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PRIMER ON PRIMARY DRIVERS OF ELECTRICITY TARIFFS FOR UTILITY REGULATORS

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PRIMER ON PRIMARY DRIVERS OF ELECTRICITY TARIFFS FOR UTILITY REGULATORS

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John obtained the Chartered Financial Analyst (CFA) designation in 1993, and continues to participate in the CFA Continuing Education Program while participating as a member of the CFA Institute and the CFA Society of Chicago. He served on the Board of the Society of Utility and Regulatory Financial Analysts (SURFA) from 1998 to 2008.

John served as a member of the National Association of Regulatory Utility Commissioners and its Committee on Gas, Committee on Consumer Affairs, and Subcommittee on Pipeline Safety during 2011-2016, the United States Department of Transportation Technical Hazardous Liquid Pipeline Safety Standards Committee during 2014-2016, and the Gas Technology Institute Public Interest Advisory Council during 2013-2016. He earned an MBA with a concentration in Finance from Michigan State University.

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List of Acronyms

ATC&C	Aggregate Technical, Commercial, and Collections
D	Depreciation and Amortization Expense
EEI	Edison Electric Institute
EIA	Energy Information Administration
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Generally Accepted Accounting Principles
IFRS	International Financial Reporting Standards
KWh	Kilowatt-hour
O&M	Operation and Maintenance Expense
PPA	Power Purchase Agreement
ROE	Return on Equity
T	Income Tax Expense
U.S.	United States
USoA	Uniform System of Accounts
WACC	Weighted Average Cost of Capital

1. Introduction

With the support of the United States Agency for International Development (USAID) – Energy Division, Office of Energy & Infrastructure, the National Association of Regulatory Utility Commissioners (NARUC) has undertaken the task of developing a Cost Reflective Tariff Toolkit. This toolkit is intended to constitute several short practical primers that can be used by utility service regulators in countries with emerging economies to design rates that are based on actual cost of service and to effectively engage the public and key stakeholders in the decision-making process.

1.1. Objective

The objective of this primer is to help utility regulators around the world understand the primary drivers of electricity tariffs based on the revenue requirement concept, with a specific focus on the expenses that are incorporated into revenue requirements. These components are primary drivers of effective cost-based ratemaking and developing cost-reflective tariffs.

1.2. Scope

This primer focuses primarily on describing the expenses that are incorporated into revenue requirement calculations that regulators in countries with emerging economies may want to consider when evaluating expenses for use in determining the utility revenue requirement in tariff-setting. Secondarily, rate base components of revenue requirements are also covered. This description is significantly based on U.S. utility regulators' practices but also incorporates topics of interest to utility regulators in emerging economies by including some observations to incorporate regional differences between the U.S. and countries with emerging economies.

1.3. Organization

This primer is organized as follows:

Section 2 provides an electricity tariffs overview.

Section 3 explains the need for cost-reflective tariffs.

Section 4 describes the need for high quality accounting data.

Section 5 describes typical expenses incorporated into revenue requirements.

Section 6 explains typical rate base assets and liabilities incorporated into revenue requirements.

Section 7 categorizes total bill impacts to end-users by distribution, transmission, and generation.

Section 8 summarizes primary drivers of electricity tariffs.

Section 9 concludes with final remarks.

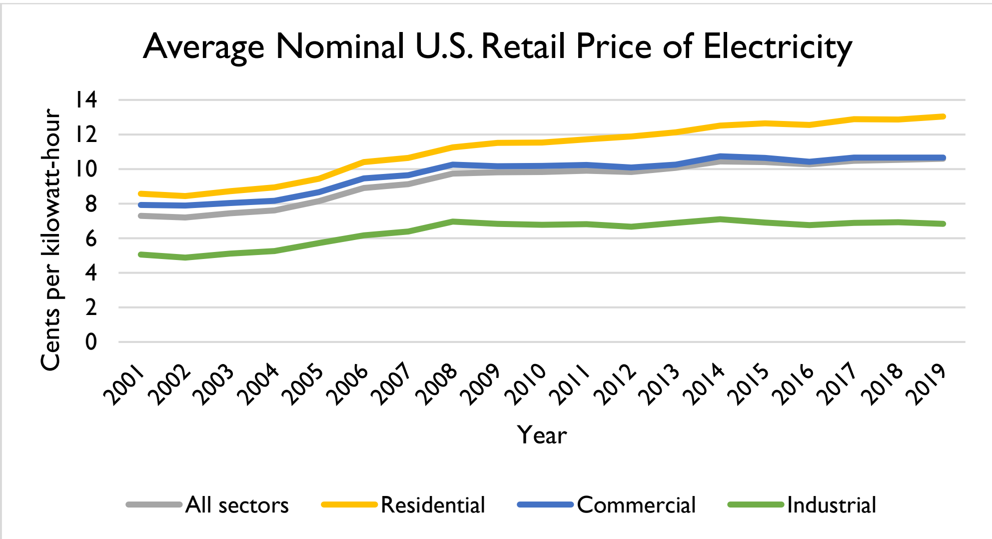
2. Electricity Tariffs Overview

Regulated electricity rates are specified in tariffs. A rate is a standard unit charge for service rendered by a utility to its customers. Tariffs are published legal documents that detail the utility's rates and service rules for specific utility services and the general terms and conditions under which services are provided. Tariffs are approved by the jurisdictional regulatory authority. An electric utility must abide by the approved tariff until it is subsequently changed by the regulatory authority. The existence of tariffs avoids the need for individual customer contracts, ensures that prices and services are transparently documented, and mitigates price discrimination concerns.

The goal of electric utility regulation is to incorporate reasonable rates for the provision of safe and reliable electricity service into the tariff. Reasonable rates are determined based on identifying the costs necessary to provide safe and reliable electricity service. This process of setting cost-reflective tariffs is alternatively referred to as cost of service regulation, rate of return regulation, traditional utility ratemaking, or conventional utility ratemaking.

Tariff prices in the United States are typically expressed on a cents per kilowatt-hour basis. The average retail price of electricity in the United States gradually trended upward in nominal terms during the last two decades, as shown in Figure 1 which is based on data gathered by the U.S. Energy Information Administration (EIA).[1]

Figure 1



For tariff purposes, electricity customers are primarily categorized as residential, commercial, and industrial customers. The residential sector refers to small-sized private household establishments, commercial refers to medium-sized non-manufacturing businesses, and industrial refers to large-sized manufacturing and other heavy businesses. Different rates apply to each sector, as shown in Figure 1. Residential rates are the highest and industrial rates are the lowest.

The upward trend in nominal U.S. electricity prices reflects increasing nominal costs over the last two decades. The annual growth rate in nominal U.S. electricity prices over this time period has been 2.5%

[1] Energy Information Administration Electric Power Annual 2019 Table 2.4, October 2020 and Electricity Data Browser.

across all sectors, 2.9% for residential, 1.9% for commercial, and 2.0% for industrial. By comparison, the general U.S. inflation rate has averaged 2.5% over this time period.

Because the inflation rate of electricity service matches the general inflation rate resulting in an average price increase in real terms of 0.00%, it would be tempting to conclude that general inflation has simply been the primary driver of electricity tariffs over this period. However, that simplistic conclusion would gloss over many important details of how electricity tariffs are set.

A regional review within the United States demonstrates that the average U.S. electricity price expressed in cents per kilowatt-hour can vary significantly across jurisdictions. U.S. electricity tariffs are set by state regulators based on the unique circumstances in each state. Figure 2 shows the average 2019 residential price by U.S. region and state.[2] The average residential price varies from a low of 9.71 cents/kWh in Washington to a high of 32.06 cents/kWh in Hawaii.

Figure 2

2019 Average Monthly Bill- Residential

(Data from forms EIA-861- schedules 4A-D, EIA-861S and EIA-861U)

State	Average Price (cents/kWh)	Average Monthly Bill (Dollar and cents)
New England	**21.10**	**126.65**
Connecticut	21.87	150.71
Maine	17.89	100.53
Massachusetts	21.92	125.89
New Hampshire	20.05	120.04
Rhode Island	21.73	121.62
Vermont	17.71	97.18
Middle Atlantic	**15.80**	**107.89**
New Jersey	15.85	105.07
New York	17.94	103.60
Pennsylvania	13.80	115.47
East North Central	**13.39**	**102.40**
Illinois	13.03	92.37
Indiana	12.58	120.74
Michigan	15.74	100.23
Ohio	12.38	108.15
Wisconsin	14.18	95.52
West North Central	**11.86**	**110.09**
Iowa	12.46	108.04
Kansas	12.71	113.26
Minnesota	13.04	99.02
Missouri	11.14	117.82
Nebraska	10.77	108.08
North Dakota	10.30	114.27
South Dakota	11.55	120.60

[2] Energy Information Administration Electric Power Annual 2019 Table 2.7, October 2020 and Electricity Data Browser.

South Atlantic	**11.93**	**130.04**
Delaware	12.55	119.16
District of Columbia	12.98	97.62
Florida	11.70	129.65
Georgia	11.76	131.84
Maryland	13.12	127.92
North Carolina	11.42	123.25
South Carolina	12.99	144.73
Virginia	12.07	135.46
West Virginia	11.25	121.90
East South Central	**11.36**	**134.81**
Alabama	12.53	150.45
Kentucky	10.80	120.08
Mississippi	11.27	135.87
Tennessee	10.87	132.33
West South Central	**11.17**	**128.17**
Arkansas	9.80	109.46
Louisiana	9.80	120.70
Oklahoma	10.21	113.93
Texas	11.76	134.07
Mountain	**11.81**	**98.94**
Arizona	12.43	126.09
Colorado	12.18	83.07
Idaho	9.89	93.83
Montana	11.13	95.43
Nevada	12.00	106.83
New Mexico	12.51	80.04
Utah	10.40	75.63
Wyoming	11.18	96.53
Pacific Contiguous	**15.65**	**100.52**
California	19.15	101.92
Oregon	11.01	100.35
Washington	9.71	94.49
Pacific Noncontiguous	**28.30**	**151.94**
Alaska	22.92	127.29
Hawaii	32.06	168.21
U.S. Total	**13.01**	**115.49**

Also, the annual 2001 to 2019 growth rate in U.S. electricity prices of 2.5% also varies significantly across jurisdictions. A review of the regional EIA data in Figure 2 to past EIA data shows a high of 5.6% for the Pacific Noncontiguous region and a low of 1.1% for the West South-Central region. A finer slice of the same data by state reveals a high of 5.8% for Hawaii and a low of 0.6% for both Louisiana and Nevada. This dispersion around the mean reflects diversity across jurisdictions and suggests that the drivers of tariffs are also different in diverse jurisdictions.

The components of cost of service regulation can reveal drivers of electricity tariffs. An important term used in utility cost of service regulation is "revenue requirement." The annual revenue requirement represents the total amount of annual revenue that a utility must collect from customers in order to recover all annual costs of providing beneficial electricity service, including a reasonable return on its investment. Stated as a series of general equations:

Cost of Service = Revenue Requirement

Revenue Requirement = Expenses + Reasonable Return

Expenses = O&M + D + T

- O&M = Operation and Maintenance Expense
- D = Depreciation and Amortization Expense
- T = Income Tax Expense

- Reasonable Return = Rate Base * Cost of Capital
- Rate Base = Net investment in assets after accumulated depreciation and liabilities

Each of these revenue requirement components can be a driver of change in electricity tariffs. At first glance, these equations and components may appear simple, but each component must be rigorously supported, analyzed, and scrutinized before the revenue requirement is determined. Behind each component defined above are hundreds or even thousands of individual calculations.

The revenue requirement components have their root in the financial statements. Expense components, including operation and maintenance, depreciation and amortization, and income tax, consist of expenses from the income statement and are discussed in Section 5. Rate base components come from the balance sheet and are discussed in Section 6. The cost of capital is discussed in NARUC's *A Cost of Capital and Capital Markets Primer for Utility Regulators*[3] that describes the development of an authorized rate of return based on a weighted average cost of capital (WACC) composed of debt and equity capital investment.

Financial statements are generated by an accounting system. NARUC's *Regulatory Accounting: A Primer for Utility Regulators*[4] describes several types of accounting systems, including GAAP, IFRS, income tax, and regulatory accounting. Virtually all utilities maintain at least three sets of books: GAAP or IFRS accounts for external reporting, tax accounts, and regulatory accounts. Regulatory accounting is designed to identify and categorize the costs of providing service and provides a basis on which to calculate the revenue requirement.

The Regulatory Accounting Primer highlights how the Uniform System of Accounts (USoA) provides a significant foundation for regulatory accounting and is used by virtually every electric utility in the United States and is gaining widespread support throughout the world.

The calculation of the revenue requirement is founded on the test year concept. A test year is a twelve-month period during which the expenses, rate base, and cost of capital are determined. Because ratemaking is prospective and forward-looking, the goal of the test year is to match the recovery of costs with the incurrence of costs. A future test year incorporates projected revenue requirement

[3] "A Cost of Capital and Capital Markets Primer for Utility Regulators." NARUC .https://pubs.naruc.org/pub.cfm?id=CAD801A0-155D-0A36-316A-B9E8C935EE4D

[4] "Regulatory Accounting: A Primer for Utility Regulators." https://pubs.naruc.org/pub.cfm?id=EE6402E5-155D-0A36-31F8-36FEBB6D4E44

components that come as close as possible to replicating the first year of the time period when the rates will be in effect.

Sometimes, a historical test year can serve as an adequate foundation, but the forward-looking goal remains the same, so adjustments and normalization must be applied for non-recurring, infrequently recurring, and regularly recurring components. Some regulators may set rates for multi-year test periods and thus may be working simultaneously with multiple future test years.

Revenue requirements change over time and need to be updated periodically. Although the legal process to accomplish a tariff change varies by jurisdiction, a tariff change can be triggered by a utility request, a regulator investigation, a stakeholder complaint, or simply the passage of time. The utility can file a rate case to request a tariff increase.

In most jurisdictions, the regulatory body may be able to initiate an investigation if it suspects that a tariff decrease may be justified. Likewise, a customer or other stakeholder may be able to initiate a complaint if it suspects that a tariff decrease is necessary. Alternatively, the regulatory calendar can set a pre-determined schedule to review tariff adequacy.

Once a tariff review filing is made and a proceeding is initiated, the goal is to expeditiously, effectively, and efficiently process the case and then revise the tariffs as warranted. However, the process must allow adequate time for due process for stakeholders to review and analyze the extensive supporting data justifying the tariff change, submit alternate proposals, and commissioner deliberations.

Most U.S. states have statutory rate case deadlines ranging from 6 months to 12 months. The commission must complete the entire proceeding from the initial filing to issuing a final order on the tariff change within the statutory timeframe.

3. The Need for Cost-Reflective Tariffs

The objective of cost-based tariff-setting is to balance the interests of investors and customers. Investors seek a reasonable return on investment and customers seek a reasonable price. Cost-reflective tariffs are the primary tool to accomplish both objectives simultaneously. The goal of this regulatory compact is to avoid both overcompensation and under-compensation by allowing full cost recovery for prudently incurred costs while disallowing imprudently incurred costs.

This tariff-setting construct imposes discipline that removes the utility's monopoly ability to earn a return significantly in excess of its cost of capital while providing a reasonable opportunity to earn the cost of capital. As such, cost-reflective tariffs minimize both upside and downside earnings opportunities.

As explained in NARUC's *A Cost of Capital and Capital Markets Primer for Utility Regulators*, utilities are required to raise capital from investors in order to provide safe, reliable, and affordable service to customers. Utility service is provided through investments in infrastructure that is constructed to last for multiple decades, which makes utilities among the most capital-intensive industries. While the *Cost of Capital and Capital Markets Primer for Utility Regulators* emphasizes the need for an adequate level of authorized ROE to encourage investment, the ability to actually earn the authorized ROE through tariff-setting is equally important.

Cost-reflective tariffs provide a needed signal to investors that depend on steady revenue streams and cash flows to invest further in needed utility infrastructure. Utility management has a fiduciary responsibility to deploy investors' capital productively. Investors recognize the importance of regulatory and stakeholder relationships and expect utility management to provide safe, reliable, and affordable service to customers in order to preserve and enhance the value of their invested capital.

In many ways, the interests of investors and customers are aligned and not in conflict and can become more aligned through the implementation of regulatory policy. Regulators are more effective at serving customers when they harness investors' desire to provide capital rather than constrain it.

Investors evaluate business risks and, for utilities, one of the most important types of business risk is regulatory risk. Investors take into account the timeliness of regulatory rate approvals, the forward-looking nature of the revenue requirement components and, of course, the authorized ROE, but also the opportunity provided for the utility to actually earn the authorized ROE. Metrics related to leverage and cash flow that are crucial to investors will be impacted by regulatory decisions.

Regulatory quality is assessed by investors when judging a utility's risk. Investors evaluate regulatory risk by understanding the regulatory climate because it is an important component of assessing risk and determining the value at which they are willing to invest in regulated utilities.

A lack of timeliness of regulatory approval and/or a backward-looking test year is often referred to as "regulatory lag." Regulatory lag may lead to an earned ROE that falls short of the authorized ROE, thus negatively impacting investors' evaluation of regulatory quality and risk.

While a short-term perspective of regulatory lag may appear to indicate that a delayed or minimal rate increase helps customers, a long-run perspective indicates that regulatory lag actually harms customers by increasing the cost of capital, and thus, the revenue requirement over time. A perpetually inadequate level of electricity tariffs impact utility financial viability.

The risks faced by utility investors are important to utility customers because risks to investors get reflected in the capital costs to the utility which are ultimately paid for by customers. Regulatory risk as perceived by investors impacts the availability and cost of capital. When investors perceive higher risk, the corresponding costs of debt and equity increase. If investors are less willing to provide capital, capital is less cost-effective for customers.

For example, rating agency downgrades generally result in higher interest rates on newly-issued debt securities. A utility downgrade would place upward pressure on the embedded cost of debt, as new long-term debt securities are issued at higher interest rates. Additionally, a utility's cost of equity would increase as investors require a higher ROE to compensate for additional risk.

Customers benefit by having a financially stable utility that has the earnings and cash flow sufficient to attract equity and debt on reasonable terms, and the resulting ability to provide safe, reliable, and affordable utility service. Receiving an adequate revenue requirement from regulators is an important contributor to financial stability. The customer benefits that result from being served by a financially healthy utility outweigh the illusory short-term "benefits" of a negative regulatory climate that heightens regulatory risk.

The existence of subsidies built into electricity tariffs also creates additional regulatory risk. Different types of subsidies violate the "cost-causer pays" rate design principle. Inter-class rate subsidies that favor residential customers have historically been built into rate design in some U.S. jurisdictions. In these circumstances, residential customers have been subsidized by commercial and industrial customers, in some instances placing a noticeable damper on economic development and hiring practices of industrial customers in particular.

As noted in Section 2, the annual growth rate in U.S. electricity prices from 2001 to 2019 has been 2.9% for residential, but only 1.9% for commercial and 2.0% for industrial customers. The unwinding of residential subsidies over this time period is a primary driver of the residential price growth rate being higher.

Another type of subsidy that creates additional regulatory risk is government subsidies, where a government utilizes government tax proceeds to buy down the tariff rate for residential customers. Government-subsidized tariffs are unsustainable and distort price signals for both investors and customers. Investors view government subsidies as temporary and a cause of heightened regulatory risk. Government-subsidized tariffs that are not cost-reflective also violate the cost-causer pays principle. It is best to avoid government subsidies or use them sparingly.

Worse yet are the challenges introduced when government subsidies are promised but not paid to the utility. In this instance, the utility's electricity tariffs are knowingly inadequate, regulatory risk significantly increases, and the utility's financial viability may be severely crippled.

In summary, cost-reflective tariff-setting that provides the opportunity for a utility to adequately recover the cost of serving customers in a timely manner, achieve its revenue requirement and earn its authorized ROE by minimizing regulatory lag and avoiding subsidies, will facilitate the achievement of customer benefits.

4. The Need for High Quality Accounting Data

High quality accounting data contributes to the accuracy of electricity tariffs. The attributes of high-quality accounting data include accuracy, timeliness, verifiability, granularity, and comprehensiveness, as described in NARUC's *Regulatory Accounting: A Primer for Utility Regulators*.

Specifically, audited financial statements and the use of a USoA contribute to these attributes. Audited financial statements demonstrate that a team of independent outside accounting experts has reviewed the financial statements for accuracy and enhances their credibility by certifying that they have been prepared in accordance with generally accepted accounting principles.

Section 2 of this primer highlights that a USoA provides a significant foundation for regulatory accounting. In the U.., the Federal Energy Regulatory Commission (FERC) provides a USoA that is widely utilized by all U.S. electric utilities and adopted by virtually all state jurisdictions, sometimes with minor modifications. The expense, asset, and liability accounts of FERC's USoA are particularly important to revenue requirement determination.

Investors recognize that accounting principles, standards, and procedures, including GAAP promulgated by the Financial Accounting Standards Board ("FASB"), ensure a level of consistency in the calculation of the revenue requirement components that make it easier for investors and regulators to analyze and extract useful information from financial statements. Utility investors recognize that a USoA provides requirements that ensure additional consistency in the calculation of the revenue requirement components.

A USoA enhances uniformity, comparability, accuracy, reliability, and consistency for reporting, cross-company benchmarking comparisons, rate regulation, rate studies, cost-of-service studies, depreciation studies, market oversight, and financial audits. When regulators scrutinize the financial statements, the existence of GAAP, IFRS, and the USoA provide a solid foundation for calculating revenue requirement components.

The existence of a well-developed USoA ensures a certain level of accuracy and comparability of expense data on the income statement, rate base asset and liability data on the balance sheet, and debt and equity capital structure data on the balance sheet.

The importance of high-quality accounting data is heightened in emerging economies as regulators work to establish cost-reflective tariffs. The need for accurate, reliable accounting information is paramount as a foundation for ratemaking. Recently, USAID and NARUC have facilitated USoA development in Ethiopia, Kenya, Tanzania, Uganda, Nigeria, and Rwanda.

5. Typical Expenses Incorporated into Revenue Requirements

FERC has established regulatory accounting and financial reporting requirements for U.S. electric utilities. As specified on FERC's website under the Enforcement and Legal Accounting Matters tab,[5] these requirements play a vital role in setting just and reasonable cost of service rates. FERC sets cost of service rates for electric transmission service, which is interstate in nature. State regulatory commissions set cost of service rates for electric distribution services.

Electric generation is regulated in approximately two-thirds of the U.S. states. In these regulated states, state regulators set cost of service rates for generation services. Approximately one-third of the U.S. states have power markets that are competitive, or restructured. In these restructured states, generation service is provided by third-party providers and generation costs are not based on cost of service rates and are either passed through on the utility bill or billed separately by competitive retail electric providers.

The foundation of FERC's accounting program and reporting is the USoA. The enabling Title 18 Part 101 of the Electronic Code of Federal Regulations is described in detail on the FERC website.[6] In addition, FERC issues accounting regulations, orders, and guidance letters that effectuate reporting requirements that promote consistent, transparent, and decision-useful accounting information. Electric utilities maintain their accounting books and records in accordance with FERC's USoA and then submit annual financial statements on a report referred to as the FERC Annual Report Form 1 (FERC Form 1).[7]

FERC relies on the FERC Form 1 data as a foundation for setting electric transmission tariffs. The states also rely on FERC Form 1 data as a foundation for setting electric distribution tariffs and generation tariffs, if applicable.

The USoA provides basic account descriptions, instructions, and accounting definitions that are useful in understanding the FERC Form 1 data. The FERC Form 1s provide a vast amount of detail on utility financial statements. The expenses on the income statement that are most likely to be primary drivers of electricity tariffs are highlighted in Sections 5.1 through 5.11.

5.1. Operation and Maintenance Expense

Operation and Maintenance (O&M) Expense is the cost incurred in operating and maintaining a utility's electric system, including power production expense, transmission expense, regional market expense, distribution expense, customer accounts expense, customer service and informational expense, sales expense, and administrative and general expense. O&M is the largest and most sub-categorized expense. Because O&M is the most significant expense, it is often a primary driver of electricity tariffs.

O&M expense covers the routine activities that enable the electric plant assets to perform their intended function of providing service to customers. O&M incorporates the cost of labor used to operate and maintain the electric system. O&M expenses are absolutely essential to the provision of electric service, but must be shown to be reasonable and necessary before inclusion in the revenue

[5] "Accounting Matters." FERC. https://www.ferc.gov/enforcement-legal/enforcement/accounting-matters

[6] "Part 101—Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject to the Provisions of the Federal Power Act." Electronic Code of Federal Regulations. https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18

[7] "FERC FINANCIAL REPORT FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report." FERC. https://www.ferc.gov/sites/default/files/2020-04/form-1.pdf

requirement. The level of O&M should be scrutinized for prudent incurrence and can be disallowed or adjusted if needed to achieve a representative level in the test year.

5.2. Technical and Non-Technical Losses

Technical and Non-Technical Losses are the difference between the amount of electricity that an electric utility generates or purchases and the amount of electricity that the utility's customers ultimately pay for as a result of billing. An alternate name for these losses is Aggregate Technical, Commercial, and Collections (ATC&C) Losses. There are five components of these losses, three technical and two non-technical.

The first component is the technical loss due to moving electrons through the electric transmission system between the electric generation location and the delivery point of the electric distribution system. In some instances, a separate transmission company serves as an intermediary between the generation company and an electric distribution company.

In other instances, one utility may own both the transmission grid and the distribution grid, but the engineering principle is the same. By the time electricity reaches the distribution company delivery point, some electrons have been lost in the transmission system due to the laws of physics. Typical high voltage transmission technical losses are 2-4%.

The second component is also a technical loss related to transformation losses. Electrical substations transfer power from a high or medium voltage transmission line to the low voltage distribution system through electrical transformers. Again, due to the laws of physics, a small percent of electrons is lost in the transformation process. The typical international standard of transformation losses between high voltage and low voltage is 1-2%.

The third component is also a technical loss that pertains to the loss of electricity flow as electricity passes through a network of distribution wires. By the time electricity reaches the end-user, some electrons have been lost in the distribution system due to the laws of physics.

Engineering design attempts to minimize technical losses but at least a minor amount is unavoidable. Distribution line losses can result from excessively long conductors, distribution-level transformers, and reactive power generated by customers operating a range of equipment from motors to individual private solar panels.

The fourth component is commercial loss, which is basically loss due to electricity theft, metering failure, inaccuracies, and tampering, or billing errors. Commercial loss is the difference between the electricity that reaches end-users and the electricity that the utility invoices end-users.

The fifth component is the collection loss due to unpaid bills. Collection loss is the difference between the electricity that gets invoiced to customers and the electricity for which the utility gets paid. Collection loss results in uncollectible expense. Collection loss can be challenging to calculate due to the timing of customer payments. Collection loss is typically calculated for the current billing period. Later collections are not counted, so collection loss is never calculated for quarterly or annual periods for this reason.

Some utilities may report collections above 100% for a billing period when they receive payment for service provided in prior periods. This impossibility should not occur under accrual accounting and may demonstrate deficiencies in accounting and financial controls. At the same time, as more developing country utilities deploy pre-paid meters, they have approached 100% collection, since customers pay in advance for service. Not all customers will be placed on pre-paid meters, especially large industrial customers and often government customers as well.

Uncollectible expense represents a charge to provide for losses from uncollectible revenues due to the unpaid bills of customers that received electricity service but did not pay due to either inability or unwillingness. When customers do not pay their bills on time, utilities are required to follow carefully-prescribed rules prior to disconnection. Regulators exercise their statutory authority to develop rules, regulations, and tariffs that balance disconnections for non-payment with appropriate customer protections.

These rules help avoid significantly growing uncollectible expense in typical circumstances. A normal expected level of uncollectible expense is typically included in the revenue requirement calculation. For a utility that operates a post-paid metering system, uncollectible expense impacts working capital requirements which may increase interest expense.

The COVID-19 pandemic in 2020 provides an example of a sudden increase in uncollectible expense. COVID-19 health issues and related widespread unemployment led to an inability of many customers to pay. In response, many jurisdictions and utilities placed a moratorium on service disconnections, thus allowing uncollectible balances to increase.

Many jurisdictions allowed for the deferral of uncollectible balances into a regulatory asset to be recovered through tariffs at some point in the future. This intentional uplift of uncollectible expense in 2020 to help offset negative pandemic impacts will be an issue to be resolved in subsequent rate cases. Effective regulation will monitor the accruing uncollectible expense amounts to inform both the timing of recovery and the appropriate amortization period.

For accounting purposes, these five ATC&C components may be recorded in different portions of the income statement. Different components may be viewed as an O&M expense or a contra-revenue.[8] The utility management is charged with minimizing all five components. These losses are usually minimal for U.S. utilities and not a primary driver of electricity tariffs, with the collections loss typically the largest component.

However, all five components can be especially significant in emerging economies. The World Bank reports that average electric transmission and distribution losses have recently been observed to be 8.3% for the world, 6.2% for the European Union, 6.3% for North America, 11.7% for Sub-Sahara Africa, and 18.3% for "heavily indebted poor countries."[9]

Nigeria provides an example for which ATC&C losses have exceeded 50%.[10] Losses of this magnitude seriously undermine the financial stability of utilities and may lead to chronic underinvestment. If ATC&C losses exceed 20%, the utility as a rule is likely de-capitalizing and not recovering depreciation expense or return on capital.

5.3. Power Purchase Agreements and Competitive Generation Passthrough Costs

Purchased power is electricity generated by a third party and purchased by an electric utility for resale. Purchased power can be sourced by a utility through a contract called a power purchased agreement (PPA) or bought on the open market from a competitive generation company. In either case, the purchased power costs are fully passed through to end-users with no discount or premium. The net impact on the electric utility is a wash between revenues and expenses.

[8] A contra revenue is a revenue that results in a debit balance instead of a credit balance.
[9] The World Bank website, Table 5.11 – World Development Indicators: Power and Communications
[10] See Nigerian Electricity Regulatory Commission data at https://nerc.gov.ng/index.php/library/industry-statistics/distribution/119-atc-c-losses

5.4. Production Expense Including Fuel Costs

Power production expense consists of the costs to operate and maintain the different types of owned generation facilities including steam, nuclear, hydraulic, and other power generation. Fuel is a significant component of production costs along with labor costs.

Fuel costs vary by generation type including coal, natural gas, nuclear, and water, and include the cost of transporting the fuel to the generating station. Wind and solar generation do not have fuel costs but experience other production costs. In most jurisdictions, fuel is treated as a passthrough item, often flowing through a fuel adjustment clause and reconciled annually to ensure dollar-for-dollar recovery of prudent fuel costs.

5.5. Depreciation Expense

Depreciation expense represents a reduction in the value of electric plant on the balance sheet with the passage of time due to wear and tear, decay, inadequacy, and obsolescence. Capital intensive electric utilities own significant long-lived assets that decrease in value over time.

The utility keeps records of property and property retirements and estimates the probable service life of each asset or asset class, along with a depreciation rate applicable to each asset class. The regulator typically periodically conducts a separate proceeding to determine the depreciation rate to apply to each asset class. This recordkeeping and regulatory process enables the quantification of test year depreciation expense to be calculated.

Amortization expense is similar in concept to depreciation expense but applies to long-lived assets that are not plant accounts. Examples of non-plant costs that may be deferred on a utility's balance sheet and then amortized include a regulatory asset, intangibles, and deferred taxes.

One inter-generational objective of cost-based regulation is to allow depreciation and amortization expense to be recovered from customers such that the rate recovery period matches the service life of the asset being recovered. The calculation of depreciable lives, depreciation rates, and depreciation expense will be more thoroughly described in an upcoming NARUC primer on depreciation. However, depreciation expense is not to be underestimated as a primary driver of electricity tariffs.

5.6. Rate Case Expense

Rate case expense represents the incremental, out-of-pocket costs incurred by the utility in connection with applying for and litigating a formal case before a regulatory commission. Examples of out-of-pocket rate case costs include fees for outside attorneys and expert witnesses, copying, printing, mailing, regulatory fees, and travel costs. The labor costs associated with permanent in-house employees that are engaged in the regulatory filing are generally excluded from rate case expense because they are already recovered elsewhere in the revenue requirement.

Rate case expense is a cost of doing business required of a utility by the government and therefore a legitimate expense. Historical filing frequency can be used to determine the length of time over which to amortize rate case expense. Customers benefit from rate case expense because it is necessary for the utility to provide the commission with the information necessary to set tariffs at the proper level.

5.7. Income Tax Expense

Corporate income taxes are imposed by federal, state, and some local governments. Income tax expense calculations can be challenging and detailed. Every jurisdiction is different so it is difficult to make income tax generalizations. The objective is to use the statutory corporate income tax rate to determine the proper level of income tax expense for the test year. Income tax expense is usually not a primary driver of electricity tariffs, but income tax law changes can be a primary driver. Tax reform definitely was a primary driver of electricity tariffs in 2018.

The U.S. Tax Cuts and Jobs Act of 2017 became effective in 2018 and is an example of a significant change in income tax law. The U.S. corporate income tax rate was reduced by law from 35% to 21%, the first major change since 1986. Utility revenue requirement impacts emanated from the corporate tax rate cut but also the revaluation of deferred tax balances, the discontinuation of bonus depreciation, and other tax features. Normalization provisions applied to deferred tax balances related to long-term utility assets.

Utility regulators in most jurisdictions responded during 2018 by establishing proceedings to investigate the revenue requirement impact of the tax changes. Regulators found a variety of ways to pass the tax reform benefits through to customers including customer rate reductions, offsetting other increasing costs such as storm costs, deferrals, recovery of existing regulatory assets, accelerated depreciation, increased capital expenditures, and higher authorized equity ratios. Regulators are likely to respond similarly to a corporate income tax increase by passing through the related revenue requirement impacts, although the utilities will likely be the petitioners for such action.

5.8. Taxes Other than Income Taxes

Taxes other than income taxes include real estate and personal property, ad valorem, gross revenue, gross receipts, unemployment, franchise, excise, and social security taxes, basically all other taxes except income taxes. These taxes are imposed by federal, state, or local governments and as such are a necessary cost of doing business.

Taxes other than income taxes are usually not a primary driver of electricity tariffs unless the underlying tax fundamentals change. The imposition of a carbon tax would likely be a primary driver but might be accounted for as an increase in production expense rather than a tax expense.

5.9. Labor Costs

It is important to note that labor costs are relatively large expenses but are not separated into unique dedicated line item accounts. Instead, labor costs are incorporated into other expense categories, largely in O&M, by either direct assignment or allocation. As such, labor costs still are monitored and tracked extensively by regulators because they can be primary drivers of electricity tariffs.

Labor costs include all forms of compensation including salaries, wages, bonuses, health care benefits, pension benefits, and other consideration paid for services. Salaries and wages generally increase gradually year over year. Over a long time period, health care benefit costs have escalated faster than the general rate of inflation and, at times, significantly faster.

In the U.S. economy, health care costs increased at an average annual rate of 5.12% from 1947 to 2020 while the general inflation rate averaged 3.41%. Health care costs significantly outpaced general inflation in the 1980s, 1990s, and the early part of the 2000s, increasing at a double-digit rate in several years. Health care benefits can be viewed as a primary driver of electricity tariffs.

5.10. Allocation of Administrative Costs from Affiliated Interests

Certain administrative costs may be more cost effectively incurred on a centralized basis by a parent company or other affiliated company and then allocated to other affiliates including the utility. Functional examples include Treasury, Auditing, or Human Resources costs where scale and scope may permit affiliated companies to efficiently and effectively perform these services on behalf of utilities.

Utility customers are likely to benefit from such arrangements. These affiliated administrative costs are legitimate costs of doing business but should be scrutinized for prudency along with allocation ratios to ensure fair allocation to the utility subsidiary.

5.11. Other Expenses

The remaining expenses on the FERC Form 1 income statement are either relatively small, somewhat self-explanatory, and/or a sub-component of O&M, so will not be described separately. Some of the other components of O&M include transmission, distribution, customer accounts, customer service, sales, and administrative and general. Expenses unrelated to providing utility service to customers should be excluded from revenue requirement calculations.

For example, some state-owned utilities in developing countries are used by governments as an instrumentality to fund non-utility operations such as election rallies. Governments also may "raid" utility accounts to raise money for other government priorities. It is the responsibility of regulators to identify such instances and ensure that these costs are not included in tariff calculations.

5.12. Significance of Each Expense Category to Total Expenses

There are many ways to aggregate and categorize the myriad expenses and sub-expense details of the FERC Form 1s. At least two organizations access and aggregate FERC Form 1 data and publish useful summaries. The two organizations are the US Energy Information Administration (EIA) and the Edison Electric Institute (EEI).

The EIA aggregates the FERC Form 1 expense data for major U.S. investor-owned electric utilities. Figure 3 shows EIA's most recent Table 8.3[11] that is based on FERC Form 1 data for 2009 through 2019. The EIA designates sub-accounts by indentation.

[11] Energy Information Administration Electric Power Annual 2019 Table 8.3, October 2020.

Figure 3

Table 8.3. Revenue and Expense Statistics for Major U.S. Investor-Owned Electric Utilities, 2009 through 2019 (Million Dollars)

Description	2009	2010	2011	2012	2013	2014
Utility Operating Revenues	**276,124**	**285,512**	**280,520**	**270,912**	**281,901**	**298,430**
Electric Utility	249,303	260,119	255,573	249,166	257,718	271,832
Other Utility	26,822	25,393	24,946	21,745	24,183	26,598
Utility Operating Expenses	**244,243**	**253,022**	**247,118**	**235,694**	**244,316**	**258,936**
Electric Utility	219,544	234,173	228,873	220,722	227,483	240,643
Operation	154,925	166,922	161,460	152,379	156,077	165,989
Production	118,816	128,831	122,520	111,714	115,046	123,366
Cost of Fuel	40,242	44,138	42,779	38,998	41,127	42,545
Purchased Power	67,630	67,284	61,447	54,570	55,529	62,066
Other	10,970	17,409	18,294	18,146	18,390	18,755
Transmission	6,742	6,948	6,876	7,183	7,881	8,902
Distribution	3,947	4,007	4,044	4,181	4,197	4,331
Customer Accounts	5,203	5,091	5,180	5,086	5,107	5,255
Customer Service	3,857	4,741	5,311	5,640	5,906	6,396
Sales	178	185	185	221	203	208
Administrative and General	15,991	17,120	17,343	18,353	17,738	17,532
Maintenance	14,092	14,957	15,772	15,489	15,505	16,801
Depreciation	20,095	20,951	22,555	23,677	24,723	25,919
Taxes and Other	29,081	31,343	29,086	29,177	31,179	31,934
Other Utility	24,698	18,849	18,245	14,972	16,833	18,293
Net Utility Operating Income	**31,881**	**32,490**	**33,402**	**35,218**	**37,585**	**39,494**

Description	2015	2016	2017	2018	2019
Utility Operating Revenues	**282,695**	**282,499**	**286,501**	**293,868**	**293,000**
Electric Utility	260,121	261,047	263,265	268,421	266,876
Other Utility	22,574	21,451	23,235	25,447	26,124
Utility Operating Expenses	**242,728**	**239,037**	**240,041**	**253,944**	**250,136**
Electric Utility	228,366	226,457	226,110	238,526	234,892
Operation	149,939	145,077	142,000	163,479	157,265
Production	107,201	100,852	98,859	104,185	99,518
Cost of Fuel	34,711	32,621	32,165	33,592	29,614
Purchased Power	52,970	49,962	49,030	53,060	50,378
Other	19,521	18,269	17,664	17,533	19,526
Transmission	9,624	10,447	10,804	11,387	11,941
Distribution	4,406	4,734	4,358	4,806	5,218
Customer Accounts	5,184	5,077	4,789	4,969	4,978
Customer Service	6,445	6,187	5,961	6,019	6,156
Sales	201	205	213	203	204
Administrative and General	16,878	17,575	17,016	31,911	29,248
Maintenance	16,392	16,982	17,996	17,786	19,898
Depreciation	26,847	30,097	30,323	32,125	34,883
Taxes and Other	35,188	34,301	35,791	25,136	22,846
Other Utility	14,362	12,579	13,931	15,418	15,245
Net Utility Operating Income	**39,968**	**43,462**	**46,460**	**39,924**	**42,864**

Notes:
Missing or erroneous respondent data may result in slight imbalances in some of the expense account subtotals.
Total may not equal sum of components due to independent rounding.

Sources: Federal Energy Regulatory Commission, FERC Form 1, "Annual Report of Major Electric Utilities, Licensees and Others via Ventyx Global Energy Velocity Suite.

From one point of view, the largest expenses can be viewed as primary drivers of electricity tariffs. Focusing on the EIA electric utility operating expenses of Figure 3, it is clear that operation expense makes up the single biggest expense category at 67.0% in 2019, as shown in Figure 4. Figure 4 demonstrates that production costs are the largest sub-component of operation expense.

In turn, production costs are comprised of the cost of fuel, purchased power, and other production costs. Other operation expenses include transmission, distribution, customer accounts, customer service, sales, and administrative and general costs, while other expenses include maintenance at 8.5%%, depreciation at 14.9%, and taxes other than income taxes and other at 9.7%.

Figure 4

Comparison of Expenses
Major U.S. Investor-Owned Electric Utilities
For 2008 and 2019

Expense	2008	% of Total	2019	% of Total
Total Electric Utility Operating Expenses	236,572	100.0%	234,892	100.0%
Operation Expense	175,887	74.3%	157,265	67.0%
Production Expense	140,974	59.6%	99,518	42.4%
Cost of Fuel	47,337	20.0%	29,614	12.6%
Purchased Power	84,724	35.8%	50,378	21.4%
Other Production Expense	8,937	3.8%	19,526	8.3%
Transmission Expense	6,950	2.9%	11,941	5.1%
Distribution Expense	3,997	1.7%	5,218	2.2%
Customer Accounts Expense	5,286	2.2%	4,978	2.1%
Customer Service Expense	3,567	1.5%	6,156	2.6%
Sales Expense	225	0.1%	204	0.1%
Administrative and General Expense	14,718	6.2%	29,248	12.5%
Maintenance Expense	14,192	6.0%	19,898	8.5%
Depreciation Expense	19,049	8.1%	34,883	14.9%
Taxes Other than Income Taxes and Other	26,202	11.1%	22,846	9.7%

Another way to view primary drivers of electricity tariffs is to review which components increased the most over time. Figure 5 uses Figure 3 data to show the annual percentage growth rate of each utility operating expense calculated over the eleven-year period of Figure 4. Total electric utility operating expenses remained relatively flat, decreasing at the rate of 0.1% during this time period.

The expense components that appear to have increased the most are administrative and general expense, other production expense, customer service expense, depreciation expense, and transmission expense. On the other hand, purchased power, cost of fuel, and production expense actually experienced significant decreases over this time period.

In aggregate, the significant operation expense component declined 1.0% annually, significantly contributing to the total electric utility operating expense annual rate decrease of 0.1%. It is interesting to note that fuel and purchased power declined during this decade of declining natural gas prices. It is also interesting to note the significant increase in depreciation expense over this decade that corresponds to a relatively high level of capital expenditures adding infrastructure investment to utility assets. In comparison, the general inflation rate over the same time period averaged 2.5%.

Figure 5

Annual Growth Rates in Expenses
Major U.S. Investor-Owned Electric Utilities
For the Period 2008 through 2019

Expense	Annual Growth Rate
Total Electric Utility Operating Expense	-0.1%
Operation Expense	-1.0%
Production Expense	-2.7%
Cost of Fuel	-3.4%
Purchased Power	-3.7%
Other Production Expense	10.8%
Transmission Expense	6.5%
Distribution Expense	2.8%
Customer Accounts Expense	-0.5%
Customer Service Expense	6.6%
Sales Expense	-0.8%
Administrative and General Expense	9.0%
Maintenance Expense	3.7%
Depreciation Expense	7.6%
Taxes Other than Income Taxes and Other	-1.2%

EEI publishes an annual financial review that also draws from FERC Form 1 data for the U.S. investor-owned electric utility industry. The annual EEI Financial Review provides consolidated financial statements including a consolidated income statement. A comparison of the 2019 and 2009 EEI Annual Financial Reviews[12] reveals that total electric operating expenses have declined at an annual rate of 0.1%, remaining virtually flat for the decade. The depreciation and amortization category has increased the most at a 5.0% annual rate while electric generation costs have declined at a 2.7% annual rate.

[12] See the annual EEI Financial Reviews on the EEI website at https://www.eei.org/issuesandpolicy/Pages/FinanceAndTax.aspx#financialreview

Figure 6

Annual Composition of Expenses and Growth Rates in Expenses
EEI U.S. Investor-Owned Electric Utilities
For the Period 2009 through 2019

Expense	2009 % of Total	2019 % of Total	Annual Growth Rate
Electric Generation Cost	45.5%	32.7%	-2.7%
Operations and Maintenance	31.0%	34.3%	1.2%
Depreciation and Amortization	13.2%	19.6%	5.0%
Taxes Other than Income Taxes	5.6%	7.3%	3.2%
Other Operating Expenses	4.7%	6.0%	2.9%
Total Electric Operating Expenses	100.0%	100.0%	0.1%

Both the EEI and EIA data provide interesting but not identical insights about the FERC Form 1 accounting data. Similar to the EIA data, the EEI data shows relative flat O&M along with a significant increase in depreciation and amortization expense over this decade when utilities invested in a relatively high level of capital expenditures. In comparison to the EIA data, the EEI data aggregates the operating expense data in fewer categories, groups the sub-categories differently, and measures over a slightly different time period.

6. Typical Rate Base Assets and Liabilities Incorporated into Revenue Requirements

Although this primer primarily focuses on expenses, the rate base is also an important revenue requirement component. As described in Section 2, the rate base represents utility property, or the net investment in assets (gross investment in assets less accumulated depreciation and amortization) less certain liabilities.

The rate base value is defined by the balance sheet and engineering, accounting, and legal concepts. The largest rate base component is generally net electric plant in service (gross electric plant less accumulated depreciation). As depreciation is accrued over time, the accumulated provision for depreciation increases, thereby reducing the net value of the plant in rate base.

Other rate base components typically include construction work in progress, cash working capital (usually based on a study of current assets and current liabilities), materials and supplies, and regulatory assets net of regulatory liabilities.

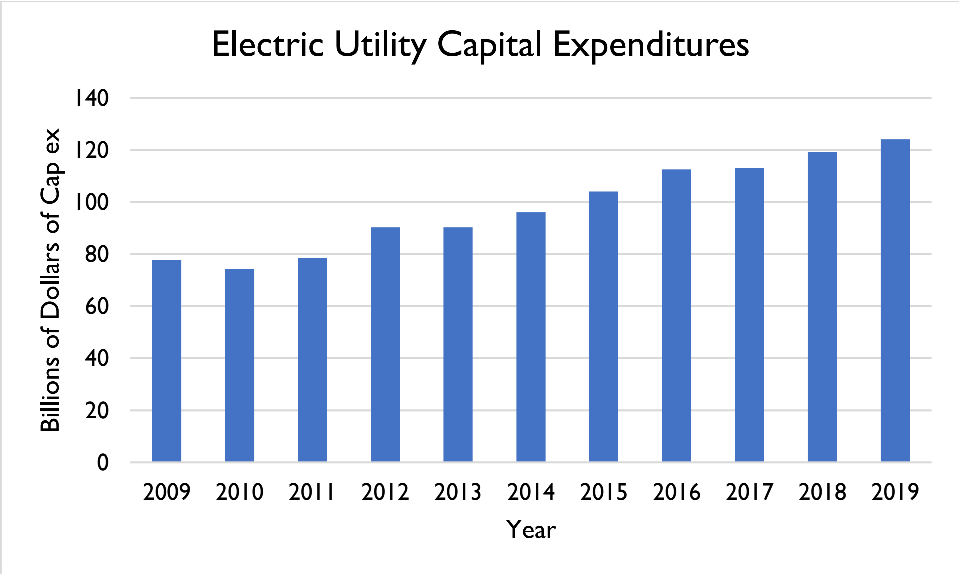
Cost-reflective tariffs provide for both a return "of" and "on" capital. The concept of accumulated depreciation helps illuminate the concept of the return "of" capital and the return "on" capital. Depreciation expense represents the return of capital, while simultaneously increasing the accumulated depreciation and decreasing the rate base.

As assets age, their value declines as the accumulated depreciation balance increases until they reach retirement and must be replaced with new investment. A utility's cost of capital (authorized and earned) on the rate base represents the return on capital. NARUC's Cost of Capital and Capital Markets Primer for Utility Regulators focuses on the return "on" capital, while NARUC's upcoming primer on depreciation will describe the return "of" capital.

A typical investment cycle consists of the utility replacing existing depreciated assets with investment in new assets, referred to as capital expenditures. Capital expenditures are major, long-term expenditures to acquire, upgrade, and maintain physical assets, in contrast to operating expenses that are day-to-day expenditures. The impact of capital expenditures is demonstrated by EEI data and Wall Street research reports.

The EEI data[13] in Figure 7 demonstrates that electric utility capital expenditures have significantly increased at an annual rate of 6.0% over the last decade. In 2019, industry capital expenditures breakdown to 33.6% generation, 22.7% transmission, 34.4% distribution, and 9.3% other.

Figure 7



Customers benefit from capital expenditures through the replacement of aging, depreciating infrastructure, the maintenance of existing infrastructure, the enablement of new projects, and the upgrade to new technologies. When fully depreciated plant requires replacement, the replacement technology often provides enhanced features, greater customer service, and environmental benefits. The customer benefits of capital expenditures planned for the test year can best be understood in the context of a forward-looking long-run (five or ten-year) capital expenditure plan.

Investment research reports from UBS Global Research,[14] Bank of America Global Research,[15] and Wolfe Research[16] show that investors expect electric utility capital expenditure to continue at high recent levels or increase over the next five years. UBS estimates electric utility capital expenditure

[13] EEI capital expenditure data is shown in the EEI annual Financial Reviews on the FERC website at https://www.eei.org/issuesandpolicy/Pages/FinanceAndTax.aspx#financialreview. See, for example, the EE! 2019 Financial Review.

[14] "North America Power & Utilities Halftime: Regulated Utility Strategy for 2H 2020." UBS Global Research. July 7, 2020, pages 13-15.

[15] "North American Utilities & IPPS: Compiling Utility Capex and Opex Trends: what the aggregated data shows?" Bank of America Global Research. May 22, 2020; and "The ABC's of Utilities: ROE, leverage, debt capital, and capex tell the story," June 12, 2020.

[16] "Utilities & Power: The Wolfe Utility Primer – 2018." Wolfe Research. July 23, 2018, pages 30-32.

levels running at twice depreciation expense through 2024 contributing to five-year forward rate base growth of 6.2%.

Despite some shifting in timing due to the COVID-19 pandemic, Bank of America estimates regulated utility capital expenditures running at a multiple of 2.1 times depreciation expense through 2025. The Bank of America also expects some upward pressure on O&M expenses, but expects sustainable O&M cuts related to optimizing and re-designing processes and efficient use of labor to hold aggregate O&M to a modest increase through 2025.

Wolfe Research provides an explanation of what is driving the growth in capital expenditures. The power plant transition from coal-fired to natural gas-fired generation plus renewable energy investment is driving generation investment, with off-shore wind the latest new area. Distribution system hardening has been a focus area given the seemingly never-ending cycle of storms and/or natural disasters.

Grid modernization and energy efficiency aimed at making a more resilient and interactive grid through the deployment of high-tech investments such as advanced meters (AMI) that enables demand response are other areas of distribution system focus. Wolfe notes that transmission investment continues to be robust as infrastructure is needed for renewable connection purposes and reliability.

UBS identifies three multi-decade pools of capital expenditures for electric utilities: 1) high-voltage transmission renewal and expansion, 2) generation fleet transformation due to improving economics paired with decarbonization policy mandates, and 3) grid automation and modernization to improve the resiliency and intelligence of the lower voltage transmission and distribution system, driven by system hardening for severe weather and physical and cybersecurity threats, adding intelligence to the wires to help bend the cost of service curve, improving outage detection and response, and ensuring suitability of utility service for emerging technologies such as mass adoption of electric vehicles, distributed generation, and batteries.

It is clear the capital expenditures have recently been and are expected to remain a primary driver of electricity tariffs.

7. Categorization of Total Bill Impacts to End-User Customers by Distribution, Transmission, and Generation

It is informative to break down the overall utility revenue requirement reflected in the utility bill paid by end-user customers between the components of distribution, transmission, and generation. Regulators pay attention to the level of total utility bills because they represent 3% of customers' disposable income on average across the U.S. In the United States, state regulators set the distribution revenue requirement, while FERC for the most part sets the transmission revenue requirement with the exception of most of the state of Texas.

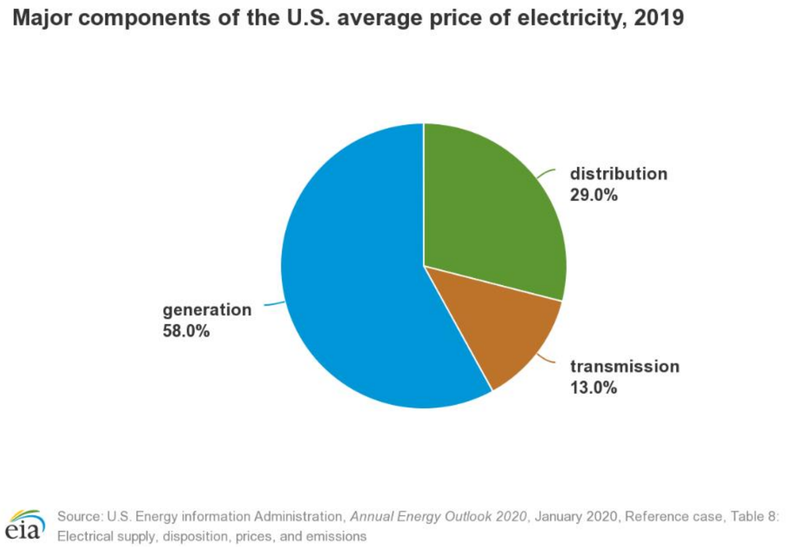
On a state-by-state basis, the generation portion is either determined by the competitive market or by the revenue requirement including fuel costs set by state regulators. All three components contribute in aggregate to the end-user bill but not necessarily in a way that is transparent to the customer.

Although Figures 3-6 help identify some expenses that are directly assigned to distribution, transmission and generation, more information about the allocation of common costs is needed to estimate a separate revenue requirement for each component. Significant expenses remain that can be allocated to these three components. In a similar manner, the rate base can be divided into the three components and combined with the authorized cost of capital to develop the return on capital.

Figure 8 is a pie chart developed by the EIA that identifies the major components of the U.S. average price of electricity during 2019. Figure 8 shows that a majority of the total bill is attributable to generation, with the smallest portion attributable to transmission. This informs the issue of primary drivers of electricity tariffs.

A large increase in transmission costs may be less impactful on the customer than a small increase in generation costs. For example, if fuel costs such as natural gas prices decrease, there may be more headroom in the total bill to the customer for distribution and transmission investment. Alternatively, if generation costs spike higher, there may be less headroom in the total bill for distribution and transmission investment.

Figure 8



The total bill to the end-user, of course, includes the impact of prices and volumes. Figure 2 shows the average monthly bill to residential end-users in 2019 by region and state. Energy efficiency programs provide an example of where higher rates provide a lower total customer bill. Energy efficiency programs encourage customers to use less electricity. These programs have costs to the utility, including customer incentives and other costs, which increase the rates paid by customers.

However, the benefits of lower usage by customers more than offset the associated costs, thus providing a net benefit to customers. For example, the Michigan Public Service Commission recently compared the benefits and costs of energy efficiency programs and found that for each dollar spent, electric energy efficiency programs returned $3.60 of customer benefits.[17]

The upward rate impact resulting from the utility recovering its energy efficiency costs results in lower volumes of electricity consumed, thus decreasing the end-user total bill. In this manner, energy efficiency programs can be a primary driver of electricity tariffs.

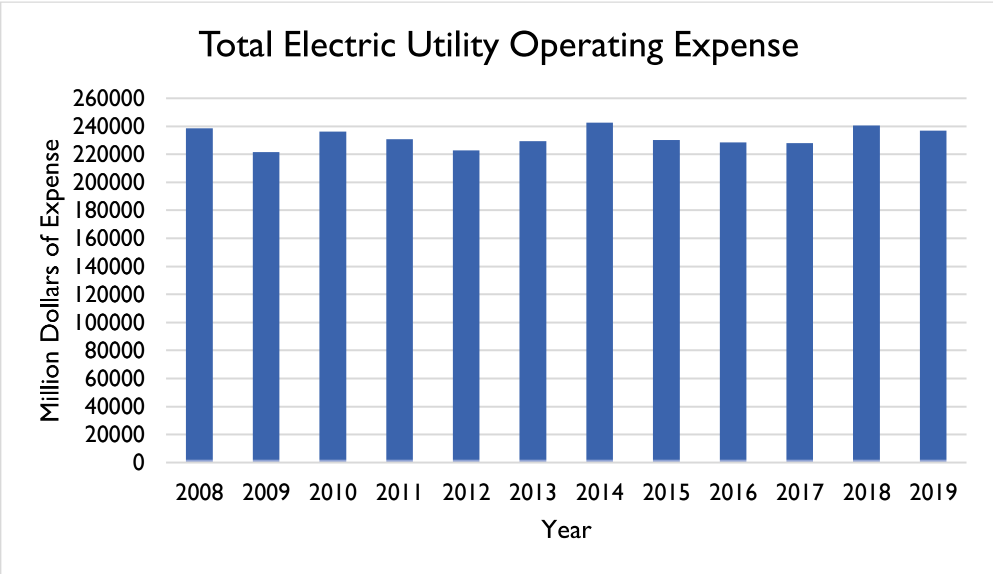
[17] "Annual Report on the Implementation of PA 295 – 2018 Utility Energy Waste Reduction Programs." Michigan Public Service Commission. February 18, 2020, page 5.

8. Primary Drivers of Electricity Tariffs

Sections 5 and 6 summarize primary drivers of electricity tariffs. Capital expenditures are certainly a primary driver of electricity tariffs as demonstrated by Figure 7 and the EEI data and investment research cited in Section 6.

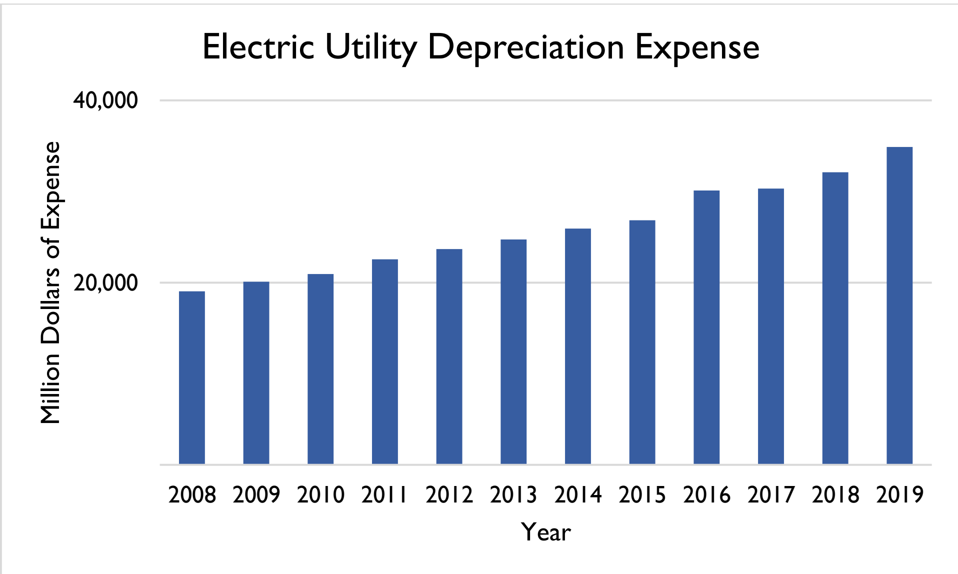
Total electric utility operating expense, discussed in Section 5 and shown in Figure 9, has remained relatively flat and has not been a primary driver, although certain component expenses have increased and decreased in offsetting fashion.

Figure 9



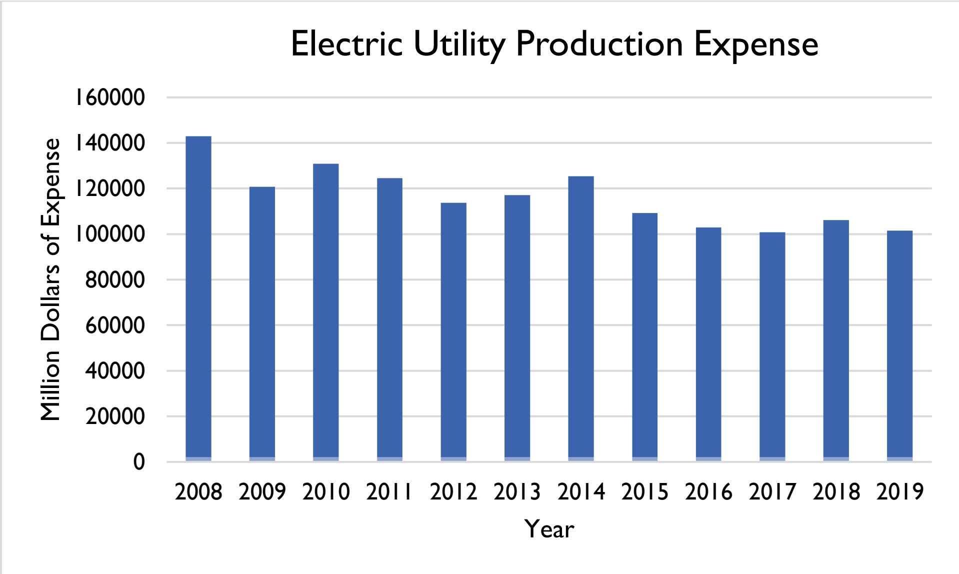
Depreciation expense is a component that has been a primary driver. Figure 10 shows the significant depreciation expense increase over the past decade. Corresponding with increased capital expenditures, depreciation expense is expected to continue to increase noticeably if capital expenditures continue at a robust level.

Figure 10



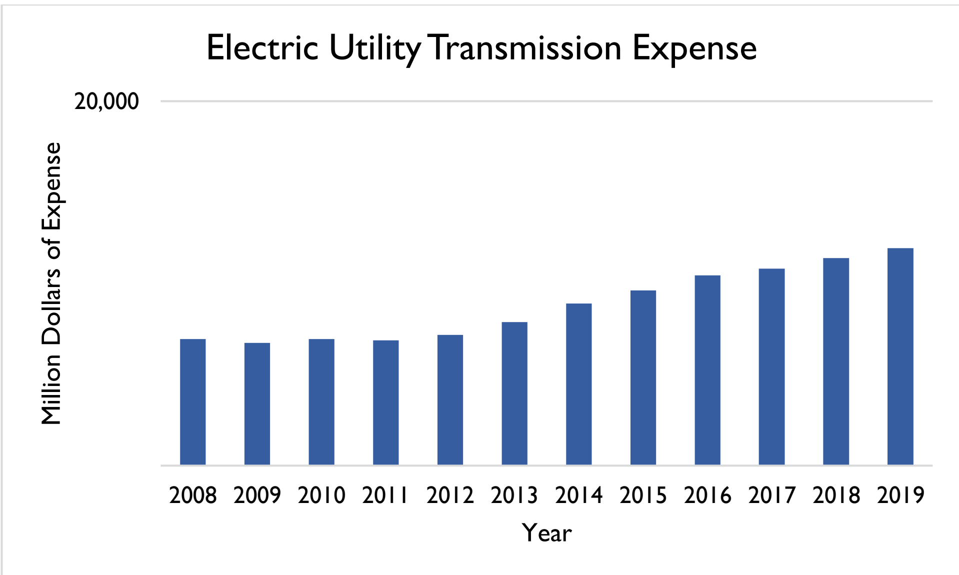
Production expense, including the sub-components of fuel costs and purchased power, is an expense that has declined during the past decade as shown in Figure 11, offsetting other increasing components of operation expense. The significant decrease in the cost of natural gas and the transition to renewables generation, with no fuel costs, have contributed to declining production expense. A reversal to an upward trend in fuels cost may transition production expense to a primary driver of electricity tariffs.

Figure 11



Another primary driver of electricity tariffs during the last decade is transmission expense, as shown on Figure 12. This increasing component is not surprising given the additional focus on transmission infrastructure over the last one-and-a-half decades after at least three decades of underinvestment.

Figure 12



The primary drivers of electricity tariffs will change over time and from case to case. For example, one rate case may be driven by rate base additions, the next rate case may be driven by operating expense increases, and a subsequent rate case may be driven by a combination of capital expenditures and operating expense increases. Tariff changes can be driven primarily by one driver or multiple drivers.

Certain cost component increases may be offset by decreases in other cost components while netting out at close to zero or a minimal tariff change. Utilities may hold off on filing for a rate increase request until the revenue requirement change is more significant.

The EEI annual Financial Reviews referenced in Section 5.12 generally provide summaries of rate case activity for the year. In the annual financial reviews for 2010 through 2018, EEI summarizes what its members perceive as the primary drivers of rate case filings.[18] It is interesting to observe how the EEI commentary on the primary drivers of rate cases summarized below meshes with the data provided in Sections 5 and 6.

2018 – Efforts to recover for capital expenditures, always a primary driver of rate filings, were again prominent in 2018. Rate design was a significant theme as utilities sought to more accurately and efficiently recover costs; the most frequent request was an increase in the residential customer charge. Utilities prefer that customer charges accurately reflect fixed costs of service so that these costs are not unfairly shifted to other customer classes. The Tax Cut and Jobs Act played a major role, too. In new filings and review decisions, utilities and commissions addressed means of incorporating lower taxes in rates and passing the benefits back to customers. While not as widespread, efforts to accommodate electric vehicle (EV) use appeared in a number of reviews.

2017 – Broadly speaking, the primary reason utilities file rate cases is to recover for the many forms of required capital expenditures (capex), such as new generation, plant upgrades, transmission and distribution expansion and upgrades, environmental compliance, system hardening, and reliability improvements. The second most common reason is electric utilities' desire to establish rate mechanisms. Recovery of operation and maintenance (O&M) expenses is typically third. All three reasons were evident in 2017.

2016 – Broadly speaking, the primary reason for rate case filings is the need to recover capital expenditures (capex). Utilities' desire to establish rate mechanisms and to recover operation and maintenance expenses are often the second and third most common reasons for rate case filings. All of these were evident in 2016.

2015 – Recovery for capital expenditures was the primary reason for rate case filings in 2015, as it generally is. The second most frequently cited driver of filings in 2015 was utilities' desire to implement rate mechanisms such as trackers, adjustment clauses and riders. Other miscellaneous costs, such as higher emission control costs, increased transmission costs and expenses related to customer processes were also frequently cited as reasons for filing in 2015.

2014 – Capital investment was by far the most cited reason for rate case filings in 2014; new generation, transmission and distribution, as well as investment in emission control equipment, were the primary needs. The second most prominent reason was a desire to implement riders, surcharges and other rate mechanisms; decoupling mechanisms, storm recovery riders and vegetation management riders were among the mechanisms requested by companies. A third common driver of filings in 2014 was recovery of rising operation and maintenance expenses.

[18] See the EEI annual Financial Reviews on the EEI website at https://www.eei.org/issuesandpolicy/Pages/FinanceAndTax.aspx#financialreview

2013 – Capital investment was the primary driver of filings in 2013, as it has been each year since the initiation of this report series. Utilities' efforts to implement adjustment mechanisms, such as trackers and riders, was the second major driver of filings in 2013, edging out recovery of operation and maintenance (O&M) expenses. Tracker and O&M recovery have been cited frequently as motivations for filings in recent years. Finally, storm cost recovery was a factor in several filings, as were utility efforts to recover for shortfalls caused by low demand growth.

2012 – Capital expenditure recovery was the overwhelming motivation for rate case filings in 2012. Utilities' desire to implement surcharges, trackers, riders, etc. was also a notable cause for filings, as was the recovery of rising operations and maintenance (O&M) expenses.

2011 – The [rising rate case] trend reflects a construction cycle in the industry driven by the need to replace aging infrastructure and reduce the environmental impact of power generation. For full-year 2011, spending on infrastructure and other capital investment was the over-riding reason for rate case filings. These expenditures were made largely to ensure system reliability and compliance with environmental regulations.

2010 – For full year 2010, recovery of infrastructure costs was the largest motivator for case filings. This was followed by utilities' requests for adjustment clauses and other tracking mechanisms and for recovery of O&M expenses. As in 2009, the state of the economy figured prominently in 2010's rate cases. The effort to recover for employee benefit costs was also a factor in many cases.

It is clear from these EEI summaries that EEI considers revenue requirements from capital expenditures as the primary driver of electricity tariffs, followed by increasing in operating expenses that varied year-by-year over the decade. As mentioned in Section 2, the average nominal electricity price increase of 2.5% since 2001 compares to the general inflation rate of 2.5%. At least for the second half of this time period, utility management pursued a disciplined strategy to hold O&M flat to down to accommodate capital expenditures with minimal bill impacts.

Utilities have recognized the need for capital expenditures for infrastructure investment and focused on a strategy to maximize capital expenditures that are necessary to provide service to customers, while also recognizing that the customer bill impacts of rate increases well in excess of the general inflation rate would not be palatable. The solution has been to pursue a strategy to control operating expenses.

Utilities have successfully identified and implemented O&M reductions in a sustainable fashion that improves efficiency to accommodate capital expenditure growth. The data reveal that this strategy was pursued by utilities over the last decade. Declining fuel costs have facilitated this strategy. It appears that this disciplined O&M management strategy can successfully continue barring any surprising upward fuel price shocks. The combination of robust capital expenditures and O&M reductions has been the primary driver of electricity tariffs.

9. Final Remarks

Cost-based regulation and tariff-setting is key to ensuring that safe, reliable, and affordable utility service is provided to customers. The identification of expenses and rate base items are integral to cost-based regulation. This primer describes concepts and tools that are useful in quantifying expenses and rate base items to incorporate into revenue requirements.

Utilizing these concepts and tools is beneficial to utilities, investors, and customers. Cost-reflective tariffs will satisfy recovery of full utility revenue requirements, provide benefits to utilities, investors, and customers, and incentivize excellent customer service.

ANNEX 1: Primer on Primary Drivers of Electricity Tariffs for Utility Regulators – A Case Study

1. Introduction

With the support of the United States Agency for International Development (USAID) – Energy Division, Office of Energy & Infrastructure, the National Association of Regulatory Utility Commissioners (NARUC) has undertaken the task of developing a Cost Reflective Tariff Toolkit which contains a *Primer on Primary Drivers of Electricity Tariffs for Utility Regulators*.

This toolkit is intended to constitute several short practical primers that can be used by utility regulators in countries with emerging economies to design rates that are based on actual cost of service and to effectively engage the public and key stakeholders in the decision-making process. This Annex 1 case study is appended to and is to be read in the context of the toolkit *Primer on Primary Drivers of Electricity Tariffs for Utility Regulators*.

1.1 Objective and Process

The objective of this Annex 1 case study is to help utility regulators in countries with emerging economies understand the potential primary drivers of electricity tariffs by examining the tariff-setting process of an example country, Uganda. The need for cost-reflective tariffs and high-quality accounting data were identified by Uganda during the 1990s as key components of effective cost-based electricity ratemaking.

This Annex 1 case study describes how the Uganda Electricity Regulatory Authority (ERA) approves cost-reflective electricity tariffs by incorporating expenses and rate base items into revenue requirements for its regulated entities.

In terms of the process to develop this case study, the author researched regulatory orders, reports, presentations, press statements, and other documents of the Uganda ERA that are available on its transparent website. The author conducted a virtual meeting with NARUC and Uganda ERA staff representatives, with significant assistance provided by Vianney Mutyaba and Michael Mwondha of the Uganda ERA staff. The author also reviewed documents available on the website of the largest electricity distribution utility in Uganda, UMEME Limited (UMEME).

1.2 Scope and Overview

This annex focuses on describing a set of pathways that regulators in countries with emerging economies may want to consider when determining the utility revenue requirement in ratemaking. This set of pathways is based on the Uganda utility regulator's practices in estimating the revenue requirement for electricity tariff-setting. Furthermore, this primer includes some observations to facilitate the incorporation of regional differences between the U.S. and countries with emerging economies.

The Republic of Uganda is a country in East Central Africa with a population of 44.3 million that lies within the Nile Basin framed by several mountain ranges. Despite being landlocked, Uganda contains many large lakes including a significant portion of Lake Victoria.

The Uganda economy has grown at a healthy annual rate of 6.7% although real GDP growth slowed to 2.9% in 2020 due to the impact of COVID-19. The largest economic sectors include coffee, oil, base metals and products, fish, maize, cement, tobacco, tea, and sugar. Agriculture comprises 25% of the economy, 50% of exports, and 70% of employment. The currency is the Ugandan shilling.

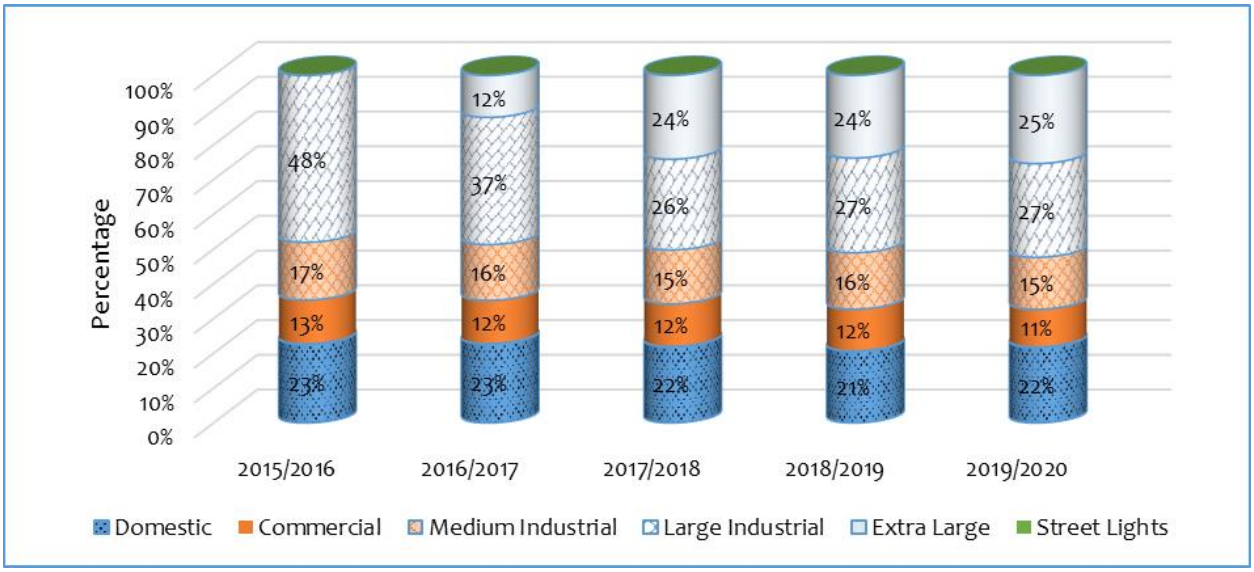
The Ugandan electricity sector is divided into three independent segments: generation, transmission, and distribution. The generation sector consists of 27 mostly privately-owned generation companies operating more than 40 generating units with more under construction. The Government of Uganda owns some generation units through the Uganda Electricity Generation Company Limited (UEGCL). One transmission company, the government-owned Uganda Electricity Transmission Company Limited (UETCL), provides all transmission services.

Nine distribution operators are licensed, with the largest one, UMEME, serving more than 90% of the customers in Uganda. UMEME is privately owned and its stock is listed on the Uganda Securities Exchange. One distribution operator, the Uganda Electricity Distribution Company Limited (UEDCL), is government-owned and serves challenging service territories. In addition, four off-grid operators operate in rural areas beyond the reach of high voltage transmission lines.

The distribution and transmission utilities do not own generation. In aggregate in 2019/2020, the electric load consists of 22% domestic (residential), 11% commercial, 15% medium industrial, 27% large industrial, 25% extra-large industrial, and less than 1% streetlights.

Figure 1

Energy Sales by Customer Category



All electric generation is provided by third parties except for some legacy generation owned by UEGCL. The third-party power producers sign power purchase agreements (PPAs) with UETCL, essentially bilateral contracts. UETCL, in turn, manages the scheduling and dispatch of power plants and then bills the distribution operators for combined generation and transmission services. The generation facilities have an installed capacity of 1,237 MW. The aggregate fuel mix is approximately 82% hydro, 8% thermal, 5% co-generation, and 5% grid-connected solar.

The current electricity sector structure is the result of Uganda-embraced reforms and shaped by a key piece of legislation called The Electricity Act of 1999. The reforms included unbundling generation, transmission, and distribution; privatization of the state-run power company; creation of an independent regulator; encouragement of competitive generation with long-term PPAs; creation of a state-owned transmission company; and licensing of independent distribution companies.

Prior to 2000, the Uganda electricity supply industry was organized as one vertically integrated government-owned entity called the Uganda Electricity Board. The pre-2000 challenges included low generation productivity, suppressed demand, a poor and degenerating network, poor supply reliability, revenue inadequacy, inadequate investment, limited private participation, and poor commercial performance characterized by low connection rates, high technical and non-technical losses, high accounts receivable, low electrification rates, and unsustainably high subsidy levels.

In mid-1997, the Uganda government embarked on an extensive economic recovery program by implementing key policy reforms that focused on price stabilization, privatization, and liberalization. The electricity sector reforms were approved in 1999 and became operational in 2000. Uganda opted for a drastic, rather than a gradual or cautious, approach. Generation concessions were awarded in 2002 and distribution concessions were awarded in 2005.

Ten objectives of the power sector reforms included:

1) Promote institutional arrangements, policies, and procedures;
2) Rehabilitate and restructure the public enterprises;
3) Attract private sector participation;
4) Increase sector efficiency;
5) Take advantage of power export opportunities;
6) Make the power sector financially viable and able to perform without subsidies;
7) Improve the sector commercial performance;
8) Meet the growing demands for electricity and increase area coverage;
9) Improve the reliability and quality of electricity supply; and
10) Attract private capital and entrepreneurs.

Uganda has enjoyed the benefits of reform. Fruits of reform including cost-reflective tariffs, improved quality of service and supply, improved collection rates, attraction of investment, increased distribution efficiency, growth in generation capacity, reduction of government subsidies, incentive-based regulation, adequate supply, increased participation, and increased access from 12-15% to 51%.

The ERA is the legal supervisor of Uganda's electricity supply industry. There are five Authority Members appointed by the Minister of Energy and Mineral Development with the approval of the Cabinet. The Authority Members serve five-year terms, with one authority member designated at the Chairperson.

As established by the Electricity Act of 1999, the ERA provides regulatory oversight; issues licenses; establishes tariffs; develops and enforces performance standards for generation companies, UETCL, and distribution companies; and protects customers on price, terms and conditions of supply, continuity of supply, and reliability.

The ERA staff is organized into seven departments: Human Resource and Administration, Procurement and Disposal, Consumer and Public Affairs, Economic Regulation, Technical Regulation, Legal and Authority Affairs, and Financial and Administrative Services, reporting up through a Chief Executive Officer.

1.3 Organization

The organization of this Annex 1 case study is patterned after the primer organization as follows:

Section 2 provides a Uganda electricity tariff overview.

Section 3 describes the ERA response to the need for cost-reflective tariffs.

Section 4 describes the ERA response to the need for high quality accounting data.

Section 5 describes expenses incorporated into revenue requirements by the ERA.

Section 6 explains rate base assets and liabilities incorporated into revenue requirements by the ERA.

Section 7 describes the categorization of total bill impacts to end-users by distribution, transmission, and generation.

Section 8 explains the primary drivers of electricity tariffs in Uganda.

Section 9 concludes with final remarks.

2. Electricity Tariffs Overview

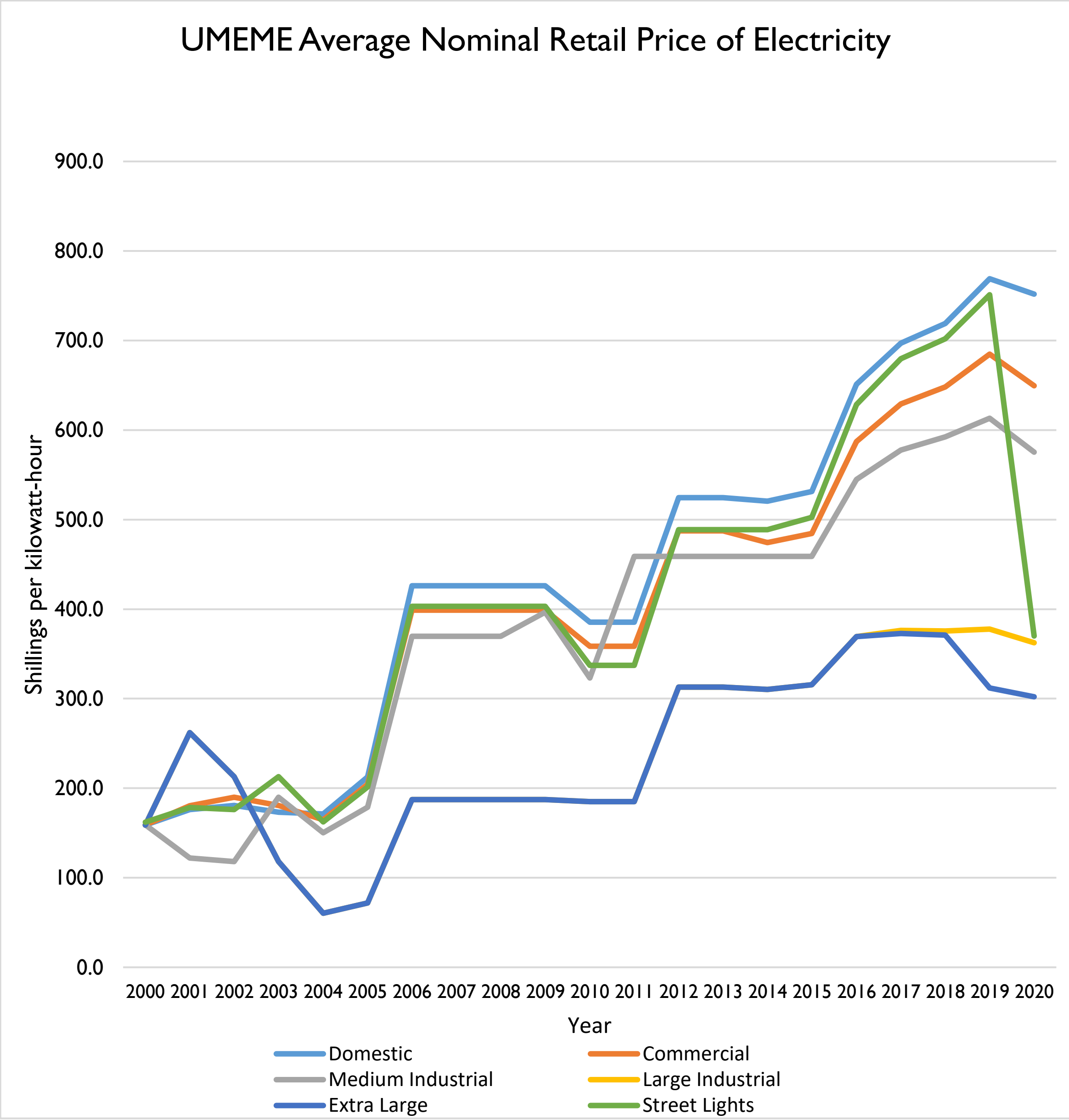
Ugandan regulated electricity rates are specified in tariffs. Tariffs are published on the Uganda ERA website. Ugandan tariff prices are typically expressed in Uganda shillings per kilowatt hour.

The case study in this Annex will focus primarily on data from Uganda's main distribution utility, UMEME. UMEME operates a 20-year electricity distribution concession from the Government of Uganda that took effect on March 1, 2005. UMEME is licensed to distribute and supply electricity to customers and is mandated to operate, maintain, and upgrade distribution infrastructure, electricity retail, and provision of related services.

UMEME tariffs are a good proxy for the Ugandan electricity sector because UMEME serves more than 90% of Ugandan electricity customers, is representative of the country in aggregate, and has more historical tariff data than most Ugandan distribution companies.

The average nominal retail price of electricity of UMEME in Uganda trended upward in nominal terms during the last 20 years, as shown in Figure 2 which is based on data provided on the Uganda ERA website. UMEME electricity prices for the primary customer categories are shown for 2000 through 2020.

Figure 2



For tariff purposes, Ugandan electricity customers are primarily categorized as domestic (residential), commercial, medium industrial, large industrial, extra-large industrial, and streetlights. Domestic customers are metered at low voltage and include residential houses, small shops, and kiosks. Commercial customers are small industries such as maize mills and water pumps metered with connected load at low voltage. Medium industrial customers are medium scale industries that take power at low voltage and maximum demand of up to 500 kilovolt-ampere (kVA).

Large industrial customers are large scale industries taking power at high voltage with a maximum demand exceeding 500 kVA up to 1,500 kVA. Extra-large customers are manufacturers taking power at high voltage with maximum demand exceeding 1,500 kVA.

The extra-large category appears to have been created in 2017 out of the large industrial category. Streetlight customers include electricity supply for street lighting in cities, municipalities, towns, trading centers, and community centers. Different rates apply to each sector, as shown in Figure 2. Domestic rates are the highest and extra-large rates are the lowest.

The upward trend in nominal Ugandan electricity prices reflects increasing nominal costs over the last two decades. The annual growth rate in UMEME electricity prices has been 18.7% for domestic, 15.4% for commercial, 13.1% for medium industrial, 6.4% for large industrial, 4.5% for extra-large, and 6.4% for streetlights. By comparison, the Ugandan general inflation rate has averaged 6.2% over this two-decade time period.

Comparing the nominal inflation rate of electricity service to the general inflation rate, the electricity rate increases have exceeded the general inflation rate, resulting in real electricity average price increases for all customer categories except extra-large customers. It appears that the Uganda general inflation rate has likely been a primary driver of electricity tariffs over this period, but clearly is not the whole story. Other electricity supply industry factors are at play.

During 2012, the electricity tariffs shown on Figure 2 experienced a significant increase, driven by the commissioning of the Bujagali hydropower plant in August 2012. The Bujagali generating station was originally approved in 1994, but construction did not begin until 2007.

During the project, the estimated cost increased from US$430 million to US$902 million, while the estimated output decreased from the installed capacity of 250 megawatts due to changing hydrological conditions. This combination of project delay, increased costs, and reduced output, along with reduced government subsidies, impacted the generation component of the tariffs in 2012 compared to 2011. The Bujagali project demonstrates that incremental generation additions can be a primary driver of electricity tariffs.

During 2019, the ERA significantly reduced the street lighting tariff for all municipalities as part of a framework for enhancing street lighting, as evidenced in Figure 2. The ERA stated that its street lighting enhancements would facilitate longer hours of commercial activities that depend on illumination and strengthen the sense of security and beauty from illuminated streets and walkways. The ERA funded this downward adjustment in the street lighting tariff by spreading the revenue requirement to the other customer categories.

The decade of 2000 to 2010 included the Uganda reform implementation period, so it is also instructive to review the price growth for the decade of 2010 to 2020. The annual growth rate in UMEME electricity prices has been 9.5% for domestic, 8.1% for commercial, 7.8% for medium industrial, 9.6% for large industrial, 6.3% for extra-large, and 1.0% for streetlights.

By comparison, the Ugandan general inflation rate has averaged 6.0% over this decade time period. It is safe to conclude that the Ugandan general inflation has continued to be a primary driver of electricity tariffs during the past decade.

Although UMEME represents more than 90% of distribution service in Uganda, a review of the tariffs of other Ugandan electric distribution companies reveals some regional differences in tariffs. Figure 3 compares the regional domestic tariffs. Figure 4 compares the regional commercial tariffs. Figure 5 compares the regional medium industrial tariffs. There are some regional differences in tariffs but also a lot of similarities.

No domestic tariffs are higher than the UMEME domestic tariff as shown in Figure 3. The domestic tariffs range from on a par with UMEME to a 21% discount to the UMEME domestic tariffs.

Figure 3

Comparison of 2020 Q1 Domestic Tariffs Across Discos
In Ugandan Shillings per kWh

Service Territory	Domestic Tariff
UMEME	751.7
WENRECO	710.0
KIL	626.4
PACMECS	669.4
BECS	635.3
Kisiizi	589.3
KRECS	750.8
KIS	742.8
UEDCL	751.7

The commercial tariffs range from a 30% premium to a 14% discount to the UMEME commercial tariffs as shown in Figure 4.

Figure 4

Comparison of 2020 Q1 Commercial Tariffs Across Discos
In Ugandan Shillings per kWh

Service Territory	Commercial Tariff
UMEME	649.4
WENRECO	643.2
KIL	571.6
PACMECS	614.0
BECS	561.2
Kisiizi	589.3
KRECS	604.8
KIS	846.2
UEDCL	649.4

For the distribution companies that have medium industrial customers, the medium industrial tariffs range from a 47% premium to a 1% discount to the UMEME medium industrial tariffs as shown in Figure 5.

Figure 5

Comparison of 2020 Q1 Medium Industrial Tariffs Across Discos In Ugandan Shillings per kWh

Service Territory	Medium Industrial Tariff
UMEME	575.2
WENRECO	620.0
KIL	566.9
PACMECS	0.0
BECS	0.0
Kisiizi	0.0
KRECS	594.8
KIS	846.2
UEDCL	575.6

Uganda cost of service regulation generally follows international best practices. The "Tariff Determination in the Uganda Electricity Sector" document prepared in October 2006 describes the ERA process of establishing generation tariffs, bulk supply tariffs, and end-user tariffs. These tariffs comport with cost-reflective principles.

The ERA sets electricity prices at three points in the industry: 1) at the interface between generation and transmission; 2) at the interface between transmission and distribution; and 3) at the interface between distribution and end-users. The transmission company acts as a single buyer of generated electricity as well as the sole Uganda importer and exporter. The generation prices are negotiated between each generator and the transmission company through PPAs, with oversight and approval of the ERA.

The sole transmission company, UETCL, sells power to the distribution companies through a bulk supply tariff that reflects the cost of both generation and transmission. In turn, the distribution company sells electricity to end-users at tariffs that reflect the cost of generation, transmission, and distribution.

The components of cost-of-service regulation that reveal drivers of electricity tariffs are utilized at all three interface points. The annual revenue requirement represents the total amount of annual revenue that a utility must collect from customers in order to recover all annual costs of providing reliable electricity service, including a reasonable return on its investment. Stated as a series of general equations:

Cost of Service = Revenue Requirement

Revenue Requirement = Expenses + Reasonable Return

Expenses = O&M + D + T

- O&M = Operation and Maintenance Expense
- D = Depreciation and Amortization Expense
- T = Income Tax Expense

- Reasonable Return = Rate Base * Cost of Capital
- Rate Base = Net investment in assets after accumulated depreciation and liabilities

Each of these revenue requirement components can be a driver of change in electricity tariffs, including the expense components, the rate base components, and the cost of capital. It is constructive to review how Uganda implements them.

The ERA determines the revenue requirement of each of the generation, transmission, and distribution companies based on rate of return regulation, as enhanced by elements of performance-based regulation such as a benchmarked level of losses (described in Section 5), operating and maintenance costs, and bad debts. The ERA's goal is for each utility's revenue to be earned equal to the cost to supply electricity plus a fair return on the rate base.

The generation revenue requirement is based on the investment component including depreciation, reasonable return, and income tax expense, the generation O&M component including fuel costs, the concession fee or lease component, and other costs such as regulatory fees and loyalties.

The bulk supply tariff is based on a revenue requirement that includes the transmission O&M component, the net purchase power costs, and an allowance for transmission debt service costs.

UMEME tariffs are calculated in reference to its distribution revenue requirement made up of O&M costs, depreciation, return on assets, return on working capital, a benchmarked allowance for bad debt and losses, and income tax. Other distribution companies may have different tariff methods but follow similar principles.

The companies apply for a revenue requirement each year, thus minimizing regulatory lag compared to less frequent test years. The revenue requirement methodology is somewhat standardized as specified in the original licenses granted by the ERA. The ERA invites the public to provide comments on the company submissions to enhance transparency and accountability.

Although the revenue requirement studies are performed annually, the tariffs are adjusted on a quarterly basis to allow for pass-through of significant non-controllable changes in fuel prices, inflation, and exchange rates. This quarterly tariff adjustment process also helps mitigate regulatory lag.

3. The Need for Cost-Reflective Tariffs

The objective of cost-based tariff-setting is to balance the interests of investors and customers. Investors seek a reasonable return on investment and customers seek a reasonable price. Cost-reflective tariffs are the primary tool to accomplish both objectives simultaneously. Uganda began its path to cost reflective tariffs in 1997, through the Act of 1999, and the ERA's founding in 2000 put Uganda on the path to commitment to cost-reflective tariffs.

The ERA accomplishes this balance through two main considerations: 1) set the fair and reasonable revenue requirement in light of the objective of continuity of supply and affordability; and 2) balance the interest of all the stakeholders including current and potential customers, government, and licensees.

The tariff setting process is guided by the ERA's objectives of maintaining a financially and operationally secure electricity supply system, efficient price signals, efficient use of plant, giving confidence to current investors and attract new investors, providing a cost-reflective tariff for each customer group, and providing for future progress towards a commercially competitive system.

The ERA tariff-setting construct imposes discipline that removes the utility's monopoly ability to earn a return significantly in excess of its cost of capital while providing a reasonable opportunity to earn the cost of capital. As such, cost-reflective tariffs minimize both upside and downside earnings opportunities.

The ERA rate-setting process serves customers when it harnesses investors' desire to provide capital for infrastructure that is constructed to provide safe, reliable, and affordable service. Investors evaluate business risks and, for utilities, one of the most important types of business risk is regulatory risk. Investors take into account the timeliness of regulatory rate approvals, the forward-looking nature of the revenue requirement components and, of course, the authorized ROE, but also the opportunity provided for the utility to earn the authorized ROE.

The ERA's two main considerations indicate that it takes a long-term perspective that minimizing regulatory lag actually benefits customers, rather than falling prey to the illusory short-term perspective that minimizing regulatory lag harms customers. Customers thus benefit by having a financially stable utility that has the earnings and cash flow sufficient to attract capital on reasonable terms, and the resulting ability to provide safe, reliable, and affordable utility service.

The ERA has also made efforts to minimize subsidies that, if built into electricity tariffs, would create additional regulatory risk. In line with modern international tariff principles and the Electricity Act of 1999 that requires cost-reflective tariffs, cross-subsidization of any customer categories was eliminated, thereby promoting efficiency.

The ERA virtually eliminated inter-class rate subsidies that favor one customer category over others through its tariff-setting process. In the case of UMEME, tariff rates for customers in each tariff sector are computed to reflect the cost of electricity supply to that category. Implementation of this principle of eliminating cross-subsidies means that domestic tariffs are often higher than industrial tariffs. Lower voltage customers impose additional investment costs for transformers and secondary lines while also experiencing greater technical losses.

As a result, unsustainable government subsidies that would distort price signals for both investors and customers have been virtually eliminated from the Ugandan distribution and transmission tariffs, and used sparingly in the Ugandan generation prices.

Cost of capital determination is an important revenue requirement component that drives cost-reflective tariffs. The ERA's approach to Weighted Average Cost of Capital (WACC) calculation is described in a May 2019 document entitled "Methodology for Calculation of Return on Capital for Uganda Electricity Generation, Transmission, and Distribution Companies."

In 2019, the ERA attempted to increase the transparency, sustainability, and efficiency of its WACC process based on the three standards of capital attraction, comparable earnings, and financial integrity.

As part of its economic regulation and rate-setting duties, the ERA set a main goal to provide an efficient company the opportunity to make a fair return on its invested capital such that: 1) it is similar to an average return, generally, being made at the same time and in the same region on investments in other businesses facing similar risks; 2) it is reasonably sufficient to assure confidence in the financial soundness of that utility, and adequate, under efficient and economical management, to maintain its credit and enable it to raise the money necessary for the proper discharge of its public duties; and 3) it attracts an efficient level of investment to the industry ensuring the long-term sustainability of the sector.

The ERA has multiple applications of WACC: distribution, transmission, and generation. WACC is generally built into the revenue requirement, rates, and tariffs of all three primary components of a customer's electric bill based on an analysis of the capital structure and the cost rates of the individual capital components as follows:

$$WACC = D/C \times K_d + E/C \times K_e$$

where WACC = Weighted Average Cost of Capital;

D = Total debt;

E = Total equity;

C = Total capital = total debt plus total equity;

K_d = the cost of debt; and

K_e = the cost of equity.

The extensive details of WACC methodologies are beyond the scope of this case study but available in NARUC's A Cost of Capital and Capital Markets Primer for Utility Regulators. However, it is important to note that one favorable aspect of the ERA's WACC determination is the manner in which it risk-adjusts WACC for the different components of generation, transmission, and distribution.

Most cost of capital parameters are common, but the specific parameters for the debt/equity proportions and the cost of equity betas are varied by the ERA to result in risk-differentiated WACCs. For example, the resulting WACCs computed in 2019 are 11.0% for merchant generation, 9.8% for fully contracted generation, 9.2% for transmission, 9.5% for distribution, and 11.9% for off-grid projects.

In summary, cost-reflective tariff-setting that provides the opportunity for a utility to adequately recover the cost of serving customers in a timely manner, achieve its revenue requirement, and earn its authorized WACC while minimizing regulatory lag and avoiding subsidies, will facilitate the achievement of customer benefits.

4. The Need for High Quality Accounting Data

In addition to recognizing the need for cost-reflective tariffs, Uganda also recognized the need for high quality regulatory accounting data as far back as 1997. High quality accounting data contributes to the accuracy of electricity tariffs. The attributes of high-quality accounting data include accuracy, timeliness, verifiability, granularity, and comprehensiveness, as described in NARUC's *Regulatory Accounting: A Primer for Utility Regulators*.

The ERA embarked on a mission to establish a Uniform System of Accounts (USoA). The importance of high-quality accounting data is heightened in emerging economies like Uganda as regulators work to establish cost-reflective tariffs. The need for accurate, reliable accounting information is paramount as a foundation for ratemaking.

Because the revenue requirement components have their root in the financial statements, regulatory accounting data is a major concern. The expense, asset, and liability accounts of the ERA's USoA are particularly important to revenue requirement determination.

Uganda's Electricity Act of 1999 required the ERA to put in place a USoA for all licensed companies in the electricity supply industry. The ERA worked through a multi-year involved process with NARUC, USAID, and the regional Power Africa organization to develop its USoA and implement a realistic implementation plan.

Power Africa emphasized the benefits of building an enabling environment for investment through improved policy and regulatory frameworks, and desired a regionally harmonized USoA and data collection tool. In particular, the ERA worked alongside regulators from South Africa, Nigeria, and Kenya. Through this cooperative process, the ERA was able to collaborate with peers.

The ERA issued a press statement on December 14, 2018 indicating that its USoA provides the benefits of heightening transparency, standardization of reporting, comparison of performance of ERA's licensed companies, and ease of the tariff determination process, while acknowledging the facilitation by NARUC supported by USAID.

The ERA recognized that the USoA enhances uniformity, comparability, accuracy, reliability, and consistency for reporting, cross-company benchmarking comparisons, rate regulation, rate studies, cost-of-service studies, depreciation studies, market oversight, and financial audits. When regulators scrutinize the financial statements, the existence of the USoA provide a solid foundation for calculating revenue requirement components.

The existence of a well-developed USoA ensures a certain level of accuracy and comparability of expense data on the income statement, rate base asset and liability data on the balance sheet, and debt and equity capital structure data on the balance sheet across licensees.

5. Typical Expenses Incorporated into Revenue Requirements

The ERA has established regulatory accounting and financial reporting requirements for Uganda electricity licensees. These requirements play a vital role in setting just and reasonable cost of service rates. The foundation of ERA's accounting program and reporting for all licensees is the USoA, as required by the enabling Electricity Act of 1999. Separate ringfencing guidelines have also been approved by the ERA.

As the ERA will rely on USoA data as a foundation for setting electricity tariffs, the USoA establishes a uniform format and set of accounts. The USoA requires the accounting separation of regulated and non-regulated activities, while facilitating preparation in accordance with International Financial Reporting Standards (IFRS). Where necessary, the ERA will conduct selected audits and reviews to assess licensee compliance with the USoA.

The USoA provides basic account descriptions, accounting definitions, and instructions that are useful in understanding licensee expense data. As licensees submit data on the USoA standard template for regulatory accounts, the ERA will have a vast amount of detail on utility financial statements. The expenses on the income statement that are most likely to be global primary drivers of electricity tariffs are highlighted in Sections 5.1 through 5.11.

The following sections of this case study provide some commentary on relevance of these global income statement accounts to Uganda.

5.1 Operation and Maintenance Expense

Operation and Maintenance (O&M) Expense is the cost incurred in operating and maintaining a utility's electric system. O&M is the largest and most sub-categorized expense. Because O&M is the most significant expense, it is often a primary driver of electricity tariffs. O&M expense covers the routine activities that enable the electric plant assets to perform their intended function of providing service to customers. O&M incorporates the cost of labor used to operate and maintain the electric system.

O&M expenses are absolutely essential to the provision of electric service, but must be shown to be reasonable and necessary before inclusion in the revenue requirement. The level of O&M should be scrutinized for prudent incurrence and can be disallowed or adjusted if needed to achieve a representative level in the test year.

In the Ugandan context, the cost of maintenance chargeable to the various operating expense and clearing accounts includes labor, materials, overheads, and other expenses included in maintenance work. Materials recovered in connection with the maintenance of property shall be credited to the same account to which the maintenance cost was charged.

Maintenance generally applicable to utility plant includes direct field supervision of maintenance; inspecting, testing, and reporting on condition of plant specifically to determine the need for repairs, replacements, rearrangements, and changes, and inspecting and testing the adequacy of repairs that have been made; work performed specifically for the purpose of preventing failure, restoring serviceability, or maintaining life of plant; rearranging and changing the location of plant not retired; repairing for reuse materials recovered from the plant, testing for locating and clearing trouble; net cost of installing, maintaining, and removing temporary facilities to prevent interruptions in service; and replacing or adding minor items of plant which do not constitute a retirement unit.

5.2 Technical and Non-Technical Losses

Technical and Non-Technical Losses are the difference between the amount of electricity that an electricity generator produces and the amount of electricity that the distribution utility's customers ultimately pay for through the end-user bill. An alternate name for these losses is Aggregate Technical, Commercial, and Collections (ATC&C) Losses. These losses are significant in Uganda and were a primary target of Uganda's electricity reform.

Prior to 1996, Uganda experienced high technical and non-technical losses exceeding 40% and high accounts receivable with about 50% being outstanding for more than six months. The five components of these losses are described in Section 5.2 of this primer and can be grouped into the two categories of distribution losses and transmission losses.

Of the five components, the two components of high voltage transmission technical losses and transformation technical losses can be grouped as transmission losses. The combined typical international standard is 3% to 6%.

The other three components of technical distribution line losses, non-technical commercial losses, and non-technical collection losses can be grouped as distribution losses. For accounting purposes, these five ATC&C components may be recorded in different portions of the income statement.

Post-reform, ATC&C losses and especially distribution losses improved but still remain a challenge. By, 2018, distribution losses reported by the ERA for the industry declined to 17%. UMEME distribution losses declined to 16.4%, although other distribution companies reported distribution losses as high as 35%. The distribution losses for four mini-grids were 26%, 17%, 6%, and 22%. UMEME has engaged different arms of government to assist in curbing theft and illegal connections.

The utility management is charged with minimizing all five components. The UMEME revenue requirement is based on a benchmarked allowance for bad debt and losses. The benchmark is set challengingly low in order to create an incentive for the distribution company to reduce them. Thus, these losses may not be fully passed on to customers. Recent distribution loss targets for UMEME include 15.38% for 2019 and 14.70% % for 2020, with the annual target gradually declining to 12.83% in 2025.

Likewise, the UETCL revenue requirement is based on a benchmarked transmission loss factor. Recent transmission loss targets for UETCL include 3.35% for 2020, 3.29% for 2021, and 3.03% for 2022.

For comparison, all five components can be especially significant in emerging economies. As noted in Section 5.2 of the main primer, the World Bank reports that average electric transmission and distribution losses have recently been observed to be 8.3% for the world, 6.2% for the European

Union, 6.3% for North America, 11.7% for Sub-Sahara Africa, and 18.3% for "heavily indebted poor countries."[19] If ATC&C losses exceed 20%, the utility as a rule is likely de-capitalizing and not recovering depreciation expense or return on capital.

5.3 Power Purchase Agreements and Competitive Generation Passthrough Costs

As mentioned previously, Ugandan generation projects are built, owned, and operated by third party generators and the distribution companies do not own generation resources. Purchased power is electricity generated by a third party and purchased by an electric utility for resale.

In Uganda, all purchased power is sourced through UETCL, the transmission provider. In all cases, the purchased power costs are fully passed through to end-users with no discount or premium. The net impact on the distribution utility is a wash between revenues and expenses. As noted in Section 5.11, PPA costs are categorized as energy purchases by the ERA's USoA.

5.4 Production Expense Including Fuel Costs

Power production expense consists of the costs to operate and maintain the different types of owned generation facilities including steam, nuclear, hydraulic, and other power generation. Fuel is a significant component of production costs along with labor costs. Fuel costs vary by generation type including coal, natural gas, nuclear, and water, and include the cost of transporting the fuel to the generating station. Wind and solar generation do not have fuel costs but experience other production costs.

Ugandan distribution companies do not directly incur production expenses and fuel costs but they do indirectly pay for these costs that are incurred by the generating company and passed on to the distribution company through PPAs and the transmission provider. The ERA tariffs are set annually but adjusted quarterly for fuel costs. As noted in Section 5.11, fuel costs are categorized as fuel purchases by the ERA's USoA.

5.5 Depreciation Expense

In the Ugandan context, depreciation means the loss in value to depreciable fixed assets from causes against which the utility in not protected by insurance. Among the causes are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in demand, and requirements of public authorities.

Licensees must use a depreciation method that allocates in a systematic and rational manner the service value of depreciable value over the service life of the property. Unless otherwise approved by the ERA, a licensee should charge depreciation by using the straight-line method.

Estimated useful service lives of depreciable property must be supported by engineering, economic, or other depreciation studies. Where composite depreciation rates are used, they should be based on the weighted average useful service lives of the depreciable property comprising the composite group. With a growing customer base and increasing levels of capital expenditures and rate base, depreciation expense is not to be underestimated as a primary driver of electricity tariffs.

5.6 Rate Case Expense

Rate case expense typically represents the incremental, out-of-pocket costs incurred by the utility in connection with applying for and litigating a formal case before a regulatory commission. Examples of

[19] The World Bank website, Table 5.11 – World Development Indicators: Power and Communications

out-of-pocket rate case costs include fees for outside attorneys and expert witnesses, copying, printing, mailing, regulatory fees, and travel costs.

Rate case expense is a cost of doing business required of a utility by the government and therefore a legitimate expense. Customers benefit from rate case expense because it is necessary for the utility to provide the commission with the information necessary to set tariffs at the proper level.

The ERA does not have a separate rate case expense category in the USoA, but it does track out-of-pocket expenses for consultants and legal expenses on a case-by-case basis.

5.7 Income Tax Expense

The ERA permits the recovery of income taxes in the revenue requirement. In the Ugandan context, licensees are required to maximize allowed deductions in calculating regulated business income tax. Only those income taxes on regulated business income that are currently payable should be included as a pass-through in the allowable revenue requirement.

Income tax expense is usually not a primary driver of electricity tariffs, but income tax law changes can be a primary driver. The Uganda corporate income tax rate has been stable at 30% since 1997.

5.8 Taxes Other than Income Taxes

Other taxes are imposed by governments and as such are a necessary cost of doing business. Taxes other than income taxes are usually not a primary driver of electricity tariffs unless the underlying tax fundamentals change. In the Ugandan context, the ERA includes the value-added tax as a passthrough to end-users.

5.9 Labor Costs

It is important to note that labor costs are relatively large expenses but are not necessarily separated and aggregated into unique dedicated line-item accounts. Instead, labor costs are incorporated into other expense categories, largely in O&M or plant accounts, by either direct assignment or allocation. As such, labor costs still are monitored and tracked extensively by regulators because they can be primary drivers of electricity tariffs.

Labor costs include all forms of compensation including salaries, wages, bonuses, health care benefits, pension benefits, and other consideration paid for services. Salaries and wages generally increase gradually year over year.

In the Ugandan context, labor cost charges to electric plant, operating expense, and other accounts for services and expenses of employees engaged in activities chargeable to various accounts such as construction, maintenance, and operations, shall be based on the actual time engaged in the respective classes of work, or in case that method is impracticable, on the basis of a study of the time actually engaged during a representative period.

5.10 Allocation of Administrative Costs for Affiliated Interests

Certain administrative costs may be more cost effectively incurred on a centralized basis by a parent company or other affiliated company and then allocated to other affiliates including the utility. Functional examples include Treasury, Auditing, or Human Resources costs where scale and scope may permit affiliated companies to efficiently and effectively perform these services on behalf of utilities.

Utility customers are likely to benefit from such arrangements. These affiliated administrative costs are legitimate costs of doing business but should be scrutinized for prudency along with allocation ratios to ensure fair allocation to the utility subsidiary.

In the Uganda context, the ERA addresses affiliated interest costs in its USoA Procedures Manual / Ringfencing Guidelines. The basic principle governing transactions between licensees and affiliates is that only costs relating to the operation of the licensed activity are allowed for tariff-setting.

Vertically integrated businesses shall, where required, keep separate accounts for separate business units and shall separate these between regulated and non-regulated businesses. The principal objectives of this separation are to minimize the potential for a utility to cross-subsidize non-regulated operations and ensure that there is no preferential access to regulated entity services.

The ERA clarifies that utility purchases from affiliates should not exceed fair market value. Where no market value exists, payment reflected should be no more than the cost-based price. Cost-based price should follow USoA cost allocation guidelines.

When Ugandan utilities incur costs that are shared between regulated and non-regulated operations, shared services costs should be assigned directly on the basis of causation or usage to the maximum extent possible, and where cost causation cannot be easily ascertained or established, cost drivers should be selected based on benefits received. A key element is to ensure that transactions occur at arms-length.

5.11 Other Expenses

Most of the remaining expenses on the USoA income statement that are not covered in Sections 5.1 to 5.10 are either relatively small, somewhat self-explanatory, and/or a sub-component of O&M, so will not be described separately.

In the Ugandan context, cost of sales for distribution companies has a very large energy purchases component that is the one expense item that stands out for special mention due to the nature of Ugandan generation and transmission billings noted in Sections 5.3 and 5.4. Cost of sales energy purchases represent billings from the transmission provider to the distribution company for both recovery of transmission costs and a pass-through of generation costs.

The energy purchases sub-account reflects the energy purchased by UETCL from the generators and the energy purchased by distribution utilities from UETCL. The fuel purchases sub-account captures the cost of fuel used for purposes of generating, distributing, or transmitting electricity including heavy and light fuel for thermal generation plants.

5.12 Significance of Each Expense to Total Expenses

From one point of view, the largest expenses can be viewed as primary drivers of electricity tariffs. A draft 2019 Form DF-10 income statement from the USoA for UMEME shows the breakout of expenses. This Form DF-10 is shown as Figure 6.

Figure 6

INCOME STATEMENT FOR THE YEAR

1. If the notes appearing in the statutory financial statements are applicable to this statement of income, such notes may be included on DF 15.

2. Enter on page 21 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including basis of allocation and apportionments from those used in preceding year.

3. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

			Regulated		Non-Regulated		Total Business	
Line No.	Title of Account (a)	Form No. DF (b)	Current Year (c)	Previous Year (d)	Current Year (c)	Previous Year (d)	Current Year (c)	Previous Year (d)
1	**Operating Revenue**	57	1,849,088,349,552		-		1,849,088,349,552	
2	**Cost of Sales:**							
3	Operating Expenses	60	1,210,631,011,070		-		1,210,631,011,070	
4	Maintenance Expenses	63	27,510,269,549		-		27,510,269,549	
5	Depreciation Expense	64	120,035,341,843		-		120,035,341,843	
6	**Sub-Total**		1,358,176,622,462				1,358,176,622,462	
7			490,911,727,090	-	-	-	490,911,727,090	-
8	Other Income/Deductions	66	(67,376,703,720)		-		(67,376,703,720)	
9			423,535,023,370		-		423,535,023,370	
10	Selling and Marketing Expenses	67	5,539,369,731		-		5,539,369,731	
11	Administrative Expenses	69	189,233,099,902		-		189,233,099,902	

12	Finance Cost	71	57,074,044,511		-		57,074,044,511	
13								
14	Other Deductions	73	32,536,509,225		-		32,536,509,225	
15								
16	Operating Profit/(Loss) before Tax from Regulatory Operations		139,152,000,001	-	-	-	139,152,000,001	-
17								
18	Provision for Taxation (Tax Payable)	56				-	-	-
19								
21								
22	Operating Profit/(Loss) after Taxation		139,152,000,001		-		139,152,000,001	
23								
24	Extraordinary Items	73	-		-		-	
25								
26	Discontinued Operations	73	-		-		-	
27								
	Net Profit/(Loss)		139,152,000,001	-	-	-	139,152,000,001	-

Focusing on the UMEME expenses on Figure 6, it is clear that operating expenses are the largest expense category constituting 78% of total expenses. Figure 6 also demonstrates that administrative expenses and depreciation expenses are also significant in size, making up 12.2% and 7.7% of total expenses, respectively.

A further breakdown of operating expenses is provided on a draft 2019 Form DF-60 from the USoA for UMEME. This operating expense detail is shown on Figure 7.

Figure 7

OPERATING EXPENSES								
			Regulated		Non-Regulated		Total Business	
A/C #	Account (a)	Form No. DF (b)	Current Year (c)	Previous Year (d)	Current Year (c)	Previous Year (d)	Current Year (c)	Previous Year (d)
	Operating Expenses – Distribution							
	Power Purchases:	61						
501359	Wheeling Charge		-		-		-	
501360	Energy Purchases		988,998,645,646		-		988,998,645,646	
501363	Deemed Energy Purchases		-		-		-	
501362	Lubrication Oil cost		-		-		-	
501365	VAT on imported power		-		-		-	
	Capacity Charges	61						
	Other Charges	61						
502407	Computer supplies and maintenance		-		-		-	
502408	N/A							
502409	Consumable Tools & Equipment		-		-		-	
502411	Customer Connection costs		193,492,850,415		-		193,492,850,415	

502412	Distribution Overhead hardware		-		-		-	
502413	Realized Exchange/Revaluation loss		-		-		-	
502414	Fuel cost		6,615,552,886		-		6,615,552,886	
502415	Legal fees		6,227,174,019		-		6,227,174,019	
502416	Line Clearance		3,290,643,755		-		3,290,643,755	
502417	Meters and other meter testing equipment		-		-		-	
502418	N/A							
502419	Pole Preservation		-		-		-	
502420	Poles		-		-		-	
502421	Repair and maintenance (Power Lines)		-		-		-	
502422	Repairs and maintenance (General)		-		-		-	
502423	Road Toll		-		-		-	
502424	Stationery		-		-		-	
502425	Substations		-		-		-	
502426	Telephone, Internet & fax Communication		5,969,138,979		-		5,969,138,979	
502427	Tools & Equipment		-		-		-	
502428	Transformer		-		-		-	
502429	Transformer Oil		-		-		-	

502430	Utility expenses		-		-		-	
502431	Vehicle Spares		6,037,005,370		-		6,037,005,370	
502432	N/A							
	Other Rental charges							
	Total Operating Expenses – Distribution		1,210,631,011,070	0	-	0	1,210,631,011,070	0
	Other Power Expenses							
	Cost of Power Adjustments							
	Charges - One-Time							
	Distribution Charges							
	Distribution Charges recovered							
	Other Expenses							
	Sub – Total		**-**	**0**	**-**	**0**	**-**	**0**
	Total Operating Expenses		**1,210,631,011,070**	**0**	**-**	**0**	**1,210,631,011,070**	**0**

Focusing on the UMEME operating expenses on Figure 7, it is apparent that energy purchases are the dominant component constituting 81.7% of operating expenses. The only other significant component is customer connection costs making up 16.0% of operating expenses.

Combining information from both Figures 6 and 7, it is apparent that the UMEME energy purchases represent 63.7% of total expenses while customer connection costs make up 12.5%.

Another way to view primary drivers of electricity tariffs is to review which components experienced the fastest growth over time. Time series data for four key expense categories is available for UMEME since 2009. Additionally, cost of sales data is available for UMEME since 2011.

Figure 8

UMEME
Annual Growth Rates in Expenses
For the Period 2009 through 2019

Expense	Annual Growth Rate
Staff Costs	19.28%
Repairs and Maintenance	5.70%
Other Costs	55.96%
Administrative Expenses	-1.92%
Cost of Sales (for the period 2011-2019)	42.12%

Figure 8 demonstrates that cost of sales, other costs, and staff costs increased the fastest at annual growth rates of 42%, 56%, and 19%, while repairs and maintenance expenses and administrative expenses remained relatively flat at annual growth rates of 6% and -2%.

With customer growth exploding over this time period due to the beneficial Uganda reforms, it is not surprising that cost of sales, other costs, and staff costs would grow significantly. Customer counts roughly doubled from 2015 to 2020, increased 11% in 2020 alone, and are expected to increase another 54% between 2020 and 2025. It is more surprising that repairs and maintenance and administrative expenses remained relatively flat during a period of significant customer growth.

These expense time series comparisons will only improve in the future as more years of Ugandan USoA data become available for additional expense categories.

6. Typical Rate Base Assets and Liabilities Incorporated into Revenue Requirements

Although this primer largely focuses on expenses, the rate base is also an important revenue requirement component. As described in Section 2, the rate base represents utility property, or the net investment in assets (gross investment in assets less accumulated depreciation and amortization) less certain liabilities.

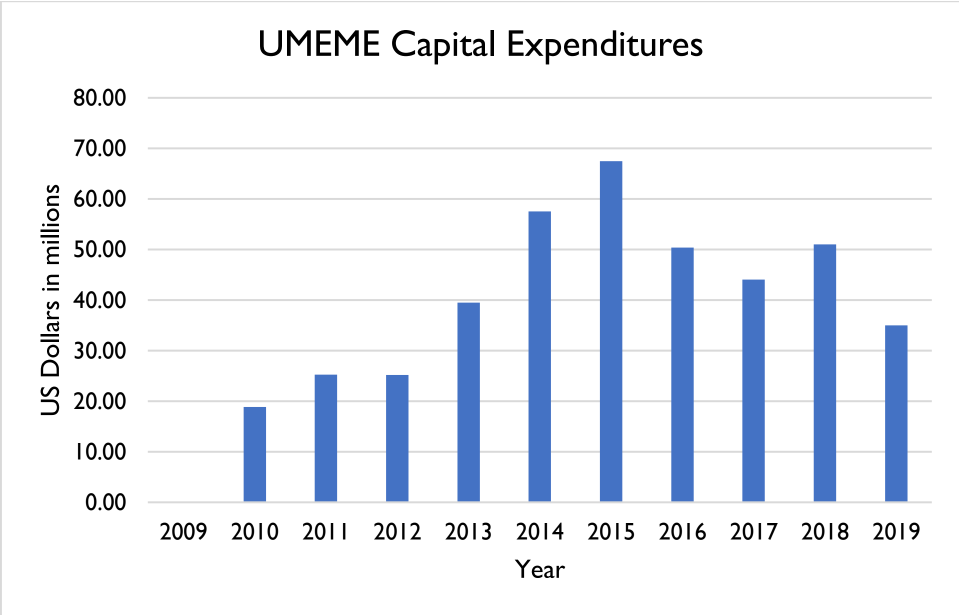
Cost-reflective tariffs provide for both a return "of" and "on" capital. The concept of accumulated depreciation helps illuminate the concept of the return "of" capital and the return "on" capital. Depreciation expense represents the return of capital, while simultaneously increasing the accumulated depreciation and decreasing the rate base.

As assets age, their value declines as the accumulated depreciation balance increases until they reach retirement and must be replaced with new investment. A utility's cost of capital (authorized and earned) on the rate base represents the return on capital.

A typical investment cycle consists of the utility replacing existing depreciated assets with investment in new assets, referred to as capital expenditures. Capital expenditures are major, long-term expenditures to acquire, upgrade, and maintain physical assets, in contrast to operating expenses that are day-to-day expenditures.

In the Uganda context, capital expenditures are driven not only by the typical investment cycle but by the significant customer growth from demand outstripping supply and expansion of the network to unserved and underserved locations. Growing UMEME capital expenditure levels are evident from Figure 9. Please note that these capital expenditure numbers are cited in US dollars rather than Ugandan shillings, but the trend is evident.

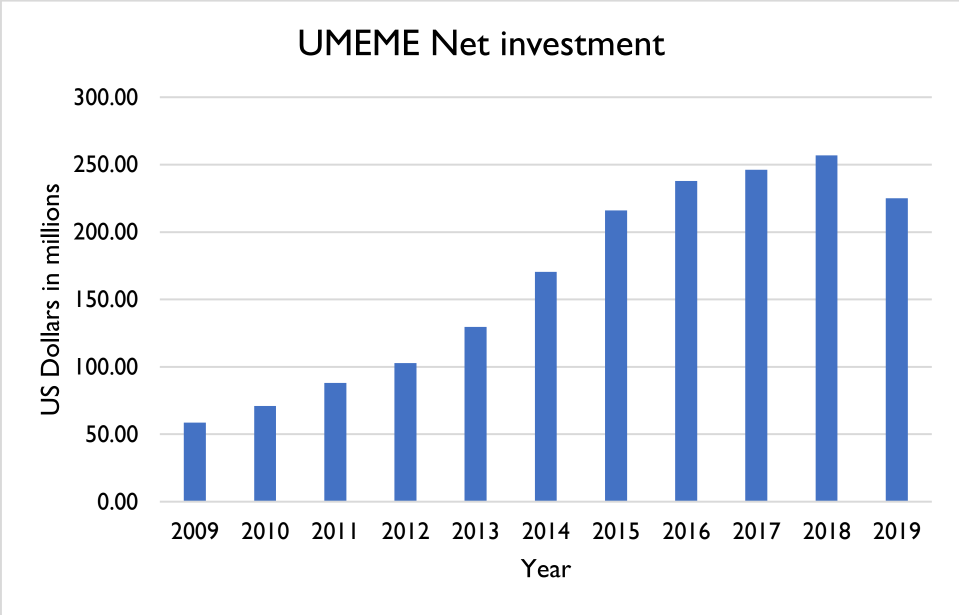
Figure 9



These significant capital expenditure levels in turn lead to a rapidly increasing rate base as well as increasing depreciation expense levels. For a Uganda distribution company, the distribution capital expenditures increase the distribution rate base, while the cost of sales also increases along with the corresponding growth in generation and transmission rate bases and depreciation expense.

Growing UMEME net investment, which is reflective of rate base, is evident from Figure 10. Please note that these net investment numbers are cited in US dollars rather than Ugandan shillings, but the trend is evident.

Figure 10



Customers benefit from capital expenditures through electrifying more areas of the country, adding new customers, replacing aged infrastructure, maintaining existing infrastructure, enabling new projects, and upgrading to new technologies. The customer benefits of planned capital expenditures often can best be understood in the context of a forward-looking long-run plan, similar to those reviewed by the ERA.

It is clear the capital expenditures have recently been and are expected to remain a primary driver of electricity tariffs.

7. Categorization of Total Bill Impacts to End-Users by Distribution, Transmission, and Generation

It is usually informative to break down the overall utility revenue requirement reflected in the utility bill paid by end-users between the components of distribution, transmission, and generation. Regulators often pay attention to the level of total utility bills. All three components contribute in aggregate to the end-user bill but not necessarily in a way that is transparent to the customer.

In the Ugandan context, it appears that generation makes up the largest portion of the total end-user bill, while transmission comprises the smallest portion. A more detailed comparative analysis is challenging to estimate. The underlying data is monitored by the ERA staff, but is not publicly available. This data is expected to become more visible as the USoA continues to be implemented.

8. Primary Drivers of Electricity Tariffs

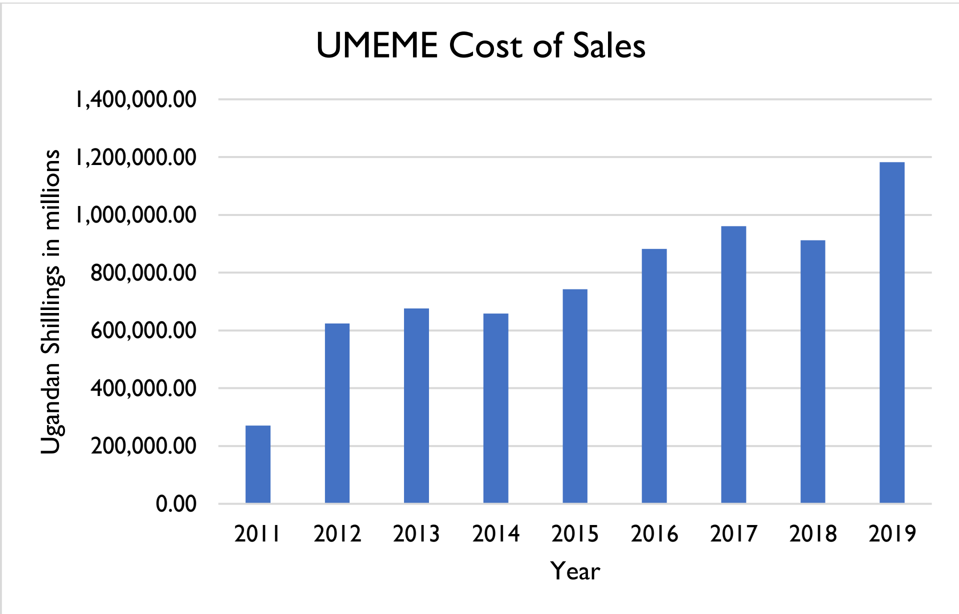
The primary characteristic of the Uganda electricity supply industry is explosive customer growth. More areas of the country are being electrified. Reliability is being enhanced and the network is being upgraded for existing customers. New generation is under construction as demand outstrips supply. The transmission grid is expanding to connect expanding generation to an expanding customer base. The distribution network is also expanding to serve new customers and enhance grid modernization.

Sections 5 and 6 of this case study summarize primary drivers of Ugandan electricity tariffs. Customer growth and needed expansion in the generation fleet, the transmission grid, and the distribution network, as well as Ugandan inflation and grid modernization, drive increases in many revenue requirement components: operation and maintenance expenses, cost of sales, and capital expenditures with the corresponding upward impact on rate base and depreciation expense are certainly primary drivers of electricity tariffs. Management control of technical and non-technical losses and administrative expenses, as well as economies of scale that tend to decrease per unit costs, help offset the upward pressure on tariffs.

Operation and maintenance expense discussed in Section 5 is the largest expense component, has increased along with customer growth, and is a primary driver of electricity tariffs, although certain component expenses have increased and decreased in offsetting fashion.

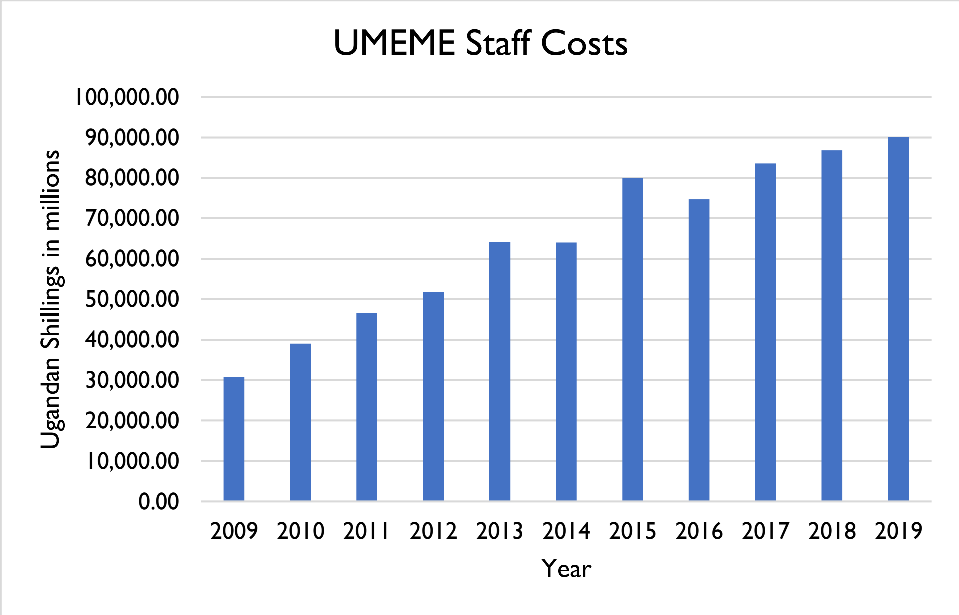
The upward trend in nominal cost of sales reflects the increasing generation and transmission investment and expenses passed through UMEME's revenue requirement as cost of sales to UMEME's customers, as shown on Figure 11.

Figure 11



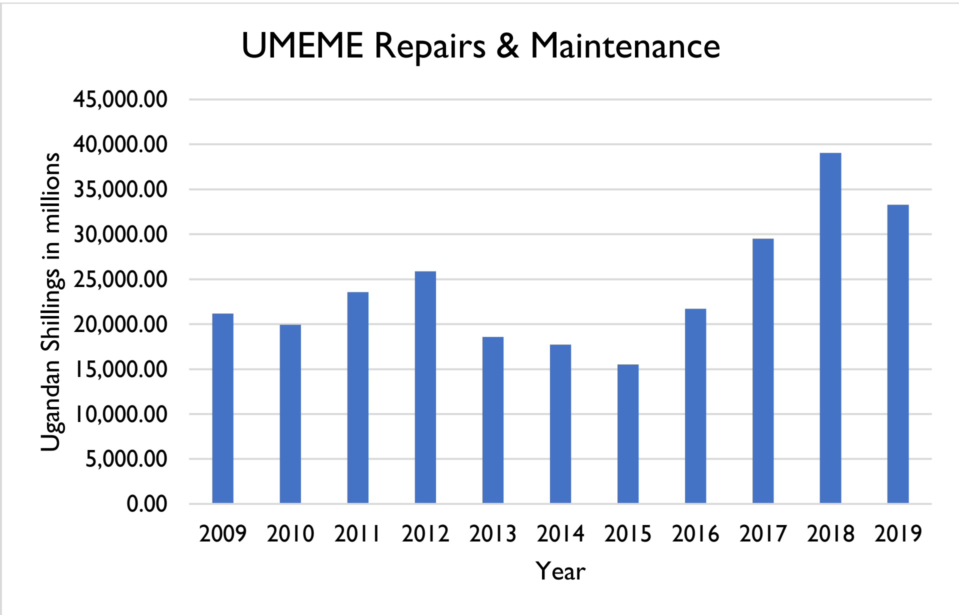
The more moderate upward trend in nominal staff costs over the past decade likely reflects an increasing need for employees to serve the expanding customer base and growing distribution network with some management control of costs, as shown on Figure 12.

Figure 12



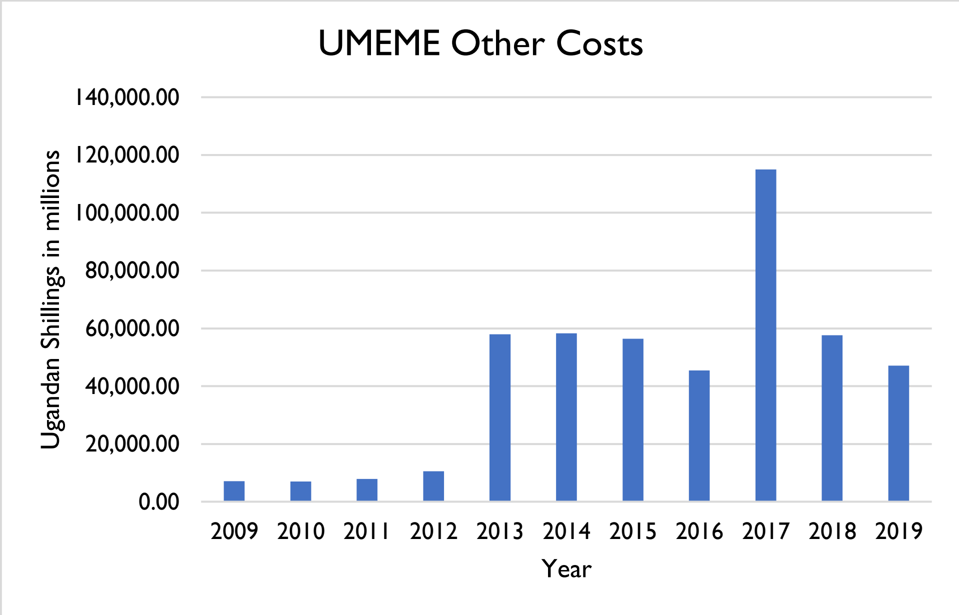
The upward trend in nominal repairs and maintenance expenses shown on Figure 13 likely reflects the need to repair and maintain additional plant. The more modest growth in repairs and maintenance expense is likely due to some degree of economies of scale and management cost discipline.

Figure 13



Other costs shown on Figure 14 have also increased significantly over time in nominal terms and likely include depreciation expense. Depreciation expense is a component that has been a primary driver. Corresponding with increased capital expenditures, depreciation expense is expected to continue to increase noticeably as capital expenditures continue at a robust level.

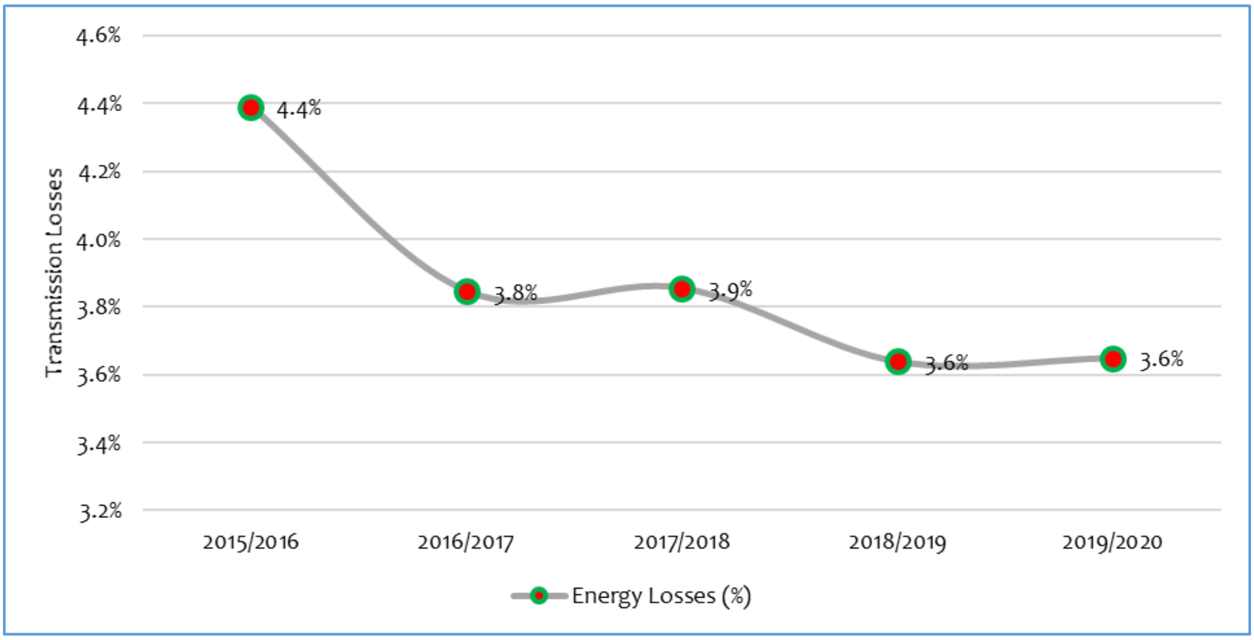
Figure 14



Technical transmission losses have decreased over time as shown in Figure 15. Declining technical transmission losses have been incented by the ERA and help to offset upward pressure on the revenue requirement.

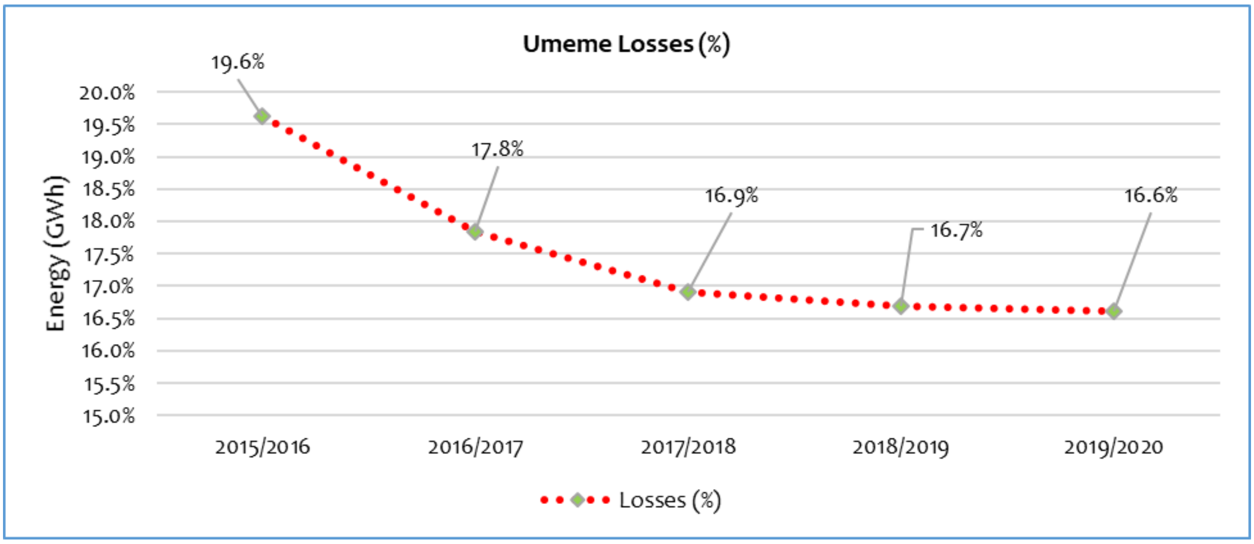
Figure 15

UETCL Transmission Losses



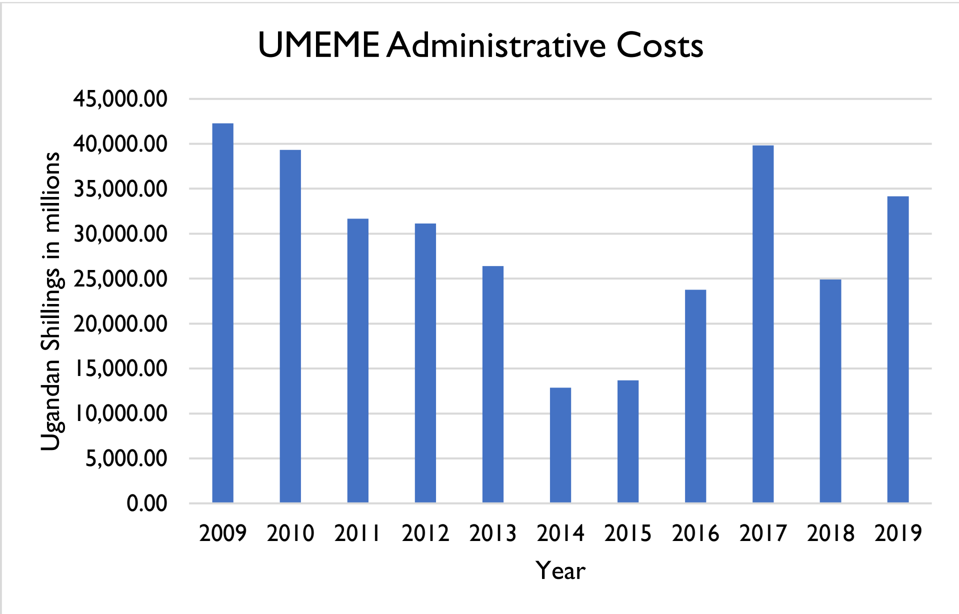
Technical and non-technical distribution losses have significantly decreased over time as shown on Figure 16. Declining technical and non-technical distribution losses have also been incented by the ERA and help to offset upward pressure on the revenue requirement.

Figure 16



Administrative expenses have actually moderated over the last decade in nominal terms as shown on Figure 17 and are not a primary driver of electricity tariffs. Management has exercised some degree of control over administrative expenses.

Figure 17



The primary drivers of electricity tariffs will change over time and from case to case. Tariff changes can be driven primarily by one driver or multiple drivers. However, it seems likely that the dynamics of the Uganda electricity supply will continue to be driven by significant customer growth.

As significant customer growth requires significant infrastructure investment, the ERA and utility management teams have recognized the need for capital expenditures for infrastructure investment. However, they must also be concerned with customer bill impacts.

The ERA and utility management teams have the opportunity to focus on a strategy to maximize capital expenditures that are necessary to provide service to customers, while also recognizing that the customer bill impacts of tariff increase well in excess of the general inflation rate will likely not be palatable. The solution may be to pursue a strategy to control operating expenses.

Utilities can identify and implement O&M expense control, or even O&M reductions in some cases, in a sustainable fashion that improves efficiency to accommodate capital expenditure growth. It appears that this disciplined O&M management strategy can successfully continue as experienced over the past decade for administrative expenses and ATC&C losses.

The combination of robust capital expenditures and increasing O&M expenses are mostly out of the control of the ERA and utility management teams and will be primary drivers of electricity tariffs going forward. The customer benefits of increased electrification are too great to interrupt. However, the focus on customer affordability will likely make an O&M cost control strategy attractive as a partial offset. An O&M cost control strategy can also serve as a primary offsetting driver of electricity tariffs going forward.

9. Final Remarks

This Uganda case study demonstrates the significant value of cost-reflective tariffs and high-quality accounting information to the benefit of utilities, investors, and customers. The pass-through of increasing generation and transmission costs, along with expense and rate base increases associated with significant customer growth are identified as the primary drivers of Uganda electricity tariffs.

It is intended that this Annex 1 analysis provides some context to utility regulators in countries with emerging economies about the primary drivers and how regulatory accounting data can facilitate the tariff-setting process.

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