PUBLIC UTILITIES REGULATORY COMMISSION (PURC), GHANA

2018 ELECTRICITY MAJOR TARIFF REVIEW DECISION

JUNE 2018

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PREAMBLE

The purpose of this Electricity Tariff Decision Paper is to fulfill the statutory mandate of the Public Utilities Regulatory Commission (PURC) as set out in the Public Utilities Regulatory Commission Act, 1997 (Act 538) relating to approval of tariffs for utility services. Additionally, it is to enhance transparency in the utility tariff setting process in Ghana in line with international best practice. The Decision Paper provides the rationale for the 2018 electricity tariffs and is issued for the benefit of the Utility Companies, Investors, Government of Ghana, consumers and the public.

The Commission warrants the accuracy of information contained in this paper as at the date of the tariff decision. The decision remains in force until duly revoked by the Commission.

Executive Summary

On the 8th March 2018, the PURC published a new single-year electricity tariff, setting out rates chargeable for the supply of electricity by distribution utilities to end-use consumers in Ghana as well as transmission service charges for the year 2018. This was done within the mandate of PURC under the Public Utilities Regulatory Commission Act, 1997 (Act 538) with regards to rate setting, particularly, Sections 3(b), 18 and 19.

The rates were arrived at after careful examination of tariff filings made by Volta River Authority (VRA), Ghana Grid Company (GRIDCo), Electricity Company of Ghana (ECG), Norther Electricity Distribution Company (NEDCo) and Enclave Power Company (EPC). The examination was conducted taking into consideration PURC's tariff principles, several utility operational considerations as well as exogenous factors including the energy policy environment, performance of the macro-economy, and other soci0-conomic reasons which have a direct bearing on electricity production, supply and consumption. It also took into consideration submissions made by major stakeholders.

In the tariff filings, GRIDCo requested an Annual Revenue Requirement (ARR) of GHS 1,077.33 Million in respect of services for the transmission of total electricity of 16,305 GWh in 2018.

ECG requested GHS 2,067 Million as its AAR with projected electricity sales of 8,786 GWh for 2018.

NEDCo and EPC requested GHS 493.*13* Million and GHS 32.28Million with projected electricity sales 0f 730 GWh and 116 GWh respectively for 2018.

The Commission upon analyses and consideration of factors mentioned above, approved ARR of GHS 393.76 Million, GHS 1,509.85 Million, GHS 281.36 Million and GHS 21.22 Million for GRIDCo, ECG, NEDCo and EPC respectively. This resulted in an average Distribution Service Charge of GHp30.75/kWh for the distribution utilities. A pass through composite generation cost of GHp42.977/kWh representing GHp28.91/kWh for VRA and GHp53.96/kWh for IPPs was approved as cost of generating electricity for the regulated electricity market.

In the determination of the total income or revenue requirement for the regulated electricity supply value chain, that is, Generation-Transmission-Distribution, the Commission also provided an amount of GHS 129.88 Million (representing 2% of the Distribution Utilities' ARR) as non-collectible revenue.

The Commission's decision, in determining the rates out of the approved total income or revenue requirement for the electricity supply value chain, resulted in residential customers experiencing 17.5% reduction in tariffs whilst the non-residential experienced 30% reduction in tariffs. The Special Load Tariff (LV, MV and HV) customers experienced 25% reduction in tariffs whilst the mines category experienced 10% reduction in tariffs.

It was noted the utility companies have more work to do in order to bring their operating costs to levels more in line with regulatory targets. The submissions made by the utility companies to the Commission show obvious structural dislocations and operational challenges. This situation implies low penetration of modern technology which is a characteristic of modern electric utility business. The utility companies need to reduce losses and increase collection in order to enhance their liquidity and profitability.

As a matter of urgency, Government and consumers must honour their financial obligations to the utility companies particularly in payment of electricity bills.

Abbreviations and Acronyms

Act	Public Utilities Regulatory Commission Act, 1997 (Act 538)
ARR	Annual Revenue Requirement
EC	Energy Commission
ECG	Electricity Company of Ghana
EPC	Enclave Power Company
ESI	Electricity Supply Industry
GDP	Gross Domestic Product
GHc	Ghana Cedi
GNPC	Ghana National Petroleum Corporation
GoG	Government of Ghana
GRIDCo	Ghana Grid Company
GW	Gigawatt
GWh	Gigawatt-hour
IPP	Independent Power Producer
KTPP	Kpone Thermal Power Plant
kW	Kilowatt
kWh	Kilowatt-hour
MDAs	Ministries, Departments and Agencies
MoEn	Ministry of Energy
NEDCo	Northern Electricity Distribution Company
O&M	Operation and maintenance
PURC	Public Utilities Regulatory Commission
RAB	Regulatory Asset Base
RoR	Rate of Return
TARR	Total Annual Revenue Requirement
TI	Tariff Income
TICO	Takoradi International Company
TT1PP	Tema Thermal 1 Power Plant
US$	United States of America Dollar
VALCO	Volta Aluminum Company
VRA	Volta River Authority

1.0 INTRODUCTION

The specific rate setting mandate of the Public Utilities Regulatory Commission (PURC) as provided in Sections 3(a) and (b) of the Public Utilities Regulatory Commission Act, 1997 (Act 538) are:

(i) to provide guidelines on rates chargeable for provision of utility services;
(ii) to examine and approve rates chargeable for provision of utility services; and

In accordance with Section 19 of the Act, the PURC on 8th March 2018, published new electricity tariffs setting out rates chargeable for the supply of electricity by distribution utilities to electricity consumers in Ghana as well as transmission service charges. The rates are contained in Appendix 3. The new rates approved by the Commission came into effect on 15th March 2018 and will remain in force until reviewed by the Commission. The Commission shall undertake rate revisions under its Automatic Adjustment Formula (AAF) mechanism to ensure that targeted revenue requirements for the public utilities are achieved. The rates are meant to recover the Total Annual Revenue Requirement (TARR) approved for the utility companies as well as to satisfy specific policy considerations.

The decision is the culmination of a major tariff review process guided by the Act and the PURC Rate Setting Guidelines. The process, which enabled the Commission to hear from both utility companies and consumers, included:

- Filings by the utility companies, namely: Volta River Authority (VRA), Ghana Grid Company (GRIDCo), Electricity Company of Ghana (ECG), Northern Electricity Distribution Company (NEDCo) and Enclave Power Company (EPC)
- Written papers and submissions by key stakeholders and the public, and
- Public consultations which provided the platform for the utility companies to make representations to the general public.

The Commission also advertised in the newspapers requesting the general public to make submissions on electricity tariffs for its consideration. A copy of the advert is attached as Appendix 2.

In determining the rates, the structure of the existing tariffs was not revised even though some stakeholders requested a revision. The Commission has decided to revise the structure of the tariffs from 2019 onwards after it has carried out sufficient analysis and consultations with stakeholders.

The Commission has made efforts to move the average rates for various classes of consumers close to the cost of service for the respective category of consumers with the view to minimizing cross-subsidies between categories of consumption. Efforts have therefore been made to focus on intra-class subsidies rather than inter-category subsidies. The residential category of consumers continues to enjoy some appreciable level of cross-subsidies from other consumer categories. This arrangement however does not create any gap or shortfall in the approved total revenue requirement for the electricity supply value chain. It must be noted that the Commission does not manage any form of subsidies outside the total approved revenue requirement.

The new rates approved by the Commission are effective 15th March 2018 and remain in force until reviewed by the Commission. The Commission shall undertake rate revisions under its Automatic Adjustment Formula (AAF) mechanism to ensure that targeted revenue requirements for the public utilities are achieved.

2.0 BACKGROUND

Tariff decisions based on prudent and efficient costs is key to the financial viability of public utilities and foster economic growth by sending signals to the market. Enhancement of operations of the country's electric utilities is a priority and the relevance of the regulatory environment must be assessed from that perspective. In arriving at prudent costs of the utility companies, the Commission took into account international best practice benchmarks as well as the utility companies' own performances in previous years.

2.1 PURC Tariff Principles

In addition to the prudent/efficient costs criterion/principle outlined in 2.0 above, the PURC Act further requires that the principle listed in table 2 below should be taken into consideration in developing tariff guidelines and approving rates for electricity consumption.

Table 2

Relevant Section of Act 538	**Objective**
16 (3) (a)	Consumer interest
16(3) (b); 3(c)	Investor / Utility interest
16(3)(c)	Assuring reasonable cost of production of the service
16(3)(d)	Assurance of the financial viability of the public utility
20(1)	Uniformity of prices throughout the country
20(1)(a)	Population distribution
20(1)(b)	Best use of natural resources
20(1)(c)	Economic development of the country
20(2)	Different rates for different consumer classes

The Commission's interpretation of these provisions are summarized below:

- **Consumer Interest**: Ensuring value for money in terms of price, quality and reliability; maintaining an optimum balance between affordability and availability of service; fair apportionment of total cost of supply to various classes of consumers; provision of a minimum level of service (lifeline supply) at an affordable price to a specified category of residential customers; ensuring long term availability of service.

- **Investor/ Utility Interest**: Ensuring the utility or investor's ability to recover operational expenses and earn a reasonable return.

- **Reasonable Cost of Production**: Examination of the cost of production of a service by a public utility or others so as to exclude unreasonable or inefficient costs from the revenue requirement of the utility company.

- **Financial Viability:** Ensuring that the utility companies maintain positive cash flows at all times to achieve reasonable financial indices.

- **Uniformity of Prices and Population Distribution**: Allowance for a tariff structure which incorporates uniform rates for all customers within a particular consumer category regardless of geographic location.

- **Economic Development of the Country**: Providing for "Special Rates" for priority consumers whose activities may enhance or significantly affect economic development.

3.0 CONSIDERATIONS, REGULATORY AND SOCIO-ECONOMIC POLICY CONTEXT FOR THE 2018 TARIFF DECISION

The decisions of the Commission culminating in the 2018 electricity tariffs, are guided not only by utility operational factors, which are key, but also wider considerations including the energy policy environment, performance of the macro-economy, and other soci0-economic dynamics which have a direct bearing on electricity production, supply and consumption. The regulatory policy considerations relating to these are discussed below.

3.1 Regulatory Philosophy

The regulatory philosophy underpinning the 2018 tariff determination revolves around two key principles.

1. Allowance of efficient and prudent cost of supply of electricity to end-users with a view to ensuring recovery of reasonable/efficient costs and return on assets; and
2. Provision of proper economic signals that recognise the state of existing infrastructure and take into account the social and cultural environment by addressing issues of equity and affordability.

Within this context, PURC has employed a hybrid tariff methodology, which combines cost-plus revenue requirement principles and a performance-based incentive mechanism to encourage public utilities to aggressively reduce technical and commercial losses as well as improve on other regulatory performance benchmarks.

3.2 Transparent Cost Centers

The Annual Revenue Requirement (ARR) is what the utilities need to spend on their entire system to provide reliable supply of power to meet the needs of all consumers. The revenue requirement is therefore the build-up of the costs of the various activities undertaken by public utilities to fulfill their mandates. In line with this, the Commission ensured that all the public utilities provided the necessary financial and technical data in order to arrive at a fair decision.

3.3 Implementation of Single-year Tariff based on 2018 Electricity Supply Plan

Owing to time constraints and the fact that the sector will be entering a new dispensation in respect of private sector take-over of ECG under a concession arrangement[1], the Commission has chosen to implement a Single-Year-Tariff for 2018.

The procurement, supply and pricing of electricity for the regulated market has therefore been based on the 2018 Electricity Supply Plan prepared by the inter-agency team including the Energy Commission and the utility companies. Pricing of electricity is also based on existing Power Purchase Agreements (PPAs) signed by the utility companies and the recent revisions concluded between the Independent Power Producers (IPPs) and the Ministry of Energy. The Commission

[1] Introduction of private sector participation into the management, operation of, and investments in the Electricity Company of Ghana (ECG) through a long-term concession over ECG's distribution business.

also considered the Hydro Allocation Scheme approved by the Electricity Market Oversight Panel (EMOP) for 2018.

3.4 Harmonization of Natural Gas Pricing for Electricity Generation

Natural gas has become the preferred fuel for electricity generation in Ghana and will continue to be a critical factor in achieving competitive production of electricity in Ghana. However, natural gas prices have varied considerably given that there are different sources of gas supply including imports from Nigeria, domestic gas sources and the potential supplies of imported LNG. In order to streamline the pricing of natural gas in Ghana, the Government in consultation with PURC, has harmonized the prices of the different sources to arrive at a single weighted average price at which natural gas from all sources shall be sold to power generators. In that regard, a weighted average natural gas price of US$7.29/MMBTU has been approved for all power generators for 2018.

3.5 Depreciation

The Commission treats depreciation as an expense on the basis that it will generate revenue that will enhance the cash flow of the utility companies after accounting for operating activities. The Commission has, as a matter of policy, decided to allow depreciation as an operating item to be passed through the tariffs.

3.6 Rate Base

The Commission per its policy excludes capital works in progress from its rate base.

3.7 System Losses

PURC regulated benchmark Transmission and Distribution Losses have been factored into the tariff decision. System losses for the 2018 Tariff Period for the transmission utility has been pegged at 3.8% while system losses for distribution utilities are benchmarked at 21%.

3.8 Non-collectible Revenue (NCR)

The Commission has approved a non-collectible revenue benchmark of 2% as part of its 2018 tariff decision.

3.9 Automatic Adjustment Formula (AAF)

The Automatic Adjustment Formula which is used to adjust tariffs to maintain the real value of the tariffs shall be applied by the Commission on quarterly basis until the next major tariff review.

4.0. FILING OF 2018 TARIFFS

The requirements for filing of tariffs by public utilities are stated in sections 21 and 22 of the Act. Each public utility is required to file its tariff proposals with the Commission showing rates to be charged by it in accordance with the PURC tariff filing forms. In furtherance of this, the Commission notified the utilities of the commencement of the tariff filing process and requested them to file tariff proposals for the period 2018-2021.

4.1 Tariff Procedure

The following procedure provided in the Commission's Rate Setting Guidelines was adopted.

i. Request for Papers

The Commission commenced the 2018 tariff review process in December 2017 by inviting submissions on electricity tariffs from interested persons. The list of entities that submitted papers in response to the Commission's invitation is provided in Appendix 2.

ii. Utility Proposals

The following electricity public utilities filed tariff proposals with the Commission requesting adjustment of rates chargeable for their services:

1. Ghana Grid Company Limited (GRIDCo)
2. Electricity Company of Ghana (ECG)
3. Enclave Power Company Limited (EPCL)
4. Northern Electricity Distribution Company Limited (NEDCo)

iii. Preliminary Review

In accordance with the Rate Setting Guidelines, the Commission undertook a preliminary review of the proposals to ensure compliance with tariff filing forms and information requirements.

iv. Filing of Supplementary Utility Data

Due to insufficient or inadequate data, some utility companies were required to submit revised or additional data to the Commission as part of their tariff proposals. The closing date for acceptance of final submissions was February 19, 2018.

v. Tariff Hearings

As required under Section 18 (4) of the Act, the Commission held a series of dedicated Technical Committee hearings with each utility company followed by stakeholder consultations commencing January 30, 2018. Additionally, a major joint consultative meeting with utility companies and stakeholders was held on February 12, 2018 which was broadcast across the country with live television and radio coverage as well as the print media. The Commission further directed all utility companies to publish a summary of their proposals to enable interested parties examine the basis of the proposals.

vi. Examination of Tariff Proposals

Section 16 of the Act obliges the Commission to take account of consumer interest, investor interest, the cost of production of the service; and assurance of the financial integrity of the public utility in its Rate Setting Guidelines, which form the basis of tariff examination and approval. All representations made by utility companies, institutions and individuals were taken into account by the Commission in arriving at a decision.

4.2 Submissions by Public Utilities

A summary of the utilities' submissions are presented below.

4.2.1 Submission by GRIDCo

GRIDCo in its submission requested an ARR of GHS 1,077.33 Million in 2018 representing an increase of 49.9% over the company's 2017 operational cost estimate. This was in respect of services they would provide for the transmission of total electricity of 16,305 GWh in 2018. Table 5-1 shows a summary of GRIDCo's filing for the period 2018-2021.

Table 4-1 Summary of GRIDCo's Proposed Technical, Financial and Economic Data

Item	2018	2019	2020	2021
Total Energy Sales (GWh)	16,305	18,314	21,212	21,805
Peak Demand (MW)	2,523	2,776	3,053	3,359
Variable Cost (MGHS)				
Transmission Losses (MGHS)	163.90	185.40	216.19	222.54
Transmission Losses (%)	4.00	4.00	4.00	4.00
Staff Salaries	186.13	195.43	205.20	215.46
Materials and spares consumed	6.65	6.78	6.92	7.05
Maintenance and Other Direct Operating Cost	132.19	114.53	75.08	76.58
Direct Operating Cost	492.86	506.14	507.38	525.64
Other Operating Cost	13.22	11.45	7.51	7.66
Total Operating Cost	506.08	517.59	514.89	533.30
Depreciation	118.51	177.09	205.00	219.72
Return on Ave. Net Assets	452.74	604.99	746.98	803.11
Expected Rate of Return on Average Net Fixed Assets	12%	12%	12%	12%
Total Capacity Cost (MGHS)	571.25	782.08	951.98	1022.83
Average Exchange Rates (GH¢/$)	4.624	4.903	5.272	5.480

4.2.2 Submission by ECG

ECG submitted that it required an ARR of GHS 2,067 Million in 2018. This represented an increase of 35% over the company's 2017 operational cost. ECG projected electricity sales of 8,786 GWh in 2018 as compared to that of 8,572 GWh in 2017. This represents an increase of 2.49%. Table 5-2 shows a summary of ECG's proposals for 2018 – 2021.

Table 4-2 Summary of ECG's Proposed Technical, Financial and Economic Data

Item	Measure	2017	2018	2019	2020	2021
Annual Energy Purchases	GWh	11,157	11,121	12,122	13,091	14,008
Sales	GWh	8,572	8,786	9,576	10,342	11,066
Operating Costs	GHS' Million					
Operation & Maintenance Expenses	GHS' Million	297	600.3	331	357	385
Administrative & General Expenses	GHS' Million	339	201.8	417	445	465.88
Human Resource Expenses	GHS' Million	484	468.8	468	450	502
Total Operating Cost	GHS' Million	**1,120**	**1,271**	**1,216**	**1,252**	**1,353**
Depreciation	GHS' Million	587	665.2	685	706	727
Return on Assets	GHS' Million	-570.14	131.3	309	519	570
Total capacity cost	GHS' Million		796.5	994.2	1,224.90	1,296.50
Total Annual Revenue Requirement	GHS' Million		**2,067.29**	**2,209.78**	**2,476.90**	**2,649.65**
Average Exchange Rate	c/$		**4.5**	**4.5**	**4.5**	**4.5**

4.2.3 Submission by NEDCo

NEDCo projected to sell 730 GWh of electricity to its customers in 2018 representing an increase of 3.11% over the sales of 2017. NEDCo submitted that it would require an ARR of GHc 493.13 million (excluding power purchases). This represents an increase of 54.5% over 2017 ARR. Table 5-3 shows a summary of NEDCo's submissions for tariff revision.

Table 4-3 Summary of NEDCo's Proposed Technical, Financial and Economic Data

Item Descrption	2017	2018	2019	2020	2021
Power Sales (GWh)	708	730	750	770	790
Energy Cost (GHS'000)					
Purchase of Electricity	262,928	286,624	308,700	330,775	352,851
Salaries and Related Expenses	113,454	128,179	132,913	137,646	142,380
Material Expenses	17,436	22,093	27,061	32,029	36,997
Transportation and Travel Cost	15,442	18,633	22,328	26,023	29,718
Repairs and Maintenance	16,521	20,510	24,499	28,488	32,477
Other Administrative Cost	18,200	31,849	33,441	34,983	36,537
Cost of PURC Approved Lost GHS'000	55,502	59,236	63,949	68,662	
Total Variable Cost	499,483	567,124	612,891	658,606	630,960
Capacity Cost (GHS'000)					
Average Net Fixed Assets (ANFA)	1,268,193	1,318,693	1,457,581	1,567,999	1,482,189
Total Depreciation	108,721	107,130	118,079	120,120	99,421
Return on ANFA	101,455	105,495	116,607	125,440	118,575
Total Capacity Cost	210,176	212,625	234,686	245,560	217,996
Average Exchange rate (GHS/USD)	**4.51**	**4.63**	**4.63**	**4.63**	**4.63**

4.2.4 Submission by Enclave Power Company Limited (EPC)

EPC for the first time submitted a full tariff proposal to the Commission in fulfillment of its Electricity Distribution License granted by the Energy Commission to operate in the regulated electricity market. In view of that, EPC put forward the following underlying reasons in support of the company's proposed tariff for 2018:

1. To achieve full cost recovery.
2. To make capital investments in infrastructure to support the growing demand from customers.
3. To enable the company sell power to its customers in the Free Zones area but within the regulated market.

The company projected to sell a total of 116 GWh in 2018 of electricity to its customers within the regulated market but located in Free Zone areas.

EPC submitted that it would require an ARR of GHc 32.28 Million for the regulated market with a tariff of GHp32.28/kWh. Table 5-4 shows a summary of EPC's submissions for tariff approval.

Table 4-4 Summary of EPC's Submissions for Tariff Approval

Input Description	Measure	Regulated & De-Regulated Mkt	Regulated Market Energy & Cost Data
Total Energy Sales	GWh	194	116
Distribution Losses	GWh		24.36
Distribution Losses	MGHS	1.98	1.19
Administrative Cost	MGHS	3.37	2.02
Operations & Maintenance Expenses	MGHS	2.25	1.35
Human Resource Cost	MGHS	1.73	1.04
Total Operating Cost	MGHS	9.32	5.59
Capacity Cost	MGHS	53.08	31.85
Total Cost	MGHS	62.4	37.44
Distribution Service Charge	GHp/kWh	40	32.28
Average Exchange Rate	GHS-USD		4.6

5.0 TARIFF SETTING METHODOLGY

Transmission and distribution grid infrastructure, comprising power lines, transformers and other equipment and plant are used to deliver electrical energy from generators to end-users. The costs associated with these grid services are separate from the electrical energy itself. The costs associated with transmission and distribution grid services are determined using the value-added approach as the cost of electrical energy is considered a pass-through cost item.

The Commission has applied the value-added approach in determining the charges for the transmission and distribution grid services.

The Commission approves tariffs for the transmission utility (GRIDCo) and the distribution utilities (ECG, NEDCo and EPC) as well as rates for end-users/consumers served by the distribution utilities. The Commission's tariff setting methodology for transmission and distribution utilities is based on the concept of regulatory ARR.

5.1 Annual Revenue Requirement (ARR) for Transmission Utility

The ARR for the transmission utility is composed of two major cost centers:

(i) transmission added value (TAV) which is related to the utility's direct operating expenses; and
(ii) cost of power that is lost in the process of transmitting electricity from the power plant gate to the Bulk Supply Points (BSPs) of the distribution utilities or bulk customers point of connection.

The all-inclusive transmission grid service cost is expressed as follows:

$$TransCost = TAV + TransLosses$$

Where:

TransCost	is the all-inclusive transmission grid service costs
TAV	is the direct operating costs of the utility
TransLosses	is the cost of power losses in transmission grid services

The TAV is designated as the (ARR) of the transmission utility, i.e. exclusive of the cost of losses. The ARR of the transmission utility is estimated as follows:

ARR = Opex + Depreciation + Cost of Working Capital + Return on Regulatory Asset Base

Where:

Opex	is the operating expenses including staff cost, administrative costs, and operating and maintenance costs
Depreciation	is straight-line depreciation of the assets for the year
Regulatory Fixed Asset Base	is Net Book Value minus Capital Works in Progress (CWIP)
Cost of Working Capital	is financial costs (interest payment) of working capital

The average cost of the transmission grid services resulting from the ARR, excluding the transmission losses, is referred to as TSC-1 to be paid to the transmission utility.

The average cost of transmission losses is referred to as TSC-2 to be paid to the relevant generator.

In summary, the average costs of transmission grid services (TSC) is expressed as follows:

$$TSC = TSC\text{-}1 + TSC\text{-}2$$

While costs associated with TSC-1 are the direct costs of the transmission utility's operations and shall be paid to the utility, the costs associated with TSC-2 shall be paid to the relevant generator, by the distribution utility or bulk customer either directly to the generator or through the transmission utility which in turn pays it to the relevant generator. The cost of transmission losses is therefore not to be retained by the transmission utility as part of its ARR.

5.2 Annual Revenue Requirement for Distribution Utilities

The ARR for Distribution Utilities is estimated as follows:

ARR = Opex + Depreciation + Working Capital + Return on Regulatory Asset Base

Where:

Opex	is the operating expenses including staff cost, administrative costs, and operating and maintenance costs
Depreciation	is straight-line depreciation of the assets for the year
Regulatory Fixed Asset Base	is Net Book Value minus Capital Works in Progress (CWIP)
Cost of Working Capital	is financial costs (interest payment) of working capital

5.3 Total Annual Revenue Requirement (TARR)

In addition to the distribution utilities' ARR, they incur other costs – power purchases, transmission grid services - which shall be recovered from end-use consumers. The combination of all these costs are computed as distribution utilities' Total Annual Revenue Requirement (TARR) to be passed on into rates. The TARR is therefore estimated as follows:

TARR = Power Purchases + TransCost + ARR

Where:

Power Purchases	are costs of electricity purchases from generators including losses in transmission and distribution grid systems.
TransCost	is cost of transmission grid services excluding transmission losses (paid to GRIDCo).
ARR	is Annual Revenue Requirement of the distribution company as defined above

5.4 Tariff Income (TI)

Tariff Income (TI) is the actual revenue that is generated from the rates that are applied to various customer consumption bands. The rates set to recover the TARR of the distribution company include the following:

1. Cost of electricity purchased,
2. Cost of transmission services and the revenue requirement of the distribution company, and
3. Percentage adjustments of the ARR to cater for non-collectible revenue (NCR).

The TI is estimated as follows:

$$TI = TARR + NCR$$

Where:

TARR	is Total Annual Revenue Requirement as defined above
NCR	is additional costs provided to adjust the TARR for non-collectible revenue that may arise due to technical or commercial challenges facing the utility in the collection of its revenue

6.0 ANALYSIS OF COSTS AND TARIFFS FOR TRANSMISSION GRID SERVICES

This section presents the outcome of the analyses of the cost and Tariffs for Transmission Grid services

6.1 Determination of the Transmission Utility's Annual Revenue Requirement

In determining the TSC, the Commission is mindful of the fact that transmission of power is a monopoly business and therefore requires the requisite regulatory supervision to ensure that its costs are prudent and efficient.

For this 2018 tariff decision the ARR is expressed as follows

ARR = Operating Expenses + Depreciation + Return on the Rate Base

It is important to note that the costs of energy losses are not included in the ARR. This is so because the costs of system losses (transmission a) are fully borne by the distribution utility companies in proportion to their usage of the grid systems and are paid directly to the generating companies.

Based on the above, the following costs centers are considered in the determination of the TSC -1 which is intended to cover GRIDCo's direct operations expenses excluding energy losses.

TSC-1 = ARR/TET

Where:

TSC-1	is Average transmission costs excluding cost of losses
ARR	is Annual Revenue Requirement of the transmission utility (GRIDCo)
TET	is Total Electricity Transmission by GRIDCo for 2018

The various components of the PURC approved costs of GRIDCo's transmission grid services (TSC 1) are discussed below:

6.1.1 GRIDCo's Operating Expenses

The Commission has approved an amount of GHS 393.76 Million to cover the operating expenses of GRIDCo. The total operational expenses of operations of GRIDCo consists of two components:

1. Direct operational expenses comprising staff costs, operation and maintenance costs, and general administrative expenses; and
2. Depreciation and return on the Regulatory Asset Base (RAB).

Table 6-1 shows the breakdown of GRIDCo's operational expenses approved by the Commission.

Table 6-1 Summary of PURC Approved Costs vs. Proposed Costs for GRIDCo

Direct Operating Expenses	Measure	Proposed	Approved
Staff Cost	MGHS	186.13	156.91
Operation, Maintenance & Other Direct Costs	MGHS	19.87	40
Sub-Total	MGHS	**206**	**196.91**
General & Administrative Costs	MGHS	132.19	69.81
Deprecistion	MGHS	118.51	74.71
Return on Net Revalued Fixed Assets	MGHS	452.71	52.33
Grand Total	MGHS	**909.41**	**393.76**

6.1.2 Staff cost

It covers salaries of staff, staff allowances and other statutory payments in respect of GRIDCo workforce. The Commission allowed GHc156.91 million for staff costs as against GHc186.13 million proposed by GRIDCo.

6.1.3 Operating and Maintenance Costs

The Commission allowed an amount of GHS40.0 million in the ARR build up to cover GRIDCo's operating and maintenance expenses in the 2018 Tariff Period as compared to an amount of GHS 19.0 million proposed by the company. The Commission was of the view that GRIDCo required more than they had proposed to in order to carry out their operations and maintenance activities.

6.1.4 General Administrative Cost

GRIDCo proposed an amount of GHc132.19 Million to cover various administrative expenses in 2018. This was to cover all administrative expenses in GRIDCo's operational areas.
The Commission allowed an amount of GHS 69.81 Million to cover GRIDCo's administrative expenses representing 53% of the proposal from GRIDCo.

6.1.5 Depreciation

The Commission allowed depreciation as an expense to be recovered directly from the transmission service tariffs. In that regard depreciation expense is considered a cash-flow item that is available to GRIDCo in excess of its operational expenses to enable it to undertake its critical capital expenditure. The Commission has approved an amount of GHc 74.71 million as against GRIDCo's proposal of GHS 118.51 Million for 2018.

6.1.6 Return on Net Fixed Assets

The Commission approved an amount of GHS 52.33 Million as a return on Net Fixed Assets as against GHS 452.71 million proposed by GRIDCo.

7.0 ANALYSIS OF COSTS AND TARIFFS FOR DISTRIBUTION SERVICES

This section presents the outcome of the analyses of the cost and tariffs for the Distribution Utilities

7.1 Analysis of Costs and Tariffs for ECG

For ECG the outcome is presented as follows:

7.1.1 Determination of ECG Annual Revenue Requirement

For this tariff decision the ECG's ARR is expressed as follows

ARR = Operating Expenses + Depreciation + Taxes + (Rate of Return × Rate Base)

The commission approved an ARR of 2018 GHS 1509.8 Million for the 2018 tariff period. The amount covers, (i) administrative cost, (ii) operations and maintenance costs, (iii) human resource costs, (iv) depreciation and (v) return on the RAB. Table 7-1 shows the cost build-up of ECG's ARR.

Table 7-1 Summary of PURC Approved Costs vs. Proposed Costs of ECG

Item	Measure	Proposed	Approved
Administrative Cost	MGHS	185.08	152.74
Operations & Maintenance Expenses	MGHS	317.90	296.48
Human Resource Cost	MGHS	468.76	468.76
Total O&M Expenses	MGHS	**971.74**	**917.98**
Depreciation	MGHS	665.15	498.86
Return on ANFA	MGHS	131.32	93.01
Annual Revenue Requirement	MGHS	**1,768.21**	**1,509.85**
Distribution Service Charge(GHp/kWh)	GHp/kWh	**36.6**	**30.75**

This results in an average distribution added value (DAV) charge of 18.6638 GHp/kWh. It should be noted that this excludes the provision for non-collectible revenue (NCR) as well as system losses. Details of the various operational cost centers are discussed below.

7.1.1.1 Administrative Costs

ECG proposed an amount of GHc201.79 million to cover various administrative expenses in 2018. This was to cover all administrative expenses in ECG's operational regions and the headquarters. Out of the total administrative expenses, an amount of GHc47.836 million, representing 25.8% was earmarked for the administrative costs in the operational regions and the rest of GHc137.243 million, representing 74.2% of the total administrative costs was to be expended at cost centers associated with the headquarters.

The Commission has allowed administrative expenses of GHS 152.74 Million to be passed through the 2018 tariff. This represents 75.7% of the amount of GHc201.79 proposed by ECG. This amount was arrived at based on a reduction on cost proposals on external training and other sundry expenses in the headquarters which the Commission found not to be prudent.

7.1.1.2 Operating & Maintenance Expenses

The Commission allowed an amount of GHc296.48 million to cover ECG's operating and maintenance expenses in the 2018 Tariff Period as compared to an amount of GHc600.27 million proposed by the company. This represents a percentage reduction of 50.6%. In taking this decision, however, the Commission was mindful of ensuring that all the O&M expenses associated with ECG's Regional operational areas totaling GHc108.389 million was fully passed through. The O&M expenses that were disallowed were largely those associated with operations and maintenance in the ECG's head office and which, in the Commission's analyses of the operations of the company, would not materially impact its operations.

7.1.1.3 Human Resource Costs

The Commission allowed all the human resource costs of GHc468.76 million proposed by ECG. It is however noted that ECG's final Human Resource costs was arrived at after the Commission had disallowed the cost of ECG plans to recruit 652 additional staff.

7.1.1.4 Depreciation Expense

The Commission has allowed depreciation as an expense to be recovered directly from the distribution service tariffs. In that regard depreciation expense is considered a cash-flow item that is available to ECG in excess of its operational expenses to enable it to undertake its critical capital expenditure. The Commission has approved an amount of GHc498.86 million as against ECG's proposal of GHc665.15 million for 2018. It should be further noted that ECG is expected to benefit substantially from financial support of about US$ 350 million from the Millennium Challenge Compact (MCC) programme for investments in the Company.

7.1.1.5 Return on Net Fixed Assets (RNFA)

A return on the revalued net fixed assets (RNFA) of GHC 93.01 million was approved representing 1% percent on the Regulatory Asset Base (RAB).

$$RNFA = ROR * RAB$$

Where:

ROR	is Regulatory Rate of Return determined by the Commission
RAB	is Regulatory Asset Base of ECG

The RAB has been calculated as the Net Book Value of ECG's assets used in operations. The build-up of RAB is as follows:

$$RAB = AV + RV + AD + D - CWIP$$

Where:

AV	is Asset Value for the preceding year (as at 1st January 2018)
RV	is Revaluation Uplift for the year
AD	is Accumulated Depreciation as at end 2017
D	is Depreciation for year 2018
CWIP	is Capital Works in Progress

All the values used in the determination of the RAB are contained in ECG's 2017 Annual Accounts and other financial documents from the company.

7.1.1.6 Cost of Distribution Losses

The cost of power losses in the distribution network is accounted for and applied as appropriate. The benchmark regulated total distribution system losses for 2018 are estimated at 21% of ECG's total electricity purchases excluding transmission losses. The total cost of the distribution losses of 2,246GWh is estimated at GHc1,068 million, representing an average cost of 12.0917 GHp/kWh. The average cost of total distribution systems losses is prefixed as DSC-2. It should however be noted that the cost of distribution losses is not applicable in cases where the total power purchases of the distribution utility includes the cost of total system losses (both technical and commercial losses).

7.1.1.7 Non-collectible Revenue (NCR)

The Commission has allowed an amount of GHC 129.88 million, representing 2% of ECG's ARR as a provision for non-collectible revenue.

7.1.2 ECG Total Annual Revenue Requirement (TARR)

ECG's TARR was determined by the Commission using the following cost items:

(i) Cost of power purchases from electricity generators including all losses in the process of high voltage transmission as well as the electricity that is not billed owing to technical and commercial losses within the utility company's distribution network (*VRA and IPPs*),
(ii) Direct cost of transmission grid services (*GRIDCo costs*),
(iii) Costs of the ECG's own operations (*ECG's ARR*), and
(iv) Provision for non-collectible revenue.

7.1.2.1 ECG Power Purchases for 2018

ECG procures power from VRA and a number of IPPs. For the 2018 Tariff decision, PURC approved ECG's projected power purchase of 11,120.6 GWh as indicated in 2018 Energy Supply Plan. A total of 4,728 GWh will be procured from VRA while the rest of 6,392 GWh will be supplied by eligible IPPs.

The Commission approved an amount of GHc 4.722 billion to cover the total cost of electricity to be purchased by ECG in 2018. Table F.1 shows the cost build-up of ECG's electricity purchases in 2018. The supply profile also takes into account the allocation of electricity from the Akosombo and Kpong hydro power plants approved by the Electricity Market Oversight Panel (EMOP) for the 2018 hydro cycle.

7.1.2.2 ECG Composite Bulk Generation Charge

The Composite Bulk Generation Charge (CBGC) represents the average cost of electricity purchased by ECG from all eligible sources – VRA and IPPs who they have contracted to supply them with power.

Based on the approved total cost of electricity of GHc4.722 billion, the CBGC for ECG in 2018 is estimated at GHp42.977/kWh. This represents a weighted average of VRA BGC of GHp28.91/kWh and IPP average of GHp 53.96/kWh. The PURC however applied the Composite BGC of GHp42.977 for all the distribution utilities in the determination of ECG's revenue requirement. The Gazetted CBGC of GHp42.977 includes VRA BGC of GHp28.9108/kWh which represents the weighted average cost of electricity supplied to ECG by VRA including the hydroelectricity from Akosombo and Kpong.

Table 7-2 Summary of PURC Approved Power Purchase Costs for ECG

ECG Purchases - incl. Trans. & Dist. Losses (GWh)			
Power Plant	GWh	GHp/kWh	GHS' Million
Takoradi Thermal Power Plant (TAPCo)	1,560.00	38.1966	595.866
AMERI	830	53.6907	445.633
Tema 1 Thermal Power Plant (TT1PP)	-	50.1033	-
Kpone Thermal Power Plant (KTPP)	63	43.6865	27.522
Hydro (Akosombo & Kpong)	2,275.83	10.2951	234.299
Takoradi International Company (TICo)	-	46.1937	-
Total VRA	**4,728.83**	**27.5612**	**1,303.32**
Karpowership	2,708.25	50.7078	1,373.30
Sunon Asogli Phase 1 (SAP 1)	51	51.8161	26.426
Sunon Asogli Phase 2 (SAP 2)	1,414.20	51.1063	722.743
AKSA	558.49	55.6013	310.529
Bui	756.21	45.3632	343.041
CENIT	381	74.8536	285.192
Cenpower	523	64.0086	334.765
BXC Solar Power Plant	25.54	89.2087	22.784
Safisana	0.69	73.4295	0.507
Total IPPs	**6,392.15**	**53.4919**	**3,419.28**
Total All Wholesale Suppliers	**11,120.98**	**42.4657**	**4,722.60**

It is important to note that the cost build-up accounts for all the associated system losses resulting from the transmission and distribution of electricity to final consumers. Table 7-3 shows the breakdown of total electricity purchases.

Table 7-3 Summary of PURC Approved Transmission and Distribution System Losses for ECG

Power Purchases	GWh
Final End-User Consumption	8,451.42
Transmission System Losses	422.58
Distribution System Losses	2,246.58
Total Purchases	**11,120.98**

7.1.2.3 ECG's Transmission Grid Services Cost

In addition to the cost of power purchases, ECG is required to pay for the transmission grid services provided by GRIDCo. The transmission service charge (TSC) has two components as follows:

(i) TSC-1 to recover the cost of transmission grid operations added value; and
(ii) TSC-2 to recover the cost of power lost in transmission.

In 2018, total power to be transmitted on behalf of ECG is projected at 11,121GWh which includes transmission losses of 622 GWh. Given that ECG's total purchases of 11,121GWh includes the cost of power lost in transmission, ECG is required to pay the Transmission Service Charge (TSC-1) only, to GRIDCo.

7.1.2.4 ECG TOTAL REVENUE REQUIRENT

The TARR is the revenue which ECG is expected to collect from consumer tariffs to cover all its costs including power purchases, transmission services, its own operating expenses as well as an allowance for non-collectible revenue which has been discussed above. Table 7-4 shows build-up of ECG's TARR approved for 2018.

Table 7-4 Summary of ECG's Total Annual Revenue Requirement

Item/Cost Center	PURC Approval (Million GHS)
Power Purchases (Incl. Trans. & Distr. System Losses)	4,779.47
Transmission Service Cost (Excl. Transmission Losses)	352.62
Total Power Purchases & Transmission Grid Service Costs	**5,105.09**
Administrative Costs	152.74
Operations & Maintenance Costs	296.48
Human Resource Costs	468.76
Depreciation	498.86
Return on Net Revalued Fixed Assets	93.01
ECG Annual Revenue Requirement (ARR)	**1,509.85**
Total Annual Revenue Requirement (TARR)	**6,614.94**

7.1.3 ECG'S TARIFF INCOME (TI)

The TI represents the total revenue that is generated from the approved rates that are applied to specific consumption bands. The targeted TI is inclusive of the non-collectible revenue. During the 2018 Tariff Period, the existing rates would be applicable from January to March 15th, 2018 (first tariff period) after which the new rates are applicable for the rest of the year, i.e. March 16th – December 31st, 2018 (second tariff period).

The Commission approved a target tariff income for ECG of GHc 6,747.24 million which is inclusive of the total annual revenue requirement and a 2% non-collectible revenue as shown in Table 7-5

Table 7-5 Summary of ECG Tariff Income

Item	PURC Approval (Million GHS)
Total Annual Revenue Requirement (TARR)	6,164.94
Non-Collectible Revenue (NCR)	132.30
Target Tariff Income	**6,747.24**

To estimate the annual target tariff income, the rates were modeled in 2 periods reflecting the period for the existing rates (January 1st –March 15, 2018) and the period during which the new rates are applicable (March 16- December 31, 2018). Electricity sales in the first and second Tariff Periods are estimated as 1,781.19 GWh and 6,740.01GWh respectively. The estimated TI for ECG for the first period based on the existing rates is GHc1, 674.96 million. The TI for the second tariff period based on the new rates approved by the Commission is estimated at GHc5, 238.42 million. The total TI revenue for the year 2018 (January – December) is estimated as GHc6, 913.38 million.

Table 7-6 Summary of Total Revenue Requirement and Tariff Income Profile for 2018 Tariff Period

Description	January 1st - March 15th	March 16th – December 31st	Total (Jan-Dee 2018)
Sales (GWh)	1,781.19	6,740.01	8,521.20
Tariff Income (TI) - (GHS' Million)	1,674.96	5,238.42	6,913.38
Total Revenue Requirement - (GHS' Million)			6,744.82
Average End-User Tariff (GHp/kWh)	94.04	77.72	81.13

7.2 Analysis of Costs and Tariffs for NEDCo

For 2018 tariff decision the NEDCo's ARR is expressed as follows:

ARR = Operating Expenses + Depreciation + Taxes + (Rate of Return × Rate Base)

Details of the Commission's analysis on the build-up of NEDCo's ARR are discussed below.

7.2.1 Annual Revenue Requirement (ARR)

NEDCo's ARR for 2018 is projected to be GHc433.89 million. These cover (i) administrative cost, (ii) operations and maintenance costs, (iii) human resource costs, (ii) depreciation and return on the RAB. Table 7-7 shows the cost build-up of NEDCo's ARR.

Table 7-7 Summary of NEDCO's ARR Build Up

Cost Center	Measure	Proposal	Approval
Administrative Cost	GHS Million	31.85	14.27
Operations & Maintenance Expenses	GHS Million	61.24	61.24
Human Resource Cost	GHS Million	128.18	128.18
Total Operating Cost	GHS Million	221.26	203.68
Depreciation	GHS Million	107.13	62.23
Return on Revalued Net Fixed Assets	GHS Million	105.5	15.45
Annual Revenue Requirement	GHS Million	433.89	281.36

NEDCo's ARR results in an average distribution added value (DAV) charge of 26.62 GHp/kWh. It should be noted that this excludes the NCR and system losses. Details of the various operational cost centers are discussed below.

7.2.1.1 Administrative Costs

NEDCo proposed an amount of GHc31.85 million to cover various administrative expenses in 2018. The Commission allowed administrative expenses of GHc14.27 million to be passed through the 2018 tariffs because it deemed it the most prudent and reasonable costs taking into account the companies administrative expenses in the previous years.

7.2.1.2 Operating & Maintenance Expenses

A total amount of GHc61.24 million proposed by NEDCo was fully allowed to cover NEDCo's operating and maintenance costs in the 2018 Tariff Period.

7.2.1.3 Human Resource Costs

The Commission allowed all the human resource costs of GHc128.18 million proposed by NEDCo to be included the 2018 revenue requirement.

7.2.1.4 Depreciation Expense

The Commission allowed depreciation expense of GHc62.23 million to be recovered directly from the tariffs representing 58% of what was proposed by NEDCo.

7.2.1.5 Return on Net Fixed Assets (RNFA)

A return on the revalued net fixed assets (RNFA) of GHc15.45 million was allowed which represents 1.2% percent on the Regulatory Asset Base (RAB).

7.2.1.6 Cost of Distribution Losses

The benchmark regulated total distribution system losses for 2018 are estimated at 21% of NEDCo's total electricity purchases of 1,338GWh. The total cost of the distribution losses is estimated at GHc127.82million, translating to an average cost of 9.6GHp/kWh. Similar to the case of ECG, the average cost of total distribution systems losses is prefixed as DSC-2 and is not applicable in the cases where the total purchases of the distribution utility include cost of total system losses.

7.2.1.7 Non-collectible Revenue (NCR)

The Commission provided an amount of GHc16.96 million (representing 2% of the NEDCo's ARR) for non-collectible revenue.

7.2.2 NEDCo's Total Annual Revenue Requirement (TARR)

In determination of NEDCo's TARR the following costs are considered:

(i) Cost of power purchases from electricity generators including all losses in the process of high voltage transmission as well as the electricity that is not billed owing to technical and commercial losses within the utility company's network,
(ii) Direct cost of operating the high voltage transmission system of the power to the consumers,
(iii) Costs of the utility companies' own operations (ARR), and
(iv) Specific costs that are allowed by the Commission to cover for sundry such as non-collectible revenue, etc.

The Commission approved a total annual revenue requirement in the sum of GHc878.24 million for NEDCo to cover all its costs including power purchases from VRA.

7.2.2.1 NEDCo's Power Purchases for 2018

NEDCo procures all its power requirements from VRA. In the 2018 Tariff Period, NEDCo has projected to purchase about 1,338GWh of electricity to meet the needs of its customers as well as provide for all losses in the transmission and distribution of the electricity.

The Commission approved an amount of GHc525.91 million to cover the total cost of electricity to be purchased by NEDCo in 2018. Table F.4 shows the cost build-up of NEDCo's electricity purchases in 2018. The sources and projected amount of electricity supply are based on the 2018 Electricity Supply Plan. The supply profile also considers the allocation of electricity from the Akosombo and Kpong hydro power plants approved by the Electricity Market Oversight Panel (EMOP) for the 2018 hydro cycle.

7.2.2.2 NEDCo Composite Bulk Generation Charge

The BGC represents the average cost of electricity purchased by NEDCo from all sources.

On the basis of the approved total cost of electricity purchased of GHc525.91 million, the BGC for NEDCo, in 2018, is estimated at of GHp39.29/kWh. The PURC has however applied the Composite BGC for all the distribution utilities of GHp 42.977 in the determination of NEDCo's total annual revenue requirement. The gazetted Composite BGC of GHp 42.977 is made up of VRA's BGC of GHp 28.9108/kWh which represents the weighted average cost of electricity supplied to NEDCo by VRA including the electricity from the Akosombo and Kpong hydro power plants.

Table 7-8 Summary of PURC Approved Power Purchase Costs for NEDCo

NEDCo Purchases incl. Trans & Dist Losses (GWh)			
Power Plant	**GWh**	**GHp/kWh**	**GHS**
Takoradi 1	-	38.1966	-
AMERI	-	53.6907	-
Tema 1	353	50.1033	176,864,649
Takoradi 2	680	46.1937	314,117,120
KTPP	10.4	43.6865	4,543,396
Hydro	295.12	10.2951	30,382,536
Total VRA Supply	**1,338.52**	**39.2903**	**525,907,701**
Karpowership	-	50.7078	-
SAP 1	-	51.8161	-
SAP 2	-	51.1063	-
AKSA	-	55.6013	-
Bui	-	45.3632	-
CENIT	-	74.8536	-
Cenpower		64.0086	-
Other WS	**-**	**-**	**-**
Total All WS	**1,338.52**	**39.2903**	**525,907,701**

It is important to note that the cost build-up accounts for all the associated system losses resulting from the transmission and distribution of electricity to final consumers. Table 7-9 shows the breakdown of total electricity purchases by NEDCo in 2018.

Table 7-9 Summary of PURC Approved Transmission and Distribution System Losses for NEDCo

Power Purchases	**GWh**
Final End-User Consumption	1,017.00
Transmission System Losses	51.00
Distribution System Losses	270.00
Total Purchases	**1,338.00**

7.2.2.3 NEDCo's Transmission Grid Services Cost

In addition to the cost of power purchases, NEDCo is required to pay for the transmission grid services provided by GRIDCo. The transmission service charge (TSC) has two components as follows:

(i) TSC-1 to recover the cost of transmission grid operations added value; and
(ii) TSC-2 to recover the cost of power lost in transmission.

In 2018, total power to be transmitted on behalf of NEDCo is projected at 1,338 GWh which includes transmission losses of 51 GWh. Given that NEDCo's total purchases of 1,338 GWh includes the cost of power lost in transmission, NEDCo is required to pay only the added value component (TSC-1) of the Transmission Service Charge.

The Commission has approved an amount of GHc 21.85 million for NEDCo to purchase transmission grid services from GRDICo. This is based on GRIDCo's average transmission service charge (TSC-1) of GHp3.0436/kWh for the 2018 Tariff Period. The amount represents only the transmission added value (DAV) of GRIDCo since the cost of electricity lost during transmission has been incorporated in the total cost of electricity purchased by NEDCo.

Similar to ECG, NEDCo's TARR is the total revenue required to be collected by NEDCo from the electricity tariffs charged to consumers in order to cover all its costs including power purchases, the cost of transmission grid services, its own operating expenses as well as an allowance for non-collectible revenue. Table 7-10 shows build-up of NEDCo's TARR approved for 2018.

Table 7-10 Summary of NEDCo's Total Annual Revenue Requirement

Item/Cost Center	PURC Approval (Million GHS)
Power Purchases (Incl. Trans. & Distr. System Losses)	575.03
Transmission Service Cost (Excl. Transmission Losses)	21.85
Total Power Purchases & Transmission Grid Service Costs	**596.88**
Administrative Costs	14.27
Operations & Maintenance Costs	61.24
Human Resource Costs	128.18
Depreciation	62.23
Return on Net Revalued Fixed Assets	15.45
Annual Revenue Requirement (ARR)	**281.36**
Total Annual Revenue Requirement (TARR)	**878.24**

7.2.3 Tariff Income for NEDCo

The Commission approved a target tariff income for NEDCo of GHc895.20 million which is inclusive of the total annual revenue requirement and a 2% non-collectible revenue. Table 7-11 shows the breakdown of NEDCo's target tariff income.

Table 7-11 Summary of NEDCo's Tariff Income

Item	PURC Approval (Million GHS)
Total Annual Revenue Requirement (TARR)	878.24
Non-Collectible Revenue (NCR)	16.96
Target Tariff Income	**895.20**

Electricity sales in the first (January 1st –March 15th, 2018) and second (Mach 16th –December 31st, 2018) Tariff Periods are estimated as 220.21GWh and 836.81GWh respectively. The estimated TI for NEDCo for the first period based on the existing rates is GHS201.33 Million. The TI for the second tariff period based on the new rates approved by the Commission is estimated at GHS594.51 million. The total TI revenue for the year 2018 (January – December) is estimated as GHS795.84 Million.

Table 7-12 Summary of Total Revenue Requirement and Tariff Income Profile for 2018 Tariff Period

Description	January 1st - March 15th	March 16th – December 31st	Total (Jan-Dee 2018)
Sales (GWh)	220.21	836.81	1,059.02
Tariff Income (TI) - (GHS' Million)	201.33	594.51	795.84
Total Revenue Requirement - (GHS' Million)			
Average End-User Tariff (GHp/kWh)	94.04	77.72	81.13

8.0 CONCLUSIONS AND WAY FORWARD

The utility companies must bring their operating costs to levels more in line with regulatory targets. Indeed, the budgets approved by the Board of the Utility Companies and actual expenditures of the utility companies must be brought within or guided by regulatory provisions. The ability of the utility companies to do this will enhance their liquidity and profitability.

The proposals presented by the utility companies show obvious structural dislocation and operational challenges because their cost structure reflects a significantly higher proportion of staff cost compared to operations and maintenance costs. This situation implies low penetration of modern technology which is a characteristic of modern electric utility business.

The utility companies need to reduce losses and increase collection in order to enhance their liquidity and profitability.

The concept of minimum cash flow reflecting provision of depreciation and return on regulatory rate base is intended to allow the utility companies to manage their debt obligations and other extraneous expenses within reasonable levels.

The Commission has received a number of submissions from stakeholders relating to the structure of electricity tariffs bordering on issues of inequity in the allocation of utility costs and subsidies. The Commission will undertake a thorough review of the current structure of electricity tariffs and during that exercise it will receive further related submissions from stakeholders.

Ancillary services are very important in the generation and supply of electricity to consumers. ASC refers to the provision of reactive power compensation, frequency regulation, reserves (both spinning and standing) which together are services that are required to support the supply of power as well as maintain system stability. The issue of bringing the costs of ancillary services into the mainstream electricity tariff setting mechanism has become critical in which regard the Commission has decided to promote the development of a viable market for ancillary services in Ghana. The Commission intends to proceed with pricing of ancillary services during the second part of the year, 2018.

9.0 KEY RECOMMENDATIONS

9.1 Distribution Utility Companies (ECG/NEDCo)

1. Utility companies must ensure their expenditures are within the annual revenue requirements approved by the PURC
2. ECG and NEDCo should take steps to aggressively reduce system losses
3. Increase efforts at revenue collection/mobilization in order to enhance liquidity at all times
4. Rationalise staff recruitment and expenditure
5. Prioritise capital investments
6. Take steps to improve quality of service delivery in respect of minimizing interruptions and duration when they occur

9.2 Government

1. Government should put in place a sustainable arrangement to ensure they honour their financial obligations to the utility companies particularly in respect of the electricity bills of MMDAs and other associated government entities
2. Rationalise fuel procurement and pricing for power generation.
3. Ensure full implementation of government's decisions regarding the rationalization of power purchase agreements (PPAs).

9.3 Ghanaian consumers

1. Ensure prompt payment of bills
2. Report illegal connections and theft of power

APPENDIX 1 - KEY ASSUMPTIONS

1. ASSUMPTIONS

Item	Measure	Value
Fuel Price:		
Natural Gas	US$/MMBtu	7.29
LCO (Including CIF)	US$/BBl	68
HFO (Including In-Plant Handling, Treatment & Related Fees)	US$/Metric Tonne	390
Exchange Rate	GHS/US$	4.43
Hydro Allocation:		
Akosombo	GWh	2,237
Kpong	GWh	373
Total	GWh	2,610
Transmission Losses	%	3.8
Distribution Losses	%	21
Collection Loss Ratio	%	98

APPENDIX 2 - REQUEST FOR SUBMISSION

PUBLIC UTILITIES REGULATORY COMMISSION

Public Input for the 2018 Major Tariff Review

In accordance with the Public Utilities Regulatory Commission Act, 1997 (Act 538), the PURC has initiated processes for the examination and approval of electricity and water tariffs for 2018. During the review the Commission will examine proposals to be submitted by utility companies. Interested organisations, groups and the general public are hereby invited to submit any inquiries or representations in respect of review of tariffs to the addresses below by 31 January 2018:

1. Public Utilities Regulatory Commission
   No. 53 Liberation Road 2nd. Floor, Olympic Committee Building
   Ridge, Accra

2. Public Utilities Regulatory Commission
   P. O. Box CT3095 Cantonments, Accra.
   E-mail: info@purc.com.gh Tel: +233 302 244181-3 +233 504434200

List of Entities which Submitted Written Inputs for 2018 Tariff Review

1. Trade Union Congress (TUC)
2. Association of Ghana Industries (AGI)
3. Africa Centre for Energy Policy (ACEP)
4. Ghana Institute of Management and Public Administration (GIMPA)
5. Electoral Commission (EC)
6. Private Enterprise Federation (PEF)
7. Ghana Journalists Association (GJA)
8. Vice Chancellors Ghana (VCG)
9. Central University (CU)
10. Ministry of Energy (MoE)

Major Joint Consultative Meeting with Utility Companies and Stakeholders
Alisa Hotel, Accra
February 12, 2018

List of Institutions that attended the program:

1 Central University College
2 Association of Ghana Industries (AGI)
3 Trade Union Congress (TUC)
4 Telecom chamber
5 Central University College
6 Association of Ghana Industries (AGI)
7 Integrated Social Development Centre (ISODEC)
8 Africa Centre for Energy Policy (ACEP)
9 Media General
10 Energy Commission
11 Imani Ghana
12 Private Enterprise Federation (PEF)
13 Trade Union Congress (TUC)
14 Consumer Protection Agency (CPA)
15 Ghana Journalist Agency (GJA)
16 Freelance
17 Select Committee on Mines & Energy
18 Ghana Grid Company (GRIDCo)
19 Northern Electricity Distribution Company (NEDCO)
20 Volta River Authority (VRA)
21 Electricity Company of Ghana
22 Ghana Water Company Limited (GWCL)
23 Enclave Power

APPENDIX 3 - RATES

		Unit	Rate
FIRST SCHEDULE			
Tariff Category			
BGC VRA	-	GHp/kWh	28.9108
Composite BGC (VRA and IPPs)	-	GHp/kWh	42.977
SECOND SCHEDULE			
Tariff Category			
TSC 1*	-	GHp/kWh	3.0437
TSC 2 - (GHp/kWh)		GHp/kWh	1.6976
THIRD SCHEDULE			
Tariff Category			
DSC 1	-	GHp/kWh	18.6638
DSC 2	-	GHp/kWh	12.0917
DWC	-	GHp/kWh	30.7555
FOURTH SCHEDULE			
EUT Tariff Category			
Residential			
0-50	-	GHp/kWh	27.6858
51-300	-	GHp/kWh	55.545
301 – 600	-	GHp/kWh	72.0866
601+	-	GHp/kWh	80.0963
Service Charge:			
Lifeline Consumers	-	GHp/month	213
Other Residential Consumers	-	GHp/month	633.1717
Non-Residential			
0-100	-	GHp/kWh	67.7536
101-300	-	GHp/kWh	67.7536
301 – 600	-	GHp/kWh	72.0971
601+	-	GHp/kWh	113.7598
Service Charge	-	GHp/month	1055.2862
SLT-LV			
Maximum Demand Charge	-	GHp/kVA/month	5909.6029
Energy Charge	-	GHp/kWh	75.664
Service Charge	-	GHp/month	4221.1449
SLT-MV			
Max. Demand	-	GHp/kVA/month	5065.3739
Energy Charge	-	GHp/kWh	58.5683
Service Charge	-	GHp/month	5909.6029
SLT-HV			
Max. Demand	-	GHp/kVA/month	5065.3739
Energy Charge	-	GHp/kWh	53.8196
Service Charge	-	GHp/month	5909.6029
SLT-HV MINES			
Max. Demand	-	GHp/kVA/month	5909.6029
Energy Charge	-	GHp/kWh	102.5739
Service Charge	-	GHp/month	5909.6029