Regional Harmonization of Regulatory Frameworks and Tools for Improved Electricity Regulation in COMESA

Framework Report on Harmonized Comparison of Electricity Tariffs and Cost Reflectivity Assessment in the COMESA region

Submitted to: Regional Association of Energy Regulators for Eastern and Southern Africa (RAERESA)

Submitted by: CRISIL Limited

September 2024

Table of Contents

List of Tables

List of Figures

Abbreviations

Acronym	Full form
AfDB	African Development Bank
AfSEM	African Single Electricity Market
A&G	Administrative & General
BGT	Bulk Generation Tariff
CAPM	Capital Asset Pricing Model
CGF	Customer or Grant Financed
COMESA	Common Market for Eastern and Southern Africa
CoS	Cost of Service
CP	Coincident Peak
CPI	Consumer Price Index
CRAFT	Cost Reflectivity Assessment Framework Tool
CWIP	Capital Works in Progress
DT	Distribution Tariff
ECOWAS	Economic Community of West African States
EUT	End-user Tariff
FSU	Former Soviet Union
GDP	Gross Domestic Product
GFA	Gross Fixed Asset
GWh	Gigawatt hours
HCET	Harmonized Comparison of Electricity Tariffs
HFO	Heavy Fuel Oil
HV	High Voltage
kCal	Kilo Calorie
kW	Kilowatt
kWh	Kilowatt hour
LRMC	Long-run Marginal Cost
LV	Low Voltage
MV	Medium Voltage
MVA	Milli Volt Ampere
MW	Megawatt
MYT	Multi Year Tariff
NARUC	National Association of Regulatory Utility Commissioners
NCP	Non-Coincident Peak

Acronym	Full form
NEA	National Electricity Authority (Somalia)
NERSA	National Energy Regulator of South Africa
NFA	Net Fixed Asset
NWC	Net Working Capital
O&M	Operations & Maintenance
P&M	Plant & Machinery
RAB	Regulated Asset Base
RAERESA	Regional Association of Energy Regulators for Eastern and Southern Africa
RoI	Return on Investment
RoR	Rate of Return
RPI	Retail Price Index
RR	Revenue Requirement
SAIDI	System Average Interruption Duration Index
SBU	Strategic Business Unit
SRMC	Short-run Marginal Cost
ToU	Time of Use
TT	Transmission Tariff
UK	United Kingdom
USA	United States of America
USD	United States Dollar
WACC	Weighted Average Cost of Capital
WPI	Wholesale Price Index

Acknowledgements

This report was developed for RAERESA (Regional Association of Energy Regulators for Eastern and Southern Africa) by a team of consultants led by CRISIL Limited with funding from the African Development Bank (AfDB). The key roles played by the following institutions, groups and individuals is acknowledged:

- The African Development Bank for initiating and funding the study and providing continuous support through its team of experts and support staff. We are grateful for the inputs and support provided by Mr. Solomon Sarpong, Senior Energy Economist/Task Manager for Regional Harmonisation Project, Mr. Kambanda Callixte, Manager for the Energy Policy, Regulation and Statistics Division and Ms. Guillaine Neza, Senior Energy Specialist (Policy and Regulations)
- RAERESA for its direct supervision of the study, methodological and practical support, including liaising with member countries for provision of data and participation in stakeholder workshops, under the leadership of Dr. Mohamedain Seif Elnasr, Chief Executive Officer and important support from Harrison Murabula, Project Coordinator and Yvonne M. M. Mambwe
- Members of the Project Technical Working Group (PTWG) - EgyptERA, Energy Regulation Board (ERB) of Zambia, COMESA Secretariat, EREA, EAPP and RAERESA for their continuous review of the draft report and methodological support, particularly their active participation in various stakeholder workshops held at Nairobi, Cairo and Rwanda during the project development. The contributions of the following individuals are specifically acknowledged:
    - Ms. Salma Hussien Mohamed Osman, Head of Central Department for Technical Affairs and Licensing, Egyptian Utility and Consumer Protection Regulatory Authority (EgyptERA)
    - Mr. Humphrey Ngwale, Engineer Electricity, Energy Regulation Board, Zambia
    - COMESA Secretariat represented by Ms. Lanka P. Dorby, Director Information Networking
    - Mr. Augustino Bernard Massawe, Finance and Administration Lead (FAL), Energy Regulators Association of East Africa (EREA)
    - Mr. Zelalem Gebrehiwot, Technical Director, East Africa Power Pool (EAPP)
- Members of RAERESA's Portfolio Committee on Legal and Regulatory Harmonization, namely Egypt, Kenya and Sudan
- Planning and Operations Portfolio Committees of the Eastern Africa Power Pool (EAPP) represented by Mr. Ermias Bekele Hirpo, EAPP Planning Committee, Chairperson and Mr. Charles Maloba Obulemile, EAPP Operations Committee Representative
- The focal points for all the 12 Member States of COMESA along with South Sudan who played crucial roles in providing and validating the data used in the study, often with important and valued support from other stakeholders in the countries, including respective ministries and regulators and electricity utilities

We gratefully acknowledge the contributions of our various stakeholders who worked to help finalize the Report. It is worth noting that we have not exhausted the list of acknowledgements since many people contributed to the success of delivering this report, including the support staff at RAERESA and the African Development Bank.

Executive Summary

This workstream on Harmonized Comparison of Electricity Tariffs (HCET) and Cost Reflectivity Assessment Framework Tool (CRAFT) seeks to provide support to COMESA to develop a framework for harmonized comparison of electricity tariffs of member countries across the electricity supply chain. Tariff data and information will be fed into the framework to produce a maiden report of comparative analysis of tariff of COMESA and subsequently be updated annually to reflect changing tariff trends in the region.

The other aspect of this workstream involves development of a framework and tool to track and assess the real time process of countries migrating towards cost reflectivity of tariffs in accordance with the decision of the COMESA Council of Ministers responsible for Energy, that urged Member States to migrate to cost reflective tariffs to encourage investments in the energy sector.

Drivers of tariff

1. Generation characteristics

1.1. Generation profile
1.2. Electricity traded
1.3. Plant availability
1.4. Capacity utilization factor
1.5. Auxiliary consumption

2. Fuel characteristics *(applicable for thermal generation)*

2.1. Landed cost of fuel (USD/ tonne)
2.2. Generation heat rate (kCal/ kWh)

3. System characteristics

3.1. System load factor (%)
3.2. System minutes lost

4. Transmission characteristics

4.1. Network length - Transmission
4.2. Transformation capacity - Transmission
4.3. Network utilization factor - Transmission
4.4. Transmission system availability
4.5. Transmission losses

5. Distribution characteristics

5.1. Network length - Distribution
5.2. Transformation capacity - Distribution
5.3. Network utilization factor - Distribution
5.4. SAIDI
5.5. Distribution losses

6. Consumption characteristics

6.1. Electricity consumption per capita
6.2. Sales mix - voltage wise
6.3. Sales mix - category wise
6.4. Prepaid customers (%)

7. Access related

7.1. Urban Population density
7.2. Rural Population density
7.3. Electricity access - Urban
7.4. Electricity access - Rural

8. Financial performance

8.1. O&M expenses (Distribution & Supply) index
8.2. Collection efficiency (%)
8.3. Average debtor days

9. Macroeconomic parameters	10. Regulatory approaches	11. Market structure & Competition
9.1. GDP per capita 9.2. Inflation rate (CPI, WPI 70: 30) 9.3. Annual spend on electricity in relation to Average Household Income	10.1. Tariff methodology 10.2. Frequency of tariff revision 10.3. Automatic tariff adjustment mechanism 10.4. Adherence to cost of service principles?	11.1. Extent of unbundling 11.2. Market share index

Understanding the key drivers of generation, transmission and distribution tariffs help us carry out peer-to-peer comparison of tariffs in the COMESA region and analyze any discernible trends that may be observed.

Cost reflectivity and its key elements

Cost reflectivity assessment is *"determination of the aggregated cost to provide each element of the electricity service to each customer class in a fair and nondiscriminatory manner, and its comparison with tariff paid by the customer class"*. Such an assessment provides a granular view of the different costs and revenue requirements imposed by each customer class on the power system.

Cost reflectivity assessment can be a useful tool to achieve the following tariff objectives:

- determining affordable tariffs for low-income consumers along with the extent of financial support needed from Government to subsidize those consumers;
- identifying the extent of cross subsidization existing between consumer categories as well as between geographical regions;
- setting a trajectory for reducing cross subsidization; and
- setting a trajectory for transitioning towards cost reflective tariffs by providing a baseline assessment of the present cost reflectivity levels

Data requirements for carrying out a cost-of-service (CoS) assessment are extensive and, to some extent, subjective. This is because complete and precise data is never available. However, the cost-of-service results for electric utilities with a good information base tend to be more reliable than results for utilities with less available information. In any case, where precise information is lacking, estimates must be made by way of proxy data or "guesstimates," using the experience and general knowledge of the electric power industry.

The methodology consists of the following 5 steps:

1. Determination of Revenue Requirement (RR)
2. Functionalisation of costs
3. Classification of costs
4. Allocation of costs
5. Cost reflectivity assessment

Steps in a Cost-of-Service Study

Revenue requirement	• Determination of total revenue requirement (RR) of utility which needs to be recovered from all customers
Functional-isation	• Segregating the costs into major functions of the licensee such as generation, transmission, distribution and customer related
Classification	• Classifying costs into energy-, demand- and customer- related depending on the component of electricity service (energy consumption, capacity, customer service) that is being fulfilled
Allocation	• Allocating Energy, Demand, and Customer costs to customer classes based on factors like energy units, connected load, customer numbers, etc.
Cost reflectivity assessment	• Consolidating the costs allocated to each consumer category and comparing with the tariff paid by that category

Gaps in current tariff practices

Based on the review of the current tariff practices followed by the Member States, following key gaps are observed:

- Absence of an operational regulatory body in Djibouti, Eritrea, Libya, Somalia, South Sudan and Tunisia, which makes it challenging to implement well-defined tariff frameworks and regulations
- Limited regulatory independence with exceptions being Egypt, Kenya, Rwanda, Uganda – this limits the independence of the tariff setting process, with tariffs being set and approved by the government
- Lack of well-defined tariff methodologies and frameworks in most countries
- Absence of tariff pass-through mechanisms with exceptions being Kenya, Rwanda, Uganda
- Lack of regular tariff reviews with the tariffs being revised once in 3-5 years in most countries
- Lack of incentive-based tariff regulation with simple rate of return approach adopted in most Member States
- Subsidy dependence on the government in the form of capital subsidy for electricity projects and cross-subsidization in consumer categories

- Inadequate regulatory information systems, which makes reporting of tariff-based parameters such as customer category-wise average billing rate, consumer category-wise connected load, average cost of supply etc. challenging for most countries
- Lack of regulatory appeal process in most countries
- Lack of good consultative practices and full regulatory disclosure and transparency

Key tariff related recommendations

- **Tariff methodology**: A RoR-based methodology (cost plus approach) be adopted for determining the utility's overall revenue requirement and the revenue requirement for each customer category. This will provide that charges recoverable by the utility for the supply of electricity should allow it to earn a reasonable return on a fair value of its fixed assets in operation plus an allowance for its working capital.
- A **multi-year tariff approach** (RPI - x) may be implemented sometime in the future, but only after a suitable baseline has been established. However, simple multi-year productivity improvement signals may be easily incorporated using parameters such as employee productivity. The multi-year approach has its advantages, which include: (i) a lower cost of regulation and (ii) a better incentive provided to the utility to increase productivity. In the meantime, performance incentives can be implemented through the RoR methodology by taking a focused multi-year approach
- **Tariff based incentives/penalties**: The tariff structure should provide tariff-based incentives/penalties to customers for the improvement of energy efficiency, load factor, and power factor while maintaining simplicity of the structure.
- **Tariff cross-subsidization**: The most common type of subsidy provided in the electricity supply industry worldwide is cross-subsidization within the tariff structure. Usually, cross-subsidies flow from commercial and industrial customers to domestic and other small customers. The extent of such subsidies is revealed through a cost-of-service study. A certain amount of cross-subsidization in a tariff structure might be regarded as tolerable, given that sales to industrial/commercial customers pose a greater risk to the electric utility than do domestic sales, which tend to be more stable over time. Nonetheless, in keeping with best practices, cross-subsidy receivers generally should not pay less than about 90% of the cost of service and subsidy providers should not pay more than 110% of the cost of service.
- **Subsidization of the low-income customers**: For the utility to be commercially viable, if there is to be any significant subsidization of the low-income customers, it should be initiated and paid for, in principle, by the respective state government. A number of mechanisms can be employed to accomplish this, including: (i) direct reimbursement to the utility of the difference between the cost of service and the revenue generated by the lifeline tariff and (ii) direct payment by the government to low-income households, which pay the regular tariff to the utility
- **Capital subsidies**: Another method to subsidize low-income customers is to subsidize construction of new plant to serve low-income areas and eliminate upfront connection charges to the maximum extent possible. This method is particularly useful if the government wishes to increase the country's electrification rate.

- **Automatic adjustment mechanism**: The purpose of an automatic adjustment mechanism is to provide some financial protection to the utility and customer when costs fluctuate in such a manner that the normal tariff setting process cannot effectively deal with them. This mechanism will automatically permit a change in the price charged to customer to track changes in a certain pre-selected cost item (or items) without waiting for a tariff change to be implemented through the normal tariff setting process.

  Automatic adjustment mechanisms are typically applied to fuel prices. In addition to fuel prices, there are other costs that an electric utility can face that significantly impact its financial performance and are beyond its control. This might include foreign exchange losses or volatility in general which changes the price level of the goods and services required to produce electricity.
- **Incentive based tariff framework**
  - Given that improving the utility operational efficiency is a key objective, indication of efficiency signals to the utility through tariffs is critical. In the absence of RPI – x, an RoR-based tariff framework can be easily used to deliver these signals without a major increase in regulatory intervention. This is best achieved in a **multi-year framework** where the utility is permitted time to make investments for efficiency improvement and also reap its benefits. The incorporation of performance incentives in a RoR-based environment can be accomplished in the following manner:
  - The regulator should determine the revenue requirement to be recovered from tariffs over the selected multi-year period. For example, target distribution losses can be used to estimate power purchase requirement, which, in turn, is used to estimate power purchase cost. Also, target plant availability factors can be used to determine full or partial recovery of fixed costs of a generating plant.
  - Under the RoR methodology, the regulator should carry out periodic tariff review exercises over the multi-year period. If utility surpasses its targeted performance on the parameters, it may be allowed to retain the entire gain or share a certain portion of it with the customers. On the other hand, if the utility under-performs on its targets, it may have to bear the entire loss or share a certain portion of it with customers. The gains/losses that are determined to be borne by the utility can be used to adjust the revenue requirement for a subsequent period
- Member States should gradually migrate towards the cost-of-service analysis, and should start maintaining the desired data points for regular reporting of the cost-of-service results

Action Plan for Implementation

The key steps necessary at a regional, collective level to promote tariff harmonization are as:

- Steps should be taken to have an independent and well-governed regulator in fact as well as in law. The key requirement for regulators is to be independent and have transparent decision making. This will automatically set the base to have well-defined legal and regulatory tariff frameworks for the sector.

- Development of standardised tariff determination mechanisms to ensure that investors have greater confidence in investing in the regional market

- Availability of key documents in the public domain, grouped together and easily and freely accessible

- Regional regulator RAERESA to monitor and report performance of the Member States towards development of well-defined tariff regulations and cost reflective tariffs as an aid to the latter rather than as a European style compliance body
- Capacity building and support to national regulators and operators, and continuous collaboration between regulators through RAERESA and its sister regional organisations

The development of tariff harmonization and cost reflective framework tool are the first steps towards regional tariff harmonization. The Member States are at radically different stages of development in electricity reform and regulation and will require different level of intervention at different stages. It is clear that the individual effort to move towards cost reflective tariffs will be enormous compared with the human resources available to many regulators and governments. The individual challenge for some smaller states at a nascent stage of power sector development in moving towards harmonized tariff frameworks will be more than the ones with already developed regulatory frameworks. The framework and related tools should be viewed as an aid to help these states to gain ground, learning from more advanced peers and to avoid *'reinventing the wheel'* rather than some kind of external enforcement mechanism. This would also require **adequate regulatory information reporting** to be in place as data requirement for appropriate development of the cost-of-service model is quite extensive.

The **regional regulatory and market bodies will have a major role** to play in supporting all States, but the greatest benefit will be felt by those countries that have limited human, technical and financial capacities at present. By extending the practice of using technical, economic, legal and regulatory working groups drawn from experts within the Member States, the work on harmonizing tariff frameworks can be done through coordination and cooperation, under the leadership of the regional regulatory and market bodies.

1 Introduction

The **Regional Harmonization of Regulatory Frameworks and Tools for Improved Electricity Regulation in COMESA (the "Project")** is being undertaken to enhance the sustainability of the electricity sector of the region through **effective, uniform, transparent and enforceable regulatory frameworks that set out clear principles, rules, processes, and standards for the COMESA region** funded by the **African Development Bank (AfDB)**. The Project covers 12 COMESA Member States (Burundi, Djibouti, Egypt, Eritrea, Ethiopia, Kenya, Libya, Rwanda, Somalia, Sudan, Tunisia, and Uganda) and South Sudan. This report covers the development of framework for Workstream 2 of the Project.

1.1 Workstream 2

The workstream 2 on **Harmonized Comparison of Electricity Tariffs (HCET) and Cost Reflectivity Assessment Framework Tool (CRAFT)** seeks to provide support to COMESA to carry out harmonized comparison of electricity tariffs of Member States across the electricity supply chain.

The other aspect of this workstream involves development of a framework and tool to track and assess the real time process of countries migrating towards cost reflectivity of tariffs in accordance with the decision of the COMESA Council of Ministers responsible for Energy, that urged Member States to migrate to cost reflective tariffs to encourage investments in the energy sector. This component is expected to build upon the 2019 comparative tariff study commissioned by Economic Community of West African States (ECOWAS) with support from AfDB.[1]

The scope of work under Workstream 2 is as below.

i. Review existing electricity tariff structures and pricing methodologies in the COMESA region, and benchmark to regional and international best standards
ii. Identify key tariff comparison parameters and underlying drivers of tariffs in the COMESA region
iii. Develop a harmonized tariff comparison methodology
iv. Develop a cost reflectivity assessment framework tool and
v. Test and validate the methodology and framework tool

The key objective of Workstream 2 is to harmonize and align tariff frameworks to ensure standardization and facilitate greater electricity exchange amongst the COMESA Member States.

1.2 Key outcomes and results of Workstream 2

The specific outcomes under Workstream 2 of the Project are as below.

- Adoption of regulatory and tariff best practices
- Improved regulatory effectiveness across the region
- Enhanced migration towards cost reflectivity of tariffs and harmonized tariff frameworks

The above benefits are aimed at improving regional cooperation and enhancing cross border electricity trade ultimately leading to lower cost of supply and increase in energy access across the Member States.

[1] *Comparative Analysis of Electricity Tariffs in ECOWAS Member Countries, AfDB, 2019*

1.3 Overview of the report

In accordance with the terms of reference, the *Report on ''Framework for Harmonized Comparison of Electricity Tariffs and for Cost Reflectivity Assessment in the COMESA region''* for COMESA Member States is being submitted herein.

This "Framework Report" describes the methodology and framework for two key components of Workstream 2:

1. Harmonized comparison of electricity tariffs
2. Cost Reflectivity Assessment in the COMESA region

The framework so developed will be populated with data and the analytical findings shall be discussed as part of the "Maiden Report".

The report is structured as follows:

Chapter 1: Introduction

This chapter provides a description of the project context, scope of work for workstream 2, objective, specific outcomes and structure of the report.

Chapter 2: Review of existing electricity tariff structures and pricing methodologies in the COMESA region and benchmark with international best standards

This chapter carries out a review of the existing tariff structures and pricing methodologies for the COMESA Member States. We have carried out a review of the international tariff best practices and compared the same with the current tariff practices to understand the gaps in the tariff practices.

Chapter 3: Harmonized comparison of electricity tariffs

This chapter carries out analysis of the underlying drivers of tariff components such as generation mix, efficiency, fuel cost, cross-border trade, losses, collection rates, etc. and their impact on the various tariff components.

Chapter 4: Cost Reflectivity Assessment Framework Tool

This chapter talks about cost reflectivity and its key objectives.

Chapter 5: Recommended methodology for cost reflectivity assessment

In this chapter, the recommended methodology for cost reflectivity comprising the five key steps of determination of Revenue Requirement (RR), functionalisation, classification, allocation of costs and cost reflectivity assessment have been detailed about.

Chapter 6: Procedures for cost reflectivity assessment

This chapter discusses in detail the features, structure and methodology for operating the cost-of-service model.

Chapter 7: Tariff related recommendations

This chapter based on the gap assessment of the tariff practices provides the key tariff related recommendations which should be implemented by the Member States to bring about harmonization of the tariff frameworks across the region.

Chapter 8: Action plan for implementation

This chapter talks about the key steps to be undertaken for standardization and harmonization of the tariff frameworks across the Member States. The key challenges pertaining to the harmonization exercise and steps to overcome them have been highlighted herein.

Chapter 9: Conclusion

This chapter highlights the key outcomes/findings of the report and provides a conclusion to the report.

Annexure 10.1 Cost Reflectivity Assessment Framework Tool (CRAFT)

Annexure 10.2 Training Manual for use of the Cost-of-Service Model

Annexure 10.3 Data requirements for carrying out cost of service analysis

2 Review of existing electricity tariff structures and pricing methodologies in the COMESA region, and benchmark with international best standards

2.1 Introduction

This chapter carries out review of the existing electricity tariff structures and pricing methodologies for the COMESA Member States. We then carried out review of the international best practices and benchmarked the current practices. Accordingly, the gaps in the current tariff practices and frameworks have been analyzed, setting out context for the harmonization of the tariff and cost reflectivity frameworks.

2.2 Review of regulatory framework in the Member States

Amongst the 13 countries which are the subject of our study, only seven countries have operational regulatory bodies namely: *Burundi, Egypt, Ethiopia, Kenya, Rwanda, Sudan and Uganda*. The remaining six countries - Djibouti, Eritrea, Libya, Somalia, South Sudan and Tunisia either do not have a regulatory body or it is not yet operational. The Ministry with portfolio responsibility for energy in the respective countries is carrying out the de facto role of a regulator for the power sector in these countries.

There is wide variation in the degree of independence of the regulatory bodies. Some countries with regulatory bodies in place still do not have functional independence of the regulator – with all key decisions requiring the Ministry's approval. This is the case in point in countries - Burundi, Ethiopia and Sudan. The way in which the regulators are funded also varies from fully state-funded to fully funded by industry licence fees.

Somalia and South Sudan are also taking steps towards setting up independent regulatory bodies. In Somalia, National Electricity Authority (NEA) has been recently established and is yet to be operationalized. In South Sudan, a bill has been proposed to set up a regulatory body.

Key observations in terms of regulatory structure, independence and appeals framework are as:

- <u>Distinct and independent regulator with provision of appeals</u>: Kenya, Uganda
- <u>Distinct and independent regulator but without provision of appeals</u>: Egypt, Rwanda
- <u>Distinct regulator but with low levels of independence and no provision of appeals</u>: Burundi, Ethiopia, Sudan
- <u>Distinct regulator is yet to established and operationalized</u>: Djibouti, Eritrea, Libya, Somalia, South Sudan, Tunisia

2.3 Market Structure

The countries also vary in the market design of the electricity sector structure. Varying degrees of unbundling are observed in the Member States. In terms of the overall market structure for the countries under consideration:

- Majorly unbundled: Egypt, Kenya, Sudan, Uganda. Additionally, Kenya is in the process of unbundling System operations.
- Partially unbundled: Ethiopia
- Fully bundled: Burundi, Djibouti, Eritrea, Libya, Rwanda, and Tunisia. Additionally, Burundi is in process of transitioning to a partially unbundled state.
- Isolated grids, Private operators: Somalia, South Sudan

Complete unbundling at the generation, transmission and distribution level is observed in the case of Egypt, Kenya, Sudan and Uganda. Burundi, Djibouti, Eritrea, Libya, Rwanda, and Tunisia have vertically integrated utilities carrying out generation, transmission and distribution of electricity in the respective Member States. Partial unbundling is observed in the case of Ethiopia.

Within the group are two states - Somalia and South Sudan – which do not yet have an integrated national grid – which makes interconnection with other states in the region difficult. These states are managed by private isolated distribution systems.

2.4 Tariff Frameworks

Based on the review of the tariff framework and methodologies in each of the specified countries, a snapshot of the comparison of the same across the specified countries is as below.

Table 1: Tariff frameworks and methodologies: Comparative assessment

	Burundi	Djibouti	Egypt	Eritrea	Ethiopia	Kenya	Libya	Rwanda	Somalia	South Sudan	Sudan	Tunisia	Uganda
Tariff approval	*Government*	*Government followed by Parliament*	*Regulator*	*Government*	*Government*	*Regulator*	*Government*	*Regulator*	*Government*	*Government followed by Parliament*	*Government*	*Government*	*Regulator*
Tariff method	Cost plus Return	--	Cost plus Return	--	Cost plus Return	Cost plus Return	--	Cost plus Return	Cost plus Return	Cost plus Return	--	--	Cost plus Return
Pass-through charges - Coverage	Unforeseen costs, Windfall gains as per new Law	--	--	--	--	Fuel cost, Forex, Inflation, Water resources authority levy	--	Yes	Fuel cost, Forex	--	--	--	Fuel cost, Forex, Inflation, Generation mix
Pass-through charges - Frequency	--	--	--	--	--	Monthly	--	--	--	--	--	--	Quarterly
Regularity in tariff revision	Irregular	Irregular	Regular	Irregular	Irregular (Last tariff 2018)	Regular	Irregular	Irregular (Last tariff 2020)	Irregular	Irregular	Irregular	Irregular	Regular

	Burundi	Djibouti	Egypt	Eritrea	Ethiopia	Kenya	Libya	Rwanda	Somalia	South Sudan	Sudan	Tunisia	Uganda
	(Last tariff 2017)	(Last tariff 2020)											
Multi-Year Tariff (MYT) Regime	--	--	--	--	Yes	Yes	--	--	--	--	--	--	Yes
Cost-of-Service Study	--	--	Yes	--	--	Yes	--	--	--	--	--	--	Yes
Time-of-Use (ToU) tariffs	--	--	Yes	--	No	Yes	--	Yes	--	--	--	Yes	Yes
Lifeline tariff threshold	50 kWh	200 kWh	50 kWh	--	50 kWh	30 kWh	--	15 kWh	--	100 kWh (JEDCO)	200 kWh	50 kWh	15 kWh
Pre-paid metering system	Yes	--	Yes	--	Yes	Yes	--	Yes	--	Yes	Yes	--	Yes
Best practices		Tariff incentive for reducing demand during peak hours	Inclining block tariff EV tariffs			EV tariffs		Lower tariff for medium and large industries		Lower tariffs for Industrial customers		Inclining block tariff Four-shift structure based on seasonal variations	Declining block tariff for large and extra-large industrial consumers

Key findings related to the tariff frameworks are as below.

Tariff approval

- Tariff approved by Regulator: Egypt, Kenya, Rwanda, Uganda
- Tariff approved by Government/ Parliament: Burundi, Djibouti, Eritrea, Ethiopia, Libya, Somalia, South Sudan, Sudan, Tunisia

Tariff methodology

Most countries have adopted a cost-plus based approach, particularly those with well-defined regulations in place.

Pass-through charges

Countries such as Kenya, Rwanda and Uganda have well-defined pass-through mechanisms which are implemented at regular intervals. Burundi and Somalia have, as per the recently notified Law and tariff regulations respectively have also defined the pass-through charges.

Tariff revisions

Regular tariff revisions are observed in the case of Egypt, Kenya, and Uganda. Rest of the countries do not have regular tariff revision mechanisms in place.

Multi-Year Tariff (MYT) regime

The MYT regime is observed in the case of Ethiopia, Kenya and Uganda.

Time-of-Use tariffs

Time-of-Use tariffs have been implemented for the commercial and industrial categories in countries such as Egypt, Kenya, Rwanda, Tunisia, and Uganda (as per available information).

Lifeline tariff

Most countries have a lifeline tariff in place. The lifeline tariff threshold varies across countries. Rwanda and Uganda have the lowest lifeline tariff threshold at 15 kWh whereas countries such as Djibouti and Sudan have a very high threshold of 200 kWh. Kenya has recently reduced lifeline threshold from 100 kWh to 30 kWh.

Pre-paid metering

Pre-paid metering systems are in practice in most countries.

2.5 Benchmarking with international best practices

We have analyzed international best practices pertaining to tariff structures and frameworks. This section provides discussion of the various tariff determination methodologies and practical examples of the same followed worldwide.

2.5.1 Tariff determination methodologies

A number of electricity tariff methodologies are employed worldwide. The terms used to describe these methodologies include:

a) Rate of return (RoR)
b) Long-run marginal cost (LRMC)
c) Short-run marginal cost (SRMC)
d) Price regulation, also known as RPI - x, where RPI means the 'retail price index' and x denotes a 'productivity improvement' factor
e) Price cap
f) Revenue cap
g) Hybrid

The above methodologies are not mutually exclusive. In fact, they can all be employed in some manner in setting electricity tariffs and for different purposes. Because of this, these methodologies are best compared and discussed in the context of the three basic steps generally required in the determination of tariff levels for the various customer categories, each of which may be more amenable to one (or more) of the above tariff methodologies:

a) Determining the overall average selling price per kilowatt hour required by the electric utility to cover its costs, which is determined by building up a **revenue requirement** to achieve a measure of its sound financial health
b) Determining the average selling price required **for each customer category** to reflect actual cost differences in providing electric service
c) Setting the average tariff for each category in terms of energy charges, demand charges and customer charges

The first step given above is typically addressed through a financial forecast, where the average overall tariff level required by the utility to cover all its costs is determined. These costs include all expenses, income taxes, and an adequate return to shareholders. The financial forecast provides projections of all such utility costs through financial statements such as the income statement, balance sheet, and sources and applications of funds statement. In this way, year-to-year changes in the average tariff level can be determined so that sufficient internal funding can be generated to meet the utility's capital expansion program, debt service, and return on equity obligations, as well as all projected future expenses and Income tax. This is the most crucial step in tariff determination, as it directly relates to the utility's financial viability.

The second step concerns the differentiation of the average tariff level amongst the various customer categories. For example, since it costs less to provide electricity to a large customer served at transmission voltage than to a small low-voltage consumer, this difference in cost should theoretically be reflected in their respective tariffs.

The third step, as described above, entails setting appropriate levels of energy, demand, and customer charges within the boundaries of the previous two analysis.

The ensuing sections describe each of the above tariff methodologies within the framework of these three tariff setting steps.

RoR methodology

In most regulated environments, the level of utility's overall revenue requirement for the utility is set with the aim of recovering three major costs, which include:

a) Operating expenses

b) Depreciation expenses

c) Return on investment (RoI)

While the first two items given above may often be determined in a fairly straightforward manner (not always), RoI tends to be more controversial and usually entails some debate, whether it is between a regulator and stakeholders in a public forum or between policy makers in the government. This type of regulation/methodology is generally known as RoR on account of this particular focus in the determination of the revenue requirement.

As previously mentioned, the centerpiece of the RoR methodology is a financial forecast of the utility's basic financial accounting statements – income statement, balance sheet, and fund flow statement – where the average overall tariff level required by the utility to cover all its financial obligations is determined.

Usually, laws or regulations stipulate that a designated regulatory body should periodically (usually annually) undertake formal tariff reviews. If no review period is specified, then applications for tariff changes may be considered on an as-required basis and may be initiated by either the regulator or the utility.

Once the first step of defining an overall revenue requirement has been completed, the second step in tariff-setting is to divide the 'revenue requirement pie' amongst various consumer groups for determining their contribution to the total revenue requirement[2]. This generally requires a cost-of-service study. This study is most often based on RoR-based costs. This direct allocation of the revenue requirement, or the 'classic' cost of service analysis, distributes the utility's total revenue requirement among the customer categories based on the relative usage of system resources. This straightforward allocation of the utility's audited financial costs (actual or estimated) is generally known as an embedded cost of service study.

The basic methodology of the classic cost of service analysis is to break down all the costs of the electric utility into simple functional areas (production, transmission, etc.), which are then classified by voltage levels as being either energy, demand, or customer related. These three major cost components are then allocated to the customer categories according to the voltage level, based on allocation factors derived from basic customer data. Although this process can be thus simply described, an electric utility's cost structure is such that the exercise is decidedly more complex.

A comparison of revenues from existing tariffs for each customer category with the total allocated costs provides the extent to which the existing tariff is recovering allocated costs. If this comparison is made in terms of the revenue to cost ratio, a ratio of 80% would mean that the current tariffs are recovering only 80% of the cost of service. A ratio of 120% would mean that the current tariffs are recovering 20% more

[2] *Given that one of its goals is to reduce the cost of regulation, application of the RPI – x method to customer categories has generally not been practiced (although in theory it is possible). Once the level of the overall average tariff has been established, electric utilities subject to RPI – x regulation usually charge individual customers without much consideration of cost recovery for each customer category.*

than the cost of service. Revenue to cost ratios, significantly divergent from 100%, would indicate that a tariff adjustment is necessary for the category in order to move this ratio closer to 100%.

In the third step related to the tariff design, cost-reflective tariffs may be developed by using the allocated costs of service of the previous step as revenue targets. A combination of energy charges, demand charges, and customer charges that result in the required revenue requirement by category (or the total allocated cost of service) can be easily developed. Given that each such charge can be expressed in a number of ways, from blocked charges (energy and demand) to the time of use (ToU), the alternatives are many. There are no 'hard and fast' rules for setting these charges, except that they should bring in the targeted revenues based on the cost of service. Therefore, it should be understood that there is relatively large flexibility in setting individual components of each tariff, as long as each possible combination results in the same amount of revenue.

An alternative to setting energy, demand, and customer charges is to use the details of the total RoR-based cost of service study, as total allocated costs to a customer category will comprise energy-, demand-, and customer-related costs. A very straightforward method of setting a cost recovery tariff is to merely fix revenue targets for each component charge (energy charge, demand charge, customer charge) at its respective allocated cost of service. Thus, the resulting tariff will comprise cost-based energy charge, a cost-based demand charge, and a cost-based customer charge.

Long-run marginal cost (LRMC)

An alternative to the RoR method is to base the revenue requirement on LRMC. Basing tariffs on LRMC aims to orient customer choices, through the billed amount of electricity, towards the most advantageous use of a country's economic resources. In theory, from a collective point of view, tariffs based on marginal costs provide an optimal distribution of the community's resources. Contrary to average costs, which are based on current and past data, marginal costs are calculated from future data and therefore reflect the expected scarcity of energy resources.

The sole objective of economic efficiency thus favors the marginal cost approach to electricity tariffs. According to this approach, the price of electricity is based on the cost of generating, transporting, and distributing energy with the new equipment that must be installed to produce the required additional kWh and kW. As a result, customers know the real cost of this additional energy and use it accordingly. There would be neither over nor under-consumption of the energy resource. Thus, tariffs based on the principle of marginal cost encourage consumers to use electricity rationally, considering the costs of other sources.

In practice, however, there is no known electric utility anywhere in the world that uses LRMC as its overall revenue requirement. This is simply because the world operates on a financial basis and not in accordance with economic theory. Most electric utilities tend to regard marginal cost pricing as a useful tool or an aid in tariff design, and not as a substitute for financial costing. Consequently, the concept of LRMC is left to be possibly applied only to other steps in the determination of tariffs and not to the crucial first step of setting the overall revenue requirement.

To apply LRMC in the second step of tariff determination (i.e., cost of service by customer category), LRMC is calculated by customer category, but then must be adjusted to a total RoR-based revenue requirement, which purportedly allows LRMC price signals to be maintained in the tariff structure while satisfying the overall financial requirement. This is an often-used application of LRMC, although most electric utilities that undertake this exercise also perform classic cost of service analysis. Still, in certain circumstances, international lending agencies **might** (not always) prefer an in-depth analysis of marginal costs (with and without the adjustment to the RoR-based revenue requirement), so their economists may be able to make a judgment on the ability of the existing tariffs to recover the LRMC of the supply projected into the future. Thus, it can be seen that although LRMC is a good concept in theory, its practical application in the real world is not so common.

Finally, as with a purely RoR-based allocation of costs, a comparison of revenues from the existing tariffs for each customer category with the total allocated LRMC-based costs (whether purely LRMC or adjusted to the RoR-based revenue requirement) provides the extent to which the existing tariff is recovering the allocated costs.

With respect to the third step related to tariff design, LRMC may be used to some extent to differentiate between on and off-peak energy and demand charges; however, SRMC is a better option for doing this.

Short-run marginal cost (SRMC)

The basic difference between LRMC and SRMC is that LRMC assumes that all cost inputs are variable, as it is the long term that is being analyzed and a fixed plant can be modified in order to provide outputs more efficiently. In the short term, certain inputs, such as capital equipment cannot vary. In fact, practically, the only variable in the computation of SRMC is the cost of fuel, variable O&M, and associated power system losses.

Certain LRMC methodologies use the argument that SRMC is equal to LRMC. If the particular LRMC calculation does not consider the short run, then an accompanying analysis of SRMC is appropriate because the SRMC is an important consideration in tariff design.

The SRMC of energy is the incremental cost of the most expensive unit currently in use. This is sometimes referred to as the ‘system lambda’. The calculation of SRMC requires an analysis of the system lambda on an hourly basis. The method of calculation entails an assessment of typical daily load curves for the present and future, and seasonal and monthly curves (if required), in order to estimate which resources will be meeting the load at different times and, in particular, which resources and their associated incremental costs are meeting the load at the margin.

This exercise may be carried out in a simple manner, through a cursory examination of existing load profiles and the generating units likely to be operating at the margin over time. Alternatively, it may entail computer simulation of how daily load will be met by the generating unit, day by day, season by season, year by year. However, the latter can be extensive and may require considerable efforts.

SRMC is useful only in the third step of tariff setting, i.e., tariff design. Quite simply, this entails setting the energy charge at SRMC. As SRMC varies according to the time of day, it can be a strong basis for designing time of use tariff. Or, depending on the SRMC cost structure, it can be used in the design of blocked energy tariff, with the last block set at some level of SRMC. With the energy charge(s) set at SRMC, demand and/or customer charges may then be set accordingly so that a given revenue target (based, for example, on a cost-of-service study) is met.

SRMC is a very effective cost signal for consumers, as they can then decide whether or not to consume the extra kilowatt-hour based more or less on the current incremental cost of generation. Also, customers generally tend to be more responsive to energy charges than other fixed charges.

RPI-x

The RPI – x methodology deals only with the overall revenue requirement of the utility. This methodology is also known as **'multi-year' tariff setting**, as it is meant to set the utility's average tariff level over a multi-year period based on a defined formula. While a strict RoR approach requires rather costly and time-consuming mechanisms and processes to revise tariffs once they become out-of-sync with the revenue requirement (say, once a year), the RPI-x approach lengthens the period for which such regulatory intervention is necessary, through the **formula that adjusts for factors such as inflation and medium-term productivity improvements within the utility**.

This approach is also known as **'incentive regulation'**, as the average tariff set through this formula provides a level of certainty to the utility regarding revenues over a relatively long period of time (say, up to five years). As a result, if the utility performs efficiently and lowers the cost of electricity, by the end of the set period, it will accrue a windfall. With frequent tariff revisions under a normal RoR regime, this is not possible. The utility subject to the RoR regulation is effectively 'penalized' if it makes productivity gains in any given year as the tariff is rebased too frequently to allow the utility to bear the fruits of its productivity improvements.

The general format of the **multi-year tariff formula** is as follows, although it can be modified to take into account a variety of other factors:

$$\text{Tariff}_{n+1} = \text{Tariff}_n \times (1 + \text{RPI} - x)$$

where

Tariff_{n+1} = Average tariff to be charged in the next period

Tariff_n = Average current tariff

RPI = Retail price index (or some other suitable measure of inflation such as the consumer price index)

x = Change in productivity factor

It should be noted that simplistic application of the above formula to all utility costs is generally not widely practiced as such a formula would normally not apply to uncontrollable costs such as imported fuel oil. In such a case, the 'tariff' expression would exclude fuel oil costs, which would then be added to the formula as a separate item not subject to the productivity improvement factor.

Also, the x factor takes into account productivity improvements in general and does not target specific areas. Desirable productivity gains in specific areas (e.g., decreases in outages, decreases in loss levels) may be addressed separately outside the formula.

Under the RPI – *x* methodology, the regulatory authority would set the x factor based on a careful study. This would entail a study of the utility productivity over a sufficiently long period (e.g. a minimum of 10 years). Such a study would involve taking the time series of total utility costs, dividing by kilowatt hour sold in each year, and then deflating/inflating the costs to constant currency terms using a suitable price index. The resulting units should (and usually do) show a decreasing trend over time, mainly due to technological improvements. Given this time series of decreasing costs in percentage terms, the regulator can then use a certain amount of judgement in setting the *x* value – either at the general downward trend or at a reasonably close achievable value, depending on his/ her opinion on the scope available to the utility for productivity improvement.

Price Cap

Price cap is an incentive-based regulatory approach in which a formula is used to set the maximum yearly price that the company can charge for each service provided over a defined period of several years. These prices are adjusted annually to account for inflation minus a correction factor typically linked with expected increases in productivity.

Revenue Cap

Revenue cap is also an incentive-based regulatory approach under which the maximum yearly revenues the company can earn for a period of several years, is calculated using a formula that makes provision for annual inflation less a correction factor associated with expected improvements in productivity. These revenues may be adjusted annually in accordance with one or several cost or revenue drivers that are beyond the control of the regulated company, such as the number of consumers, total energy supplied or, in the case of network companies, the size of the network.

Hybrid methodology

Hybrid is a combination of different tariff methodologies.

2.5.2 Worldwide experience

Historical development of tariff methodologies

The RoR regulation (or 'cost of service' regulation as it is sometimes called) was developed during the early part of the 20th century in USA and probably a little later in Europe. The concept of LRMC gained prominence in the electricity supply industry during the 1970s as it was realized in western countries that energy is a scarce resource and should therefore be properly valued. Using LRMC as a costing methodology for electricity became a current topic in electric utility circles during the 1980s. Many utilities were ordered by their regulators to undertake LRMC studies in addition to the traditional RoR-based analysis. Development agencies such as the World Bank dictated in their terms of reference for electricity tariff studies that they should be based on LRMC analysis.

This focus on electricity tariff-setting changed significantly in the early 1990s as the industry began to slowly transform from being highly regulated (with tariffs being no exception) to finding ways of lessening regulation. UK led the way in developing an alternative regulatory model, 'price cap' regulation, whereby the RPI – x model was developed and introduced. It is important to note that this model was conceived with the aim of decreasing the cost of regulation and regulatory involvement in the running of the utility. As a result, emphasis was placed on determining the level of the overall average tariff without any regard to tariffs of the individual customer categories. The utility could set prices in any way it wished, as long as the overall average tariff was not exceeded. Thus, how pricing was formulated for individual customer categories generally became less important during this period. Also, the introduction of retail competition (whereby retailers or 'middlemen' buy electricity from providers at wholesale rates and then sell to customers) in some US states and most of Europe has made regulated pricing of retail electricity in those markets irrelevant (except where customers have chosen not to select a retailer different from the local distribution company).

Tariff methodologies used worldwide

It should be noted that the below paragraphs show how electricity tariffs are generally developed and set in other parts of the world.

Today, the regulatory model in use throughout North America varies tremendously from one jurisdiction to another. With many different regulators established in each state/province, the diversity of methods used is large. Jurisdictions employing primarily the RoR methodology will generally rely on the RoR model in all costing exercises, although some (i.e., those with larger staffs) may also conduct LRMC analysis.

In the developing world, tariff reform is underway in many countries. In India, where retail tariffs are under the jurisdiction of state regulatory authorities, the emphasis has been to have distribution companies operate on an efficient and commercially viable basis. It has been a struggle in most states due to decades of government ownership and the politicization of electricity tariffs. Tariff structures are generally complicated and unwieldy and contain huge cross-subsidies. The regulation is RoR based but costing exercises generally do not consider individual customer categories. The RPI - x type regulation has been introduced in a few states and to varying degrees (e.g. although tariff reviews might be conducted annually in line with the RoR regulation, regulators have, in some places, set multi-year performance targets in line with the RPI - *x* regulation). LRMC for all intents and purposes does not exist.

In China, where a large proportion of the world's population resides, the power sector is largely government controlled and prices are simply set by the government. Power utilities tend to be somewhat self-sustaining in that cash flows generally cover operating costs, but cannot keep up with huge increases in demand, which requires substantial government investment. Tariff structures tend to comprise simple, one-part tariffs based on energy consumption for a relatively small number of customer categories. Time-of-day pricing is practiced for large customers. Significant cross-subsidization is available from industrial/commercial to residential and agriculture consumers. No real RoR-based regulation exists, nor are costing studies of any kind undertaken on a widespread basis.

In Russia and most Former Soviet Union (FSU) countries, the situation is generally similar to that of China. The sector is mainly government controlled and prices are dictated by the government. Some FSU countries have established more or less financially viable power sectors with the help of international lending agencies; however, costing by customer category is generally not undertaken. In Russia, a certain degree of costing is carried out through submissions by the electric utilities to the state regulators of a number of standardized forms providing details of costs and a relatively simplistic allocation to customer categories.

South Africa

Eskom is an integrated electricity utility responsible for the generation, transmission, and distribution of electricity in South Africa. The National Energy Regulator of South Africa (NERSA) is the designated independent regulator responsible for the electricity supply industry. Thus, NERSA has the responsibility of reviewing and approving Eskom's tariffs.

NERSA regulates the electricity sector in South Africa in accordance with the Electricity Regulation Act, which provides for the following tariff principles:

1. Licensee must be able to recover the full cost of its licensed activities, including a reasonable margin or return

2. Licensee must be provided a prescribed incentive for the continuous improvement of technical and economic efficiency
3. Licensee must avoid undue discrimination between customer categories and may provide cross-subsidy of tariff to certain classes of customers

Key highlights of the tariff methodology implemented by NERSA for Eskom are:

1. Retail tariffs shall satisfy three objectives: economic efficiency and sustainability, revenue recovery, and fairness and equity.
2. Revenue requirement is determined, based on a cost plus return methodology. Allowable expenses include all expenses that are incurred in the production and supply of electricity. These costs include normal operating expenditures, maintenance costs, manpower costs, and overheads. Adjustments are provided for increase in fuel prices, inflation rate, and foreign exchange rate. Primary energy costs incurred for purchase of primary energy resources are considered to be efficiently incurred and, hence, allowed to be passed through to consumers.
3. The required RoR is calculated using the weighted average cost of capital (WACC). The cost of debt is based on the weighted average costs of debt for Eskom's regulated business under review. The cost of equity is derived using the capital asset pricing model (CAPM)
4. A defined regulatory asset base (RAB), on which WACC is applied, covers all assets employed by Eskom in the production and supply of electricity.
5. Tariffs are determined over a multi-year period consisting of three years.
6. If there is any under-expenditure compared to the forecasted capital expenditure, the value of RAB is adjusted downwards at the end of the multi-year period, and the revenue in the next multi-year period is adjusted to compensate for the return earned on unused funds in the previous period. In case of any over-expenditure compared to forecasted capital expenditure, the balance would be added to RAB, and Eskom would be allowed additional returns to recover the costs of the over-expenditure at the start of the next period.

The tariff is approved by NERSA, based on its analysis and inputs from the public hearing process initiated by Eskom’s application. Although Eskom is a bundled utility, for tariff determination, each division (generation, transmission, distribution) is financially ring fenced and regulated separately. Key features of each division’s tariff are provided below.

Generation

The tariff is a time-differentiated tariff with differing rates in time periods and seasons.

Transmission

The transmission tariff comprises:

- Network charges for reserving transmission network capacity - These are differentiated as per transmission zones. The zones are formed based on their distance from Johannesburg, which is the high-load center of the country.
- Reliability service charge

- Connection charge

<u>Distribution</u>

The tariffs for each customer category are set based on the allocation of Eskom's total costs across customer categories through a cost-of-service exercise. As a first step, cost-reflective rates are derived for each category, which are then evaluated against the current tariff and adjusted where required to include allowable subsidies. The sum of all the rates and volumes calculated are tested against the approved revenue requirement to ensure revenue neutrality. An increasing block-based tariff structure is in effect for all residential consumers to provide protection to lower-usage residential customers against high price increases and to promote energy conservation.

As the customer density is vastly different for rural and urban areas, which, in turn, affects the connection cost per customer in terms of total distribution facilities required, tariff categories are formed separately for rural and urban areas to ensure that costs are allocated correctly to avoid or identify cross-subsidies between rural and urban supplies. Customers are further segmented according to the supply size and level of service delivered. This segmentation is based on retail or customer service-related costs.

2.6 Gaps in current tariff practices

Based on the review of the current tariff practices followed by the Member States, following key gaps are observed:

- Absence of an operational regulatory body in Djibouti, Eritrea, Libya, Somalia, South Sudan and Tunisia, which makes it challenging to implement well-defined tariff frameworks and regulations
- Limited regulatory independence with exceptions being Egypt, Kenya, Rwanda, Uganda – this limits the independence of the tariff setting process, with tariffs being set and approved by the government
- Inadequacy of well-defined tariff methodologies and frameworks in most countries
- Absence of tariff pass-through mechanisms with exceptions being Kenya, Rwanda, Uganda
- Inadequate regular tariff reviews with the tariffs being revised once in 3-5 years in most countries
- Inadequate incentive-based tariff regulation with simple rate of return approach adopted in most Member States
- Subsidy dependence on the government in the form of capital subsidy for electricity projects and cross-subsidization in consumer categories
- Inadequate regulatory information systems, which makes reporting of tariff-based parameters such as customer category-wise average billing rate, consumer category-wise connected load, average cost of supply etc. challenging for most countries
- Limited regulatory appeal process in most countries
- Inadequate consultative practices and full regulatory disclosure and transparency

2.7 Conclusion

Regional and continental inter-state electricity trade depends on good infrastructure and an enabling regulatory and tariff environment. Different trading regimes, different laws, different market structures and a high level of political control and influence increase the risk premium for investors to invest in the market. For an investor in energy infrastructure, the greater the risks faced in any country, the higher the return that will be demanded, which impacts energy prices. Harmonization of tariff frameworks, including **well-defined tariff regulations, tariff pass-through mechanisms (uncontrollable costs), regular tariff revisions and implementation of cost-of-service methodology** will help to standardize and streamline the process of tariff determination across the Member States. This will enable greater cost reflectivity in the tariffs and increase investor confidence in the regional market. Eventually, this will make the market self-sustaining without undue dependence on governmental support.

Therefore, to develop the market further and attract capital investment, there is an overwhelming need to harmonize the tariff frameworks amongst the Member States. This will also bring the States **one-step closer to the African Single Electricity Market (AfSEM) agenda and help in aligning the regulatory and tariff frameworks at the continental level.**

3 Harmonized comparison of electricity tariffs

3.1 Introduction

The objective of this chapter is to carry out analysis of the underlying drivers of tariff components such as generation mix, efficiency, fuel cost, cross-border trade, losses, collection rates, etc. and assessing their impact on the generation, transmission and distribution tariff components. This will help us to carry out peer-to-peer comparison of tariffs in the COMESA region and analyze any discernible trends that may be observed.

3.2 Drivers of tariff

1. Generation characteristics

1.1. Generation profile
1.2. Electricity traded
1.3. Plant availability
1.4. Capacity utilization factor
1.5. Auxiliary consumption

2. Fuel characteristics *(applicable for thermal generation)*

2.1. Landed cost of fuel (USD/ tonne)
2.2. Generation heat rate (kCal/ kWh)

3. System characteristics

3.1. System load factor (%)
3.2. System minutes lost

4. Transmission characteristics

4.1. Network length - Transmission
4.2. Transformation capacity - Transmission
4.3. Network utilization factor - Transmission
4.4. Transmission system availability
4.5. Transmission losses

5. Distribution characteristics

5.1. Network length - Distribution
5.2. Transformation capacity - Distribution
5.3. Network utilization factor - Distribution
5.4. SAIDI
5.5. Distribution losses

6. Consumption characteristics

6.1. Electricity consumption per capita
6.2. Sales mix - voltage wise
6.3. Sales mix - category wise
6.4. Prepaid customers (%)

7. Access related

7.1. Urban Population density
7.2. Rural Population density
7.3. Electricity access - Urban
7.4. Electricity access - Rural

8. Financial performance

8.1. O&M expenses (Distribution & Supply) index
8.2. Collection efficiency (%)
8.3. Average debtor days

9. Macroeconomic parameters	10. Regulatory approaches	11. Market structure & Competition
9.1. Real GDP per capita 9.2. Inflation rate (CPI, WPI 70: 30) 9.3. Annual spend on electricity in relation to Average Household Income	10.1. Tariff methodology 10.2. Frequency of tariff revision 10.3. Automatic tariff adjustment mechanism 10.4. Adherence to cost of service principles?	11.1. Extent of unbundling 11.2. Market share index

Each of the drivers is explained in terms of its importance and its impact on tariff, in the sections below.

3.3 Generation characteristics

Driver	Description & Importance	Impact[3] on tariff
Generation profile	Percentage of hydro and oil (diesel, HFO, liquid fuel, etc.) based sources in installed capacity (MW) Hydro-based and Oil-based generation are generally the cheapest and most expensive means of generation. The variable cost of generation accounts for significant portion of the total cost of generation, and hence the choice of generation source has a direct impact on the total cost of generation.	Higher share of hydro → Lower BGT Higher share of oil → Higher BGT
Electricity traded	Electricity traded as % of total energy flowing through the system Countries in COMESA region vary significantly in terms of the quantum of natural resources and electricity demand, thereby resulting in generation surpluses/ deficits amongst countries. This presents significant opportunities for generation cost equalization between countries through trading. Trading provides means to countries with generation deficit to source cheaper electricity while countries with surplus generation can benefit from export revenue and higher utilization rate of their generation and transmission assets. Thanks to trading, the resultant cost saving (for generation deficit countries) can reduce the cost of generation. For generation surplus countries, the additional income helps reduce the revenue requirement to be recovered from tariffs, for the bulk generation segment.	Higher Electricity traded → Lower BGT Lower Electricity traded → Higher BGT
Plant availability	Fraction of the period in which the Generation assets are available without any forced or planned outages, expressed as a percentage. Higher availability indicates that the generating unit is available for greater amount of time to service consumer demand. Higher availability is therefore a prerequisite for higher generation capacity utilization, which in turn helps to reduce the average per unit cost of generation. Higher availability also indicates better maintenance practices that result in lower outages.	Higher Plant availability → Lower BGT Lower Plant availability → Higher BGT
Capacity utilization factor	An indicator of the extent of utilization of generation capacity. It is calculated as the ratio of actual gross generation to the potential generation resulting from operations at full capacity throughout the period under consideration. Higher capacity utilization results in lower average per unit cost of generation as the fixed costs get distributed over a higher number of generation units.	Higher Capacity utilization factor → Lower BGT Lower Capacity utilization factor → Higher BGT
Auxiliary consumption	It is the extent of auxiliary energy consumption within the plant premises, expressed as a percentage of the gross energy generated. Higher the auxiliary consumption, lower are the net units sent out from the generation plant. This results in a higher average per unit cost of generation.	Higher Auxiliary energy consumption → Higher BGT Lower Auxiliary energy consumption → Lower BGT

[3] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

3.4 Fuel characteristics *(applicable for thermal generation)*

Driver	Description & Importance	Impact[4] on tariff
Landed cost of fuel (USD/ tonne)	This considers cost of procuring and transporting fuel upto the generating plant. The landed cost of fuel is impacted by several factors. Global commodity prices are volatile and impacted by geo-political factors. Further, most of the COMESA member countries import fuel which adds costs associated with currency exchange, freight, border taxes, etc. Higher landed cost of fuel will translate into a higher variable cost of generation.	Higher Landed cost of fuel → Higher BGT Lower Auxiliary energy consumption → Lower BGT
Generation heat rate (kCal/ kWh)	This refers to the generation efficiency of the generator unit. It indicates the amount of heat in (kCal) terms required to produce 1 kWh of electrical output. A higher value indicates lower efficiency and vice versa. The generation efficiency is affected by the type/ make of the machine, MW size of machine, age, maintenance practices, wear and tear, etc. Older machines generally have low efficiency (higher heat rate) whereas modern machines based on supercritical technology and possessing large unit sizes have high efficiency (lower heat rate). The heat rate (kCal/kWh) along with the landed cost of fuel (USD/tonne) and calorific value of fuel (kCal/kg) can help get a sense of overall variable cost of generation [USD/kWh = (USD/tonne divided by kCal/kg) multiplied by kCal/kWh].	Higher Generation heat rate → Higher BGT Lower Generation heat rate → Lower BGT

3.5 System characteristics

Driver	Description & Importance	Impact[5] on tariff
System load factor (%)	This parameter characterizes the system load curve in terms of the extent of its "peakiness" or "flatness". A value close to 100% denotes a flatter load curve.	Higher System load factor → Lower BGT Lower System load factor → Higher BGT

[4] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

[5] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

Driver	Description & Importance	Impact[6] on tariff
	The load curve shape is impacted by customer mix of the utility. Domestic consumers generally contribute a peaky load curve, which peaks during morning/ afternoon and late evening times. Industrial consumers and Mines generally have flatter load curves due to the continuous nature of their operations. A flatter load curve (high system load factor) can be serviced by base load, large sized generation units (e.g. coal or large hydro based) which have lower generation costs. A peakier load curve requires peaking plants (e.g. gas or liquid fuel based) with quick ramp-up/ down capabilities, to be dispatched to service the peaks – these are generally costlier to run. Thus, the shape of load curve impacts the mix of base load vs. peaking plants deployed in the system, which ultimately affects the generation cost.	
System minutes lost	This index measures the severity of system interruptions' duration relative to size of the system (system peak). As it is an indexed parameter, it can be compared between countries possessing different system sizes. A higher value indicates greater extent of system interruption, in terms of magnitude of load lost (MW) and/ or duration (minutes). System interruptions can be a result of generation deficit (leading to load shedding) or due to failures in transmission system. In either case, system interruptions result in unserved energy i.e. energy which potentially could not be sold. Due to predominantly fixed nature of costs of the transmission system, any reduction in energy served redistributes higher fixed cost onto lower number of units, thereby resulting in increase in average per unit transmission costs. This leads to higher transmission tariff.	Higher System minutes lost → Higher TT Lower System minutes lost → Lower TT

3.6 Transmission characteristics

Driver	Description & Importance	Impact[6] on tariff
Network length - Transmission	In general, higher network length can potentially lead to lowering the network congestion and thereby evacuation of more energy units through the system. Smaller networks generally have lower redundancies and hence higher congestion. Thus, higher network length would result in lowering of the average per unit transmission costs.	Higher Network length → Lower TT Lower Network length → Higher TT

[6] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

Driver	Description & Importance	Impact on tariff
Transformation capacity - Transmission	This driver works similarly to the Network length parameter. Higher transformation capacity in the network leads to potentially lower cases of network congestion, thereby resulting in higher evacuation of energy.	Higher Transformation capacity → Lower TT Lower Transformation capacity → Higher TT
Network utilization factor - Transmission	This parameter indicates extent of utilization or loading of transformation capacity of the network. It is computed as the ratio of peak demand in transmission network (in MVA) to the total transformation capacity (in MVA) installed in the network. A higher value of this parameter indicates better utilization of the network capacity, thereby resulting in lowering of the average per unit transmission costs.	Higher Network utilization factor → Lower TT Lower Network utilization factor → Higher TT
Transmission system availability	Fraction of the period in which the Transmission assets are available without any forced or planned outages, expressed as a percentage. Higher availability indicates that the transmission network is available for greater amount of time to service consumer demand. Higher availability is therefore a prerequisite for higher transmission of electricity units, which in turn helps to reduce the average per unit cost of transmission. Higher availability also indicates better maintenance practices that result in lower outages.	Higher Transmission system availability → Lower TT Lower Transmission system availability → Higher TT
Transmission losses	Higher transmission loss reduces the energy sent out to distribution for further sale to consumers. This results in recovery of the transmission revenue requirement from a lower number of units, which in turn increases the average per unit cost of transmission.	Higher Transmission losses → Higher TT Lower Transmission losses → Lower TT

3.7 Distribution characteristics

Driver	Description & Importance	Impact on tariff
Network length - Distribution	In general, higher network length can potentially lead to lowering the network congestion and thereby evacuation of more energy units through the system. Smaller networks generally have lower redundancies and hence higher congestion. Thus, higher network length would result in lowering of the average per unit distribution costs.	Higher Network length → Lower DT

[7] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

Driver	Description & Importance	Impact[8] on tariff
		Lower Network length → Higher DT
Transformation capacity - Distribution	This driver works similarly to the Network length parameter. Higher transformation capacity in the network leads to potentially lower cases of network congestion, thereby resulting in higher evacuation of energy.	Higher Transformation capacity → Lower DT Lower Transformation capacity → Higher DT
Network utilization factor - Distribution	This parameter indicates extent of utilization or loading of transformation capacity of the network. It is computed as the ratio of peak demand in distribution network (in MVA) to the total transformation capacity (in MVA) installed in the network. A higher value of this parameter indicates better utilization of the network capacity, thereby resulting in lowering of the average per unit distribution costs.	Higher Network utilization factor → Lower DT Lower Network utilization factor → Higher DT
SAIDI	This parameter indicates the total duration of system interruptions. A higher value potentially leads to lower duration that the load is served. Distribution network costs being largely fixed in nature, lower passage of energy distributes costs amongst lower number of units. Thus, average per unit distribution costs increases.	Higher SAIDI → Higher DT Lower SAIDI → Lower DT
Distribution losses	Higher Distribution loss reduces the energy sent out to customers. This results in recovery of the distribution revenue requirement from a lower number of units, which in turn increases the average per unit cost of distribution.	Higher Distribution losses → Higher DT Lower Distribution losses → Lower DT

3.8 Consumption characteristics

Driver	Description & Importance	Impact[8] on tariff
Electricity consumption per capita	Indicates electricity consumption on a per-person basis. A lower value of this indicator denotes lower levels of population's access to electricity or high extent of load shedding, both of which indicate significant unmet demand in the system, either connected or not connected.	Low levels of electricity consumption per capita → Potential for increase in tariffs

[8] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

Driver	Description & Importance	Impact[9] on tariff
	To address the unmet demand, significant capital investment in generation sources or network assets may be needed. One of the reasons for low levels of capital investment could be low tariffs which reduces private sector investor interest. Thus, this parameter could give important signals for increasing tariffs.	
Sales mix - voltage wise	This parameter indicates the proportion of energy sales amongst HV, MV and LV customers. Distribution losses are generally higher at lower voltages and vice versa. This results in distribution of fixed costs of the network amongst lower units, thereby increasing the average per unit cost of supply.	Higher proportion of sales at lower voltages → High EUT Higher proportion of sales at higher voltages → Low EUT
Sales mix - category wise	This parameter indicates the proportion of energy sales amongst the consumption categories of Social, Domestic, Small Non-domestic, Large Commercial, Industrial, Street lights, etc. Each consumption category has a unique load profile depending on the nature of consumption, which ultimately impacts the system load curve. Categories such as domestic, small non-domestic whose load factor is lower, impose higher costs on the network. Categories such as large commercial, industrial have better load factors thereby imposing lower costs on the network.	Higher proportion of sales to Social, Domestic, Small Non-domestic categories → High EUT Higher proportion of sales to Large commercial, Industrial categories → Low EUT
Prepaid customers (%)	This parameter indicates the proportion of domestic customers with a prepaid connection. A prepaid connection is better from cashflow perspective due to upfront payment and avoidance of debtors. Costs incurred in debtor collection, follow-ups and maintenance of a working capital line are saved. A prepaid customer also does not impose costs incurred in meter reading and billing, on the network. Additionally, commercial losses come down with prepaid meters and therefore result in lower tariff.	Higher proportion of Prepaid customers → Low EUT Lower proportion of Prepaid customers → High EUT

3.9 Access related

Driver	Description & Importance	Impact[9] on tariff
Urban Population density	Higher population density helps in lowering the cost of setting up distribution network as a higher number of customers can be connected using a certain length of network.	Higher Population density → Low EUT Lower Population density → High EUT

[9] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

Driver	Description & Importance	Impact[10] on tariff
Rural Population density		
Electricity access rate – Urban, Rural	Lower access rate results in distribution of fixed network costs over a lower customer base, thereby increasing the average per unit supply cost.	Higher Electricity access rate → Low EUT Lower Electricity access rate → High EUT

3.10 Financial performance

Driver	Description & Importance	Impact[10] on tariff
O&M expenses (Distribution & Supply) index	Indicates O&M expenses incurred for every unit of electricity sold. Expenses incurred only in the Distribution and Retail supply functions are included. The O&M cost to be included here is the <u>prudent cost</u> – which is reasonable and should be acceptable. Higher value of this parameter increases the average per unit cost of distribution.	Higher O&M expenses (Distribution & Supply) index → High DT Lower O&M expenses (Distribution & Supply) index → Low DT
Collection efficiency (%)	This parameter indicates the revenue collection in proportion to revenue invoiced. A higher value of this parameter indicates that the Utility can manage its cash flows better and will incur lower costs on maintaining working capital to cover the cash deficit.	Higher Collection efficiency → Low EUT Lower Collection efficiency → High EUT
Average debtor days	This parameter indicates the average duration incurred by the Utility to collect debtors. A higher value of this parameter indicates that the Utility is unable to collect invoices in a timely manner and will incur higher costs on maintaining working capital to cover the cash deficit.	Higher Average debtor days → High EUT Higher Average debtor days → Low EUT

[10] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

3.11 Macroeconomic parameters

Driver	Description & Importance	Impact[11] on tariff
Real GDP per capita	Real GDP, which denotes economic activity, has a direct correlation with electricity sales. For a given network, higher per capita sales would lead to lowering of the average per unit supply cost.	Higher GDP per capita → Low EUT Lower GDP per capita → High EUT
Inflation rate (CPI, WPI 70: 30)	Higher inflation impacts staff costs, repair and maintenance, and admin & general expenses for the utility. This increases the average per unit cost of Generation, Transmission, Distribution and Supply.	Higher Inflation rate → High BGT, TT, DT, EUT Lower Inflation rate → Low BGT, TT, DT, EUT
Annual spend on electricity in relation to Average Household Income	This parameter indicates the ability of consumers to pay for electricity. Low values of this indicator indicate that domestic consumers have a greater room to tap into their incomes for expenditure on electricity.	Higher Annual spend on electricity in relation to Average Household Income → Low potential to increase tariffs Lower Annual spend on electricity in relation to Average Household Income → High potential to increase tariffs

3.12 Regulatory approaches

Driver	Description & Importance	Impact on tariff
Tariff methodology	Methodologies for tariff determination include: • Cost plus Return approach: Utility is allowed to recover costs plus a suitable return on capital invested. The rate of return is the weighted average cost of capital (WACC) • RPI – x: Revenue requirement is increased every year by inflation rate and adjusted each year by an efficiency factor “x”	• Cost plus Return approach is suitable for cases where utility needs to be incentivized to make capital investments in the network • RPI – x approach is suitable for utilities with capability to bring in efficiency improvements

[11] *All impacts described are general without any inference of the extent of correlation between the driver and tariff*

Driver	Description & Importance	Impact on tariff
Frequency of tariff revision	A higher frequency of tariff revision is preferable so that tariffs remain in sync with costs	Higher Frequency of tariff revision → Tariffs are in sync with costs Lower Frequency of tariff revision → Tariffs are out of sync with costs
Automatic tariff adjustment mechanism	Automatic tariff adjustment allows pass through of uncontrollable expenses such as forex fluctuations, fuel prices, inflation rate, into tariff.	Automatic tariff adjustment mechanism is present → Tariffs are in sync with uncontrollable costs Automatic tariff adjustment mechanism is absent → Tariffs are out of sync with uncontrollable costs
Adherence to cost of service principles?	Adherence to cost of service principles ensures that tariffs remain in sync with costs	Adherence to cost of service → Tariffs are in sync with costs Non-adherence to cost of service → Tariffs are out of sync with costs

3.13 Market structure & competition

Driver	Description & Importance	Impact on tariff
Extent of unbundling	An unbundled market structure allows segregated reporting of costs and tariffs to be unbundled.	Unbundled market structure → Tariffs can be unbundled in BGT, TT, DT and EUT
Market share index	A higher value of this parameter indicates higher competition in generation which should lead to lowering of generation costs. Greater participation by private players in the market results in a more efficient market.	Higher Market share index → Low BGT Lower Market share index → High BGT

4 Cost Reflectivity Assessment Framework Tool (CRAFT)

4.1 Cost reflectivity

Cost reflectivity assessment is *"determination of the aggregated cost to provide each element of the electricity service to each customer class in a fair and nondiscriminatory manner, and its comparison with tariff paid by the customer class"*. Such an assessment provides a granular view of the different costs and revenue requirements imposed by each customer class on the power system.

Cost reflectivity assessment can be a useful tool to achieve the following tariff objectives:

- determining affordable tariffs for low-income consumers along with the extent of financial support needed from Government to subsidize those consumers;
- identifying the extent of cross subsidization existing between consumer categories as well as between geographical regions;
- setting a trajectory for reducing cross subsidization; and
- setting a trajectory for transitioning towards cost reflective tariffs by providing a baseline assessment of the present cost reflectivity levels.

5 Recommended methodology for cost reflectivity assessment

Undertaking a cost-of-service (CoS) assessment is a prerequisite for assessing the cost reflectivity. The methodology for CoS assessment provided in this chapter is consistent with that provided in a publication issued by the National Association of Regulatory Utility Commissioners[12] (NARUC) of the USA. This document describes in some detail the basic costs of electric utility supply and the rationale for their allocation to various customer categories. The **principles of cost allocation** put forth in the publication are generally **consistent with international best practices**.

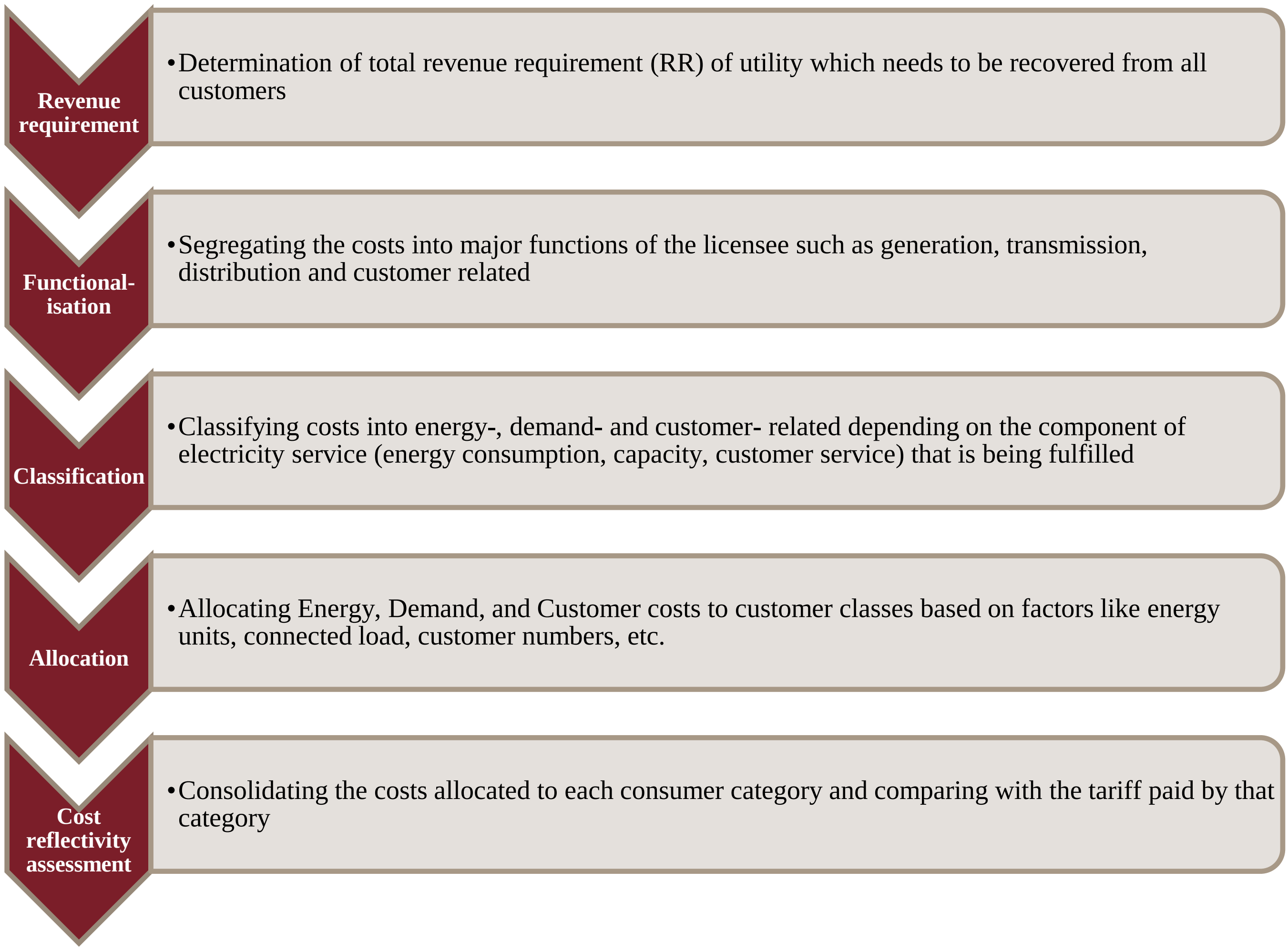
Data requirements for such an analysis are extensive and, to some extent, subjective. This is because complete and precise data are never available. However, the cost-of-service results for electric utilities with a good information base tend to be more reliable than results for utilities with less available information. In any case, where precise information is lacking, estimates must be made by way of proxy data or "guesstimates," using the experience and general knowledge of the electric power industry.

The methodology consists of the following 5 steps:

1. Determination of Revenue Requirement (RR)
2. Functionalisation of costs
3. Classification of costs
4. Allocation of costs
5. Cost reflectivity assessment

[12] *"Electric Utility Cost Allocation Manual", National Association of Regulatory Utility Commissioners, Washington, DC, 1992.*

Figure 1: Steps in a Cost-of-Service Study



Each of the above steps are explained in detail below.

5.1 Step 1 – Determination of Revenue Requirement

Revenue requirement (RR) is the sum of all operating, capital and financing costs along with a return on capital which need to be recovered from customers through tariff, adjusted for any income obtained from customers through non-tariff sources (e.g. meter rent, delayed payment penalties, interest earned on security deposit, etc.). The elements used in the process are "embedded" or accounting costs of the utility.

RR = Power generation or power procurement related costs *plus*

Operations and Maintenance (O&M) expenses *plus*

Depreciation *plus*

Return on capital employed *less*

Income obtained from non-tariff sources

Following considerations are important when determining the RR:

- The costs and income pertaining only to the regulated electricity business should be considered. Thus, operations such as gas supply, provision of water or other utility services, advertising, etc. must be excluded.
- The portion of asset cost financed through consumer contribution and/ or grant, should be excluded.
- The basis of costs and income should be the audited financial statements, to the extent possible.

5.2 Step 2 – Functionalization of costs

Functionalisation entails segregation of the costs according to major operating functions of a licensee namely generation, transmission, distribution, and supply:

Table 2: Functionalisation of costs

No.	Function	Associated activity	Associated assets
1	Generation	• Generation • Procurement of power	• Generating plant • Power planning software
2	Transmission	• Transfer of power from generator terminal to the transmission-distribution network interface • Ancillary services	• Transmission lines and towers • Transmission substations
3	Distribution	• Transfer of power through the distribution network upto the distribution transformer	• Distribution substations • Medium voltage lines • Line transformers • Distribution transformers
4	Supply	• Flow of power through the service line upto customer premises	• Service lines • Customer accounting • Billing • Collections • Meter reading • Customer service

5.3 Step 3 – Classification of costs

Classification is the process of separating the functionalized costs into classifications based on the drivers of utility service costs. The primary cost classification categories are as follows:

- **Demand-related costs:** These costs vary with the demand imposed on the system. Demand-related costs include all costs associated with creating the generation capacity and network capacity (transmission and distribution) to fulfil consumer demand and operating such capacity. E.g. debt servicing cost associated with acquisition of fixed assets, depreciation of fixed assets, O&M expenses related to fixed assets.

- **Energy consumption-related costs:** These costs vary with the volume of consumption. Energy consumption-related costs include all costs associated with the generation of energy units. E.g. primary fuel cost and startup fuel cost.
- **Customer-related costs:** These costs vary with the number of customers. Customer-related costs include all costs associated with provision of electricity services to customers. E.g. costs associated with service connection, metering, billing, collection, and customer service.

Table 3: Cost classification categories

No.	Classification category	Driver	Nature with respect to energy consumption
1	Demand-related	System peak demand	Fixed
2	Energy consumption-related	Energy volume	Variable
3	Customer-related	Customer numbers	Fixed

The relationship between functionalized costs and classified costs is as follows:

Table 4: Mapping between functionalized costs and classified costs

	Demand-related	Energy consumption -related	Customer-related	Rationale
Generation	X	X		• Generation facilities are jointly used by all customers on the system. The capacity sizing of facilities is thus based on the system peak demand. • The variable component of generation cost varies as per the energy consumption.
Transmission	X			• Transmission facilities are jointly used by all customers on the system. Thus, the capacity sizing of facilities is based on the system peak demand.
Distribution	X		X	• Distribution facilities are developed to serve demand of particular customer categories. The capacity sizing of facilities is thus based on individual customer class peak demands and not system peak demand. • As we move further “downstream”, a higher share of the costs is customer related and distribution facilities are used by a smaller subset of customers

	Demand-related	Energy consumption -related	Customer-related	Rationale
Supply			X	• The Supply function costs are highly sensitive to customer numbers and the investment made in metering/ service connection. Residential customers are significant in numbers and hence require higher investment in manpower to serve the customers. On the other hand, bulk industrial/ commercial customers require sophisticated metering equipment and service connection.

5.4 Step 4 – Allocation

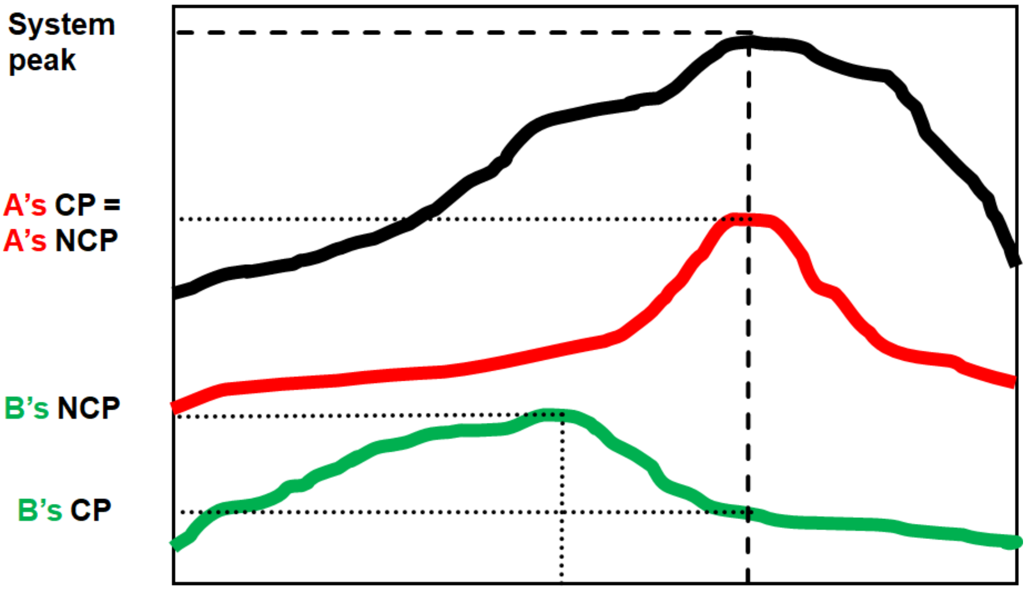
This step involves allocating the functionalized and classified costs to different customer categories. The allocation is in proportion to the demand, energy consumption and customer-service related requirements imposed by each consumer category on the power system. Different cost categories require different allocation methods – a particular allocation method is a set of percentages that sum to 100%. The allocation methods are explained below:

- **Demand-related cost allocation methods:** Demand-related costs are driven by the peak demand imposed on the system. While generation and transmission related demand costs are allocated as per contribution of each consumer category to the system peak demand (Coincident peak or CP), the distribution related demand costs are allocated as per peak demand of each customer category (Non-coincident peak or NCP).

Table 5: Allocation of demand-related costs

Demand-related costs → / Allocation factors ↓	Generation Demand-related	Transmission Demand-related	Distribution Demand-related
System Peak Responsibility (CP)	X	X	
Non-Coincident Peak (NCP)			X

Figure 2: Illustration of System and Customer peaks; Coincident and Non-coincident peaks

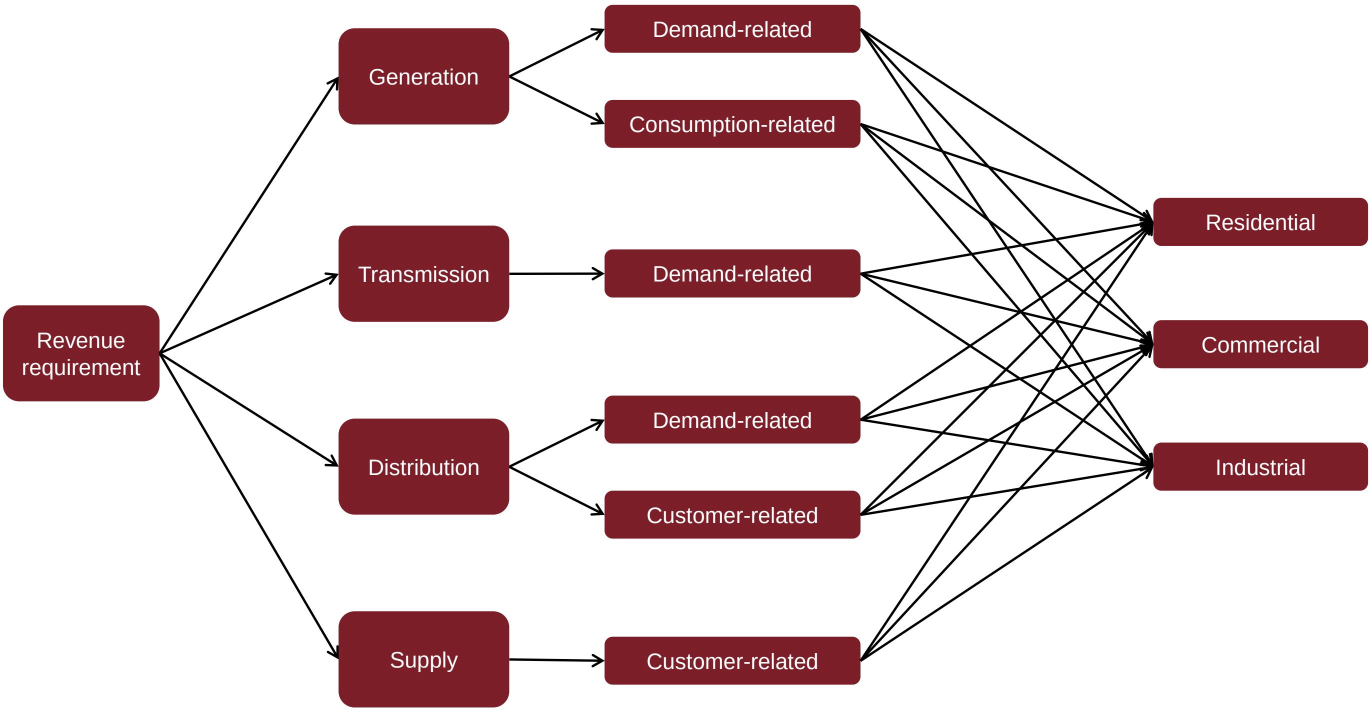


- **Energy consumption-related cost allocation methods:** These costs are driven by the energy units required to be inputted into the system to satisfy the consumer's energy requirement. The units inputted are the sum of energy units consumed by customer and the energy units lost in the network while delivering to the customer. The extent of losses depends on the voltage level (lower losses at higher voltages and vice-versa) and network length (lower losses at lower conductor lengths and vice-versa) – customers connected at low voltage levels towards downstream end of the network must bear much higher losses as compared to customers who are connected at higher voltage at a relatively upstream position in the network. Thus, customers with higher losses would have to bear higher share of the energy-related costs, other things being equal.
- **Customer-related cost allocation methods:** These costs are driven by the number of customers and the investment made in metering/ service connection. A simple way to allocate Customer-related costs is by using the "category-wise customer numbers". A more refined method uses a *weighted* customer number which is adjusted based on the "category-average meter cost" or "category-average service connection cost" – if these data are difficult to get, a proxy of "category-average connected load" can also be used.

5.5 Step 5 – Cost reflectivity assessment

The costs allocated to each customer category are consolidated and compared with the tariff levied on that category to calculate a percentage figure, which denotes the extent of revenue requirement recovered through tariff. A figure of 100% denotes full cost recovery while any figure higher/ lower than this represents over/ under recovery respectively.

Figure 3: Summarized representation of functionalization, classification and allocation of costs



6 Procedures for cost reflectivity assessment

6.1 Choosing the reference year

Cost-of-Service (CoS) assessments are done on whole of the year cost data. Timely and reliable data is critical, and hence the latest financial year for which audited financial data is available, must be preferred. In case the regulator has set the tariff determination methodology, in that case the utility can adopt the regulatory costs being allowed by the regulator for the determination of the cost-of-service results.

6.2 Features of the CoS model

A comprehensive model has been developed in Microsoft Excel to carry out the CoS assessment. The model is annexed to this report.

The CoS model splits the revenue requirement (RR) based costs of whole utility into customer category-wise breakups, using a cost breakup and allocation methodology. Through a series of steps and employing accounting and technical data and assumptions, the costs are broken up and allocated. The model features are listed below:

- Allows for cost-of-service determination for upto 30 customer categories.
- The high, medium and low voltage bands are predefined thereby allowing comparability of results across COMESA member countries.
- Model is flexible to incorporate the different power industry structures which exist across COMESA member countries – fully bundled (G+T+D), partially unbundled (G and T+D / G+T and D) and fully unbundled (G and T and D). Further, costs and customer data of multiple distribution utilities can be integrated into a single model (useful for countries like Egypt which have multiple distribution utilities) to produce a single, country-level cost of service assessment.
- Model allows for RR of entire electricity value chain (Generation, Power purchase, Transmission, Distribution, Retail supply) to be included.
- RR is determined using a rate of return (RoR) approach – either accounting or marginal costs can be inputted.
- Regulated Asset Base (RAB) requirements consider depreciated fixed assets, capital works in progress and working capital requirements.
- Model provides a structure for deduction of Customer or Grant financed assets and associated expenses from the RR and RAB.
- The model segregates customers located in Urban and Rural areas, thereby providing for more granular cost allocations.
- Cost of service even for customers connected at transmission voltages (> 66 or 132 kV) can be computed.
- Cost data for the model can be inputted using the local currency and results are available as a percentage, thereby allowing ease of data input and comparability of results between COMESA member countries.

6.3 Structure of the CoS model

The sheet structure of the model is explained below:

1. **<u>‘RR’</u>**: A buildup of the revenue requirement (RR) to be recovered from tariffs, including the return to be earned on regulated asset base (RAB), is developed in this sheet.
2. **<u>‘Customer’</u>**: Customer category-wise data covering customer count, geography, voltage level, energy sales, connected load, connection charge, load factor, coincidence factor, and revenue from electricity sales is inputted in this sheet. The data inputted is further built upon to derive the complete energy balance (GWh) and power balance (MW) for each customer category, which entails adding non-technical and technical losses to sales quantum, to derive the requirement to be inputted into the system to meet the demand of each category.
3. **<u>‘Loss’</u>**: This sheet provides a facility to input key assumptions related to technical and non-technical losses, voltage-wise. The model includes a segregation across 3 voltage classes - HV: above 66 kV, MV: above 400 V and up to 66 kV, and LV: 230 V, 400 V. The sheet derives the energy (GWh) and power (MW) balance for the system at each voltage level. This output is used in the ‘Customer’ sheet to derive the energy and power balance for each customer category.
4. **<u>‘Assets’</u>**: This sheet functionalizes the assets reported in financial statements into categories which are the building blocks for cost of service. Assets includes fixed assets (plant & machinery, land, buildings and other assets), accumulated depreciation, assets under construction (capital works-in-progress or CWIP), current assets and current liabilities (working capital). These elements are used to build the RAB, and hence this sheet helps derive the functionalized RAB. The functionalization is carried out at multiple levels: i) strategic business units (SBUs) of Generation, HV network, MV network, and LV network; ii) geographical segregation of Urban and Rural; (iii) purpose-based segregation of Demand-related and Customer-related assets.
5. **<u>‘Expenses’</u>**: This sheet functionalizes the expenses reported in financial statements into categories which are the building blocks for cost of service. Expenses include operational (fuel, power purchase, transmission, staff, maintenance, administrative and general) and non-operational (depreciation, interest and financing, provision for bad debts). The functionalization is carried out at multiple levels: i) strategic business units (SBUs) of Generation, HV network, MV network, and LV network; ii) geographical segregation of Urban and Rural; (iii) purpose-based segregation of Energy-related, Demand-related and Customer-related expenses.
6. **<u>‘V.Realloc’</u>**: This sheet reallocates the voltage-levels based functionalized allocations to reflect the contribution of assets at higher voltages in serving customers at lower voltages. The re-allocation covers Demand (Network)-related RAB and Demand (Network)-related Expenses.
7. **<u>‘Output’</u>**: This sheet presents the results of CoS exercise by tabulating the cost to serve each customer category alongside the revenue recovered from tariffs. The Energy-related, Demand-related and Customer-related costs are compared with the recoveries from Energy charge, Demand chargeand Fixed charge.

6.4 Operating the model and deriving results

1. Enter data and assumptions in cells with blue text. Cells which are in black text are formula driven and “read-only”.

2. Data and assumptions are to be entered in sheets titled “RR”, “Customer”, “Loss”, and “Assets”. Refer to the accompanying notes in the model for guidance.
3. After inputting data in “Customer” and “Loss” sheets, review the parameter of “Energy loss => Demand loss conversion factor” in the “Loss” sheet. This factor denotes the relationship between demand loss (in MW terms) and energy loss (in GWh terms) and needs to be entered manually. The value is to be determined using a trial-and-error method, by inputting values incrementally greater than 1 and ensuring that value in the cell marked “ERROR” is minimized as close to zero as possible. Doing so will ensure that the voltage-wise demand loss and energy loss figures are internally consistent.
4. The results can be viewed in “Output” sheet as customer category-wise cost incurred, revenue recovered through tariffs and percentage cost reflectivity of tariffs.

6.5 Methodology of the CoS model

The model methodology can be explained in five steps:

1. Deriving customer category-wise energy balance and power balance
2. Functionalizing assets
3. Functionalizing expenses
4. Reallocating demand-related RAB and RR, voltage wise
5. Deriving cost of service results

Each of these steps is described in detail in the following sections.

6.5.1 Deriving customer category-wise energy balance and power balance

This step derives the energy balance and power balance for each customer category. Starting with the sales data (both energy sales in GWh and power sales in MW terms), the non-technical and technical losses are added to each category to derive the energy requirement (GWh) and the coincident contribution to system peak demand (MW) of each category. These are further used as allocation factors in various steps of the cost-of-service analysis.

Sales = Billed to customer
Consumption = Sales + Non-technical losses
Requirement = Consumption + Technical losses

Deriving energy and power balance is a two-step transformation process:

1. From sales to consumption
2. From consumption to requirement

<u>From sales to consumption</u>

Deriving consumption in terms of gigawatt hours is fairly straightforward. The non-technical losses for each category are simply added to energy sales to derive the energy consumption in terms of gigawatt hours. To derive the power consumption in terms of megawatts, firstly the non-coincident peak power consumption is derived from energy consumption for each category by applying the respective load factor. Non-coincident peak power consumption is then transformed to coincident peak power consumption in terms of megawatts by applying the coincidence factor for each category.

From consumption to requirement

The energy requirement is derived by adding technical losses (in GWh terms) to energy consumption derived earlier. The coincident contribution to peak demand (which is nothing but requirement for power) is derived by adding technical losses (in MW terms) to coincident peak power consumption derived earlier.

The technical losses for each category are derived using the following process. Firstly, the technical losses in terms of gigawatt hours, are assumed for the three voltage levels namely HV, MV and LV. Each of the three loss figures are then transformed to technical losses in terms of megawatts by assuming a conversion factor called 'demand loss to energy loss factor'. This factor is generally incrementally greater than 1, and in most cases between 1.1 to 1.3. The technical loss (both in GWh and MW terms) for each category is then computed based on the share of energy consumption (GWh) or coincident peak power consumption (MW) (as the case maybe) of that category in the total energy consumption or coincident peak power consumption for its voltage level (HV, MV, or LV).

6.5.2 Functionalizing assets

The first step of functionalization of assets involves breaking out the utility's asset base into key strategic business units (SBUs) of generation, HV network, MV network and LV network. The MV and LV network SBUs are further subdivided into Urban and Rural units. The 3 network SBUs put together should cover the entire network of utility to which all its customers are connected, including customers connected at transmission voltage levels. In the next step, the asset base is further classified as demand-related or customer-related.

The aim of the exercise is twofold: i) derive asset-based allocation factors[13] for allocating key elements in the cost-of-service analysis; and ii) derive functionalized RAB for estimating return on RAB for customer categories.

The process involves following steps:

1. Functionalizing Gross Fixed Assets (GFA)
2. Deriving functionalized Net Fixed Assets (NFA) financed by the utility
3. Deriving functionalized RAB

Functionalizing Gross Fixed Assets (GFA)

The need for functionalizing GFA arises from the fact that the assets reported in Utility's financial statements are functionalized into broad categories of plant, lines, networks (plant & machinery or 'P&M' in short); land and buildings; and other assets. For deriving the cost of service for each customer category, a more granular classification is needed as shown below.

SBU	1st level functionalization	2nd level functionalization
Generation	-	-
HV network	-	Demand-related assets
	-	Customer-related assets
MV network	Urban	Demand-related assets
	Rural	Customer-related assets

[13] *As electricity is asset intensive business, asset-based allocations are the most appropriate way to segregate costs between different parts of the business.*

SBU	1st level functionalization	2nd level functionalization
LV network	Urban	Demand-related assets
	Rural	Customer-related assets

Firstly, P&M is allocated to the above functions based on actual asset values as provided in Utility's asset register. Secondly, the remaining GFA, i.e., land, buildings and other assets are functionalized based on the ratio of allocation of P&M. The sum of all GFA so functionalized is referred to as "Unadjusted GFA" since it is not adjusted for customer or grant financed (CGF) assets.

The next step involves functionalizing CGF assets and deducting them from "Unadjusted GFA" to derive the "Adjusted GFA". The CGF assets should be functionalized as per the values provided in Utility's asset register.

<u>Deriving functionalized Net Fixed Assets (NFA) financed by the utility</u>

This involves deducting Accumulated depreciation on assets financed by Utility from GFA financed by Utility. The accumulated depreciation on assets financed by Utility is considered after deduction of accumulated depreciation on CGF assets. The total accumulated depreciation on assets financed by Utility is then functionalized in proportion of GFA financed by Utility (Adjusted GFA).

<u>Deriving functionalized RAB</u>

The final step involves derivation of the functionalized RAB. The RAB is derived by adding capital works in progress (CWIP) and net working capital (NWC) to NFA financed by Utility. The CWIP value is functionalized in proportion of Adjusted GFA. Next, NWC is computed as the sum of the following:

1) O&M expense (1 month): fuel cost of generation, staff costs, maintenance expenses, admin & general expenses
2) Receivables (2 months): Tariff receivable from sale of electricity
3) <u>Minus</u> -> Trade payables (1 month): power purchase cost, transmission charges
4) <u>Minus</u> -> Consumer security deposit

Post this, NWC is functionalized in two steps: (i) by allocating to SBUs based on SBU's share of total expenses, and (ii) allocating demand-related and customer-related assets in proportion of unadjusted GFA (which includes CGF assets).

6.5.3 Functionalizing expenses

This section deals with the process of functionalizing expenses to allocate them to energy-related, demand-related, and customer-related costs. The expenses are considered on a net basis, after deducting the non-tariff income recovered from consumers.

It is to be noted that interest and financing expenses are not included in net expenses. This is because interest expense is an integral part of the return on RAB, which is funded by both equity and debt. Further, depreciation does not include depreciation charged on customer financed assets.

> ***Net Expenses*** *=*
>
> *Operating expenses (fuel, power purchase, staff costs, maintenance, A&G, provision for bad debts)* <u>*plus*</u>
>
> *Depreciation* <u>*less*</u>
>
> *Non-tariff income*

The cost functions for which functionalization has been carried out are given below.

SBU	1st level functionalization	2nd level functionalization
Generation	-	Energy-related cost
		Demand-related cost
HV network	-	Energy-related cost
		Demand-related cost
		Customer-related cost
MV network	Urban	Energy-related cost
		Demand-related cost
	Rural	Customer-related cost
MV network	Urban	Energy-related cost
		Demand-related cost
	Rural	Customer-related cost

As a first step towards functionalization, the fuel cost and energy charge (power purchase cost) are functionalized. While the fuel cost is directly allocated to variable costs under ‘Generation’ SBU, the energy charge (power purchase cost) is allocated to customer categories based on their energy requirement.

Capacity charge (power purchase cost) and transmission charges are allocated to customer categories based on their contribution to system peak demand.

Next, the maintenance and A&G costs are functionalized into demand-related and customer-related costs because they are either demand related or customer related. The functionalization is carried out based on unadjusted GFA (including CGF assets since Utility has to incur maintenance and A&G expenses on these assets as well).

The staff costs are functionalized as per following process: (i) allocation to SBUs based on staff count, (ii) allocation to demand-related and customer-related costs within the SBUs based on unadjusted GFA values.

The depreciation expense on assets financed by utility is functionalized into demand-related and customer-related costs based on adjusted GFA. The CGF linked values are removed for allocation purposes since depreciation is not supposed to be charged on CGF assets.

In the final step, non-tariff income items are functionalized. As these are income, they are treated as a ‘negative’ expense. These are allocated only to customer-related costs. The allocation is done based on the count of customers. This is because these income items are proportional to the number of customers served.

6.5.4 Reallocating demand-related revenue requirements, voltage-wise

In an electricity transmission and distribution system, demand-related assets (e.g. substations, transformers, lines) at HV are used to serve not only HV customers but also MV and LV customers. Similarly, MV assets are used to serve LV customers as well. Hence, some portions of the costs associated with such assets at higher voltages (demand-related RAB and demand-related expenses) need to be allocated to lower voltages.

The reallocation is undertaken based on voltage-wise share of peak demand. As a first step, the costs at HV are allocated to HV based on the share of HV peak demand. The balance unallocated HV costs are then added to MV costs to 'update' the MV costs. The 'updated' MV costs are allocated to MV based on MV's share of peak demand, while the balance unallocated MV costs are added to LV costs to derive the 'updated' LV costs. Thus, at the end of this process, the demand-related RAB and demand-related expense, reallocated to HV, MV, and LV levels are obtained. Upon applying the rate of return to RAB and adding it to expenses, the final revenue requirement (RR) re-allocated amongst HV, MV, LV levels is obtained.

		HV	MV		LV	
			Urban	Rural	Urban	Rural
Generation SBU	Energy-related RR	X	X	X	X	X
	Demand-related RR	X	X	X	X	X
Network-related	Energy-related RR	X	X	X	X	X
	Demand-related RR	X	X	X	X	X
	Customer-related RR	X	X	X	X	X

6.5.5 Deriving cost of service results

In this final step, unitary costs of the above functionalized RR elements are obtained. These unitary costs are multiplied with the sales quantity of each customer category to obtain the cost of service.

	Deriving unitary cost		**Energy CoS**		**Demand CoS**		**Customer CoS**	
	Factor	*Unitary cost (a)*	*Quantity (b)*	*Cost a X b*	*Quantity (c)*	*Cost a X c*	*Quantity (d)*	*Cost a X d*
Energy-related RR	Energy Sales (GWh)	$$$/ kWh		X				
Demand-related RR	NCP Sales (MW)	$$$/ kW				X		
Customer-related RR	Customer count	$$$/ Customer						X

The Total cost of service is calculated as the sum of Energy, Demand and Customer cost of services.

The CoS for each customer category is compared with the Revenue recovered from energy charge, demand charge, and customer charge to calculate the percentage cost recovery. The cost recovery percentage results are presented charge-wise as well as on a consolidated basis for each customer category.

7 Key tariff related recommendations

Based on the review of the current tariff practices and benchmarking the same with international best practices, following are the key set of recommendations:

- **Tariff methodology**: A RoR-based methodology (cost plus approach) should be adopted for determining the utility's overall revenue requirement and the revenue requirement for each customer category. This will provide that charges recoverable by the utility for the supply of electricity should allow it to earn a reasonable return on a fair value of its fixed assets in operation plus an allowance for its working capital.
- Actual tariff design should employ simple marginal cost-based signals (e.g., SRMC) for the purpose of sending appropriate price signals to consumers.
- A **multi-year tariff approach** (RPI - x) be implemented sometime in the future, but only after a suitable baseline has been established. However, simple multi-year productivity improvement signals may be easily incorporated using parameters such as employee productivity. The multi-year approach has its advantages, which include: (i) a lower cost of regulation and (ii) a better incentive provided to the utility to increase productivity. In the meantime, performance incentives can be implemented through the RoR methodology by taking a focused multi-year approach
- **Tariff based incentives/penalties**: The tariff structure should provide tariff-based incentives/penalties to customers for improvement of energy efficiency, load factor, and power factor while maintaining simplicity of the structure.
- **Tariff cross-subsidization**: The most common type of subsidy provided in the electricity supply industry worldwide is cross-subsidization within the tariff structure. Usually, cross-subsidies flow from commercial and industrial customers to domestic and other small customers. The extent of such subsidies is revealed through a cost-of-service study. A certain amount of cross-subsidization in a tariff structure might be regarded as tolerable, given that sales to industrial/commercial customers pose a greater risk to the electric utility than do domestic sales, which tend to be more stable over time. Nonetheless, in keeping with best practices, cross-subsidy receivers generally should not pay less than about 90% of the cost of service and subsidy providers should not pay more than 110% of the cost of service.
- **Subsidization of the low-income customers**: For the utility to be commercially viable, if there is to be any significant subsidization of the low-income customers, it should be initiated and paid for, in principle, by the respective state government. A number of mechanisms can be employed to accomplish this, including: (i) direct reimbursement to the utility of the difference between the cost of service and the revenue generated by the lifeline tariff and (ii) direct payment by the government to low-income households, which pay the regular tariff to the utility
- **Capital subsidies**: Another method to subsidize low-income customers is to subsidize construction of new plant to serve low-income areas and eliminate upfront connection charges to the maximum extent possible. This method is particularly useful if the government wishes to increase the country's electrification rate.

- **Automatic adjustment mechanism**: The purpose of an automatic adjustment mechanism is to provide some financial protection to the utility and customer when costs fluctuate in such a manner that the normal tariff setting process cannot effectively deal with them. This mechanism will automatically permit a change in the price charged to customer to track changes in a certain pre-selected cost item (or items) without waiting for a tariff change to be implemented through the normal tariff setting process.

  Automatic adjustment mechanisms are typically applied to fuel prices. In addition to fuel prices, there are other costs that an electric utility can face that significantly impact its financial performance and are beyond its control. This might include foreign exchange losses or volatility in general which changes the price level of the goods and services required to produce electricity.
- **Incentive-based tariff framework**
  - Given that improving the utility operational efficiency is a key objective, indication of efficiency signals to the utility through tariffs is critical. In the absence of RPI – x, an RoR-based tariff framework can be easily used to deliver these signals without a major increase in regulatory intervention. This is best achieved in a **multi-year framework** where the utility is permitted time to make investments for efficiency improvement and also reap its benefits. The incorporation of performance incentives in a RoR-based environment can be accomplished in the following manner:
  - The regulator should identify performance parameters where there is good scope for the utility to improve and which can be used to determine the allowed expenses for cost recovery. These may include, among other parameters, plant availability factors, distribution losses and customer outage periods.
  - The regulator should then establish baseline targets for these performance parameters by analyzing historical performance or through benchmarking exercises. Further, it should forecast the improvements in these parameters that the utility can achieve over a three-to-five-year period.
  - The regulator should determine the revenue requirement to be recovered from tariffs over the selected multi-year period. For example, target distribution losses can be used to estimate power purchase requirement, which, in turn, is used to estimate power purchase cost. Also, target plant availability factors can be used to determine full or partial recovery of fixed costs of a generating plant.
  - Under the RoR methodology, the regulator should carry out periodic tariff review exercises over the multi-year period. If utility surpasses its targeted performance on the parameters, it may be allowed to retain the entire gain or share a certain portion of it with the customers. On the other hand, if the utility under-performs on its targets, it may have to bear the entire loss or share a certain portion of it with customers. The gains/losses that are determined to be borne by the utility can be used to adjust the revenue requirement for a subsequent period
- The tariff-setting process will depend on the type of regulatory model followed (e.g., RPI –x versus RoR) as well as other factors such as the perceived need for formal reviews at defined intervals (as opposed to an as-required basis) and the emphasis placed on public hearings. Below is an example of a tariff-setting process that may be modified in tariff regulations to suit the needs of the Member States.

- **Example of a formal tariff setting process**

  The process outlined below is a simply stated process assuming a formal tariff review every year, which is the recommended regulatory model.

  Tariff Review Period

  Tariff review period is the period for which the regulator will set tariffs. Tariffs will remain unchanged during the tariff review period (subject to the possible introduction of automatic adjustment mechanisms within a tariff review period, which will initially be a year. Tariff review period will be a calendar year and will be set at the conclusion of a formal review of the distribution licensees' costs and operational data.

  Form of tariff application

  The tariff application for any licensee (generation, transmission or distribution) will include:

  - A write-up summarizing the basic elements and rationale for the licensee's proposed revenue requirement and tariff proposal
  - Financial and customer information as may be specified in the tariff regulations
  - Measures of operational performance as may be defined in the performance standards included in the license

  Date for submitting tariff application

  The tariff application will be due three months before the start of the tariff review period. For example, if the tariff review period begins January 1, then the tariff application should be submitted to the regulator on or before September 30 in the previous year.

  Preliminary examination of the tariff application

  After receiving the tariff application, the regulator will examine it for compliance with the submission requirements. Within one week of receipt of the tariff application, the regulator will either accept or reject it.

  In either case, the regulator will provide a list of deficiencies found in the tariff application that the licensee must rectify as soon as possible.

  Tariff application review

  Notwithstanding any confidentiality considerations (there should not be many), the tariff application will be made available in full to the public within one week of its acceptance by the regulator. The regulator will provide all other stakeholders, including consumers, with one month to respond and make comments on the tariff application.

  The regulator will, in the period after acceptance of the tariff application, analyze the information available in sufficient detail to allow a tariff decision to be made.

  Tariff decision

  If the application is accepted, the regulator will render a tariff decision within 10 weeks of acceptance of the tariff application. This tariff decision will document:

  - The proposed revenue requirement for the licensee
  - The resulting tariffs for each customer category
  - The reasons for accepting or rejecting the licensees' proposed costs and investment levels

  Public notification

  The regulator will notify the licensee and the public regarding the final tariff decision. Tariffs will become applicable 21 days after the publication of the tariff decision by regulator or the beginning of the tariff review period, whichever comes later. At this time, the licensee must update its tariff information and notify all customers of the new tariffs.

Appeal of tariff decision by the licensee

Following the publication of the final tariff decision, the licensee will have the ability to appeal the tariff decision by the regulator if it believes that the regulator has not set tariffs according to the principles set out in existing tariff policies and regulations.

A licensee must submit an appeal on the tariff decision within 60 days of the publication of the decision to a designated appeal body. In the event that a licensee appeals the regulator's tariff decision, the new tariffs will remain in operation until the appeal has been reviewed.

- Member States should gradually migrate towards the cost-of-service analysis, and should start maintaining the desired data points for regular reporting of the cost-of-service results

8 Action plan for implementation

8.1 Introduction

The harmonization of tariff frameworks and development of cost reflective tariff is an important step towards regional harmonization and getting all countries on-board the harmonization initiative.

The implementation of the suggested tariff harmonization framework will require concerted efforts from the concerned Member States in moving towards greater regional harmonization. The States are at radically different stages of development in electricity reform and regulation and will require different levels of intervention at different stages. It is important that these frameworks are seen in the light of *'leave no country behind'* rather than ranking or comparing; the aim is not to highlight the gaps between the regulatory leaders and those who follow, but to aid the latter in identifying the measures to be taken to make up the ground.

The harmonization across all states will take time and special efforts from all the concerned stakeholders to align and bring all Member States to the same level. The progress of each Member State is to be measured on an incremental basis from which the country started. The aim is to keep track of the performance and measure progress of the States on a year-to-year basis and provide capacity building support as required in moving towards tariff harmonization and cost reflective tariffs.

8.2 Implementation Strategy and Action Plan

The development of harmonized tariff framework will help the Member States move towards regional integration. The key steps necessary at a regional, collective level to promote harmonization and standardization are as:

- Steps should be taken to have an independent and well-governed regulator in fact as well as in law. The key requirement for regulators is to be independent and have transparent decision making. This will automatically set the base to have well-defined legal and regulatory tariff frameworks for the sector.
- Development of standard tariff determination mechanisms to ensure that investors have greater confidence in investing in the regional market
- Availability of key documents in the public domain, grouped together and easily and freely accessible
- Regional regulator RAERESA to monitor and report performance of the Member States towards development of well-defined tariff regulations and cost reflective tariffs as an aid to the latter rather than as a European style compliance body
- Capacity building and support to national regulators and operators, and the continuing collaboration between regulators through RAERESA and its sister regional organisations

Standardised texts

The principal texts where standardization can be done is by having well-defined tariff frameworks in place – wherein the process of tariff determination including tariff determination methodology, tariff frequency, review mechanism, pass-through charges, automatic adjustment mechanism etc. are laid out. This can be in the form of detailed tariff regulations for each of the Member States. These may be defined separately for generation, transmission and distribution segment of the electricity value chain. Same be may defined separately for an integrated utility. Each country can make a deviation with respect to these in case of any special circumstances.

Availability of documents in the public domain

All key documents such as the Electricity Act, tariff regulations, tariff structure, charges, time of use tariffs etc. should be made available in the public domain. In general, they should be accessible from one site, for example that of the regulator. It is good practice, however, for the utility to publish the documents on its own website. This helps to promote transparency in the market and helps the new entrants and existing operators understand their rights and obligations.

Monitor and report performance of the Member States

Each Member State should set up a nodal officer to report performance on the development of the harmonized and cost reflective tariffs. The timeframe for collection of data for the same needs to be finalized and adhered to amongst the Member States. Member States need to input relevant data after review and approval by the designated officer. Efforts should be made to get the desired data points for carrying out the cost-of-service analysis which are presently not being reported. Any desired training or capacity building support required for this should be discussed amongst the Member States and regional capacity building sessions can be conducted in support of this.

Capacity building and support

The regional regulator can make available guidance notes which suggest 'best practice' approaches to areas of tariff regulation and cost of service approach. Subjects where this could be appropriate include:

- Tariff determination mechanism
- Principles for pass-through charges
- Incentive based regulation
- Automatic adjustment mechanism
- Cost of service approach

We believe that it would also be beneficial to develop guidance notes for the use and adaptation of the standard form documents to guide national authorities in making any necessary modifications in particular circumstances. Likewise, additional capacity building support may be provided to the Member States in developing and implementing cost of service model.

8.3 Conclusion

The development of tariff harmonization and cost reflective framework tool are the first steps towards overall tariff harmonization. The Member States are at radically different stages of development in electricity reform and regulation and will require different level of intervention at different stages. It is clear that the individual effort to move towards cost reflective tariffs will be enormous compared with the human resources available to many regulators and governments. The individual challenge for some smaller states at a nascent stage of power sector development in moving towards harmonized tariff frameworks will be more than the ones with already developed regulatory frameworks. The tariff frameworks should be viewed as an aid to help these states to gain ground, learning from more advanced peers and to avoid 'reinventing the wheel' rather than some kind of external enforcement mechanism. This would also require adequate regulatory information reporting to be in place as data requirement for appropriate development of the cost-of-service model is quite extensive.

The regional regulatory and market bodies will have a major role to play in supporting all States, but the greatest benefit will be felt by those countries that have limited human, technical and financial capacities at present. By extending the practice of using technical, economic, legal and regulatory working groups drawn from experts within the Member States, the work on harmonizing tariff frameworks can be done through coordination and cooperation, under the leadership of the regional regulatory and market bodies.

9 Conclusion

The tariff harmonization and cost of service approach have been proposed to have a **uniform set of regional tariff frameworks across the COMESA Member States**. Different tariff regimes, different laws, different market structures and a high level of political control and influence increase the risk premium for investors to invest in the market. For an investor in energy infrastructure, the greater the risks faced in any country, the higher the return that will be demanded, which impacts energy prices. Harmonization of tariff frameworks, including **well-defined tariff regulations, tariff pass-through mechanisms (uncontrollable costs), regular tariff revisions and implementation of cost-of-service methodology** will help to standardize and streamline the process of tariff determination across the Member States. This will enable greater cost reflectivity in the tariffs and increase investor confidence in the regional market. Eventually, this will make the market self-sustaining without undue dependence on the government support.

10 Annexures

10.1 Cost Reflectivity Assessment Framework Tool (CRAFT)

Please refer the Microsoft Excel file titled “CoS Model_v1” enclosed with this report.

10.2 Training Manual for use of the Cost-of-Service Model

10.2.1 Glossary of key terms used in the model

S. No.	Term	Definition
1	Capacity charge (Power Purchase)	Capacity charge (fixed charge) covers the power project company's fixed costs, including a return on equity
2	Capital works in progress (CWIP)	Capital work in progress (CWIP) is the cost of fixed assets that are still being constructed or developed and aren't yet ready for use. It is a balance sheet item that includes expenses like construction costs, equipment purchases, and other project-related expenditures.
3	Consumer grant funded assets (CGF)	CGF assets are those financed by customers or grant money, which need to be excluded when calculating costs to be recovered from tariffs
4	Consumer security deposit (CSD)	Consumers pay their electricity bill after the bill is generated. The security deposit in electricity bill is taken by customers to ensure that the electricity board does not incur any loss. In case the customer does not pay their electricity bill, despite notice and warning being given - the amount of their electricity bill will be deducted from the security deposit. The amount of the deposit is usually based on the average monthly cost of electricity over the previous year.
5	Coincidence factor	Coincidence factor is the ratio of coincident peak of a customer category's load curve to the category peak i.e. non-coincident peak
6	Coincident peak (CP)	Coincident peak is contribution of each consumer category to the system peak demand or the consumer category demand value at the time of system peak
7	Customer related assets	Customer related assets include assets such as customer service line, customer transformer, meters, etc.
8	Customer related cost	Customer related costs vary with the number of customers. These include all costs associated with the provision of electricity services to customers. E.g. costs associated with service connection, metering, billing, collection, and customer service.
9	Demand charge (Revenue - Electricity Tariff)	Demand charges are capacity-based (priced per-kW) components of a distribution tariff which charge a user according to the maximum power they consume during a given time-period. Demand charges are a component of commercial electricity tariff that are based on a customer's peak power usage during a billing period. They are designed to help utilities recover the costs of generating and distributing power.
10	Demand related assets	Demand related assets include assets such as lines, transformers, substations, systems & instrumentation, etc.
11	Demand related cost	Demand-related costs include all costs associated with creating the generation capacity and network capacity (transmission and distribution) to fulfil consumer demand and operating such capacity. e.g. debt servicing cost associated with acquisition of fixed assets, depreciation of fixed assets, O&M expenses related to fixed assets.
12	Energy charge (Power Purchase)	Energy charge covers the variable cost of energy generation.
13	Energy charge (Revenue - Electricity Tariff)	Energy charges are a variable component of an electricity tariff that is applied to the total amount of electricity consumed during a billing period

S. No.	Term	Definition
14	Energy consumption	Energy consumption is energy sales plus non-technical losses
15	Energy requirement	Energy requirement is energy consumption plus technical losses
16	Energy related cost	Energy related costs vary with the volume of consumption. Energy consumption-related costs include all costs associated with the generation of energy units. E.g. primary fuel cost and startup fuel cost.
17	Fixed charge (Revenue - Electricity Tariff)	The fixed charge component of an electricity tariff is a fee that covers the cost of maintaining the infrastructure needed to supply electricity to a home or business. This charge is independent of the actual electricity consumption and is usually the same each month. It is also known as the customer charge.
18	Gross fixed assets (GFA)	Gross fixed assets (GFA) is an accounting term that refers to the total cost of a business's fixed assets, including equipment, machinery, and property.
19	High Voltage (HV)	High voltage as a general practice has been considered as a voltage level above 66 kV
20	Load factor	Load factor is the ratio of actual energy consumption to peak energy consumption for a particular consumer category
21	Low Voltage (LV)	Low voltage as a general practice has been considered as a voltage level of 230 V, 400 V etc.
22	Medium Voltage (MV)	Medium voltage as a general practice has been considered as a voltage level from 11 kV upto 66 kV
23	Meter rent	Meter rent is a monthly fee that customers pay if they don't own their electricity meter. The electricity distributor usually owns the meter, and the customer pays the rent during the billing period. The meter rent is listed on the customer's electricity bill.
24	Non-Coincident Peak (NCP)	Non-coincident peak is the peak demand of each customer category
25	Net fixed assets (NFA)	Net fixed assets (NFA) is the total value of a company's gross fixed assets, minus the total accumulated depreciation on the same
26	Net fixed assets (NFA) financed by the utility	This involves deducting accumulated depreciation on assets financed by utility from GFA financed by utility. The accumulated depreciation on assets financed by utility is considered after deduction of accumulated depreciation on CGF assets.
27	Non-technical losses	Non-technical losses arise from several reasons including theft, un-billed accounts, and estimated customer accounts, errors due to the approximation of consumption by un-metered supplies, metering errors etc.
28	Technical losses	Technical losses are regarded as the electrical system losses which are caused by network impedance, current flows and auxiliary supplies. The sources of technical losses may be directly driven by network investment or by network operation. Technical losses are the losses that occur within the distribution network due to the cables, overhead lines, transformers and other substation equipment that we use to transfer electricity.
29	Provision for bad debts	A provision for bad debts is an estimate of the amount of money a company owes that is unlikely to be paid back. It's also known as a provision for doubtful debts or an allowance for doubtful accounts. A company might make a provision for bad debts to cover debts that are not expected to be paid during an accounting period. The provision is based on an

S. No.	Term	Definition
		estimate of how much of the accounts receivable will not be collected during the given period. A general provision, such as 2% of debtors, cannot be deducted for tax purposes. However, a specific provision can be deducted if there is documentary evidence that the debts are unlikely to be paid.
30	Reconnection charges	Reconnection charges apply when a service line is disconnected for payment defaults, breach of supply conditions, or a temporary request from the consumer. Reconnection is allowed within six months of disconnection, but no charges apply if the disconnection was due to a natural calamity. Reconnection charges for electricity vary by provider and the reason for disconnection.
31	Regulated asset base (RAB)	RAB is derived by adding capital works in progress (CWIP) and net working capital (NWC) to net fixed assets (NFA) financed by utility
32	Return on RAB	Return on RAB is the rate of return on the regulated asset base (RAB) as approved by the regulator. In case of absence of a regulator approved rate of return, same can be considered as the weighted average cost of capital (WACC).
33	Revenue Requirement (RR)	Revenue requirement (RR) is the sum of all operating, capital and financing costs along with a return on capital which need to be recovered from customers through tariff, adjusted for any income obtained from customers through non-tariff sources (e.g. meter rent, delayed payment penalties, interest earned on security deposit, etc.).
34	Strategic Business Unit (SBU)	A strategic business unit (SBU) is a business unit within a larger organization that operates as a separate division with its own plans and activities. SBUs are profit centers that focus on a specific market segment. In the present context, SBU means Generation, Transmission, Distribution-Urban, Distribution-Rural, Corporate & Shared services
35	Weighted average cost of capital (WACC)	The weighted average cost of capital (WACC) is the average rate that a utility pays to finance its assets. It is calculated by averaging the rate of all of the company's sources of capital (both debt and equity), weighted by the proportion of each component. In this model, in absence of a regulator approved rate of return, same may be used to calculate the return on RAB

10.2.2 Choosing the reference year

Cost-of-Service (CoS) assessments are done on whole of the year cost data. Timely and reliable data is critical, and hence the latest financial year for which audited financial data is available, must be preferred. In case the regulator has set the tariff determination methodology, in that case the utility can adopt the regulatory costs being allowed by the regulator for the determination of the cost-of-service results.

10.2.3 Structure of the CoS model

The sheet structure of the model is explained below:

1. **‘RR’**: A buildup of the revenue requirement (RR) to be recovered from tariffs, including the return to be earned on regulated asset base (RAB), is developed in this sheet.
2. **‘Customer’**: Customer category-wise data covering customer count, geography, voltage level, energy sales, connected load, connection charge, load factor, coincidence factor, and revenue from electricity sales is inputted in this sheet. The data inputted is further built upon to derive the complete energy balance (GWh) and power balance (MW) for each customer category, which entails adding non-technical and technical losses to sales quantum, to derive the requirement to be inputted into the system to meet the demand of each category.
3. **‘Loss’**: This sheet provides a facility to input key assumptions related to technical and non-technical losses, voltage-wise. The model includes a segregation across 3 voltage classes - HV: above 66 kV, MV: above 400 V and up to 66 kV, and LV: 230 V, 400 V. The sheet derives the energy (GWh) and power (MW) balance for the system at each voltage level. This output is used in the ‘Customer’ sheet to derive the energy and power balance for each customer category.
4. **‘Assets’**: This sheet functionalizes the assets reported in financial statements into categories which are the building blocks for cost of service. Assets includes fixed assets (plant & machinery, land, buildings and other assets), accumulated depreciation, assets under construction (capital works-in-progress or CWIP), current assets and current liabilities (working capital). These elements are used to build the RAB, and hence this sheet helps derive the functionalized RAB. The functionalization is carried out at multiple levels: i) strategic business units (SBUs) of Generation, HV network, MV network, and LV network; ii) geographical segregation of Urban and Rural; (iii) purpose-based segregation of Demand-related and Customer-related assets.
5. **‘Expenses’**: This sheet functionalizes the expenses reported in financial statements into categories which are the building blocks for cost of service. Expenses include operational (fuel, power purchase, transmission, staff, maintenance, administrative and general) and non-operational (depreciation, interest and financing, provision for bad debts). The functionalization is carried out at multiple levels: i) strategic business units (SBUs) of Generation, HV network, MV network, and LV network; ii) geographical segregation of Urban and Rural; (iii) purpose-based segregation of Energy-related, Demand-related and Customer-related expenses.
6. **‘V.Realloc’**: This sheet reallocates the voltage-levels based functionalized allocations to reflect the contribution of assets at higher voltages in serving customers at lower voltages. The re-allocation covers Demand (Network)-related RAB and Demand (Network)-related Expenses.
7. **‘Output’**: This sheet presents the results of CoS exercise by tabulating the cost to serve each customer category alongside the revenue recovered from tariffs. The Energy-related, Demand-

related and Customer-related costs are compared with the recoveries from Energy charge, Demand chargeand Fixed charge.

10.2.4 Operating the model and deriving results

1. Enter data and assumptions in cells with blue text. Cells which are in black text are formula driven and "read-only".
2. Data and assumptions are to be entered in sheets titled "RR", "Customer", "Loss", and "Assets". Refer to the accompanying notes in the model for guidance.
3. After inputting data in "Customer" and "Loss" sheets, review the parameter of "Energy loss => Demand loss conversion factor" in the "Loss" sheet. This factor denotes the relationship between demand loss (in MW terms) and energy loss (in GWh terms) and needs to be entered manually. The value is to be determined using a trial-and-error method, by inputting values incrementally greater than 1 and ensuring that value in the cell marked "ERROR" is minimized as close to zero as possible. Doing so will ensure that the voltage-wise demand loss and energy loss figures are internally consistent.
4. The results can be viewed in "Output" sheet as customer category-wise cost incurred, revenue recovered through tariffs and percentage cost reflectivity of tariffs.

10.2.5 Methodology of the CoS model

The model methodology can be explained in five steps:

1. Deriving customer category-wise energy balance and power balance
2. Functionalizing assets
3. Functionalizing expenses
4. Reallocating demand-related RAB and RR, voltage wise
5. Deriving cost of service results

Each of these steps is described in detail in the following sections.

10.2.5.1 Deriving customer category-wise energy balance and power balance

Sales = Billed to customer
Consumption = Sales + Non-technical losses
Requirement = Consumption + Technical losses

This step derives the energy balance and power balance for each customer category. Starting with the sales data (both energy sales in GWh and power sales in MW terms), the non-technical and technical losses are added to each category to derive the energy requirement (GWh) and the coincident contribution to system peak demand (MW) of each category. These are further used as allocation factors in various steps of the cost-of-service analysis.

Deriving energy and power balance is a two-step transformation process:

1. From sales to consumption
2. From consumption to requirement

From sales to consumption

Deriving consumption in terms of gigawatt hours is fairly straightforward. The non-technical losses for each category are simply added to energy sales to derive the energy consumption in terms of gigawatt hours. To derive the power consumption in terms of megawatts, firstly the non-coincident peak power consumption is derived from energy consumption for each category by applying the respective load factor. Non-coincident peak power consumption is then transformed to coincident peak power consumption in terms of megawatts by applying the coincidence factor for each category.

From consumption to requirement

The energy requirement is derived by adding technical losses (in GWh terms) to energy consumption derived earlier. The coincident contribution to peak demand (which is nothing but requirement for power) is derived by adding technical losses (in MW terms) to coincident peak power consumption derived earlier.

The technical losses for each category are derived using the following process. Firstly, the technical losses in terms of gigawatt hours, are assumed for the three voltage levels namely HV, MV and LV. Each of the three loss figures are then transformed to technical losses in terms of megawatts by assuming a conversion factor called 'demand loss to energy loss factor'. This factor is generally incrementally greater than 1, and in most cases between 1.1 to 1.3. The technical loss (both in GWh and MW terms) for each category is then computed based on the share of energy consumption (GWh) or coincident peak power consumption (MW) (as the case maybe) of that category in the total energy consumption or coincident peak power consumption for its voltage level (HV, MV, or LV).

10.2.5.2 Functionalizing assets

The first step of functionalization of assets involves breaking out the utility's asset base into key strategic business units (SBUs) of generation, HV network, MV network and LV network. The MV and LV network SBUs are further subdivided into Urban and Rural units. The 3 network SBUs put together should cover the entire network of utility to which all its customers are connected, including customers connected at transmission voltage levels. In the next step, the asset base is further classified as demand-related or customer-related.

The aim of the exercise is twofold: i) derive asset-based allocation factors[14] for allocating key elements in the cost-of-service analysis; and ii) derive functionalized RAB for estimating return on RAB for customer categories.

The process involves following steps:

1. Functionalizing Gross Fixed Assets (GFA)
2. Deriving functionalized Net Fixed Assets (NFA) financed by the utility
3. Deriving functionalized RAB

[14] *As electricity is asset intensive business, asset-based allocations are the most appropriate way to segregate costs between different parts of the business.*

Functionalizing Gross Fixed Assets (GFA)

The need for functionalizing GFA arises from the fact that the assets reported in Utility's financial statements are functionalized into broad categories of plant, lines, networks (plant & machinery or 'P&M' in short); land and buildings; and other assets. For deriving the cost of service for each customer category, a more granular classification is needed as shown below.

SBU	1st level functionalization	2nd level functionalization
Generation	-	-
HV network	-	Demand-related assets
	-	Customer-related assets
MV network	Urban	Demand-related assets
	Rural	Customer-related assets
LV network	Urban	Demand-related assets
	Rural	Customer-related assets

Firstly, P&M is allocated to the above functions based on actual asset values as provided in Utility's asset register. Secondly, the remaining GFA, i.e., land, buildings and other assets are functionalized based on the ratio of allocation of P&M. The sum of all GFA so functionalized is referred to as "Unadjusted GFA" since it is not adjusted for customer or grant financed (CGF) assets.

The next step involves functionalizing CGF assets and deducting them from "Unadjusted GFA" to derive the "Adjusted GFA". The CGF assets should be functionalized as per the values provided in Utility's asset register.

Deriving functionalized Net Fixed Assets (NFA) financed by the utility

This involves deducting Accumulated depreciation on assets financed by Utility from GFA financed by Utility. The accumulated depreciation on assets financed by Utility is considered after deduction of accumulated depreciation on CGF assets. The total accumulated depreciation on assets financed by Utility is then functionalized in proportion of GFA financed by Utility (Adjusted GFA).

Deriving functionalized RAB

The final step involves derivation of the functionalized RAB. The RAB is derived by adding capital works in progress (CWIP) and net working capital (NWC) to NFA financed by Utility. The CWIP value is functionalized in proportion of Adjusted GFA. Next, NWC is computed as the sum of the following:

1) O&M expense (1 month): fuel cost of generation, staff costs, maintenance expenses, admin & general expenses
2) Receivables (2 months): Tariff receivable from sale of electricity
3) Minus -> Trade payables (1 month): power purchase cost, transmission charges
4) Minus -> Consumer security deposit

Post this, NWC is functionalized in two steps: (i) by allocating to SBUs based on SBU's share of total expenses, and (ii) allocating demand-related and customer-related assets in proportion of unadjusted GFA (which includes CGF assets).

10.2.5.3 Functionalizing expenses

This section deals with the process of functionalizing expenses to allocate them to energy-related, demand-related, and customer-related costs. The expenses are considered on a net basis, after deducting the non-tariff income recovered from consumers.

It is to be noted that interest and financing expenses are not included in net expenses. This is because interest expense is an integral part of the return on RAB, which is funded by both equity and debt. Further, depreciation does not include depreciation charged on customer financed assets.

Net Expenses =
Operating expenses (fuel, power purchase, staff costs, maintenance, A&G, provision for bad debts) plus
Depreciation less
Non-tariff income

The cost functions for which functionalization has been carried out are given below.

SBU	1st level functionalization	2nd level functionalization
Generation	-	Energy-related cost
		Demand-related cost
HV network	-	Energy-related cost
		Demand-related cost
		Customer-related cost
MV network	Urban	Energy-related cost
	Rural	Demand-related cost
		Customer-related cost
MV network	Urban	Energy-related cost
	Rural	Demand-related cost
		Customer-related cost

As a first step towards functionalization, the fuel cost and energy charge (power purchase cost) are functionalized. While the fuel cost is directly allocated to variable costs under 'Generation' SBU, the energy charge (power purchase cost) is allocated to customer categories based on their energy requirement.

Capacity charge (power purchase cost) and transmission charges are allocated to customer categories based on their contribution to system peak demand.

Next, the maintenance and A&G costs are functionalized into demand-related and customer-related costs because they are either demand related or customer related. The functionalization is carried out based on unadjusted GFA (including CGF assets since Utility has to incur maintenance and A&G expenses on these assets as well).

The staff costs are functionalized as per following process: (i) allocation to SBUs based on staff count, (ii) allocation to demand-related and customer-related costs within the SBUs based on unadjusted GFA values.

The depreciation expense on assets financed by utility is functionalized into demand-related and customer-related costs based on adjusted GFA. The CGF linked values are removed for allocation purposes since depreciation is not supposed to be charged on CGF assets.

In the final step, non-tariff income items are functionalized. As these are income, they are treated as a 'negative' expense. These are allocated only to customer-related costs. The allocation is done based on the count of customers. This is because these income items are proportional to the number of customers served.

10.2.5.4 Reallocating demand-related revenue requirements, voltage-wise

In an electricity transmission and distribution system, demand-related assets (e.g. substations, transformers, lines) at HV are used to serve not only HV customers but also MV and LV customers. Similarly, MV assets are used to serve LV customers as well. Hence, some portions of the costs associated with such assets at higher voltages (demand-related RAB and demand-related expenses) need to be allocated to lower voltages.

The reallocation is undertaken based on voltage-wise share of peak demand. As a first step, the costs at HV are allocated to HV based on the share of HV peak demand. The balance unallocated HV costs are then added to MV costs to 'update' the MV costs. The 'updated' MV costs are allocated to MV based on MV's share of peak demand, while the balance unallocated MV costs are added to LV costs to derive the 'updated' LV costs. Thus, at the end of this process, the demand-related RAB and demand-related expense, reallocated to HV, MV, and LV levels are obtained. Upon applying the rate of return to RAB and adding it to expenses, the final revenue requirement (RR) re-allocated amongst HV, MV, LV levels is obtained.

		HV	**MV**		**LV**	
			Urban	Rural	Urban	Rural
Generation SBU	Energy-related RR	X	X	X	X	X
	Demand-related RR	X	X	X	X	X
Network-related	Energy-related RR	X	X	X	X	X
	Demand-related RR	X	X	X	X	X
	Customer-related RR	X	X	X	X	X

10.2.5.5 Deriving cost of service results

In this final step, unitary costs of the above functionalized RR elements are obtained. These unitary costs are multiplied with the sales quantity of each customer category to obtain the cost of service.

	Deriving unitary cost		**Energy CoS**		**Demand CoS**		**Customer CoS**	
	Factor	*Unitary cost (a)*	*Quantity (b)*	*Cost a X b*	*Quantity (c)*	*Cost a X c*	*Quantity (d)*	*Cost a X d*
Energy-related RR	Energy Sales (GWh)	$$$/ kWh		X				
Demand-related RR	NCP Sales (MW)	$$$/ kW				X		
Customer-related RR	Customer count	$$$/ Customer						X

The total cost of service is calculated as the sum of Energy, Demand and Customer cost of services.

The CoS for each customer category is compared with the Revenue recovered from energy charge, demand charge, and customer charge to calculate the percentage cost recovery. The cost recovery percentage results are presented charge-wise as well as on a consolidated basis for each customer category.

10.3 Data requirements

Specific data requirements for carrying out cost of service analysis

- Utility load curve data for the previous three years
- Consumer category-wise load curve data for the previous three years
- Gross fixed assets details for generation, transmission, and distribution assets in order to carry out the cost-of-service analysis
- Quantum of power purchase over the past 3 years - source-wise (in million kWh)
- Cost of power purchase - source-wise
- Consumer category-wise number of consumers by voltage level of supply
- Consumer category-wise consumption (kWh)/energy sales by voltage level of supply
- Consumer category-wise revenue billed by voltage level of supply and by billing determinant (i.e., from energy charge, demand charge, customer charge)
- Consumer category-wise connected load or contracted billing demand (in MW) by voltage level of supply
- Non-coincident peak demand (in MW) consumer category-wise
- Demand forecast study, if any, carried out
- Typical load curve during summer, monsoon, and winter season