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GUIDELINES FOR ADVANCING ECONOMIC AND QUALITY OF SERVICE REGULATION IN AFRICA'S ELECTRICITY SECTOR

BASED ON THE AFRICAN DEVELOPMENT BANK'S ELECTRICITY REGULATORY INDEX FOR AFRICA

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GUIDELINES FOR ADVANCING ECONOMIC AND QUALITY OF SERVICE REGULATION IN AFRICA'S ELECTRICITY SECTOR

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Author(s):	Emtech Energy Services Ltd.

National Association of Regulatory Utility Commissioners

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List of Acronyms and Abbreviations

AfDB	African Development Bank
AIT	Average Interruption Time
ASIDI	Average System Interruption Duration Index
ASIFI	Average System Interruption Frequency Index
AUC	African Union Commission
CAIDI	Customer Average Interruption Duration Index
CAIFI	Customer Average Interruption Frequency Index
CEER	Council of European Regulators
CI	Customer Interruptions
CIAC	Contribution in Aid of Construction
C&I	Commercial and Industrial
CML	Customer Minutes Lost
CoS	Continuity of Supply
CoSS	Cost of Service Study
CQ	Commercial Quality
CRSE	Commission de Regulation du Secteur de l'Electricite
DNO	Distribution Network Operator
DSO	Distribution System Operator
ECB	Energy Control Board (Namibia)
ECRB	Energy Community Regulatory Board
EHV	Extra High Voltage
ENS	Energy Not Supplied
ER	Economic Regulation
ERB	Energy Regulation Board (Zambia)
ERI	Electricity Regulatory Index for Africa
GI	Guaranteed Indicators
GIS	Geographical Information System
HEA	Hungary Energy & Public Utility Regulatory Authority
HV	High Voltage

KPI	Key Performance Indicator
kV	Kilo Volt
LBT	Lifeline Bulk Tariff
LEC	Lesotho Electricity Corporation
LEWA	Lesotho Electricity and Water Authority
LV	Low Voltage
MAIFI	Momentary Average Interruption Frequency Index
MV	Medium Voltage
NARUC	National Association of Regulatory Utility Commissioners
NERC	Nigeria Electricity Regulatory Commission
NRA	National Regulatory Authority
OI	Overall Indicators
O&M	Operation and Maintenance
PCR	Price Cap Regulation
QoS	Quality of Service
RAB	Regulatory Asset Base
RCR	Revenue Cap Regulation
RIA	Regulatory Impact Assessment
RGI	Regulatory Governance Index
ROI	Regulatory Outcome Index
RoR	Rate of Return
RR	Revenue Requirement
RSI	Regulatory Substance Index
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SENELEC	Senegal Electricity Company
SO	System Operator
TSO	Transmission System Operator
TSP	Transmission System Provider
USAID	United States Agency for International Development

VQ	Voltage Quality
WACC	Weighted Average Cost of Capital
ZESCO	Zambia Electricity Supply Company

Executive Summary

Background

The Electricity Regulatory Index for Africa (ERI) is a publication by the African Development Bank (AfDB) aimed at providing insights on regulatory developments and issues on the African continent. The first edition of the ERI was published in 2018 and has been updated and issued each year since then, with the third edition released in November 2020. Starting with a review of regulatory developments and capacities in 15 countries in 2018, the 2020 edition includes data for 36 participating African countries.

The ERI is made up of three pillars or sub-indices: the Regulatory Governance Index (RGI); the Regulatory Substance Index (RSI); and the Regulatory Outcome Index (ROI). The 2020 ERI report explains that:

"The RGI assesses the level of development of the legal and institutional set up of the regulatory framework in a country. It is concerned with the existence and content of electricity sector regulations.

The RSI assesses how each regulator has operationalized its mandate by developing and implementing key regulatory instruments and frameworks for the sector.

The ROI assesses the outcome of regulatory decisions, actions, and processes on the sector from the perspective of regulated entities. It offers insights into how the actions of regulators have affected the performance of the sector."[1]

The ERI report has shown that whereas countries tend to score highest on the RGI, scores on the RSI are relatively lower, while the ROI has the lowest average score. A National Regulatory Authority's (NRA's) RSI performance is crucial to its overall effectiveness, as it reflects the extent to which a regulator's mandate translates into effective decisions and actions. The RSI is determined in the 2020 ERI using seven indicators: Economic Regulation; Technical Regulation; Licensing Framework; Institutional Capacity; Renewable Energy Development; Mini-Grid and Off-Grid systems; and Energy Efficiency.

Over the course of the last three years, most of the assessed countries have demonstrated average or below average performance on the RSI indicators measuring economic and quality of service regulation. The 2020 ERI report shows the mean score for economic regulation as 0.534, while the average score for technical regulation was 0.506. The ERI reports provide a number of recommendations as to how these indicators may be improved.

The AfDB initiated collaboration with USAID and NARUC to formulate concrete strategies for implementing its recommendations and other interventions in line with global best practices to improve power sector regulation in Africa. This project aims to develop Guidelines for Advancing Economic and Quality of Service Regulation in Africa's Power Sector, and provide clear steps for countries to take to improve implementation of effective economic and quality of service regulation.

With the 2020 ERI demonstrating poor performance of many AfDB countries as measured by indicators on quality of service and economic regulation, it is expected that the Guidelines will act as

[1] African Development Bank "*Electricity Regulatory Index for Africa, 2020*"

a catalyst to improve regulatory performance in these two critical areas.

Economic Regulation

Economic regulation is concerned with the efficient operation of the electricity market to ensure that prices are fair to both the supplier and the customer. It covers such areas as tariff design, pricing of services, network investments, and technical and commercial losses. Economic regulation is necessary to steer the electricity market toward sufficient liquidity and viability.

In assessing economic regulation in Africa's power sector, the ERI report identified several key challenges. First, nearly half of the countries surveyed had no framework in place to develop electricity tariff methodologies with transparent and predictable review procedures and adjustment mechanisms. Even where robust tariff methodologies have been developed, reliance on inaccurate and insufficient data, as well as information asymmetry, result in non-cost reflective tariffs due to errors in the underlying assumptions for rate setting.

Other critical issues that have not been sufficiently addressed by NRAs include the treatment of subsidies for the poor and vulnerable and migration towards cost-reflective tariffs. This is especially important given the fact that affordability of cost-reflective tariffs remain a major challenge for expanding electricity access to the poor in Africa, and also given the social objectives of most governments to provide access to electricity to the population regardless of economic considerations.

This Guidelines report therefore aims to address these challenges and provide workable options and recommendations for NRAs to improve economic regulation. In doing this, the report provides useful background information considered essential to strengthening the capacity of regulators for effective tariff setting, including basic insights into the objectives, characteristics, principles, procedures, and methods for designing and implementing electricity tariffs.

In discussing options for the development of transparent and predictable tariff methodologies with adequate review procedures and adjustment mechanisms, this Guidelines report advocates the consideration of factors such as fuel costs, rates of inflation, and foreign exchange fluctuations. A case study on Uganda was used to showcase the Uganda Electricity Regulatory Authority's (ERA's) implementation of a tariff methodology that ensures cost-reflectivity with appropriate review procedures and adjustment mechanisms.

This Guidelines report also provides recommendations related to the treatment of poor and vulnerable customers in the context of encouraging migration towards cost-reflective tariffs. NRAs may consider cross-subsidization among different customer segments or use of government subsidies as they chart a transition path towards cost reflectivity. However, this decision must be predicated on a regulatory impact assessment to fully understand the cost implications and to develop a clear and realistic timeline for migration. A case study from Lesotho highlights the regulator's utilization of lifeline tariffs to ensure affordability for low-income customers.

Based on the findings from the ERI Report that most countries on the continent have not recently performed Cost of Service Studies (CoSS), this report examines in detail the impact of CoSS on cost-reflective rate setting. Two approaches to CoSS are examined: the embedded approach and the marginal cost approach. The embedded approach is recommended as it is less complex and much more commonly used.

The ERI Guidelines discusses the methodology for undertaking CoSS, starting with the calculation of the utility's revenue requirement, and followed by cost attribution, functionalization, classification, and allocation. The cost of service is a major factor in the determination of revenue allocation and rate design for a utility. It is therefore imperative that a CoSS is carried out to facilitate the determination of a prudent revenue requirement (i.e., cost plus a fair margin of return) and appropriate allocation of costs to each customer class.

Finally, this Guidelines report discusses challenges to conducting CoSS in Africa and provide context-specific options and recommendations to tackle these challenges. Key among the challenges discussed is the absence of network connection policies in most of the countries surveyed, preventing utilities' and regulators' ability to assign appropriate connection-related costs. Case studies illustrate U.S. utility company Spanish Fork's experience implementing a CoSS, and the use of the outcomes of CoSS by Zambia and Uganda in tariff setting.

Quality of Service Regulation

Quality of service (QoS) regulation falls under an NRA's technical regulatory responsibilities. QoS is the totality of characteristics of power supply services that bear on its ability to satisfy the needs of consumers. Traditionally, QoS is addressed from the perspective of end-users, whose perception of power supply services is influenced by a number of factors including technical issues, commercial principles, and resolution/enforcement mechanisms. QoS has two primary aspects: (1) commercial quality (CQ) and (2) technical quality. Technical quality can be further divided into two sub-categories, (1) continuity of supply (CoS) and (2) voltage quality (VQ).

The 2020 ERI Report shows that regulatory frameworks for quality of service are weak across Africa's power sector; 55% of the countries surveyed have not developed any country level QoS regulations, and many of the countries with QoS regulations do not have clear cut standards and benchmarks for key QoS indices. In addressing the challenges in QoS regulation, this Guidelines report treats the issues and challenges based on the three components of QoS noted above: CoS, VQ and CQ.

Continuity of supply (CoS) concerns interruptions in electricity supply and focuses on the events during which the voltage at the supply terminals of a network drops to zero or nearly zero. This Guidelines report discusses common indicators used for monitoring CoS, including System Average Interruption Duration Index (SAIDI); System Average Interruption Frequency Index (SAIFI); Consumer Average Interruption Distribution Index (CAIDI); Consumer Average Interruption Frequency Index (CAIFI); and Energy Not Supplied (ENS.) These indicators and surveyed countries' monitoring procedures are compared to those in Europe as outlined in the Council of European Energy Regulators (CEER) 6th Benchmarking Report on Quality of Service.

Based on the identified challenges and international best practices, this Guidelines report provides options and recommendations for improving CoS regulation in Africa, including the gradual introduction of monitoring of short interruptions (in addition to the current practice of monitoring long interruptions); standardization of data collection procedures across the continent for easier comparison and benchmarking; and implementation of adequate incentive schemes to maintain and improve CoS.

Voltage quality (VQ) measures cover a wide range of voltage disturbances and deviations in voltage magnitude or waveform from the optimum values. Any such disturbances to voltage quality can impact the operation of the power grid and/or of units connected to the grid.

Voltage quality is the most technically complex aspect of quality of electricity supply. Measurement issues, the choice of appropriate indicators, and the setting of limits require detailed monitoring of every single disturbance. Moreover, multiple stakeholders' actions may contribute to the level and impact of the disturbance. This often makes it difficult to lay the responsibility on any one particular stakeholder, such as the network operator or one of the connected end-users. For this reason, voltage quality regulation must weigh the cost to customers resulting from equipment malfunctions or damage versus any direct or indirect increase in tariffs due to investments in grid improvement.

This Guidelines report takes this into consideration in making appropriate recommendations for improving VQ regulation in Africa. Recommendations include the need for the regulator to establish a transparent framework for due diligence in identifying stakeholder responsibilities on voltage disturbances, in accordance with the concept of responsibility sharing described in this report; regular publication of voltage quality data or statistics based on monitored data for public awareness; and the development of more robust awareness and education campaigns on the effects of voltage quality issues on the network and individual customers connected to the network.

Commercial quality (CQ) is directly associated with transactions between utilities (distribution service operators [DSOs], suppliers, or both) and customers. Commercial quality covers not only the supply and sale of electricity, but also various forms of interaction between utilities and customers.

Commercial quality indicators can be classified into four main groups representing the main areas of interface between the customer and the utility. These are: (1) connection, (2) customer care, (3) technical service, and (4) metering and billing. These four categories of CQ and their associated measurement indicators are analyzed in this Guidelines report. Most of the indicators for commercial quality of service are time-based, since from the customer's perspective, timeliness in service provision or complaints resolution is at the core of their engagement with the utility. This is often translated into a customer service charter, which may or may not be derived from the country's QoS regulations.

Some of the recommendations made to improve CQ regulation in Africa's power sector include the need to regularly review CQ indicators, taking into account any changes in national conditions or customer expectations; ensuring greater protection of customers through the gradual introduction of guaranteed levels of CQ with automatic compensation for the utility's failure to meet these thresholds; and undertaking periodic customer satisfaction surveys. Case studies from Hungary and Namibia show how these countries have used different approaches for effective CQ regulation.

Cross-Cutting Issues

In addition to providing strategies for improving economic and quality of service regulation, this Guidelines report also addresses three key cross-cutting issues that consistently hamper the ability of NRAs to effectively implement economic and QoS regulations.

These cross-cutting issues are (1) institutional capacity, (2) regulatory impact assessment, and (3) data management. This report offers several recommendations to tackle critical challenges facing each of these issues.

This Guidelines report was developed to provide clear steps for countries to take to strengthen the development and implementation of effective economic and QoS regulation. It is expected that implementing the recommendations therein will deliver measurable improvements in economic and QoS regulation in Africa's power sector.

1. Introduction

1.1 Project Background

Electricity access in Africa in 2020 is estimated at about 54%. This means that almost 600 million Africans do not have access to power supply, either grid-connected or off-grid.[2] This problem may be traced to lack of adequate investments in the sector, as well as the absence of resources and capacity to address major underlying issues, including sector governance. Most utilities on the continent remain state-owned and over the years, African governments have been unable to provide the necessary public investment and expertise to steer the sector to viability and profitability. They have accordingly opened the electricity sector to private sector participation.

Effective private sector participation in the sector is largely predicated on the assurance that investments made on projects will yield a reasonable return backed by an enabling environment to foster predictability and accountability. Based on this, electricity sector reforms enacted across Africa in the past two decades have been marked by the establishment of independent regulators to provide the foundation on which a sustainable electricity supply industry can be built. Independent regulators are essential to providing the transparency, predictability, and effective governance required to attract and retain investment, while protecting consumers and furthering social policy objectives such as universal access to electricity.

The African Union Commission (AUC) is working in tandem with development partners and other continental institutions to meet the United Nations' target of universal access to modern energy services by 2030 and to harmonize African electricity markets. Key among these initiatives is the publication of the Electricity Regulatory Index by the African Development Bank. Through the ERI, AfDB hopes to strengthen regulatory governance in Africa by monitoring changes in the regulatory landscape of the power sector of African countries and highlighting key areas for improvement.

1.2 Objectives of the Assignment

The Electricity Regulatory Index for Africa (ERI) is a publication by the African Development Bank (AfDB) aimed at evaluating the state of electricity regulation across the African continent. The first edition of the ERI was published in 2018 and has been updated and issued each year since then, with the third edition released in November 2020. Starting with a review of regulatory developments and capacities in 15 countries in 2018, the 2020 edition includes data for 36 African countries.

The ERI is made up of three pillars or sub-indices: the Regulatory Governance Index (RGI); the Regulatory Substance Index (RSI); and the Regulatory Outcome Index (ROI).

The RGI assesses the primary legislation setting up the NRA to examine the efficacy in respect of the regulator's mandate, functions, structure, and independence. The RSI utilizes several indicators to assess how effectively the NRA has translated its mandate into enabling regulations, rules, and codes for the efficient regulation of the power sector. The ROI, on the other hand, is concerned with the impact of the rules and regulations made by the NRA, primarily from the point of view of the regulated entities and power consumers.

[2]IEA, *Population without access to electricity in Africa, 2000-2020*, IEA, Paris https://www.iea.org/data-and-statistics/charts/population-without-access-to-electricity-in-africa-2000-2020

Countries tend to score highest on the RGI, whereas scores on the RSI are relatively lower, and the ROI has the lowest average score. This clearly shows that even where there are enabling laws to stimulate the development of robust regulatory frameworks, regulators are constrained in operationalizing their mandates by putting in place the required regulatory interventions. This in turn has a negative impact on the development of the sector as is borne out by the below average regulatory outcome indices.

The 2020 ERI determines RSI scores using seven indicators: economic regulation; technical regulation; licensing framework; institutional capacity; renewable energy development; mini-grid and off-grid systems; and energy efficiency. Over the course of the last three years, most of the assessed countries have received average or below average scores on the RSI indicators measuring the economic and commercial quality of service regulation. The ERI reports provide a number of recommendations on how these indicators may be improved.

The AfDB initiated collaboration with USAID and NARUC to formulate concrete strategies for implementing the recommendations and other interventions in line with global best practices to improve regulatory governance in Africa. This project to develop Guidelines for Advancing Economic and Commercial Quality of Service Regulation in Africa's Power Sector will provide clear steps for countries to take to improve implementation of effective economic and quality of service regulation.

With the 2020 ERI demonstrating poor performance of many African countries as measured by indicators on quality of service and economic regulation, these Guidelines are designed to enable improved regulatory performance in these two critical areas. These thematic issues, if properly addressed, will deliver the most impact in improving regulatory performance and outcomes. This Guidelines report, while taking into consideration the trends in regulatory performance in Africa from 2018 to 2020, primarily utilizes the findings of the 2020 edition of the ERI as a benchmark.

1.3 Methodology

This Guidelines report addresses the underlying gaps in economic and quality of service regulation, as identified in the AfDB ERI reports. The proposed strategies for addressing these issues are consistent with international best practices adapted for Africa's power sector. The recommendations outlined in this Guidelines report were developed based on a comprehensive desk review analyzing key documents and other important information relevant to the assignment. In particular, the 2018, 2019 and 2020 ERI Reports were analyzed to understand the trends in economic and quality of service regulation in Africa.

A comparative analysis on the economic and quality of service regulation in various regions including Europe, America and Asia was also done to ascertain international best practices and trends. Regional regulatory associations such as NARUC and Energy Regulators Regional Association (ERRA) provided input on best practices in their respective regions with respect to economic and quality of service regulation, drawing from lessons and case studies undertaken on similar issues. This regional comparison ensures that this Guidelines report reflect current international trends in economic and QoS regulation.

While focusing on international best practices, this Guidelines report also relies on the findings in the 2020 ERI reports with respect to good regulatory practices in Africa as well as local knowledge and understanding of the African power sector. The authors also conducted interviews with African regulators who scored highly in certain areas of economic and QoS regulation. Some of their regulatory interventions are highlighted as case studies in this Guidelines report.

2 Economic Regulation

2.1 Fundamentals of Economic Regulation

Regulation is commonly defined as the rules and instructions which set, monitor, and enforce maximum allowable tariffs and minimum allowable service standards for service providers[3]. Electricity industry regulation is grouped into technical and economic regulation. Technical regulation, which includes regulation of service quality, covers such areas as technical standards, quality of service standards, availability of service, and technical losses.

Economic regulation is concerned with the efficient operation of the electricity market to ensure that prices are fair to both the supplier and the customer. It covers such issues as tariff design, pricing of services, network investments, and commercial losses. Economic regulation is necessary to steer the electricity market to liquidity and viability. The ultimate goal of regulation is to help provide a sector that is cost efficient; is commercially viable; provides best value for money in terms of quality, output and price; and makes services available, safe and affordable for all, including the poor.

Two key concepts in regulation are **incentives and efficiency**. Operators are incentivized to invest through the opportunity for capital recovery afforded by cost-reflective tariffs. Consistent, predictable revenue streams for services rendered ensure that operators are adequately resourced to operate efficiently and carry out effective maintenance on plants and equipment to provide good quality of service (technical and commercial) and satisfy consumer expectations.

Regulators may utilize a number of means to enact effective economic oversight of electricity market activities, including:

- Regulation of revenues: The allowed revenue should be high enough to sustain the network operators, but should not be so high that the consumers are made to pay unjustifiably high prices.
- Quality standards and performance incentives: Quality standards are the service requirements that a utility has to meet, such as reliability of supply, voltage quality, etc. These requirements can be linked to the regulation of revenue through tariff setting. Performance incentives are economic incentives designed to encourage the utility to improve performance (e.g., reducing the losses in the network).

Economic regulation generally deals with issues of costs, affordability, and financial sustainability. The critical elements of economic regulation are:

- The number and locations of market participants (to assess impacts on competition and price);
- Sizes of market participants (to address issues of market power and price control);
- Generation technology mix (to assess the cost and security of generation, and price of power); and
- Financial structure of electricity sector investments (including gearing ratios, weighted average cost of capital [WACC], and prices).

[3] Dr. De Mastle, Clemencia Torres, "Infrastructure Trends and Priorities: A view from the World Bank." *A Paper presented at the WB – PURC Training Program, University of Florida* - June 2008

Pricing is the most critical element of economic regulation. General pricing considerations are:

- ❖ Price signals to end-users should reflect costs and incentivize efficient behavior.
- ❖ Pricing should promote efficiency in delivering services and products.
- ❖ The market fails or grows depending on the efficiency and methodology of pricing.

There are two common forms of economic regulation. These are:

- ❖ Cost of Service Regulation or Rate of Return (ROR) Regulation, which is supported by prudent capital investments and other costs, and;
- ❖ Incentive Regulation (IR), also in two forms: Price Cap Regulation (PCR) and Revenue Cap Regulation (RCR).

Both forms of economic regulation aim to regulate prices to ensure cost-reflectivity.

The ERI reports assess economic regulation as a sub-index of the RSI. Results of the 2020 ERI are summarized in the table below:

Table 2.1: Summary of Country Performances on the Economic Regulation Sub-Index for 2020

S/N	Country	Score	Methodology for Tariff Setting	CoSS	Existence of Lifeline Tariff	Tariff Cost-Reflectivity	Automatic Tariff Adjustment Mechanism
1	Angola	0.615	Yes	Yes	Yes	Yes	Yes
2	Benin Republic	0.846	Yes	Yes	Yes	Yes	Yes
3	Botswana	0.462	No	No	No	No	No
4	Burkina Faso	0.308	No	No	No	No	No
5	Burundi	0.538	No	No	No	No	No
6	Cameroon	0.538	No	Yes	No	No	No
7	Central African Republic	0.154	No	No	No	No	No
8	Chad Republic	0.00	No	No	No	No	No
9	Cote d'Ivoire	0.231	No	Yes	No	No	No
10	DRC	0.538	Yes	No	Yes	No	No
11	Eswatini	0.692	Yes	Yes	Yes	No	No
12	Ethiopia	0.615	Yes	Yes	Yes	Yes	No
13	Gambia	0.462	No	No	Yes	No	No
14	Gabon	0.308	No	No	No	No	No
15	Ghana	0.692	Yes	Yes	Yes	Yes	Yes
16	Guinea	0.462	No	No	No	No	No
17	Kenya	0.923	Yes	Yes	Yes	Yes	Yes
18	Lesotho	0.615	Yes	Yes	Yes	Yes	No
19	Liberia	0.462	In progress	Yes	Yes	Yes	In progress
20	Madagascar	0.385	Yes	No	No	No	No

21	Malawi	0.538	Yes	Yes	Yes	No	Yes
22	Mali	0.692	No	No	No	No	No
23	Mauritius	0.538	In progress	No	Yes	No	No
24	Mozambique	0.462	In progress	No	No	No	In progress
25	Namibia	0.769	Yes	Yes	Yes	Yes	Yes
26	Niger	0.538	Yes	No	No	No	No
27	Nigeria	0.769	Yes	No	Yes	No	Yes
28	Republic of Congo	0.154	No	No	No	No	No
29	Rwanda	0.615	No	Yes	Yes	Yes	No
30	Senegal	0.692	Yes	Yes	Yes	Yes	Nil
31	Sierra Leone	0.462	Yes	No	Yes	No	No
32	Tanzania	0.923	Yes	Yes	Yes	Yes	Yes
33	Togo	0.385	No	No	No	No	No
34	Uganda	0.923	Yes	Yes	Yes	Yes	Yes
35	Zambia	0.462	Yes	In progress	Yes	No	No
36	Zimbabwe	0.462	No	No	Yes	No	No

Source: ERI for Africa, 2020

The ERI Economic Regulation Sub-Index notes the existence or achievement of the following: tariff setting methodology, cost of service study, lifeline tariff options, cost reflectivity of tariffs and tariff adjustment mechanisms. Each country's overall performance in this sub-index gives a fair indication of its performance in the constituent indicators.

Apart from a few countries such as Angola, Benin Republic, Ghana, Kenya, Lesotho, Namibia, Nigeria, Senegal, and Uganda, country performances on the above indicators are sub-optimal and therefore require improvements. This Guidelines report shows how improvements can be attained to enhance countries' Economic Regulation Sub-Index scores. By enhancing economic regulation, countries can also boost their performances in the RSI and ROI. The recommendations made here are generally based on best practices with due regard to the realities of the enabling environment in a majority of African countries.

2.2 Tariff Setting in the Power Sector

Tariff setting is one of the core processes necessary for the effective functioning of an electricity system. It not only captures the needs and interests of consumers, utilities, and policy makers, it determines the sustainability of the electricity system as a whole. Before delving into the detailed procedures for tariff setting, it is necessary to understand some of the fundamental characteristics of the subject, such as the definition of an electricity tariff, the key objectives of tariff setting, qualities of a good tariff, and the internationally accepted principles of tariff setting, as follows.

2.2.1 Definition of Electricity Tariff

A tariff, in the context of this assignment, refers to the end-user tariff, and it is the rate at which electrical energy is supplied to a consumer. Although the tariff includes the total cost of producing and supplying electricity, plus any profit, it is not the same for every type of consumer. Therefore, due consideration is given to different types of consumers (domestic, commercial, and industrial) while setting the tariff. This makes the task of rate making highly complicated. A typical tariff takes the following items into consideration:

- Recovery of prudent costs of electricity generation;
- Recovery of prudent cost of capital investments in the transmission and distribution systems;
- Recovery of all expenses; including depreciation, taxes, and the cost of operation and maintenance of electrical infrastructure, metering equipment, billing infrastructure, etc.; and
- A suitable return on capital investments.

2.2.2 Objectives for Tariff Setting

A clear statement of objectives helps all stakeholders assess the appropriateness of tariff proposals and the approved tariff. Clear objectives establish predictability and improve stakeholder confidence in the regulatory process. Some of the objectives in tariff setting include:

- Recovering prudently incurred investments;
- Improving service quality;
- Enhancing energy security;
- Maintaining the financial health of the utility;
- Promoting energy efficiency;
- Expanding access to electricity services; and
- Alleviating poverty.

2.2.3 Characteristics of a Just and Reasonable Tariff

A just and reasonable tariff has the following characteristics:

- Reasonable return: The tariff should provide an opportunity for the utility to earn a reasonable return on its prudently incurred investments for providing reliable electric services. This implies that the total receipts from the consumers should be equal to the cost of producing and supplying electrical energy to those consumers, plus a reasonable return on investment. This will enable the utility to provide reliable electric service.
- Fairness: The tariff must be fair so that different types of consumers are satisfied with the rate charged for electrical energy consumed. Thus, a big consumer of electricity should be charged at a lower rate than a small consumer because increased energy consumption spreads the fixed charges over a greater number of units, thus reducing the overall cost of producing a unit of energy.
- Simplicity: The tariff should be simple so that an ordinary consumer can easily understand it. A complicated tariff may generate opposition from the public.
- Reasonable: The profit element in the tariff should be reasonable and as low as possible.
- Affordable**:** The tariff should be affordable for each customer class, so that a large number of consumers are encouraged to use electricity.

2.2.4 Principles of Tariff Setting

In setting the tariff, a regulator should apply the following principles:

- The tariff should allow the utility to recover its costs of efficient business operations.
- The tariff should allow for recovery of a fair return on investment, provided that the investments have been approved by the regulator through a review of the utility's network expansion plan.
- The tariff should *not* allow for recovery of costs covered by tax exemptions, subsidies or grants provided by the government or donor agencies. (This is critical, yet overlooked by many African regulators.)
- Tariff stability should be taken into account. Factors that affect the price of electricity are constantly changing, but governments and utilities are better able to accommodate these fluctuations than customers. Bill stability is considered important because it ensures that businesses and households have a degree of certainty as to their expected electricity costs over time. If extreme fluctuations in electricity prices are directly passed on to the consumers, it will hamper consumers' ability to plan and invest, thereby limiting economic growth.
- Access charges for the use of the transmission or distribution system should be based upon comparable charges for comparable uses (e.g., a residential customer cannot be charged an identical access charge to an industrial customer).
- Cost should be allocated so that no customer class pays more than is justified by the utility's cost of providing service to that customer class.
- Tariffs should be designed to enhance the efficiency in electricity consumption.

2.2.5 Procedures for Tariff Setting

Electricity tariffs best serve the public interests when established through a process that is transparent, accountable, predictable, and participatory. To start, there should be a national legal framework for setting and approving tariffs to establish the requisite regulatory rights and responsibilities. The mandate to set tariffs is typically laid out in the establishment legislation of the regulator, and will therefore fall under the RGI.

The tariff regime traditionally known as "Cost of Service" or "Rate of Return" regulation is the dominant approach in the determination of public service tariffs, especially those that involve natural monopolies such as electricity supply. Under this approach, the regulated utility is allowed to charge tariffs that cover its reasonable incurred operating expenses and ensure a fair rate of return on its capital. To the extent a utility is no longer able to recover all of its allowable expenses and returns on its prudent investments, it is permitted to file a change in tariff application with the regulator.

The general procedure for tariff setting is as follows:

1. The regulator establishes the objectives for tariff setting in the electricity industry.
2. The regulator determines (and justifies) the methodology that will be used for setting the tariff. Common methodologies include the traditional RoR (or cost of service) methodology, the price cap methodology, etc. The regulator should undertake extensive stakeholder consultation during the development of the tariff methodology.

3. An applicant (a regulated utility) applies to the regulator for tariff review based on the approved methodology, following the requisite rules and tariff application guidelines. The information provided by the utility in the application should include the cost breakdown (following a standard system of accounts) so that the regulator can adequately assess the proposed tariffs.
4. The regulator evaluates the tariff application, using an approved set of criteria, including technical accuracy, completeness, and consistency, to decide whether the application should be granted or not, or whether the regulator requires additional information from the utility.
5. The regulator approves the tariff if satisfied with the application. Major tariff reviews should be carried out every three to five years, in line with the tariff setting principles and methodologies shown below. The approved tariff should be published, noting the date it is set to go into effect.
6. Notwithstanding the provision in (5) above, the regulator should have the authority to review the tariff before the expiry of the specified period if it discovers that the tariff set is contrary to the provisions of the rules or guidelines, or is no longer consistent with the accepted principles of tariff setting. Specifically, the tariff should be adjusted on quarterly basis to allow for a pass-through of the changes in some relevant macro-economic fundamentals or other uncontrollable costs such as fuel or exchange rate fluctuations. Adjustments should be based on a transparent equation that allows for at least a portion of these costs to be recovered by the utility, while protecting consumers from extreme bill increases. Adjustments may also result in the tariff reductions.
7. The tariff setting process should include forums that allow consumers and other stakeholders to participate in the decision making process. Any person who is adversely or unfairly impacted by the decision of the regulator may appeal to the appropriate tribunal and seek redress, where necessary.

As stated above, a typical end-user electricity tariff allows for the recovery of costs of electric generation, transmission, distribution, and customer services in the electricity industry.

2.2.6 Tariff Setting Methodologies

This Guidelines report focuses on the RoR or Cost of Service methodology, which is an internationally accepted cost-plus based method of regulating a utility's revenues and is commonly used in Africa due to the level of electricity market development across the continent. This type of regulation ensures that the revenue to be earned is equal to the cost to supply electricity plus a fair return on the rate base, therefore encouraging African utilities to invest in maintaining, improving, and expanding the network.

2.2.7 Methodology for Setting the Generation Tariff

The determination of the wholesale electricity generation tariff for an interconnected system of generators should be based on the weighted average cost of generation of the system. Included in the cost of generation are:

- ❖ Benchmark variable costs per generator, which include:
    i. Variable operations and maintenance (O&M) costs

ii. Fuel costs (for power generation and system start-up)

- Automatic tariff adjustments for pass-through cost items, which are outside the control of the generators; and
- Benchmark system-wide capacity payments.

The system-wide generation tariff consists of the weighted average cost of generation (WACG) for the entire system, and is made up of the energy and capacity payments for the system. The system-wide generation tariff is determined by the following equation:

$$\text{WACG } \left(\frac{\$}{MWh}\right) = \frac{\sum_{i=1}^{n} GiXi + (PDt * BCCt)}{\sum_{i=1}^{n} Xi}$$

Where:

Xi is forecast total units, expressed in MWh, planned for generation by the generator i in the system, where i = 1,2,…n, in year t.

Gi is the benchmark/weighted average cost of energy generated by generator i, where i = 1,2,…n, in year t, and shall include all known variable costs.

BCCt is the benchmark/weighted average system-wide capacity charge, expressed in $/MW in year t.

PDt is the system peak demand, expressed in MW, in year t.

The capacity payment (PDt*BCC) shall be based on the system peaking plant.

The fixed cost of generation per plant per year, from which the capacity payment is derived, shall be determined from the following equation:

$$\text{Fixed Cost } \left(\frac{\$}{year}\right) = \text{(RAB*WACC) +DP + Fixed O\&M + T}$$

Where:

"RAB" is the un-depreciated Regulatory Asset Base.

"WACC" is the Weighted Average Cost of Capital, which is the percentage return the plant is permitted on its RAB. It is the average cost of debt and cost of equity, weighted by the share of debt and equity in the plant's capital structure.

"DP" is regulatory depreciation for the year, in which the salvage value of the asset is estimated following the principle of a "used and useful asset," and is often calculated using the straight line depreciation method. This method is recommended in line with best practice due to ease of implementation in comparison to alternative depreciation methodologies.

"T" is property tax, which is fixed for the year in question.

Therefore, the capacity charge for the plant i in year t is given by the equation:

$$\text{CCi} = \frac{\text{(RAB*WACC) +DP + Fixed O\&M+T}}{PDt}$$

The weighted average of the capacity charges for all the plants in the system shall be calculated and used as the Benchmark Capacity Charge (BCC), which shall be multiplied with the system peak demand (PD) to determine the capacity payment for the system.

2.2.8 Methodology for Setting the Transmission Tariff

Determination of an electricity transmission tariff is typically based on the "postage stamp" methodology. This method applies a fixed and uniform price for every unit of energy transmitted within a particular zone, regardless of the distance the energy travels. The cost elements included in the transmission tariff are:

i. Capital expenditure

ii. Operating expenditure

iii. Return on the RAB

iv. Transmission network losses

v. Taxes

The transmission tariff is determined using the revenue requirement methodology, and based on the postage stamp principle. The revenue requirement equation is given as follows:

$$RR = (RAB*WACC) + DP + O\&M + T - R$$

Where:

"RR" is the revenue requirement.

"RAB" is the amount of capital or assets the utility dedicates to providing its regulated service.

"WACC" is the Weighted Average Cost of Capital, or the allowed rate of return. This is the cost a utility incurs (both debt and equity) to finance its rate base.

"DP" is regulatory depreciation, which shall be determined through the straight line method.

"O&M" are the operation and maintenance costs (including administration and general expenses) that are prudently incurred for the provision of service by the transmission service provider (TSP) in accordance with the applicable technical standards and regulations.

"T" represents annual taxes not counted as operating expenses, and not directly charged to consumers.

"R" signifies other revenues related to the regulated activity, including net revenues realised through cross-border trade.

The RAB for setting the transmission tariff shall be determined using the following methodology:

$$RAB = \left(\frac{RABt+RABt-1}{2}\right)$$

Where:

"RABt" is the regulatory asset base for the current year t.

"RABt-1" is the regulatory asset base for the previous year t-1.

The RAB for the current year t is given by:

$$RABt = RABt\text{-}1 + CAPEXt - St - Dt + \Delta WCt$$

Where:

"CAPEXt" is the capital expenditure for the current year t.

"St" means asset disposals during the year t.

"Dt" means depreciation in the reporting year t.

"∆WCt" is the change in working capital in the reporting year t.

The total transmission tariff (TT) shall be determined in accordance with the following equation:

$$TT = \frac{RR}{MWh}$$

Where:

"RR" is the revenue requirement for the transmission service provider.

"TT" is the system average transmission tariff.

"Kwh" equals the total energy units transmitted on the transmission network.

This assumes that all of the transmission charges are assigned to the transmission utility, which recovers its costs from end-users.

2.2.9 Methodology for Setting the System Operation (SO) Tariff

SO fees are charged to utilities and customers connected directly to the transmission network, who take power at the transmission voltages. The SO tariff shall include the following elements:

- Energy injected into the transmission network by the generators connected to the network
- Ancillary services to ensure grid stability and power quality

The revenue requirement of the system operator, which is equivalent to the cost of the SO service, is determined using the formula:

$$RRso = O\&M + DP - R$$

Where:

"RRso" is the revenue requirement of the system operator, to be generated from the customers connected directly to the transmission network.

"O&M" are the system operation and maintenance costs that are prudently incurred for the provision of service by the system operator, in accordance with the applicable technical standards and national legislation.

"DP" is depreciation, which shall be determined via the straight line method.

The system operator's assets being depreciated are mainly the building and information technology (IT) infrastructure for generation scheduling and dispatching. In Africa, system operators generally do not own any network assets, and do not earn a profit.

"R" means other revenues related to the regulated activities of the system operator, including net revenues realised through cross-border trade.

The SO tariff is to be paid by off-takers and generators, and determined in accordance with the following formula:

$$Tso = \frac{Rcso+Rgso}{MWh}$$

Where:

"Tso" is the average system operation tariff.

"Rcso" is the revenue requirement with respect to the customers, which shall consist of energy charges and capacity charges.

"Rgso" is the revenue requirement with respect to the generators, which shall consist of energy and capacity related charges.

"MWh" is the annual energy taken by the customers.

2.2.10 Methodology for Setting the Market Operation (MO) Tariff

The MO tariff is charged for market operation services offered to utilities/customers connected to the transmission network, who take supply at the transmission voltages. The tariff is determined using the revenue requirement methodology, in accordance with the following formula:

$$RRmo = O\&M + DP - R$$

Where:

"RRmo" is the revenue requirement of the market operator, to be generated from customers and generators connected directly to the transmission network.

"O&M" are the operation and maintenance costs that are prudently incurred for the provision of service by the market operator, in accordance with the applicable technical standards and national legislation.

"DP" is regulatory depreciation, which shall be determined by the straight line method. Like the system operator, the market operator does not own any network assets. Its only assets are offices and IT infrastructure for data collection and settlement activities.

"R" means other revenues related to the regulated activities of the market operator, including net revenues realised through cross-border trade.

The MO tariff is paid by customers and generators connected to the transmission network, and is determined in accordance with the following formula:

$$Tmo = \frac{RRmo}{MWh} = \frac{Rcmo+Rgmo}{MWh}$$

Where:

"Tmo" is the average market operator tariff.

"Rcmo" is the revenue requirement with respect to customers, which shall consist of energy charges and capacity charges.

"Rgmo" is the revenue requirement with respect to generators, which shall consist of energy and capacity charges.

"MWh" is the annual energy taken by the customers.

2.2.11 Methodology for Setting the Distribution and Supply Tariff

Determination of the distribution and supply tariff shall be calculated by the following equation:

D&S = CE + O&M + (WACC*RAB) + D + NL

Where:

"D&S" refers to distribution and supply costs, equivalent to the revenue requirement for the distribution and supply services.

"CE" means prudent capital expenditures required to supply the future projected growth in demand (approved by the regulator). This is the cost of construction work in progress. Using this method, the utility is allowed to recover construction-related financing costs as they are incurred, rather than capitalizing them and incorporating them into the rate base once the assets are operational.

"O&M" are operation and maintenance costs. A utility's O&M expenses shall be determined using the reference utility model, which is the best practice model with all cost elements highlighted as follows: overhead, personnel, spare parts, and supply (meter reading, billing, revenue collection, dispute reconciliation, etc.).

"(WACC*RAB)" is the return on the regulated asset base.

"WACC" is the weighted average cost of capital (or the rate of return) for the providers of capital (both equity and debt).

"RAB" is the regulatory asset base. This Guidelines report recommends that the RAB is determined by the new replacement value (NRV).

"DP" is regulatory depreciation, in which the salvage value of the assets is estimated using the principle of "used and useful assets". This shall be calculated using the straight line method. Assets acquired through government or consumer contributions shall be considered in the calculation of depreciation, but shall be excluded from the calculation of the rate of return.

"NL" refers to the capital and O&M expenditures required to reduce network losses for the period. Costs associated with technical and commercial losses shall be included in the distribution costs, as determined by the regulator on an annual basis.

These cost elements shall be reviewed and approved by the regulator based on the level of prudence employed in incurring them, and the adequacy of the investments to meet the forecast demand and provide an acceptable quality of supply.

The average distribution and supply tariff for the utility is determined by the equation:

Td&s = $\frac{D\&S}{MWh}$

Where**:**

"**Td&s"** is the distribution and supply tariff for the utility.

"D&S" is the revenue requirement for the distribution and supply services.

"MWh" refers to the total units of energy delivered to consumers.

2.2.12 The End-User Tariff

The end-user tariff reflects the costs of the entire value chain for the electricity industry, from generation, including fuel cost, to transmission (including system and market operations), to distribution, to metering, billing, and consumer services. This end-user tariff is arrived at by the following formula:

End-user tariff = WACG + TT + Tso + Tmo + Td&s

Using the tariff setting methodologies outlined above, the regulator should set the end-user tariff to cover the costs of electricity generation (energy and capacity), transmission use of system, system operation and market administration charges, distribution, and supply (metering, billing, marketing, revenue collection, etc.), as summarized in figure 2.1 below.

Figure 2.1: Building Blocks for the End-User Tariff

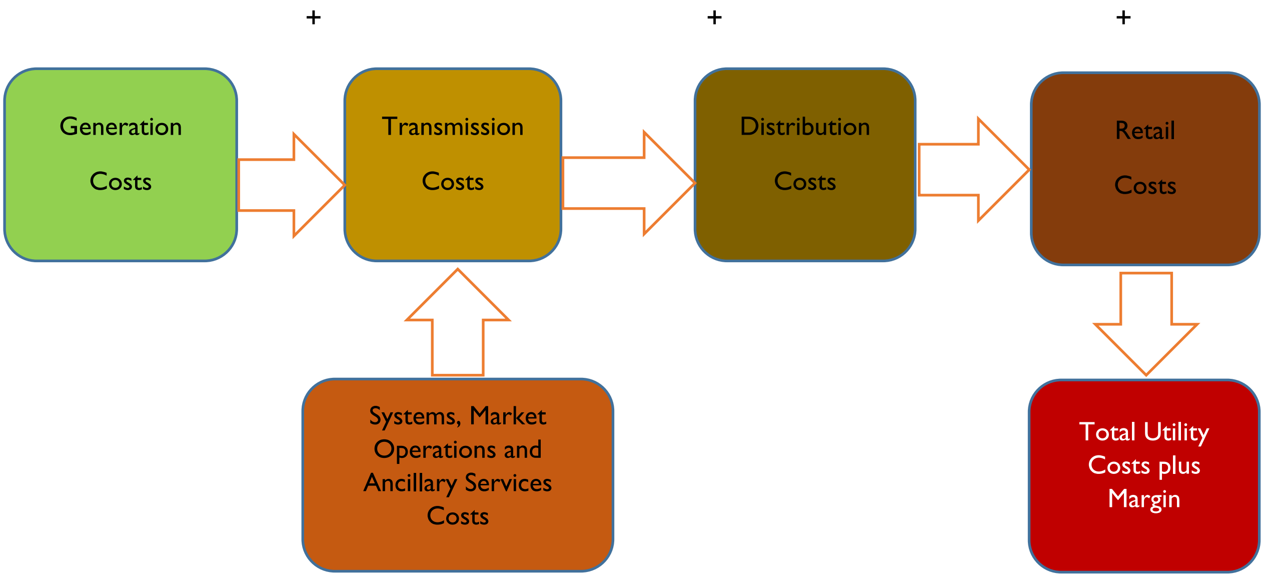


Figure 2.1 illustrates the overall revenue requirement to be recovered through the tariff. The component tariffs contain the associated returns to the providers of the investments. Until customer choice is introduced in a country, end-user tariffs should be regulated in order to protect the interests of customers. The regulator, by law, is required to ensure not only that prices are cost-reflective, but also that losses (and their associated costs to customers) are minimized. This is to encourage utilities to develop and employ strategies for loss reduction.

Furthermore, the regulator should consider and approve tariffs proposed by the utilities for customers in each tariff sub-class based on the specific cost profile of serving that particular tariff sub-class.

2.2.13 Sensitivity Factor

A number of macro-economic sensitivity factors must be taken into account in tariff setting due to their regular impact on price fluctuations. Automatic adjustment mechanisms should be built into the tariff methodology to address them. These factors include:

- Fuel prices: Given the high share of thermal generation in the total energy mix in Africa, costs are highly sensitive to fuel prices. An increase in fuel price has a significant upward effect on the energy purchase cost of the utility. These costs are typically passed on to consumers through the tariff. However, when there are significant deviations in the heat rate of generators from the benchmarks agreed in the power purchase agreement (PPA), the full fuel costs may not be passed on to the consumers since the deviation may be a result of the ineffective operation or maintenance of the generator.

- Exchange rates: A number of costs in the Africa's power sector are denominated in foreign currency; cost of power is therefore sensitive to exchange rate fluctuations. A significant devaluation of the local currency may cause tariffs to increase sharply, even when every other index is stable.
- Inflation: Some of the costs that make up a utility's revenue requirement are adjusted on a quarterly basis to account for changes in inflation. An increase in inflation in any given period will cause an upward movement in tariffs, and vice versa.

2.2.14 Development of Transparent and Predictable Adjustment Mechanisms for Electricity Tariffs

From the sensitivity factors discussed above, it can be seen that there are economic variables that might change within regulatory periods, and that such changes may lead to financial risks for the utility if costs exceed the allowed revenue, or an unreasonably high tariff for customers if revenues exceed costs for an extended period. These issues can be addressed by allowing for certain adjustments within the regulatory period, or by adjusting the revenue requirement determined at the next regulatory review to compensate for deviations in the previous regulatory period. To most effectively address these variations, the regulator should:

- On a quarterly basis, automatically adjust the tariff for costs associated with fuel and exchange rate fluctuations;
- On a quarterly basis, adjust the tariff for costs associated with inflation;
- On an annual basis, review and adjust the tariff based on utility capital budget/project performance as specified in its investment plan/annual budget; and
- Review and adjust the tariff whenever the utility receives tax exemptions, grants, donations, or subsidies from the government or donor agencies, without compromising tariff stability, which is a critical principle of tariff setting.

For a tariff adjustment mechanism to be transparent and predictable, the mechanism must be automatic and based on verified and approved models. Adjustments for the costs associated with fuel price fluctuations, exchange rate fluctuations, and inflation should be done in accordance with a model developed specifically to address such costs. The adjusted tariffs should be published on a quarterly or annual basis, in accordance with the assigned timeline for adjustments, in newspapers of wide circulation.

The ERI 2020 shows that out of the thirty-six (36) countries covered, only seven (7) countries – Angola, Benin Republic, Kenya, Malawi, Namibia, Nigeria, and Uganda – have developed mechanisms for transparent and predictable tariff review and adjustments for the costs associated with external sensitivity factors. For all power generators, irrespective of market structure, the adjustment factors for fuel costs, foreign exchange rate fluctuations, and inflation can be determined through the below calculations.

Fuel Cost Adjustment

Fuel cost adjustments should take place on a quarterly basis to account for possible variations in the fuel price from the reference price. The reference price of fuel is usually taken on the date of determination of the tariff for the generator. The fuel cost adjustment factor (FCAF) is the variation in the tariff as a result of the difference between the reference price and the actual price of fuel. This variation may result in an upward or downward impact on the tariff.

The FCAF is calculated in accordance with the following formula:

$$\text{FCAF} = \frac{1}{1-L} x \left\{ \frac{\sum(Cq-Cr)iGiSi}{Gt} \right\}$$

Where:

"Cq" is the actual price per mmBTU paid by power producers for fuel consumed by plant i, where i = 1,2,……….n, during the preceding quarter, at all existing thermal plants in the system (interconnected and off-grid).

"Cr" is the reference price of fuel, taken on the date the tariff for the generator was determined.

"(Cq – Cr)i" is the difference between the actual price and reference price of fuel for the plant i.

"Gi" refers to all units of energy generated by plant i, where i = 1,2,………n, during the preceding quarter, at each existing thermal power plant in the system (interconnected and off-grid).

"Gt" refers to the total of all units generated by all power plants in the system during the preceding quarter.

Si is the fuel efficiency (in mmBTU/KWh) of the thermal plant i, where i = 1,2,………n, in the system.

L is the target system loss factor in the transmission and distribution systems.

Therefore, as the fuel cost (C) changes, the FCAF changes correspondingly. Fuel efficiency degrades over the life span of the plant, but the degradation will have a limited impact on this factor.

Exercise 2.1: Evaluation of the Effect of Changes in the Cost of Fuel on the Price of Electricity

Assuming i = 1, Cq = \$3.2/mmBTU, Cr = \$2.5/mmBTU, G = 20,000MWh, S = 0.0034mmBTU/KWh, and L = 15%, the associated FCAF shall be

$$\frac{1}{1-0.15} * \left\{ \frac{\$(3.2-2.5)/mmBTU*20{,}000{,}000KWh*0.34mmBTU/KWh}{20{,}000{,}000KWh} \right\} = 1.176*\{\$0.7*0.0034\}/\text{KWh}$$

i.e., \$ 0.002799/KWh

This means that the end-user tariff attracts an increase of **\$0.002799** on every KWh of electricity generated for or purchased by the utility, as a result of the increase in the price of fuel from \$2.5/mmBTU (from the reference price) to \$3.2/mmBTU in the quarter under consideration.

Foreign Exchange Rate Fluctuation Adjustment

All tariffs for electrical energy should be subject to foreign exchange rate fluctuation adjustments (FERFA), especially in Africa, given the frequent local currency fluctuation rates. The FERFA should be calculated in accordance with the following formula:

$$\text{FERFA} = \frac{1}{1-L} * \left\{ \frac{\sum_{i=1}^{n}(Fit-1*Zt)*Xo+\sum_{i=1}^{n}(Pit-1*Zt)*Xo}{G} \right\}$$

Where:

"Fit" is the foreign currency cost on non-fuel cost item i, where i = 1,2,…….n, incurred by a utility in the preceding quarter.

"Pit" is the foreign currency cost on non-fuel cost item i, where i = 1,2,…….n, paid by the utility for the purchase of energy in the preceding quarter.

"G" refers to the total units of generation (self-produced + purchased from generators) during the preceding quarter.

"L" is the target loss factor in the transmission and distribution systems.

"Zt" is the proportionate change in the exchange rate (Xt) in the current billing period t, from the base exchange rate (Xo) in the base period, and shall be determined according to the formula:

$$\text{Zt} = \frac{Xt-Xo}{Xo}$$

Where:

"Xt" is the exchange rate for the current quarter.

"Xo" is the exchange rate for the base quarter.

Exercise 2.2: Evaluation of the Effect of Changes in the Exchange Rate on the Price of Electricity

Assuming: i = 1, (i.e., only one non-fuel cost item is involved in energy production), Ft-1 = \$100,000, Pt-1 = \$50,000, G = 200,000MWhL = 15%, Xo = 15 (i.e., 15 units of the local currency is equivalent to one U.S. Dollar), and Xt = 20.

Therefore:

$$\text{Zt} = \frac{20-15}{15} = 0.33, \text{ and}$$

$$\text{FERFA} = \frac{1}{1-0.15} * \frac{(\$100{,}000*0.33)*15+(\$50{,}000*0.33)*15}{200{,}000MWh} = \frac{1}{0.85} * \frac{(\$495{,}000 + \$247{,}500)}{200{,}000MWh} = \frac{1.176*742{,}500}{200{,}000{,}000KWh}$$

$$= \$0.0044/\text{KWh}$$

This implies that an exchange rate increase of 5 will have an upward impact of **\$0.0044/KWh** on the end-user tariff.

Inflation Adjustment

All tariffs for electrical energy should be subject to automatic adjustment on quarterly basis for changes in the rate of inflation, starting from a date to be specified by the regulator. Higher rates of inflation provide greater impetus to ensure there are adjustment factors in the tariff to ensure costs and prices do not diverge unduly. The impact of domestic and international inflation on cost of power supply should be calculated in accordance with the following formula:

$$\text{INFA} = \frac{1}{1-L}\, x \left\{ \frac{\sum_{i=1}^{n}(INFAgeni)+ INFAt\&d+\sum_{i=1}^{n} INFAippi}{Gp} \right\}$$

Where:

"INFA" is the total inflation adjustment per unit (KWh) for the preceding quarter. The first adjustment shall be effected on a date to be specified by the regulator.

"L" is the aggregate loss factor in the transmission and distribution systems.

"Gp" is the total energy generated and/or purchased by a distribution or supply licensee from power producers during the adjustment period.

"$\sum_{i=1}^{n}(INFAgeni)$" is the total inflation adjustment relating to the licensee's generation facilities, where i = 1,2…..n.

"$INFAt\&d$" is the inflation adjustment relating to the company's transmission and distribution operation and maintenance costs.

"$\sum_{i=1}^{n} INFAippi$" is the total inflation adjustment during the adjustment period relating to contracted generation (from IPPs), where i = 1,2….n.

Any difference between the total inflation costs and the actual billed amount for a given adjustment period shall be adjusted for in the following quarter.

Exercise 2.3: Evaluation of the Effect of Inflation on the Price of Electricity

Assuming: i = 1 (i.e., this utility has only one generating plant), INFAgen = \$200,000 (i.e., the adjustment in the cost of the generation assets for the one plant of the system for inflation is \$200,000), INFAt&d = \$350,000 (i.e., the adjustment in the cost of the transmission assets for the system for inflation is \$350,000), INFAipp = \$50,000 (i.e., the adjustment in the cost of the assets related to the contracted generators for inflation is \$50,000), and Gp = 200,000,000KWh.

Therefore:

$$\text{INFA} = \frac{1}{1-L} * \left\{\frac{\sum_{i=1}^{n}(INFAgeni) + INFAt\&d + \sum_{i=1}^{n} INFAippi}{Gp}\right\} = \frac{1}{1-0.15} * \frac{\$200{,}000+\$350{,}000+\$50{,}000}{200{,}000{,}000KWh}$$

$$= 1.176 * \frac{\$600{,}000}{200{,}000{,}000KWh} = \$0.003528/\text{KWh}$$

This implies that the increase in the rate of inflation on all the energy supply assets during the period being considered translates to a tariff increase of **\$0.003528/KWh.**

The overall effect on the end-user tariff of the variations in all exogenous variables during the quarter being considered is the sum of the adjustments for all variables: \$0.002799/KWh + \$0.0044/KWh + \$0.003528/KWh = **\$0.010727/KWh.**

Case Study 1: Tariff Setting Procedures in Uganda

This case study describes the tariff methodology adopted by Uganda's large electricity distribution company, Umeme Ltd and approved by the Electricity Regulatory Authority (ERA). ERA mandates that the distribution company carries out periodic CoSS and Umeme has complied accordingly since the CoSS is used as basis for its tariff review applications.

At Umeme Ltd, tariffs for customers in each class are calculated to reflect the cost of electricity supply to that class. This is in line with the enabling legislation and international best practice, which require that tariffs should be cost reflective. Implementation of this principle eliminated the practice of cross-subsidization of any class of customers by any other, thereby promoting greater efficiency in the electricity market.

As a result of cost-reflectivity, tariffs for domestic consumers are often higher than tariffs for the industrial consumers. This is so because domestic consumers who take supply at low voltages impose higher investment and operational costs on the system than industrial consumers, who are supplied at high and medium voltages.

At Umeme Ltd, end-user tariffs are developed in line with the following steps:

- *Calculating the revenue requirement (RR) of the distribution company*
- *Allocating this RR to the different customer classes*
- *Converting the RR into fixed, energy, and capacity tariffs, as appropriate for each tariff class.*

The RR of the distribution company is made up of:

- *O&M costs, which include the prices for energy and transmission services (i.e., the bulk supply tariff). A portion of this cost is indexed to foreign exchange, and the remainder to local inflation.*
- *Asset depreciation*
- *Return on assets*
- *Return on working capital*
- *Allowance for bad debts and losses. Benchmarks are set in contracts in order to create an incentive for the distribution company to reduce bad debts and losses. These costs are therefore not fully passed over to the consumers.*
- *Taxes*

The end-user tariffs are adjusted quarterly to reflect changes in i) the bulk supply tariff, ii) the inflation rate and iii) the exchange rate, to which the RR is very sensitive. The application of the automatic adjustment mechanisms as well the periodic CoSS ensures that tariffs in Uganda remain cost-reflective and stable for the benefit all stakeholders.

2.2.15 Options for Treatment of Subsidies, Tariffs for Poor and Vulnerable Customers, and Migration towards Cost-Reflective Tariffs

Tariffs are said to be cost-reflective when the revenues generated by the utility from the sale of electricity to the consumers reflect the cost the utility incurs to procure the electricity from power producers, plus transmission and distribution, and the customer associated costs.

Less than 30% of the countries in the 2020 ERI survey have cost-reflective tariffs. In most of the countries, the utilities are operating with tariffs that are less than their costs of providing service. One of the challenges facing the regulator in tariff setting is managing the critical balance between maintaining affordability for customers and the financial viability of utilities. Managing this balance is most difficult in developing countries, especially in Africa, where the affordability issue is most acute, and cost of service often very high.

In Africa, utilities often face pressure to electrify consumers that cannot afford to pay cost reflective tariffs. Under this situation, the experience and competence of the regulator are seriously called to action. The regulator has two options. The first is to request direct subsidization from the government. The government may offer subsidies to power generators to encourage them to deploy new and more efficient technologies. Government may also offer subsidies to specific industries to encourage investment, to farmers to encourage food production, or to domestic consumers to encourage energy consumption.

The other option is to resort to cross-subsidization, whereby one group of consumers pays higher rates for electricity to cover or subsidize lower rates for other consumers. In choosing either option, the regulator's objective is to enable utilities to meet their revenue requirements, while reducing the burden of high tariffs on consumers. These two options are discussed below.

Government Subsidies

Government subsidies are interventions to support energy consumption and production. Subsidies can be referred to as consumption or production subsidies depending on where in the value chain the intervention is introduced, but the main objective, irrespective of the source and form, is to make electricity more affordable to consumers, especially low-income households.

Governments can intervene in the electricity market in various ways to support energy production and consumption. On the production side, governments may:

- Transfer funds directly to the producers of power to finance certain inputs;
- Assume a portion of the production risk, such as the liquidity risk, by providing guarantees for the off-taker's payment obligations;
- Reduce taxes for power producers; or Undercharge for the use of government assets in the power production process.

Often, more than one transfer mechanism is used. For example, governments may provide tax breaks while capping the price of fuel below the international market price, or even below the cost of producing the fuel. Governments may also forego revenues by offering the use of its assets, such as land or fossil fuel resources, under its control.

On the consumption side, government may make direct transfers to utilities to make up the difference between the real price of electricity and the actual price paid, or subsidize consumers directly through case transfers or bill reduction schemes.

These government interventions should be taken into consideration when calculating the RAB and the RR in the tariff development process. Whereas these assets should be depreciated, they should not be factored into the RAB. As a rule, utilities should not be allowed to recover costs on any investment they did not make themselves.

Cross-Subsidization

In the absence of direct provision of subsidy by the government, regulators and utilities may employ the cross-subsidization option to bring down the cost of service for low-income customers. Cross-subsidization is the practice of setting higher tariffs than cost-reflective for certain customers in order to subsidize other customers, whose tariffs will be set lower than the cost-reflective level.

While the intention of cost allocation (based on a utility's CoSS) is to ensure that all customer classes pay tariffs that are consistent with their respective costs of service, a certain level of cross-subsidization is almost always necessary in tariff setting to ensure affordability for low-income groups. In this regard, regulators should avoid heavy cross-subsidization as this can be counter-productive and result in market distortions that can hamper economic growth.

Reliable electricity is critical for commercial and industrial (C&I) customers, and is generally considered productive, as it contributes to activities that generate economic development. Also, C&I customers play an important role in maintaining base loads, managing system peaks, and creating long-term certainty for those who wish to invest in electricity infrastructure. In contrast, electricity that is consumed domestically has a less direct impact on economic activity, but directly affects the quality of life. Therefore, cross-subsidization schemes must be designed carefully, with the regulator weighing the associated trade-offs.

A major advantage of cross-subsidies, especially when used to achieve overall cost-reflectivity for the utility and results in an economically viable and sustainable electricity sector, is that it avoids using government finances to support the low-income customers, thereby freeing those funds to be deployed in other sectors of the economy, such as education, health care, etc. On the other hand, cross-subsidies distort prices, and may result in reduced consumption by the customers that fund the cross-subsidy. In addition, the scheme is not sustainable in the long run.

Development of Tariffs for Poor and Vulnerable Customers (Lifeline Tariffs)

Irrespective of the fact that electricity tariffs in most African countries are not cost reflective, about 50% of the countries surveyed in the 2020 ERI had developed tariffs for poor and vulnerable consumers. It is therefore necessary that the issue of lifeline tariffs be given adequate consideration in this Guidelines report, so as to encourage their development in the remaining 50% of ERI countries.

Access to electricity is an essential driver of economic growth in every country. According to the World Bank, "Electricity is known to have significant impacts on wide range of development indicators, including health, education, food security, gender equality, and poverty reduction".[4] Tariff setting should address not only the issue of cost-reflectivity, but affordability as well, so as to fulfil the basic energy necessities of poor households.

The balance between cost recovery and affordability is difficult to strike. Only a few countries in Africa, like Kenya, Uganda, Angola, Benin Republic Lesotho, Namibia, and Ghana have been able to do so effectively. Many other countries have fared well on affordability, but have not been able to achieve cost recovery, e.g., Zambia, South Africa, and the Democratic Republic of the Congo (DRC), or they have done well with cost recovery but have struggled to maintain affordability, e.g., Rwanda.

[4] "Access to energy is at the heart of development – Who We Are", The World Bank, https://www.worldbank.org/en/news/feature/2018/04/18/access-energy-sustainable-development-goal-7

In countries where lifeline tariffs have been developed and implemented, regulators and utilities use the tariffs to expand access to affordable electricity for poor and vulnerable households, which rely on electricity mainly for lighting. African countries generally adopt a consumption-based lifeline tariff due to the absence of empirical data to establish a cadre of "poor households" based on income.

Generally, a lifeline tariff for households that consume less than 50KWh/month would adequately address the basic energy needs of low-income customers, and lead to improvement in living standards. However, countries are encouraged to set thresholds that their electricity markets and economies can support. For example, Nigeria uses 50KWh/Month, Uganda uses 15KWh/Month, and Lesotho uses 30kWh/Month.

The regulator should set the lifeline tariff lower than cost-recovery level for customers that consume very low amount of electricity. Typically, customers are eligible for a lifeline tariff if their total consumption is lower than a certain monthly threshold to be specified by the regulator. It is important to conduct a study before determining the monthly threshold for lifeline tariff, so as to have a fair idea of the size of the population to be subsidized.

If the affected population is large, the threshold should be set as low as possible to avoid an over-elevated tariff for the few higher consumption customers. However, the lifeline tariff should allow a percentage of the cost of service to be recovered from the affected consumers through the tariff. The deficit resulting from the lifeline block tariff being lower than cost-reflective would be paid by an increase in all other tariffs or through a government subsidy.

The lifeline tariff can be introduced as part of the overall tariff setting mechanism approved by the regulator. This will be a tariff that will apply to the first tranche of consumption per month for domestic consumers. The resultant loss of revenue in those units delivered can be recovered from non-domestic customers and domestic customers with monthly consumption above the lifeline level, by a modest increase in tariffs above the cost-reflective levels.

Public education and consultation with key stakeholders is critical to effective lifeline tariff implementation. Convincing the population that there is a credible commitment to compensate vulnerable groups is essential for the successful introduction of a lifeline tariff. Therefore, both the utility and the regulator should ensure that awareness campaigns are rolled out nationally to educate communities on the introduction of the Lifeline Block Tariff (LBT).

It should also be noted that subsidies are sometimes criticized for jeopardizing the financial viability of utilities, and for being subject to capture by unintended groups. Poorly designed or implemented subsidies can have perverse effects. For example, cross-subsidies resulting in very high tariffs for industrial users can lead to these users to opt for alternative sources, such as captive power, which is capable of straining the utilities financially, increasing CO_2 pollution, and diminishing system reliability. In Kenya, industries cited high electricity tariffs as a principal reason for closure and relocation. Fewer drawbacks may result from cross-subsidization from high- to low-income households rather than from industrial or commercial customers to residential customers.

In order to minimize the negative effects of subsidies, and to ensure that their objectives are being met, the NRA should carry out periodic reviews of the subsidy, its benefits, beneficiaries, and outcomes.

Case Study 2: Electricity Tariffs for Poor and Vulnerable Households in Lesotho

The 2020 ERI Report lists Lesotho as one of the countries in Africa with a lifeline tariff for the poor and vulnerable. Additionally, according to the AfDB Country Note for Lesotho to support the ERI assessment, the Lesotho Electricity and Water Authority (LEWA) recently carried out a CoSS to determine the actual costs of providing service to consumers within the Lesotho Electricity Company (LEC) network. The ERI Report also revealed that an LBT and cross-subsidies are two of the tariff mechanisms utilized to keep Lesotho's tariffs affordable for low-income and vulnerable consumers.

In 2017, with support from the AfDB, the MRC Group conducted a CoSS for LEWA, with the purpose of setting electricity tariffs to promote economic efficiency and ensure the financial viability of the electricity sector. Specifically, the study required the collection of data on poor households' use of electricity in order to define basic electricity needs, as well as an analysis of affordability. The study recommended a lifeline tariff, specifying the consumption threshold and the process for delivering the associated subsidy.

The CoSS analysis showed a strong case for the introduction of a lifeline tariff in Lesotho. A majority of households connected to the grid would be considered energy poor if they were required to pay for the energy usage at the prevailing tariff levels. Surveys carried out over many years also pointed to the fact that most households in Lesotho use electricity only for lighting.

The study suggested that a lifeline tariff for households that consume less than 50kWh per month would adequately address the basic energy needs of Lesotho's poor households and lead to improvements in the standard of living. However, a review of this energy threshold revealed that about 57% of connected households consumed less than 50kWh per month. LEWA determined that subsidized tariffs charged on the basis of the 50kWh/month threshold would lead to an over-elevated tariff for higher consumption households. LEWA therefore chose to adopt a lower threshold of 30kWh per month, which would result in subsidized electricity to about 25% of households.

The analysis showed that a lifeline tariff of 0.5-0.6M/KWh would ensure that customers at or below the poverty line could reasonably afford to pay for electricity. A lifeline tariff of 0.5M/kWh was initially proposed, but a lifeline tariff of 0.65M/kWh was ultimately introduced for the energy threshold of 30kWh per month. The tariff went into effect April 1, 2018.

LEWA and LEC carried out public education and stakeholder consultation activities to enhance understanding and garner support for implementation of the lifeline tariff. The CoSS report was subjected to stakeholder review and was updated with stakeholder comments and remarks.

Prior to the introduction of the LBT, there was only one domestic tariff class. It was therefore relatively straightforward to introduce one additional tariff class (i.e., the lifeline tariff class) for all domestic customers, and to adjust the pre-paid metering software to charge all domestic customers at the lifeline rate up to the agreed threshold, and at a higher rate for consumption above the lifeline threshold level. All households consuming more than 30KWh subsidize the lifeline households, with the amount of cross-subsidy directly proportional to their levels of consumption.

The process of introducing the LBT in Lesotho is consistent with international best practice. To start with, there is a legal and regulatory basis for the tariff, which comes from LEWA's regulatory mandate through the LEWA Act. With the lifeline tariff, poor households and other vulnerable members of society can access electricity for their basic needs. This will eventually result in overall improvements in the standard of living. Through implementation of the lifeline tariff, LEWA is simultaneously addressing the issues of access, cost-reflectivity, and affordability.

Migration towards Cost-Reflective Tariffs

Apart from the lifeline tariff block, during the migration towards cost-reflective tariffs, it is important for the regulator to ensure that tariffs are increased gradually towards the economic levels to avoid a rate shock. As a best practice, the regulator should conduct a tariff study to determine an appropriate timeframe for implementing the transition. Assuming a three-year migration path, utilities should expect to under-recover its revenue requirement in years one and two. By the third year, the tariffs should reach economic levels, including returns on capital. At this point, cross-subsidization will only affect the lifeline tariff.

Cost-reflective tariffs enable utilities to raise adequate capital to expand and maintain the system, and provide the right signals for investments in the sector. They also promote economic efficiency, as consumers make better consumption decisions and utilities are able to make informed investment decisions when the true cost of power is reflected. In fact, the power challenges currently facing most African countries are partly attributable to non-cost reflective tariffs in most utilities on the continent. While cost-reflective tariffs are necessary, sudden, or unpredicted tariff increases negatively impact on economic growth through their effects on inflation.

The two key considerations for transition to cost-reflective tariffs are **gradualism** and **avoidance of rate shock.** Therefore, regulators should consider a phased approach. In some cases, the governments can fund the subsidy over a number of years, at a reducing rate, to enable the tariffs to attain the cost reflective levels.

For example, Nigerian Electricity Regulatory Commission (NERC) transitioned to cost-reflective tariffs through implementation of a series of Multi-Year Tariff Orders (MYTOs).

The first MYTO approved by NERC went into effect in 2008. Whereas the prevailing average tariff at the time was N6/KWh, the average cost-reflective tariff was N11.2/KWh. An increase of N5.20/KWh (or 87%) to reach cost-reflectivity was considered too high based on the likelihood of generating a rate shock for customers. The regulator instead requested that the Government of Nigeria provide a subsidy to help introduce a viable tariff for the industry. The subsidy took the form of a per unit payment to be reduced each year, in order to reach a viable electricity tariff by 2011 (i.e., after three years).

The table below shows the estimated cost of supply (which changed yearly due to projected efficiency improvements, and projected changes in the macro-economic variables), the government subsidy, and the regulator-determined average tariff for the year.

Table 2.1: Migration towards Cost-Reflective Tariffs in Nigeria (MYTO 1)

Year starting July 1st	**2008**	**2009**	**2010**	**2011**	**2012**
Estimated Cost of Supply (N/KWh)	11.20	10.64	9.49	10.00	10.00
Subsidy (N/KWh)	5.20	3.64	0.99	0.00	0.00
NERC-determined Subsidized Tariff for Consumer Payment (N/KWh)	6.00	7.00	8.50	10.00	10.00

Source: NERC Multi-Year Tariff Order (2008 – 2012)

While Nigeria strove to achieve cost-reflectivity through the MYTO 1 program, supported by the abovementioned subsidy arrangements, tariffs did not reach cost-reflective levels by the end of the migration period in 2011 due to inaccurate data and variations in the economic fundamentals, which were outside the projected ranges. A subsequent MYTO set NERC on an updated migration path toward cost-reflectivity.

Case Study 3: Migration to Cost-Reflective Electricity Tariffs in Zambia

Though ZESCO'S tariffs are not fully cost-reflective, Zambia has made significant progress towards achieving cost-reflectivity in its electricity tariffs. Tariffs did actually achieve cost-reflectivity at a point, but shifting macro-economic variables led to a new imbalance between costs and tariffs. There are three principal steps involved in the process of setting cost-reflective tariffs:

- Determination of the utility's revenue requirement (RR): to ensure that the utility will remain financially viable, and will have the opportunity to recover every prudently incurred expense, including a fair rate of return.

- Completion of a Cost of Service Study (CoSS): to assess and allocate costs across the various utility customer classes. The utility's actual costs and revenues can then be compared to its RR.

- Rate design: the results of the CoSS will indicate the degree to which the existing rates recover revenues from each customer class, on a cost of service basis, and can be used by the regulator to design new rates that will fully cover the required revenues and sustain the utility and the sector going forward.

The Zambian Energy Regulatory Board (ERB) commissioned a CoSS for the Zambian Electricity Supply Company (ZESCO) in 2006, with the intent to determine the cost incurred by the utility in generating, transmitting, distributing, and supplying electricity to its various customers.

The COSS established that tariffs were not cost-reflective and recommended an average increase of 45.4% in the 2007/2008 financial year for ZESCO. Residential customers would experience the highest increase of 147.6%, followed by the large power consumers at 46.3%. Commercial and service customers would see the smallest tariff increases, at 2.4% and 6.3%, respectively. The ERB planned to adjust the tariff annually to account for changes in the economic fundamentals. Cost-reflectivity is a shifting target; any change in factors such as inflation, exchange rates, price of fuel, etc. requires adjustment in the tariff for the utility's financial position to be maintained.

ZESCO has since made five separate tariff applications based on the COSS, resulting in the ERB approving average tariff increases of 27%, 35%, 26%, 16% and 75% in 2008, 2009, 2010, 2014 and 2017, respectively. These increases enabled ZESCO to raise sufficient revenue to meet its costs and earn a reasonable return. After each tariff increase, new rates were designed to allocate the new tariff to the various classes of customers.

A new COSS is currently in progress.

2.2.16 Challenges to Electricity Tariff Setting in Africa

The ERI Reports and other documents consulted in the course of developing this Guidelines report reveal a number of challenges to electricity tariff setting in Africa, and particularly to the achievement of cost-reflectivity. Several of these challenges are highlighted below.

Limited Data and Poor Data Quality

Reliable data on the utility performance is essential to tariff setting, but ensuring data accuracy and transparency have always constituted major challenges to most African electricity regulators. Even when specific reporting requirements or templates are provided by the NRA, utilities still find it difficult to abide by these requirements, making it difficult for the regulator to determine appropriate tariffs. For example, several countries have developed a Uniform System of Accounts (USoA) to ensure that utilities record and categorize their financial transactions accurately, consistently, and coherently, but some utilities are still unable to present the required data. Some NRAs resort to sending their own staff to the utilities to obtain information in person. This practice is tedious and cumbersome, and places undue administrative burden on the regulator.

Regulators may address the issue of data quality by:

- ❖ Developing strategies to incentivize utilities to report accurate data and provide the required documentation, such as easy to use templates for periodic reporting requirements.
- ❖ Developing effective monitoring and enforcement procedures for accurate data reporting through the use of external independent auditors for data verification.

Information Asymmetry

The regulatory effectiveness of electricity tariffs is dependent on the availability of quality information. In the tariff determination process, the utility will typically have better information on its own costs than the regulator. This information asymmetry may result in the regulator approving tariffs that either over-compensate the utility or are not adequate for recovery of prudent costs. The regulator can minimize this risk by developing an efficient data management framework. This can be achieved through a dedicated unit within the NRA which is responsible for mining and collation of organization-wide data and ensures the constant updating of all relevant data.

Determination of the Regulatory Asset Base (RAB)

The RAB is a key building block of the tariff. One of the challenges of tariff setting is the difficulty in determining the asset base of the network due to lack of proper record keeping by the utility. There is also the issue of capacity of regulatory staff in reviewing the utility's calculation of its RAB. Regulators should dedicate appropriate resources to capacity building for its staff to build its proficiency in reviewing utility data.

Assessing Prudency of O&M Costs

Investments in operation and maintenance constitute a major component in a regulated utility's revenue requirement. These costs are expected to be prudently incurred by the utilities, but there is no standard method for verifying" prudence." Regulators may therefore approve uneconomic tariffs based on inflated utility costs. This challenge can be addressed by developing and circulating guidelines for utilities on record keeping related to the procurement of goods and services. Utilities should then be required to submit regular reports on the implementation of these guidelines. The NRA should review such reports and approve or disapprove procurements for inclusion in the RR for tariff determination.

Inaccurate Forecasts and Assumptions for Modelling in Tariff Setting

Tariff setting involves a significant amount of modelling, which requires reasonable forecasts and assumptions (e.g., the volume of investments to be deployed, consumer demand, etc.). In many cases, however, these forecasts and assumptions depart widely from actuals, affecting the adequacy of the end tariff.

The development and use of country-specific long-term forecasting tools can be employed for use in tariff modelling and local capacity building for regulators and utilities. This will greatly reduce deviation of forecasted values from actuals.

Inadequate Regulatory Capacity in Tariff Setting

Tariff setting requires staff knowledge and coordination across a number of areas of expertise, including engineering, economics, accounting, statistics, and law. Adequate staff experience in tariff setting is also critical. Unfortunately, many NRAs, especially nascent ones, struggle to develop a workforce with the right qualifications and experience. Some regulators resort to outsourcing for tariff setting, but there is still the need to be able to verify that the deliverables are in accordance with the needs of the sector. It is therefore imperative that regulators hire candidates with strong tariff setting expertise, good knowledge of the local electricity sector context, understanding of the relevant national legal frameworks, and the ability to liaise effectively with the regulator and key stakeholders.

Absence of Cost of Service Studies

One of the fundamental principles in tariff setting is that the tariff must ensure the opportunity for cost recovery. That is, the tariff should be cost-reflective. Cost-reflective tariffs can only be determined through cost of service analysis. The accuracy of the costs obtained from such studies affect the appropriateness of the tariff determined. As shown in the ERI Reports, most utilities in Africa have not been able to conduct comprehensive CoSS. Where such studies are conducted, doubts persist regarding the efficiency of the exercise and the accuracy of the output costs. Given its importance to effective tariff setting, strategies for implementing a CoSS are comprehensively discussed in this Guidelines report.

Aging Infrastructure

Aging infrastructure poses a challenge across most electricity networks in Africa. In such networks, the cost of service is high and volatile due to frequent breakdowns and need for regular maintenance (or in some cases, replacement). Under these circumstances, it is difficult to achieve a balance between cost and revenue through a cost-reflective tariff.

Affordability Concerns)

In setting electricity rates, a regulator must always aim to balance the need for cost reflectivity with that of customer affordability. To achieve economic efficiency in the electricity market, tariffs should support financial viability for utilities; however, they must also be affordable to encourage electricity consumption at all levels of society.

A large percentage of the population of African nations are currently unable to pay cost-reflective tariffs. In line with national and global objectives to increase access to electricity, regulators are often compelled to keep tariffs lower than costs.

High Cost of Generation

The costs of electricity generation, transmission, and distribution in most developing countries, including African countries, is very high due to a number of factors, ranging from the need to adopt rapidly advancing, expensive technologies, inadequate technical and managerial capacity, non-prudent procurements, etc. This results in high end-user tariffs, with attendant affordability issues.

2.2.17 *Recommendations for Regulators on Enhancing Tariff Setting Practices in Africa*

- **NRAs may address the issue of data quality by developing strategies to incentivize utilities to report accurate data and provide the required documentation and develop effective monitoring and enforcement procedures for accurate data reporting.** Qualitative and accurate data lay the foundation upon which the various building blocks for effective tariff setting can be erected. In the absence of such data, the ability of the NRAs to make informed decisions with regards to tariff setting will be hampered.

- **NRAs should encourage the development and use of country specific long-term forecasting tools to be employed for use in tariff modelling to reduce deviation from actuals.** This is especially important as tariff methodologies are forward looking, often spanning a period of three to five years, while integrated power sector planning covers even longer time horizons of 10-15 years. Regulators need to utilize forecasting tools that take into account realistic assumptions based on the local context.

- **NRAs should dedicate appropriate resources to capacity building for its staff to build proficiency in reviewing utility data**. Tariff setting requires that regulatory staff have a firm understanding of energy economics as well as the local operating environment. It is therefore imperative that in staffing economic regulation departments, NRAs hire candidates with strong tariff setting expertise, good knowledge of the local electricity sector context, understanding of the relevant national legal frameworks, and the ability to liaise effectively with other regulatory staff and key stakeholders**.** Regular capacity building and cross-training of staff will also ensure that staff with the needed capacity are available**.**

- **NRAs should mandate utilities to carry out CoSS as key requirement for tariff setting and review.** A CoSS reveals the total utility cost to provide electricity service to each customer class and enables the utility to allocate costs among its different customer classes as fairly as possible based on their respective consumption patterns. Since tariffs are set based on customer classes and categories, it is therefore imperative that a CoSS forms the empirical basis upon which the utility can propose appropriate rates for each customer class for approval by the regulator.

- **NRAs should develop and implement comprehensive guidelines and accounting frameworks for the preparation and submission of applications for tariff adjustments, which must include data on utility costs, procurement practices, and all activities that could have impact on tariffs.** Development of such guidelines and frameworks will allow for transparency and predictability in tariff setting and will clearly specify the regulatory obligations of the utilities with regards to application for rate reviews. A guideline or framework document also makes it easier for the NRA to monitor compliance and conduct an objective assessment of rate review applications.

2.3 Cost of Service Studies (CoSS) in the Electricity Sector

2.3.1 Background to COSS in the Power Sector

In supplying electricity loads, generators need to ensure that the system is not over or under provisioned, in terms of generation and network capacities. Periodic system planning exercises help to achieve this balance. The first stage in the planning process is to conduct a demand forecast, i.e., to determine the magnitudes and locations of the loads that will need to be supplied, as well as when the supply will be required. The second step is to conduct a generation forecast, i.e., to determine the needed generation capacity to match the determined load.

The third is to determine the capacities, locations, and distances of the transmission and distribution networks to convey power from the generating plants to the various load locations. These forecasts enable utilities to make the right investments in the right places and at the right times, thereby avoiding the incidence of stranded and redundant generation and network capacity assets that may unduly raise the tariff. Regulators should review utility forecasts annually. Forecasts should cover a minimum of five years, in each case, to produce a joint investment cost for all customers, rather than for specific customer classes. A key outcome of this planning exercise is the RAB, which is a major input into the determination of the utility's RR.

A CoSS reveals the total utility cost to provide electricity service to each customer class. This analysis involves analyzing historical expenses during a twelve-month test period, and enables the utility to allocate costs among its customer classes as fairly as possible based on their respective consumption patterns. The effectiveness of the CoSS and the accuracy of its outcome largely depend on the adequacy of the available data on costs and revenues.

According to the 2020 ERI Report, only about 40% of the countries surveyed had carried out a CoSS within the last ten years. The majority of African countries are yet to carry out a CoSS. This is the primary reason for non-cost-reflectivity in the tariffs of most African countries. It should, however, be noted that the existence of CoSS does not always guarantee that cost-reflective rates will be approved or implemented. In a number of African countries, political intervention results in artificially low rates even when the true cost of service is known. This Guidelines report therefore provides an insight to the detailed methodology for carrying out a CoSS, so as to encourage those countries that are yet to carry one out to do so, and enable the achievement of-cost reflective tariffs in the region.

2.3.2 Approaches to CoSS

There are two main internationally recognized approaches to analyzing a utility's cost of service. These are:

Embedded Costs Approach

This type of CoSS is based on historical information that can be verified. It is less complex than the Marginal Cost Approach described below, and is therefore more commonly used in Africa as well as internationally.

Marginal Costs Approach

This approach is based on projected information and assumptions. Though much more complex than the Embedded Costs Approach, the resulting rates may not differ dramatically.

The table below compares the two cost approaches.

Embedded Cost Approach	**Marginal Cost Approach**
Allocation of total Revenue Requirement to smaller and smaller units (top-down)	Identification of unit costs (bottom-up)
Cost allocation to classes	Costs by voltage levels
Based on verifiable historical information	Forward looking and based the extra cost of producing an extra unit of output
Capital costs often treated as completely demand-related	Not all capital costs are assumptions demand-related
Total allocated costs equal the overall Revenue Requirement	There is always a revenue gap

Source: Parmesano, Hethie S. "Electricity Sector Issues in Rate Structure: Basic Techniques." A Paper presented at the World Bank - Public Utility Research Centre training program, University of Florida – January 2005

Given the above, the Embedded Costs Approach is the recommended approach for African countries.

2.3.3 Benefits of CoSS

CoSS provide the detailed cost information necessary for designing rates, showing cost differences among rate classes, and unbundling rates into separate functional components. The CoSS takes all the utility expenses and shows how the costs are attributed to the various customer classes. It also shows how much each class contributes to overall utility revenue and margins.

CoSS benefit utilities and regulators in the tariff setting process by providing:

- Overall utility margins and rate of return;
- Margins and rate of return for each class of customers;
- The differences in rates of return, thus highlighting the cross-subsidies among customer classes;
- Detailed cost information; and
- Average customer information for each class.

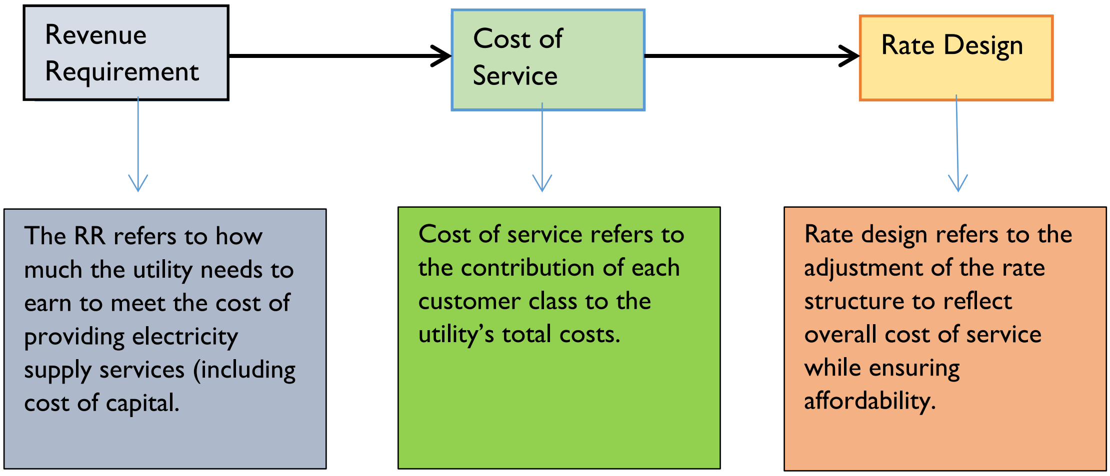
Some of the applications of CoSS are described below

Rate Design

A CoSS identifies the costs incurred to serve each customer class, plus fair margins, such that each rate class makes an equivalent contribution to the utility's overall return. The rates that recover these costs are said to be cost-reflective, and set the ideal targets for rate design for each customer class.

Rate design is the end result of a CoSS, in which the cost recovery mechanisms (rates and charges) for each customer class are established so as to collectively meet the utility's RR. The figure below shows the basic rate making process in the electricity sector.

Figure 2.2: Rate Making Process in the Electricity Sector



Cross-Subsidization between Rate Classes

CoSS identify the rate classes that are contributing more than their proportional share of overall utility returns, and those classes contributing less. Any rate class with a rate of return that is higher than the overall system rate of return is subsidizing any class with a rate of return that is lower than the overall system rate of return. This relative rate of return comparison allows the utility to adjust rates so that the subsidized classes can begin to pay more and the subsidizing classes can pay less, thereby moving all rate classes toward cost-reflective levels.

2.3.4 Connection Policies

Another application of CoSS is in the Connection Policies developed by utilities. A network connection is the physical link between a distribution system and a customer's premises, to allow the flow of electricity to the customer from the utility network. The connection policy sets out the nature of power connection services offered by the utilities, as well as the charges that may apply for these services.

Connection policies specify:

- The categories of persons that may be required to pay a connection charge and the circumstances in which such requirements may be imposed;
- The aspects of a connection service for which a charge may be made;
- The basis on which connection charges are determined; and
- The manner in which connection charges are to be paid.

In addition, the connection policy must comply with the regulator's guidelines and the connection charging principles. The connection charges payable by a customer are set by the regulator. The regulator is also responsible for making determinations on customer connection disputes with the utilities (where such issues are unresolved by the utility) and disputes arising between utilities.

The ERI Reports disclosed that very few of the countries surveyed have developed network connection policies, and fewer still take that into account in tariff computation. Most of these countries also lack an effective dispute resolution mechanism to address conflicts related to network connection issues.

CoSS can help to inform the development of connection/line extension policies. CoSS show the total distribution costs for each customer class, as well as the total cost for the utility. The average investment per customer is the level of investment that the existing rate will support. This means a utility can use the total distribution costs to calculate the average distribution investment per customer, and use that average cost per customer to establish the amount that the utility should be willing to invest to connect any new customer to the distribution network. This amount is set forth in the utility's connection/line extension policy.

Higher than average line extension costs can be recovered from the customer through a Contribution in Aid of Construction (CIAC). This CIAC is a capital contribution that prospective customers make towards construction of the infrastructure to supply them with electricity, if the budget is more than that provided in the policy. This stabilizes distribution costs and allows the utility to operate in a non-discriminatory manner with respect to new customers.

Some aspects of the connection policy are addressed in a country's distribution and metering code, which sets forth the general principles and practice of meter connection. These codes also define the procedures for dispute settlement between utilities and customers with regards to customer connections and metering.

2.3.5 Methodology for Conducting CoSS in Africa's Power Sector

The cost of providing electricity service is a major factor in the determination of a utility's RR and rate design. It is therefore imperative that a CoSS is carried out to facilitate the determination of revenue allocation (i.e., cost plus a fair margin) to each customer class. CoSS are detailed analyses that assign costs to each customer class based on its consumption attributes. This study, which consists of a range of activities involving a number of professions, such as engineering, accounting, economics and statistics, is an essential step in ensuring that rates are cost-reflective. Implementation involves the steps and processes discussed below.

Determination of the Utility's Revenue Requirements

A utility's RR is the total cost of providing electricity service by a utility, plus a reasonable rate of return. It provides a guide for carrying out a CoSS, from which cost-reflective tariffs can be developed. Therefore, calculation of the RR is the first step in the tariff setting process. Once it is established, the next step is to determine how the costs shall be allocated among the utility's various customer classes and how the associated revenues shall be collected from each customer class through rates.

The key requirements for the determination of the RR are: the RAB, regulatory depreciation of the assets, O&M expenses, WACC, and taxes. Assets and their values should be documented in a database, which should be updated regularly. In the first year of carrying out this exercise, field work may be required to identify, verify, and value the assets.

Investments in network expansion plans are key inputs in the determination of the RR. By extension, these investments constitute inputs into the CoSS.

Cost Attribution

After the determination of the utility's RR, the next is to attribute the costs that make up the RR equitably. The first costs to be dealt with are the directly assigned costs, because they can be easily attributed to the particular customer class that benefits from them. Joint and common costs are more complicated to attribute, as they need to be attributed to their function, classification, and customer classes proportionately, based on their responsibility for incurring such costs.

The principle of cost causation is fundamentally important when attributing costs to different customer classes. It states that costs should be borne by those who cause them to be incurred. At a basic level, attributing joint and common costs to various customer classes will normally follow three stages, as outlined below.

1) Functionalization of Costs

Cost functionalization refers to the identification of costs in relation to the functional elements of the electricity supply chain: generation, transmission and distribution, and customer costs. The table below provides a typical categorization of the cost of service by function in the electricity industry.

Table 2.3: Costs of Service by Function

Function	**Test Year Value (USD)**	**Percentage**
Generation	*13,832,483.00*	67.6%
Transmission	*1,555,131.00*	7.6%
Distribution	*4,337,998.00*	21.2%
Customer	*695,717.00*	3.4%
Direct Assigned	*40,924.00*	0.2%
Total	20,462,253.00	100%

Source: An adaptation from Dave Berc Consulting LLC, "Electric Cost of Service and Rate Design Study Report." Spanish Fork City Council, 2016

The table shows that on average, about 67.6% of the end-user cost of electricity is contributed by the generation function, while the transmission function contributes about 7.6%. The distribution function contributes about 21.2%, while the balance of 3.6% is shared between the customer function costs and the directly allocated costs.

2) Classification of Costs

In this step, utility costs are classified as demand-related, energy-related, customer-related, revenue-related, or directly assigned.

a. Demand (fixed) costs: These include the capital and operating expenses incurred to provide sufficient capacity to meet the peak demand at all hours. Demand costs are not affected by the number of customers or annual usage. Transmission infrastructure constructed to provide service to meet the peak demand would be classified as a demand cost. All capital and operating expenses associated with the construction and maintenance of this infrastructure would also be considered demand costs.

b. Energy (variable) costs: These are defined as those expenses that vary directly with the amount of energy sold (generated and purchased), including fuel and a portion of O&M expenses (known as variable O&M).

c. Customer costs: These are defined as those costs directly related to the number of customers, type of customers served, and size of the services required, such as those associated with meter reading, meter maintenance, customer installations, billing, and collection. A portion of distribution investments and operating costs are also classified as customer costs because the size and design of the distribution network is a function of both the number of customers and their load demand.

d. Revenue-related costs: These are costs that are associated with the amount of revenue generated. Taxes are one example of a revenue-related cost.

e. Direct assignment: Direct assignment or direct allocation costs are known costs that are incurred on behalf of one customer or one class of customers, which should be directly assigned to that customer or class. This may be related to demand, energy, customer, or other types of classification. Uncollectable expenses incurred by residential customers fall into this category. Class ratios are developed to allocate the remaining costs.

The table below shows how the different types of costs are assigned to different functions in the electricity supply chain.

Table 2.4: Classification of Costs According to Function in the Supply Chain

Function	**Classification**		
	Demand	**Energy**	**Customer**
Generation	X	X	
Transmission	X		
Distribution	X		X
General			X

Allocation of Costs

Once costs are functionalized and classified, the next step is to allocate them among the various customer classes based on each class's contribution to those costs. The costs of providing services are caused by all customers and, therefore, are charged to all customers on a weighted basis through a CoSS.

Example:

- ❖ Customer records and collection expenses are allocated to customer classes based on the average number of customers per class. An example of a factor (class ratios) developed for such allocation is shown in the table below:

Table 2.5: Allocation of Costs to Customer Classes

Class	**Number of Customers**	**Ratio to Total**
Residential	75	0.75
Commercial	15	0.15
Industrial	10	0.1
Total	100	1.0

This means that, if the costs were classified as customer-related costs, the residential customer class would be allocated 75% of all the customer-classified costs that are not directly assigned. For example, meter reading expenses are allocated to customer classes based on the number of meters in each customer class.

Cost allocation – the association of costs to each customer class – is the primary method of allocating the utility's respective RR. A utility's revenue allocation is said to be cost-justified when all customer classes are moving towards the average system rate of return. Rate rebalancing becomes necessary when some customer classes are charged rates that are significantly higher or lower than the system average. However, regulators should always consider adhering to gradualism to avoid rate shock when such rebalancing is to be carried out. The fundamental objective of cost allocation is to ensure that the revenue burden is equitably shared by each customer class.

In all, CoSS seek to facilitate the development of cost-reflective tariffs for all customer groups, but regulators must utilize rate design to ensure rates are affordable for poor households within the network.

2.3.6 Challenges to Conducting CoSS in Africa and Options to Address Them

Data Quality

The methodologies used to conduct a credible CoSS require in-depth consideration of a utility's financial and regulatory accounts, as well as significant technical data, disaggregated by customer class. Data availability and data quality issues are common throughout Africa's power sector. Where data is available, there is the issue of information asymmetry between utilities and regulatory authorities. This is one of the reasons many African utilities have not been able to conduct CoSS, and therefore do not benefit from cost-reflective tariffs. The accuracy, dependability, and credibility of CoSS depends on the analysis of relevant and reliable data.

The issue of data reliability can be addressed by involving all relevant experts involved in asset identification and verification to verify the "used and useful" assets in the system. Appropriate values (e.g., replacement costs) can be assigned to the assets, to develop a database of assets and costs to inform future exercises such as CoSS. This database should be updated periodically to correct errors, capture omissions, record new assets deployed in the network, and remove retired assets.

Limited Capacity of Utility and Regulatory Staff

Both regulators and utilities must have a strong technical foundation to be able to understand and carry out CoSS and utilize the resulting information to determine cost-reflective tariffs. In order to ensure sufficiency, which is one of fundamental principles of rate design, the regulator and utility must calculate the RR and conduct a CoSS to understand exactly how much it costs for the utility to provide reliable electric service to each class of customers.

Regulators and utilities also need to understand cost allocation methods, and must be able to determine how much electricity is being consumed by whom in order to apportion costs fairly among customer classes.

Most electricity utilities in Africa have limited capacity to implement effective CoSS. In some cases, utilities or regulators may procure a consultant to conduct a CoSS. Even if the CoSS is outsourced, regulators and utilities must be familiar with the key concepts in order to be able to interpret the findings and understand how they impact cost-reflective rate design. There is therefore an urgent need to build up strong capacity for conducting and/or analyzing CoSS among the regulators and utilities in the region.

This issue of staff capacity can be addressed through targeted training in the various components of CoSS. Whereas the regulator does not have to carry out the studies itself, it should be in a position to understand the entire process of conducting CoSS, which it has to review to ensure consistency with procedures. Utility and regulatory staff will need to be trained on the principles and practice of integrated system planning and how to determine the revenue requirement of a utility. They will need to be trained on cost functionalization, cost classification, cost allocation and cost attribution, and must understand the principles of cost causation and direct cost allocations for restricted costs.

High Incidence of System Losses

The high technical and non-technical losses in networks of many utilities within the continent and the inability of the consumers to pay for energy consumed and invoiced, tend to distort the outcome of any CoSS, and compromise any attempt to bring tariffs to cost-reflective levels. In many African countries, practically all costs associated with losses (including those that ought to be borne by utilities) are allowed to pass through to the consumer through the tariff.

Loss reduction may not be achieved in the short-run, but this issue can be addressed by ensuring effective cost functionalization, classification, and allocation, so as to isolate losses from the cost of service. The Regulator should develop a loss reduction trajectory for the utilities, with associated incentives for the achievement of loss reduction.

2.3.7 *Recommendations for Conducting CoSS in Africa*

- **The issue of data reliability can be addressed by involving all relevant experts involved in asset identification and verification to verify the "used and useful" assets in the system.** Appropriate values (e.g., replacement costs) can be assigned to the assets, to develop a database of assets and costs to inform future exercises such as CoSS. This database should be updated periodically to correct errors, capture omissions, record new assets deployed in the network, and remove retired assets.
- **There is need to build up strong capacity for conducting and/or analyzing CoSS among the utilities and regulators in the region.** Regulators and utilities need to understand cost allocation methods, and must be able to determine how much electricity is being consumed by whom in order to apportion costs fairly among customer classes.
- **Cost of losses should be isolated from cost of service. It should be noted that loss reduction may not be achieved in the short-run, but this issue can be addressed by ensuring effective cost functionalization, classification, and allocation.** By separating cost of losses from cost of services, consumers will not have to bear losses attributable to the inefficient operations of the utility company, as only those losses within the allowable regulatory threshold will be passed on through the tariff.

Case Study 4: Cost of Service Study for Spanish Fork

Spanish Fork is a small but successful utility in the State of Utah in the United States of America, providing service to approximately 11,500 customers. Research revealed that this utility has done well in the area of CoSS.

A cost of service analysis was carried out by the utility to determine the allocated cost to serve each of Spanish Fork's customer classes. The analysis was based on 2015 financial, operations, and sales data. The study indicated the degree of revenue recovery from each customer class. A comparison of the allocated cost to serve each customer class and the actual revenues from that customer class informed the final rate design. With the RR determined, the analysis was carried out in steps as follows:

(a) Functionalization of costs; (b) Classification of costs; (c) *Allocation of costs*

Based on an analysis of the characteristics of the various customer classes, the classified costs above were allocated to the various customer classes. Specific allocation factors were utilized in each of the cost classification categories as follows:

- *Demand allocations*
- *Energy allocations*
- *Customer allocations*
- *Revenue allocations*

Based on the above classifications and allocations, the utility determined the estimated cost to serve each class of customers for the test year (2015). The table below summarizes the allocated costs for each class compared with the total revenues received from that class in 2015.

Table a: Comparison of Total Class Cost with Total Class Revenues for the Year 2015

Customer Class	***Allocated Cost to Serve ($)***	***Class Revenue ($)***
Residential	*8,947,519.00*	*8,828,868.00*
General Service	*7,603,847.00*	*8,121,880.00*
Large Power Service	*3,866,767.00*	*3,498,313.00*
Lighting	*8,121.00*	*5,249.00*
Total	*20,426,253.00*	*20,454,309.00*

The table below makes the comparison based on percentages of total costs to serve and total revenues. The percentage increase/decrease in each class revenue is the adjustment necessary to make the class revenues consistent with the cost of service. These results were considered in the rate design for the utility.

Table b: Comparison of Percentage Costs and Revenues for the Test Year

Customer Class	***Allocated Cost to Serve***	***Revenue***	***Increase/Decrease***
Residential	*43.8%*	*43.2%*	*0.561%*
General Service	*37.2%*	*39.7%*	*(2.536)%*
Large Power Service	*18.9%*	*17.1%*	*1.803%*
Lighting	*0.04%*	*0.03%*	*0.0141%*
Total	*100%*	*100%*	*0.158*

The above analysis shows that the existing class revenues do not exactly match the allocated costs to serve each class. As a result of this study, no overall rate increase was recommended for the utility. However, rate

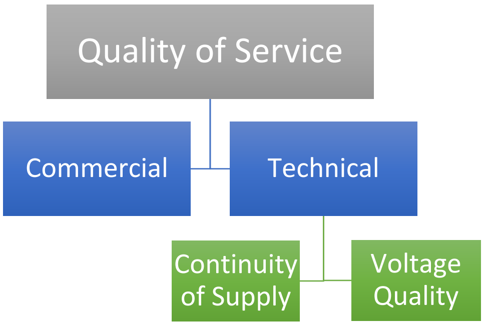
3 Technical Regulation (Quality of Service)

3.1 Introduction to Quality of Service Regulation

Quality of Service (QoS) is the totality of characteristics of power supply services that bear on its ability to satisfy the needs of end users. End users' perception of power supply services is influenced by a number of factors including technical issues, commercial principles, and resolution/enforcement mechanisms.

Experience shows that when the regulator chooses to apply a price or revenue cap to the tariff, utilities aim to maximize profits by reducing costs, often at the expense of service levels. On the other hand, under rate of return regulation, the emphasis is on the asset base, upon which the utility's earnings are based. This form of regulation can lead to over-investment in the network, with limited incentives for exceptional performance. For that reason, all types of regulation must be supplemented by some kind of service quality regulation.

As shown below, service quality has three aspects, one commercial and two technical.



Commercial quality of service refers to performance related to the provision of new connections, meter reading, billing, customer complaint handling, etc. Technical quality of service refers to power quality issues, which can be grouped into two main fields, namely:

- ❖ Continuity of supply, generally described by the number and duration of interruptions. The most common continuity indices at the system and customer levels are:
  - System Average Interruption Frequency Index (SAIFI)
  - System Average Interruption Duration Index (SAIDI)
  - Customer Average Interruption Duration Index (CAIDI)
  - Energy Not Supplied (ENS)
- ❖ Voltage quality, which refers to variations in voltage characteristics from the desired values, such as under-voltage, over-voltage, harmonic voltage distortion, transient over-voltages, voltage dips, and voltage flickers.

Considering the importance of QoS, especially with regards to meeting the expectations of customers who pay for access to an agreed level of service, it is of utmost importance and a core mandate of the regulator to ensure that effective QoS regulations are put in place to protect consumers, incentivize the utility towards improved performance, and stipulate penalties and sanctions for non-failure to provide a given level of service.

3.2 Challenges in Regulating QoS in Africa's Power Sector

The ERI Reports identify a number of challenges to QoS regulation in Africa's power sector. These are discussed below.

3.2.1 Absence of QoS Regulations

The 2020 ERI Report shows that regulatory frameworks for QoS are weak across Africa's power sector. 55% of the countries surveyed have not developed any country-level QoS regulations; without these regulations in place, there is no basis for standards setting or compliance.

3.2.2 Key Performance indicators and Performance Monitoring

Another key issue identified in the ERI is that many of the countries with QoS regulations do not have clear cut standards and benchmarks for key QoS indices. In some cases, the regulator has not established Key Performance Indicators (KPIs) to guide utility operations. Where KPIs do exist, there are no benchmarks for these critical performance indicators (either commercial or technical). Where there are benchmarks, incentives and sanctions are insufficient to drive utilities to ensure excellent performance.

In some cases, the regulator has suspended sanctions because the networks are too weak for utilities to comply with SAIDI/SAIFI limits. Countries also lack effective systems to accurately monitor and measure these indices. Again, it was observed that in most countries where SAIFI/SAIDI values are determined, regulators do not factor these indices into the tariff as an incentive to improve service reliability. It should be noted that this exclusion of QoS indices from the tariff denies the utilities the funds and incentives to improve the network, and consumers are left to cope with unreliable supply situations.

3.2.3 Ineffective Engagement with Utilities in Setting Standards

Setting QoS standards effectively require three-way engagement between regulators, utilities, and consumers. Standards should be set based on local conditions, and the utility is best positioned to develop current quality thresholds. On the other hand, certain requirements for improvement in standards may also have pecuniary implications. In a number of African countries, regulators set performance benchmarks without due recourse to a consultation process with the utility and consumers. Invariably, when standards are set this way, it may be impossible for the utilities to meet them, and may even lead to non-compliance with the entire QoS regulatory framework. This is observed in a number of African countries today.

3.2.4 Absence of Reliable Data

Setting performance indicators and targets for QoS Regulation relies on the availability of good data sources to ensure that the agreed benchmark for current indices are reasonable. Typically, benchmarks should be based on an approximation of data collected by the utility over two to three years. However, most African utilities struggle to capture and report the data required by the regulator.

Additionally, it is not unusual to find different data values for the same indices coming from the same utility. The data quality problem is made worse due to inadequate data collection systems at many utilities within the region. Many utilities do not have the appropriate technological means and tools for effective data collection within their networks. Many utilities also face constraints in converting or synthesizing raw data into the format required by the regulator.

3.2.5 Difficulty in Meeting Reporting Obligations

Another challenge with QoS regulation in Africa is the difficulty utilities face in meeting some reporting obligations, due to these obligations being either too detailed or too frequent. Given the challenges already identified with respect to data availability and data reliability, onerous reporting obligations can also trigger non-compliance with QoS regulations, especially for utilities that have not invested in a data management and analytics framework (as is the case with most state-owned utilities in Africa today).

3.2.6 Data Auditing

While it is the responsibility of the utility to provide primary KPI data to the regulator, the regulator is responsible for ensuring the veracity and authenticity of the data provided. This should be done through periodic audits, which can be undertaken by an independent party on behalf of the regulator. Even though a few of the regulatory authorities in Africa do have provisions in QoS regulations for independent verification of data, this is often not implemented. Reliance on inaccurate data when setting quality standards setting results in unsatisfactory regulatory outcomes.

3.2.7 Customer Satisfaction Surveys

QoS is addressed from the perspective of end-users, whose perception of power quality and customer relationship is related to consumers' expectations of reliability, accessibility, timeliness, etc. The ERI reports, however showed that regulators in only ten of the countries surveyed have conducted customer satisfaction surveys to assess the provision of service from the perspective of the customer.

Given that the ERI ROI relies on the views of utilities and customers to assess the general effectiveness of the regulator and regulations put in place for the efficient operation of the power sector, customer engagement should be a major focus in developing and implementing QoS regulations. While the 2020 ERI report established the average RSI score for technical regulation as 0.506, the ROI score was lower at 0.393, suggesting a disconnect between regulatory framework development and expected impacts on consumers and utilities.

3.3 Technical Quality of Service Regulations

Technical quality of service refers to power quality issues, which could be grouped into two main fields, namely, continuity of supply and voltage quality as described above.

The basic elements of the service quality regulation instruments are:

- **Quality indicators,** which describe the actual performance of the regulated company.
- **Performance standards,** which specify the level of quality that company is expected to deliver to consumers.
- **Financial incentives** for penalizing a utility that does not perform up to the standards set by the regulator.

Quality indicators measure the corresponding dimensions of service quality. Minimum quality standards represent the lower limit of service quality delivered to the individual customer. In the case of reward and penalty schemes, performance standards establish an average level of service quality.

Financial incentives constitute penalties or rewards put in place to incentivize improved performance by the utility. In principle, a utility performing below the performance standard will be penalized, while performing above the performance standard will be rewarded. In the case of applied minimum quality standards and premium quality contracts, financial penalties take the form of money compensation paid to the affected customers. Any incentive or penalty scheme is characterized by a structure with defined functional relationships between quality of service and price.

To improve electricity QoS in Africa, regulators must develop and implement appropriate and adequate frameworks to incentivize enhanced utility performance. This process should incorporate the establishment of KPIs based on context-specific benchmarking exercises, as well as robust mechanisms for performance monitoring, evaluation, and enforcement. Proposed interventions are discussed below.

3.3.1 Continuity of Supply (CoS)

Continuity of supply concerns interruptions in electricity supply and focuses on events during which the voltage at the supply terminals of a network drops to zero or nearly zero. Continuity of supply can be described by various quality dimensions. The ones most commonly used are frequency of interruptions, duration of interruptions, and energy not supplied (ENS) per year.

A forced interruption is a shutdown condition of a power station, transmission, or distribution line that renders the system unable to provide power. Forced interruptions can be caused by equipment failures, disruption in the plant fuel supply system, operator error, etc. A scheduled (or "planned" or "notified") interruption is typically due to execution of some scheduled works in the electricity network for which network users are informed in advance.

Most countries consider advance notification to the affected network users to be sufficient and necessary for an interruption to be classified as planned or scheduled. Whereas there is a general agreement on this definition, the requirement for advance notice can vary from 24 hours to 360 days, depending on the country's level of development. Unscheduled Interruptions are those that are sudden but necessary to be approved at a short notice to prevent an emergency.

Network users expect a high continuity of supply at an affordable price, with few interruptions quick restoration of supply following any interruption. Therefore, one of the roles of a network operator is to optimize the continuity of performance of its distribution and/or transmission network in a cost-effective manner. The role of the regulator is to ensure that this optimization is carried out in a manner that appropriately considers users' expectations and willingness to pay.

Continuity of supply indicators are important tools for making decisions on the management of distribution and transmission networks. The most widely utilized indicators focus on frequency of interruptions, their duration, and the aggregate energy not supplied due to interruptions. These measures normally complement incentive regulation, which is commonly used in Africa (either in the form of price or revenue cap mechanisms).

Incentive regulation provides a motivation to increase economic efficiency over time. However, it also carries a risk of network operators refraining from carrying out investments and proper operational arrangements for better continuity, in order to lower their costs and increase their returns. To account for this risk, many regulators around the world, especially in Europe, adopt additional monitoring mechanisms.

Continuity of Supply Monitoring

Interruption of supply at any level is not desirable for either the system or consumers. For example, some production lines cannot tolerate any form of interruption irrespective of the duration.

Therefore, regulators should monitor various levels of interruptions. Knowledge of the causes of these interruptions facilitates development of strategies to prevent or mitigate them.

Interruptions can be described as transient, momentary, or sustained depending on the duration, as shown below[5]:

- Transient interruptions: T < 1 second
- Momentary (short) interruptions: 1 second < T ≤ 3 minutes
- Sustained (long) interruptions: T > 3 minutes

Monitoring equipment can be installed on feeders to record interruptions. Such equipment (sometimes referred to as System Event Recorders (SERs) or Automatic Loggers) may records conditions such as voltage, load, power frequency, etc. at the point and time of the interruption. The monitoring device should also be capable of recording the frequency and duration of interruptions on such feeders over a period of time. The regulator should therefore mandate utilities to install SERs on every high voltage and medium voltage feeder, and, ultimately, on low voltage feeders in the network, for the purposes of recording system events.

It would be very difficult to discuss the monitoring of interruptions on different voltage levels without first addressing how those voltage levels are defined. The terms low voltage (LV), medium voltage (MV), high voltage (HV) and extra high voltage (EHV) have quite different meanings across Europe, the Americas, and Africa. For example, in Western Europe, HV network ranges from 63kV to 150kV whereas in West Africa, the range is from 66kV to 220kV.

Continuity of Supply Indicators

Network reliability performance is internationally qualified and quantified by measuring the number of end-users *not* served electricity during a period of time. Indicators commonly used to report the number and duration of sustained interruptions are listed follows:

a. ***System Average Interruption Duration Index (SAIDI)*** is the average duration of interruptions per consumer during the year. It is the ratio of the annual duration of sustained interruptions to the total number of consumers. If duration is specified in minutes, SAIDI is given as consumer minutes.

$$\textbf{\textit{SAIDI}} = \frac{Total\ Duration\ of\ Sustained\ Interruptions\ in\ a\ year}{Total\ number\ of\ Consumers}$$

b. ***System Average Interruption Frequency Index (SAIFI)*** is the average number of sustained interruptions per consumer during the year. It is the ratio of the annual number of interruptions to the number of consumers.

$$\textbf{\textit{SAIFI}} = \frac{Total\ Number\ of\ Sustained\ Interruptions\ in\ a\ Year}{Total\ Number\ of\ Consumers}$$

c. ***Consumer Average Interruption Duration Index (CAIDI)*** is the average duration of an interruption, calculated based on the total number of sustained interruptions in a year. It is the ratio of the total duration of interruptions to the total number of interruptions during the year. This is expressed as follows:

[5] 6th CEER Benchmarking Report on quality of electricity and gas supply, 2016

CAIDI = $\frac{Total\ Duration\ of\ Sustained\ Interruptions\ in\ a\ Year}{Total\ number\ of\ Interruptions\ in\ the\ Year}$

This can also be expressed as:

CAIDI = $\frac{SAIDI}{SAIFI}$

d. ***Consumer Average Interruption Frequency Index (CAIFI)*** is the average number of interruptions for consumers who experience interruptions during the year. It is the ratio of the annual number of interruptions to the number of consumers affected by interruptions during the year. Consumer is counted only once regardless of the number of interruptions.

CAIFI = $\frac{Total\ duration\ of\ Sustained\ Interruptions\ in\ a\ Year}{Total\ Number\ of\ Consumers\ Affected}$

e. ***Energy Not Supplied (ENS)*** and ***Average Interruption Time (AIT)*** are mostly used to monitor continuity of supply for transmission networks.

AIT = $\frac{Sum\ Total\ of\ Network\ Outage\ Time\ in\ a\ Year}{Total\ Number\ of\ Interruptions\ in\ the\ Year}$

ENS = Maximum energy that can be delivered from a system over a period of one year – Actual energy delivered during the same period

This difference is a result of network interruptions.

Short and transient interruptions are not monitored as widely as sustained interruptions. One indicator commonly used to quantify the number of momentary interruptions is given below:

a. ***Momentary Average Interruption Frequency Index (MAIFI)*** is the average number of momentary (less than five minutes) interruptions per consumer during the year. It is the ratio of the annual number of momentary interruptions to the number of consumers. This is described as follows:

MAIFI = $\frac{Total\ Number\ of\ Momentary\ Interruptions\ in\ a\ Year}{Total\ number\ of\ Consumers}$

Performance Standards in Continuity of Supply

Performance-based regulatory frameworks focus on the following with regard to continuity of supply:

a. **Continuity monitoring:** This is a prerequisite for setting standards and implementing reward/penalty regimes. Here, robust and reliable data are needed in terms of the actual continuity levels as well as the level perceived by the network users.

b. **Maintenance and improvement of general continuity levels:** The investment decisions of network operators influence current and future quality levels. Depending on the actual quality level, the regulator must ensure that the current status is either maintained (if continuity of supply has already reached good levels) or improved (if continuity of supply is not yet satisfactory). Preferred regulatory actions to reach these goals include publishing continuity data and implementing reward/penalty schemes.

c. **Continuity ensured for each network user:** Continuity standards typically reflect expected QoS levels for individual network users. Enforcement of minimum standards for quality levels allow users to be compensated if the standard is not met by the network operator.

Measurement of Quality Levels

The measurement of actual continuity levels through the above indicators constitutes the basis for regulating continuity and quality of supply as a whole. In general, continuity of supply can be measured at two different levels: ***system level*** and ***user-specific level***.

- ❖ The measurement at system level is usually done on an aggregate basis;
- ❖ The measurement at user level is often based on surveys asking customers about their satisfaction, expectations, and willingness to pay for high quality (or willingness to accept low quality levels).

The implementation of adequate measurement systems is essential for setting appropriate standards and incentives at both measurement levels.

Regulation at System Level and Reward/Penalty Regimes

African countries may look to Europe for lessons learned from implementing reward and penalty regimes to ensure continuity of supply. As shown in the 6th CEER Benchmarking Report, 2016, general reward/penalty schemes and/or other incentives to optimize continuity of supply levels have been introduced in most European countries. However, the use of rewards, penalties, or a combination of both differs among countries and is also applied differently at the transmission and the distribution levels.

A few African countries have also adopted reward and penalty schemes in their QoS regulations, though these provisions are not always enforced.

The main objective of a performance-based incentive scheme is to keep quality levels at a socio-economically acceptable level. As such, NRA's may aim to maintain or improve existing service levels. Nevertheless, the input- output relationship has to be considered: if the quality level is poor as in many African countries, a progressive improvement framework is required; however, if the quality level is already very high**,** then further improvements might be very costly for the consumer. In the latter case, the only cost-effective option is to maintain the existing quality level.

3.3.2 *Recommendations for Regulators on Improving Continuity of Electricity Supply in Africa*

Recommendations for improving regulatory frameworks impacting continuity of electricity supply are as follows:

- ❖ **NRAs should ensure that utilities keep all records and submit all reports specified in the relevant set of standards**. Reports should be retained for a period not less than five (5) years, to be specified by the respective NRA.
- ❖ **Some countries monitor sustained interruptions, but it is recommended that NRAs also monitor momentary interruptions.** Monitoring of momentary interruptions will serve as a trigger for continuous improvement in CoS as African countries make the needed transition from frequent brown-outs to much steadier service.
- ❖ **Monitoring of transient interruptions should be introduced through progressive steps when possible**. This is envisaged to be longer term strategy for most countries depending on the strides made by each country in improving its CoS.

- **In order to enable easy comparison and benchmarking between countries, harmonized data collection procedures should be implemented with respect to key indicators**:
    - The duration and frequency of sustained interruptions (SAIDI and SAIFI),
    - The frequency of momentary interruptions (MAIFI), and
    - Energy Not Supplied (ENS) and Average Interruption Time (AIT) due to interruptions in transmission networks.
- **Regulators should implement adequate incentive schemes in order to maintain or improve continuity of supply levels at both the distribution and transmission levels, if economically viable.**
- **Monitoring of interruptions should be expanded to include customer surveys at the end-user level to provide the basis for individual compensation schemes.**

Case Study 5: Monitoring and Enforcement of QoS Regulation in Senegal

In Senegal, QoS standards and incentives are developed by the Ministry of Petroleum and Energy. The Ministry collaborates with the sector regulator (CRSE), which is responsible for applying incentives relating to Energy Not Supplied (ENS).

Senegal's QoS regulations also provide for the payment of compensation and reimbursement to customers and utility service providers (USPs) that are impacted by the utility (Senelec) for non-compliance with certain QoS standards. Senelec executes reimbursement payments directly. CRSE has no direct oversight over the payment of reimbursements, but may intervene if customers or USPs submit petitions on claims for reimbursement.

The global Quality of Service Regulation in Senegal includes 27 different indicators tied to 22 incentives or penalties. The objective is to incentivize Senelec to pursue excellent service delivery in line with best practices.

In compliance with its regulatory mandate, CRSE monitors ENS on a year-to-year basis. For instance, in 2019, the Ministry set the standard of availability and security (ENS) at 1% of sales for the year. Beyond this limit, a contractual penalty of €2.02 per KWh not supplied was to be applied to Senelec. With sales of 3,600.88 GWh in 2019, the limit for non-supplied energy stood at 36 GWh. Senelec's actual ENS in 2019 was estimated at 16.9 GWh.

Thus, the 2019 standard of availability and security was achieved, and the contractual penalty for breach of the standard to be deducted from Senelec's Maximum Authorized Income was zero (€0).

However, as CRSE has no direct oversight over customer reimbursements, Senelec has not provided any data to CRSE relating to customers impacted by non-compliance. The low number of complaints to CRSE from consumers on this subject indicate that a consumer information campaign is needed to sensitize consumers on their rights to compensation.

Without more delegation of power to CRSE on monitoring and enforcement of payment of incentives and penalties for Senelec's non-compliance with QoS standards, it is doubtful if the intention of the regulations can be achieved, as monitoring and enforcement powers are critical to the successful implementation of QoS regulations.

3.3.3 Voltage Quality (VQ) Regulation

Voltage quality (VQ) indicators cover a wide range of voltage disturbances and deviations in voltage magnitude or waveform from the optimum values. In this Guidelines report, voltage quality refers to all voltage-related disturbances in the supply of electricity, such as:

- Under- or over-voltages
- Voltage imbalances
- Harmonic distortions
- Voltage dips
- Voltage flickers
- Voltage surges
- Switching disturbances

Any such disturbances to voltage quality could occur in the operation of the power grid and/or of units connected to the grid. Examples are:

- Large load changes at the costumer level;
- Voltage dips caused by short-circuits in the grid; or
- Rapid voltage changes caused by changes in power generation.

All users connected to the power grid can influence the quality of the voltage delivered at his/her own connection point or at other connection points throughout the power grid.

Any VQ regulation must consider the cost to specific customers as a result of equipment malfunction or damage versus the cost to consumers (through the tariff) of network upgrades.

Whereas interruptions may affect all end-users on a feeder(s), voltage disturbances do not affect all end-users in the same way.

Importance of Voltage Quality

VQ is becoming an ever more important issue in Africa due to, among other things, the increasing susceptibility of end-user equipment and industrial installations to voltage disturbances. This increase reflects the growing use of energy-efficient equipment whose operational safety may cause rapid load switching due to the sensitivity of such equipment. Future developments, such as rising amounts of distributed generation, could result in further increases in voltage disturbances.

Regulation of Voltage Quality

VQ is the most technically complex aspect of quality of electricity supply. Measurement issues, the choice of appropriate indicators, and the setting of limits require detailed monitoring of every single disturbance. Moreover, multiple stakeholders may impact the severity of the disturbance and the consequences of high disturbance levels. This makes it difficult to assign responsibility to any one particular stakeholder, such as the network operator or an end-user.

The impact of different types of voltage disturbances can vary for different individual users. Whereas there is a need for harmonization with regard to the limits on voltage disturbances (as end-user equipment is the same throughout the region), the emphasis on VQ regulation is likely to be different between countries.

To illustrate this issue, the below table shows how responsibility for VQ regulation is assigned in some European and African countries. About half of the responding NRAs have powers/duties to define VQ regulation alone or in coordination with other competent authorities.

Table 3.2 Responsibility for Voltage Quality Regulation

RESPONSIBILITY FOR VOLTAGE QUALITY REGULATION					
Country	Does the NRA have exclusive powers/duties to define voltage quality regulation?	Does the NRA have powers/duties to define voltage quality regulation together with other competent authorities? Authorities?		Has the NRA issued regulatory orders regarding voltage quality	Has the NRA issued public consultations regarding voltage quality
France*	Yes	Yes	NRA has partial powers/duties delegated from Ministry	No	No
Great* Britain	No	No	Department of Energy and Climate	Yes	No
Czech Republic*	Yes	Yes	NRA has partially powers/duties delegated from Ministry of Energy and Trade		
Namibia	Yes	No		Yes	Yes
Egypt	Yes	No		Yes	No
South Africa	Yes	No		Yes	Yes

*Source: 6th CEER Benchmarking Report

In the context of Africa's power sector, the responsibility for setting quality indicators and VQ Regulation should be split between the utilities and the NRAs. The utilities will propose most of the quality indicators (especially those to be included in the grid code) for approval by the NRAs while the NRA should be responsible for monitoring compliance with the VQ regulation.

Individual Voltage Quality Verification

Individual VQ verification can be initiated in a couple of ways which are discussed below.

a. By customer complaint:

   In several European countries, network operators are obliged to inform customers about actual VQ levels (i.e., measured levels in the recent past). If a customer complains about the VQ at the costumer's connection point, the DSO or transmission system operator (TSO) is, in most countries, obliged to perform measurements to verify the levels of all relevant VQ parameters. The cost for performing these measurements is generally covered in two ways, namely:

- The cost is borne by TSO/DSO if the quality does not conform to the approved standards.
- The customer pays if the VQ does meet the approved standard.

Some countries allow end-users to install their own VQ recorders when the results are to be used to settle a dispute between the end-user and the DSO/TSO.

In Africa, Namibia has developed a Quality of Supply and Quality of Service Standard as a framework for implementing VQ monitoring and measurement, billed for implementation effective July 1, 2021. The Standard stipulates that operators should be responsible for the quality of supply, including VQ, delivered to all customers at their respective connection points. Operators should also be responsible for managing the power quality contributed by the customers at their connection points.

b. On customer request:

In some European countries, if a customer wants to monitor VQ at his/her own connection point, the DSO/TSO is compelled to provide a VQ monitor. In situations not related to complaints, the end-user usually pays for this equipment. Most commonly, there is no pre-defined payment for this service.

As an African example, a limited number of power contracts have been entered into in South Africa, where power quality monitoring equipment are installed and maintained by Eskom Enterprises, and paid for on a monthly basis by customers.

Emissions of Voltage Disturbance

The VQ on the grid and at the end-user's connection point may be influenced by:

- How the grid is operated by the grid operator,
- How the grid is dimensioned by the grid owner, and
- The design and use of all units connected to the grid.

Since voltage disturbances may be caused by or remedied by the grid itself or a unit connected to the grid, CEER emphasizes the importance of responsibility sharing for VQ regulation. This concerns, among other things, the setting of maximum levels of voltage disturbances at the point of delivery between the network operator and its customers, as well as emissions limits for installations connected to the network. Emissions from individual customers need to be limited to keep voltage disturbance levels within the requirements.

This Guidelines report recommends that enforceable limits are set at a reasonable level for customers and the network operator. The concept of responsibility sharing may be applied as follows:

- Good VQ for electricity delivered *to* the customer's bus bar is the network operator's responsibility;
- Good quality for load current drawn *from* the bus bar is the customer's responsibility; and
- Developing and supplying equipment with adequate tolerance for power quality variations and power conditioning devices with appropriate technology are the manufacturer's responsibility.

Ensuring an efficient balance of these three responsibilities is the role of the NRAs. The system operator has the overall responsibility for maintaining the VQ of the system; however, if a grid user is the source of a VQ disturbance, the responsibility lies with that grid user. This implies that grid users also have an obligation to use appropriate devices. NRAs may also choose to allocate the responsibility for taking mitigating measures to reduce voltage disturbances according to the source of the problem.

Awareness on Voltage Quality

The impact and frequency of VQ issues vary between different customers and between different grid areas. For this reason, the objectives of and approach to VQ regulation is likely to differ across and between countries. Nevertheless, voltage disturbance is expected to be an increasingly important concern with regard to quality of electricity supply. Therefore, customer education on VQ can reduce inconveniences arising from voltage disturbances. Therefore, this Guidelines report recommends regular reporting and publishing of Voltage Quality Monitoring (VQM) results as standard regulatory practice. One way of disseminating knowledge on VQ is through the internet (e.g., NRA/utility/network operator websites). Currently, VQ is mainly discussed at conferences for industry organizations, DSOs and experts working on power quality, rather than with the general public.

3.3.4 *Recommendations on Regulating Voltage Quality in Africa's Power Sector*

This Guidelines report recommends the following interventions for improving regulatory frameworks on voltage quality in Africa.

- ❖ **VQ regulation is an emerging area that requires more research by NRAs**. Consequently,
    - NRAs should carry out investigations to assign stakeholder responsibilities for voltage disturbances, according to the concept of responsibility sharing described above.
    - In order to verify whether the network operator, the customer, or the manufacturer is responsible, it is necessary to describe the factors that should be taken into account when identifying the responsible party.
- ❖ **Monitored voltage quality data or statistics should be published regularly for public awareness.**
- ❖ **Stakeholders Education and awareness campaigns about the impacts of VQ issues on the network and connected customers**. This will contribute towards reducing inconveniences due to voltage disturbances.

3.3.5 *General Recommendations for Strengthening Quality of Service Regulation in Africa*

This Guidelines report recommends the following general interventions for improving regulatory frameworks for QoS in Africa.

- ❖ **Every country should work to develop comprehensive QoS regulations covering all aspects of reliability, including SAIFI, SAIDI, CAIDI, etc.** Following wide stakeholder consultation, especially utilities, the development of these regulations is the first step in ensuring the implementation of an effective QoS Regulation. KPIs must be set in collaboration with utilities to ensure that the targets proposed and approved are realistic based on country-specific operating environments.

- **NRAs should mandate utilities to submit annual reports on all power quality components. NRAs should specify the timing for reporting.**

- **Utilities should keep all records and complete all specified in the relevant standards. Reports should be retained for a period not less than five (5) years, or as specified by the NRA.** Utilities' historical records typically serve as the basis for setting initial QoS KPIs, and subsequently reviewing them for adequacy. Availability of these records allows the NRA and the utility to periodically reassess whether the established KPIs are realistic and achievable.

- **Annual reporting is the basis for fundamental assessment by regulators of regulatory impact and progress within the electricity industry.** At a minimum, the following report components should be mandatory for any utility within the region:

    - Continuity of supply indicators, such as:

        i. SAIDI
        ii. SAIFI
        iii. CAIDI
        iv. CAIFI
        v. MAIFI
        vi. AIT
        vii. ENS

    - Voltage waveform quality indicators, including:

        i. Voltage magnitude
        ii. Voltage imbalance
        iii. Voltage harmonics
        iv. Voltage flicker

- **Although tariff methodologies in most African countries are cost-based, regulators should seek to factor appropriate QoS standards into the tariff to incentivize utility performance and enhance value to consumers.**

- **For those countries that have factored reliability issues into the tariff, the regulator should regularly monitor the quality of supply through periodic reporting by the utility.**

- **In situations where the state of the distribution network is weak, the regulator should work with utilities to develop an implementable transition path that may include flexible mechanisms, (rather than merely suspending implementation of enforcement policies).**

- **Utilities should regularly carry out customer satisfaction assessments to keep track of the commercial and technical quality of service received by consumers. Regulators should enforce this customer satisfaction survey as a KPI for electric utilities.** This will help regulators evaluate the impact of regulation on consumers, both large and small.

- **Regulators should impose different types of sanctions to operators not meeting their QoS obligations, ranging from publicizing failures, fines, and license suspensions.** In some cases, operators may be required to provide rebates to end users. The type of sanctions applied will depend on the particular circumstances of each country and the maturity of its electricity market.

Case Study 6: Quality of Service Regulation in Hungary

Hungary's electricity distribution companies were privatized in 1995. However, the performance of the distribution utilities began to deteriorate in 1998-1999 as outage rates significantly increased. This development revealed an urgent need for monitoring and regulation of quality of supply. The Hungarian Energy and Public Utility Regulatory Authority (HEA) was subsequently authorized by an Act on Electric Energy in 2003 to issue regulations on quality of supply.

The Act states that "for the protection of customers, the regulator shall determine quality indicators, including minimum quality requirements and expected quality levels for the licensees to be met at both a system level and on the individual customer level. The regulator is authorized to entrust independent experts with measuring the level of customers' satisfaction and the level of quality of electricity supply the licensees are expected to deliver."

HEA worked with the licensees to improve quality of service to develop the new quality standards (rather than merely mandating them to implement the outcome of the process). The licensees and customer associations were given the opportunity to comment on the draft regulation, and in some cases, helped the regulator to define appropriate requirements by providing data on actual performance or by pointing out potential obstacles.

The regulator has also introduced the new or revised quality standards gradually, based on the same consultation process. The regulator initially identified some quality indicators for monitoring, based mostly on verifiable information on the actual performance of the licensees. After some years of observation, data collection, and verification, the regulator reviewed the minimum quality requirements and expected quality levels, revised quality indicators accordingly.

This approach ensured that Hungary's standards were not set too low, as licensees would not be motivated to improve their performance, or unrealistically high. The regulator also takes care to assess the financial implications of the investment needed to meet the required level of quality vis-a-vis the impact on the end-user tariff that customers will bear in return for getting better quality services. If the current environment does not allow the regulator to increase the network charges, and consequently the end-user price, then setting stricter quality requirements should be postponed to a more appropriate time.

Hungary's collaborative and gradual approach to QoS regulation ensures that the final result of the process is usually accepted and supported by all stakeholders.

3.4 Commercial Quality of Service Regulation

Commercial quality is associated with transactions between utilities (DSOs, suppliers, or both) and customers. Commercial quality covers not only the supply and sale of electricity, but also various forms of contact established between utilities and customers.

New connections, disconnections, meter reading and verification, repairs and elimination of VQ problems, customer complaints and claims processing, etc. are all services that involve some commercial quality aspect. The commercial quality issues that arise most frequently relate to timeliness of services (e.g., connections). These services often represent the customers' first interaction with the energy market.

The CEER-European Consumer Organization (BEUC) 2020[6] Vision for Europe's Energy Customers identifies four principles that must guide energy market participants' efforts to engage with and understand the diverse needs of customers: (1) reliability, (2) affordability, (3) simplicity, and (4) protection and empowerment. These principles aim to ensure that each customer is empowered with the right information to make informed decisions related to electricity consumption.

3.4.1 Performance Indicators for Commercial Quality of Service Regulation

Commercial quality (CQ) indicators can be classified into four groups representing the main areas of interface between the customer and the utility:

- Connection
- Customer care
- Technical service
- Metering and billing

As pointed out previously, most of the indicators for commercial quality of service are typically time based. From the customers' perspective, timeliness in service provision or complaints resolution is at the core of their engagement with the utility. This is often codified in a customer service charter, which may or may not be derived from the overarching QoS regulation.

Some performance indicators for commercial QoS may be classified as "guaranteed," or subject to appropriate rewards or penalties depending on the performance of the utility. These will be discussed further in Section 3.4.3

Connection Services Indicators

Connection service indicators apply only to DSOs, and are applied by a large of number of NRAs in Africa. They deal specifically with assessing the DSO's timeliness in connecting new customers to the distribution network.

The importance of this indicator is two-fold: first, the timeliness in being connected to a distribution network and speedy clarification of the network access issues are both of high priority to customers, and second, connection is mainly related to distribution and is therefore subject to regulation of a monopoly activity.

Indicators used to assess connection services include:

- Response time to customer enquiries for connection to the network;
- Response time for cost estimation for simple works;
- Response time for connecting new customers to the network;
- Response time for disconnection upon customer's request; and
- Response time for switching a customer's supplier upon request (where choice is possible).

[6] CEER "CEER-BEUC 2030 Vision for Energy Consumers." https://www.ceer.eu/documents/104400/-/-/3b167ae3-9a7a-fd36-a02e-c64ad7595a51

Customer Care Indicators

While indicators for connection services apply exclusively to DSOs, indicators for customer care apply mostly to DSOs, but also to suppliers and TSOs. In Europe, most customer care indicators are guaranteed, with payment of compensation to the customer in case of non-compliance. This is not yet the case in Africa, though a few African NRAs are gradually introducing this concept. Customer care indicators include the following:

- Punctuality of appointments with customers;
- Response time to customer complaints;
- Response time to customer enquiries;
- Response time to customer voltage and/or current complaints;
- Response time to customer interruption complaints; and
- Response time to questions related to costs and payments (excluding connection).

Technical Service Indicators

Technical service indicators relate to distribution and/or transmission services, and therefore apply to DSOs and TSOs.

Handling technical service (e.g., voltage) complaints normally involves two steps: first is to verify, through performance measurements, whether any regulation or norm has been violated; second is the correction of the technical issue through appropriate work on the network. It is important that any customer complaint related to voltage disturbance is rectified without undue delay. The exact time needed to rectify the problem or to implement temporary solutions may vary, and will depend on the complexity of the given situation.

Technical service indicators include:

- Time between the date of receiving a VQ complaint and elimination of the problem;
- Time between a fuse failure and the DSO's restoration of supply;
- Window of advance notice of a planned interruption; and
- Time between an unplanned interruption and the restoration of supply.

Metering and Billing Indicators

Metering and billing indicators constitute a sub-set of CQ indicators related to customer metering and billing:

- Time for meter supply and installation (new connections)
- Time for meter inspection in case of meter failure;
- Time from the notice to pay until disconnection;
- Time for restoration of power supply after payment of full or part of outstanding bill following disconnection due to non-payment;
- Yearly number of meter readings by the regulated company; and

- ❖ Percentage of meter readings made within less time since the last one.

3.4.2 Monitoring Commercial Quality

There are two ways to monitor CQ:

- ❖ Monitoring the average value of the indicator (e.g., the average time for making a new connection); and
- ❖ Monitoring the percentage of cases ("compliance percentages") for which the utility complies with the time limit set by the NRA, i.e., the percentage of cases for which the limit was met (over the total number of cases) is below or above the standard (90%, for example).

For benchmarking purposes, it is important to note that the first method does not depend upon the country/utility-specific standard and is therefore comparable between countries (assuming that requirements of the same type are considered). The second method only provides a meaningful mode of comparison if the time limits to which it refers are the same, even if the standards themselves are not.

3.4.3 Penalties and Customer Compensation

Penalties and/or compensatory payments are tools available to a regulator to ensure compliance with CQ standards and incentivise efficient service delivery. CQ indicators are typically categorized into two categories based on the attendant consequences for non-compliance or under-performance: (1) overall indicators (OIs) and (2) guaranteed indicators (GIs).

OIs are minimum standards which need to be achieved by the utility, usually for a defined percentage of all instances. There are no penalties levied for failing to meet these standards. The regulator may, however, consider penalizing a utility that consistently fails to meet these standards over an extended period of time.

GIs are minimum standards which must be met for every occurrence of the service to which they refer. Penalties are levied where these guaranteed standards are not met. Typically, the customer affected by the poor service delivery is compensated in line with a pre-agreed rate approved by the regulator.

European regulators increasingly rely on GIs, based on the premise that GIs ensure that no customer category systematically receives sub-optimal service. GIs are also simpler to administer than other enforcement schemes and directly benefit customers.

In a number of African countries, regulators rely more heavily on OIs, due to reluctance to impose financial penalties on utilities that are not financially viable and struggle to maintain operations. In a recent review of its QoS regulations, the Energy Control Board (ECB) of Namibia clearly specified that "the minimum indicators given in this document are overall indicators except where specifically noted. Guaranteed indicators and associated penalties will not be implemented at this time but will be considered in future.[7]" This provision is not unusual given the current challenges facing the African power sector and the need to proceed gradually in the implementation of optimal best practices. Regulators must recognize the need for this transition and plan accordingly.

[7] ECB "Namibia Electricity Supply Industry, Quality of Service Standard, 2019

While GIs should be the ultimate goal in terms of incentivizing excellent service delivery, countries in Africa can observe and apply lessons learned from some Eastern European countries that are also pursuing a gradual transition from OIs to GIs over an extended timeframe. The example below, proposed for implementation by the Serbian energy regulator, may be useful.

Table 3.3 Proposal for the Gradual Introduction of CQ Guaranteed Indictors in Serbia

Group	**Overall Indicator**	**Associated Guaranteed Indicator**
Connection	Average time for response to customer request for connection	Response to customer request for connection within 5 days
	Average time for connecting new customers to the network	Connection of new customer to the network within 20 days
Customer Care	Average response time to customer voltage complaints	Response to customer voltage complaint within 5 days
	Average time to respond to a call	Response to call within 30 seconds
Technical Service	Average time between the answer to the VQ complaint and the elimination of the problem	Elimination of VQ problem within 60 days from answer to complaint
	Average time to restore supply in case of unplanned interruption	Supply restoration within 4 hours in case of unplanned interruption
Metering and Billing	Average time for meter inspection in case of failure	Meter inspection within 15 days from customer notification
	Billing accuracy (%)	Under 1% billing complaints
	Average time to settle billing complaints	Settling of billing complaint within 30 days

Source: Dr. Thyrsos Hadjicostas; VIS Economic & Energy Consultants, Remote Technical Workshop Series: Improving Investment Planning Through the Implementation and Enforcement of Quality of Service Standards

Case Study 7: Setting Context-Specific QoS KPIs in Namibia

In 2004, the Energy Control Board of Namibia (ECB) developed the Namibia Quality of Supply and Quality of Service Standards in line with the South African Rationalized User Specification series.

The ECB followed a consultative process to determine appropriate service quality standards for licensees in Namibia. The standards were developed as a framework for implementing voltage quality monitoring, measurement and reporting on service, and measurement and recording of network performance.

The ECB has since reviewed the 2004 Standards and made recommendations with regards to specific application of the Standards within the Namibian Electricity Supply Industry.

Through benchmarking against international standards and application practices, and in line with technological changes, the ECB recommended additional components or modifications to be incorporated into revised and updated Quality of Supply Standards. In reviewing the Quality of Service Standards, the ECB considered the experiences of the major licensees with the implementation of the 2004 Standards. For example, the provisions for penalties included in the 2004 Standards were never implemented, and the ECB opted to remove them from the updated version.

The approach to reviewing the Quality of Supply Standards differed significantly from that of reviewing the Quality of Service Standards. Since quality supply standards for most electrical equipment used in Namibia is determined by standards organizations and manufacturers outside Namibia, the Namibia Quality of Supply Standards align closely to these international requirements. This means that the Namibia Quality of Supply Standards are guided more by applicable international standards than any local conditions, particularly when it comes to compatibility requirements and measurement methods. The scope for adjustment is limited.

In contrast, the Quality of Service Standards are developed primarily with local conditions, network topology, customer needs, and economic realities in mind. While it is instructive to consider international examples, the primary drivers for these standards are local realities. As an example, utilities everywhere need to deal with restoring power after interruptions. However, the required speed of restoration and the acceptable number of interruptions per year must be aligned with local realities and expectations.

In its revised Quality of Service Regulations, Namibia has decided to suspend the application of GIs until such a time that the country is fully ready.

3.4.4 *Recommendations for Improving Commercial Quality of Supply Regulation in Africa*

To improve regulation on commercial quality of supply in Africa, NRAs may consider the following options and recommendations:

- **Regularly review (and revise, if necessary) CQ indicators, taking into account the development of national conditions and evolving customer expectations**. While it is important to consider international best practices in the development of CQ regulations, NRAs must ensure that CQ indicators are appropriate to the level of development of the national power sector. Furthermore, NRAs must confirm that relevant and accurate data form the underlying basis in setting the associated standards. It is also important to ensure that indicators are manageable and relevant to the local environment, as not every indicator is relevant at every stage and can be gradually introduced as the sector becomes more developed.

- **Encourage the harmonization of CQ indicator definitions in Africa**. A clear framework and harmonized parameters for the definition of CQ indicators can support streamlined benchmarking and identification of targets for further improvement. In addition, the development of regional power pools on the continent, necessitates harmonisation of indicators among the members of each power pool.

- **Ensure greater protection of customers through the gradual introduction of guaranteed indicators with automatic compensation mechanisms.** NRAs should gradually apply GIs with automatic compensation, or introduce an option to impose sanctions for failure to comply with OIs to incentivize better service delivery. A combination of the above options should be implemented for connection activities (the most important indicators), in order to improve utility performance. This recommendation is targeted mainly at DSOs, given their important direct relationship with customers. Automatic compensation payments should also be deployed gradually in all countries. From the customer protection point of view, the most efficient regulation is based on GIs, or minimum requirements set by the NRA where sanctions can be issued.

- **Ensure utilities undertake customer satisfaction surveys at prescribed regular intervals** (e.g., every two years), to assess how customers actually perceive the service they receive and enable the NRAs to identify gaps in and challenges with the CQ regulations.

- **Ensure the deployment of meters to all customer classes facilitate accurate, efficient billing**. African countries should also gradually introduce smart meters in in order to minimize billing inaccuracies and enable more efficient planning by utilities and consumers. NRAs should, however, be diligent in analyzing the cost-benefit impact of the switch to smart meters; countries should not initiate this transition until it makes economic sense to do so.

- **Utilize multiple mediums to monitor CQ indicators**. Regulators often rely solely on written reports and forms to collect data, which provide an incomplete picture of commercial quality of service. Other forms of communication, such as telephone and internet requests and complaints, should also be taken into account. NRAs should also regulate the performance of the service level provided to customers through communications such as phone, e-mail and online (e.g., website/apps), and visits to customer call centres. Regulators should consider not only the timeliness of utility responses, but also whether these responses are thorough and useful.

3.5 Developing Frameworks for Assessing Customer Satisfaction in the Electricity Sector

Customer satisfaction surveys serve as an empirical analysis tool with which the regulator and utility can monitor the level of service delivery from the point of view of the customer. It is particularly useful given that there may often be a major disconnect between the "high service levels" purportedly given by the utility and the customer's perspective of that same service as being unsatisfactory. Customer surveys can also be viewed as ex-post impact assessments of the efficacy of the standards imposed through QoS regulations, allow the regulator to assess whether the desired regulatory outcomes are being met or whether the utility is improving its performance over time, and indicate possible areas for review and adjustment.

Additionally, customer satisfaction surveys provide a platform for customers to convey their individual views on the quality of services being provided.

While some electricity utilities may periodically carry out customer satisfaction surveys on their own as part of their corporate monitoring and evaluation frameworks, this is not usually the case in Africa. The 2020 ERI report stated that only ten countries of the 36 surveyed have carried out any customer satisfaction surveys in the past five years.

Regulators should therefore mandate customer satisfaction surveys through their QoS regulatory standards.

3.5.1 Challenges to Implementing Customer Satisfaction Surveys in Africa

Absence of Mandatory Regulatory Frameworks

With the exception of a few countries, most NRAs on the continent do not mandate utilities to carry out periodic customer satisfaction surveys. Namibia's QoS Regulation, for instance, mandates that NamPower and other regional electricity distributors conduct customer satisfaction surveys at least once every two years. Without a regulatory mandate, it is unlikely that most utilities would complete this exercise.

Capacity Constraints

Utilities may be constrained by the time and resources required to carry out customer satisfaction surveys. To minimize the administrative burden on the utility, the regulator should specify a transparent process for conducting customer satisfaction surveys. Ideally, the survey should be carried out by an independent company engaged by the utility for that purpose. The regulator may have authority to approve the selection of the independent entity and of the survey instrument to ensure compliance with due process.

While it is not possible to survey every customer, the procedure must ensure that sample clusters sufficiently represent every customer class and cover an adequate geographical spread of the utility's area of operation.

Written questionnaires should employ simple, easily understandable questions to enable every class of customers to respond well. As much as possible, within the African context, translation into local languages is encouraged, especially for rural customers who may not be able to express their perception in the country's official language(s).

3.5.2 *Recommendations for Conducting Electricity Sector Customer Satisfaction Surveys in Africa*

- **NRAs should mandate the periodic conducting of customer satisfaction surveys as part of QoS Regulations.** Customer satisfaction surveys enable NRAs to assess the effectiveness of utility performance and associated regulatory interventions from customers' point of view. It also acts as an impetus for improving utility performance and identifying gaps in the various regulatory frameworks put in place by the NRAs.
- **NRAs should specify a transparent process for conducting customer satisfaction surveys**. An effective customer satisfaction survey must be seen to have been carried out objectively and independently, hence the need for clear guidelines on the process.

4 Cross-Cutting Issues

This chapter will address a number of cross-cutting issues related to improving economic and quality of service regulation in Africa. This is particularly important based on the fact that the ERI Reports show that even where countries have put in place rules and regulations for economic and quality of service regulation, the regulatory outcomes from such regulations remain below average.

In addressing the challenges to various aspects of economic and quality of service regulation in the foregoing chapters, these cross-cutting issues were frequently identified as hindrances on the ability of the regulator to develop and effectively implement regulations. They may also impede the effective implementation of the recommendations in this Guidelines report if not addressed.

Key amongst these challenges are institutional capacity, regulatory impact assessment, and data collection and management. Each of these challenges will be briefly examined below, and recommendations put forth on how to address these critical issues.

4.1 Institutional Capacity

4.1.1 Status of Institutional Capacity among Africa's Energy Regulatory Authorities

An effective regulator is a knowledgeable regulator and, hence, there is a need for NRAs to attract and retain knowledgeable staff and continually build staff capacity to effectively carry out their regulatory functions. As the power sector evolves, it is also important that regulatory staff are continually trained to keep up with evolving trends and provide innovative solutions to emerging regulatory issues and challenges.

The 2020 ERI Report showed while a number of regulators have notably improved in terms of strengthening institutional capacity over the past year, some regulators, especially the most nascent ones, still lack the necessary experience and technical capacity in key regulatory disciplines, and will need consistent capacity building support.

The ERI Report also identified weaknesses in the capacity of even the more mature regulators to enforce enacted rules and regulations. Also, the capacity to exert the levels of regulatory oversight and authority over regulated entities to achieve measurable outcomes for the sector is quite low. Without adequate technical capacity, regulators will struggle to implement the recommendations in this Guidelines report. Therefore, there is a clear need to address how some of the basic capacity gaps can be bridged.

4.1.2 Challenges to Institutional Capacity Development for Regulators in Africa's Power Sector

Prevalence of New Regulatory Bodies

While the continent has a couple of regulatory authorities that are over 25 years old, independent regulatory authorities are still to a large extent a relatively new trend on the continent, with most of African NRAs being less than 15 years old. In addition, a number of countries on the continent only recently embarked on power sector reform. Power sector experience and technical expertise still reside largely with the utilities, as opposed to the NRAs.

Absence of Core Regulatory Skills

While a number of regulatory staff may have fitting professional backgrounds in fields such as accounting, finance, economics, engineering, law, etc., utility regulation requires years of specialized training and experience to fully master. Often, when the pioneer staff for a regulatory authority are drawn from utilities and ministries of energy, there is often the wrong assumption that they know how to regulate, and special care is not taken at the beginning to provide the type of multidisciplinary training required to transition them from specialized professionals to economic/reliability regulators.

Lack of Funding for Capacity Building

For capacity building to be effective, it has to be provided on a continuous basis. However, experience has shown that while new regulators often receive capacity building support through grants and technical assistance programmes, this support often ends after two to three years. At the end of the initial start-up period, most regulators do not have independent sources of funding to enable continued capacity strengthening. Where NRAs are not independently funded (i.e., where funds for operations are sourced primarily from government subvention), capacity building is usually not considered a top priority.

Adequacy of Staff Remuneration and Incentives

Tied to funding is also the issue of ensuring that African NRAs can offer a remuneration scale that incentivizes staff to stay with the NRA rather than to move on to other sectors of the industry. Where the remuneration of utility companies is higher than what is offered by NRAs, the tendency is that NRAs will experience rapid staff turnover. Without dedicated funding for continued capacity building, institutional and technical knowledge disappear when more experience staff depart. Ideally, the NRA should be empowered to guarantee adequate remuneration for its staff, which should be comparable to that offered by the regulated utilities.

4.1.3 *Recommendations for Building Institutional Capacity for Regulators in Africa's Power Sector*

While this Guidelines report is not intended to fully address and provide solutions to the much larger challenge of institutional capacity in the Africa Power Sector, it is deemed necessary to offer some recommendations aimed at ensuring that certain urgent interventions are made. These recommendations include the following:

- **Regulators should undertake comprehensive skill or capacity needs assessments and develop a consistent training program to match it.** Given the very limited resources often available to regulators for capacity building, it is important that these plans ensure that staff capacity is built in those areas most needed by individual staff members and relevant to the execution of the regulator's strategic goals. A comprehensive needs assessment will include interviews with all regulatory staff members to understand their roles within the organization and to establish the skill gaps that have to be filled to enable better and more effective performance. Where multiple gaps are identified, these need to be prioritized in accordance with the most urgent and important goals of the NRA. The needs assessment plan can also serve as a basis to identify staff members' areas of strength. This will be especially useful where the NRA may have to rely on in-house cross-training among its staff members, with those who are more knowledgeable in each area supporting those who are less-knowledgeable or experienced.

- **NRAs should invest resources in training existing staff in key regulatory areas.** Capacity building should be a recurring item on the NRA's annual budget. A number of the well-established utility regulatory training institutions are unfortunately located outside the African continent, which makes it expensive for African regulators to participate regularly in their courses. The trend is, however, changing, with a few institutions in Africa offering comparative courses at lower rates. NRAs will also benefit from regional initiatives to establish centers of excellence for regulatory training across the continent. Beyond formal training courses, a very practical way of building capacity is through internships or twinning programs with other more established regulators, either within the continent or internationally. Through NARUC, USAID provides technical assistance to a number of regulators in Africa through partnership programs between African NRAs and U.S. State Public Service Commissions. In West Africa, the Economic Community of West African States (ECOWAS) Regional Electricity Regulatory Authority (ERERA) provides a platform that gives new regulators in the region the opportunity to undertake internship programs with more established regulators in the region. The 2020 ERI Report notes that the only three nascent regulators that scored above average in institutional capacity (Benin, Niger, and Sierra-Leone) are from the ECOWAS region, with two of them, Benin and Sierra-Leone, having taken part in the ERERA regional internship program in 2019. This demonstrates that collaboration between a region's newer and more mature regulators has its benefits. Based on the 2020 ERI Report, the top five performing countries (Uganda, Namibia, Tanzania, Zambia, and Kenya) are the more mature regulators on the continent, with an average age of 22 years. Conversely, the average age of the five worst performing regulators (Chad, Congo Republic, Gabon, the Central African Republic, and Mauritius) is just about seven years. This therefore makes a strong case for a more structured collaborative framework between mature regulators and nascent regulators in Africa to facilitate institutional strengthening.
- **In addition to training existing staff, NRAs should proactively work towards recruiting additional qualified staff.** In a number of cases, institutional capacity is hampered by the fact that the NRAs are understaffed. As a regulatory authority grows, and as the power sector develops, there is always a need to ensure that the right skill sets are brought in to meet changing needs. For instance, expertise in renewable energy/energy efficiency and gender mainstreaming, which was not considered necessary 15 years ago in the African regulatory landscape, is now key. Regulators must therefore always be proactive in identifying industry trends and dedicating resources to meet those changing needs through hiring and/or re-training.
- **While building capacity, regulators should put in place incentives to support staff retention.** This should include adequate remuneration, good working conditions, and packages that are comparable to those of government, utilities, and other regulated entities. Ideally, NRAs should determine its own staff remuneration policies. Truly independent NRAs will have the power to hire, fire, and determine the conditions of staff employment. Unfortunately, not every African regulator has been given this mandate, and there is therefore a need to address this at the governance level. An attractive staff remuneration package is not only an incentive to ensure that the NRA is able to attract and retain the best hands, it also acts as a mechanism against regulatory capture. In situations where staff of the utility company earn far more that regulatory staff, there is no incentive for staff to stay on if they are offered a position at the utility. Since staff members are typically not bound by the employment restrictions that commissioners face upon leaving office, it is easy to seek new employment

with better compensation or working conditions. It is therefore important that policy makers and regulators take this into consideration when devising salary scales and other conditions of employment for NRA staff.

- **Regional regulators or regulatory associations can also play key roles in institutional strengthening, especially with regards to supporting newer regulators in the region.** Given the rapid growth of regional power pools and regional power markets, regional institutions can help to ensure that the capacities of the constituent NRAs are built up to enable the effective functionality of the regional/continental market. In the last couple of years, ERERA has institutionalized a training program on electricity markets and regulation that is offered to all ECOWAS NRAs. Given the level of disparity in power sector development of the different member states, the course is structured in a way that allows nascent regulators to be trained as a group. Together with the ERERA's internship program, this training program has contributed a great deal in building the capacity of nascent regulators in the region, while also sensitizing the more matured regulators to the regulatory framework for the regional electricity market**.**

Case Study 8: Building Institutional Capacity at Togo ARSE

Autorite de Regulation du Secteur de l'Energie Electricite (ARSE) was set up as an independent regulator for the electricity sector in Togo in 2000 by virtue of Articles 11-14 of Law nº 2000-012. In 2011, law n° 2011-024 further entrusted the regulation of the water and sanitation sector to ARSE.

The Management Committee of ARSE is made up of 3 members, appointed by decree by the Council of Ministers for a term of four (4) years, renewable once. They elect from among themselves a Chairman for a non-renewable period of two (2) years during a term of office. The Chairman of the Management Committee also serves as Chairman of the Regulatory Authority. The Director General, who is also appointed by the Council of Ministers is in charge of the technical, administrative and financial management of the Regulatory Authority and the implementation of the decisions of the Management Committee.

The Management Committee is responsible for the recruitment of staff of ARSE and also have powers to fix staff remuneration. Staff recruitment is outsourced to competent human resources agencies to ensure that highly qualified and skilled persons are employed by the Authority. In order to ensure the retention of its staff members, ARSE Management ensures that staff salaries are comparative to that of the utilities in addition to providing other incentives such as bonus pays, family health plans as well as insurance plans.

In order to ensure that staff members continue to build capacity to enable them to effectively carry out their regulatory functions, a staff capacity building program is drawn up annually by the administrative department in collaboration with other departments. Every staff member is typically slated to attend at least one training program per year. The Capacity Building Plan is based on training needs assessment for each staff member which is aligned to the yearly institutional goals. The department is also responsible for the implementation and monitoring of the training plan. The training programs are typically based on the employee's area of core competence as well as on general regulatory issues based on international best practices. The second category of training on regulatory issues is somewhat of a challenge to ARSE since most international regulatory training programs are offered in English Language and the cost of such international programs, including travel cost is also a barrier.

ARSE has also been actively involved and participated in a number of regional training initiatives as well as stakeholder dialogues put in place by ERERA, the ECOWAS regional regulator. This has helped in building the capacity of its staff members on the ECOWAS regional electricity market, where Togo utilities are active participants.

Despite some of the constraints in the area of capacity building, ARSE has in place sufficient number of well qualified and trained regulatory staff across every department to effectively carry out its regulatory mandate and continues to work towards the further strengthening of its institutional capacity.

4.2 Regulatory Impact Assessments (RIAs) in the Power Sector

RIAs offer a systematic approach to critically assessing the positive and negative effects of proposed and existing regulations and non-regulatory alternatives.[8] Most developed countries recognize RIAs as key instruments in regulatory decision making. RIAs are becoming increasingly popular in developing countries as well.

An effective RIA will include both ex ante appraisal of a proposed regulation and an ex-post evaluation of existing regulations. This two-pronged approach ensures that not only is a full appraisal done before a new regulation is put in place, but the regulator will also have a tool to assess the efficacy of

[8] OECD "Regulatory Impact Analysis" https://www.oecd.org/regreform/regulatory-policy/ria.htm

regulations that have been enacted previously to gauge if the anticipated regulatory outcome has been met.

4.2.1 Introduction to Regulatory Impact Assessments in the Power Sector

Stakeholder consultation is one of the principal requirements of effective regulation, and RIAs fall within the purview of stakeholder consultations. A number of regulators in Africa have established administrative rule making processes that require the regulator to ensure wide stakeholder consultation prior to the enactment of any new rules or regulations. While this is considered best practice, the 2020 ERI Report shows that stakeholder consultation is mandatory in just 64% of the countries surveyed.

Rule-making typically involves the steps outlined below. The RIA process should be as transparent as possible to ensure that all potential scenarios are highlighted, with a view toward arriving the best suited solution.

- A typical rule-making process starts with the regulator preparing and issuing a consultation paper on the proposed new rule. This consultation paper should be very well researched, as it will form the basis of the ex-ante appraisal of the regulation, elaborating what issue(s) the regulation seeks to address and presenting different scenarios and outcomes. It should also include a position on the possible scenarios if no interventions are made by the regulator.

- The consultation paper should be widely circulated to all key stakeholders and published on the regulator's website. The regulator should specify a given timeframe within which stakeholders and the general public are invited to present their written responses to the regulator. Upon the expiration of the deadline, the regulator will typically convey a public hearing during which stakeholders are given the opportunity to further elaborate on their written submissions, while others may simply make oral comments on the proposed new rule.

- The regulator will consider all feedback, comments and contributions received during this public consultation process in coming to a final decision on the proposed new rule.

4.2.2 Challenges to Conducting Regulatory Impact Assessments in Africa's Power Sector

The rule-making process discussed above represents the best practice. However, most electricity regulatory authorities in Africa have not put in place a transparent rulemaking process that rigorously appraises the basis for every new rule and allows for wide stakeholder participation.

Inadequate or No Stakeholder Consultation

A rigorous ex-ante appraisal framework pre-supposes that the regulator has done an in-depth assessment of all of the potential issues and challenges relating to any proposed new rule, and in the process has also consulted with all relevant stakeholders.

The reality, though, is that more often than not, especially for new regulatory bodies, new regulations are developed mostly by adapting (or even directly adopting) existing regulations from other jurisdictions, without taking the local power sector context into account.

Adaptation of Regulatory Precedents without Considering Local Context

Relatedly, while regulatory precedents play a useful role in rule-making, and there is a lot of benefit in learning from what has taken place in countries with older regulators, for each rule-making process to be effective, regulators must go through the entire rule-making process to ensure that each solution is the best fit for the country at the current stage of its power sector development.

In QoS regulation, for instance, while all countries generally monitor similar indicators, it does not make sense to assume that standards set in a country with a relatively mature power sector, in which quality standards have evolved over time, will be appropriate for another country that is just beginning to implement its power sector reform program.

No Implementation of Ex-Post Impact Assessment

Regulatory bodies in Africa tend to emphasize ex-ante appraisal in rule-making, while neglecting to perform ex-post evaluation of regulations. A regulator should aim to review the impact of a regulation two to three years after it has been in place to assess if the intended regulatory outcomes have been achieved. If not, the regulator should conduct a new RIA to identify gaps and challenges and propose appropriate alternative options.

The very poor average scores in both the 2019 (0.357%) and 2020 (0.393%) ERI ROI shows that even those regulators that have done well on regulatory substance by putting in place rules and regulations for the governance of the sector have not achieved the desired impacts. This highlights the need for regulators across the continent to conduct ex-post RIAs.

4.2.3 *Recommendations for Implementing Effective Regulatory Impact Assessments in Africa's Power Sector*

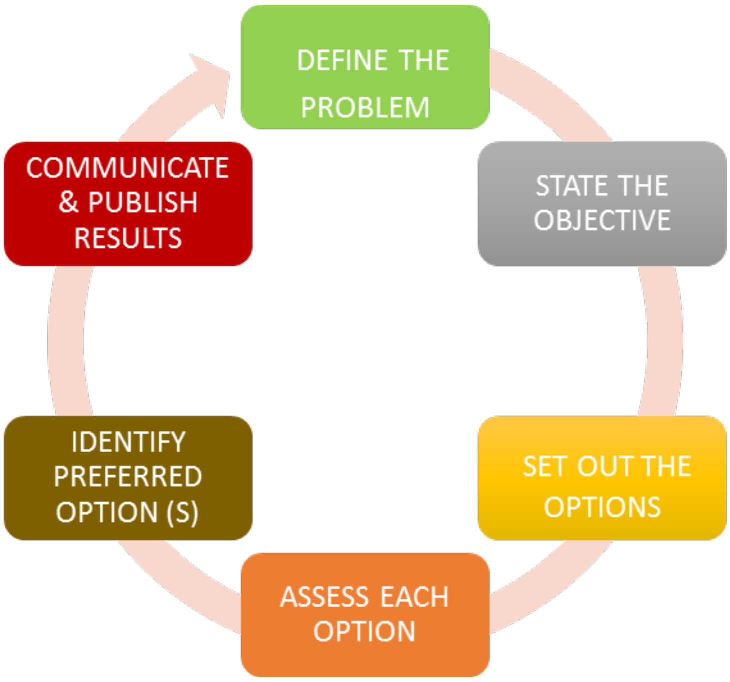
In order to ensure that regulators have a robust framework for the effective implementation of RIAs in the power sector, the following recommendations are advocated:

- **Every regulator should proactively put in place a framework for undertaking RIAs.** This framework should go beyond the basic administrative process for rule-making and clearly stipulate the regulator's objectives and processes for completing RIAs. The Handbook for Regulatory Impact Assessment published by the Organisation for Economic Cooperation and Development OECD[9] outlines the fundamental components of the process, as outlined below:
    - Define the regulatory problem to be addressed. This will usually fall within three main categories: market failure, regulatory inefficiencies, and new policy targets or objectives.
    - Identify concrete regulatory options for addressing the regulatory problem.
    - Collect data through public consultations, telephone and face-to-face interviews, paper questionnaires, online surveys, focus groups, etc.
    - Assess alternative options. This central step often takes the form of a cost-benefit analysis, but can also be a cost-effectiveness analysis or a risk analysis. Options assessed must include the "no policy or regulatory change" scenario.

[9] OECD. 2008. Introductory Handbook for Undertaking Regulatory Impact Analysis. Paris: OECD Publishing

- Identify the preferred regulatory option/s. Once the different options have been identified and scrutinized the regulator will identify the most efficient option.
- Communicate and publish the results of the RIA. This allows for further exchange with stakeholders and improves the general transparency of the regulatory process.

Figure 4.1 RIA Process



- ❖ **NRA should build internal regulatory capacity to conduct RIAs.** While efforts should be made to ensure that some NRA staff undergo formal training programs on RIAs, those staff should also be mandated to provide in-house training to other staff members.
- ❖ **NRA should ensure Publication of RIA results on their website.** Transparency is a core competence of a regulator, and publishing the results of an RIA on the regulator's website enables all stakeholders to assess the justification behind the final decision.

4.3 Data Management

Quality data is critical for effective regulatory rule making, standard setting, and performance monitoring. Without good qualitative and quantitative data, a regulator will inevitably make errors of judgment in critical regulatory decisions.

4.3.1 Data Management in Power Sector Regulation

Power sector data includes details on utility technical and financial performance, consumption patterns, customer interaction data, etc. Each of these sectors requires different data sets derived from a variety of sources for a variety of uses. Accordingly, regulators need to develop effective data management strategies.

With the increasing complexity of the power sector and the growing influence of information and communication technology across the industry, utilities in developed countries are investing significant resources in data management architectures with advanced analytics to better understand the business environment and make well informed investment decisions.

In most developing countries, including those in Africa, utilities struggle to keep pace with global trends in data analytics and management. This limits regulators' ability to access quality data. Economic and quality of service regulation, in particular, rely a great deal on accurate and regularly updated data to guide decision making.

4.3.2 Data Management Challenges for Regulators in Africa's Power Sector

African electricity regulators face a number of challenges with regards to data management. While the ERI Reports do not specifically address the issue of data asymmetry, this remains one of the key challenges faced by NRAs. Utilities will always have better access to and understanding of their own data. However, a number of the interventions needed to strengthen economic and quality of service regulation depend largely on regulators' access to reliable data to serve as benchmarks.

Further, many regulators and utilities lack the in-house capacity to effectively collate and analyze the available data. As stated earlier, many African countries struggle to implement cost-reflective tariffs because the underlying data on which the tariff models are based are flawed or incomplete. The case of NERC's initial implementation of the MYTO showcased the impacts of inaccurate and incomplete data on economic regulation. The major challenge with MYTO I was that some of the underlying assumptions with regards to forecasted electricity demand, expansion of the transmission and distribution networks, capital expenditure investments, and revenue collection efficiencies were inaccurate.

Data management presents similar challenges in setting KPIs for quality of service regulation across the continent. When Namibia first adopted its QoS Regulations, it relied heavily on the South African Regulation with the attendant consequences of setting standards based on data that was not relevant within the Namibian Context.[10] Fortunately, the regulator learned from this experience, and has now put in place a very good QoS Regulation based on relevant local data that is regularly reviewed in line with best practices.

4.3.3 *Recommendations for Developing Improved Data Management Systems in Africa's Power Sector*

A robust data management framework should be an integral part of a regulator's decision making toolbox. By enhancing accountability and assigning data ownership, these frameworks enable more efficient, accurate data collation and provide a consistent foundation for regulatory audits. Regulators must take an organization-wide approach to data strategy (structure, process, enablers, etc.) to ensure that the right data is captured from the beginning, the right set of tools and technologies are deployed, and that data is kept consistent across data management systems.

A regulator's data management framework put in place by the regulator should also make clear and transparent provisions for conducting regulatory audits, including the frequency at which such audits should take place.

A number of practical steps can be taken by the regulator to mitigate and minimize the challenges of data management, even in the absence of very sophisticated software or analytical tools.

[10] Electricity Control Board of Namibia "Quality of Supply and Service Standards Implementation and Benchmarking Framework"

NRAs are encouraged to:

- **Set up in-house research units for data collection**. For the regulator, utility reports constitute the primary source of information. Such historical data serves as the basis for establishing benchmarks in standards or target setting. In-house research units or departments may supplement utility data by working with relevant stakeholders to collect and analyze relevant industry data.
- **Mandate that utilities adopt and implement a uniform system of accounts (USoA) for cost of service studies, especially as interconnected power pools are evolving all over the continent.** As much as possible, regulators should require that data is reported in a uniform, consistent format. This is especially useful among regional blocks where the development of regional power pools pre-supposes the need to meet a basic level of harmonization with respect to certain regulatory mandates. When ECOWAS approved the Directive on the Organization of the ECOWAS Regional Electricity Market, one of the obligations for utilities was to ensure transparent cost separation mechanisms – even for utilities that remain vertically integrated – through a USoA. ERERA is working with development partners like USAID to assess how other countries in the region might benefit from the kind of technical assistance made available to Nigeria and Senegal on the USoA implementation. ERERA is also encouraging collaboration between regulators that have the USoA in place and those that do not to ensure that every country in the region meets this obligation within a certain timeframe. Such regional initiatives can be very effective in ensuring the uniformity of data across certain regulatory jurisdictions.
- **NRAs should encourage the development and use of country specific long-term forecasting tools for econometric and technical analysis.** This will enhance the capacity of NRAs in core areas like tariff setting, integrated system planning, and load forecasting and generally improve regulatory outcomes in economic and technical regulation.
- **Consider adopting electronic information management systems.** This would not only dramatically enhance the ease and accuracy of data entry and analysis, but would also ensure seamless upload of data from the utility to the regulator. Cost remains a barrier to the adoption of electronic management information systems for many African regulators, but NRAs may consider purchasing a more affordable system that can be upgraded over time. This could also be a target area for impactful technical assistance interventions.
- **Establish relationships with other entities such as tertiary institutions as collaborators for research, data collection, and analysis.** Where regulators do not have the in-house capacity for research and data management, or where it is prohibitively expensive to run a data management system within the NRA, a good option is to enter into a collaboration agreement with a tertiary research institution (academic institution, data analytics firm, etc.) whose primary focus is to gather and analyze relevant power sector data. Even for regulators that do have in-house resources, such institutions can perform data audits.

5 Conclusion

The importance of effective and efficient regulatory frameworks for economic and quality of service regulation cannot be overemphasized. Both are critical to cultivating an enabling environment for investment and supporting sustainable electricity sector development.

In Africa, where most electricity utilities are still state owned and struggle with financial viability and liquidity, it is even more important for regulators to embrace innovation to develop workable and effective regulations that will enable utilities to recover their costs of providing reliable services at rates that are just and reasonable.

While this Guidelines report has attempted to highlight and emphasize international best practices in economic and quality of service regulation, it continually reiterates the need to adapt these practices to local conditions. Experience shows that a gradual approach towards implementation of international best practices yields better results by allowing time for stakeholders to plan future production or consumption according to realistic cost expectations, avoiding the risk of market or rate shock, and enabling regulators to adjust their methods through an iterative process to achieve the desired regulatory outcomes.

Case studies of some African NRAs that have implemented successful economic and quality of service regulations highlights the fact that it is indeed possible to achieve effective regulation if due attention is paid to developing strong institutional capacity and learning from experience. These success stories show that with effort and persistence, African electricity regulators possess enormous potential to improve the state of power sector regulation on the continent.

This Guidelines report has also stressed the need for NRAs to address the cross-cutting issues discussed, as they all have a direct impact not just on economic and quality of service regulation, but on all aspects of utility regulation. A good and effective electricity regulator must prioritize continuous capacity building, robust stakeholder engagement, and data management and analysis to keep pace with the regulated industry, support an enabling environment for investment, enhance the financial viability and efficiency of the sector, and ensure universal access to safe, reliable, and affordable electricity across Africa.

It is expected that this Guidelines report will serve as a roadmap for regulators, utilities, and policy makers seeking to advance economic and quality of service regulation in Africa's power sector. Not all recommendations will apply to every country. Each country should identify the most critical interventions based on its unique context and on its ERI sub-index scores, and adapt those interventions accordingly. In doing so it is envisioned that countries will be well positioned to improve their performance in subsequent ERI reports.

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For questions regarding this publication, please contact
Rachel Estrada (restrada@naruc.org)
or
Erin Hammel (ehammel@naruc.org).

National Association of Regulatory Utility Commissioners (NARUC)
1101 Vermont Ave, NW, Suite 200
Washington, DC 20005 USA
Tel: +1-202-898-2210
www.naruc.org