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Electricity Tariff Design "Theoretical Concepts versus Practices": Review of Tariff Design Approaches in East Africa-Case Studies of Rwanda, Kenya, Uganda and Tanzania

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ABSTRACT

This paper presents a comparative analysis between the theoretical concepts of tariffs design methodologies and tariff design practices in developing countries especially in East African countries including Rwanda, Tanzania, Uganda and Kenya. The theoretical concepts impose regulatory principles to be followed by the utilities for a fair and efficient tariff. A well-defined and appropriate tariff structure must balance the financial sustainability of the sector on the one hand and the well-being of various segments of society on the other. Even if utilities in regulated markets, especially in East African Countries are currently supposed to apply dynamic pricing models, their governments are still providing significant subsidies and this can create operational inefficiencies. In addition, inappropriate dynamic pricing models can lead to cross subsidization between customers which violate the equity or non-discrimination principle of a good tariff which discourages use by the overcharged and promotes overconsumption by the subsidized. The work presented in this paper evaluate the performance of different methodologies used by developing countries to set electricity prices against the theoretical concepts of electricity dynamic pricing. It also highlights the opportunities and challenges to be addressed in order to set efficient and appropriate tariffs. The conclusion and policy recommendations are provided.

Keywords: Tariff Design, Electricity Production, Regulated Markets, Peak Hours
JEL Classifications: D11, D24, D7

1. INTRODUCTION

Electric power is a crucial form of energy in the world today, it has become a basic need in all sectors of the economy. Electricity production and distribution involve huge investments. In contrary to the developed countries, most of the developing economies need foreign investors with required human and financial resources means to develop the planned projects. The bargaining power of foreign investors equip them with the capacity to negotiate a short payback period, which discourages a tariff that can ensure a social and economic well-being of various segments of society. Consequently, Cost recovery and affordability of electricity through power tariff setting has become a subject of conflict between electricity providers and regulators. On one hand, electricity providers expect a tariff that covers all costs related to the electricity production and distribution as well as a positive return on their investments. On the other hand, regulatory authorities seek to balance between positive return on the investments and social-economic well-being of the population through tariff signals (Briceño-Garmendia and Shkaratan, 2011).

In most of developed countries, the electric power market is characterized by competitive market model, while in most of developing countries, it is characterized by monopoly market model. Zweifel et al. (2017) point out that before their liberalization, most electricity markets in developed countries were organized as closed concession areas in which the regulator allowed retailing to be performed by a single utility only. They add that without the pressure of competition, utilities often had no incentive to invest in an efficient way, resulting in high cost and hence high regulated prices. However, in developing countries, the investments in production and supply of electricity are still almost done by the governments budget where the private investments are still very low and this provides them with high bargaining power. Thus, their electricity markets behave as a monopoly market where there is one seller to a lot of buyers.

Bhattacharyya (2011) clearly note that in a perfect competitive market model, consumers maximize their utility subject to their budget constraints and producers maximize their profits subject to the constraints of production possibilities. In addition, He add that there are several consumers and producers trying to transact in the marketplace where all agents are price takers and there is no market power of any agent. This implies that the price of any good is the results of the interaction between supply and demand of that good. The key feature of a competitive market is that no individual's actions have a noticeable effect on the price at which the good or service is sold (Krugman, 2009). Nevertheless, a perfect competitive market assumes a set of strong assumptions and some elements of the electric power market have the technical or other characteristics that amount to the violation of the most basic assumptions of a competitive market model (Bhattacharyya, 2011).

Opposite to developing countries, developed countries have developed the electricity production using modern technologies such as nuclear. They have been able to satisfy the internal demand and started to produce electricity for export. In doing so, they have attracted private investments to complement public investment, is in this way that their electricity market has become more and more competitive with multiple electricity supplies. Electricity is now treated as a commodity worldwide, which can be bought, sold and traded at market rates like any other commodity (Girish and Vijayalakshmi, 2013). Therefore, the demand for electricity is subject to daily, weekly, and seasonal variations like other goods on the market. Even so, since electrical power storage is not economically viable yet and has to be consumed whenever it is produced (Shiels, 2001), the suppliers attempt to pursue the tariff differentiation designed to shift demand from peak to off-peak periods and to encourage consumption when there is excess supply. This is because the costs of service are higher during peak hours than off-peak hours of supply.

Properly designed tariffs are essential both for ensuring that the system is used to the best advantage in the short-term and for mapping out long-term demand trends (Reneses et al., 2011). Tariffs must generate the income required to cover all the costs of supplying electricity and send the right economic signals to each customer to ensure that they use the service in the most efficient way. After the liberalization of the electric power markets in developed countries, the researchers have started to develop the appropriate dynamic pricing models allowing prices to reflect electricity costs that vary over time. However, for these pricing models to work better, require the utilities to meet some conditions such as advanced metering technology, meter data, operational support and Customer education and awareness (Spiller, 2015).

While no universal pricing model, most of the literature agrees that the dynamic pricing models served as catalysts for the development of the liberalized electric markets. Despite the differences in electrical market structures for developed and developing countries, regulated markets of developing countries can benefit from dynamic pricing from the welfare point of view. Even if utilities in regulated markets, especially in East African Countries are currently supposed to apply dynamic pricing models, their governments are still providing significant subsidies and this can create operational inefficiencies. In addition, inappropriate dynamic pricing models can lead to cross subsidization between customers which violate the equity or non-discrimination principle of a good tariff.

To attract possible future investors, a good tariff design has to show that the different activities (generation, transmission, distribution and retailing) of the electricity sector will be profitable and their revenue flows stable in the medium and long term. Research in this area is rare in developing countries. Given the theoretical concepts of tariff design and practices in regulated markets of developing countries especially in East African Countries, the appropriate dynamic tariff scheme for developing countries is worth studying to highlight the opportunities and challenges to be addressed.

2. THEORETICAL CONCEPTS OF TARIFF DESIGN

"Tariffs are computed, not decreed". This quotation from The White Paper on power sector reform, prepared by Ignacio Pérez-Arriaga for the Spanish Government in 2005, warns against tampering with electricity tariffs, a common practice of many governments, unfortunately (Pérez-Arriaga, 2013). The electricity tariff design must meet two main objectives including, to raise the money needed to pay for the costs of the activities (Apolinário et al., 2006) as well as to send the right economic signals to each customer to favor the optimal socio-economic use of electricity (Pérez-Arriaga, 2013).

To achieve the above objectives, the literature has emphasized on the theoretical regulatory principles that must be borne in mind when designing tariffs. These comprise, the economic sustainability or revenue sufficiency, equity or non-discriminatory, economic efficiency in resource allocation, transparency, simplicity and stability of the methodology used, consistency with liberalization and the regulatory framework in place in each country and tariff additivity (Batlle, 2011; Berg and Tschirhart, 1988). However, Batlle (2011) clearly note the difficulty or the impossibility of simultaneously meeting all the above principles, at least in their full dimension. This is often attributable to the conflicts among the principles themselves and add that the ultimate objective is to reach a reasonable balance among all the principles.

2.1. Tariff Structure Design

While various authors differ on appropriate theoretical approaches for the allocation of the cost items to the tariff structure, most of the literatures agrees on the main steps or phases for tariff design. According to Rodríguez Ortega et al. (2008), tariff design can be divided into three fundamental steps. The first is the choice of remuneration methods and levels for each business activity (generation, transmission, distribution, retailing, system operation); the second is the definition of the tariff structure applicable to end consumers and lastly, the allocation of allowed costs to that structure. Reneses et al. (2011) suggest that the tariff design involves four main phases, the first is to clearly define the allowed total income which has to be recovered through tariffs, the second is dividing these costs into the different cost drivers, the third is allocating them to the different customers' Categories and finally the structure can be computed using the additivity principle for tariffs. The following sections describe different steps and approaches for a good tariff design trying to reach a reasonable balance among all the principles.

2.2. Components and Drivers of Electricity Supply Cost

Reneses et al. (2011) clearly note that three cost drivers have to be considered when designing a tariff. They include, peak demand or Capacity charge or demand charge (kW), energy consumption (kWh) and number of customers. Some authors like Wayne C. Turner and Steve (2006) went further and propose the following main three components of costs. The customer costs which include the operating and capital costs associated with metering, billing, and maintenance of service connections. The energy costs that vary with changes in consumption of kilowatt-hours (kWh) of electricity. These are the capital and operating costs that change only with the consumption of energy, such as fuel costs and demand related costs which include the capital and operating costs for production and transmission that vary with demand requirements. Andrey and Hauriey (2013) conclude that the amount charged to consumers resulting from the transmission and distribution costs may have two components, the first one being proportional to the quantity of delivered energy (kWh) while the second is proportional to the maximal power (kW) used in a given period of time.

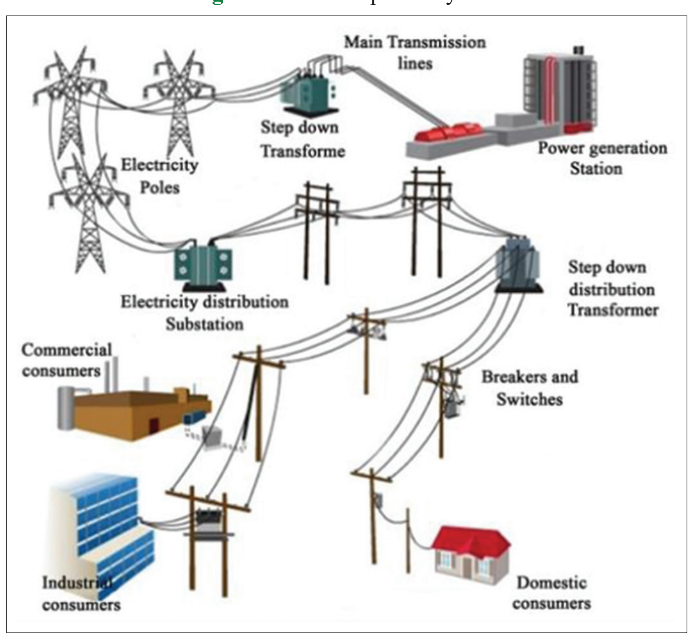
Andrey and Hauriey (2013) explain the main sources of the generation, transmission and distribution costs of electricity. They report that the price of a kWh is subdivided into the electricity generation cost which corresponds to the cost of producing one kWh of electricity which may depend on the type of generation facility, on the price of the primary energy, on the facility's amortization rate, etc. While for the electricity transmission and distribution costs, the price is related to the network use necessary to carry the electricity from its generating facility to the final user. It is typically further split in two sub-components corresponding to high voltage networks (transmission, import and export) and low voltage networks (distribution). Eid et al. (2014) propose the main electricity billing variables but in their study, they insisted cost-causality and tariff principles. Primary, there is a billing based on transported energy (in €/kW h). Mandatova et al. (2013) highlighted that even if this type of billing for network costs is not the most cost reflective of network utilization, it could provide signals for overall energy efficiency. The another, is the billing based on contracted capacity of utilized maximum capacity (in €/kW). They additionally precise that, low voltage users are frequently being billed by the contracted capacity, and not through an observed maximum capacity. Lastly, billing based on a fixed charge (in €/year or €/month). These costs can be related to the contribution to losses, the contribution to the network peak and the connection costs (Rodríguez Ortega et al., 2008).

Pérez-Arriaga (2013) in his book related the regulation of the power sector, has evidently noted that in the case of electric power, the greater share of system costs is determined by two fundamental variables which comprise a customer's installed capacity (typically, the peak demand that can be handled by the facility in question) and the energy consumed at a given connection point and time. However, network revenue requirements are often based on embedded costs, which are typically higher than long run marginal costs which creates the problem of recovering residual costs and several methods available for doing so have been highlighted (Brown et al., 2015). In most of the cases, the sum of the three charges do not correspond to all required revenues, a final adjustment should be made. This adjustment could be based on applying a proportional coefficient to both charges (in order that their sum is equal to the total generation costs), or even on applying a second-best criterion, such as Ramsey prices**.** Adding to the energy charge, most utility tariffs include a network access charge and a service charge (Cousins, 2009).

2.3. Cost Allocation Approaches

Once the allowed income to be recovered is determined and prior to the allocation of costs, all customers would be categorized. Each customer category groups a number of customers with a similar load profile and responsibility in the cost. All the customers in a category should be connected to the same voltage level (Reneses et al., 2011). The level of voltage at which electricity is transmitted and distributed varies from country to country. In Rwanda, electrical power is transmitted from power generation stations to electricity distribution substations at 110 and 220 kilovolts and it is distributed at 30 and 15 kilovolts for big consumers in rural and urban areas respectively, 0.4 kilovolts for medium consumers and 220V for small consumers. Figure 1 shows the different parts of a power system (Munyemanzi, 2021).

Figure 1: Electric power system



The Figure 1, shows three consumer categories which comprise domestic, commercial and industrial customers. To calculate energy flows between different voltage levels requires to define a network model and energy loss factors caused by energy flows between different voltage levels. The distribution grids are built with a wide variety of voltages, the cost of each voltage level can be allocated to the actors responsible for the cost in question who are typically, the consumers connected at that level (Pérez-Arriaga, 2013). From practical point of view, Reneses et al. (2011) used a cascade grid model proposed by Spain's National Energy Commission that envisages the existence of transformers between non-consecutive voltage levels to describe the Libyan power system. They also point out that with this grid layout, inter-voltage level flows and their respective shares can be calculated fairly simply, bearing in mind network losses, power plant delivery at each level and consumption records.

Customers that cause similar network costs are identified and grouped considering different voltage levels, customers' demand measured as peak demand, average demand or contracted demand, their load profiles in each voltage level related to the definition of the time-of-use blocks and geographical areas (Rodríguez Ortega et al., 2008). Each group have a different tariff. Based on the categorization of customers and time blocks definition, the generation, network and customer services costs are allocated. Mostly, utilities in providing their package incurred two broad types of costs. The first are the fixed capital costs related to their investment. Some of the expenses associated with fixed capital costs include interest on debts, depreciation and insurance. The second are the expenses related with the operation and maintenance (O&M) of those same facilities. These expenses include costs such as salaries and benefits, spare parts, costs related to purchasing, handling, preparing, and transporting of energy resources.

The main step toward cost allocation is to attribute to each kilowatt-hour produced both the capital and operating costs of the three power production segments: Generation, transmission, and distribution (Briceño-Garmendia and Shkaratan, 2011). The depreciation and a reasonable rate of return of the network investment (capital) represents a large stake of the total distribution costs. The network assets need to be maintained to perform adequately and to optimize their useful life. Usually, maintenance costs are considered to be proportional to network investment, and operation costs proportional to the number of customers and the service area being considered (Rodríguez Ortega et al., 2008).

For the appropriate allocation, the generation and network costs are divided into variable and fixed cost. The asset depreciation and investment return are considered as fixed cost while operations and maintenance costs are considered as variable. One of the most widely used criteria for dividing costs between the capacity charge and the energy use charge was to allocate the variable costs of generation to energy component of the tariff (€/kWh) and the fixed costs (capital costs and generation independent operating and maintenance costs) to the capacity component (€/kW) (Pérez-Arriaga, 2013). Some authors base on the variable and fixed cost to introduce the marginalist theory in cost allocation. Reneses et al. (2011) propose the cost allocation by charging the short-term marginal production costs (variable) to the energy consumed. And long-term Marginal costs (fixed cost of the adapted peak generation technology) to demand or capacity charge.

2.4. Theoretical Approaches for the Costs Allocation

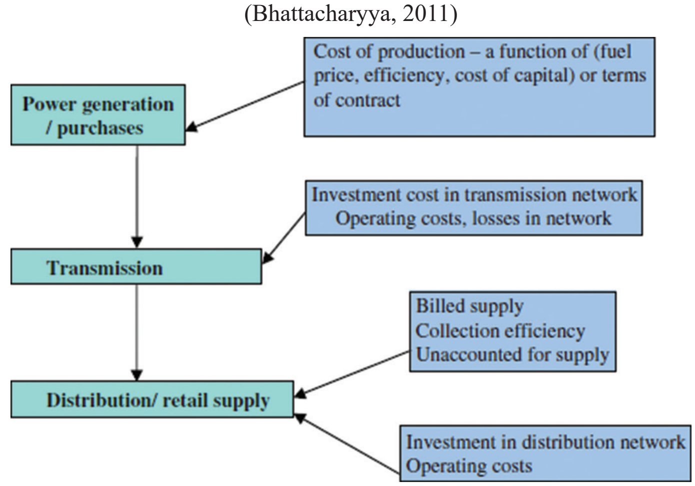
The literature on electricity pricing models suggests various approaches, the allocation of the cost items to the tariff structure is a very complex task for which no universally accepted procedure has been found. Generally, the accounting approach, marginal cost based and average cost pricing are proposed. In addition, demand for electricity shows significant daily, weekly, monthly and seasonal variations, to meet such fluctuating needs, the suppliers use different types of technologies to meet demand but the cost characteristics of these technologies are different, thereby imposing different costs of service during peak and off-peak hours of supply. Therefore, peak and off-peak pricing is also proposed. The Figure 2, describes the electricity supply value chain and cost determinants.

2.4.1. Accounting approach

The main objective of the accounting approach is to recover all the cost items posted in companies' accounts, to which end each item is allocated on the tariff structure. The traditional accounting approach is concerned with recovering historical, or sunk, costs. The accounting approach that uses historical assets and embedded costs implies that future economic resources will be as cheap or as expensive as in the past (Munasinghe and Warford, 1982). This could lead to overinvestment and waste, or underinvestment and the additional costs of unnecessary scarcity.

As described in the Figure 3, the accounting approach requires the breakdown of total allowed revenues into different functional segments. This is followed by further breakdown into several cost components: costs associated with demand (installed capacity), costs associated with the amount of energy produced, and costs associated with the number of users. Finally, the costs itemized by function and component are allocated among end-users of all categories, and the costs allocated to each category is averaged over all users of the same category (Parmesano et al., 2004). While the method constituted a significant step forward in its time, it does not send consumers the most suitable economic signals and

Figure 2: Electricity supply value chain and cost determinants (Bhattacharyya, 2011)



from the standpoint of sound tariff design theory, its use is not recommended (Pérez-Arriaga, 2013).

2.4.2. Marginal cost pricing

The marginal cost-based approach, unlike the accounting approach, does not directly allocate the allowed revenues to be recovered over the tariff structure. Instead, as described in Figure 4, it allocates the Long-Run Marginal Cost (LRMC) which means the economic value of future resources required to meet incremental changes in consumption of electricity over the next 5–10 years for each category of customers (Peng and Poudineh, 2016). In other words, the marginal cost approach provides ratepayers with cost information about the future, whereas the accounting approach (average cost approach) is based on historical data and

Figure 3: Accounting approach (Peng and Poudineh, 2016)

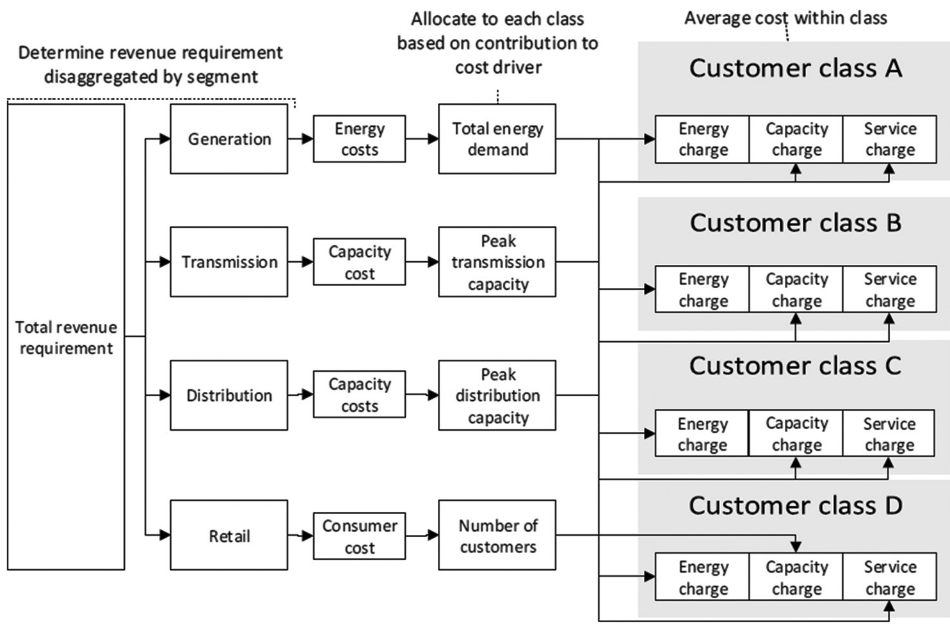
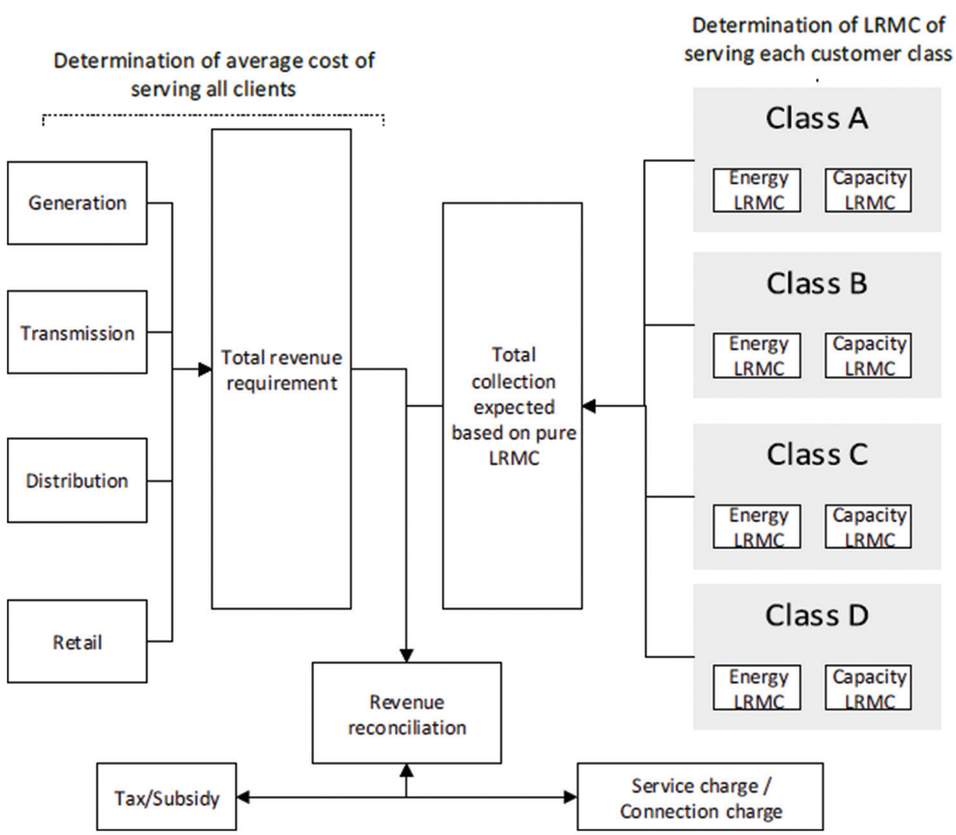


Figure 4: The marginal cost approach for cost allocation (Peng and Poudineh, 2016)



thus provides ratepayers with cost information about the past. Under the conditions of pure and perfect competition, the marginal cost-based approach follows from the competitive market model where prices are decided by the marginal costs of the last supplier (Bhattacharyya, 2011). He additionally indicated that due to the specific features of the energy market, the marginal cost-based pricing may not be appropriate.

Pérez-Arriaga (2013) point out that the main advantage of using marginal cost-based rates is they constitute an attempt at making that each consumer defrays the system costs incurred by his/her own use. However, he highlighted that, marginal rates do not generally recover allowed costs completely (especially for the networks, due to economies of scale), and consequently call for significant adjustments that may ultimately distort the economic signals sent to users. If the revenue collected based on LRMC is more than the total current expenses of the utility, the surplus could be taxed away or used on subsidizing non-energy related charges such as connection fees. Conversely, when the revenue collected based on LRMC is lower the total current expenses of the utility, then the deficit could be made up by higher connection fees, service fees, or even government subsidies (Peng and Poudineh, 2016). The Figure 5, shows Revenue surplus and revenue deficit under different LRMC curves.

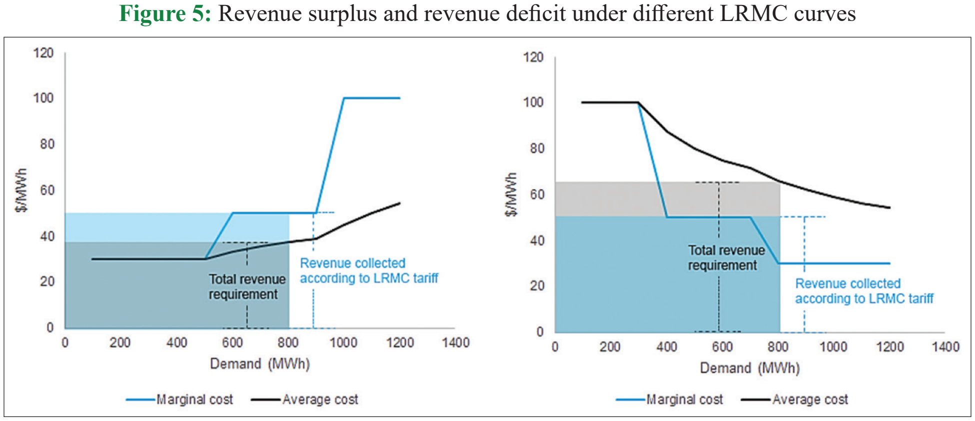
While Long Term Marginal Cost (LTMC) refers to network total costs, Short Term Marginal Cost (STMC) refers to electric energy costs note Pérez-Arriaga (2013). Some practical problems may be raised by the contradiction of having to choose between Short Run Marginal Cost (SRMC) and Long Run Marginal Cost (LRMC). *SRMC* may be defined in economic terms as the cost of meeting additional electricity consumption with fixed capacity. *LRMC is* the cost of meeting an increase in consumption, sustained indefinitely into the future, when needed capacity adjustments are possible (Munasinghe and Warford, 1982). If there is an incremental increase in consumption, in the short run both the system operating costs and the outage costs (especially during the peak period) will also rise at the margin. Similarly, in the long run, an increase in demand will result in a corresponding increase in the operating costs as well as in the capacity costs. Thus, in both the short and long run an equivalent increase in operating costs will occur. But the optimal reliability rule ensures that the marginal outage and capacity costs are also equal.

Therefore, when the system is optimally planned and operated-that is, capacity and reliability are optimal-SRMC and *LRMC* coincide. Therefore, the estimation and use of the strict *LRMC* is simplest when the system is near the ideal operating point. If the system plan is suboptimal, however, significant deviations between *SRMC* and *LRMC* will have to be resolved within the pricing policy framework (Munasinghe and Warford, 1982). In the first stage of calculating the Long Run Marginal Cost (LRMC), the objective of economic efficiency in setting tariffs is satisfied, because the method of calculation is based on future economic resource costs rather than on sunk costs, and also incorporates economic considerations, such as shadow prices and externalities. In the second stage of developing a tariff based on *LRMC,* deviations from the strict *LRMC* are considered to meet important financial, social, economic (second-best), and political criteria (Munasinghe and Warford, 1982). This second step of adjusting the strict *LRMC* is generally as important as the first calculation, especially in developing countries.

Classical economic theory states that Short-term marginal costs-based prices are the most efficient economical signals. But, in the case of natural monopolies, these marginal costs in general will not allow to recover the revenue requirement. Therefore, an additional adjustment would be needed to comply with the sustainability criterion (Rodríguez Ortega et al., 2008). With the advent of restructuring and liberalization of the power sector especially in developed countries, electricity is traded in wholesale markets with short-term energy prices, the application of short-term marginal costs was shown to be the most efficient economic signal for power system operation (Pérez-Arriaga, 2013).

When marginal-cost pricing creates a deficit, one regulatory option is to maintain these prices and subsidize the firm to cover the deficit. This is because the society's welfare might be better served in some industries if a price-discriminating monopolist were allowed to supplant competition (Berg and Tschirhart, 1988). In addition Berg and Tschirhart (1988) cite Hotelling (1929) in their book to note that in decreasing-cost industries, prices should be set equal to marginal cost. The monopolist knows that his market includes consumers of different types but does not know which consumer is of which type. What he wants to do is to set a pricing scheme that will result in consumers revealing their type through their actual purchases. Block pricing or second-order discrimination is generally implemented by setting two-part tariffs, which include a fixed fee and a variable fee, depending on the quantity used (Leveque, 2003). If tariffs are based on marginal costs, it is possible to avoid inter-customer cross subsidization.

Figure 5: Revenue surplus and revenue deficit under different LRMC curves



The closer those tariff prices are to marginal costs, the closer is to get an efficient resource allocation that promotes wellbeing maximization (Apolinário et al., 2006).

2.4.3. Peak and off-peak pricing

Economists have long been arguing that time-differentiated pricing schemes have to be enforced in order to provide end users with incentives convincing them to modify their consumption pattern. In off peak periods, only those facilities that are characterized by low operation costs are used. When the demand grows in peak periods, the production adapts itself and facilities whose variable costs are higher and higher begin to be used and the cost of electricity production is thereby rising (Andrey and Hauriey, 2013). This implies that the order in which the power plants are switched on is related to their marginal cost of production i.e., low marginal cost for off peak hours and high marginal cost for peak hours as described in Figure 6.

Where: Peak demand curve is $D_{p,}$ off-peak demand curve is D_{op}, off-peak period price is "a" and Peak period price is "(a+b)". This model assumes a constant operating cost "a" (which is the short-run marginal cost) and the fixed cost is "b" (which added with the operating cost gives the long-run marginal cost). During peak period the system feels pressure on capacity and the price would have to take into consideration the cost for adding capacity (Bhattacharyya, 2011). Accordingly, the relevant price at this period is the operating cost supplemented by the capacity cost (or fixed cost). The simple rule then is that those consumers who come to the grid during peak-periods should bear the full responsibility of capacity cost and operating costs while those who use electricity during off-peak period should pay only for the short-run marginal costs (Munasinghe and Warford, 1982).

2.5. Tariff Adjustments

Large investments and capital intensiveness are required for the development of the energy sector, this implies that few large suppliers tend to dominate the market. Most of the developing countries, electricity markets are state dominated or dominated by very few electricity suppliers, this leads them to behave as monopoly markets. Figure 7, shows that a profit-maximizing monopolist will set her price at the intersection of marginal cost and marginal revenue in contrary to the competitive market where the price is equal to the marginal cost of the last supplier (Bhattacharyya, 2011).

Where AC is the average cost, MC is the marginal cost and MR is the marginal revenue. Qm is the electricity supplied by a monopoly market and Pm is the price charged by the monopoly market. Qc is the electricity supplied by a competitive market and Pc is the price charged by the competitive market. Thus, as Pm is greater than Pc, the consumers pay Pm-PC as monopoly rent and this leads to a deadweight loss equivalent to the triangle BCD.

According to Leibenstein (1996), it could be indicated that a monopolist might operate in the inefficient zone of the production possibility frontier. This means that a monopolist may choose the factors of production in an inefficient manner, thereby operating at a point above its theoretical cost curve, this is known as X-inefficiency. Another source of monopoly-related inefficiency is the possibility of rent seeking by charging more than the competitive market price with the aim of earning a monopoly rent (Bhattacharyya, 2011). The economic theory stipulates that, prices in a competitive market equal the marginal cost of production. Due to monopoly inefficiencies, applying this principle to a monopoly market, the price will be less than the average cost of production and the firm will incur a loss. As no private enterprise will be interested in providing a good by incurring a loss, the literature proposes the alternative solutions such as two-part tariff and Ramsey pricing for tariff adjustments (Shepherd, 1992).

2.5.1. Use of power factor and demand charge penalties

Power factor can be described as the percentage of the total apparent power which is converted to real or useful power (Sankaran, 2002). This implies that the power factor (PF) is the mathematical ratio of Active Power (KW or MW) to Apparent Power (KVA or MVA).

$$PF = \frac{Active\,Power(KW\ or\ MW)}{Apparent\,Power(kVA\ or\ MVA)}$$

In an electrical system, the total apparent power (KVA or MVA) is what is supplied to the load, while the active power (KW or MW) is just the percentage of the total apparent power which performs useful work (Gboney, 2015). Therefore, if the power

Figure 6: Peak pricing model

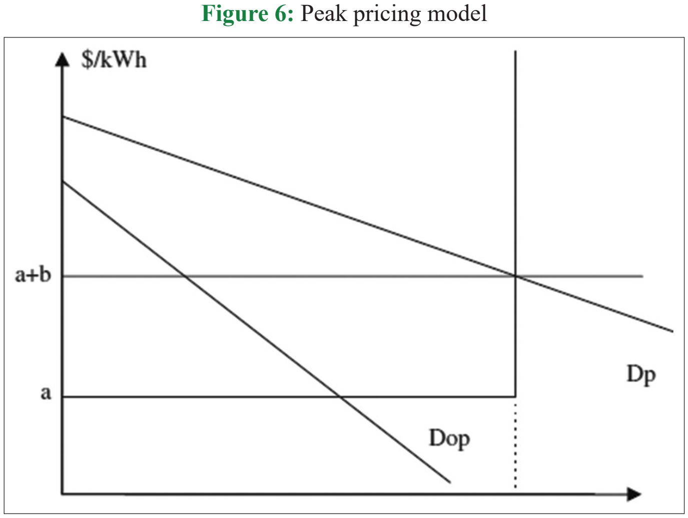
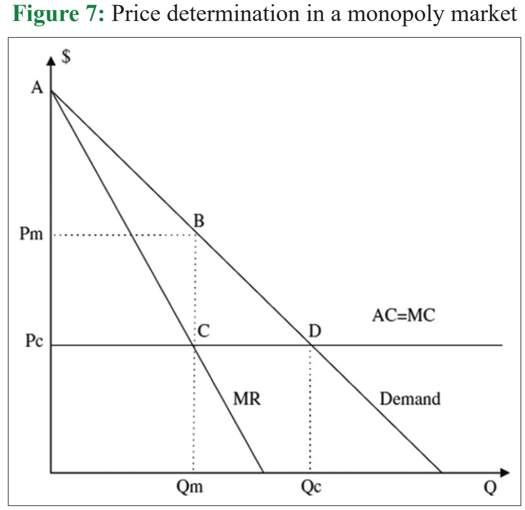


Figure 7: Price determination in a monopoly market



factor of a load is 0.85, it means only 85% of the apparent power is converted into useful work. (Gboney, 2015) cites Stoft (2002) to note that in practice, loads cannot achieve a power factor of 100% since all electrical circuits require some minimum reactive power requirements because of the presence of inductance and capacitance to perform useful work.

If loads are reactive, then voltage and current will be out of phase and the Apparent Power (S) will need to be greater to accomplish the same work (in Watts) as a non-reactive load. As described in Figure 8, the hypotenuse shows the total Apparent Power (S) given a certain combination of real (P) and reactive power (Q). The bottom side of the triangle shows the amount of power (P) available to do work which decreases as reactive power (Q) increases.

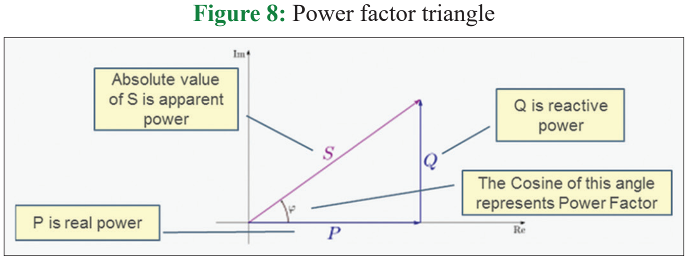
Reactive energy affects energy losses and voltage regulation and this is a challenge to satisfactory system operation. As most reactive power is consumed in users' facilities, consumers can and should, then, participate in controlling this power, with a view to maintaining voltage levels and minimizing system losses. Thus, signals should be sent to consumers in the form of a specific charge (Pérez-Arriaga, 2013). This is a method used to charge for the power lost due to a mismatch between the line and load impedance. Where the power-factor charge is significant, corrective action can be taken, for example by adding capacitance to electric motors (Wayne C. Turner and Steve, 2006). Charges that penalize reactive power consumption in peak periods and its generation during off-peak periods are often implemented by utilities.

3. BASIC RATE STRUCTURE AND INNOVATIVE RATES

Revenue management and dynamic pricing are concepts that have immense possibilities for application in the energy sector. Both can be considered as demand-side management tools that can facilitate the offering of different prices at different demand levels (Dutta and Mitra, 2016). The rate tariff structure generally follows the major cost component structure. Each type of charge may consist of several individual charges and may be varied by the time or season of use. applying the principle of tariff additivity to the End-User tariff of the regulated supplier, assures that there is no cross-subsidization between the binding customers and the non-binding customers (Apolinário et al., 2006).

Briceño-Garmendia and Shkaratan (2011) assessed 27 Sub-Saharan African countries, representing 85% of the population, their study reveals that most electricity tariffs of 2010 s in Africa were based on block tariff-pricing schemes; that is, the price of power is linked to the level of consumption. However, Andrey and Hauriey (2013) in their study conducted in Switzerland, make an inventory and a characterization of the various time-varying electricity pricing schemes that are available to electricity distributors. They highlighted the main categories of tariffs, ranging from time-of-use tariffs (TOU) to real-time pricing (RTP). While there is no universal electricity tariff model, each pricing scheme presents its advantages and disadvantages. The appropriateness of each tariff scheme depends on various conditions such as the availability of required technology and electricity market environment.

Figure 8: Power factor triangle



3.1. Block Tariff-pricing Scheme

This scheme differentiates between customers based on the quantity of electricity consumption. The scheme consists of multiple tiers characterized by the amount of consumption. Inclining rate schemes increase the per-unit rate with increasing consumption and declining schemes do the opposite (Dutta and Mitra, 2016). However, any of the tariff under block scheme may be complemented by a fixed monthly charge, and are then described as two-part electricity tariffs.

3.1.1. Increasing block tariffs (IBTs)

This is described as a regime in which the unit price per kWh follows an increasing step-function linked to sequentially defined blocks (Briceño-Garmendia and Shkaratan, 2011). The increasing block structure reflects the fact that the incremental cost of production exceeds the average cost of energy (Turner and Doty, 2006). Hence, use of more energy will cause a greater cost to the utility and have to discourage the consumption through the electricity price.

3.1.2. Decreasing block tariffs (DBTs)

This is defined as a regime in which the unit price per kWh follows a decreasing step-function linked to sequentially defined blocks (Briceño-Garmendia and Shkaratan, 2011). With the declining or increasing block structures, the number of kWh used is broken into blocks and the unit cost is lower or higher for each succeeding block (Turner and Doty, 2006). A decreasing block is mostly applied for utilities that can generate additional electricity for lower and lower costs up to a point.

3.1.3. Linear tariffs (LTs)

Linear tariff represents a regime in which all units of power consumed are charged at exactly the same rate. This implies that the price remains static even though power demand changes. Consumers under such a scheme do not face the changing costs of power supply with a change in aggregate demand. Thus, consumers have no financial incentive to reschedule their energy usage (Dutta and Mitra, 2016). In electricity markets, residential consumers typically pay fixed rate per unit of electricity irrespective of the time of day or season of consumption. It is supposed that prices that are reflective of the time-varying and season-dependent costs of generation and distribution may encourage consumers to reduce some of their electricity consumption from peak periods when prices are higher to off-peak periods when prices are lower. Therefore, Wesseh and Lin (2022) clearly note that such flat payments ignore the fact that real system costs vary based on time of day, season, or location, thus undermining the efficiency with which power resources are allocated.

3.2. Time-varying Tariffs

Time-varying tariffs are intended to reduce system costs for utilities. Their load shape objective is to reduce peak loads and/or shift load from peak to off-peak periods. This is because during peak period, the cost of electricity production is high than in off-peak periods. Most of the literature agrees that real time pricing (RTP), time-of-use (TOU) pricing, and critical peak pricing (CPP) are forms of dynamic pricing commonly used. However, some authors and practitioners went further and propose rate combinations.

3.2.1. Time-of-use (TOU) pricing

Cousins (2009) points out that TOU rate design features prices that vary by time period, being higher in peak periods and lower in off-peak period. He explains that the simplest rate involves just two pricing periods, a peak period and an off-peak period. Andrey and Hauriey (2013) agree that, time varying tariffs are the simplest and the most extensively used. They however add that, the days are typically split in 2 to 5 periods (depending on the country), each being characterized by a static price. The splitting and prices are pre-determined and typically adapted on a monthly basis. In some cases, TOU rates may have a shoulder (or mid-peak) period, or even two peak periods (such as a morning peak and an afternoon peak).

Faruqui et al. (2012) highlighted the advantages and disadvantages of TOU pricing scheme. TOU rates encourage permanent load shifting away from peak hours. They have a simple design that is predictable and easy for customers to understand. For developing countries, TOU rates also could be used to encourage adoption of electric cookers and plug-in electric vehicles by providing lower rates during the off-peak periods. It should be noted also that offering TOU rates does not necessarily require deployment of advanced metering infrastructure. However, TOU rates are criticized to not provide as large a peak load reduction as dynamic rate designs due to the price signal being averaged over a large number of peak hours instead of a relatively limited number of very high-priced hours.

3.2.2. Critical peak pricing (CPP)

CPP is a normal tariff generally belonging to the TOU family, this is a dynamic pricing scheme in which prices are high during a few peak hours of the day and discounted during the rest of the day. The peak price remains same for all days. It gives a very strong price signal and enhances the reduction of excessive peak load (Dutta and Mitra, 2016). However, a small number of days per year are subject to a price change. These occurrences correspond to periods of very high demand (peak loads) during which the generating utilities could not provide sufficient a quantity of electricity if keeping the prices flat (Andrey and Hauriey, 2013).

Customers are naturally informed of the critical peak periods a day ahead or hours ahead so that they can adjust to price changes in the critical periods (Wesseh and Lin, 2022). The electricity price may increase dramatically during this period to reflect system costs. Like the TOU rate, the CPP rate is simple for customers to understand. It provides a strong price signal and has produced some of the highest observed peak reductions among participants. In addition, it exposes customers to higher prices during only a very limited number of hours (Faruqui et al., 2012).

3.2.3. Real time pricing (RTP)

In Real-Time Pricing (RTP) schemes, electricity tariffs are reflecting the electricity market situation. Prices are not pre-determined and are typically subject to hourly changes. This pricing scheme being extremely difficult to handle (intensive exchange of data, new billing procedures to define, etc.), it is often proposed in conjunction with other contracts (Andrey and Hauriey, 2013). According to Dutta and Mitra (2016), the change in the price in such small intervals increases the efficiency of the pricing scheme in reflecting the actual costs of supply, but such schemes require advanced technology to communicate and manage these frequent changes. Retail electricity markets may find it difficult to practice this scheme due to the high rate of data collection and transfer. Therefore, this could be the reason, Borenstein et al. (2002) point out that while RTP has not been widely accepted or implemented, time-of-use (TOU) pricing has been used extensively. Faruqui et al. (2012) clearly note that while RTP rates provide the most granularity in conveying accurate hourly price signals to customers, without automating technologies it is difficult for customers to respond to prices on an hourly basis response.

3.2.4. Rate combinations

The rate options described above can also be offered in combination to take advantage of the relative advantages of each. Because TOU rates don't capture the price variation within a price block, TOU pricing is often combined with a separate charge for peak usage. These "demand charges" are a price per kilowatt for the customer's highest usage during the billing period (usually a month). Most of the meters that register maximum usage for demand charge billing are not capable of storing information indicating the precise date and time at which that maximum usage occurred (Borenstein et al., 2002). However, Faruqui et al. (2012) note that one common combination is CPP and TOU. The TOU component of the rate reflects the average daily variation in peak and off-peak energy prices. The CPP component during a small percentage of hours each year reflects the cost of capacity during the seasonal system peak. Together, these rates can facilitate greater energy awareness among customers and provide a greater opportunity for bill savings through a more heavily discounted off-peak rate. They added that combining a time-varying rate with an inclining block rate can encourage peak load reductions as well as conservation.

4. REVIEW OF TARIFF DESIGN PRACTICES IN EAST AFRICAN COUNTRIES

4.1. Tanzania

Tanzania Electric Supply Company Limited (TANESCO) is a parastatal that generates, transmits, distributes and sells electricity in Tanzania. TANESCO owns most of the electricity generating, transmitting and distributing facilities in Tanzania. Yet in 1992, the government of Tanzania removed TANESCO's monopoly as the sole power generating and distributing company. Between 2007 and 2010, revenue collected through tariffs was enough to cover TANESCO's cost of sales, while its other expenses (operating expenses and finance cost) were covered through other operating incomes (mainly in the form of government contribution). Starting in 2011, the revenue collected through tariffs, despite increases, no longer covers its cost of sales. Under the current regulatory regime, it is the duty of Energy and Water Utility Regulatory Authority (EWURA) to scrutinize all expenses incurred by TANESCO, safeguarding the interests of ratepayers, deciding which costs are to be recovered via the regulated tariff and governmental contribution, and which costs are to be borne by TANESCO through cost savings.

Currently, remuneration for the electric power industry in Tanzania is recovered via a multi-year integral tariff, proposed by TANESCO and approved by EWURA, to be reviewed at least once in every 3 years. The integral tariff does not distinguish between the origin of costs that need to be recovered into functional segments such as generation, transmission, and distribution (Peng and Poudineh, 2016). This is a feature which reflects the fact that Tanzania's power industry structure is not yet unbundled. TANESCO uses the formula in equation (1) to compute its revenue requirement:

$$R_{required} = C_{OM} + D + L + I - R_{other} \tag{1}$$

Where:

$R_{required}$: Revenue Requirement;

C_{OM}: allowed operating and maintenance costs, including general and administrative expenses;

L: loan repayment; I: investment plan;

R_{Other}: revenue from other sources

TANESCO uses also a tariff indexation mechanism to adjust changes in costs that are outside of TANESCO control, so that the tariff revenue keeps pace with rising costs during periods between formal reviews. Local inflation and foreign exchange rate fluctuation adjustments, along with the indexation of fuel costs are used. It is required that the adjustments would be published by EWURA on a quarterly basis but practically this is not the case. The tariff structure in Tanzania does not differentiate between different geographic regions of the country or different consumption periods. The five categories of customers are differentiated based on the voltage at which they are connected and their average level of consumption. The tariff applicable to each class of customers can include an energy charge, a capacity charge, and a service charge (Peng a nd Poudineh, 2016):

- Domestic low usage tariff (D1): this category covers domestic customers with low consumption at low voltage (230 V). The first 75 kWh of consumption is charged at a subsidized lifeline rate, and monthly consumption exceeding that is charged at a higher rate and capped at 283 kWh. This tariff only contains an energy component.
- General usage tariff (T1): this category covers customers from a wide range of sectors, with average consumption above 283 kWh per month, supplied at low voltage (230 V for single phase and 400 V for three phase). There is both an energy component and a fixed component in this tariff.
- Low voltage maximum demand usage tariff (T2): this category covers customers with monthly average consumption of more than 7,500 kWh at 400 V. Energy, demand (capacity), and fixed components all exist for this tariff.
- Medium voltage maximum demand usage tariff (T3-MV): this category covers customers connected to the grid at 11 kV and above. Energy, demand (capacity), and fixed components all exist for this tariff.
- High voltage maximum demand usage tariff (T3-HV): this category covers customers connected to the grid at 132 kV and above. Energy and demand (capacity) components exist for this tariff. It is also known as the bulk tariff (T5).

4.2. Kenya

Energy and Petroleum Regulatory authority (EPRA) is the authority in charge of electricity tariff setting in Kenya. The Energy Regulatory Commission (2018) clearly describes the process of tariff setting. This process consists of demand forecasting; generation and transmission planning to meet the forecast demand; determination of the sector revenue requirements; determination of marginal costs of generation, transmission, distribution and retailing; allocation of total revenue requirement; computation of initial retail tariff proposals, sensitivity analysis of the proposed retail tariffs; public exposure of the proposed tariffs and the determination of the final retail tariffs.

4.2.1. Customer categories

Energy and Petroleum Regulatory authority (EPRA) categorize customers as follows:

- Domestic Consumers for supply provided and metered by the Company at 240 or 415volts and whose consumption does not exceed 10 Units per Post-paid Billing Period or Pre-paid Units Purchase Period.
- Domestic Consumers for supply provided and metered by the Company at 240 or 415 volts and whose consumption is greater than 10 units but does not exceed 15,000 Units per Post-paid Billing Period or Pre-paid Units Purchase Period
- Non-domestic Small Commercial Consumers for supply provided and metered by the Company at 240 or 415 volts and whose consumption does not exceed 15,000 Units per Postpaid Billing Period or Pre-paid Units Purchase Period
- Commercial and industrial consumers for supply provided and metered by the company at 415 volts three phase four-wire and whose consumption exceeds 15,000 Units per Post-paid Billing Period
- Commercial and industrial consumers for supply provided and metered by the company at 11,000 volts, per Post-paid Billing Period
- Commercial and industrial consumers for supply provided and metered by the company at 33,000 volts, per Post-paid Billing Period
- Commercial and industrial consumers for supply provided and metered by the company at 66,000 volts, per Post-paid Billing Period
- Commercial and industrial consumers for supply provided and metered by the company at 132,000 volts, per Post-paid Billing Period
- Public and County Governments metered by the Company

at 240 or 415 volts per Post-paid Billing Period for supply of electrical energy to public lamps (Street Lighting).

4.2.2. Kenya tariff structure

EPRA apply different tariffs based on voltage levels, customer categories, level of consumption and Time of Use (off-peak or peak hours) the Table 1 shows off-peak hours. Depending on customer categories, energy charge (volume charge), demand charge (capacity charge), fixed charge and tariff adjustments are applied through one-part, two-part and three-part tariffs Table 2 describes tariff components in Kenya. Commercial and Industrial Consumers are required to meet their monthly energy consumption threshold then any units over and above that threshold is billed at the discounted TOU Tariff. Energy consumption threshold shall be the existing average monthly consumption for the last six consecutive months and a new threshold determined after every 6 months interval based on preceding 6 months actual consumption. However, to collect all revenue requirements and to upgrade electricity production and distribution infrastructure, EPRA adjust the tariff based on the following factors:

- Fuel energy cost
- Foreign exchange rate fluctuation
- Inflation
- Security support facility
- Water levy
- Taxes and levies
- Power factor of <0.90.

All charges resulting from the tariff adjustments are added to other components of the electricity tariff as "other charges". Mumo et al. (2015) in their study to the adjustment factors conducted in Kenya, conclude that the price of electricity (tariff) is mainly determined by fuel prices, economic factors such as inflation and the purchasing power of the consumers, capital cost and running or operational costs. Additionally, Kippra (2010) in their conclusion shows that the fuel and exchange rate costs affect the electricity prices in Kenya. This implies that the tariff adjustment serves as a tool for appropriate tariff determination.

4.3. Uganda

A new Electricity Act was passed on November 1, 1999 and this enabled private participation in the power sector; paved the way for the establishment of the Electricity Regulatory Authority (ERA) in 2000, and provided the legal basis for the privatization of Uganda Electricity Board (UEB) formally a vertically integrated monopoly. The ERA was established with the responsibility to regulate the electricity industry in Uganda. The restructuring of the power sector in Uganda called for unbundling of the vertically integrated, composite functions performed historically by the UEB into separate business functions of generation, transmission and distribution business (ERA, 2007). The successor companies were registered in accordance with the Companies Act under the following names:

- Uganda Electricity Distribution Company Limited (UEDCL)
- Uganda Electricity Transmission Company Limited (UETCL)
- Uganda Electricity Generation Company Limited (UEGCL)

After unbundling, Government of Uganda proceeded with the process of privatization. The generation concession license was competed for and won by Eskom (U) Ltd, which took over in April 2003. Umeme Ltd won the distribution concession and took over in March 2005.

The Table 3 describes the customer categories in Uganda. The time of use differentiated tariff (peak, shoulder and off-peak) is applied on Commercial Consumers, Medium Industrial Consumers, Large Industrial Consumers and Extra - large industrial consumers categories. Particularly, for Large and Extra-Large Industrial Consumers, a Declining Block Tariff which is a stepped tariff structure where consumers are charged a Lower Tariff on Energy Consumption above the Pre-Determined threshold level is applied (ERA, 2021).

ERA(2018) reports that the price of electricity depends on base tariff on one hand, which is set taking into account on Revenue Requirements but this doesn't include the cost of fuel and this will remain constant throughout the respective year. The annual Base Tariff shall be adjusted at the beginning of each calendar year to take into account changes in other tariff parameters such as energy losses, collection rates, operations and maintenance costs, investment costs and other costs approved by the Authority. In setting of the base tariff there are also macroeconomic factors that are taken into account which are Exchange rate, CPI (Inflation), US producer price index and international price of fuel. Although the Base Tariffs shall remain constant throughout the calendar year, the macroeconomic parameters used in the determination of the Base Tariffs don't necessarily remain constant necessitating a need for Adjustment Factors.

The Tariff Adjustment Factor applicable in each quarter comprises the Fuel, Exchange and Inflation Rate Adjustment Factors. Within 2 weeks following the end of each respective quarter, the Authority shall publish the applicable Adjustment Factors for that particular quarter. The quarterly Adjustments shall not be applied on other charges such as fixed monthly service charges, maximum demand charges, reactive energy charge, reconnection fees, and the Lifeline End-User Tariff. In any given quarter the applicable Tariff Adjustment Factor shall be capped at a level where it does not lead to an increase in the End-User Tariff of more than 2.5% compared to the previous quarter.

4.4. Rwanda

The Electricity Market in Rwanda is operated by the national utility, which is state owned and vertically integrated, and some Independent Power Producers (IPPs) participate in electricity generation market. Rwanda Energy Group (REG) Ltd executes the managerial functions of the national utility, and it has two subsidiaries, namely; Energy Utility Corporation Limited (EUCL) devoted to producing and distributing electricity countrywide and to manage the grid operation functions, and Energy Development Corporation Limited (EDCL) entrusted with energy infrastructure planning and development. IPPs sell bulk electricity to EUCL which has the monopoly over transmission, distribution and sale of electricity to customers connected to the national grid and international electricity trade. Besides the grid system, there is a list of mini-grids and standalone systems operated by private developers.

Among the industrial customers, some of them have smart meters and others do not possess smart meters. This implies that the tariff applied to this category is different. For those that have smart meters, their tariff includes energy charge, capacity charge (maximum demand charge) and a fixed customer charge. For small, medium and large industrial customers, the same flat rate is applied for all units (kWh) of electricity consumed for each sub-category and the rate differ based on their level of consumption as described in Table 4. The maximum demand charge (Frw/kVA/month) is billed based on the time of use is described in Table 5. Therefore, the final applied tariff is a three-part tariff, computed based on the additive principle including energy charge, maximum demand charge and a customer service charge. However, for the industrial category without smart meters, the same flat rate for all units (kWh) consumed is applied for each sub-category (Rwanda Utilites Regulatory Authority, 2020). For residential and non-residential customer categories, the increasing block tariffs are applied. Therefore, capacity charge and customer service charge are only applied to industrial customers with smart meters, while the remaining customers are billed energy charge only.

5. CHALLENGES AND OPPORTUNITIES

Electricity dynamic pricing is a demand side management technique that is capable of stimulating demand response. The regulatory authorities apply this technique to shape the electricity consumption pattern of their customers. Still, the ultimate objective of utilities is to reach the financial sustainability of the sector and the well-being of various segments of society. Therefore, in the pursuit of optimal tariff design, most of the literature shows that establishing a single rate for all customers is unsuitable. The optimal tariff structure should reflect a reasonable balance among all the regulatory principles. This section highlights the opportunities and challenges face most of the developing countries in general and East African countries in particular that could be addressed in order to set a fair, efficient and appropriate tariffs of electrical power.

- Most of developing countries face the challenge of lack of accurate data and skills to conduct load study, this negatively affect load research activities which are fundamental to inform tariff setting and development of any Demand Side Management
- Insufficiency or lack of advanced meters able to measure consumption within the interval of time required by the chosen price mechanism, have huge impact on use of time-variant pricing
- Introducing time-variant pricing on a large scale requires investment in an advanced system that can collect, store, manage, and integrate the larger amount of data
- Some models discussed in this study could not be applied normally, due to the lack of skilled personnel
- Absence of adapted technology related to metering
- Lack of awareness and knowledge on of the functioning of maximum demand charge
- Low level of electricity consumption and low access to electricity reduces revenues to cover all the cost (revenue requirement). This force the governments to provide subsidies which normally have a number of perverse consequences. They send wrong price signals to consumers and promote over-consumption, often inefficiently. They also hinder growth of alternatives and act as a trade barrier
- In most of the developing countries domestic consumers may not have time block differentiation or not have a peak demand meter or maximum power limitation device. This is a Challenge which limits most of the regulators in developing

Table 1: The off-peak hours

Days	Start (Hrs.)	End (Hrs.)
Weekdays	00:00	06:00
	22:00	00:00
Saturday/Holidays	00:00	08:00
	14:00	00:00
Sunday	00:00	00:00

Table 2: Tariff components

Customer categories	Tariff components
• Domestic Consumers • Non-domestic Small Commercial Consumers • Public and County Governments	Fixed price per unit of energy consumed/kWh (energy charge) +Fixed Charge +Other charges related to tariff adjustments
• Commercial and Industrial Consumers	Fixed price per unit of energy consumed/kWh during non-off-peak hours (energy charge) +Fixed price per unit of energy consumed/kWh during off-peak hours (energy charge) + Fixed price per kVA (Demand charge). This price varies according to the predefined voltage levels +Fixed Charge +Other charges related to tariff adjustments

Table 3: Customer categories in Uganda

Customer categories	Voltage level
Domestic consumers	Low Voltage, Single Phase supplied at 240 Volts. Not exceeding 15 Units (kWh) of consumption. Low Voltage, Single Phase supplied at 240 Volts. Exceeding 15 Units (kWh) of consumption
Commercial consumers	Three-Phase, Low Voltage Load Not Exceeding 100 Amperes
Medium industrial consumers	Low Voltage 415Volts, with Maximum Demand up to 500kVA
Large industrial consumers	High Voltage 11,000Volts or 33,000Volts, with Maximum Demand Exceeding 500kVA but up to 1,500 kVA
Extra-large industrial consumers	High Voltage 11,000V or 33,000V, with Average Demand of at least 1,500kVA and dealing in Manufacturing
Street lighting	

Table 4: Customer categories in Rwanda

Customer categories	Consumption block	Frw/kWh (VAT & Regulatory fee exclusive)
Residential	[0–15] per month (kWh)	89
	[15–50] per month (kWh)	212
	>50 per month (kWh)	249
Non-residential	[0–100] per month (kWh)	227
	>100 per month (kWh)	225
Water Treatment Plants & Water Pumping Stations	Flat rate for all consumed units (kWh)	126
Telecom towers	Flat rate for all consumed units (kWh)	201
Hotels	Flat rate for all consumed units (kWh)	157
Health Facilities	Flat rate for all consumed units (kWh)	186
Broadcasters	Flat rate for all consumed units (kWh)	192
Commercial data centers	Flat rate for all consumed units (kWh)	179
Small Industry category	≤22,000	
Medium Industry category	[22,000–660,000]	
Large Industry category	>660,000	

Table 5: The off-peak, shoulder and peak hours for industrial customer category with smart meters

Tariff period	*Start (Hrs.)*	*End (Hrs.)*
Off-peak hours	11:00 PM	07:59 AM
Shoulder hours	8:00 AM	5:59 PM
Peak hours	06:00 PM	10:59 PM

countries to include in the tariff structure all billing variables for some of the existing customer categories

- However, the existence of required technology in developed countries is a good opportunity for developing countries to apply dynamic pricing without costly and time-consuming research
- Some developing countries like Kenya have started to use advanced meters and tariff design respecting most of the theoretical concepts, this can serve as a best practice for other developing countries.

6. CONCLUSION AND POLICY RECOMMENDATIONS

The dynamic tariff systems are crucial for electricity consumption optimization due to financial incentives that could transform into savings due to consumers' behaviour changing. In this paper, advanced tariff systems such as Block tariff-pricing scheme which includes, Increasing, decreasing and linear block tariffs and Time varying schemes which includes, Time-of-use (TOU), critical peak and real time pricing as well as rate combinations have been discussed. In addition, tariff structure, cost allocation approaches and components and drivers of electricity supply cost have been described. A review of tariff design and practice in Rwanda, Uganda, Kenya and Tanzania have been discussed and the challenges and opportunities for developing countries have been highlighted.

A Fair, efficient and appropriate electricity tariff design must raise the money needed to pay for the costs of the activities, send the right economic signals to each customer and generate a fair return on investment. This could attract new investors in electricity generation, transmission and distribution which is a challenge for developing countries with limited human and financial resources. Therefore, to achieve this objective, policy makers should first address the challenges highlighted by this study. In addition, they should achieve customer buy-in with effective marketing and education campaigns as well as identifying and implementing other appropriate ways to educate consumers and regulators about the benefits that dynamic pricing can bring to society without harming the interests of any stakeholder.

Even if most of the African countries suffer from lack of economies of scale due to geopolitical fragmentation, large populations too poor to afford tariffs set at cost-recovery levels, reduction of costly operational inefficiencies as well as timely maintenance and servicing of electric power infrastructure will reduce distribution and transmission losses which affect the tariff level.

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