859,327**	**5,149,797**	**5,459,199**	**5,788,769**	**6,139,821**	**6,513,758**
CI2	3,638,842	3,853,139	4,081,403	4,324,545	4,583,535	4,859,406
CI3	1,220,486	1,296,657	1,377,795	1,464,223	1,556,286	1,654,352
HV	**2,993,332**	**3,167,645**	**3,353,319**	**3,551,094**	**3,761,758**	**3,986,154**
CI4	1,699,187	1,793,846	1,894,672	2,002,068	2,116,462	2,238,310
CI5	1,294,145	1,373,799	1,458,647	1,549,026	1,645,297	1,747,844

TOTAL	**13,744,037**	**14,618,608**	**15,542,871**	**16,519,389**	**17,547,860**	**18,636,778**

Source: Own analysis from KPLC data. No capacity is assumed for CI6.

10.2.2 Cost inputs

The key system costs to be recovered through tariffs can be divided into three different blocks:

- Retail service costs: represent the costs that do not depend on actual energy usage (e.g., those associated with customer administration, metering, invoicing and collection).
- Transmission and distribution costs: represent the cost of maintenance, operation, and planning of the system. These costs are fixed for the system.
- Generation costs: represent the cost of the energy generation.

10.2.2.1 Retail service costs

The retail service costs are represented as the commercial services in KPLC's Financial Statements. The following table presents the composition of these costs for 2019-20:

Table 57: Estimate of KPLC retail service costs 2019-20 (KSH'000)

Activity	Amount
Salaries and Wages	4,424,060
Depreciation	4,253,780
Advertising and public relations	131,560
Staff welfare	29,863
Transport and travelling	286,656
Consumable goods	15,182
Office expenses	12,760
Other costs	17,542
TOTAL COSTS	**9,171,403**

Source: KPLC Annual Report 2019-20, includes costs attributed to rural electrification scheme

For tariff setting purposes, retail service costs are assumed to be zero to ensure that no fixed charge is included consistent with the current tariff schedule, with all these costs allocated as part of the distribution costs.

10.2.2.2 Transmission and distribution costs

The costs of the transmission and distribution network can be interpreted as the cost of operation, maintenance, and planning of the system. These costs have been represented through the Long Run Marginal Cost (LRMC). The values applied in the 2018 COSS have been used based on confirmation by KPLC. The method applied to calculate the LRMC in that study was the Average Incremental Cost (AIC) method. These were calculated for both transmission and distribution. The following table presents the LRMC estimated for each voltage level:

Table 58:LRMC inputs

LRMC	KSh/kW/year
LV	12,576
11 kV	3,386
33 kV	3,200
66 kV	466
HV	27,629

Source: AF Mercados Cost of Service Study, 2018

In general, it is expected that the LRMC will decrease from LV to HV. A feature of these figures is that up to 66kV this relationship holds, with planned investment in 66kV particularly low in comparison with lower voltages. However, huge investment on the transmission network reverses this relationship for 132kV and above. A similar jump in transmission investment is assumed in the capital expenditure, and hence the similar divergence between HV and the lower voltage levels is considered equally applicable here.

10.2.2.3 Generation costs

The generation costs are sometimes known as the retail supply cost. These costs depend on the energy consumption, with costs increasing as more expensive technologies are required to supply the energy to the system. The generation dispatch has been obtained from the SDDP model used to minimise the operation costs of the system and considering agreed PPAs between KenGen or IPPs and KPLC.

To evaluate the time of use tariffs, two different values of the generation costs are needed:

- Generation costs during peak hours
- Generation costs during off-peak hours

The CALCUTTA model calculates internally the average generation cost weighting the different costs depending on the duration of each time-block. The approximation applied to represent the costs in the different time-blocks considers not only the energy charge of each generation unit but also its capacity charge. If only the energy charge is considered, there is no difference between peak and off-peak. However, the peak is considered most relevant for capacity costs, with these allocated entirely to peak periods.

The generation costs comprise:

- Energy charge: composed by energy and capacity charge of the generators.
- Fuel charge.
- Other charges: including steam costs, FERFA and INFA.

The first two terms have been considered variable for each time block. However, “Other charges” have been considered equal for all time blocks. Only the energy charge is reflected in the non-fuel tariffs defined. However, the fuel charge and the FERFA and INFA are variable costs that are updated monthly in the end-user tariffs.

The following table presents the generation costs of the system split by time-period:

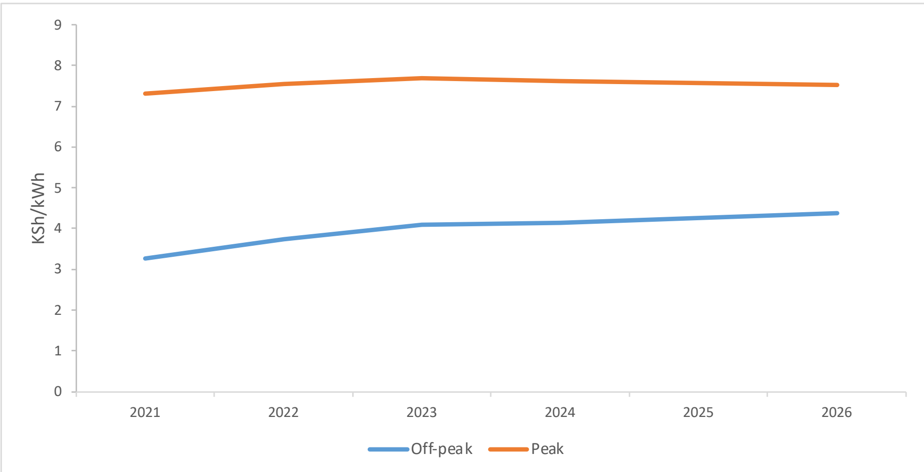
Table 59: Calculated generation costs, 2020-21 to 2025-26 (KSh/kWh)

	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
Energy Charge						
Off-peak	3.29	3.74	4.12	4.18	4.28	4.40
Peak	7.33	7.58	7.74	7.69	7.64	7.56
Fuel Charge						
Off-peak	0.01	0.03	0.02	0.01	0.00	0.02
Peak	0.04	0.04	0.02	0.01	0.01	0.03
Other charges	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL						
Off-peak	3.30	3.77	4.14	4.19	4.29	4.43
Peak	7.37	7.62	7.76	7.69	7.65	7.59

Source: Own analysis. Other charges include FERFA, INFA and royalty payments.

The resulting estimates are set out graphically below.

Figure 46: Estimated peak and off-peak energy charges 2020-21 to 2025-26 (KSh/kWh)



Source: Own analysis

10.2.3 Tariff Structure

The end-of user tariff is composed by the three different charges which represent the costs to be recovered, namely:

- Retail charge: retail service costs
- Wheeling charge: transmission and distribution costs
- Energy charge: generation costs.

Depending on the type of customer, the form of charging varies.

10.2.3.1 Retail service

The retail service cost is a fixed charge for the customer that does not depend on the amount of energy consumed. As noted earlier, in the model the fixed is constrained to be zero, with the costs of retail service allocated to the general costs of distribution.

10.2.3.2 Wheeling charges

The wheeling charges represent the fixed costs of the system. These costs are evaluated through the LRMC of the transmission and distribution network. All users of the transmission and distribution facilities should pay for the network usage of the system following an efficient pricing mechanism that can recover the costs and allocate them to the users in a proper way. For this reason, this is the key charge that varies according to the tariff group.

The coincident peaks methodology has been applied to allocate existing network costs. In this approach the allocation of the fixed costs depends on the participation of each group during the peak hours of the system.
The costs to be allocated – namely the LRMC by voltage level, are set out below on a fixed cost per KVA per month basis.

Table 60:LRMC by voltage level

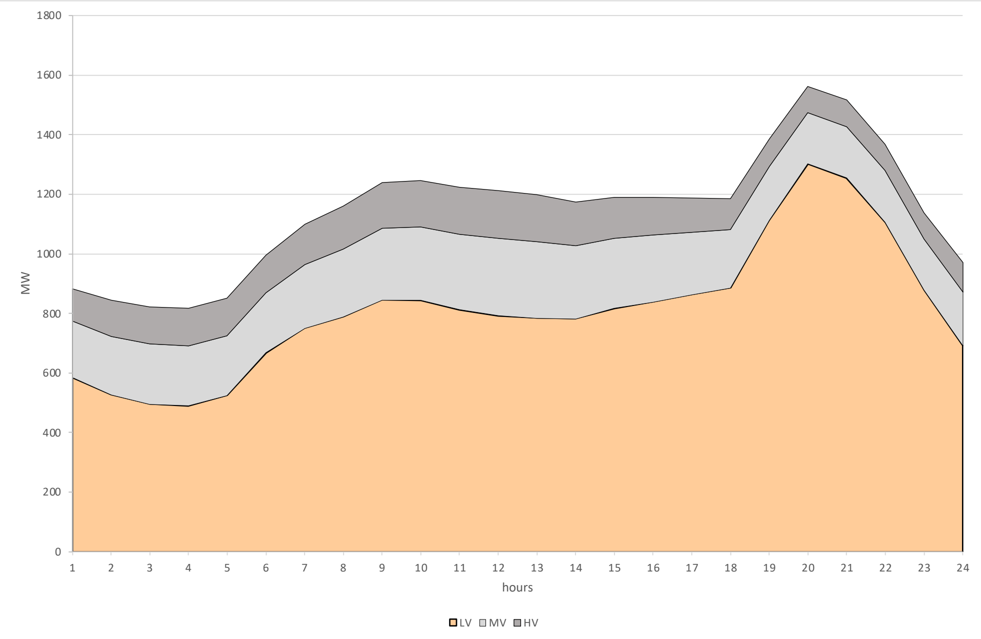
LRMC	KSh/kVA/month
LV	891
11 kV	254
33 kV	240
66 kV	37
HV	2,187

Source: Own analysis from data in AF Mercados Cost of Service Study, 2018

In addition to these fixed costs, an allowance for technical and non-technical losses is included. They are evaluated through factors that vary depending on the voltage level.

Under the coincident peaks methodology only the peak of the system is analysed to allocate the fixed cost of the system. The following figure presents the total load curve of the system divided by voltage level. The peak hours are broadly between 19:00 and 22:00.

Figure 47: Estimated load profile of system and contribution by voltage level (MW by hour)



Source: Own analysis

A notable feature of the above graph is that there is a clear peak in LV demand at the system peak hours, while those of MV and HV occur earlier in the day.

Two different coincident peak factors (CPF) need to be defined:

- The CPF of the tariff group with its voltage level group (e.g., CI1 within LV)

$$CPF_{group(i)} = \frac{P_i(peak\ group)}{P_i(peak\ i)}$$

- The CPF of the voltage level with the total peak demand (e.g., LV to total peak demand).

$$CPF_{level\ i\ vs\ level\ j} = \frac{Pi\ (peak\ level\ j)}{P_i(peak\ level\ i)}$$

Finally, this wheeling charge may be represented as an energy charge or as a two-part charge. Where a two-part structure is used there is a need to include allowance for losses on an energy basis.

The following base year wheeling charges are calculated through this methodology:

Table 61: Estimated wheeling charge – coincident peaks methodology 2020-21

	1-part option: Energy Charge Wheeling Rate (KSh/kWh)	2-part option a) Capacity charge Wheeling Rate (KSh/kVA)	2-part option b Energy component (KSh/kWh)
LV			
Commercial and Industrial CI1	8.25	2,541	0.77
MV			

Commercial and Industrial CI2	5.38	1,699	0.38
Commercial and Industrial CI3	4.07	1,607	0.38
HV			
Commercial and Industrial CI4	3.56	1,189	0.26
Commercial and Industrial CI5	3.51	1,102	0.26
Commercial and Industrial CI6	2.11	981	0.26

Source: Own analysis from KPLC data

10.2.3.3 Energy retail tariff charge

The energy retail supply charge represents the generation cost of the system. There is no allocation difference of these cost between the different tariff groups, thus, the value of this charge is as specified previously.

In this table, the charges per time-block are specified. However, in the tariff calculation not only the Time of Use (ToU) tariff has been calculated but also the tariff for those customers that would not operate under ToU conditions. Moreover, this ToU tariff is only assumed available for Commercial and Industrial consumers (CI1 to CI6).

To obtain an average value of this energy costs a weighting factor has been calculated for each time-block during the day and for each tariff category. The sum of these factors for each tariff category considered is 1.0.

$$K = \frac{Daily\ load\ in\ time\ block}{Total\ daily\ load}$$

The values applied by tariff category are set out below.

Table 62: Retail supply charge – weighting factors

	K-off peak	K-peak
LV		
Domestic 0 - 100 kWh	0.29	0.71
Domestic >100 kWh	0.29	0.71
Small Commercial 0-100 kWh	0.29	0.71
Small Commercial > 100 kWh	0.29	0.71
Street lighting	0.82	0.18
Commercial and Industrial CI1	0.34	0.66
MV		
Commercial and Industrial CI2	0.34	0.66
Commercial and Industrial CI3	0.34	0.66
HV		
Commercial and Industrial CI4	0.34	0.66
Commercial and Industrial CI5	0.34	0.66
Commercial and Industrial CI6	0.34	0.66

Source: Own analysis

The resulting energy retail supply by tariff group is set out in the following table.

Table 63: Energy Retail Supply Charge per tariff group, 2020-21 (KSh/kWh)

	Average	Off-peak	Peak
LV			
Domestic 0 - 100 kWh	6.18	3.29	7.33
Domestic >100 kWh	6.18	3.29	7.33
Small Commercial 0-100 kWh	6.18	3.29	7.33
Small Commercial > 100 kWh	6.18	3.29	7.33
Street lighting	4.03	3.29	7.33
Commercial and Industrial CI1	5.96	3.29	7.33
MV			
Commercial and Industrial CI2	5.96	3.29	7.33
Commercial and Industrial CI3	5.96	3.29	7.33
HV			
Commercial and Industrial CI4	5.96	3.29	7.33
Commercial and Industrial CI5	5.96	3.29	7.33
Commercial and Industrial CI6	5.96	3.29	7.33

Source: Own analysis

The resulting fuel retail supply by tariff group is set out in the following table. This is very low, reflecting the limited assumed dispatch of fuel-fired generators.

Table 64: Fuel Retail Supply Charge per tariff group, 2020-21 (KSh/kWh)

	Average	Off-peak	Peak
LV			
Domestic 0 - 100 kWh	0.03	0.01	0.04
Domestic >100 kWh	0.03	0.01	0.04
Small Commercial 0-100 kWh	0.03	0.01	0.04
Small Commercial > 100 kWh	0.03	0.01	0.04
Street lighting	0.03	0.01	0.04
Commercial and Industrial CI1	0.03	0.01	0.04
MV			
Commercial and Industrial CI2	0.03	0.01	0.04
Commercial and Industrial CI3	0.03	0.01	0.04
HV			
Commercial and Industrial CI4	0.03	0.01	0.04
Commercial and Industrial CI5	0.03	0.01	0.04
Commercial and Industrial CI6	0.03	0.01	0.04

Source: Own analysis

Other charges (INFA, FERFA, royalties) are close to zero for all tariff categories.

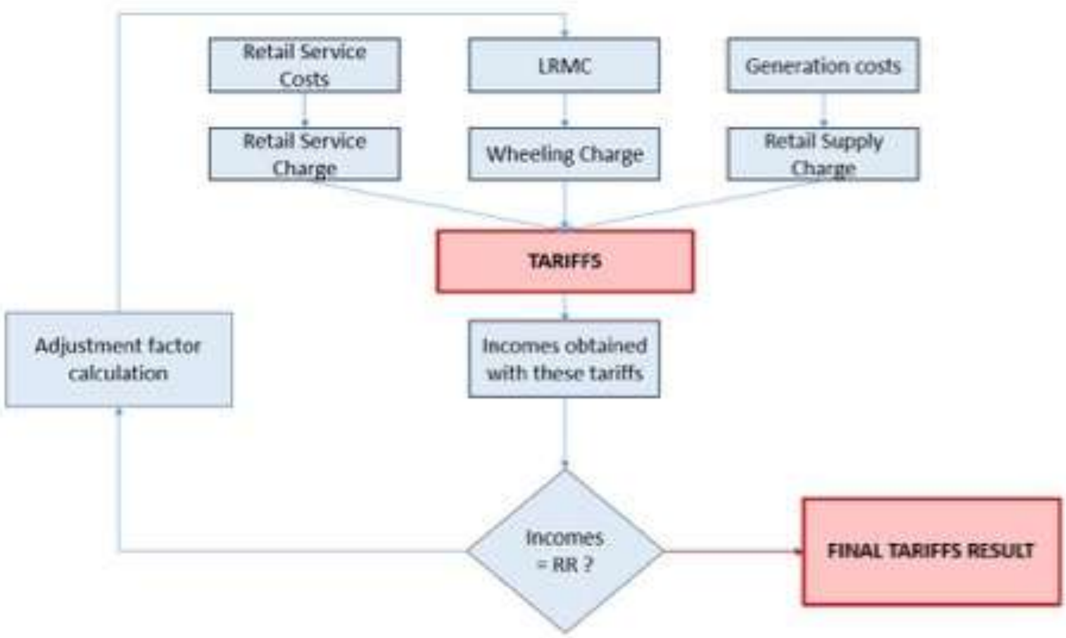
10.2.4 End user tariff development

Two key steps in tariff development are the estimation of a cost-reflective tariffs, and then its adjustment to reflect social or other constraints.

10.2.4.1 Cost reflective tariff

The methodology to calculate cost recovery tariffs is described in the following chart.

Figure 48: Tariff calculation flowchart



Three different charges are needed to calculate the cost recovery tariffs: retail service cost, wheeling charge and retail supply charge. However, in this case the retail service charge is constrained to be zero. The retail supply charge is divided equally between consumers and consumption respectively. In the case of the wheeling charge, depending on the voltage level where the customer is connected, different costs apply.

The process to estimate the wheeling charges is:

a. Define the energy consumption and the capacity contracted per tariff group.
b. Define the fixed cost of the system that in this case have been defined through the LRMC.
c. Choose an allocation method to divide these fixed costs between the different consumers. In this case, the coincident peak method has been applied.
d. Calculate the final wheeling charges per tariff group.

Once all the different charges are calculated and with the defined customers, consumption, and capacity contracted, the expected incomes are calculated. The main target of the tariff design is to recover all the revenue requirements of the system, thus, once these incomes are obtained, if they're different that the revenue requirements, an adjustment factor is applied. In this case, the adjustment factor has been designed so it just applies to the fixed charges of the system, that is, to the long run marginal cost.

The following tables present an estimate of cost reflective tariffs. The data presented contains the fixed charge, the energy charge, and the monthly charges, which refer to the variable part of the tariff updated each month (fuel cost, FERFA and INFA).

Table 65: First estimation of cost recovery/cost reflective tariffs

	Unit	Current	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
DC 0 - 100 kWh								
Energy charge	KSh/kWh	10.00	22.05	22.35	22.57	22.55	22.55	22.53
Monthly charges	KSh/kWh		0.03	0.04	0.02	0.01	0.01	0.03
DC >100 kWh								
Energy charge	KSh/kWh	15.80	22.05	22.35	22.57	22.55	22.55	22.53
Monthly charges	KSh/kWh		0.03	0.04	0.02	0.01	0.01	0.03
SC 0-100 kWh								
Energy charge	KSh/kWh	10.00	22.05	22.35	22.57	22.55	22.55	22.53
Monthly charges	KSh/kWh		0.03	0.04	0.02	0.01	0.01	0.03
SC > 100 kWh								
Energy charge	KSh/kWh	15.60	22.05	22.35	22.57	22.55	22.55	22.53
Monthly charges	KSh/kWh		0.03	0.04	0.02	0.01	0.01	0.03
Street lighting								
Energy charge	KSh/kWh	7.50	22.85	23.26	23.60	23.64	23.72	23.80
Monthly charges	KSh/kWh		0.01	0.03	0.02	0.01	0.01	0.02
CI1 TOU								
Energy charge peak	KSh/kWh	12.00	8.33	8.61	8.78	8.73	8.68	8.58
Monthly - peak	KSh/kWh		0.04	0.04	0.02	0.01	0.01	0.03
Energy charge o/p	KSh/kWh	6.00	3.74	4.25	4.68	4.75	4.86	5.00
Monthly – off peak	KSh/kWh		0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	800	2,541	2,541	2,541	2,541	2,541	2,541
CI2 TOU								
Energy charge peak	KSh/kWh	10.90	8.19	8.47	8.64	8.59	8.54	8.44
Monthly - peak	KSh/kWh		0.00	0.00	0.00	0.00	0.00	0.00
Energy charge o/p	KSh/kWh	5.45	3.68	4.18	4.61	4.67	4.79	4.92
Monthly – off peak	KSh/kWh		0.00	0.00	0.00	0.00	0.00	0.00
Demand charge	KSh/kWh	520	1,699	1,699	1,699	1,699	1,699	1,699
CI3 TOU								
Energy charge peak	KSh/kWh	10.50	8.19	8.47	8.64	8.59	8.54	8.44
Monthly - peak	KSh/kWh		0.04	0.04	0.02	0.01	0.01	0.03
Energy charge o/p	KSh/kWh	5.25	3.68	4.18	4.61	4.67	4.79	4.92
Monthly – off peak	KSh/kWh		0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kWh	270	1,607	1,607	1,607	1,607	1,607	1,607
CI4 TOU								
Energy charge peak	KSh/kWh	10.30	7.67	7.93	8.09	8.04	7.99	7.90
Monthly - peak	KSh/kWh		0.04	0.04	0.02	0.01	0.01	0.03
Energy charge o/p	KSh/kWh	5.15	3.44	3.91	4.31	4.37	4.48	4.60
Monthly – off peak	KSh/kWh		0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kWh	220	1,189	1,189	1,189	1,189	1,189	1,189
CI5 TOU								
Energy charge peak	KSh/kWh	10.10	7.67	7.93	8.09	8.04	7.99	7.90
Monthly - peak	KSh/kWh	5.05	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge o/p	KSh/kWh		3.44	3.91	4.31	4.37	4.48	4.60
Monthly – off peak	KSh/kWh	220	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kWh		1,102	1,102	1,102	1,102	1,102	1,102
CI6 TOU								

Energy charge peak	KSh/kWh	7.99	7.55	7.81	7.97	7.92	7.87	7.78
Monthly – peak	KSh/kWh		0.04	0.04	0.02	0.01	0.01	0.03
Energy charge o/p	KSh/kWh	4.00	3.39	3.85	4.25	4.31	4.41	4.53
Monthly charge	KSh/kWh		0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kWh	200	981	981	981	981	981	981

Source: Own analysis

10.2.4.2 Adjusted tariffs

The tariffs proposed in the previous section result in significant variations in customer tariffs, which may not be socially acceptable. For this reason, cross-subsidy adjustments will be necessary to facilitate their introduction, especially for DC and SC customers.

In this simplified cross-subsidy adjustment, intra-group cross-subsidies have been applied for the DC and SC categories, that is, subsidies inside the same tariff group. Specifically, the first band of the DC and SC groups is constrained at 10KSh/kWh. Commercial and industrial tariff remain unchanged.

The revised tariffs are set out below.

Table 66: Final tariffs (potential adjustment) 2020-21 to 2025-26

	Unit	2020-21	2021-22	2022-23	2023-24	2024-25	2025-26
DC 0 - 100 kWh							
Energy charge	KSh/kWh	10.00	10.00	10.00	10.00	10.00	10.00
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
DC >100 kWh							
Energy charge	KSh/kWh	25.45	25.84	26.12	26.10	26.09	26.06
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
SC 0-100 kWh							
Energy charge	KSh/kWh	10.00	10.00	10.00	10.00	10.00	10.00
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
SC > 100 kWh							
Energy charge	KSh/kWh	23.24	23.58	23.82	23.80	23.79	23.77
Monthly charges	KSh/kWh	0.03	0.04	0.02	0.01	0.01	0.03
Street lighting							
Energy charge	KSh/kWh	22.85	23.26	23.60	23.64	23.72	23.80
Monthly charges	KSh/kWh	0.01	0.03	0.02	0.01	0.01	0.02
CI1 TOU							
Energy charge peak	KSh/kWh	8.33	8.61	8.78	8.73	8.68	8.58
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.74	4.25	4.68	4.75	4.86	5.00
Monthly charge - o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	2,541	2,541	2,541	2,541	2,541	2,541
CI2 TOU							
Energy charge peak	KSh/kWh	8.19	8.47	8.64	8.59	8.54	8.44
Monthly charge - peak	KSh/kWh	0.00	0.00	0.00	0.00	0.00	0.00
Energy charge off-peak	KSh/kWh	3.68	4.18	4.61	4.67	4.79	4.92
Monthly charge – o/p	KSh/kWh	0.00	0.00	0.00	0.00	0.00	0.00

Demand charge	KSh/kVA	1,699	1,699	1,699	1,699	1,699	1,699
CI3 TOU							
Energy charge peak	KSh/kWh	8.19	8.47	8.64	8.59	8.54	8.44
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.68	4.18	4.61	4.67	4.79	4.92
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	1,607	1,607	1,607	1,607	1,607	1,607
CI4 TOU							
Energy charge peak	KSh/kWh	7.67	7.93	8.09	8.04	7.99	7.90
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.44	3.91	4.31	4.37	4.48	4.60
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	1,189	1,189	1,189	1,189	1,189	1,189
CI5 TOU							
Energy charge peak	KSh/kWh	7.67	7.93	8.09	8.04	7.99	7.90
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.44	3.91	4.31	4.37	4.48	4.60
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	1,102	1,102	1,102	1,102	1,102	1,102
CI6 TOU							
Energy charge peak	KSh/kWh	7.55	7.81	7.97	7.92	7.87	7.78
Monthly charge - peak	KSh/kWh	0.04	0.04	0.02	0.01	0.01	0.03
Energy charge off-peak	KSh/kWh	3.39	3.85	4.25	4.31	4.41	4.53
Monthly charge – o/p	KSh/kWh	0.01	0.03	0.02	0.01	0.00	0.02
Demand charge	KSh/kVA	981	981	981	981	981	981

Source: Own analysis

10.3 Annex 3 – Long Term Optimization of Hydroelectric Plants

The variable cost of ‘fuel’ for a hydro plant, water, is zero (unless a usage fee must be paid). However, when a hydro plant is associated to a specific reservoir its operation becomes linked over time. This means that using water for hydro generation today affects the future water level of the reservoir, and future system operation costs and risks (shortages, spilling). Thus, hydro plants with storage capacity have an opportunity cost associated with “moving” (or storing) energy from periods of higher water inflows and/or lower thermal costs in the system, to periods of higher costs, or even risk of shortage.

This opportunity cost represents the system savings between using hydro to replace thermal generation today (or in the extreme case, to avoid unserved energy), or later by storing water in the reservoir. Consequently, the optimal use of stored water in a reservoir requires looking into the future to choose the best decision - least cost or maximum profit decision.

Since the availability of hydroelectric energy is limited by reservoir storage capacity, this optimal policy should implicitly minimize expected variable costs and unserved energy in the power system. To some extent means that unnecessary spilling should also be minimized.

In practice, this means the plant is exposed to a **hydrological risk**. This hydrological risk can be measured as the relationship between the economic value of a hydro generation decision in each moment and the future economic consequences of the decision, taking into consideration the following hydrological uncertainties:

- If stored water is used for power generation today, the hydro-energy reserves stored in the reservoir are reduced. If a drought occurs later, or the demand is higher than expected, the system will require more expensive thermal generation than that which would be required if water had been stored. Load shedding may also be required, also causing an increase in system operation costs.
- When stored water is not used to generate power today, maintaining higher reservoir levels, the empty storage capacity of the reservoir is reduced. Wet conditions, such as higher than expected rainfall or other inflows may later cause "unnecessary spilling". Unnecessary spilling is water that is spilled from the reservoir but that could have been used to produce energy if previous decisions on hydro generation had been different. This means a waste of energy and, in consequence, an increase in operation costs. However, it is important to mention that sometimes water spilling may be an economically appropriate decision, not for an individual plant, but for chains of reservoirs, to take advantage of generation capacity located downstream of a reservoir.

Hence water storage and use are a dynamic optimization decision that requires a probabilistic evaluation on how not to store "too little" but also not to store "too much". The ideal solution to reservoir optimization is to establish a balance between the immediate benefit of using the water to generate power now and the future benefit of storage for later use. This leads to the opportunity cost of the stored water (or water value), that should be used by the SMO as an equivalent of the "fuel cost" for the dispatch of the hydroelectric plants.

Therefore, the recommendation for the initial phases of the KEM is the use of the opportunity cost of the water stored in the reservoirs as the variable cost of these plants in the economic dispatch of generation.