



## EXPLAINING ELECTRICITY TARIFFS IN KENYA

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### ABSTRACT

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Kenya has been struggling with increasing electricity tariffs. Several regulatory reforms introduced in the sector have not succeeded in lowering the electricity tariffs necessitating the need to investigate the push factors of tariffs. This study explained electricity tariffs by exploring the drivers of Kenya Power and Lighting Company (KPLC) tariffs and the scale of operation of KPLC. Using cost time series data from KPLC for the period 1986 to 2016 and Autoregressive distributed lag model (ARDL) an average cost function for KPLC was estimated. The results indicated average tariffs of electricity increased with price of labour and system losses and decreased with output and system load factor. KPLC was found to be enjoying economies of scale and density. Transmission and distribution of power should therefore be retained as a natural monopoly. The Government of Kenya should continue reforming power supply to reduce the system losses and price of labour. Incentives aimed at increasing the system load factor such as special tariffs should be introduced.

**Contribution/Originality:** This study contributes to the existing literature by estimating the drivers of KPLC tariffs and scale of operation. The findings will be useful in determining revenue requirements, setting efficiency targets and in future yardstick regulation for transmission and distribution utilities.

## 1. INTRODUCTION

Electricity tariffs in Kenya are set by the Energy Regulatory Commission (ERC) now the Energy and Petroleum Regulatory Authority (EPRA) (Republic of Kenya, 2019). The tariffs are bundled so as to cover the operating costs of KPLC and the capital costs of generation, transmission, distribution and retailing (AF-Mercados, 2018; Electricity Regulatory Board, 2005; Godinho & Eberhard, 2019). The tariffs reflect KPLC's revenue requirements and are based on the total cost of KPLC (Godinho & Eberhard, 2019).

The generation costs are as captured in the Power Purchase Agreements (PPA) signed between KPLC and the generators. The costs include capacity charges that allow the developers to recover their investment costs; energy charges paid based on the amount of energy generated by the power plants and pass through costs that include fuel costs. The fuel costs rise with the amount of energy generated and the price of the fuel. Other generation associated costs include geothermal steam charge, water resource management levy, foreign exchange and inflation adjustment (AF-Mercados, 2018). Transmission costs are incurred by Kenya Electricity Transmission Company (KETRACO) and KPLC. KETRACO costs are mainly in operation and maintenance of completed transmission assets. The KPLC transmission and distribution costs include operation, maintenance, and depreciation of the assets in the company's audited books. KPLC's also has the retail supply service costs that includes customer

administration metering, invoicing and collection (Electricity Regulatory Board, 2005). These total revenue requirements are subdivided amongst the different customer classes to form the retail tariff of each of the customer category.

Cost of electricity supply has been rising resulting in a general increase in the revenue requirements of KPLC and in the overall tariffs. Average tariffs increased from Kshs 12.6/kWh in June 2009 to Kshs 15.9/kWh in June 2018 (Kenya & Lighting, 2018). Energy purchase costs contribute the most to the cost of power sold by KPLC. The share of the generation costs averaged 74% of KPLC's revenue requirements in the period 2007/8 – 2017/18. In the same period, network service costs associated with transmission, distribution and retailing service averaged 26%. The share of network service costs increased from 22% in 2007/08 (Kenya & Lighting, 2018) to 32% in 2017/18 (Kenya & Lighting, 2018).

There is need to interrogate the costs build up in the overall tariff. First, generation costs are included in the tariff as energy purchase costs. The costs are as contained in the PPAs and KPLC has minimal control over these costs once the agreements are signed. PPAs once signed cannot be amended by law and this protects the generators even when they are inefficient. The contracts are long term on take-or-pay basis meaning KPLC must pay the capacity charges whether it takes the power or not (Electricity Regulatory Board, 2005). The generation costs are therefore known to the regulator and utility and present no information asymmetry.

The other component in the bundled electricity tariff is network cost. KPLC is a natural monopoly undertaking the network functions (Electricity Regulatory Board, 2005). With the intention of protecting consumers and improving the welfare of electricity consumers ERC regulates KPLC tariffs using cost of service regulation. KPLC is allowed to charge tariffs that allow it to recover only its costs of supply. The costs are based on data provided by KPLC, presenting information asymmetry between the utility and the regulator. The regulator reduces the information asymmetry by undertaking intensive financial analysis of the data provided by KPLC. The regulator also subjects any tariff adjustment application to public hearing and participation as required by the Constitution of Kenya (Republic of Kenya, 2010). ERC only decides on the final tariffs after the public expresses itself on any proposed tariffs (Electricity Regulatory Board, 2005). Despite these measures by the regulator to reduce information asymmetry, there is need to understand the drivers of KPLC costs. These would inform future regulatory interventions that could be contributing to excessive costs affecting the overall price. Understanding the tariff drivers can help improve cost observability with implications on welfare of electricity consumers. KPLC overall tariffs are expected to equal its average cost as is common with transmission and distribution companies (Kirschen & Strbac, 2004). Therefore, it is important to study the average cost of KPLC.

The Government of Kenya proposed reforms in the Energy Act 2019 favour competition in the generation and retailing sections of power sector leaving the transmission, distribution, and system operation sections as natural monopolies. It argues that it does not make economic, environmental, and aesthetic sense to have competing transmission, distribution, and system operation in one area. This further necessitates an investigation into the current monopoly pricing of electricity by KPLC. There is also need to assess the effects of the over decade old reforms on the tariffs. The assessment needs to cover KPLC's scale of operation with a view to determine whether there is need for other competitors in distribution. The identification of electricity cost push factors will reduce the information asymmetry between the regulator and KPLC and assists in designing appropriate efficiency targets for the monopoly. The regulator could also adopt the method in this article to predict the unit costs of KPLC, estimate network access costs and inform future regulatory decisions.

## 2. LITERATURE REVIEW

Economic theory of perfect competition has it that many sellers and buyers ensure none of them have the power to determine market price. A monopoly is the only seller and has power to determine the price or quantity in a market. Monopolies arise due to technological, financial, or legal impediments to entry by others (Jehle & Reny,

2011). The presence of a monopoly in an economy leads to social costs in form of welfare loss arising from the firm setting its price above the equilibrium and output below the competitive level (Gumus, 2007). Consumers are denied the surplus value they would derive from a competitive market (Posner, 1968). However, there are cases where competition is seen as self-destructive and inefficient. This is the case of a natural monopoly. The firm can serve the entire market demand at a lower cost than would a combination of several smaller firms (Public Utility Research Center, 2012). Kahn (1998) and Public Utility Research Center (2012) cite the economic benefits of natural monopolies to include great economies of scale and their costs and prices depend on the rate at which the economy and its demand for their service grow. The costs of a single supplier are lower creating an efficiency case for monopolistic organization. Most of these industries are providing infrastructure services with high fixed and sunk costs and an inelastic demand. This creates the need for regulation to protect consumers from welfare loss as the monopoly attempts to maximise its profit.

Regulation is instituted to protect the public interest and to correct for these market failures. These led to the introduction of public interest theory also referred to as theory of economic regulation (Posner, 1974; Stigler, 1971). The theory assumes that government regulation is able to correct market failures associated with natural monopolies by controlling prices and imposing standards (Shleifer, 1985). Other regulatory direct controls include profits control, quality of service, entry into the business and extensions and abandonments of service and plant (Posner, 1968).

The desire to regulate is also driven by the need to deal with the information asymmetry as well as to meet government objectives which sometimes differ with those of the utilities. Regulators use competition, information gathering and incentive regulation to deal with the asymmetries in information and government objectives. Competition is introduced through market liberalization and facilitating competition (Public Utility Research Center, 2012). However, this is only feasible if the demand and technology of supply allows, if demand can be supplied by one firm at lowest cost then the market is a natural monopoly (Posner, 1999). Information gathering involves collecting information on the market and operating statistics. Incentive regulation controls the overall price levels using rate of return or cost of service, price capping or yardstick regulation (Public Utility Research Center, 2012). The regulatory process involves the determination of the overall revenue requirements based on the cost of service for the regulated firm, which is then used to determine the tariff schedule (Posner, 1968). The approach in Kenya's power sector is similar as it is based on the costs of service regulation (Electricity Regulatory Board, 2005).

Shleifer (1985) notes that in costs of service regulation the regulator adjusts the firm's prices to equal the costs of providing service to consumers. This avoids welfare loss from monopoly pricing, but the allowed price is high enough to allow the firm to supply. However, this approach does not adequately address cost efficiency as the firms are aware that prices follow costs and the costs are adjusted upwards or downwards with any rise or fall in costs (Posner, 1968). Shleifer (1985) proposes this be remedied using yardstick competition between identical firms. Where there are no identical firms such as in Kenya, the study proposes the use of cost data and firm specific characteristic to predict unit cost level for the firm. The regulator then uses the regression predicted costs to set the prices as opposed to the costs incurred by the firm.

Joskow (2005) identifies the characteristics of a natural monopoly to be a declining average cost with respect to output. Also, when a firm's average cost declines as its output expands its production technology is characterised by economies of scale. According to Kahn (1998) this tendency is mostly attributed to the need for such companies to make large investments to meet their customers' demand. Kirschen and Strbac (2004) show that for natural monopolies with huge fixed costs and minimal marginal costs, pricing based on marginal cost may result in the firm making losses. In such cases the regulator should set the price at the point of intersection between the demand and average costs curves. But this results in the firm producing output that is less than the efficient level of output. The price just allows the firm to break-even.

In electricity, transmission and distribution functions are identified as sectors that remains a natural monopoly (Jamash & Pollitt, 2004; Laffont, 2005). This lack of a competitive market entails a welfare loss as the monopoly attempts to maximize profits (Gumus, 2007; Posner, 1999). However, requiring the monopoly to charge the competitive price would result in a deficit and make the firm financially insolvent. The society is better off if the firm is allowed to remain a natural monopoly and under appropriate regulatory policies such as provision of subsidies or average cost pricing (Berg & Tschirhart, 1988).

The regulators optimization problem becomes that of maximizing social welfare. Cost observability improves welfare as it allows more control over pricing (Laffont & Tirole, 1986). Cost service regulation involves adjusting the firm's prices to equal the costs of providing service to consumer (Laffont, 1994; Shleifer, 1985). Brown and Heal (1983) indicates the efficient price for a natural monopoly is the average cost price, where the monopoly makes normal economic profits. Producing at the point where price equals marginal cost results in a loss for the monopoly due to the large fixed costs (Kirschen & Strbac, 2004). The marginal costs in a power utility are also very small. A monopoly such as KPLC would require a subsidy or a transfer to remain in operation and to price its output at the marginal cost of production. Shleifer (1985) proposes the use of average cost price where the regulator can only use prices and not lump-sum transfers to compensate the firm. Dramani and Tewari (2014) also indicates setting the monopolies price equal to the average cost is more superior than other forms of regulatory price setting mechanism such as price cap regulation.

Studies on pricing of regulated natural monopolies in the transmission and distribution segments of electricity supply have been undertaken using average costs and their application in yardstick regulation. Most of these studies have largely been undertaken in developed countries of Switzerland (Farsi, Filippini, & Greene, 2006; Filippini, 1998; Filippini, Wild, & Kuenzle, 2002); New Zealand (Filippini & Wetzel, 2014; Nillesen & Pollitt, 2011); Slovenia (Filippini, Hrovatin, & Zorič, 2004).

Burns and Weyman-Jones (1996) study for 12 distribution companies in England and Wales informs a lot of these studies especially on the variables to be included in the estimation of costs. The findings show that the number of customers, price of labour, price of capital, total energy delivered, maximum demand, network length, transformer capacity and customer density drive costs. Some of the studies that have borrowed from this study include Filippini and Wild (1999), Filippini et al. (2002), Farsi et al. (2006) and Dramani and Tewari (2014). Similar studies had been undertaken earlier in the US (Nelson & Primeaux, 1988; Neuberg, 1977). The variables considered were very similar to Burns and Weyman-Jones (1996) and included energy sold, number of customers, number of miles of distribution lines, price of labour, square miles of service territory and price of capital.

Among the few developing country studies, Dramani and Tewari (2014) estimate average cost as a function of output, price of capital, load factor, price of labour, customer density, voltage, and time in Ghana. The study uses panel data from two power distribution companies over the period 1990 to 2010 and finds all the variables except for the price of capital to be significant. This they attribute to capital forming a small proportion of distribution costs as a result of low investments.

### *2.1. Economies of Density and Size*

Roberts (1986) identifies the complexity of measuring output expansions for transmission and distribution companies due to the geographic distribution of customers. Consequently, the study develops three measures of economies of density and size. The measures assume that the firm has three outputs expansion: energy, number of customers and service area. Using cross sectional data from 65 utilities in the USA, the study finds existence of economies of output density and economies of customer density. The size of the service area is however found to have no significant effect on the cost. Using the same measurement of output expansion parameters, Al-Mahish (2017) finds existence of economies of output density and economies of customer density in Saudi Arabia. Several other studies have been undertaken in Switzerland. Filippini (1998) finds existence of economies of density and

scale. Filippini and Wild (2001); Filippini and Wild (1999); Filippini and Wild (1998) also finds economies of scale. A later study by Filippini et al. (2002) finds increasing returns to scale, output, and customer density. Filippini et al. (2004) study for Slovenia finds presence of economies of scale. In New Zealand, Filippini and Wetzel (2014) finds economies of scale based on two outputs: quantity of energy and number of customers.

There is paucity of studies on cost of service regulation in the power sector in Africa region compared to other regions in the world. There are no studies that have explained the electricity tariffs in Kenya. This article fill this research gap by estimating the average costs of the transmission and distribution segment of electricity supply in Kenya that remains a natural monopoly and hence subject to cost of service regulation.

### 3. METHODOLOGY

According to Berg and Tschirhart (1988) a welfare maximizing monopoly producing output  $q$  and charging price  $p$  faces a welfare and profit function of the following nature:

$$\max_q W = CS + \pi \quad (1)$$

$$CS = \int_0^q p(x)dx - p(q)q \quad (2)$$

$$\pi = p(q)q - C(q) \quad (3)$$

where  $W$  in Equation 1 is the welfare,  $CS$  in Equation 2 is consumer surplus,  $\pi$  in Equation 3 is the profits,  $C$  is the cost and  $p(q)$  is the inverse market demand function.

The first order condition of the welfare maximization problem yields a price that is equal to the marginal cost

$$p(q^w) = C'(q^w) \equiv MC(q^w) \quad (4)$$

$q^w$  in Equation 4 is the output produced and sold in a competitive market. However, if the monopoly is left to maximize profits, it will maximize Equation 3 yielding the result that marginal revenue equals marginal cost.

$$MR(q^m) \equiv p(q^m) + q^m p'(q^m) = C'(q^m) \equiv MC(q^m) \quad (5)$$

$q^m$  in Equation 5 is the profit maximizing output of an unregulated monopoly and its less than the efficient market output  $q^w$  in Equation 4. There is therefore need for regulation to avoid the welfare loss associated with output  $q^m$  in Equation 5. The price charged by the monopoly should be equated to the average cost instead of marginal cost. This results in an output less than the efficient output of  $q^w$  in Equation 4 but higher than the monopoly output of  $q^m$  in Equation 5 reducing the welfare loss.

Following Dramani and Tewari (2014), average cost of transmission and distribution utility depends on energy sold, price of labour, load factor, price of capital and number of customers or customer density. To avoid

multicollinearity problems associated with the average cost being a division of cost and energy sold, this article used energy sold relative to the customer density. [Dramani and Tewari \(2014\)](#) model was extended to include network losses and reforms. Network losses in Kenya are critical as KPLC is also a monopoly in retailing function, the inclusion of losses therefore helps capture inefficiency such as corruption, theft, metering, and billing errors. The reforms were included to assess the effect of regulation on the monopoly cost behaviour. Since Kenya has only one distribution company time series data was used for estimation. The general form of the average cost function at period  $t$  was assumed to take the form

$$AC_t = e^{\beta_0} Y_t^{\beta_1} e^{\beta_2 LF_t} PK_t^{\beta_3} PL_t^{\beta_4} e^{\beta_5 SL_t} e^{\beta_6 D_1} e^{\beta_7 D_2} e^{\mu_t} \tag{6}$$

where  $AC$  was the average cost,  $Y$  was the output (energy sold/customer density),  $PL$  was the price of labour,  $LF$  was the load factor,  $PK$  was the price of capital,  $SL$  was the system losses,  $D_1$  was the dummy variable for 1998 reforms and  $D_2$  the structural break dummy variable from the 2001 occasioned by KPLC return to profit financing strategies and measures aimed at addressing the drought that lasted from 1999 to 2001.  $\beta_0 \dots \beta_7$  were the coefficients to be estimated,  $\mu_t$  was the error term and  $t$  was the time period. The other variables were as earlier defined

The log of Equation 6 gave:

$$\ln AC_t = \beta_0 + \beta_1 \ln Y_t + \beta_2 LF_t + \beta_3 \ln PK_t + \beta_4 \ln PL_t + \beta_5 SL_t + \beta_6 D_1 + \beta_7 D_2 + \mu_t \tag{6}$$

where all the variables were as earlier defined.

Following [Pesaran, Shin, and Smith \(2001\)](#), Equation 7 was estimated using ARDL bounds test procedure by modelling it as an error correction model specified as

$$\begin{aligned} \Delta \ln AC_t = & \beta_0 + \beta_1 D_1 + \beta_2 D_2 + \delta_1 \ln AC_{t-1} + \delta_2 \ln Y_{t-1} + \delta_3 LF_{t-1} + \\ & \delta_4 \ln PK_{t-1} + \delta_5 \ln PL_{t-1} + \delta_6 SL_{t-1} + \sum_{i=1}^p \Delta \theta_i \ln AC_{t-i} + \sum_{j=1}^q \Delta \omega_j \ln Y_{t-j} + \\ & \sum_{l=1}^q \Delta \varphi_l LF_{t-l} + \sum_{m=1}^q \Delta \gamma_m \ln PK_{t-m} + \sum_{p=1}^q \Delta \eta_p \ln PL_{t-p} + \sum_{s=1}^q \Delta \alpha_s LF_{t-s} + \\ & \mu_t \end{aligned} \tag{7}$$

where in Equation 8,  $\beta_0$  was the constant,  $\beta_1 \dots \beta_2$  were the coefficients for the dummy variables,  $\delta_1 \dots \delta_6$  were the long run elasticities,  $\theta, \omega, \varphi, \gamma, \eta, \alpha$  were the short run coefficients.

The ARDL model for  $AC_t$  was estimated as Equation 9

$$\begin{aligned} \ln AC_t = & \sum_{i=1}^p \delta_1 \ln AC_{t-i} + \sum_{i=0}^{q_1} \delta_2 \ln Y_{t-1} + \sum_{i=0}^{q_2} \delta_3 LF_{t-1} + \sum_{i=0}^{q_3} \delta_4 \ln PK_{t-1} + \\ & \sum_{i=0}^{q_4} \delta_5 \ln PL_{t-1} + \sum_{i=0}^{q_5} \delta_6 SL_{t-1} + \mu_t \end{aligned} \quad (8)$$

The error correction model was given by Equation 10

$$\begin{aligned} \Delta \ln AC_t = & \beta_0 + \beta_1 D_1 + \beta_2 D_2 + \sum_{i=1}^p \Delta \theta_i \ln AC_{t-i} + \sum_{j=1}^q \Delta \omega_j \ln Y_{t-j} + \sum_{l=1}^q \Delta \varphi_l LF_{t-l} + \\ & \sum_{m=1}^q \Delta \gamma_m \ln PK_{t-m} + \sum_{p=1}^q \Delta \eta_p \ln PL_{t-p} + \sum_{s=1}^q \Delta \alpha_s LF_{t-s} + \vartheta_{t-1} + \mu_t \end{aligned} \quad (9)$$

where  $\vartheta$  in Equation 10 was the speed of adjustment. As specified by Pesaran et al. (2001), the dummy variables only appear in this error correction model.

### 3.1. Economies of Scale and Density

Economies of scale exist if the elasticity of average cost with respect to output is negative, that is if an output expansion results in lower average costs. The elasticity of average cost with respect to output is given by Equation 11 as

$$\text{Economies of scale} = \frac{\partial AC}{\partial Y} \frac{Y}{AC} \quad (10)$$

However, the output  $Y$  in Equation 6 combined the outputs, that is energy sales and customer. To estimate the economies of output density and scale, we estimated the total cost function. All the variables in Equation 6 were retained apart from average costs ( $AC$ ) which was replaced by total cost ( $TC$ ), output and customer density were introduced as two separate independent variables. The total cost function of Equation 6 was restated as

$$\begin{aligned} \ln TC_t = & \beta_0 + \beta_1 \ln Y_t + \beta_2 \ln CD_t + \beta_3 LF_t + \beta_4 \ln PK_t + \beta_5 \ln PL_t + \beta_6 SL_t + \\ & \beta_7 D_1 + \beta_8 D_2 + \mu_t \end{aligned} \quad (11)$$

where  $TC$  is the total cost and  $CD$  is the customer density in Equation 12. The other variables are as earlier defined.

Following Filippini and Wetzel (2014) and considering KPLC is the only distribution company in Kenya<sup>1</sup> economies of scale were defined in Equation 13 as

$$\text{Economies of scale} = \frac{1}{\frac{\partial \ln TC}{\partial \ln Y} + \frac{\partial \ln TC}{\partial \ln CD}} \quad (12)$$

and economies of output density in Equation 14 as

<sup>1</sup> The geographical size of its service area is the same for the study period since KPLC is the only distributor

$$\text{Economies of Output Density} = \frac{1}{\frac{\partial \ln TC}{\partial \ln Y}} \quad (13)$$

A value greater than 1 indicates economies of scale and density while a value less than 1 indicates diseconomies of scale and density.

### 3.2. Data Type, Source and Measurement

The article used annual data for 31 years for the period 1985/1986 to 2015/2016 sourced from KPLC annual reports. Table 1 provides a description and measurement of each of the variables used in the analysis. Price of capital and price of labour were adjusted for inflation using the electricity CPI index for Kenya base period February 2009 sourced from KNBS.

Table-1. Description and measurement of variables used to estimate the average costs.

Variable	Definition and measurement
$AC^*$	Total operating cost– less energy purchase cost divided by energy sold (Ksh/kWh).
$Y$	Electricity sold in (kWh) divided by the customer density. The customer density was calculated by dividing number of customers with the kilometres of line.
$LF$	System load factor in percentage
$PK$	Operations related capital net book value (Kshs) divided by total transformer capacity (Kva). This gave the price of capital in Ksh/kVA.
$PL$	Staff costs (Kshs) divided by number of employees. This gave the price of labour in Ksh/per employee.
$SL$	System losses as a percentage of energy generated
$D_1$	Reforms introduced in the sector in 1997/98, 0 was the period 1985/86 to 1996/97 and 1 the period 1997/1998 to 2015/16
$D_2$	Strategies structural break, 0 was for the period 1985/86 to 2000/01, 1 for the period 2001/02 to 2015/16

## 4. EMPIRICAL RESULTS AND DISCUSSION

### 4.1. Summary Statistics

The descriptive statistics of the logged variables used in the analysis are presented in Table 2.

Table-2. Summary statistics.

Log of Variable	Mean	Standard. Deviation	Maximum	Minimum
Average cost	1.562	0.595	2.322	0.770
Output	18.792	0.138	19.131	18.523
Load Factor	0.697	0.017	0.726	0.644
Price of Capital	8.305	0.383	8.849	7.650
Price of Labour	13.808	0.283	14.333	13.097
System Losses	0.175	0.026	0.227	0.129

### 4.2. Diagnostic Tests Results

Diagnostic tests necessary for time series data were undertaken, this included unit roots, cointegration and model stability tests.

### 4.3. Unit Root Test

As presented in Table 3, the variables were found to be stationary at levels. Some of the variables indicated the possibility of having structural breaks; average costs, output, and load factor were found to have breaks in year

2001. This year witnessed financing strategic initiatives aimed at returning KPLC to profitability. The structural breaks could also be associated with the drought period of 1999 to 2001 that affected electricity supply.

**Table-3.** Unit root tests for variables used to estimate the average cost.

Variable	Test	Intercept only	Intercept and Trend	Results
Average Cost	ADF	-0.757188	-2.368701	The series are stationary at level at 1% level of significance based on the breakpoint unit root test; Intercept.
	PP	-0.648831	-2.481435	
	KPSS	0.653866	0.095902	
	Breakpoint	-5.787136	-6.257584	
Output	ADF	-1.415374	-0.700004	The series are stationary at level at 5% level of significance based on the breakpoint unit root test: Intercept.
	PP	-1.844218	-1.185262	
	KPSS	0.179960	0.084691	
	Breakpoint	-4.755418	-5.789077	
System losses	ADF	-1.810361	-1.724127	The series are stationary at level at 10% level of significance based on the breakpoint unit root test: Intercept and at 5% for Trend and intercept, trend only.
	PP	-1.823426	-1.765146	
	KPSS	0.267246	0.145169	
	Breakpoint	-4.255751	-4.945066	
Load factor	ADF	-3.784367	-3.71767	The series are stationary at level at 1% level of significance based on the ADF, PP and breakpoint unit root test; Trend and intercept - trend and intercept.
	PP	-3.770010	-3.704217	
	KPSS	0.088748	0.084921	
	Breakpoint	-3.997779	-8.513490	
Price of Capital	ADF	-1.045931	-2.346089	The series are stationary at level at 1% level of significance based on the breakpoint unit root test: Trend and intercept - trend and intercept.
	PP	-1.531329	-1.326560	
	KPSS	0.165692	0.158962	
	Breakpoint	-4.863098	-6.536462	
Price of labour	ADF	-1.6910956	-1.9072234	The series are stationary at level at 1% level of significance based on the breakpoint unit root test: trend and intercept – intercept only
	PP	-1.6910956	-1.9027701	
	KPSS	0.2242067	0.151222	
	Breakpoint	-2.857157	-5.464668	

**Note:** Critical levels 1%, 5%, and 10% significance levels are as follows; Intercept ADF(-3.67017, 2.963972, -2.621007), PP(-3.67017, -2.963972, -2.621007), KPSS(0.739000, 0.463000, 0.347000), Break point (-4.949133, -4.443649, -4.193627) Intercept and Trend ADF(-4.296729, -3.568379, -3.218382), PP (-4.296729, -3.568379, -3.218382), KPSS(0.216000, 0.146000, 0.119000) break point; Intercept (-5.347598, -4.859812, -4.607324) Trend and intercept (-5.719131, -5.175710, -4.893950); trend(-5.067425, -4.524826, -4.261048).

4.4. Lag Length

**Table-4.** Lag selection results.

Model	Akaike information criterion
ARDL (1, 1, 0, 0, 0, 0)	-2.56617
ARDL (1, 1, 0, 0, 1, 0)	-2.51293
ARDL (1, 1, 1, 0, 0, 0)	-2.50172
ARDL (1, 1, 0, 0, 0, 1)	-2.50074
ARDL (1, 1, 0, 1, 0, 0)	-2.49985

The model failed the LM serial correlation, CUSUM and CUSUM of squares at lag 2 and lag 3. Based on the Akaike information criterion the ARDL model (1, 1, 0, 0, 0, 0) was selected for further analysis. Table 4 indicates the selected model at lag 1.

All the models at lag 1 passed all the residual and stability diagnostic test as presented in Table 5. ARDL bounds cointegration test found the presence of a long run relationship amongst the variables in all the models. The model without trend had a higher F statistic and a higher adjusted R squared, this model was therefore selected for analysis. Table 6 presents the Bounds cointegration test results.

## 4.5. Residual and Stability Test

Table-5. Residual and stability diagnostic test results of the average cost model.

Description	LM serial correlation	Normality	Heteroskedasticity	CUSUM and CUSUM of squares	Conclusion
No intercept no trend model	0.2274	0.4827	0.6882	within the confines of the 5% significance	Diagnostic tests passed
Intercept and no trend model	0.1932	0.3617	0.4441	within the confines of the 5% significance	Diagnostic tests passed
Intercept with trend model	0.2970	0.3762	0.6107	within the confines of the 5% significance	Diagnostic tests passed

## 4.6. Cointegration Test

Table-6. Bounds test Cointegration results for the average cost model.

Description	Critical Values		F statistics	Conclusion
Intercept and no trend model	I (0)	I (1)	21.81005	Long run relationship exists
	2.26(10%)	3.35(10%)		
	2.62(5%)	3.79(5%)		
	3.41(1%)	4.68(1%)		

## 4.7. Elasticities of Average Costs

Table-7. ARDL estimates of Average cost elasticities.

Variable	Coefficient
<b>Short run coefficients</b>	
Constant	5.728* (2.959)
Average Cost (-1)	-0.948*** (0.092)
Load Factor(-1)	-5.083*** (1.120)
Price of Capital	0.037 (0.045)
Price of Labour	0.387*** (0.056)
System Losses	2.170* (1.102)
Output	-0.325** (0.147)
Change in Load Factor	-0.335 (0.979)
Reforms	-0.792*** (0.094)
Structural changes	-0.370*** (0.069)
Error correction term	-0.948*** (0.074)
<b>Long run coefficients</b>	
Load Factor	-5.364*** (1.036)
Price of Capital	0.040 (0.048)
Price of Labour	0.409*** (0.057)
System Losses	2.290** (1.081)
Output	-0.343** (0.154)

Notes: \*\*\* indicates the coefficient is significant at 1% level; \*\* indicates the coefficient is significant at 5% level; \* indicates the coefficient is significant at 10% level. The figures in parenthesis are the standard errors.

The short and long run results are presented in Table 7. Most of the variables were found to be significant determinants of average costs and had the expected signs. The coefficients were smaller in the short run compared to the long run; this can be attributed to the short time taken to adjust in the short run. The error correction coefficient was negative (-0.948) and significant. This indicated that convergence to equilibrium was fast.

Price of labour and system loss had the effect of increasing average cost in the short run while output, load factor, previous period average cost, reforms and structural changes were likely to decrease average costs. The significance and signs of the short run coefficients were maintained into the long run. An increase in the load factor and outputs was likely to decrease the average cost of electricity in the long run while an increase in price of labour

and system losses was likely to cause an increase in the average cost of electricity. Increasing output by 1% was found likely to decrease the average cost by about 0.32% in the short run and 0.34% in the long run. Similarly, increasing system load factor by 1% was also likely to decrease the average costs by 5.36% in the long run, while a 1% in one year back would also decrease average cost by 5.08% in the short run. Increasing price of labour by 1% was likely to lead to an increase in the average cost of 0.39% in the short run and 0.41% in the long run. System losses were found to have a higher magnitude with a 1% increase in system losses causing an increase in the average cost of 2.17% in the short run and 2.29% in the long run. Increasing the preceding period average costs by 1% was likely to see the company reducing the present average costs by 0.95%. The reforms of 1998 reduced average costs by 0.79%, the second set of structural reforms of 2001 also reduced average costs by 0.37%. These findings were relatable to other empirical studies undertaken in Africa and other regions. For example, study for Ghana also finds the drivers of average costs to be output, load factor and price of labour. The price of labour elasticity in their study is 0.31 making it very close to the finding of this study. The significance of price of labour in driving average costs can be attributed to the fact that distribution systems require more labour for meter reading, billing, and distribution network trace clearance [Dramani and Tewari \(2014\)](#). In addition to this, in Kenya, the ageing distribution network also means deploying more labour for maintenance of the network which is prone to outage. None of the studies reviewed in existing literature had considered system losses and sectoral reforms. This study found the reforms of 1998 that allowed for the regulation of the monopoly contributed to reducing of the average cost. This finding is consistent with the theory of regulation that the regulator allows more control over the pricing policy improving welfare and ensuring socially desirable outcomes. The second reforms of 2001 that saw further unbundling of the sector and accelerated customer connection also contributed in driving down the average costs. This indicates that the reforms agenda that push for effective operation of the utilities in the sector are bearing fruit. Network system losses were found to be increasing average costs. This finding is intuitive as system losses contribute to the operational expenses of a company. System losses is energy purchased that should have been sold but was lost in the system and captures losses arising from the power lines, theft, corruption, metering and billing errors all of which have been issues affecting KPLC in the recent past.

#### 4.8. Economies of Scale

The elasticity of average cost with respect to output was found to be negative at -0.343079, meaning that increasing output with 1% was likely to decrease average cost by 0.34%. This indicates the presence of economies of scale. The result indicates the need to retain the transmission and distribution segment of electricity supply as a natural monopoly as competition could lead to excess capacity. KPLC is still able to meet the country's electricity demand at a lower cost than having several firms. Competition may not be an efficient solution in this segment of electricity supply.

#### 4.9. Economies of Scale and Density

Table 8 presents the long-run elasticities of the total cost function. The results indicate output, load factor, price of labour, system losses and customer density to be significant determinants of the total costs for KPLC. All the coefficients have the expected sign and are consistent with the average cost function estimates. The output and customer density elasticity is positive implying an increase in production of output will increase total cost.

Economies of scale and density were found to be greater than 1. The economies of output density were found to be 1.75. This indicates that KPLC is characterised by economies of output density. Economies of output density indicate decreasing average costs as the volume of electricity sold to a fixed number of customers increases ([Filippini, 1998](#)). This is confirmed by the elasticity of average cost with respect to output which was found to be negative at -0.343079, meaning that increasing output with 1% was likely to decrease average cost by 0.34%. The

economies of scale were found to be 1.069, indicating the average costs of KPLC decrease when output and customers' density increase.

**Table-8. Economies of scale and density estimates.**

Variable	Coefficient
<b>Elasticities</b>	
Output	0.571** (0.225)
Load Factor	-4.636** (1.738)
Price of Capital	0.031 (0.050)
Price of Labour	0.369*** (0.084)
System Losses	2.178* (1.063)
Customer Density	0.364** (0.157)
C	7.967 (4.681)
<b>Economies of Scale and Density</b>	
Economies of output density	1.750
Economies of Scale	1.069

**Notes:** \*\*\* indicates the coefficient is significant at 1% level; \*\* indicates the coefficient is significant at 5% level; \* indicates the coefficient is significant at 10% level. The figures in parenthesis are the standard errors.

The indicators of economies of output density and scale shows that KPLC is still able to meet the country's demand and distribute electricity at a lower cost than having several firms. Competition would be less cost efficient than a monopoly in the distribution of electric power. The result indicates the need to retain the transmission and distribution segment of electricity supply as a natural monopoly as competition could lead to excess capacity.

## 5. CONCLUSION AND POLICY RECOMMENDATIONS

Electricity tariffs in Kenya were explained by exploring the drivers of average costs of the natural monopoly, KPLC, that is charged with supplying all electricity consumers. The drivers of the long run average costs were found to be output, load factor, system losses and price of labour. Price of labour and system losses increased the average cost. In the short run average costs responded to the previous period average cost, previous period load factor, price of labour, system losses, output, 1998 reform and 2001 structural break. Apart from price of labour and system losses the other variables reduced the average cost in the short run. The elasticity of average costs with respect to output was negative. This indicated the presence of economies of scale.

There is need for KPLC to set up measures geared towards reducing the system losses. The regulator should also be strict in setting the loss targets for KPLC. This will protect consumers from paying high costs resulting from losses associated with theft, corruption, metering and billing errors. The loss targets should be coupled with the necessary investments in the distribution network to reduce non-commercial losses associated with a weak network.

The regulator should also set efficiency targets aimed at ensuring the management of KPLC continues to reduce average costs by lowering the cost of labour. This can be done by tying staff costs to certain performance standards such as improved quality of supply and customers supplied.

The finding on the system load factor indicated the need for the government to put up measures that are likely to increase the load factor. High load factor can be achieved by distributing the load through time of use tariffs and increased consumption of energy. Implementation of measures that encourage the establishment of energy intensive industry, 24-hour economy and economic advancements such as special economic zones and industrial parks is also

likely to increase consumption of energy hence increasing the load factor. The Ministry of Energy can support these initiatives by providing attractive electricity tariffs as well as stable supply of power.

Previous reforms were found to reduce the average costs encouraging the implementation of the proposed reforms in the Energy Act of 2019. The proposed reforms include the establishing of an electricity market, independent system operator to facilitate open access to the distribution and transmission networks and enhance regional trade.

The finding on existence of economies of scale indicates the need to retain transmission and distribution as regulated natural monopolies. The regulator can take advantage of regional association to introduce yardstick regulation using similar firms in the region as benchmarks to improve the cost efficiency of the utilities. The regulator can also reduce information asymmetry associated with costs of service regulatory through constant monitoring of the utility cost data. The regulator could also apply the model in this study as one of its pricing rules. This can be by using the model to estimate the average costs of KPLC and comparing with the actual costs incurred as a way of checking KPLC's efficiency before making pricing regulatory determination. This would reduce information asymmetry between the regulatory and the utility. The regulatory can also consider engaging other regulators in Africa that are regulating utilities of a similar size and function for yardstick regulation. This would facilitate efficiency competition amongst the utilities participating in the benchmarking.

This article is important as it estimates the drivers of average electricity costs and hence tariffs, filling a gap that has not been addressed in Kenya before. The regulator could also benefit by using the model suggested in this article to predict the cost levels for KPLC in place of the costs incurred and reduce information asymmetries. The paper also provides an opportunity for future yardstick regulation in determining network prices for utilities in the Eastern African Power Pool once the regional integration process is completed and the power market operationalised.

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