Journal of Newviews in Engineering and Technology (JNET)
Vol 1, Issue 1, October 2019
Available online at http://www.rsujnet.org/index.php/publications/2019-edition

Improved Electricity Transmission Pricing for theNigerian Network

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ABSTRACT

The restructuring of electricity system in Nigeria has made the pricing of electricity a challenge. Price forecasting has over time become the centre of intense studies. Considering a market where the Electrical industry is segmented, attempts must be made to evolve a good pricing method. This method however should be economically viable to those participating in all the sectors of the market: generation, transmission and distribution. The aim of this work is to develop an improved transmission pricing method for the Nigerian Network. This is important in order to make the network reliable, fair and protect its operations.This study considered the cost of electricity generation and transmission with the gross annual income of average Nigerian and formulated an electricity pricing model that can be adaptable to the Nigerian power system. This work developed a model for an improved transmission pricing method for the Nigerian Network which was used for forecasting of electricity price for a financial planning period of five years. Within the period considered the best price was projected for five years. The results obtained were validated with that of Transmission Company of Nigeria. They confirmed a very low electricity tariff in the country which is grossly disadvantageous to the transmission company. The developed model will aid both electricity producers and consumers to receive fair share of pricing.

Keywords: Electricity network, Energy charge, Marginal cost, Pricing, Transmission

Cite This Article: Ogbonna, B. O., Ahiakwo, C. O., Idoniboyeobu, D. C., & Orike, S. (2019). Improved Electricity Transmission Pricing for the Nigerian Network. *Journal of Newviews in Engineering and Technology (JNET)*, 1(1), 8-18.

1. INTRODUCTION:

The electricity sector is very important to the economy of any country because it is a key to the industrial, technological and social development of the country. Many countries in the world have transformed virtually their integrated electricity companies and thereafter have segmented them into generation, transmission and distribution companies (Bodenhofer *et al*., 2001). In most of the cases private participation have been highly encouraged thereby leaving the government to assume the role of supervision and regulation (Araneda, 2002). Chile was the first country to deregulate and privatize their electricity sector in 1982. The second country was the United Kingdom which restructured hers in 1990 for competition first in generation sector and thereafter in the retail sector as well (Illic, 1997). Other countries like USA, Germany, Switzerland and Australia followed later. The aim of all this segmentation and privatization is to ensure that the power sector is operated at a profit. To determine the price of providing a particular transmission service is very vital. This will confirm if such services can yield profit to both the service provider and the user or customer (Bialek, 2001). The process of estimating the pricing of transmission network can be obtained by the analyses of the engineering situations of the network (Lima, 1996).

The method employed for pricing of electricity in Nigeria has been uneconomical and unclear since the establishment of the power sector. Previously the provision of electricity in Nigeria was considered as a government welfare program. This informed the high subsidization of electricity by government (Desai *et al.*, 2013). Before 2008 when the Multi Year Tariff Order (MYTO) was introduced, the power industry in Nigeria had been using the same system of pricing. In this mechanism the price of electricity was kept

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the same for some years irrespective of consistent change in the cost of fuel. Interestingly, over 80 per cent of electricity is generated in Nigeria with gas (Saheed, 2013). The Power Holding Company of Nigeria (PHCN) tariff was last set in February 2002 and averaged between N4.50/kwh and N6/Kwh. Following that setting, the company was operating with a shortfall of almost N2billion a month (Saheed, 2013). This led to its inability to tackle the problems of inadequate and unreliable electricity service. The challenges obtained from this pricing mechanism are:

(i) The transmission service providers (TSP) are not given a fair share in the pricing system

(ii) Transmission network users or consumers are not effectively considered in pricing mechanisms.

(iii) Due to insufficient pricing systems, transmission investment costs are not realized. This therefore has discouraged more investment on transmission network facilities from stakeholders.

(iv) Power generation is affected due to non-realization of cost of generation from transmission service providers.

There is need therefore to establish an appropriate pricing policy to achieve fairness and a stable electricity pricing system. The reasons above informed the establishment of the Nigerian Electricity Regulatory Commission (NERC). This commission was saddled with the development of tariff structure that will depend on industry revenue requirements. This led to the new tariff regime that took effect through a Multi–Year Tariff Order (MYTO) in 2008.

1.1 Policies in Pricing Electricity

The policy in pricing electricity is such that the pricing is divided into:

(i) Static Prices: The prices of electricity in this group do not change no matter the change in demand of energy.

(ii) Dynamic Prices: In this group the prices of electricity change with change in demand of the product (Murali *et al.*, 2014).

Some of the different types of static pricing policies are summarized as follows:

Flat Rate Pricing: Here, the price remains the same irrespective of change in power demand. Transmission users enjoy this scheme because they do not face incessant changes in cost of power supply due to changes in power demand. Therefore consumers do not face any chance of receiving high cost of electricity bills because of high consumption of electricity (Faruqui *et al*., 2014).

Seasonal Pricing: In this method, the prices change according to different seasons so as to tally with changes in the level of demand within the seasons. At the season the demand is high, transmission price is high. The price decreases as the season demand is low (Desai *et al.,* 2013).

Transmission Use of System (TUOS) Pricing: This tariff is normally given to distributors. It is a system where the consumer is billed on each unit of MWh that is released to the users over the points of bulk supply. The TUOS charge comprises the network's fixed charges. They include, the capital returns, depreciations and operations and maintenance cost. The charge is uniform throughout Nigeria (Schweppe, 1998).

1.2 Types of Electricity Transmission Pricing Methods

In the past few years, so many works has been carried out on transmission pricing schemes and different pricing methods have been proposed and adopted in various markets. Some of the methods adopted in electricity transmission pricing are defined below as follows:

The Postage Stamp Method**:** On this case, no matter the distance the transmitted power travels, a consumer pays a price that equals the fixed price for each unit of MWh that is released by a transmission system (Green, 1998). It is expressed as:

$$CR_t = TR \times \frac{S_t}{S_p} \tag{1}$$

Where:

CR_t = Transmission charge in Naira/MWhr,

TR = Total transmission charge in Naira/MWhr

S_t = Amount of power marketed in MW

S_p = Peak power demand from the system in MW

1.3 The MW – Mile Method

This method takes consideration of the change in the flow of MW transmissions and the length of transmission lines are measured in miles (Happ, 1994). The Mw-mile method was the first tariff mechanism to be developed and it is used to recover the fixed cost of transmission assets. This method depends on when the network is used. The equation is modeled as (Ahiakwo *et al*., 2008):

$$TC_t = TC \frac{\sum_{k \in K} C_k L_k MW_{t,k}}{\sum_{t \in T} \sum_{k \in K} C_k L_k MW_{t,k}} \tag{2}$$

Where:

TC_t = Transmission charge for transactions (Naira/MWhr)

TC = Total transmission charge (Naira/MWhr)

$MW_{t,k}$ = Increment in transmission real flow from transactions (MW).

C_k = Total annual revenue requirement accruing from transmission (Naira/year).

L_k = Mean revenue required per hour of the equipment k.

Tracing Methods: Tracing mechanism indicates the contribution of users to transmission usage (Illic, 1997). The method was formulated in Mohammed (2002).

The Bialek's Tracing Method: The Bialek's tracing method is used in developing the transmission price algorithm. This method is based on the proportional sharing principle shown in Figure 1(Ahiakwo *et al.,* 2008).

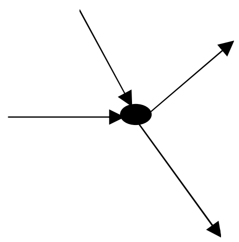

Figure 1: Proportional Sharing Method (Bialek et al., 1996)

The power outflows P_1 and Ps_2 can be calculated in terms of the power inflows P_a and P_b. We can therefore deduce how much of P_1 that comes from P_a and how much of P_1 that comes from P_b. The same can be done to P_2. In view of the above, P_1 is modeled as indicated in (3):

$$P_1 = P_1 \frac{P_a}{P_a + P_b} + P_1 \frac{P_b}{P_a + P_b} \tag{3}$$

P_2 is expressed as shown in equation (4) as:

$$P_2 = P_2 \frac{P_a}{P_a + P_b} + P_2 \frac{P_b}{P_a + P_b} \tag{4}$$

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2. MATERIALS AND METHODS:

The parameters used for this work are:

(i) Inflation Rate
(ii) Exchange Rate
(iii) Fuel Cost
(iv) Actual generation Capacity
(v) Asset Valuation and Depreciation
(vi) Operating and Maintenance Costs/Losses

2.1 A Development of the Model

In this work, the transmission use of system (TUOS) or postage stamp method is employed to determine the best transmission pricing scheme for Nigeria. Figure 2 shows a two bus network system which is used to develop the model for engineering analysis of the pricing scheme.

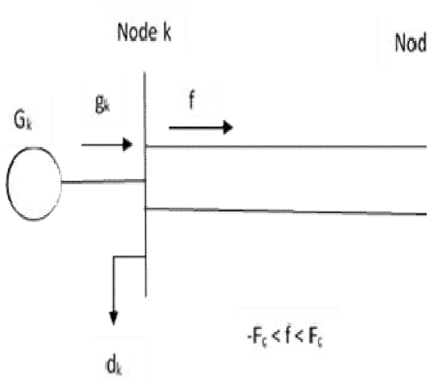

Figure 2: Two Bus Network (Araneda, 2002)

Two identical circuits are connected together at nodes 'k' and 'L'.
F_c = Transmission capacity of each circuit at the nodes 'K' and 'L'.
G_k = Generator capacity at node 'K'
f = Power flow from node 'K'
G_L = Generator capacity at node 'L'
d_k = Demand at node 'K'
d_L= Demand at node 'L'
D_1 = Maximum demand
D_0 = Minimum demand
g_k, g_L = Actual generated power output into nodes 'k' and 'L' respectively.

The cost of electricity generation by the generator G_k and G_L is given by equations (5) and (6) (Happ *et al*., 1994):

$$C(g_k) = C_j + C_{1k} * g_k + C_{2k} * g_k^2 \quad (5)$$

$$s.t.\colon\ g_k < G_k$$

$$C(g_L) = C_L + C_{1L} * g_L + C_{2L} g_L^2 \quad (6)$$

$$s.t.\colon\ g_L < G_L$$

2.2 Short Run Marginal Cost (SRMC)

Considering marginal cost of transmission on the short run basis, F_c is constant. It is necessary to calculate the power flow '*f*' from node '*k*' to node '*L*' for a time interval *T* (which is one year). This can be expressed by minimizing a complete one year Operations Cost (OC) of the transmission network. Schweppe*et al.* (1988) formulated the expression as follows:

$$\text{Min OC}\ (g_k, g_L) = \int_0^T [c_t(g_k) + c_t\,(g_l)]dt \quad (7)$$

$$s.t. 0 \le g_k \le G_K A_K \quad (8)$$

$$0 \le g_L \le G_L A_L \quad (9)$$

$$|f| \le F_c \eta \quad (10)$$

$$d_T - g_k - g_L = 0\lambda \quad (11)$$

Where:
η = Constraints for transmission capacity
λ = Network demand constraints or the power balance.
Applying the Lagrangian multiplier on (7), with the constraints of (8) to (11), (7) can be optimized with the expression (Araneda, 2002):

$$Z = \int_0^T [c_t(g_k) + c_t(g_L) + \lambda * (d_T - g_k - g_L) + A_k * (g_k - G_k) + A_L * (g_L - G_L) + \eta * (f - F)]dt \quad (12)$$

The first order derivative conditions are:

$$\frac{\delta Z}{\delta g_K} = 0 : \frac{\delta Z}{\delta g_L} = 0 \quad (13)$$

Thus:

$$\frac{\delta c_t(g_k)}{\delta g_k} - \lambda + A_k + \eta \frac{\delta f}{\delta g_k} = 0 \quad (14)$$

$$\frac{\delta c_t(g_l)}{\delta g_L} - \lambda + A_L + \eta \frac{\delta f}{\delta g_L} = 0 \quad (15)$$

The SRMC at nodes '*K*' and '*L*' are respectively expressed as:

$$\lambda_k = \lambda - \eta \frac{\delta f}{\delta g_k} \text{ and } \lambda_L = \lambda - \eta \frac{\delta f}{\delta g_L} \quad (16)$$

The transmission cost based on SRMC is therefore expressed as:

$$\lambda_L - \lambda_k = \eta\left(\frac{\delta f}{\delta g_k} - \frac{\delta f}{\delta g_L}\right) \quad (17)$$

Power flow, *f* can be denoted as (Araneda, 2002):

$$f = \alpha_L g_k - \alpha_k g_L ; \alpha_L + \alpha_k = 1 \quad (18)$$

$$\frac{\delta f}{\delta g_k} = \alpha_L \text{ and } \frac{\delta f}{\delta g_L} = -\alpha_k \quad (19)$$

$$\lambda_L - \lambda_k = \eta \quad (20)$$

Where: α_k, α_l is the nodal power distribution at the nodes '*k*' or '*L*'.

Equation (20) explains how transmission capacity constraints and the difference with SRMC at the nodes between the both sides of the transmission line are related. When transmission occurs, then η is not equal to zero and SRMC at the nodes 'k' and '*L*' are different without the transmission losses. Without transmission congestion in the system, the SRMC at the nodes are the same throughout and equal to λ. From (8), transmission capacity F_c, is not captured because it is a constant. Therefore a connection between SRMC and transmission investment must be discovered via formulation of a long term optimization problem.

2.3 Long Run Marginal Cost (LRMC)

For LRMC, the transmission capacity F_c is a variable and its maximum value can be obtained so that this action will complement equation (8). Therefore the LRMC problem can be solved by minimizing the total operation cost in a year and the annual transmission investment cost *I(F)*. It is assumed that the fixed operations and maintenance cost of transmission network are included in the *I(F)* function. The expression for the LRMC of the operations and investment cost is written as, minimize operations and investment cost (OIC) of the transmission network (Schweppe, 1994).
Hence:

$$\text{Min OIC} = (g_k, g_L, F) = \int_0^T [C_t(g_k) + c_t(g_L)]\delta t + I(F) \quad (21)$$

$$s.t{:}\ 0 \le g_k \le G_k A_k \quad (22)$$

$$0 \le g_L \le G_L A_L \quad (23)$$

$$/f/ \le F_c \eta \quad (24)$$

$$d_T - g_k - g_L = 0\lambda \quad (25)$$

The generating conditions for the first order equations are (Schweppe, 1994):

$$\frac{\delta Z}{\delta g_k} = 0 : \frac{\delta Z}{\delta g_L} = 0 \quad (26)$$

So,

$$\lambda_k = \eta - \lambda \frac{\delta f}{\delta g_k} : \quad \lambda_L = \eta - \lambda \frac{\delta f}{\delta g_L} \quad (27)$$

$$\lambda_L - \lambda_k = \eta \quad (28)$$

In relation to transmission capacity F_c, the first order condition is given as:

$$\frac{\delta z}{\delta F_c} = 0 \qquad (29)$$

This shows that:

$$-\int_0^T \eta \delta t + \frac{\delta I(F_c)}{\delta F_c} = 0 \qquad (30)$$

Hence,

$$\int_0^T (\lambda_L - \lambda_k)\delta t = \frac{\delta I(F_c)}{\delta F_c} \qquad (31)$$

Equation (31) shows the expression for optimal transmission capacity, F_c between the two nodes. When the pricing is optimum, the marginal cost of investment (if one MW of transmission capacity is added) between two nodes must be equal to the operational marginal cost of the savings between the nodes over a period of time.

2.4 The Improved Transmission Pricing Scheme (ITPS)

The Improved Transmission Pricing Scheme(ITPS) defines as that network that minimizes the overall operation and investment cost within a certain period of time. This method is normally applied for pricing activities due to the relation that occurs in optimization of transmission network. In order to determine the parameters for ITPS, the optimal transmission capacity, F_C^{optm} of all paths of the network must be calculated. The transmission optimal capacity, F_C^{optm} can be ascertained by taking evaluation of (32). By substituting the values of marginal cost of all the nodes and the annual investment costs, the marginal cost can be written as:

$$\lambda_k = c_k + 2 * c_{1k} * g_k$$

$$\lambda_L = c_L + 2 * c_{1L} * g_L \qquad (32)$$

So:

$$\int_0^{T_0} (\lambda_L - \lambda_k)\delta t = (c_L - c_k) * T_0 + 2\int_0^{T_0} (c_{1L} * g_L - c_{1k} * g_k)\delta t \qquad (33)$$

Where:

$$T_0 = \frac{T}{(D_1 - D_0)} * \left(D_1 - \frac{F_C^{optm}}{\alpha_L}\right) \qquad (34)$$

2.5 Improved Investment Cost

The cost of investment in transmission is a nonlinear curve in relation to transmission capacity F_c. This means that for a 1MW energy transmitted, the cost of investment will be less with more MW wheeled by a transmission line (Lima, 1996). In order to analyze the optimal transmission capacity, a linear relation between cost of investment and transmission capacity is assumed as:

$$I_c(F_c) = r \bullet l_c \bullet F_c \qquad (35)$$

Where:

I_c = The investment cost

r = The annual marginal investment cost with fixed operations and maintenance cost

l_c = The length of the transmission line in (km)

Taking the derivative of F_c in (35) gives:

$$\frac{\delta I_c(F_c)}{\delta F_c} = r * l_c \qquad (36)$$

Analysis of (33) gives:

$$r * l_t = (C_L - C_k) * T_0 + 2\int_0^{T_0} (C_{1L} * g_L - C_{1k} * g_k)\delta t \qquad (37)$$

2.5.1 The Improved SRMC Transmission Revenue

The SRMC transmission revenue is computed as:

$$SRMC_{trm} = \int_0^T [\lambda_L(t) - \lambda_k(t)] * f(t)\delta t \qquad (38)$$

Analysis and computation of (38) gives the equation for short run marginal cost revenue as:

$$SRMC_{trm} = a * l_c F_c^{optm} = I\left(F_c^{optm}\right) = LRMC_{trm} \quad (39)$$

Equation (39) shows that 'for an optimal transmission network the SRMC revenue is equal to LRMC of transmission and also equal to the transmission investment cost'. This conclusion is true only when transmission investment cost is considered to be linear to transmission capacity.

2.7 Transmission Revenue Requirement and Tariff in Nigeria

The following are the requirements:

Transmission Asset Value: This value is obtained based on the history of the cost of the transmission assets plus recent additional costs incurred towards the asset base. As at 1st July 2008, an initial value of transmission asset was assumed as N189.4b.

Capital Expenditure: In the calculation of TUOS charge, a significant increase in capital expenditure is allowed by TCN. This includes the expenditure on the system operator (SO).

Transmission Use of System (TUOS) Charge: TCN pays some institutional charges to cover the cost of other departments of the industry. They include:

Head Quarter (HQ) Charge: This charge is done against energy (MW) leaving the transmission system and delivered to the distributor/retailers at their bulk supply points.

Regulatory Charge: The regulatory charge covers part of the cost of Nigerian Electricity Regulatory Commission's (NERC) operations in regulating TCN.

So, Total Annual Revenue Tar is given as:

$$Tar = a + r_c + d_{rp} \quad (40)$$

Where:

a = Annual Operations and Maintenance cost

r_c = Return on Capital

d_{rp} = Depreciation (return of capital)

Therefore, Transmission Cost per MW, T_C (Naira/MWh) is given as:

$$T_C = \frac{T_{ar}}{GWh} \quad (41)$$

The players in electricity market are expected to pay some charges to be used to regulate and administer the electricity market. The tariffs are; the regulatory charge, System Operations (SO), Market Operations (MO), ancillary service charges.

2.8 Major Parameters Used for TUOS Calculation

NERC in 2012 decided that TCN's initial asset valuation will largely reflect historical costs plus recent additions to TCN's asset base. This provides an initial asset value at the beginning of 2012 to be N189billion. In order to calculate the asset value in each year of the tariff period, the forecast capital expenditures are added to this amount and depreciation plus any reduction in asset values due to optimization are deducted. However, this was reviewed to reflect additional asset base as follows:

Starting balance as at end of 2010 based on NERC's ODRC (Optimized Depreciated Replacement Cost) valuation of NGN 189 billion. Recognition of additional asset base that will result in higher return of capital (depreciation cost on assets in service) based on:

(i) Recognition of additional transmission assets of NGN 72 billion not captured in

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the 2010 valuation as reported in PHCN books to have been procured/completed as at December 31st 2013;

(ii) Transfer of NIPP asset received by TCN in 2014 amounting to NGN 310.4 billion:

(iii) Transfer of Investment in plant using internally generated funds and World Bank/other donor (NTDP and NEDP) assisted transmission projects managed by the Project Management Unit (PMU) of PHCN not reflected in valuations used in 2010. These assets together amounted into NGN23.4 billion as at 2013 (www.tcnng.org).

Table 1 shows a summary of the budgeted and proposed asset value approved by NERC.

Table 2, shows the proposed TUOS tariffs for billing on distributors/ retailers. These charges are made on the basis of each unit of energy transmitted to the users per year. The institutional charges are outlined as shown. The table also indicates the total annual required revenue obtained from aggregation of operations and maintenance costs, return on capital and depreciations.

Table 1: NERC's Approved Capital Budgeted Asset Value

Year	2017	2018	2019	2020	2021	2022
SB		189				
ATA	72					
AT	310.4					
IT	23.4					
BCAV		594.8	594.8	594.8	594.8	594.8
ECE		265.2	247.82	224.4	202.1	204.78

Source: MYTO 2012 (www nerc.gov.ng)

Key:
SB – Starting Balance
ATA – Additional Transmission Assets
AT – Assets Transfer
IT – Investment Transfer
BCAV – Budgeted Capital Assets Value
ECE – Estimated Capital Expenditure

Table 2: Proposed Transmission Revenue Requirement and TUOS Tariff per MWh in (N'000)

	2018	2019	2020	2021	2022
Variable Costs	24,661,330	26,821,663	29,171,240	31,726,641	34,505,894
Administrative Costs	3,898,625	4,240,144	4,611,581	5,015,555	5,454,918
Fixed Costs	13,703,040	14,251,162	14,821,208	15,414,056	16,030,619
Total Operating Costs	42,262,995	45,312,969	48,604,029	52,156,252	55,991,431
Return on Capital	21,562,801	65,631,973	44,277,488	48,085,557	51,760,132
Return of Capital (Depreciation)	21,945,819	23,338,791	24,731,763	25,581,506	26,974,478
NERC Regulatory Charge	1,439,607	1,561,124	1,682,756	1,796,810	1,920,043
Ancillary Service Charge	289,809	312,704	585,715	662,971	750,417
Grand Total	**87,501,031**	**136,157,559**	**119,881,752**	**128,283,097**	**137,396,501**
Electricity delivered to Distribution (GWh)	23,403	23,403	40,663	42,696	44,831

3. RESULTS AND DISCUSSION

Table 3 describes the approved TUOS charges for TCN. The charges in (Naira/MWh) for transmission services are derived from (40) and (41). In Table 1, TCN usually insist that the charges should be split into two as: energy charge and capacity charge. NERC approved 20% of TCN's revenue as fixed recoverable capacity charge. 80% of TCN's revenue was approved as variable recoverable energy charge.

Table 4 describes the NERC's approved sharing ratio of the TUOS charge among TCN's MO, SO, ASF and TSP charges. This ratio is based on energy delivered to distribution and export companies. The ratio is applied after the recovery of revenue from the distributors/consumers.

Table 5 shows the breakdown of TCN charges to be recovered from distribution and export companies. The charges are billed at 20% fixed per average hourly energy transmitted (i.e., capacity charge) and 80% variable per energy transmitted to distributors (i.e., energy charge). The revenues are obtained after the application of NERC's approved sharing ratio in Table 4.

Figure 1 shows an analysis of TUOS energy and capacity charge variations for a five year financial period. The figure shows that for the first two years of review (i.e., 2018-2019), the energy charge was high. The best price was obtained in the year 2020 for both the energy and capacity charges. After the year 2020, the charges gradually began to increase again. This is because of rise in TUOS components (i.e., operation and maintenance, return on capital and depreciation).

Figure 2 shows an analysis of TUOS breakdown of charge variations. The figure shows that the charges recoverable for MO and SO are higher than that of ASF and regulatory charges. This is because the MO and SO will normally generate their capital and operating expenditure from the revenue shared to them. This explains why they receive high ratio of revenue.

Table 3: Proposed TUOS Charges for TCN (N'000/MWh)

Energy Charge (NGN/MWh): 80% of Revenue	Energy Charge (NGN/MWh): 20% of Revenue
2991	748
4654	1164
2359	590
2404	601
2452	613

Source: (MYTO, 2012)

Table 4: TCN Distribution of Charges Ratio

Name	Ratio %
Market Operator (MO)	3.37
System Operator (SO)	12.81
Ancillary Services Fund (ASF)	2.50
Regulatory Charge	1.37
TSP Charges	79.95

Source: (MYTO, 2008)

Table 5: Proposed TCN Breakdown of Charges(N'000,000/MWh)

Year	2018	2019	2020	2021	2022
MO	126.0	196.1	99.4	101.3	103.3
SO	478.9	745.3	377.7	384.9	392.6
ASF	93.5	145.5	73.7	75.1	76.6
Regulatory Charge	51.2	79.7	40.4	41.2	41.9
TSP Charge	2,989	4,651	2,357	2402	2450
Totals	3,738.6	5817.6	2948.2	3,004.5	3,064.4

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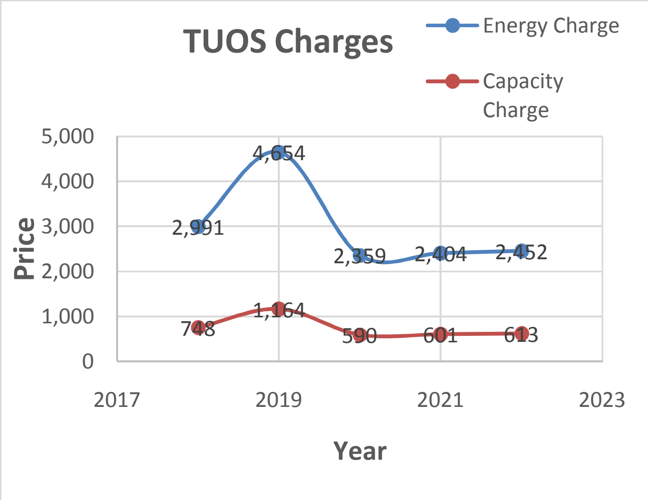

Figure 1: Yearly Charge Variations

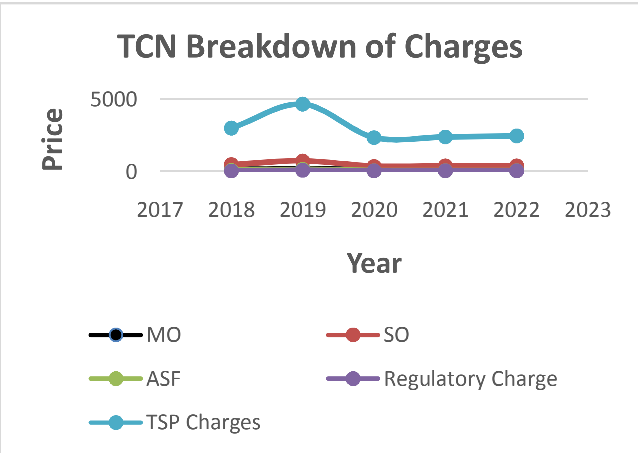

Figure 2: Breakdown of Charge Variations

3.1 Comparison with NERC Multi Year Tariff Order Review 2017

The proposed TUOS charges obtained in this work in Table 2 is higher compared to the approved TUOS charges for TCN during NERC review of MYTO (2012). The results obtained in this work were validated with that of Transmission Company of Nigeria. The results confirmed a very low electricity tariff currently in operation in the country which is grossly disadvantageous to the transmission company.

4. CONCLUSION:

In a restructured electrical power system like that of Nigeria, transmission sector is the most important. A model has been proposed with the use of improved TUOS method for forecasting the transmission price of the industry for a five year financial period (from 2018-2022). Results for the suggested improved electricity transmission pricing for Nigeria was obtained for a five year financial period. The results obtained from the model shows that the improved transmission use of system pricing methodology is an excellent application for electricity transmission pricing in Nigeria. The required quality of TUOS is its ability to apply the aggregate of capital returns, depreciation of assets/equipment and operations and maintenance costs to achieve the charges billed to the distributors. All of these components are difficult to achieve in a single process. The TUOS charges provided from the results indicates that the prices are able to carry along both the transmission service providers and the consumers. With the proposed price, transmission investment costs can be achieved, and the attraction of transmission investment into the system will be very high. However, it must be noted that there is no pricing system in transmission network that is sufficient to provide all the required profit but the improved TUOS has proved to be excellent in the system.

It is however recommended that in order to maintain this best result from improved TUOS, there should always be a review of the price after every five years. This is true because of changes in inflation rate, exchange rate, cost of fuel and actual generated capacity of energy in MWh.

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