PRIMER ON RATE DESIGN FOR COST-REFLECTIVE TARIFFS

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RATE DESIGN FOR COST-REFLECTIVE TARIFFS

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Acknowledgments

This Primer was developed by the National Association of Regulatory Utility Commissioners (NARUC) with the generous support of the United States Agency for International Development (USAID). This primer is one in a series focusing on the regulator's role with achieving cost-reflective tariffs and will be incorporated into a larger comprehensive guide on tariff settings – The Cost-Reflective Tariff Toolkit.

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About the Author

Cadmus combines over 20 years of experience developing robust and impactful energy policies, regulations, programs, and projects to support thriving energy markets in over 50 countries worldwide.

Founded in 1983 and headquartered outside of Boston, Massachusetts, USA, Cadmus is an international, multi-disciplinary consultancy committed to helping its clients address complex challenges by applying innovative solutions that create social and economic value now and for future generations. Cadmus' 600 professionals serve public, private, and non-profit clients globally.

Cadmus' energy practice brings together an interdisciplinary team of experts in law, policy, engineering, economics, finance, stakeholder engagement, and communications. The Cadmus team works in synergy to support governments, utilities, and communities to design and deliver high-impact, locally tailored energy sector solutions. Cadmus is a trusted advisor to energy regulators, utilities, and policymakers in emerging markets worldwide, serving as an on-call technical assistance expert for several global and regional energy programs.

Introduction

Rate design – the framework that utilities and regulators use to set prices for electricity services – is a fundamental element of a well-functioning electricity system. Rate design sits at the nexus between customers and utilities, determining the prices that customers pay for electricity and impacting the revenues that utilities raise to support commercial viability.

Designing rates is not an easy task. It involves complex consideration of a wide range of factors, including the costs of providing electricity service, customers' willingness to pay, long-term infrastructure investment, social equity, technology, and various other elements. In addition to knowledge of local market conditions, policy objectives, and stakeholders, regulators and utilities must have a strong technical foundation to be able to understand, assess, and develop rates that are in line with the principles of cost-reflective tariff setting.

It is for this reason that NARUC, in partnership with USAID, has developed this Primer on Rate Design for Cost-Reflective Tariffs to support electricity regulators in emerging markets. This primer aims to act as a resource for electricity regulators and utilities by outlining the fundamental principles of cost-reflective rate design and describing key rate design processes. It offers regulators and utilities a practical guide for adopting, reviewing, and assessing rate structures based on core principles, international case studies, and widely accepted practices.

At the outset, it is important to make it clear that there is no such thing as a "perfect" rate design. While the principles and processes explored by this primer lay the foundation for cost-reflective rate design, ratemaking is both an art and a science. In practice, regulators are forced to make decisions with imperfect information and are regularly called upon to exercise judgment in the face of competing principles and interests.

Despite these limitations, regulators need to have a basic understanding of the core principles and processes underpinning cost-reflective rates. Understanding the principles behind calculating a utility's costs and the methods of allocating such costs to different customers forms the basis of sound ratemaking. Understanding the fundamental principles and objectives of rate design ensures that regulators are equipped to grapple with inevitable trade-offs in the ratemaking process.

This primer is divided into four key sections:

- Section 1: Provides an overview of the principles of rate design
- Section 2: Explores key concepts and processes associated with rate design
- Section 3: Discusses common rate structures and their various pros and cons
- Section 4: Explores several issues in rate design that often arise in emerging markets

Annexure A contains a case study, highlighting the reforms that were undertaken in Brazil to promote cost-reflective rate design. This case study serves as an example for regulators and utilities that are operating markets that are either undergoing a process of market reform or pursuing a more cost-reflective rate design in their tariff setting processes.

This primer forms part of a Cost-Reflective Tariff Toolkit that NARUC has developed to support electricity regulators in emerging markets, including:

- Promoting Transparency and Public Participation in Energy Regulation: A Communications Primer for Utility Regulators

  This primer focuses on developing a set of recommendations that regulators in countries with emerging economies may want to consider when designing a communications strategy, particularly with regard to engaging the public and key stakeholders during a pending tariff change.

- Regulatory Accounting: A Primer for Utility Regulators

  This primer is a guide to the structure and function of a system of accounts that regulated utilities can use to ensure they are accurately recording and categorizing financial transactions and presenting coherent data to the regulator.

- Cost of Capital and Capital Markets: A Primer for Utility Regulators

  This primer is a guide to helping utility regulators around the world understand the capital markets and estimate the cost of capital, which is one of the elements of effective cost-based ratemaking and developing cost-reflective tariffs.

1 Principles of Rate Design

There is no such thing as a "perfect" rate design. Accounting, economic, and financial analyses allow regulators to understand certain parameters for rate design. However, the final tariff will almost always call upon a regulator to balance the interests of different stakeholders, all of whom offer rational arguments for their position. For instance, government stakeholders might want to maintain uniform postage-stamp tariffs because it is more acceptable to constituents, while utilities might want to charge different tariffs to ensure that certain customers are not unduly subsidizing others. At the end of the day, an electricity tariff will normally reflect a regulator's best attempt at a brokered compromise between competing interests.

In brokering the compromise, regulators should have regard to core principles. While a "perfect" answer is not necessarily achievable, a "principled," well-reasoned answer certainly is. The principles articulated by Professor James Bonbright's *Principles of Public Utility Rates*[1] are widely accepted as the gold standard for the issues that regulators should consider when setting electricity rates. The "Bonbright Principles" are explored in this section of the primer.

1.1 Sufficiency

The Bonbright Principle of sufficiency requires that electricity rates should allow a utility to recover its Revenue Requirement, that is, the costs of providing electricity service plus a reasonable rate of return. Sufficiency also considers the extent to which the electricity rates incentivize utilities to make continuing investments in the electricity system in order to ensure long-term viability and sustainability.

In order to satisfy this principle, the regulator and utility must conduct Revenue Requirement and Cost of Service studies to understand exactly how much it costs for the utility to provide reliable electric service to each class of customer. These will be discussed in greater detail in Sections 2.1 and 2.2 of this primer.

1.2 Fairness

Fairness can be considered on two levels. First, a regulator should consider whether the electricity tariff apportions costs and risks fairly between customers and utilities; put simply, "Are customers being asked to pay too much and are utilities earning too much profit?" Fair apportionment of risk is particularly important when setting multi-year tariffs as the tariff structure will normally determine whether the financial burden due to unforeseen events – such as economic shocks and natural disasters – falls upon customers or utilities.

Second, regulators should also consider fairness *among* the customer classes; that is, "Are certain customers shouldering more than their fair share of costs?" So that the regulator and utility can properly apportion these costs, they must also understand how much electricity is being consumed, by whom, and when. This is discussed in Section 2.2 of this primer, which deals with cost allocation.

1.3 Efficiency

Efficiency refers to the notion that electricity prices should be set at economically efficient levels. The prices should reflect, as closely as possible, the true costs of providing reliable electric service to each class of consumers; prices should not be unintentionally inflated or deflated as this may inadvertently distort the market.

[1] Bonbright, J. C. "Principles of Public Utility Rates [1st ed.]." (New York: Columbia University Press, 1961), Retrieved from http://www.raponline.org/document/download/id/813.

Efficiency is discussed in greater depth in section 4.3; however, the key point to note is that price plays a crucial role in determining how much electricity is consumed and when it is consumed. [2] Setting an electricity tariff that does not accurately reflect the costs of producing electricity can have serious consequences for the electricity system as a whole, leading to under or overinvestment in electricity infrastructure.

1.4 Customer Acceptability

There are two dimensions to customer acceptability. The first dimension relates to a customer's ability to understand, interpret, and react to an electricity tariff. For this to happen, an electricity tariff must be simple and clear enough for the customer to understand. If the method of communicating electricity prices is incomprehensible, then there is little chance of the customer being able to respond appropriately to the price signals set out in the tariff.

The second dimension of customer acceptability relates to a customer's ability or willingness to pay. One of the issues that a regulator is almost always required to consider is whether the electricity tariff is affordable. In emerging markets, tensions often arise between customers who struggle to afford electricity, particularly in rural areas, and utilities that encounter relatively high costs of service. This tension is exacerbated in countries where the Government has limited fiscal space to subsidize electricity. Section 4.1 of this primer discusses some of the tools that regulators use to ensure customer acceptability in such circumstances, such as cross-subsidization and lifeline tariffs.

1.5 Bill Stability

Bill stability refers to the need to ensure that electricity tariffs remain relatively stable over time. The exact cost of providing electricity is a constantly moving target. Fluctuating fuel prices, the variable output from renewable energy sources, and varying customer demand patterns are just a few examples of everyday factors that can drastically change the cost of providing electricity. This is in addition to unforeseen events such as economic shocks and natural disasters.

It is generally accepted that utilities and governments are better able to weather such fluctuations than customers. Bill stability is considered important for society because it ensures that businesses and households have a degree of certainty over their electricity costs over time. If extreme fluctuations in electricity prices were passed directly on to consumers, it would have widespread impacts on consumers' ability to plan and invest, thereby limiting economic growth.

Typically, these five core principles – sufficiency, fairness, efficiency, customer acceptability, and bill stability – are always in play when a regulator is asked to determine the appropriateness of certain rates. Rarely will all five principles be satisfied to their fullest extent; rather, it is common for regulators to consider trade-offs between these principles when coming to a final determination on a tariff.

[2] Specifically, marginal cost pricing.

2 Key Concepts

The principles outlined in Section 1 offer a framework for analyzing and assessing the efficacy of a rate design. Alongside this framework, it is important for regulators and utilities to understand the process for designing rates and the concepts that underlie these processes. This section deals with three of the most critical concepts: cost recovery, cost allocation, and rate structure.

2.1 Cost Recovery

Cost recovery is the fundamental tenet of cost-reflective tariff setting. It refers to the notion that electricity tariffs should be designed so that a utility has the opportunity to recoup its costs of providing reliable electric service, plus a reasonable rate of return. While this is clearly important for utilities, cost recovery also ensures that utilities are able to maintain and invest in the electricity system, which ensures reliable and affordable electricity for consumers in the long-term.

2.1.1 Revenue Requirement

A utility's total cost of providing services is often expressed as their "Revenue Requirement." Revenue Requirement is a formula that calculates the total annual revenue that a utility must earn in order to recover the costs of providing service plus a reasonable rate of return.[3]

The Revenue Requirement formula is as follows:

Revenue Requirement = Opex + (Capital Asset Base x Return on Capital) + Return of Capital + Taxes

Where:

- Opex (also known as "Operating Expenditure") refers to the day-to-day expenses that a utility incurs to provide electricity services;
- Capital Asset Base (also known as "Rate Base" or "Regulatory Asset Base") refers to the value of facilities, equipment, and other assets that the utility uses in providing electricity services;
- Return on Capital (also known as "Cost of Capital" or "Rate of Return") refers to a utility's costs of raising finance to invest in the Capital Asset Base;
- Return of Capital (also known as "Depreciation") refers to the annual write-down of a utility's Capital Asset Base to reflect the decrease in value over time; and
- Taxes refers to the tax payable by the utility in the course of providing electricity services.

Each element of the revenue requirement formula raises several issues, methodologies, and considerations which are beyond the scope of this primer on rate design. For the purposes of this primer, the important takeaway is that a utility's Revenue Requirement forms the foundation from which a cost-reflective tariff can be built. It reflects the "cost" in "cost-reflective" tariff setting.

If a regulator conducts a tariff review in multiple phases, the first phase will almost always be the calculation of a utility's Revenue Requirement. It is a critically important step because underestimating a utility's Revenue Requirement will make it nearly impossible for the utility to recover its costs, no matter how the tariff is structured. Conversely, overestimating the Revenue Requirement will result

[3] Greer, Monica. "Chapter 10 - Efficient Pricing of Electricity." *Electricity Cost Modeling Calculations*, no. 10 (2011): 283-315. https://doi.org/10.1016/B978-1-85617-726-9.00010-8.

in consumers being overcharged for electric service and the utility earning greater than its authorized Return on Capital.

2.1.2 Consequences of Under-Recovery

In emerging markets, it is much more common for utilities to under-recover their costs of providing service rather than reaping additional profits. Utilities in emerging markets commonly face issues that drive up the costs of providing electricity, such as aging infrastructure, fuel import costs, and limited organizational capacity, which can lead to system inefficiencies. Sometimes utilities and regulators do not even have sufficient data or sufficient expertise to accurately calculate a utility's Revenue Requirement. Coupled with political pressure to keep electricity rates low, this places significant downward pressure on electricity tariffs, which in turn leads to under-recovery.

Under-recovery has significant short- and long-term consequences for utilities, customers, and the broader economy. In the short-term, under-recovery will normally result in cost-cutting or capital raising for a utility in order to bridge the shortfall. The former will often lead to poorer service quality or less investment in maintenance and upgrades. The latter shifts the financial burden onto future ratepayers, making electricity less affordable in the future. In some cases, in which there is chronic under-recovery, the Government is forced to bail out utilities that are at risk of becoming insolvent, resulting in broader implications for the management of public finances.

In the long-term, under-recovery results in systemic underinvestment in electricity infrastructure, and eventually, higher costs for customers. Cash-strapped utilities may lack sufficient revenue to maintain existing infrastructure, let alone invest in new infrastructure that might lower the costs of providing electricity in the long-term. Inevitably, an under-recovering utility will face rising costs of service, as it remains dependent on older, less-productive plant. Rising costs lead to further under-recovery, leading to even less investment in infrastructure, even higher costs, and a negative feedback loop.

For this reason, accurately understanding a utility's Revenue Requirement is critical to the sustainability of the electricity market.

How BC Hydro Amassed Billions in Debt Due to Under-Recovery and the Consequences

BC Hydro is a government-owned Canadian electric utility in the province of British Columbia. It is regulated by the British Columbia Utilities Commission (BCUC); however, due to various political actions, BCUC was not fully able to regulate BC Hydro's tariff for a significant period.

In 2019, former Auditor-General of British Columbia, Carol Bellringer, concluded that “there is an appropriate framework in place, but we found that government had largely overridden this framework in the case of BC Hydro. Specifically, government had provided detailed direction to BCUC, thereby limiting BCUC’s ability to regulate BC Hydro. BC Hydro was not allowed to charge it customers enough to cover its operating costs each year.”

A large share of these losses – approximately CAD $5.5 billion in unrecovered costs were recorded in BC Hydro's “deferral accounts,” for future recovery. Originally, these “deferral accounts” had been created to facilitate rate “smoothing,” the practice of carrying over certain losses in bad years so that they could be offset by gains in subsequent years. However, they were being used to account for chronic under-recovery, without any real plan for how these accounts were going to be made whole.

In an attempt to partially address the situation, the Government was forced to write off CAD $1.1 billion from BC Hydro's deferral accounts.[4] The Government also restored the powers of BCUC to regulate BC Hydro's tariff to ensure that the situation could be governed by an independent regulator.

2.2 Cost Allocation

After calculating a utility's Revenue Requirement, the next step in the tariff setting process is Cost Allocation. Cost Allocation is the process by which a utility's costs are attributed to different customers. The fundamental objective is to ensure that the revenue burden is being equitably shared amongst each customer class.

The cost allocation process is normally conducted by way of a Cost of Service Study, a detailed analysis that assigns costs to each customer class based on class consumption attributes. It is beyond the scope of this primer to explore the Cost of Service Study methods in detail. However, the general principles applicable to cost allocation are discussed briefly below. The key takeaway is that Cost of Service Studies are an essential step in ensuring that rates are cost-reflective for each customer.

Utilities and regulators may have the expertise to conduct a Cost of Service Study in-house or may commission Cost of Service Studies as part of a rate review process. Even if a Cost of Service Study is outsourced, it is important for regulators and utilities to be familiar with the key concepts in order to interpret the findings and understand how they impact cost-reflective rate design.

2.2.1 Customer Classes

As discussed in Section 1, one of the fundamental principles for tariff setting is fairness – the notion that customers should only be required to pay their fair share of the costs of electricity service. In an ideal world, we would be able to know the exact cost that *each* customer should bear and set individual rates based on this cost. However, individualized rates are impractical and would be virtually impossible to administer.

At the other end of the spectrum, many electricity markets start with a single uniform tariff (discussed further in section 3.1) in which all customers are charged in the same way. While this approach is relatively simple to administer, it does not account for the fact that the cost of providing service can vary appreciably for different customers.

The middle-ground that is commonly adopted is to develop customer classes. Customer classes are the different categories of customers that are grouped together based on shared characteristics under each rate schedule and are charged identically for their electricity use. Terms and conditions usually determine whether a customer falls into one class or another. While it is permissible for customers to change class from time to time, frequent class changes are normally prohibited in order to prevent "gaming" the system.

A customer class typically consists of a group of customers that possess similar characteristics, including:

- Delivery voltage

[4] "Rate-Regulated Accounting at BC Hydro." Office of the Auditor General of British Columbia. https://www.bcauditor.com/sites/default/files/publications/reports/OAGBC_RRA_RPT.pdf; "Political Manoeuvring behind $5.5-Billion BC Hydro Debt, Auditor-General Says." Accessed November 13, 2020. https://www.theglobeandmail.com/canada/british-columbia/article-political-manoeuvring-behind-55-billion-bc-hydro-debt-auditor/.

- Energy consumed
- Load and end-use characteristics
- Conditions and types of metering
- Conditions of service
- Geography

International best practice does not define the optimal number of customer classes a utility or regulator should consider when designing electricity tariffs. However, a basic structure usually starts with a schedule for each of the following:

- **Residential customers:** Customers metered at low voltage supply single phase
- **Commercial customers:** Often split between small and large commercial customers based on their load
- **Industrial customers:** Medium- and large-scale industries that take power at higher voltages with a maximum demand exceeding a minimum amperage
- **Street Lighting:** Electricity supply for street lighting in a variety of locations

If significant variations – in terms of consumption patterns and cost burdens – exist within these classes, then additional schedules can and should be created in order to ensure that customers are charged commensurately to the cost of providing them with electricity. Obviously, with additional schedules comes additional administrative complexity. Thus, the need for simplicity ultimately limits the number of customer classes.

The Benefits of Defining Customer Classes: Uganda

In Uganda, the establishment of clearly defined customer classes and associated rates for each customer class has been critical to achieving cost-reflective tariffs and encouraging efficient use of electricity.

In Uganda, residential customers have a two-tier increasing block tariff, with the consumption quantity for the first tier set at 15 kilowatt hours (kWh) per month.[5] Residential customers that exceed this 15 kWh per month threshold are required to pay a higher rate per kWh for all electricity consumption in a month exceeding the threshold, helping to encourage efficient use of electricity among residents.

Time-of-use metering is available for large industrial customers, medium industrial customers, and commercial customers in Uganda. By offering lower rates during off-peak and shoulder times, these time-of-use tariffs encourage efficient use of electricity by incentivizing businesses to shift electricity consumption to non-peak times and reducing strain on the grid during peak times.[6]

[5] Moussa Blimpo, Shaun McRae, and Jevgenijs Steinbuks. "Why Are Connection Charges So High? An Analysis of the Electricity Sector in Sub-Saharan Africa." Policy Research Working Papers (The World Bank, 2018). https://doi.org/10.1596/1813-9450-8407.

[6] Geofrey Okoboi and Joseph Mawejje. "Electricity Peak Demand in Uganda: Insights and Foresight." Energy, Sustainability and Society 6, no. 1 (October 10, 2016): 29. https://doi.org/10.1186/s13705-016-0094-8.

By clearly defining these customer classes, Uganda has been able to formulate tariff approaches that correspond to different customers' usage patterns and needs. In doing so, Ugandan utilities have been able to assign costs and recover revenue from customers more accurately and effectively.[7]

2.2.2 Cost Categories

Typically, a utility's costs can be assigned to one of three cost categories:

- **Direct Assigned Costs** are costs that are clearly incurred by and for only one customer class. An example of this would be a transmission line that is constructed to service a remote mineral processing facility and no other customer.
- **Joint Costs** are costs that are clearly caused by two or more customer classes. Most utility costs are joint costs. For example, an electricity generating plant would be considered a joint cost as it produces electricity jointly for several customers.
- **Common Costs** are costs that are common to all rate classes but not directly attributable to any single class. They can be thought of as being general costs that are incidental to providing electricity service for which all customers are responsible, for example, salaries of a utility's management.

Categorizing costs in this way makes it easier to understand how they are treated and allocated under a Cost of Service Study.

2.2.3 Attributing Costs

Direct Assigned Costs are usually dealt with first as they can be easily attributed to the particular customer class that benefits from them. Joint and Common Costs are more complicated as they need to be attributed to customer classes proportionately, based on their responsibility for incurring such costs.

The principle of **Cost Causation** is fundamentally important when attributing costs to different customer classes. It states that costs should be borne by those who *cause* them to be incurred. This is not only fair but is also considered to be economically efficient as it sends the correct price signal to the consumer about how much it costs to service them. Pricing for economic efficiency is discussed further in Section 4.3 below.

The precise methodologies that are used as part of the cost allocation process are complex and require an in-depth consideration of a utility's accounts as well as significant data, disaggregated by customer class, including:

- Number of customers in each class
- Peak demand: The maximum hourly demand, or load, during the cycle (in terms of either kW or MW). Peak demand can be measured using a customer class's peak load at the time of the total system peak (co-incident peak load) or by using a customer class's peak load without regard to time (non-coincident peak load).
- Energy consumed: Consumption should be adjusted for a transmission and distribution loss factor, as losses will vary based on the exit voltage level of the respective customer class.

At a basic level, attributing Joint and Common Costs to various customer classes will normally follow a three-stage approach: (1) functionalization, (2) classification, and (3) allocation.

[7] Catrina Godinho and Anton Adriaan Eberhard. "Learning from Power Sector Reform: The Case of Uganda." Policy Research Working Papers (The World Bank, 2019). https://doi.org/10.1596/1813-9450-8820.

- **Functionalization** is the assignment of costs to specific accounts according to the major functions of the utility. In the United States, utilities follow the accounting methods set out under the Uniform System of Accounts structure of accounts and sub-accounts.[8] However, the basic categorization involves assigning costs to generation, transmission, distribution, or administration.

  The purpose of functionalization is to assign each cost to the function that it provides in the electricity supply chain.

- **Classification** further categorizes costs based on the metric or measurable usage characteristic that can be used to determine a customer's proportionate share of such costs. For instance, transmission and distribution costs might be apportioned based on each customer's contribution to the co-incident peak load. The rationale here is that a customer's load during peak is a measure of how much that customer has contributed to the size and scale of the system, and they should therefore carry that cost. By contrast, fuel costs are normally determined by the volume of electricity that a customer consumes.

  Classification assists with improving the accuracy of cost allocation by determining exactly how different cost burdens are determined; however, it is also critical in the rate design process as it informs the demand charges, energy charges, and customer charges that are ultimately included in the final tariff.

- **Allocation** is the final step in cost allocation, in which costs are apportioned to each customer class based on the metric that is determined in the Classification step. For instance, using the example above, if one customer class consumes 63% of the electricity, then that customer class will be attributed 63% of the fuel costs.

  Attribution of demand costs is a complicated exercise, which goes beyond the scope of this Primer. However, at a high level, it is generally determined by the extent to which a customer class's demand coincides with peak electricity demand of the system as a whole. For example, if a customer is responsible for 34% of the system load during a system peak (say 6:00 PM on a weekday), then they will be responsible for 34% of the transmission network and fixed generation costs.

A graphic depiction of the functionalization, classification, and allocation process is illustrated in Figure 1 below.

[8] "Electronic Code of Federal Regulations (ECFR)." Electronic Code of Federal Regulations (eCFR). Accessed October 13, 2020. https://www.ecfr.gov/.

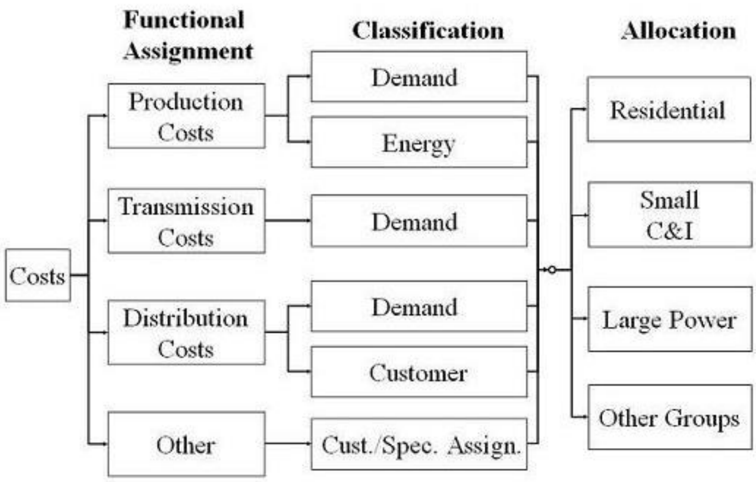

Figure 1. Cost Allocation Process[9]

At the end of the cost allocation process, the utility and the regulator should have a clear idea of the revenue a utility should be recovering from each customer class. If cost allocation is done correctly, each customer class should, in theory, produce roughly the same rate of return to the utility. If it can be shown that a particular customer class is producing a rate of return significantly above (or below) the utility's overall average rate of return, then there is a strong indication that the customers of a class are being overcharged (or undercharged).[10]

2.3 Rate Structure

A rate schedule typically comprises a series of prices or charges related to a customer's usage characteristics (e.g., volume, peak demand) that are used to determine the total price that is paid by a customer for electric service. These charges are known as Rate Elements. As discussed in Section 2.2.3, Rate Elements are often derived from the metrics that are used to classify and allocate costs between customer classes.

At a basic level, this rate structure will be based around three core Rate Elements: an Energy Charge, a Demand Charge, and a Customer Charge.

2.3.1 Energy Charge

The Energy Charge is the most common Rate Element that is used. It reflects a per kWh charge based on how much electricity a customer consumes in each billing period. In some jurisdictions, customers will pay for electricity solely based on an energy charge. A typical example of this is where pre-paid metering is implemented, which is discussed in Section 4.2.2.

2.3.2 Demand Charge

A Demand Charge is a charge that is typically levied against a customer based on its maximum demand in each billing period. It is calculated on a per kW basis and is not directly related to a customer's volume of use. Demand Charges are typically applied to large customers as they are designed to reflect the extent to which the electricity network must be sized to meet a certain customer's load.

[9] Feltner, Larry. "Overview of Electric Cost of Service Studies." The Prime Group LLC. Accessed October 13, 2020. http://www.theprimegroupllc.com/COSS_Overview.php.
[10] "Cost of Service Studies." Electricity Consumers Resource Council. Accessed October 13, 2020. https://elcon.org/cost-service-studies/.

2.3.3 Customer Charge

A Customer Charge (also known as "Basic Charge" or "Basic Service Fee") is a fixed monthly charge that is intended to recover costs that increase per each additional customer, such as maintenance of meters, billing systems, and customer support. The rationale for leveraging a customer charge is that there are certain costs that a utility must incur regardless of how much or how little electricity a customer consumes in any given month.

Sometimes, instead of levying a Customer Charge, a utility will levy a Minimum Charge. A Minimum Charge serves a similar purpose to the Customer Charge as it reflects the minimum amount a customer should pay each month based on certain costs that the utility must incur regardless of the customer's level of electricity consumption.

Typically, a utility is granted broad discretion to devise a rate structure that it believes will allow it to recover its costs across each customer class. The rationale behind this approach is that a utility is better placed to drive pricing innovation than regulators because the utility is more directly involved with consumers and the market. A regulator's task is generally limited to ensuring that the underlying revenue requirement and cost allocation assumptions are correct, that the proposed structure will generate the authorized revenues, and that the final rate design is fair and reasonable.

In emerging markets, however, this distinction is not always clear. Utilities, regulators, and policymakers will often play a joint role in formulating a rate structure.

3 Common Rate Designs

There is a wide breadth of possibilities when it comes to designing rates. The Bonbright Principles articulated in Section 1 offer a framework for assessing different rate designs, and the processes and principles articulated in Section 2 assist regulators and utilities in ensuring that rates are based upon correct cost assumptions. However, there are no set methodologies or parameters that determine exactly how rates should be designed. To the extent that the Bonbright Principles are followed and the cost assumptions are sound, rates can be designed in whatever way a regulator or utility deems is most effective in sending efficient price signals and ensuring that revenues flow to the utility.

That being said, there are several commonly used rate structures that are geared toward specific policy objectives. It is important for regulators and utilities to be aware of the structures as they offer some guidance on how rate design is used to bring about certain outcomes.

3.1 Flat Tariffs

A flat tariff provides a uniform rate for all levels of usage. Rate Elements remain constant regardless of whether a customer uses 1 kWh of electricity or 100 kWh of electricity in each billing period. A flat tariff is generally simple to understand, which is consistent with the Bonbright Principle of customer acceptability.

3.2 Inclining Block Tariffs

Inclining block tariffs require customers to pay higher prices with higher levels of usage. For instance, an inclining block structure might charge a customer eight cents per kWh for the first 150 kWh, but then 10 cents per kWh thereafter in each billing period. Inclining block tariffs are normally used to encourage efficient use of electricity. Figure 2 is an example of the difference between a flat tariff and an inclining block tariff.

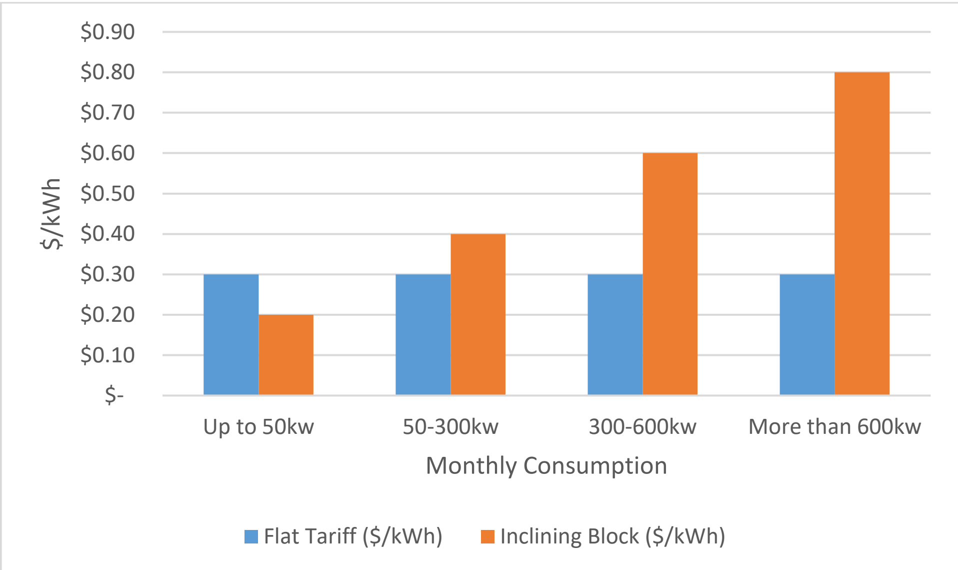

Figure 2. Flat Tariff vs. Inclining Block Tariff

3.3 Time-of-Use Tariffs

Time-of-Use (TOU) Tariffs vary electricity prices based on the time of day that electricity is consumed. Typically, demand spikes at certain times of day, such as in the evening when the majority of workers are returning home from work. At other times, demand will trough, such as in the middle of the night when most people are asleep. Figure 3 offers an example of TOU Tariff pricing.

TOU Tariffs encourage consumers to shift their load to off-peak times (where possible) in order to avail of cost savings. For instance, a factory might elect to conduct the bulk of its processing in the evening instead of during the day to reduce its electricity costs. TOU Tariffs tend to promote economic efficiency by more closely resembling marginal cost (discussed in Section 4.3). Put simply, the price of electricity should be higher during peak periods because the cost of meeting that demand is higher.

TOU Tariffs require the installation of Smart Meters that are able to record not only the total amount of electricity consumed within each period but also when that electricity is consumed. Smart Meters are often more costly to install and more complicated to operate and maintain than traditional meters.[11] This has limited the use of TOU Tariffs, particularly in emerging markets.

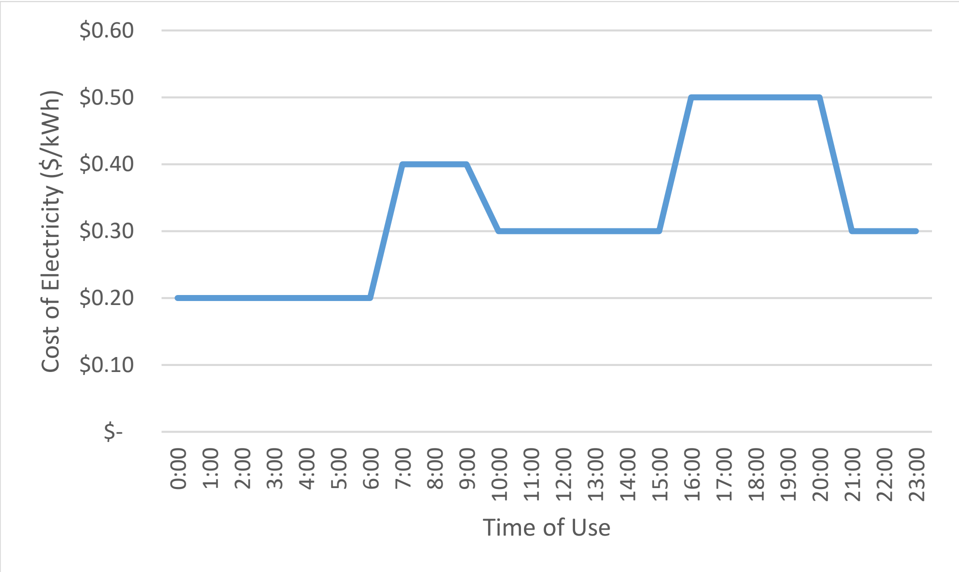

Figure 3. Example of Time-of-Use Tariff Pricing

3.4 Seasonal Rates

Seasonal Rates charge customers different prices depending on the season or time of year. In certain markets, electricity demand can vary greatly by season. In particularly warm climates, for instance, demand could spike during the summer months. In these situations, regulators and utilities can implement higher seasonal rates that reflect the higher costs to provide electricity in these months. Similar to Time-of-Use Tariffs, the rationale behind this approach is that it reflects a truer cost of electricity and therefore promotes economic efficiency. An example of Seasonal Rates is contained in Figure 4.

[11] Pablo Rámila and Hugh Rudnick. "Assessment of the Introduction of Smart Metering in a Developing Country," n.d., 10. https://hrudnick.sitios.ing.uc.cl/paperspdf/RamilaRudnick.pdf

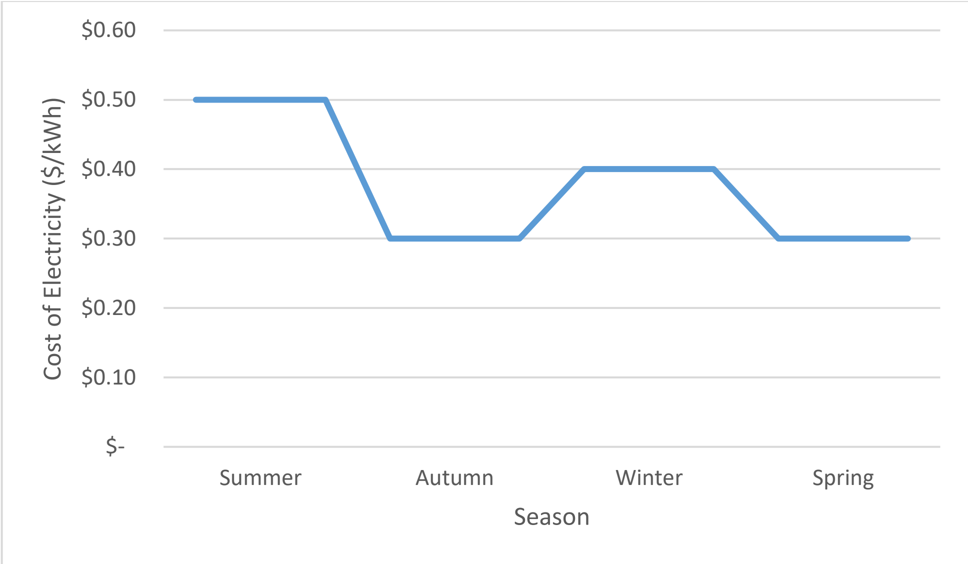

Figure 4. Example of Seasonal Rates

4 Issues in Rate Design for Emerging Markets

The principles of cost-reflective rate design discussed above are applicable in most contexts. However, there are several unique issues that arise when applying these principles in emerging markets. Emerging markets are typically affected by challenges such as aging infrastructure, high costs of generation, lower ability to pay, and limited capacity, all of which impact how cost-reflective rate design occurs in practice.

This section describes three key issues that regulators, policymakers, and utilities will typically encounter when designing rates in emerging markets, namely (1) tariff subsidization, (2) alternative methodologies and technology, and (3) marginal cost pricing.

4.1 Tariff Subsidization

One of the issues that a regulator must manage is the tension between a customer's desire to keep rates low and the need to ensure that a utility is able to recover its costs of providing service. This tension is particularly acute in emerging markets where socio-economic factors mean that ability to pay is often very low, and costs of service are often very high due to factors such as aging infrastructure and higher fuel costs. On the one hand, regulators face social and political pressure to ensure that tariffs are as low as possible, while, on the other hand, regulators must set rates that ensure cost recovery for all of the reasons set out above in Section 2.1.

In several markets around the world, customers' ability to pay for electricity is simply too low to recover a utility's costs of providing service. A study on willingness to pay in Sub-Saharan Africa found that low-income households are willing to dedicate around 10% of their monthly expenditures toward electricity; however, this amount was still not sufficient to cover the operational and capital costs of on-grid electricity.[12] Utilities often face social and political pressure to electrify these customers for a price that is below the cost of providing electricity service, and regulators are regularly called upon to broker these sorts of situations.

4.1.1 Cross-Subsidization

In the absence of direct subsidization, regulators and utilities often employ cross-subsidization to bring down the cost of service to poorer households. Cross-subsidization is the practice of setting higher tariffs for certain customers in order to subsidize tariffs for others. For instance, tariffs for poorer households can be cross-subsidized by setting higher commercial and industrial tariffs. In some cases, cross-subsidization is used even if customers' willingness to pay is sufficient to cover the costs of providing electricity service. Normally, in these situations, the Government or the regulator has taken the policy position that certain customer classes should shoulder more of the cost burden than others.

A certain level of cross-subsidization is generally acceptable and practically necessary. While the intention of cost allocation is to ensure that all customer classes generate equal rates of return, there is generally a bit of leeway allowed. Regulators and utilities recognize that cost allocation is not a precise science and that certain policy factors might need to be considered when designing rates.

However, heavy cross-subsidization can result in market distortions that can hamper economic growth. Electricity for commercial and industrial (C&I) customers is generally considered "productive use" as it contributes to activities that generate economic activity. This can be contrasted with electricity that is consumed in the home, which has a less direct impact on economic activity but directly affects the quality of life. Accordingly, overcharging C&I customers may hamper economic

[12] Maximiliane Sievert and Jevgenijs Steinbuks. "Willingness to Pay for Electricity Access in Extreme Poverty: Evidence from Sub-Saharan Africa." World Bank Group. n.d., 39. https://openknowledge.worldbank.org/bitstream/handle/10986/31925/WPS8906.pdf?sequence=4&isAllowed=y

development but positively affect residential customers' ability to pay. In the 2018 World Bank Enterprise Survey, which included 139 economies, business owners identified electricity services as the fourth biggest obstacle to their commercial activities.[13] In some cases, some firms might choose to pursue business in alternative markets or opt to produce their own electricity, which can have impacts on base load and future system planning.

Balancing Cross-Subsidization: The Switch to On-Site Power Generation in Africa

A study conducted by BloombergNEF has found that on-site solar is cheaper than electricity tariffs paid by C&I customers in seven out of 15 markets in Sub-Saharan Africa.[14] BloombergNEF reports that an industrial facility in Ghana operating seven days per week could buy on-site solar power for 29% less than electricity from the grid.

While cheaper, more reliable, more renewable sources of electricity offer clear benefits to society, the shift toward on-site generation for C&I customers presents significant challenges for regulators and utilities in terms of setting electricity tariffs. C&I customers play an important role in maintaining base load, managing system peak, and creating long-term certainty for those who wish to invest in electricity infrastructure. In theory, base load customers generally lower prices by guaranteeing that a certain amount of electricity will be sold (and revenue obtained) even when demand is not at its peak. The exodus of C&I customers can be particularly challenging for utilities and regulators in emerging markets in which the costs of generation are already high and long-term investor confidence in electricity markets is already low.

This is still a live issue as regulators and utilities around the world consider the best approach to take in the face of the growing technological advancement of distributed energy. However, there is a general consensus that cross-subsidization against C&I customers exacerbates problems for regulators and utilities alike. Higher C&I tariffs mean a greater potential for cost savings, increasing the impetus for C&I customers to consider and invest in alternative on-site generation options. The BloombergNEF study is an example of the growing business case that is being presented to these customers in Sub-Saharan Africa. Moreover, the fewer C&I customers that remain on the grid, the smaller the base upon which to leverage the cross-subsidy, which, in turn, generates pressure on regulators and utilities to find new ways to maintain the cross-subsidization.

4.1.2 Lifeline Tariffs

Lifeline tariffs are another tool that regulators and utilities use in emerging markets to increase electricity access to those who would otherwise not be able to afford it. The philosophy underpinning lifeline tariffs in emerging markets is that access to electricity is an essential component of economic growth. The World Bank, for instance, regularly cites the fact that electricity is known to have significant impacts on a wide range of development indicators, including health, education, food security, gender equality, livelihoods, and poverty reduction.[15]

Lifeline tariffs can be structured in a multitude of ways; however, the general approach is to set a tariff that is lower than cost-recovery for customers that consume a very low amount of electricity. Typically, customers are eligible for a lifeline tariff if their consumption is lower than a certain monthly

[13] "Why It Matters - Getting Electricity - Doing Business." World Bank Group. Accessed October 13, 2020. https://www.doingbusiness.org/en/data/exploretopics/getting-electricity/why-matters#note1.
[14] "Solar for Businesses in Sub-Saharan Africa." BloombergNEF. Accessed December 14, 2020. https://www.responsability.com/en/media/3174/download?delta=0
[15] "Access to Energy Is at the Heart of Development - Who We Are." The World Bank. Accessed October 13, 2020. https://www.worldbank.org/en/news/feature/2018/04/18/access-energy-sustainable-development-goal-7.

consumption threshold, the assumption being that limited electricity consumption reflects lower socio-economic development. However, there have been moves toward using other metrics to target lifeline tariff programs.[16] Lifeline tariffs can be financed by government subsidies. However, more commonly, cross-subsidization is the method used to support lifeline tariffs.

There continues to be significant debate over the design and usefulness of lifeline tariffs in emerging markets. The most common criticisms levied against lifeline tariffs are that they create misaligned incentives and ineffective targeting, resulting in questionable impact. Utilities administering lifeline tariffs have little commercial incentive to serve poor customers because these customers pay lower rates and are therefore less profitable for the business. Regulators and policymakers often adopt performance-based programs to address the misalignment of incentives, with mixed success.

In addition, there is an overarching concern that lifeline tariffs fail target those who are in dire need of support while, at the same time, allowing less-needy consumers to “game” the system. Some commentators have noted that some of the world's poorest individuals live in multi-family households that either share a single meter or lack proper metering infrastructure altogether.[17] These customers are unable to benefit from programs that allow lifeline tariffs based on usage because their usage is not accurately captured. Instead, it is argued usage-based programs benefit households that have the means to track and spread out their electricity use across multiple locations and several meters.[18]

The difficulty is that utilities are often burdened with the responsibility of administering lifeline tariff programs. Utilities are accustomed to classifying customers based on commercial indicators such as a customer's sector, electricity consumption, or demand. Utility systems are not designed to understand a customer's socio-economic situation. For this reason, it is often suggested that vouchers or direct subsidies administered by government departments are a more effective way of driving economic empowerment and making electricity more affordable to those in need.[19]

Ultimately, it remains up to regulators, utilities, and policymakers to work together to decide the best approach for making electricity more affordable for customers that do not have the means of paying the full cost of service.

[16] Siyambalapitiya, Tilak. “Tariff Appraisal Study: Balancing Sustainability and Efficiency with Inclusive Access.” Asian Development Bank. October 2018. http://hdl.handle.net/11540/9050.

[17] Sophie Tremolet and Diane Binder, “What Are the Strength and Limitations of Lifeline Rates?” Body of Knowledge on Infrastructure Regulation. June 2009. Accessed October 13, 2020. http://regulationbodyofknowledge.org/faq/social-pricing-and-rural-issues/what-are-the-strength-and-limitations-of-lifeline-rates/.

[18] Ibid.

[19] Hennessy, Michael. “The Evaluation of Lifeline Electricity Rates: Methods and Myths.” Evaluation Review 8, no. 3 (June 1, 1984): 327–46. https://doi.org/10.1177/0193841X8400800303.

An Example of a Lifeline Tariff: Lesotho

With a poverty rate above 50%, Lesotho has a high number of residential customers that require some level of subsidization to meet their most basic electricity needs.[20] Most households in Lesotho use electricity only for lighting, and 30% of grid-connected households consume less than their basic needs.[21] The development of a lifeline tariff is currently being investigated to improve the overall standard of living for poorer residents and to reduce reliance on biomass, which contributes to environmental degradation and CO_2 emissions.[22]

The lifeline tariff currently being considered in Lesotho would enable eligible households access to electricity up to a threshold of 30 kWh per month and reduce rates 35%-42% below current domestic tariffs. All consumption above this 30-kWh threshold would be charged at the standard rate, and the standard rate would be set high enough to adequately cross-subsidize the lifeline tariff.[23]

4.2 Alternative Methodologies and Technology

In emerging markets, issues surrounding payment methods and technologies can have a significant impact on the scope of options available to regulators and utilities when designing rates. In some respects, emerging markets present an opportunity to innovate when it comes to introducing new technology, developing prices, and charging customers for electricity.

4.2.1 Traditional Utility Billing

Under traditional utility billing, a customer is charged for their consumption over the previous month. The traditional approach allows regulators and utilities to employ all of the techniques and processes discussed in this Primer. However, one challenge with this approach in the context of emerging markets is that, as a result of customers receiving a large bill at the end of the billing cycle, it often results in a high percentage of bills going unpaid.[24] Utilities in emerging markets often face challenges associated with enforcing bill payment, including high costs and political barriers, resulting in lost revenues.[25]

In addition, metering issues commonly lead to collection problems in emerging markets, including customers receiving free electricity or being overcharged for electricity consumption. In Nigeria, for example, 50% of customers are not charged based on actual meter readings; instead, these customers are charged based on the "Estimated Billing System," whereby utilities calculate an estimate of how much a customer is likely to consume in any given period.[26] Naturally, estimation may lead to both under and over-charging of certain consumers.

Even where metering technology is available, faulty meters or ineffective payment and collection systems can result in significant commercial losses by making it challenging for utilities to effectively monitor the status of payments and collect from all customers.[27] Ultimately, limited or impaired ability

[20] Moeketsi Mpholo et al., "Determination of the Lifeline Electricity Tariff for Lesotho." Energy Policy 140 (May 1, 2020): 111381. https://doi.org/10.1016/j.enpol.2020.111381.
[21] Ibid.
[22] Ibid.
[23] Ibid.
[24] Kelsey Jack, Kathryn McDermott, and Anja Sautmann. "Pre-Paid Electricity Metering and Its Effects on the Poor." International Growth Centre (Blog). September 11, 2019. https://www.theigc.org/blog/pre-paid-electricity-metering-and-its-effects-on-the-poor/.
[25] Kelsey Jack, Kathryn McDermott, and Anja Sautmann. "Pre-Paid Electricity Metering and Its Effects on the Poor."
[26] Seyi John Salau, "Estimated Billing: Nigerians in Tale of Woes." Businessday NG (Blog). June 14, 2020. https://businessday.ng/features/article/estimated-billing-nigerians-in-tale-of-woes/.
[27] Kelsey Jack, Kathryn McDermott, and Anja Sautmann. "Pre-Paid Electricity Metering and Its Effects on the Poor."

to collect revenue from customers has the potential to significantly impact utilities and the electricity system as a whole.

Without capital investment in metering infrastructure, utilities and regulators are not able to realize some of the basic principles and processes involved in rate design, let alone some of the more advanced rate structures such as time-of-use tariffs.

4.2.2 Pre-paid Metering

In response to challenges associated with deploying traditional utility billing in emerging markets, pre-paid metering has gained popularity in recent years. Customers using a pre-paid meter obtain access to electricity through the purchase of a voucher. Typically, these vouchers can be purchased at nearby retail locations, including shops and grocery stores, or online through mobile phones. Under this system, the customer only has access to electricity if there is remaining value on the voucher.

One benefit of pre-paid metering is that it enables customers to avoid large, monthly bills that they may not be able to pay and, instead, offers them a system by which they can purchase small amounts of electricity frequently throughout the month as funds are available.

Pre-paid metering has several benefits to utilities in emerging markets where they have been widely deployed:

- The utility receives payment in advance of providing the service, instead of waiting for the closing of the billing cycle to issue a bill, which then may be paid within 30 days or even later. This eliminates the need for financing bill collection, which results in significant savings as capital is generally very expensive in developing countries.
- The utility saves the cost of sending meter readers out to the field, which reduces the costs of vehicles, fuel, and hotel lodging, which can be substantial in developing countries where utilities often have far-flung networks with low customer concentration in rural areas.
- The utility is able to reduce commercial losses relating to employee error, fraud, or theft.

The benefits of these savings can be shared and passed through to customers in future rate cases.

Given the prevalence of lifeline tariffs in developing countries as well as the prevalence of inclining tariff structures within customer classes, it is important when procuring and installing meters that utilities ensure the hardware and software of the meter can function consistent with the desired tariff structure. For instance, if the desire is to offer a discounted or lifeline tariff up to a certain maximum monthly usage, the regulator, utility, and policymakers must decide what to do after a customer consumes this maximum monthly limit before the end of the period. The metering and billing systems must be aligned to account for the desired tariff regime.

While pre-paid meters can decrease the burden of revenue collection, switching to pre-paid metering can involve high costs for utilities.[28] In certain places, customers are asked to pay an upfront connection charge and own their own meters, which they can transfer when they move to a new location in the utility's service territory.

However, this may not always be feasible. Pre-paid metering is most effective in situations where customers' income is irregular.[29] In these situations, charging customers high installation charges can often become unfeasible due to their limited access to capital. The costs of large-scale metering

[28] Masami Kojima and Chris Trimble. "Making Power Affordable for Africa and Viable for Its Utilities." (World Bank, 2016), https://doi.org/10.1596/25091.

[29] Kelsey Jack and Grant Smith, "Charging Ahead: Prepaid Metering, Electricity Use, and Utility Revenue." Accessed October 14, 2020. https://voxdev.org/topic/energy-environment/charging-ahead-prepaid-metering-electricity-use-and-utility-revenue.

upgrade programs may be supported by governments or development partners, or spread across all ratepayers in the form of a general tariff increase.

4.2.3 Mobile Payment Solutions

In recent years, the growth and technological advancements in mobile money ecosystems have unlocked the potential for pay-as-you-go mobile utility bill payments. Because many customers in emerging markets rely on day labor and both earn and spend their wages daily, pay-as-you-go mobile payments can be an option that fits the spending patterns of these customers.[30]

Similar to pre-paid metering, mobile utility bill payments enable customers to make small, frequent transactions. However, unlike pre-paid metering, customers are not required to make trips to retail shops to purchase additional vouchers; instead, making the purchase directly on their mobile device. In certain situations, mobile payments can dramatically reduce the time burden associated with purchasing vouchers.

From the perspective of the utility, mobile payments have additional benefits, including reducing leakage and reducing operational costs compared to other billing and payment methodologies.[31] However, relatively high mobile money transaction fees, which often account for a significant proportion of the average customer's electricity bill payment, can be a potential downside of mobile payment solutions. In addition, as with pre-paid metering, utilities are forced to undertake a degree of risk in relation to recovering their fixed costs, which can be mitigated in the same manner as mentioned in Section 4.2.2.

4.2.4 Service-Based Approaches

Regulators and utilities around the world are experimenting with different pricing structures to make electricity more affordable to certain customers and to incentivize utilities to improve their efficiency.

Countries that have more advanced electricity markets sometimes employ sophisticated "incentive-based" regulatory approaches to drive service quality and efficiency. These "incentive-based" approaches typically project and affix a utility's revenue requirement over a regulatory period and then allow the utility to keep any financial benefits accrued through efficiency-driven cost reductions, subject to the utility maintaining certain minimum service standards. Utilities are also forced to bear any cost increases caused by inefficient performance. These approaches rely upon robust accounting systems and entrenched practices relating to cost-reflective tariff setting.

Service-Based Approaches operate in a related manner, wherein a utility's tariff is calculated on the basis of a certain pre-determined service quality, which can be assigned to different customer classes. Service-based approaches can be structured in several ways. However, the crux of a service-based approach is that utilities are permitted to charge customers based not only on how much electricity they use but also other service-based attributes such as whether electricity is available for 24-hours per day. The idea is that the utility is incentivized to improve their service quality in order to recoup higher tariffs from customers. The underlying premise is that the utility will want to invest in capital works in order to generate higher revenues.

At the opposite end of the spectrum, the rationale is that utilities are able to right-size infrastructure investment in line with the needs of the community. In some instances, service-based approaches represent significantly discounted electricity for the lowest-tier customers. While some argue that a

[30] Alderman, Jessica. "The Next Big Thing for Pay-as-You-Go." Standard SOCIAL INNOVATION Review, June 10, 2019, Accessed October 13, 2020. https://ssir.org/articles/entry/the_next_big_thing_for_pay_as_you_go.

[31] "Mobile money transaction fees and utility bill payments in emerging markets." Mobile for Development, January 19, 2019. Accessed October 13, 2020. https://www.gsma.com/mobilefordevelopment/programme/m4dutilities/mobile-money-transaction-fees-and-utility-bill-payments-in-emerging-markets/.

service-based approach entrenches inequality,[32] others suggest that it enables customer choice, allowing those who do not require high standards of service to avail of lower electricity rates.

It is important to note that service-based approaches can add significant complexity to existing tariff structures, which can cause confusion among consumers.[33] Just as incentive-based approaches rely upon robust accounting systems and entrenched practices relating to cost-reflective tariff setting, service-based approaches also rely upon transparency.

Service-based approaches are not yet widely used, so their effectiveness remains yet to be determined; however, they offer an example of the breadth of options when it comes to rate design and the potential for further innovation in this space.

An Example of a Service-Based Approach: Nigeria

In 2020, the Nigerian Electricity Regulatory Commission (NERC) introduced a service-based tariff that divides customers into five distinct bands and charges those customers who require more hours of service per day higher rates. The five bands include:

- Band A: 20 hours of service per day at rates up to 62.33 NGN per kWh (Ibadan Electricity)
- Band B: 16 hours of service per day at rates up to 57.33 NGN per kWh (Ibadan Electricity)
- Band C: 12 hours of service per day at rates up to 55.00 NGN per kWh (Enugu Electricity)
- Band D: 8 hours of service per day at rates up to 49.50 NGN per kWh (Enugu Electricity)
- Band E: 4 hours of service per day at rates up to 43.20 NGN per kWh (Port Hardcourt Electricity) [34]

The five service band tariffs will help NERC recover costs from customers not just strictly based on total electricity consumption, but also factoring in the hours of service and reliability of service that ratepayers can expect in a given day.

4.3 Marginal Cost Pricing

Marginal Cost Pricing is based on the theory that electricity prices should reflect, as closely as possible, the cost to produce the last unit of electricity (i.e., the marginal cost).[35] The rationale for Marginal Cost Pricing is that it supports economic efficiency and encourages utilities to produce the market-efficient amount of electricity.

In economic theory, it is generally accepted that resources are scarce and that price signals ensure that society is producing and consuming resources efficiently. If prices are set too high, then production will exceed consumption and result in a market surplus. If prices are set too low, then consumption will exceed production and result in a market shortfall. In a free market, the factors of supply and demand will regulate prices to ensure that this does not happen. Prices are set where the desires of consumers and the desires of producers agree: the maximum a consumer is willing to pay and the

[32] *The New Service -Based Electricity Tariff : How It Affects You*, YouTube video, 7:56, posted by "Channels Television." September 16, 2020. https://www.youtube.com/watch?v=8faw9pt8WXY.
[33] Ibid.
[34] "Frustration as Nigerians reject 100% increase for new electricity tariff - See how much you go pay now & seven reasons why NERC suddenly hike." BBC News Pidgin, September 2, 2020. https://www.bbc.com/pidgin/tori-53995109.
[35] Kahn, Alfred E. *The Economics of Regulation: Principles and Institutions*, 2nd Edition (Cambridge, Mass: MIT Press, 1988).

minimum a producer is able to charge based on their costs. This is one of the principles of economic efficiency.

The principle of Marginal Cost Pricing requires regulators to allow utilities to charge as close to the marginal cost as is commercially feasible so that the product is not being over- or under-produced. Marginal Cost Pricing, in theory, is intended to simulate the free market by sending accurate price signals to electricity consumers so that they can make rational choices as to the level and timing of their electricity consumption. Inflated prices mean that consumers are deterred from consuming electricity, whereas deflated prices mean that consumers will likely overconsume electricity.

Under and overconsumption may not seem like a significant issue for something as ubiquitous as electricity. However, in emerging markets, overly inflated or deflated prices can have severe impacts on economic growth because financial capital is so constrained. Underpricing, which leads to overconsumption, can unduly redirect capital away from other productive activities toward electricity. Similarly, overpricing, which leads to underconsumption, can unduly redirect capital away from electricity markets, which can cause service issues that can impede economic growth.

Ultimately, marginal cost pricing aims to ensure that just enough of the market's resources are used to generate electricity and not more. Overall, numerous econometric studies have shown a causative link between electricity supply and economic growth.[36] Thus, artificially restricting electricity supply through underpricing or via government or administrative fiat (e.g., load shedding) can have a severe negative impact on economic growth.

Similar to many of the processes discussed in this primer, many utilities and regulators in emerging markets currently lack the data and the regulatory capacity to determine and assess the marginal cost. However, efforts are continuously underway to support regulators and utilities with gathering data on costs and demand and equipping regulatory staff with additional skills to understand the marginal cost, economic efficiency, and the role these concepts play in cost-reflective tariff setting.

[36] David I. Stern, Paul J. Burke, and Stephan B. Bruns. "The Impact of Electricity on Economic Development: A Macroeconomic Perspective." May 31, 2019. https://escholarship.org/uc/item/7jb0015q.

5 Conclusion and Final Remarks

Regulators, utilities, and policymakers in emerging markets face a difficult challenge when designing electricity tariffs. It is not an easy exercise to design prices for electricity – an incredibly technical and complex undertaking – when faced with limited data and limited capacity, all while managing widely-ranging perspectives and interests of different stakeholders.

While a "perfect" rate design may not be attainable, a principled, rational, and justifiable cost-reflective tariff certainly is. This primer has attempted to deconstruct the complexities of the rate design process in a manner that can be of assistance to regulators and electricity sector stakeholders around the world. It sets out the core foundation toward a principled, rational, and justifiable cost-reflective tariff by:

- Setting out the Bonbright Principles that illustrate the trade-offs that one must balance when designing tariffs
- Describing the systems and processes that go into cost-reflective rate design
- Illustrating some of the unique issues and considerations that are faced in emerging markets

Rate design is one of the processes that is core to the functioning of an electricity system. It not only captures the needs and interests of customers, utilities, and policymakers; it determines the sustainability of the electricity system as a whole. To this end, it is hoped that this Primer has been able to set out some of the fundamental principles that will assist regulators and other electricity sector stakeholders in undertaking this critical task.

Annexure A: Tariff Reform in Brazil

Over the last several decades, the Brazilian electricity market has faced challenges stemming from a range of factors, including rapidly growing electricity consumption, inadequate electricity supply due to lack of private investment to meet system expansion needs, and non-cost-reflective tariff structures. As a result, the electricity sector in Brazil has undergone a series of transformations since the 1990s to move toward more cost-reflective tariffs, while seeking to ensure security of electricity supply and fair rates for customers.

Brazil's experience in electricity market reform highlights regulatory approaches and challenges to addressing several key issues in rate design. As explored throughout this case study, these key issues include challenges in setting rates that are sufficient, efficient, and fair in the context of economic constraints and rapidly growing electricity consumption.

Electricity Market Context

Hydropower has historically been the dominant source of electricity generation in Brazil. As of 2019, the electricity generation mix in Brazil was about 64% hydropower, 10% natural gas, 9% biofuels, and 9% wind, with the remaining supply coming from coal, oil, nuclear, and solar PV.[37] Prior to the market reforms described in this case study, however, hydropower dominated an even greater share of the electricity generation market, making up about 90% of total electricity generation in 1990.[38]

Until the 1990s, Brazil's electricity infrastructure was government-owned. Between the 1950s and 1970s, significant investment from the federal government led to the rapid expansion of the electricity sector. This period of expansion was characterized by centralized operation and planning, vertically integrated transmission, distribution, and generation, and heavily subsidized tariffs. As investment in the electricity sector tapered off due in part to a series of economic shocks in the 1970s and 1980s, the state-owned system quickly became unsustainable. By the 1990s, the electricity sector was on the verge of collapse, with inadequate investment and tariff subsidies resulting in a revenue shortfall of around USD $35 billion.[39]

Move Toward Privatization

In the 1990s the government decided to address the sector's financial challenges with a series of privatization reforms aimed at attracting increased private investment and improving the financial health of utilities. These reforms included:

- Allowing private investment and ownership of distribution and generation infrastructure
- Creating supply contracts between generators and distributors to facilitate a gradual transition to deregulated wholesale markets
- Creating a new market model in generation and commercialization (Mercado Atacadista de Energia Electrica (MAE))
- Introducing Independent Power Producers (IPPs) and the concept of a "free consumer." Customers with demand greater than three megawatts (MW) could choose to be "free consumers" and negotiate prices directly with generators and IPPs rather than purchasing electricity from regulated distribution companies (DISCOs)
- Eliminating the national uniform tariff and allowing electric utilities to increase prices by charging rates reflecting operational costs plus a reasonable return on capital. Wholesale

[37] International Energy Agency. Data retrieved from: https://www.iea.org/countries/brazil
[38] Ibid.
[39] Silva, Fabio Stacke. "Making Competition with Renewable Power Plants in Brazilian Electric Energy Market." School of Business and Public Management, Institute of Brazilian Business and Public Management Issues, 2010, https://www.aneel.gov.br/documents/656835/14876412/Artigo_Fabio_Stacke.pdf/33815a5b-7b2a-415d-8377-52b407d1fd4d

power costs could be passed through to customers, subject to a price-ceiling set by the regulator and calculated to approximate long-term expansion costs (long-term marginal costs).

In 1996, the government also established the Brazilian regulatory agency, National Agency for Electric Energy (ANEEL), and the National System Operator (ONS) to oversee the national transmission system.

Rate Design Issues

The 1990s privatization reforms illuminated several key rate design challenges. The first key issue related to the efficiency of wholesale electricity prices that were passed through to retail customers. Under the 1990s regulatory model, the price-ceiling for wholesale electricity, known as Valor Normativo (VN), was not based on the actual costs of generation and did not account for differences between generation technologies. The VN was well below the actual costs of setting up new plants, which meant the tariff was too low to attract the needed investment in system expansion. As a result, electricity consumption in Brazil grew by 45% between 1990 and 1999 while generation capacity only grew by 28%.[40]

Second, the introduction of free consumers resulted in issues related to cross-subsidization. To allow free consumers access to the system, it was necessary to create separate energy tariffs and distribution (system usage tariffs) from the existing supply tariffs. However, the revised tariff methodologies created significant disparity between rates paid by high-voltage and low-voltage customers. In effect, residential and commercial customers ended up paying significantly higher energy rates compared to industrial customers.[41] Besides raising issues of fairness to residential and commercial customers, this cross-subsidization between low and high voltage customers raised questions regarding market efficiency.

Finally, the privatization reforms in the 1990s did little to address issues of expanding access to electricity in low-income and rural areas. While the reforms did lead to increased private sector investment, rates also rose during this period, which disproportionately affected the low-income customers, impacting their ability to pay for electricity services.

The ongoing challenges in the electricity sector came to a head during Brazil's energy crisis in 2001. Inadequate system planning and investment combined with several years of lower-than-average rainfall led to severe electricity shortages. In response to threats of widespread blackouts, then President Fernando Henrique Cardoso set up the Crisis Management Board (CGE) to implement a series of strict demand reduction programs. These programs included electricity quotas based on historic and target consumption and imposed penalties on consumers that did not meet their targets. While the quotas effectively reduced consumption by about 20%, generators and distribution companies saw a corresponding 20% reduction in revenues while residential electricity rates increased 140%.[42]

The Hybrid Regulatory Model

By 2003, when the new government administration took over under the leadership of President Lula da Silva, distribution utilities remained in severe financial distress and private investment was stagnant due to investor uncertainty. The new administration sought to address these challenges by returning to a more regulated tariff setting regime.

[40] Silva, Fabio Stacke. "Making Competition with Renewable Power Plants in Brazilian Electric Energy Market."
[41] "Background Study for a National Rural Electrification Strategy: Aiming for Universal Access." Energy Sector Management Assistance Program. 2005. https://esmap.org/sites/default/files/esmap-files/06605.Brazil%20Background%20Study%20for%20a%20National%20Rural%20Electrification%20Strategy%20Aiming%20for%20Universal%20Access.pdf
[42] Silva, Fabio Stacke. "Making Competition with Renewable Power Plants in Brazilian Electric Energy Market."

The goals of the regulatory reform under the new administration included:

- Attracting long-term private investment
- Ensuring long-term supply requirements were met
- Achieving fair prices through competition in system expansion
- Universal access to electricity services

In 2004, a new regulatory model was adopted involving a hybrid approach of regulated electricity and market competition. First, the administration established two new energy trading markets: the Regulated Contracting Environment (RCE) and the Free Contracting Environment (FCE). Power sold on the RCE would be auctioned following regulatory guidelines, while power sold on the FCE would be freely negotiated in bilateral contracts between the producer and free consumers.

Second, the government established energy auctions as the main procurement mechanism for distribution companies to purchase energy in the RCE. "Existing energy" auctions included auctions from existing generators for delivery of electricity one year in advance and with contract durations of 5-15 years. "New energy" auctions included auctions for new generation capacity, held three and five years in advance of when the new systems will come online, and with contract durations of 15-30 years.

To help implement the new model the government established the Energy Research Company (EPE), a non-profit public sector firm responsible for long term energy planning for the Brazilian energy sector, and the Chamber of Electric Energy Commercialization (CCEE), a private non-profit responsible for administering both the regulated and free contracting markets.

Rate Efficiency Under the Hybrid Model

The goal of the auction approach is to create economic efficiency through competition while keeping prices low for retail customers. Under this model, the government maintains a version of price-cap regulation and market competition. However, unlike the VN, price caps are intended to be more reflective of costs of generation.[43]

Under this model, EPE facilitates auctions by reviewing proposed revenue requirements submitted by generators and determining prices based on total assured energy supply. EPE selects projects based on least-cost until total supply equals total projected demand. Energy supply from selected projects is then allocated to distribution companies, which sign PPAs for 100% of their projected demand.[44]

The cost of energy passed through in retail energy rates is calculated based on the average rate of electricity contracted by distribution companies through the auction process. To encourage efficient contracting and prevent consumers from assuming the risk of distribution companies over-contracting with generators, distribution companies are limited to passing through costs of energy up to 105% of total load.

The least-cost approach to setting wholesale tariffs under the auction approach is designed to ensure only costs of the most efficient generators are passed on at the retail level. In theory, this competition pushes new energy prices toward long run marginal costs for wholesale electricity, in turn resulting in more efficient retail rates. Long-term contracts provide assurance of future cash flows to reduce investor risk and further drive down cost of capital, which is ultimately reflected in lower retail rates.

[43] de Souza, Fabio Cavaliere. "Brazilian Electricity Market Structure and Risk Management Tools," 2008, retrieved from: https://www.researchgate.net/publication/224325283_Brazilian_electricity_market_structure_and_risk_management_tools

[44] Under the new model, DISCOs are only required to contract for 100% of the demand from "captive" consumers, or consumers that have not migrated to the FCE. High voltage consumers that meet minimum load requirements may choose to migrate to the FCE to purchase directly from generators or IPPs.

New energy auctions proved initially successful in attracting private investment for new generation capacity and driving down wholesale electricity prices. In 2007, 2008, and 2010, three new energy auctions for hydropower plants sold 70% of the assured energy from the plants at prices well below the price cap set by ANEEL.[45]

Critics of the current auction approach question its effectiveness in setting efficient wholesale electricity rates due to over-reliance on the centralized price setting mechanism. These critics have suggested that new energy auctions currently result in prices in excess of long run marginal costs, and that price ceilings for existing energy auctions are set too low to attract sufficient existing energy bids to meet current demand.[46] ANEEL plans to gradually transition to a more open generation market, which may address some of these concerns.

Rate Fairness Under the Hybrid Model

The 2003 reform also introduced a subsidized electricity tariff to address the government's goal of universal access. The government intended to lower electricity costs for low-income customers by applying a discount to all residential electricity consumed below 80kWh, regardless of customer income level.

In 2010, ANEEL improved upon this tariff to more accurately target customers based on income level. Currently, the Social Electricity Tariff (TSEE) is offered to customers registered on the federal government's Unified Registry for Social Programs (CadÚnico), and provides volume-differentiated subsidies for electricity consumed up to 220 kWh per month.[47]

Although the TSEE comes with significant administrative costs, and improvements can be made to increase its cost effectiveness,[48] it has generally been viewed as an improvement in rate design from the previous approach. By more accurately targeting low-income customers, the TSEE prices electricity based on ability to pay and broadens electricity access to the country's poor.

In addition to addressing low-income customers, ANEEL undertook a tariff realignment process between 2003 and 2007 to remove the cross subsidy between low voltage and high voltage customers.[49] In particular, the government recognized this cross-subsidization as a key barrier preventing the desired transition to a more open market, as high-voltage customers were paying artificially low rates in the regulated market. The issue of cross-subsidization is continually being assessed and refined.

Emerging Rate Designs and Ongoing Considerations

Since the 2004 reforms, Brazil has continued to move toward increasingly cost-reflective (and complex) tariff designs. Time-of-use (TOU) Tariffs, which were available in the industrial sector since

[45] Élbia Melo, Evelina Maria de Almeida Neves, and Luiz Henrique Alves Pazzini. "The Brazilian Electricity Model: An Overview of the Current Structure and Market Design." Câmara de Comercialização de Energia Elétrica, 2001, retrieved from: https://www.researchgate.net/publication/228701847_The_Brazilian_Electricity_Model_An_Overview_of_the_Current_Structure_and_Market_Design
[46] Joisa Dutra and Flavio M. Menezes, "Electricity Market Design in Brazil: An Assessment of the 2004 Reform." http://www.uq.edu.au/economics/abstract/545.pdf
[47] All end consumers, with the exception of self-producers, Independent Power Producers (IPPs) and consumers benefited by the Tarifa Social, pay into the Energy Development Account, which is used to fund the rate discount.
[48] Leticia dos Santos Benso Maciel, Benedito Donizeti Bonatto, Hector Arango, and Lucas Gustavo Arango, "Evaluating Public Policies for Fair Social Tariffs of Electricity in Brazil by Using an Economic Market Model." Institute of Electrical Systems and Energy, Federal University of Itajuba, 2020, retrieved from: https://www.mdpi.com/1996-1073/13/18/4811/htm
[49] da Nóbrega, André Pepitone. "The Free Consumers in the Brazilian Electrical Energy Sector." School of Business and Public Management, Institute of Brazilian Business and Public Management Issues (2006). https://www.aneel.gov.br/documents/656835/14876412/Artigo_Andre_Pepitone.pdf/a57ff7bb-efea-4fc3-9871-a28bcdd984c2

the 1980s, were introduced to residential consumers in 2011 to improve demand side management and optimize use of the system through more accurate and efficient price signals.

The current residential TOU Tariff (White Tariff) includes three charges:

1. Higher on-peak charge for residential electricity consumption during a 3-hour peak period, which is determined by the utility, but which must fall within the 5-11pm window set by ANEEL.
2. Intermediate charge for electricity consumed one hour before and after the peak period.
3. Lower off-peak charge for electricity consumed outside of peak and intermediate periods.

Table 1 displays the approved White Tariff charges compared to the conventional tariff for each distribution company.

Table 1. Comparison of Conventional and White Tariff Rates for Brazilian DISCOs[50]

DISCO	Conventional Tariff (R$/kWh)	Off-Peak Tariff	Intermediate Tariff	On-Peak Tariff	Peak Hours
AMAZONAS	.693	.587	.892	1.356	8:00pm-11:00pm
Castro-DIS	.370	.318	.462	.606	6:00pm-9:00pm
CEA	.537	.441	.769	1.194	7:00pm-10:00pm
CEAL	.583	.480	.893	1.332	5:30pm-8:30pm
CEB-DIS	.515	.434	.617	.945	6:00pm-9:00pm
CEDRAP	.585	.461	.753	1.044	5:30pm-8:30pm
CEDRI	.695	.555	.939	1.323	5:30pm-8:30pm
CEEE-D	.515	.436	.621	.979	6:00pm-9:00pm

ANEEL hopes that the White Tariff will reduce customer demand during peak hours and shift to off-peak times when the grid had more flexibility. However, distribution companies face several challenges to effectively implementing the TOU tariff.

First, residential peak hours do not align with system peak hours, limiting the impact of the White Tariff on system peak load. The industrial TOU tariff introduced in the 1980s successfully shifted industrial load and had long-term impacts on usage patterns, resulting in the system peak shifting to around 4PM (outside of the window established by ANEEL for TOU). While the White Tariff may help in flattening peak residential load (occurring at around 5PM), it may not have a significant impact on flattening the system peak.[51]

Second, because the off-peak rate is set so much lower than the non-TOU residential rate, customers benefit from opting into the White Tariff regardless of consumption patterns. As a result, customers have limited incentive to change consumption patterns.[52]

The White Tariff has been rolled out slowly and its actual impacts are yet to be seen – as of 2020 only about 0.07% of residential consumers have opted into the tariff. There is indication that ongoing refinement of the time of use tariff may be required for DISCOs to realize the full system benefits. However, its introduction is a positive step toward increasing the efficiency of rates across all

[50] Data retrieved from ANEEL: https://www.aneel.gov.br/tarifa-branca

[51] Júlia Rambo Hammarstron, Alzenira da Rosa Abaide, Bruna Luise Blank, and Leonardo N. Fontoura da Silva, "Analysis of the electricity tariffs in Brazil in light of the current behavior of the consumers," Conference Paper: International Universities Power Engineering Conference (2018), retrieved from: https://www.researchgate.net/publication/329654408_Analysis_of_the_electricity_tariffs_in_Brazil_in_light_of_the_current_behavior_of_the_consumers

[52] FS Azevedo and R F Calili. "The impact of time-of-use electricity tariffs for Brazilian residential consumers using smart meter real data," Journal of Physics: Conference Series 1044 012068 (2018). https://iopscience.iop.org/article/10.1088/1742-6596/1044/1/012068/pdf

customer classes. As Brazil continues to move toward an increasingly liberalized market, additional improvements in tariff design may be needed to improve efficiency and transparency to consumers, ensuring that price signals are efficient and rates are reflective of marginal costs while able to attract the investment to meet Brazil's growing demand.

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