NIGERIAN ELECTRICITY
REGULATORY COMMISSION

MULTI-YEAR TARIFF ORDER

FOR THE DETERMINATION OF THE COST OF ELECTRICITY TRANSMISSION AND THE PAYMENT OF INSTITUTIONAL CHARGES FOR THE PERIOD 1 JUNE 2012 TO 31 MAY 2017

Nigerian Electricity Regulatory Commission

1 June, 2012

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Glossary of Terms

ARR	Annual Revenue Requirement
BPE	Bureau of Public Enterprises
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CCGT	Combined Cycle Gas Turbine
CPI	Consumer Price Index
Disco	Distribution/Retail company
DUOS	Distribution Use of Service
EPC	Engineering, Procurement and Construction
EPSRA	Electric Power Sector Reform Act
FGN	Federal Government of Nigeria
GENCO	Generator Company
IFC	International Finance Corporation
IMF	International Monetary Fund
IPP	Independent Power Producer
KWh	Kilo Watt hours of electrical energy
LRMC	Long Run Marginal Cost
MAR	Maximum Allowable Revenue
MDAs	Ministries, Departments and Agencies of the (FGN)
MLF	Marginal Loss Factor
MMBTU	Millions of British Thermal Units
MO	Market Operator
MWh	Mega Watt hours of electrical energy
MYTO	Multi Year Tariff Order
N/KWh	Naira per Kilo Watt Hour
NBET	Nigerian Bulk Electricity Trading Company

NELMCO	Nigerian Electricity Liability Management Company
NEPP	National Electric Power Policy
NERA	National Economic Research Associates
NERC	Nigerian Electricity Regulatory Commission
NESI	Nigerian Electricity Supply Industry
NTB	Nigerian Treasury Bonds
NUT	National Uniform Tariff
OCGT	Open Cycle Gas Turbine
ODRC	Optimised Depreciated Replacement Cost
O&M	Operations & Maintenance
Opex	Operating expenditure
PHCN	Power Holding Company Of Nigeria
PI	Price Index
PPA	Power Purchase Agreement
RAB	Regulatory Asset Base
ROE	Return on Equity
ROT	Rehabilitate, Operate, and Transfer
SO	System Operator
SPE	Special Purpose Entity
SPV	Special Purpose Vehicle
TCN	Transmission Company Of Nigeria
TSO	Transmission System Operation
TSP	Transmission Service Provider
TUOS	Transmission Use of System
WACC	Weighted Average Cost of Capital

ORDER NO: NERC/GL116

ORDER for the Establishment of a Transmission Tariff and Institutional Charges

PART ONE

The Nigerian Electricity Regulatory Commission (NERC) is Nigeria's independent regulatory agency for the NESI established by the Electric Power Sector Reform Act (EPSRA) 2005. NERC was officially inaugurated on 31st October 2005.

The Act provides the legal and regulatory framework for the electricity supply industry in Nigeria. It empowers the Commission to regulate the Nigerian Electricity

Supply Industry (NESI), comprising the Generation, Transmission and Distribution/Retail sectors.

One of the primary functions of NERC as contained in Section 32(d) of the EPSRA is to ensure that the prices charged by licensees are fair to consumers and sufficient to allow the licensees finance their activities and to allow for reasonable earnings for efficient operation. Section 76 of EPSRA further empowers the Commission to establish one or more tariff methodologies for regulating electricity prices.

In its effort to provide a viable and robust tariff policy for the Nigerian Electricity Supply Industry (NESI), the Commission in 2008 decided to introduce a Multi-Year Tariff Order (MYTO) as the framework for determining the industry pricing structure. The MYTO methodology establishes and lays out the process to be followed in meeting the statutory obligation in Section 76 of the EPSRA. It provides a fifteen (15)-year tariff path for the electricity industry with minor and major reviews bi-annually and every five years respectively.

In consultation with industry stakeholders and consumers, NERC adopted a holistic and scientific approach to balancing electricity tariffs to ensure a fair and cost-reflective tariff regime capable of sustaining the NESI while at the same time attracting investment into the sector; all of which are non-negotiable enablers for driving socio-economic development across the country. The key principles of cost reflectivity and affordability were taken into consideration in evolving the new tariff regime. The MYTO further incentivises and assumes a steady, continuous reduction in transmission and distribution/retail loses. Revenue earned by operators is made dependent on achieving these performance improvements.

The process for adoption of this methodology was open transparent as consultations took place with government, customer groups, other major stakeholders and industry practitioners who contributed to the proposed methodology at various public fora and through written representations. Even after this Tariff Order becomes effective, implicit in the fact of Minor and Major Reviews is the expectation that all stakeholders are entitled to continuously review it and propose modifications to NERC.

There are three separate Tariff Orders, one each of generation, transmission and distribution/retail sectors of the NESI. This Transmission Tariff Order is divided into two parts – Part One, which is the proclamation of the Order; and Part Two, which presents the basis of the Order. Part Two is further sub-divided into eight sections - the Introduction, Legal and Regulatory Framework, Pricing Methodology, Economic and Financial Assumptions for the 2012 MYTO, Inputs to the Transmission Use of System (TUOS) Calculations, TUOS Charges, the Bi-Annual Reviews and Date for Effectiveness.

Accordingly, and by virtue of the powers conferred by S. 76 of the Electric Power Sector Reform Act, the Commission hereby **ORDERS** that:

1. The Tables for Transmission Use of System charges and institutional charges that shall come into effect as from midnight on 31st May 2012 and continue in force until midnight on 31st May 2017 shall be as shown herein below, subject to the provisions of this Order.
2. Upon coming into effect, the said charges shall continue in force subject to such Minor and Major Reviews as the Commission may hold from time to time.

This Order shall be called the Nigerian Electricity Transmission and Institutional Charges Multi-Year Tariff Order, 2012.

PART 2

1 Introduction

By this Tariff Order the Nigerian Electricity Regulatory Commission (NERC) establishes the regulated transmission use of system (TUOS) charge to be paid to the Transmission Company of Nigeria (TCN) by distribution/retailing companies (Discos) in the transportation of electricity from generators to their (Disco) local bulk supply point(s). This Order also establishes the losses to be covered by generators when they inject their energy into the TCN network and the various institutional charges to be paid for the administration, management and regulation of the electricity system. These regulated charges are established for the period 1 June 2012 to 31 May 2017 pursuant to the authority given under Section 76 of the Electric Power Sector Reform Act (2005).

TUOS charges will be reviewed bi-annually and a change made to the TUOS charge if Nigerian inflation, exchange rate and generation capacity has varied materially from that used in the calculation of the tariff. A major review of all inputs to the tariff calculation will be undertaken in 2016 as the basis for a new Multi Year Tariff Order (MYTO) to commence for 5 years from 1 June 2017.

1.1 Background

The Nigerian Electricity Regulatory Commission (NERC) is an independent regulatory agency established by the Electric Power Sector Reform (EPSR) Act, 2005. NERC was officially inaugurated on 31st October 2005. The Act provides the legal and regulatory framework for the electricity supply industry in Nigeria. It empowers the Commission to undertake technical and economic regulation of the entire NESI.

The key challenges that the NESI must contend with may be summarised as follows:

- Acute shortage of generation capacity;
- Acute shortage of natural gas;
- Transmission constraints and inadequacies;
- Lack of private sector participation;
- Inadequate generation mix e.g. solar, wind, coal, etc;
- Unacceptable technical and non-technical loss levels; and
- Unacceptably high payment or credit risk in the distribution sector.

The establishment of NERC was the direct result of a genuine desire to transform the electricity supply industry into a market-based industry in line with the Federal Government’s reform agenda for the country’s economic, industrial and social development. Thus, the Commission was established to facilitate the introduction and management of competitive, safe, reliable and fairly-priced electricity in the country.

Pursuant to the above, the objectives of the Commission include:

- To create, promote, and preserve efficient industry and market structures, and to ensure the optimal utilisation of resources for the provision of electricity services;
- To maximize access to electricity services, by promoting and facilitating consumer connections to distribution systems in both rural and urban areas;
- To ensure that an adequate supply of electricity is available to consumers;
- To ensure that the prices charged by licensees are fair to consumers and are sufficient to allow the licensees to finance their activities and to allow for reasonable earnings for efficient operation;
- To ensure the safety, security, reliability and quality of service in the production and delivery of electricity to consumers;
- To ensure that Regulation is fair and balanced for licensees, consumers, investors and other stakeholders.

In its effort to provide a viable and robust tariff policy to support the long-term viability of the Nigerian Electricity Supply Industry (NESI), the Commission in 2008 decided to introduce a Multi-Year Tariff Methodology as the framework for determining the industry pricing structure. The MYTO Methodology establishes and lays out the process to be followed in meeting the statutory obligation in S.76, Electric Power Sector Reform Act (EPSRA). It provides a fifteen (15) year tariff path for the electricity industry with bi-annual minor reviews and major review every five years.

This is the second Tariff Order issued by NERC for the period 1 June 2012 to 31 May 2017. Two other Tariff Orders are being issued concurrently to cover generation wholesale prices and distribution and retail tariffs for the eleven (11) Discos.

The MYTO regulatory model depends on data received from the Market Participants. Institutions within the NESI have supplied estimates and forecasts upon which the industry costs and tariffs developed in the MYTO are based. NERC is conscious that the NESI must develop and change to meet the demands placed upon it. The data inputs and estimates underlying the MYTO will be reviewed periodically to ensure they remain current.

Following the procedures set out in Section 76, EPSRA, the Commission has published the MYTO Methodology upon which both MYTO 1 and 2 are based – see www.nercng.org. In describing its methodology the Commission noted that it had adopted three basic principles. These principles require that a regulatory methodology:

- produces outcomes that are fair;
- encourages outcomes that are efficient in that it involves the lowest possible costs and encourages investment in electricity generation; and
- is simple, transparent and devoid of excessive regulatory costs.

In establishing MYTO 2, the Commission has sought to apply these principles more precisely in order to produce tariffs that incentivise the NESI to attain standards of performance set by NERC to produce the positive outcomes mandated in Section 32(1), EPSRA.

NERC's recent major review highlighted the need for an amendment to the existing methodology and so a "Notice of Proposed Change to the Multi-Year Tariff Methodology" was published, explaining the need to adjust the existing methodology. There were two (2) major changes to the existing methodology and these were brought about by:

- the need to be more flexible in wholesale generation pricing; and
- the need to consider a number of other variables during the minor reviews.

1.2 Insight into the 2008 Multi Year Tariff Order

The 2008 MYTO was based on the new entrant cost profile for generation companies and the building block approach to electricity pricing of transmission and distribution services, all based upon a set of pricing principles and cost assumptions. The ultimate objective is to provide the industry with a stable and cost-reflective pricing structure that provides a modest return on investment to efficient industry operators. At the same time the tariff will protect consumers against excessive pricing, since the price is set at the entry level of the most efficient generation company.

The MYTO provides a fifteen (15) year tariff path and allows for bi-annual minor reviews and a major review no more than five years apart so as to keep the tariffs in line with current realities. The minor reviews only take into consideration four variables, namely:

1. Rate of inflation,

2. Gas prices, and
3. Foreign exchange rates
4. Actual daily generation capacity

The major reviews involve a comprehensive review and overhaul of all the assumptions in the MYTO model. During the minor review of MYTO in May 2009, Successor Discos requested that the major review of MYTO scheduled for 2013 be brought forward in order to take care of the increasing cost of power, the rising cost of O&M expenses and also declining revenue due to the absence of the growth in generation capacity envisaged in the 2008 Tariff Order. The Commission considered this request and the MYTO major review was brought forward.

This major review affords stakeholders the opportunity to evaluate the methodology, inputs to the existing model, incorporate Feed-In Tariffs (FITs) for renewable energy (wind, biomass, solar and small hydro) and also develop tariffs for coal-fired generators. Some of the assumptions reviewed include:

- Available generation capacity
- Forecast of electricity demand
- Expansion of the transmission and distribution networks
- Capital expenditure (capex)
- Actual and projected sales
- Operating costs (opex)
- Fuel costs
- Interest rates
- Weighted average cost of capital (WACC)
- Revenue collection efficiencies
- Subsidies

Having concluded that establishing a cost-reflective tariff would ordinarily lead to a general increase in tariffs across all classes; and in other to avoid the effects of a rate shock on more vulnerable consumers, the tariffs paid by certain classes consumers will be less than cost-reflective values over the first two years, up to June 2014, following the introduction of MYTO 2. In this vein, FGN support will be provided in the form of a subsidy to make up the shortfall between actual and cost-reflective tariffs over this period, while the tariff moves gradually towards viable levels.

Unlike before, this will be enjoyed only by the tariff classes that genuinely need support. The removal of the subsidy over a period of time is expected to lessen the burden on consumers while allowing them to adjust to the new price level. The Federal Government subsidy is intended to exit when power availability increases enough to enable a further rebalancing of tariffs. This rebalancing will be such that the NESI is left with only a cross-subsidy scheme established within the framework of the Power Consumer Assistance Fund (PCAF), as mandated by Part VIII (Sections 83 – 87), EPSRA.

1.3 Electricity Pricing in Nigeria

In Nigeria, the true cost of electricity production is not reflected in the consumer tariff. This new Tariff Order is intended to be cost-reflective and provide financial incentives for immediately-needed increased investments in the industry. These investments, in turn, lead to a significant and continuous improvement in the quantity of energy and quality of service enjoyed by the consumer.

The Commission has since September 2010 carried out wide consultations with the industry operators, consumer advocacy groups, the legislature and relevant MDAs on both the MYTO methodology and tariff (see Appendix 1 for the list of stakeholders consulted).

1.4 Rationale for Tariff Review

Electricity is similar to any other manufactured product. The costs are made up of O&M costs (e.g. gas, salaries, maintenance etc), and capex (such as turbines, switchyards and transformers). The industry is capital intensive and electricity plant have a long technical and economic life but also takes a considerable amount of planning, time and effort to be put in place. Electricity differs from other products in that it cannot be economically stored as it is produced. The implication of instantaneous supply and consumption is that price has to be sufficient to cover the cost of production, otherwise supply will be jeopardised.

If electricity is under-priced, then supply will not meet demand. At the moment in Nigeria there is a very high level of unsatisfied demand for electricity. One indicator of this is the extensive use of diesel generators, which typically produce electricity at price levels that are much higher than the price of grid-connected electricity. It is imperative that electricity should be priced such that it covers its supply costs if adequate and reliable electricity is to be produced to meet demand. As with any other product, it needs to cover O&M and capital costs and provide a reasonable return. If this is done, new investment will be attracted into the industry.

At present the revenue from electricity tariffs covers about half of the revenue required to achieve a viable and growing electricity sector. In other words, the tariffs currently set for the industry can barely fund routine activities and certainly cannot provide for investment in new generation, transmission and distribution infrastructure.

MYTO 2 is intended purely to facilitate the Industry's successful passage through a period of significant reform, performance improvement and growth. It will:

- allow for the recovery of an appropriate return on capital invested, depreciation (and replacement) of capital and recovery of fuel, operation, maintenance and overhead costs;
- provide an incentive for new investment in capital equipment.
- provide incentives for reducing technical and non-technical losses, lowering forced outages and improve demand-side management;
- provide a viable and transparent tariff path that facilitates the NESI's progress towards a reformed and market-oriented system; and
- finally, ensure that the benefits of a reformed NESI are passed through to all consumers in the form of reliable electricity supply at the lowest possible price consistent with the above objectives.

The NESI will, in time, move to a market-based system whereby generators and electricity retailers will be free to contract with each other for the supply of electricity. Transmission and distribution, as monopoly wires businesses, will remain regulated.

1.4.1 Transmission Tariff Issues Addressed in 2012 MYTO

- *Cost recovery*: due to TCN's funding constraints, IPPs are obliged to invest in the provision of transmission infrastructure to connect to the grid if they are located at long distances (i.e. above 1km) from TCN's main line). The Commission has deliberated with TCN and prospective IPPs on various ways in which to manage this issue satisfactorily. The most acceptable option is for each IPP so affected to build the necessary transmission or spur line and then recover the cost of this construction as a separately identifiable part of the wholesale generation tariff; while ownership of the infrastructure remains with TCN. This recovery will be deducted from the Connection Charge attributable to TCN's return of capital and paid to the IPP instead of to TCN on terms stated in the Connection Agreement between the IPP and TCN.

- *Retention of building blocks approach:* The Commission retained the use of building blocks to develop the revenue requirement for transmission as the basis for setting the price cap. This approach will also be used for the distribution sector. The structure of transmission tariffs is thus designed to yield this revenue while providing as far as possible appropriate signals to users of the costs they impose on the system network.

1.4.2 Structure of Transmission Cost

Total transmission costs include the connection cost (between generator and main transmission line), the cost of building the network and the cost of operating and maintaining the network. Below are more detailed explanations of the costs associated with the transmission network:

i. The cost of connecting generators and load customers to the network. There are two approaches to connection charges which are as follows:

- Shallow connection cost: is the cost of construction, operation and maintenance of the network facilities that are strictly needed to connect a network user to the main grid. The connection fee will cover the cost of the meter and the cost of the line between the customer and the existing network.

- Deep connection charge: provide locational signals for new users as it is more expensive to connect in an area where reinforcements are necessary due for example to a non-existent or a saturated/congested network. This charge may be considered in areas to which the existing network does not extend. Costs of connecting new customers (generators) to the transmission network are typically recovered through connection charges levied on individual customers (generators). The cost of grid reinforcement and maintenance is recovered through the Transmission Use of System (TUOS) charges that are part of the fixed costs of building and maintaining the grid.

ii. The fixed costs of building and maintaining the network, including a return on capital employed: Transmission prices should be sufficient to cover the fixed costs of the network, which include depreciation and a return on capital. The level of such costs to be recovered in this Order for this purpose was determined by NERC based on the value of the regulated asset base value as at the end of 2010.

iii. The cost of operating and maintenance of the network.

2 Legal and Regulatory Framework

The establishment of NERC was the direct result of a genuine desire to transform the NESI into a market-based industry in line with the government's reform agenda for the country's economic, industrial and social development. Thus, NERC was established to facilitate the introduction and management of competition in the country's electricity supply industry.

Pursuant to the above, the objects of the Commission include:

I. To create, promote, and preserve efficient **industry and market structures**, and to ensure the optimal utilization of resources for the provision of electricity services;

II. To maximize **access** to electricity services, by promoting and facilitating consumer connections to distribution systems in both rural and urban areas;

III. To ensure that an **adequate supply of electricity** is available to consumers;

IV. To ensure that the **prices** charged by licensees **are fair** to consumers and are sufficient to allow the licensees to finance their activities and to allow for **reasonable earnings** for efficient operation.

Section 76(1) of the Act subjects the following activities are subject to tariff regulation:

(a) Generation and trading, in respect of which licences are required pursuant to this Act, and where the Commission considers regulation of prices necessary to prevent abuse of market power and

(b) Transmission, distribution and system operation, in respect of which licences are required under this Act.

Section 76(2) provides for the Commission to adopt appropriate tariff methodology within the general principles established in the Act, which amongst others:

- Allows recovery of efficient cost including a reasonable rate of return
- Gives incentives to improve efficiency and quality
- Sends efficient signals to customers on costs they impose on the system
- Phases out or reduces cross subsidies

This Tariff Order (MYTO 2) is based on a set of principles designed to provide tariffs for each of the generation, transmission, and distribution (including retail) sectors (reference Section 1.4 above) based on the following rationale:

- **Cost recovery/financial viability** – regulated entities should be permitted to recover their (efficient) costs, including a reasonable rate of return on capital.
- **Signals for investment** – prices should encourage an efficient level and nature of investment (for instance, location) in the industry.
- **Certainty and stability** of the pricing framework is also important for private sector investment.
- **Efficient use of the network** – Generally, this requires "efficient" prices that reflect the marginal costs that users impose on the system and the reduction of cross-subsidies.
- **Allocation of risk** – pricing arrangements should allocate risks efficiently (generally to those who are best placed to manage them).
- **Simplicity and cost-effectiveness** – the tariff structure and regulatory system should be easy to understand and not excessively costly to implement (e.g., facilitate metering and billing).
- **Incentives for improving performance** – the tariff structure should provide incentives for operators to reduce costs and/or increase quality of service.
- **Transparency/fairness** – prices should be non-discriminatory and transparent. Non-discriminatory access to monopoly networks is a key prerequisite for effective competition in the contestable sectors.
- **Flexibility/robustness** – the pricing framework needs to be able to cater for unforeseen changes in circumstances.
- **Social and political objectives** – the pricing framework needs to provide for the achievement of social policy goals such as universal access, demand-side management and user affordability.

3 Pricing Methodology

3.1 Pricing Principles

The building blocks approach was used as a regulatory method to set TUOS charges in the MYTO in line with the Methodology. The building blocks approach is simply a way of bringing together all of the industry's costs in a consistent accounting framework.

The standard building blocks used in this approach are:

- **The allowed return on capital** – being the return necessary to achieve a fair (market based) rate of return on the assets necessarily invested in the business;
- **The allowed return of capital** – associated with recouping the actual capital invested during the useful lives of the assets (depreciation); and
- **Efficient operating costs** and overheads.

In order to calculate a projected annual value for each of the building blocks an estimate was required for:

- The initial value of the NESI's capital stock;
- A particular Weighted Average Cost of Capital (WACC) to be achieved each year;
- A capital expenditure program developed from a forecast of feasible growth;
- An appropriate method of depreciation;
- An efficient level of operating expenditure and overheads; and
- A rate of improvement in industry losses.

The annual revenue requirement for transmission determined using the building block approach was then divided by the forecast level of energy transmitted on the TCN network each year to produce a TUOS charge per unit of transmitted energy.

3.2 Transmission prices

Those using the transmission network will be subject to three forms of payment for transmission services:

- A connection charge for new generators;
- A transmission use of system charge (TUOS) paid by distributor/retailers; and

- A loss factor applied to generation so that generators provide for transmission losses.

This pricing structure is intended as far as possible to assign charges for system use to the user or group of users incurring those costs.

If generators are exposed to connection charges, they are more likely to choose locations that minimise these charges. Similarly, if they are exposed to the costs associated with the losses incurred in transmitting their generation, they will have an appropriate incentive to locate so as to minimise transmission losses. This mechanism will begin to work more effectively when MLFs are set for various injection points on the network.

The distributor/retailers, on their part, effectively cover the fixed costs of the transmission network, thus paying for the power delivery system to be available to them.

3.2.1 The Connection Charge

This is a one-off charge levied when new power stations are connecting to the existing transmission network. It is intended to cover the costs associated with the generator's connection to the nearest node on the system. This might include transmission lines and towers, a switch yard and transformer if necessary and any additional power conditioning equipment required for safe and reliable injection of power into the network. The connection charge covers only costs incurred between the generator's site and the nearest node where it connects to the network. Costs incurred elsewhere on the system as a result of the generator's connection are not included.

The one-off connection charge will vary according to where generators locate their new plant with respect to the existing network. The charge for generators will be calculated by TCN and approved by NERC. TCN can then proceed to build the connection using the funds from the connection charge but if generators can get their connection for a lower cost, or in a shorter time, by having it built by an alternative provider to a standard acceptable to TCN then they may do so. Again, NERC will approve this process, ensuring that the connection can be built to the standard required to maintain the integrity of the network at the lowest cost.

3.2.2 TUOS Charges

The Transmission Use of System Charge (TUOS) will be levied on distributor/retailers and charged per unit of energy delivered to them at the bulk supply points. The TUOS charge is determined using the building blocks methodology, bringing together existing and forecast capital costs, an allowance for a return on capital and depreciation and efficient operating costs

The TUOS charge is mostly comprised of the system's fixed charges, such as the return on capital, depreciation and fixed operation and maintenance. The charge will be uniform throughout Nigeria (sometimes referred to as a postage stamp tariff) and billed monthly to distributors/retailers.

3.2.3 Transmission Losses

Transmission losses are the marginal (or variable) costs of operating a transmission system. Losses vary with the position of generation with respect to load centres. They also vary from year to year according to changes that take place during the year in load growth and the location of new generation.

Each node on the system at which generators connect will have a loss factor associated with it. The loss factor reflects the average losses incurred each year by generators connecting at that point. The loss factor is called a Marginal Loss Factor (MLF) as it is calculated by estimating the losses associated with injecting an additional, or marginal, unit of electrical energy at that point.

In fulfilling their contracts, generators will need to make an allowance for the rate of loss at their connection point. For example, if the loss factor at a bulk supply point is 8% and a generator has contracts over an hour requiring 100 units then the generator must supply 108 units in that hour to meet its contracts and the losses associated with it.

In this Tariff Order, the MLFs within the TCN network will be a uniform 0.915, reflecting the average technical losses on the system estimated at 8.05%. NERC envisages that in future new MLFs will be calculated by TCN from time to time to reflect improvements in actual marginal losses associated with particular connection points. The methodology used and the MLFs developed by TCN will be approved by NERC before they are applied.

4 Economic and Financial Assumptions for 2012 Tariff Order

4.1 Introduction

To develop the tariffs, a considerable mass of economic and financial assumptions were made by the regulator as the basis of the Tariff Order. These include the following variables.

4.2 Inflation

An inflation rate of 13% was adopted. This however, is subject to minor review bi- annually. In the event of a material change in inflation rate, this would be reflected and the tariff adjusted accordingly. In the MYTO, the rate of inflation is used to ensure that investors are well compensated against rising cost of doing business and workers in the industry are paid living wages. To achieve this, the Commission escalates the following variables:

- WACC
- Fixed labour cost
- Fixed admin cost
- Variable O&M cost
- Other Fixed O&M cost
- Capital Investment

Table 1: Assumed Rate of Nigerian Inflation Rate (2012-2016)

	2012	2013	2014	2015	2016
Inflation	13	13	13	13	13

4.3 Exchange Rate

Being an importer of electricity generation equipment components opens Nigeria to foreign exchange risk. The foreign exchange risk associated with this is accommodated in the MYTO model on a bi-annual basis during the minor reviews. In addition, although this risk is regularly adjusted during the minor reviews, investors have informed the Commission that the official CBN rates are not always accessible to them and that they are often charged a commission by their bankers for purchasing foreign exchange. NERC therefore recommends a 1% premium above CBN rates to cover these additional costs. The exchange rate adopted is assumed to increase steadily over the years. This is also subject to review bi-annually.

Table 2: Assumed Naira/US Dollar Exchange Rate (2012-2016)

	2012	2013	2014	2015	2016
Exchange Rate	161	169	178	189	198

4.4 The Weighted Average Cost of Capital (WACC)

The cost of capital included in the MYTO is intended to provide a return on existing assets and appropriate incentives for future investment. The cost of capital is an important component of the tariff and is included in the annual revenue requirement calculation as a return on the value of capital invested. The regulated asset value at the start of a given year is calculated by taking the depreciated replacement cost of capital assets at the start of the immediate proceeding twelve months and adding the investments in new capital assets acquired during the same period.

The Capital Asset Pricing Model (CAPM) is used to estimate a WACC for the NESI. While this approach gives a method for estimating the average cost of capital in a sector and is widely used by regulators, it requires consideration of volatility of returns in the sector as well as the domestic cost of debt. Even in developed economies the calculation of a WACC frequently requires estimation of a number of the inputs. This is the case in Nigeria and most of the inputs in the WACC calculation are, at this point, NERC estimates. The WACC is set at the level that attracts investment funds to the industry but is not sufficient to produce windfall profits.

The CAPM provides estimates of the appropriate return on equity and the returns to equity are measured in relation to the risk premium on the equity market as a whole. Thus:

$$Re = Rf + ße\,(Rm - Rf) \qquad (1)$$

Where:

R_e is the return on equity

R_f is the risk free rate observed in the market

$ß_e$ is the correlation between the equity risk and overall market risk

R_m is the return on the market portfolio

$R_m - R_f$ is the market risk premium

The WACC lies between the cost of equity and the cost of debt and is calculated as:

$$\text{WACC} = \text{Rd x D/(D + E) + Re x E/(D + E)} \tag{2}$$

Where:

D is the total market value of debt

E is the total market value of equity

R_d is the nominal cost of debt; and

R_e is the nominal cost of equity.

This formulation does not include the effects of tax. The formulation of the WACC that allows for the effects of taxation (T_c) and used extensively by regulators is as follows:

$$\text{Nominal post tax WACC (w) = Re x E/V + Rd (1 - Tc) x D/V} \tag{3}$$

Where:

T_C is the company tax rate,

V is the total market value of the business, i.e. debt plus equity

A transformation is applied to derive an estimate of the real pre-tax WACC, as follows:

$$\text{Real pre tax WACC (RW)} = [(1 + w/(1 - Tc)) / (1 + i)] - 1 \tag{4}$$

Where:

W is the nominal post tax WACC, as given by equation (4)

I is the inflation rate

The company tax rate used is the statutory corporation rate of 30% plus 2% education tax.

4.4.1 Estimating the WACC Components

This section provides NERC's estimates of the various components required to calculate a WACC for the NESI. These estimates are then drawn together as shown abovein a description of the process used for the first WACC calculation.

The Risk Free Rate

The yield on government bonds is regarded as the risk free rate and NERC has had regard to relevant yields on Nigerian Treasury bonds and has selected a risk free rate of 18%

Many regulators use 10-year bond rates or 10-year (index-linked) bonds or their local equivalent. The longer term also ensures consistency with the risk free rate used to estimate the market risk premium - that is also based on 10-year bonds.

The Cost of Debt

NERC adopted a nominal cost of debt of 24% reflecting current debt levels for most businesses. The cost of debt is generally determined by adding a debt premium, and sometimes a transaction cost, to the risk free rate.

$$Rd = Rf + DRP + DIC \tag{5}$$

Where:

DRP is the debt risk premium

DIC is the debt issuance cost lending in Nigeria

Betas

Betas reflect the risk weighting of an asset relative to the market as a whole (usually represented by the stock market). Equity betas will reflect the financial risk carried by shareholders, which is in turn influenced by the level of gearing since high levels of debt increase the risk to shareholders.

Electricity supply is not an area with any history of investment from which to draw information on the relative risk and it is not considered possible to derive at statistically significant betas.

The Commission has decided not to apply any value to beta for the current tariff order and appropriate estimate will be made against next tariff review when enough data exists for estimates to be made.

Gearing

The ratio of equity and debt is used to weight the equity and debt returns in the WACC calculation. In the past, independent power producers in developing countries were financed with high gearing ratios – commonly 80:20 debt to equity. However, the World Bank considers that in future greater caution by lenders will result in project sponsors being expected to assume a greater degree of the project risk, by accepting lower debt-equity ratios.

The Bank suggested that future ratios would be closer to 60:40. This level would also apply to regulated assets, such as transmission and distribution. The Commission has selected a gearing ratio of 70:30 in the development of the WACC for the NESI.

WACC estimate

The following are the main assumptions used in the WACC calculations:

risk free rate	18%
nominal cost of debt	24%
gearing level (debt/equity)	70:30
corporate tax rate	32%

These assumptions provide the following WACC estimates:

Nominal pre-tax WACC	25%
Nominal post- tax WACC	17%

Real pre-tax WACC	11%
Real after tax WACC	7%

4.5 Asset Valuation and Depreciation Method

NERC has adopted the optimised depreciated replacement cost (ODRC) method to determine the value of TCN's assets. This value is then used to calculate the depreciation charge in the annual revenue requirement. The ODRC methodology involves:

- Determining the replacement cost of modern equivalent assets;
- Optimising its capacity (i.e. assuming it is the size that is needed for the job it is required to do now); and
- Applying depreciation over the economic life of the individual asset or groups of assets.

The depreciation schedule for regulatory purposes would be applied to each group of assets so that, to the maximum extent that is reasonable, it reflects the remaining economic life of the asset or group of assets. In the case of a regulated monopoly, such as the transmission network, technical life will usually approximate economic life as there are no competitive forces that might reduce the economic life of an asset in future. Similarly, the capital expenditure assumed in the tariff calculation has been developed as the appropriate expansion for the sales growth assumed.

Within the life of the Tariff Order, the Commission does not envisage that any transmission assets will be reduced in value (or "optimised") because they are found to be in excess of what is required now to do their job. The rationale for this is that currently there is a severe deficit of reliable infrastructure in the Nigerian ESI and practically all available assets will be used to the fullest. It is difficult to foresee a time in Nigeria when transmission investments will be surplus to requirements. However, the approach is intended to ensure that the "*gold plating*" (or over-spending on) of assets does not find its way into the regulated annual revenue requirement. NERC will continue to examine capital expenditure submissions to make sure that this does not happen.

The asset lives used for the purpose of deriving an allowance for depreciation are set out below:

Table 3: Asset lives used in depreciation

Existing assets	Years	New assets	Years

Plant & Machinery	20	Plant & Machinery	35
Land & Buildings	40	Land & Buildings	50
Furniture & Fittings	10	Furniture & Fittings	10
Motor Vehicles	5	Motor Vehicles	5

5 Inputs to the TUOS Calculation

5.1 Asset Value and Capital Expenditure

At the start of a regulatory period, it is necessary to establish initial values for assets and for methods of determining additions to assets and depreciation. NERC has determined 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 of =N=189billion (one hundred and eighty-nine billion Naira). 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 the optimization of asset values are deducted.

NERC has not included any reductions in valuation through the optimisation of assets but has not accepted TCN's capital expenditure forecast in its entirety. Rather, considering TCN's historical lack of system planning capacity and its consequent inability to fully justify its projected capex, the Commission has for the time being applied a flat =N=56billion annually during the tariff period and, particularly taking account of the impending arrival of new management in TCN, is willing to revise the figures below once it is convinced that credible capex projections backed by equally credible funding plans have been put forward.

Table 4: Capital expenditure included in the TUOS calculation (nominal N' 000)

2012	2013	2014	2015	2016
56,000,000	56,000,000	56,000,000	56,000,000	56,000,000

5.2 Operating and Maintenance Expenditure and Transmission Losses

The table below shows the allowance made for annual operation and maintenance and administration costs in the tariff calculation. These costs were provided by TCN and adjusted by NERC.

Table 5: Annual O & M included in the TUOS calculation (nominal =N='000)

		2012	2013	2014	2015	2016
TCN Variable O&M Costs - excluding Admin	TSP	9,999,870	11,499,851	13,224,828	15,208,552	17,489,835
	MO	0	0	0	0	0
	SO	0	0	0	0	0
	Total Variable O&M	9,999,870	11,499,851	13,224,828	15,208,552	17,489,835
TCN Fixed O&M Costs - excluding Admin	TSP	5,271,948	6,754,826	8,297,019	8,628,900	8,974,056
	MO	1,251,518	1,301,579	1,353,642	1,407,788	1,464,099
	SO	2,919,768	3,036,559	3,158,021	3,284,342	3,415,716
	Total Fixed O&M	9,443,234	11,092,963	12,808,682	13,321,029	13,853,870
TCN Fixed Costs - Admin	TSP	7,131,412	7,252,646	7,375,941	7,501,332	7,628,854
	MO	169,179	172,055	174,980	177,954	180,979
	SO	2,317,620	2,357,020	2,397,089	2,437,839	2,479,283
	Total Admin	9,618,210	9,781,720	9,948,009	10,117,125	10,289,116

6 TUOS Charges

Market Participants will be required to pay a number of institutional charges in order to enhance the effective regulation and administration of the electricity market. These charges are the regulatory charge, system operation (SO) charge, market operation (MO) charge and payment for ancillary services. While the SO and MO charges are embedded in the TUOS charge, the regulatory and ancillary service charges are stated separately.

The table below shows the annual costs that have been allowed by NERC for each year of the TUOS calculation, including the institutional charges noted above. The table shows the revenue requirement from the three building blocks (operation and maintenance, return on capital and depreciation) plus institutional charges. These costs are brought together and aggregated to a total annual revenue requirement. This annual revenue requirement is then divided by the forecast energy transmitted and delivered to distribution and export customers to arrive at the estimated unit cost of transmission.

NERC has determined that this charge will be shared among TCN’s MO, SO and TSP Divisions. Both MO and SO are expected to provide for their respective capex and opex costs from their share of the revenue.

Table 6: Transmission costs (N ‘000) and TUOS charges per MWh

	2012	**2013**	**2014**	**2015**	**2016**

Variable O&M Costs	9,999,870	11,299,853	12,768,834	14,428,782	16,304,524
Admin costs	9,618,210	9,781,720	9,948,009	10,117,125	10,289,116
Fixed O&M Costs	9,443,234	9,770,083	10,110,007	9,191,527	9,559,188
Total Opex	29,061,314	30,851,656	32,826,850	33,737,435	36,152,829
Return on Capital	685,247	7,650,833	14,588,726	22,204,608	30,058,290
Depreciation	11,589,542	13,941,805	14,685,663	19,437,225	22,100,979
Regulatory Charge	620,042	786,664	931,519	1,130,689	1,324,681
Ancillary service charge	1,006,131	1,550,356	2,116,532	2,658,274	3,152,983
Grand Total	**42,962,276**	**54,781,316**	**65,149,290**	**79,168,231**	**92,789,762**

During the consultation period, TCN requested for a two-part tariff – split into fixed and variable charges. In response, the Commission considered, first, that a substantial portion of the costs of the transmission business is indeed of a fixed nature, and so part of TCN revenue could be recovered through a fixed charge. On the other hand, second, the Commission also considered the low availability of power supply. Hence NERC is hesitant at this point to place too much of a burden on consumers by way of the relatively high fixed charge than would be necessary.

To balance these two considerations, 20% of TCN's revenue has been set to be recovered as fixed charge and 80% as an energy charge. The fixed charge is to be paid based on average hourly energy wheeled within the preceding month, while the energy charge is to be paid based on energy actually wheeled on an hourly basis.

The following are the approved rates for 2012 to 2016:

Table 7: Approved charges for TCN (=N='000/MWh)

	2012	2013	2014	2015	2016
Energy Charge	1,217	1,138	1,120	1,225	1,368
Capacity Charge	304	284	280	306	342

The table below shows the ratio for distribution of charges for TCN based on energy delivered to Discos and Export Customers.

Table 8: TCN Ratios

Name	Ratio %
Market Operator	3.37
System Operator	12.81
Ancillary Services	2.50
Regulatory Charge	1.37
TSP Charges	79.95
Total	100.00

The charges in the table below should be recovered from distribution companies and export customers at 20% fixed per TCN average hourly energy wheeled within the preceding month and 80% variable per energy delivered to Distribution/Export injection point.

Table 9: Breakdown of charges for TCN (=N='000,000/MWh)

	Ratio (%)	2012	2013	2014	2015	2016
Market Operator	3.37	51.26	47.94	47.19	51.59	57.61
System Operator	12.81	194.87	182.21	179.37	196.11	218.98
Ancillary Services Fund	2.50	38.03	35.56	35.01	38.27	42.74
Regulatory Charge	1.37	20.84	19.49	19.18	20.97	23.42
TSP Charges	79.95	1,216.20	1,137.24	1,119.48	1,223.94	1,366.68
Total	100.00	1,521.20	1,422.44	1,400.22	1,530.88	1,709.41

7 Bi-Annual Review

The Commission is willing to review the TUOS charges bi-annually as part of the minor review. If TCN or other interested parties wish the Commission to consider variations in the TUOS charge they need to make a submission to the Commission supporting their case on the basis stated in the relevant notice of review.

The Commission will consider reviewing the TUOS charge if there is a material change in the inflation rate, exchange rate and generation capacity used in the calculation of TUOS charges. The Commission considers that a material change would be plus or minus 5% in these indices. Other parameters, such as variations in the forecast of capital expenditure on the network or the forecasts for energy transmitted through it, will be considered if requested by TCN or as part of a comprehensive major review of the MYTO.

8 Date for Effectiveness

For various reasons, particularly the need to balance the necessary overall increase in tariffs with an obligation on electricity licensees to quickly deliver much improved services; the need to focus on TCN's central role as a major player in the NESI's evolution into the Transition Stage market as envisaged by the Market Rules; and the need to ensure that TCN does not resort to abusive behaviour, this Tariff Order will become effective on 1st June 2012 but the Commission has set down certain performance indicators the delivery of which it will monitor very closely during the next eighteen (18) months.

None of these indicators are new and NERC is indeed aware that TCN has made some progress on all of them. Nevertheless, the pace of movement leaves a lot to be desired, especially as certain conditions precedent stipulated in the Market Rules towards the commencement of the Transition Stage Market cannot be undertaken until some of the TCN actions are completed. However, since the TCN management contract recently agreed with Manitoba Hydro International Limited is also to commence on 1st June 2012, the agreement of a time frame for completing these performance indicators will await the assumption of duties by the new management. The indicators are:

1. Implementation of the full ring-fencing of the SO, incorporating a separate Market Operations (MO) function, within TCN, such that the SO and MO are conferred with full financial and operational autonomy within TCN.

2. Installation, testing and commissioning of grid meters at all identified points in the transmission grid by a date falling within eighteen (18) months of this Order becoming effective.

3. Development of systems and procedures required to implement the Grid Code ahead of the commencement of the Transition Stage market.

4. Development of systems and procedures required to implement the Market Rules ahead of the commencement of the Transition Stage market.

5. Submission by TCN of a system plan and the reports (Annual Report, Generation Adequacy Report and Load Projection Report) required for the procurement of new generation capacity. The Annual Report required for the procurement of new capacity shall be prepared and submitted to NERC by 31st August 2012; while the system plan and other reports shall be delivered to NERC within a time frame to be agreed with TCN's new management as soon as it is in place.

DATED AT ABUJA THIS 31st DAY OF May 2012

DR. SAM AMADI
CHAIRMAN

DR. STEVEN ANDZENGE, MON
COMMISSIONER, LEGAL, LICENSING AND ENFORCEMENT