PROPOSED TARIFF REVIEW FRAMEWORK, GUIDELINES AND PROCEDURES FOR PUBLIC ELECTRICITY SUPPLIERS.

Consultation Document

ES: 02/2021

ISSUE DATE: 10 March 2021

RESPONSE DATE: 15 April 2021

ABSTRACT

On 1 May 2018, Bahamas Power and Light Company Limited (BPL) was issued a new licence, the Electricity Licence, 2016 (the Licence). The Licence has introduced several changes in the regulatory framework governing the electricity sector. Additionally, the Licences for the Authorised Public Electricity Suppliers (APESL) has introduced several changes in the regulatory framework governing the electricity sector. The two most notable changes are:

(1) Price Controls Mechanism and Tariffs - URCA shall determine BPL's rates for electric power pursuant to URCA's powers under the EA as amended from time to time and on the principles set out in its Licence; and
(2) Separated Accounts - BPL shall maintain separate accounts for Generation, Transmission, Distribution and Supply services, in order to assist in tariff setting.

Further, it is noted that the Government of The Bahamas created and by virtue of the 2018 Amendment to the Electricity Act, 2015, preserved a regulatory exclusion period regarding BPL's rate until 2021. URCA proposes to proportionally adopt the same general tariff review framework to the APESL.

The Price Controls Mechanism and Tariffs requires that (1) URCA shall conduct a tariff review for BPL in accordance with the procedure set out under section 20 of the Electricity Act, 2015 (EA); and (2) BPL shall comply with the processes and timelines established by URCA for tariff reviews. URCA proposes to apply the same principles to the APESL albeit the timeline for tariff review may differ from that of BPL.

In accordance with section 20 of the EA, URCA's remit is that rates be based on, among other things, the requirement of a rate reduction bond fee, revenue and demand and where necessary, a detailed plan and justification for investment in necessary systems upgrades. Consequently, the Licence stipulates that BPL shall develop any expansion plans in consultation with the Government and submit to URCA for approval, when satisfied that the plan represents the least economic costs for the electricity supply system expansion. To ensure consistency for tariff setting across the Islands, URCA proposes to proportionally apply the same principle to the APESL. The EA requires that URCA consults with stakeholders on issues of public significance. Consequently, the purpose of this Consultation Document is to present a framework outline of the principles, methodologies and procedures that URCA proposes to use in the rate setting exercise and to elicit comments and inputs from all stakeholders. All responses and comments will be taken into consideration in the process of development and promulgation of a final decision.

ACRONYMS, ABBREVIATIONS AND DEFINITIONS

AFUDC -	Allowance for Funds Used During Construction
APESL -	Authorised Public Electricity Supplier
Base Year -	The latest twelve months of operation of the Licensed Business for which there are audited accounts adjusted to reflect: 1) Normal operation conditions, if necessary; 2) Such changes in revenues and costs as are known and measurable with reasonable accuracy at the time of filing and are demonstrated as part of the Business Plan. The Base Year shall represent the first year of the Business Plan
Business Plan -	The five (5) year plan incorporating, among other things, the Final Criteria set by the Office and the Integrated Resource Plan (IRP) which forms the basis for the Rate Review Process to establish the non-fuel rates.
CAIDI -	Customer Average Interruption Duration Index
CAPM -	Capital Asset Pricing Model
CCGT -	Combined Cycle Gas Turbine
CIS -	Customer Information System
CPI -	Consumer Price Index
CAIDI	Customer Average Interruption Duration Index
CWIP -	Construction Work In Progress
EA	Electricity Act, 2015
PESL	Public Electricity Suppliers Licence
PES	Public Electricity Supplier
GoB	Government of The Bahamas
IPP -	Independent Power Producer
IRP -	Integrated Resource Plan

KPA	Key Performance Area
KPI	Key Performance Indicator
kWh	Kilowatt-hour
MW	Megawatt
MWh	Megawatt-hours
NEP	National Energy Policy
O&M	Operating and Maintenance
OPEX	Operating Expenses (prudently incurred)
PBRM	Performance Based Rate-Making Mechanism
PPA	Power Purchase Agreement
PPE	Property Plant and Equipment
Project Model	A file in Excel format, which specifies, inter alia, all costs and costing assumptions used in determining the projects that are being proposed in the Business Plan
RAB	Regulatory Asset Base
RE -	Renewable Energy
Rate Review Process	The five (5) year rate setting process of the Office to determine the non-fuel rates to be charged by the Licensee as well as the targets related to the Licensee’s performance.
Rate Review period	The five (5) year period being considered in the Rate Review Process.
Regulatory Accounts	The reports on the financial and operational performance of the Licensee in such detail and format as designed by the Office.
Revenue Cap	The revenue requirement approved in the last Rate Review Process as adjusted for the rate of change in non-fuel electricity revenues
ROE	Return on Equity
ROI	Return on Investment
ROR	Rate of Return
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
T&D	Transmission & Distribution

TOU	Time of Use
WACC	Weighted Average Cost of Capital
URCA	Utilities Regulation and Competition Authority

1.0 INTRODUCTION

The Utilities Regulation and Competition Authority (URCA) is the independent regulator and independent authority for the Electricity Sector (ES) in The Bahamas. URCA regulates the ES in accordance with the Electricity Act, 2015 (EA), which includes inter alia the functions and powers to issue regulatory and other measures to regulate the sector. Hence, URCA is responsible for the technical and economic regulation of the Electricity sector. URCA's role generally involves regulating prices, service standards, market conduct and consumer protection. URCA also investigates and issues Orders on regulatory matters that affect the ES.

In undertaking the tariff review, URCA's objective is to build a methodology, procedure and guidelines for negotiating and establishing tariffs that both accords with the Public Electricity Supply Licence (PESL) and meets standards for good regulatory practice. The proposed guidelines, procedures and methodology include clarifying the process for resetting tariffs in the future and establishing an appropriate financial model to be used for tariff resets. URCA hereby proposes to develop the methodology in consultation with BPL and key stakeholders in a manner that considers the need for openness and transparency, while also being reasonably efficient.

The rationale for the tariff review is to assess the continuing appropriateness of tariffs, both in terms of their level and structure. URCA's aims to find the right balance between the interests of the consumers of The Bahamas, of the utility, and of the Government. In short,

- consumers should not pay more than necessary to receive electricity service of a given standard;
- the utility should be able to charge tariffs in such a manner that it can cover all its prudently incurred costs, and this includes operating, maintenance and investment costs; and finally,
- the government needs to keep the long-term growth and economic development of The Bahamas in view and thus wants present tariffs to support improvements and future investments in electricity supply.

To assess whether tariffs are appropriate to balance the concerns of all stakeholders, URCA proposes the following process and methodology:

- the costs of the utility are reviewed in order to determine what the minimum revenue requirement is for electricity supply to operate in a commercially viable manner;
- the cost information gathered from BPL to inform what level of expenses are associated with the provision of services will be cross-checked by URCA staff/Consultant on the basis of known and measurable costs and using benchmarking information. This will allow URCA to assess BPL's costs of electricity supply compared to other similar countries;
- the appropriateness of costs is intimately linked to the quality and reliability of service that consumers request, and the level of safety that is imposed. Service standards are therefore reviewed for their appropriateness at the same time as company costs;
- in order to determine whether the medium to long term growth and development concerns are addressed, a forward-looking assessment of consumer demand (commercial and residential) and future network investments is undertaken; and
- regarding forward-looking investments, it is also highly relevant to assess renewable generation technologies such as wind or solar.

Given the considerations set out above, the required revenues to cover present and future costs of electricity supply will be calculated by URCA. The instrument to calculate the revenues will be a financial and economic model tailored to The Bahamas.

URCA believes that while this tariff rate review framework has the advantage of being more proactive in its orientation, it will rely to a significant degree on the capacity of BPL and URCA to impose charges for electricity having regard to reasonably incurred operating and fuel costs.

Against this background, the Rate Review Process is likely to be a rigorous and time consuming one, which in order to be effective must begin at least twelve (12) months prior to the actual submission of the Rate Review application by BPL.

The proposed Tariff Review framework is designed to provide a consultative guidance to BPL with respect to the elements of the tariff mechanism that are integral to the Rate Review Process. In this respect, it provides a channel for stakeholders in the industry to discuss critical issues related to the tariff, thereby minimizing the risk for significant disputes after the rates are determined by URCA.

In arriving at the Tariff Review Framework, the Licence requires that URCA consults with stakeholders. Accordingly, this proposed Framework is to seek consensus on the tariff principles, methodology, and the tariff review elements that are to be included in setting the tariff levels.

1.1 Purpose of this Framework consultation

The consultation seeks comment on the following key issues:

I. Framework and procedure for determining the revenue required and the cost of service for the PES

   Having established the outcomes that must be delivered, the revenue requirements, which are sufficient to enable the PES to deliver these outcomes are efficiently, are then determined. The building blocks approach involves building up BPL's revenue from key components that reflect the operating and maintenance costs and financing requirements. PES's financing costs (return on and of capital) are built up with reference to the rolled forward value of the regulatory asset base and the capital expenditure that PES must undertake.

II. Framework for translating the revenue requirement into a price control

   Having determined the revenue required, it is then translated into unit prices using forecasts of energy consumption and customer numbers. This is then translated into specific tariff proposals in accordance with a price control mechanism which specifies how prices will be adjusted annually. The building blocks approach is broadly consistent with other jurisdictions on setting tariffs. While different jurisdictions may use different terms, in essence, it is concerned with allowing an operator to recover a reasonable cost of service, and often uses forward looking estimates of reasonable costs as a basis for tariff resets. URCA in consultation with the PES and key stakeholders, will further explore the possibility of bringing these concepts together, and assess whether such an approach would be acceptable to all concerned.

URCA has set out specific issues on which stakeholders are invited to comment. However, stakeholders should make any other comments that they wish, which may not be covered by the issues raised in this consultation document.

1.2 How to Respond to this Consultation Document

URCA invites comments on this document from all interested parties. Responses to this document should be submitted to URCA by 5:00 p.m. on **15 April 2021**. Written responses or comments on this document should be sent to URCA's Chief Executive Officer, either:

- By hand, to URCA's office at Frederick House, Frederick Street, Nassau;
- By mail to P.O. Box N-4860, Nassau, Bahamas;
- By fax, to (242) 393-0153; or
- By email, to info@urcabahamas.bs.

URCA reserves the right to make all responses available to the public by posting responses on its website at www.urcabahamas.bs. If a response is marked confidential, reasons should be given to facilitate evaluation by URCA of the request for confidentiality. URCA may publish or refrain from publishing any document or submission, at its sole discretion.

URCA will review all responses and comments received from this consultation document before publishing its Statement of Results and the Final Decision.

Consultation Timetable

The timetable for the consultation is summarized in the table below:

Event	Date
Publish Consultation Document	10 March 2021
Responses to Consultation Document	20 April2021
Comments on Responses to Consultation Document	12 May 2021
Publication of Results and the Final Decision	25 May 2021

1.3 Structure of the Remainder of this Document

The remainder of the document is structured as follows:

1) Legal and Regulatory Framework – discusses URCA's authority to conduct BPL's Rate Review Process
2) Rate Review Framework – identifies the basis on which the PES tariff will be established for the ensuing five-year period
3) Approach to Tariff in the region – outlines elements of tariff framework in effect in the some Caribbean Islands
4) URCA proposed Tariff Review Framework – outlines URCA's proposed tariff review framework for the PES
5) Information and Supporting Documents – outlines the proposed information and documentation framework required with PES Tariff Review submission

6) Proposed Tariff Review Procedure – outlines URCA procedure for reviewing and evaluation a Tariff Review submission for a PES
7) Conclusion and next steps

2 LEGAL AND REGULATORY FRAMEWORK

The following section sets out the legal and regulatory remit of URCA as encapsulated by the EA and the BPL licence.

Under various provisions of the EA and additional legislations, URCA may develop and enforce regulation and conditions with respect to rates, tariffs and other charges for the provision of utility services.

URCA is tasked under the EA to carry out various duties and functions as the regulator of the electricity sector in The Bahamas. Pursuant to section 74 of the EA and Condition 24 of the PESL, URCA may specify the framework as it relates to the procedures and guidelines for a Public Electricity Supplier (PES) to furnish such information and to submit such returns in relations to their operations and at such intervals as URCA may require. Additionally, section 20 of the EA outlines URCA's role in determining the rates and scales of charges for electricity by BPL and Part G, Condition 52 of the BPL Licence outlines URCA's role in determining the Price Controls Mechanism and Tariffs.

2.1 GOVERNMENT POLICY

The Government of The Bahamas (GoB) National Energy Policy (NEP) sets out the strategic aims for meeting the electricity sector policy objectives. The strategic aim includes but not limited to:

- Plans for the efficient use and supply of safe, least cost, reliable and environmentally sustainable electricity.

Consistent with the aims and goals of the NEP, shall be, among others, the:

a) Provision of safe, least cost electricity supplies to all consumers.

b) Advancement to The Bahamas' economic growth and development and international competitiveness.

c) Enhancement of the energy security of The Bahamas.

d) Encouragement of competition in the generation of renewable electricity.

e) Introduction of a structure for the sector that is overseen by an independent regulator.

2.2 THE ELECTRICITY ACT, 2015 (EA)

2.2.1 Rates and scales of charges for electricity by BPL

Section 20 of the Electricity Act, 2015 (as amended by the Electricity (Amendment) Act 2018) states:-

“

(1) Subject to subsections (6), BPL shall in accordance with an approval granted by URCA impose fixed charges for electricity sold in bulk or direct to customers, and for additional services rendered by BPL, having regard to reasonably incurred operating and fuel costs.

(2) UCRA shall, in determining the tariff rate, have regard to -

  (a) The requirement of a rate reduction bond fee; and

  (b) The need for revenue derived by BPL from sales, services and other sources to be sufficient to pay –

    i. All other expenses and obligations of BPL properly chargeable to income;

    ii. payments due to be made in respect of interest or principal of money borrowed by BPL, whether or not there is a continuing economic return on the money borrowed;

    iii. Sums required for redemption of securities issued by BPL under section 21;

    iv. Such sum as may be required for a reserve fund, extensions, renewals, depreciation, loans and other like purposes.

(3) Subject to the approval of URCA, BPL may, where no undue preference is given to any class of customer or locality, fix the charges under this section at different rates and scales for different classes of customers, including residential, commercial, general service and other service categories.

(4) BPL may submit to URCA, where necessary, a detailed plan and justification for investments in necessary system upgrades that include, for URCA's consideration proposals for cost recovery through the tariff rate.

(5) URCA may modify the tariff rate for electricity supply services by BPL to take account of significant and unforeseen increases or decreases in costs occurring during any twenty-four-month period.

(6) Without prejudice to subsection (5), URCA shall for a period of three years adopt and apply the tariff rate for electricity supply services recommended by BPL.

(7) BPL shall within three months of the date of the commencement of this Act file with URCA the tariff rate for electricity supply services.”

2.2.2 Role of URCA[1]

The primary role of URCA is the regulation of the electricity sector in accordance with the goals, objectives and principles underpinning the national energy and electricity sector policies.

[1]Electricity Act, 2015, section 37(1)(2)(m)

URCA in regulation of the electricity sector shall… "provide for and carry out periodic rate review" among other things.

2.2.3 Functions and powers of URCA

Section 38(a) of the EA states that the functions and powers of URCA are to-

"

(a) review and determine that the rates and scale of charges comprising the tariff rate for electricity supply services proposed by a public electricity supplier are reasonable, reflect efficiently incurred costs and are not inconsistent with or in contravention of the Act or any other law and allow an opportunity for public input."

Subsection 38(3)(i)-(j) states that URCA may issue regulatory and other measures, including without limitations, as follows: –

"

(i) requiring any licensee to furnish such information and submit such returns in relations to the operations at such intervals as it may require;

(j) conducting market investigations and market reviews and publishing regular information and reports."

2.2.4 Consumer Protection

Section 40 (9) states that a licensee shall –

"

(a) Monitor its performance against such key performance indicators as may be set out in its licence or in any regulatory measures issued by URCA; and

(b) Pursuant to a written request made by URCA, publish and provide in a manner required by URCA its performance results against the relevant key performance indicators."

2.2.5 Determination by URCA

Section 64 of the EA gives URCA the remit to make determinations where URCA sees it necessary relating to the terms and conditions of a licence, including obligations in licence conditions, regulatory and other measures, standards or technical rules.

2.2.6 Power to request information

Section 74 of the EA gives the URCA the power to request information. Subsection (2) states that when requesting information, URCA shall inter alia –

(a) state the legal basis and purpose of the request;

(b) specify what information is required;

(c) fix the time limit within which information is to be provided; and

(d) state that a person who fails to provide information as and when lawfully requested to do so, or supplies incorrect or misleading information, commits an offence.

2.3 LICENCE CONDITIONS

2.3.1 General Conditions

The general conditions or the PESL further states that "*the Licensees shall comply with regulatory and other measures including any directive, order, rule, decision or approval issued, made or granted by URCA in accordance with their duties and functions under the Act or their Licence*".

Condition 5.1 of the PESL and APESL outline the role and duties of URCA. It states that the Licensee shall be subjected to the regulatory supervision of URCA. URCA shall perform its functions and carry out its duties pursuant to the URCA Act, the EA and any other relevant laws, the licence and have regard to relevant Government policy.

2.3.2 Reporting Obligations

Condition 24 of the Licence outlines BPL's reporting obligations. In particular, Conditions 24.2, 24.3 and 24.8 respectively state:

> 24.2 "URCA may require the Licensee to maintain separate Regulatory Accounts for regulatory reporting and tariff analysis."
>
> 24.3 "The Licensee shall furnish to URCA without delay such information, documents and details related to the Licensed Business, as URCA may reasonably require in order for it to fulfil its functions and discharge its obligations under the Act."
>
> 24.8 " The Licensee shall, annually, provide URCA with its capital investment plan and updated five year capital investment plan."

2.3.3 Engaging in other business

> 26.1 "The licensee may engage in other business activities and shall keep separate accounts for its different activities. The licensee's profits and losses from such other business activities shall not be considered for the purpose of setting tariffs."

2.3.4 Price controls mechanism and tariffs

> Part G, Condition 52 outlines the Tariff Principles - "URCA shall determine the Licensee's rates for electric power pursuant to URCA's powers under the Act as amended from time to time and on the principles set out therein."

Conditions 53.1 and 53.2 of the BPL licence stipulates the respective tariff reviews as follows:

> "53.1 URCA shall conduct a tariff review for the Licensee in accordance with the procedure set out under section 20 of the Act," and
>
> "53.2 The Licensee shall comply with the process and timelines established by URCA for tariff reviews."

3 RATE REVIEW FRAMEWORK

PES tariffs have traditionally been set on the basis of two components – fuel and non-fuel. URCA, as prescribed by legislation, namely EA, and the PESL has the remit to approve a tariff methodology and approve tariffs submitted by PES within that methodology.

Section 20(2) of the EA gives URCA the remit to determine the tariff rate and in so doing have regard to -

(a) The requirement of a rate reduction bond fee; and

(b) The need for revenue derived by PES from sales, services and other sources to be sufficient to pay for the Cost of Service.

This section outlines the general framework and methodology for negotiating and establishing tariffs that both accords with the Public Electricity Supply Licence (PESL) and meets standards for good regulatory practice.

3.1 Tariff Setting –Principles and Procedures[2]

In the power sector, tariff setting is a vital process of resource management for the utility's survival and growth and delivery of efficient service to consumers. An important factor, which has material bearing in pricing of electricity, is that it cannot be stored to meet fluctuations in demand, additionally, the service is intangible. A utility is expected to pursue profits, and other nonfinancial objectives like consumer service, technological excellence, growth and human resources development. These multiple objectives are to be harmonized without affecting commercial viability. The choices made while designing the tariff are difficult and costly to reverse and the decisions have far-reaching and long-term implications for a utility, consumers and the country. Internationally, the principles that have underpinned tariff design are as follows:

I. Effectiveness of yielding total revenue
II. Stability and predictability of revenue
III. Stability and predictability of rates
IV. Discouraging wasteful use of services
V. Understanding the present and future private and social costs and benefits of service provided
VI. Fairness of rates in the apportionment of total costs of service among different consumers
VII. Avoidance of discrimination of rates
VIII. Promotion of innovation and cost-effectiveness in the face of changing demand and supply patterns
IX. Simplicity, comprehensibility, public acceptability and feasibility

3.1.1 Tariff design Methodology

Internationally three methodologies have generally been adopted towards price control. These are -

[2] Reference http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/NERA_Electricity_Tariff_Structure.pdf

1. Cost Plus or Rate of Return Regulation
2. Performance Based or Incentive Regulation
3. Hybrid Approach

The older of the three is termed “Cost Plus or Rate of Return Regulation” in which prices are fixed at a level which will provide the investor with a target rate of return on investment and adjusted up or down over time as the rate of return respectively falls below or rises above the target rate. Rate of Return Regulation is essentially a process of balancing costs incurred by the utilities and future estimated revenues.

Performance Based or Incentive Regulation is an extension of Cost Plus approach that provides incentives for improving efficiency and reducing costs.

Hybrid Approach is a performance based cost of service approach by considering actual cost and normative parameters specified in the regulations.

Price Cap, Revenue Cap and Hybrid Approach regulation are a form of Performance Based Ratemaking Mechanism (PBRM) which became popular worldwide after it was introduced in Britain in the 1980s. Performance based regulation could include: quality of service, operating standards such as plant load factor, T&D losses management, O&M expenses per customer etc. as well as quality of service indices such as duration of outages and blackouts.

Performance based regulation methods most often are in the form of Price Cap and/or Revenue Cap. In Price Cap regulation, a formula is specified where the average price[3] is allowed to increase at a rate that is no more than the inflation rate, usually as measured by the consumer price index. Revenue Cap - attempts to do the same thing, but for revenue rather than prices. This method places an upper limit on revenues, thereby, constraining the price indirectly. Revenue Cap regulation is preferred for utilities that face high fixed costs.

Normally prices are required to increase slower than the rate of inflation because of expected efficiency improvements (i.e. real unit cost reductions). This approach is often referred to as CPI-X (“X” referring to the defined efficiency factor). Under certain circumstances, for example where considerable investment in infrastructure must be undertaken, the price increases permitted may exceed the rate of inflation (in which case the formula would be CPI+X). The tariff adjustment formula is reviewed by the regulator at fixed intervals, usually four to five years, primarily to determine the value of X, but also to adjust the structure of the price cap mechanism to changing circumstances. If there were conditions of high inflation, the price cap formula would allow significant automatic increases in nominal prices (although, if the formula were CPI-X, there would be reductions in real prices, i.e. net of inflation). In this respect, however, the price cap would not necessarily differ materially from rate of return regulation. The inflation would lead to an increase in the utility’s costs through higher operational expenses, such as labour costs, and higher capital costs, because of the revaluation of assets. In such circumstances, the utility would be permitted price increases to maintain its rate of return. Price cap regulation

[3] The weights to be used to compute the average price need to be defined (e.g. a common approach is for the weights to be the volume share of each service in the prior financial year).

is, in reality, not the means by which prices are initially determined, but rather a methodology by which tariffs are adjusted over time from a previously accepted level. Therefore, the starting level of prices will be an issue to be addressed. If it is considered that the current level of prices are too low to provide an adequate rate of return, the price cap could be used to smooth the transition to higher prices, e.g. by choosing a value of X below the expected real unit cost reductions.

Key issues in defining a price cap mechanism are how the rate of inflation is to be determined, the initial value of X (the factor by which increases in tariffs will lag inflation), the weights in the computation of the average price, and the frequency of tariff reviews.

One potential disadvantage of price caps/revenue caps is that the investor may feel exposed to greater "regulatory risk" than under rate of return regulation. This risk does not relate to the initial details of the price cap, such as the value of X, so long as these are pre-announced but investors may have a concern about factors such as how subsequent values of X will be set, who will be setting them, how much credibility that body has as an impartial regulator, what rights of appeal exist and how credible and impartial they are among other concerns.

There are various advantages of price caps. First, price caps provide the utility operator with an incentive to improve efficiency. This is initially to the benefit of the investor, as lower costs feed through into higher profits (this is the source of the incentive). But, later on, at the periodic price control reviews, consumers obtain a share of these benefits through price adjustments or higher values of X. This is a tried and proven feature of price caps and it is often the case that the efficiency improvements achieved greatly exceed the initial expectations at the time of the introduction of price caps/revenue caps.

Price caps also involve less intrusive regulation. Under price caps, the regulated company can choose the timing and frequency of price changes, and the structure of prices[4]. There may be restrictions to this flexibility, but they must be explicitly identified in the price cap formula. It also requires less direct supervision and intervention by the regulator.

3.1.2 Determination of Revenue Requirement [5]

The Regulatory process for tariff determination consists of two steps. The first step is the determination of revenue requirement of the utility. The second step is the design of the tariff elements which, when multiplied by sales, produce the allowed revenue that the utility can collect from customers. The allowed revenue should be equal to the revenue requirement to enable the utility to recover its costs. There are three general approaches for determining the revenue requirement:

a) Actual historic accounted for costs and sales volumes;
b) Estimated future costs and forecast loads; and
c) Estimated marginal costs (usual long-run incremental costs) and forecast loads

[4] Structure here meaning differences in prices between customer groups, or geographically, or by time of day etc.

[5] Reference:
http://documents1.worldbank.org/curated/en/648501468218416920/pdf/ACS48450WP0P120cial0use0only0900ACS.pdf

The main difference between these approaches is in the choice of a "test year," i.e., the period over which the utility's cost of supply and sales are measured.

Historic Test Year defines a specific 12-month period as the latest twelve month period for which audited financial statements are available as the historic test year, which may become the basis for assessing the costs of supply and sales of electricity. The costs and sales of the historic test year may be then adjusted for "known and measurable changes". Examples of known and measurable changes are an increase in power purchase cost due to a new PPA, a change in tax laws, or a decrease in load due to an exit from the system of a major industrial customer. This approach is being traditionally used in the Caribbean and Indian power sector and some jurisdiction in the United States.

Future Test Year defines a projected 12-month period as the projected twelve month period which may become the basis for assessing the costs of supply and sales of electricity. Future test years come from the utility's forecasted budget. The utility may not be able to produce forecasts with sufficient degree of reliability nevertheless, the costs and sales of the future test year may be then adjusted for "known and measurable changes".

Estimation of marginal cost. This approach reflects the cost of expanding the system efficiently to satisfy the load forecast over a long time horizon. Estimation of long-term marginal cost is difficult and sensitive to many subjective assumptions that must be made during the estimation process.

A test year is restated to the extent necessary (or permitted) to produce the data considered reflective of conditions during the period rates which are to be in effect The adjustments that need to be made to the test year are generally classified as:

- Regulators' prescribed adjustments
- Accounting adjustments
- Pro forma adjustments

Pro Forma adjustments are usually made to reflect an ongoing change and are typically made to historic test year data. This form of adjustment should be readily reconcilable to the test year without creating serious possibilities of distortion or mismatching. Typical pro forma adjustments include:

- Normalization - restate the period data for abnormal conditions
- Annualization - extend over the period, or eliminate from the period, events that had partial period effects and are either recurring or have terminated
- Out-of-period - required when an event is recorded in one period but applies to another period
- Reclassification - add or remove items for purposes of rate recovery

Tariff setting in some countries[6] stipulates that the non-fuel revenue requirement shall be based on a test year in which the new rates will be in effect and shall include efficient non-fuel operating costs, depreciation expenses,

[6] Some jurisdiction even Jamaica Public Service Company Limited (JPS) 2001 Licence Schedule 3, section C prescribed the requirement of a "Test Year" used for the tariff setting Revenue Requirement.

taxes and a fair return on investment. It is sometimes referred to as cost-plus pricing because the regulated entity is able to collect all its cost, plus a regulated return on its investment from consumers. In general this method permits the total revenues allowed to the utility, under the following formula:

RR = [RB x ROI] + ED + O&M + I + T

Where:

RR	= the total annual non-fuel revenue requirement of the utility
RB	= the rate base (required investment) of the utility
ROI	= the allowed rate of return (debt and equity) on investment (Rate Base)
ED	= expense on annual depreciation
O&M	= expense on non-fuel annual operation & maintenance (O&M)
T	= annual taxes, if any, paid by the utility

<u>Return on Investment (RoI)</u>

The ROI is the product of the utility's Rate Base (RB) and its Weighted Average Cost of Capital (WACC). Mathematically, this may be expressed as:

$$ROI = RB \text{ } x \text{ } WACC$$

Where:

RB	= Rate Base
WACC	= Weighted Average Cost of Capital

WACC combines the approved rate of return (ROR) of all category of funds in the business in proportion to each funds' contribution to the actual or deemed capital structure to yield a single ROR for the company. WACC (pre-tax) may be expressed as[7]:

$$(pre{-}tax) = (D/D{+}E) + r_E/(1{-}t)(E/D{+}E)$$

Where:

r_D	= Cost of debt
r_E	= Rate of return on equity (or ROE)
D	= Value of debt in the capital structure
E	= Value of equity in the capital structure
t	= Tax rate.

<u>Cost of Debt</u>

The cost of debt should be based on the weighted average borrowing cost for the Utility's long-term debt. This is consistent with the practice in most regulatory jurisdiction. Additionally, all prudently incurred costs associated with the issuance of debt such as commitment fees, arrangement fees, due diligence fees, breakage costs and refinancing fees should be included in the non-fuel operating costs/expenses.

[7] Note, $(D/D{+}E)$ represents the 'gearing ratio'.

Rate of Return on Equity

The Capital Asset Pricing Model (CAPM), Dividend Growth Model and the Market to Asset Ratios method approach have been the methodologies adopted for the determination of Return on Equity (ROE). While there has been broad acceptance of these approaches, there have been disagreements with respect to the interpretation and application of specific components of the methodologies.

<u>Comparison of ROE Methodologies</u>

The methodologies were compared and a summary from the comparison is outlined below;-

- CAPM has very *strong theoretical underpinnings* that are supported by empirical evidence for explaining stock returns, including those in emerging markets.
- The *practicality of its use in the Bahamian context* particularly, as it relates to access to relevant data.
- It affords *balanced regulatory discretion* regarding the estimation of the parameters in the CAPM formulation.

In general, the data required for estimating the ROE under the CAPM is readily available and the application of different methodologies for estimating individual parameters has been extensively debated in international regulation. In this regard, the CAPM methodology will allow utility to draw on international best practice in the calculation of the ROE.

<u>Rate Base</u>

The Rate Base is the value of the net investment in the Licensed Business. Normally Utility Rate Base includes the assets that are in use, will be expected to be in use over the Rate Review period and are deemed useful in providing electricity services to its customers. The Rate Base shall be based on the approved net book value of the utility's assets for the review period as informed by the Business Plan.

$$\boldsymbol{Rate\ Base} = \boldsymbol{Property\ Plant\ and\ Equipment} + \boldsymbol{Intangible\ Assets} + \boldsymbol{Working\ Capital} + \boldsymbol{Long\ Term\ \ Receivables} + \boldsymbol{Other\ Assets} - \boldsymbol{offsets}$$

The components of the Rate Base identified in the above formula shall be as follows:

a) The Property Plant and Equipment ("PPE") ; along with the net book value of the company's assets this shall also include construction work in progress; offset by impaired assets, customer financed assets, less revaluation balance/capital reserve;

b) Intangible Assets (i.e. assets that are not physical in nature e.g. copyright, software licences);

c) The working capital (i.e. accounts receivable + cash & short term deposits + tax recoverable + inventory – account payable – customer deposits – bank overdraft – short term loans) deployed;

d) Long Term Receivables;

e) Other Assets; and

f) Offsets which, refer to:
   - Employee benefit obligations; and
   - Deferred revenue.

Operation and Maintenance Costs (O&M)

Generally regulators see O&M costs as all prudently incurred costs which are not directly associated with investments in capital plant and other operating costs, which shall include but not be limited to,

- salaries and other costs related to employees;
- operating costs of generation, transmission and distribution and supply facilities;
- power purchase costs and other related costs including but not limited to working capital and credit support charges incurred under approved PPAs, fuel supply agreements and other related infrastructure arrangements;
- interest and other financial costs on other borrowings and working capital requirements not associated with capital investment; foreign exchange results loss/(gain); rents and leases on property associated with the Licensed Business;
- taxes which the Licensee is required to pay other than income taxes of the Licensee; and
- other costs which are determined to be reasonably incurred in connection with the generation, transmission and distribution and supply of electricity.

Depreciation expense[8]

The regulatory literature defines depreciation, essentially, as the decline in or loss of value in an asset. Depreciation is also a systematic and rational accounting process that is used to allocate (not valuate) tangible capital assets less salvage value (if any), over the estimated useful life of the item. The costs are allowed operating expense, which results in the reduction of the Rate Base. Depreciation represents a non-cash expense but regulators typically allow it to be recovered through tariff so that energy companies have some funds with which to renew or replace old assets.

Under this general RR framework, the utility has the responsibility of proving to the regulators' satisfaction that each proposed element of the RR is prudent. Utility proposed revenue requirement ought to be based upon the values of the terms used in the formula during a "Test Year" and as is the practice in rate case proceedings, adjusted for known and measurable changes in accounting principles as recommended by their independent auditors.

3.1.3 Cost of Service and Consumer Tariff Design[9] [10]

Generally in the Electric utilities, an integral part to setting a tariff is the method for allocating costs across categories of users. Unless the costs to be recovered are allocated appropriately then the tariff structure for an individual customer category will not reflect the appropriate costs. After the total revenue requirement of the

[8] Ref:http://documents1.worldbank.org/curated/en/648501468218416920/pdf/ACS48450WP0P120cial0use0only0900ACS.pdf

[9] Ref:Dover_Electric Rate Study_FINAL_04-27-18

[10] https://www.our.org.jm/ourweb/sites/default/files/documents/sector_documents/jps_tariff_review_determination_notice_-_june_25_2004_0.pdf

utility / licensee is determined, it is necessary to assign the total requirement to various class of services and to fix tariff within those classes. There are broadly at least three approaches to tariff setting identifiable in the industry. These are:

Average Historical Cost Approach

The average historical cost approach entails taking the expenses actually being incurred or allowed by the energy regulator and a return on capital invested in the past as a starting point. This bucket of revenue is classified as being related to demand, energy consumption, and number of customers being served. The classified costs are then allocated across the various customer classes based on measures of their demand, energy use, and customer counts. The classified and allocated costs are then converted to tariff charges by dividing the identified costs of customer group categories by billing units (e.g. kWh, customer-months).

The Average Reproduction Cost

The average reproduction cost approach modifies the average historical cost approach by adjusting asset values to reflect the cost of replacement. The revaluation affects the return on asset base, but not the depreciation charges.

The Marginal Cost approach[11]

The marginal cost approach is a forward-looking process that estimates the change in the cost of producing or delivering energy in response to a small change in customer usage. In many systems, the marginal cost of generation will be the market price. The marginal cost of transmission, however, is a function of:

- Congestion and losses reflected in locational marginal prices although these are not included in all EU Member States; and
- The annualised cost of incremental investment needed to accommodate load growth.

Table 03 – Pros and Cons of Marginal and Average Cost Pricing

	Marginal Cost Pricing	Average Cost Pricing
Allocative efficiency	High	Relatively low (not optimal), size of inefficiencies depend on elasticity of demand
Cost recovery	If the Company is not financially viable, then adjustments will be needed to MC tariffs (usually government subsidies)	Ensures financial viability of regulated firm, cost recovery results automatically from the cost allocation, eliminates economic profits provides 'fair' rate of return
Efficient regulation	Depends on the regulatory role in the tariff setting process. Administration and compliance cost of MC pricing may be relatively high	Depends on the regulatory role in the tariff setting process
Transparency and simplicity	Low – MC pricing concepts may apply sophisticated modelling	High – AC pricing easily understood by users

[11] Ref:http://regulationbodyofknowledge.org/wp-content/uploads/2013/03/NERA_Electricity_Tariff_Structure.pdf

	Marginal Cost Pricing	Average Cost Pricing
Non-discrimination	High – but also depends on adjustments for cost recovery	Variable – depends on the rules for cost allocation and tariff setting
Implementation in practice	Used to provide short and long term locational signals, may require sophisticated modelling	Usually used with energy and demand charges differentiated by voltage level

The marginal cost of distribution is the annualised cost of incremental local facilities needed to connect customers and the annualised cost of higher voltage facilities needed to accommodate increased use by many customers. The output from a marginal cost study is unit marginal costs, per kWh by time period, per kW and per customer. These unit costs can be used to compute the marginal cost revenues (the marginal unit costs multiplied by units expected to be sold) by customer category and in total. Since total marginal revenue does not necessarily match the allowed revenue requirement, adjustments must be made to cover any positive or negative gap. The adjustment can be proportional (so that all classes are allocated the same percentage of their marginal cost revenues) or on a differential basis that takes other factors into account. As applied to the generation sector, the cost of building power generation capacity is a stock concept, marginal cost (and more usually, long-run marginal cost) is a flow concept which relates to the cost per period of producing an additional kWh. Peak load pricing is a system of price discrimination whereby peak time users pay higher prices to reflect the higher marginal cost of supplying them. There are two benefits from adopting peak load pricing:

- Peak time users pay for the higher marginal costs that they impose on the system; and
- Those users who would not mind consuming at a different time (for example, residential customers who can use electricity at a different time when marginal costs are cheaper) are induced by cheaper prices to switch to consuming at off-peak times. By spreading total daily consumption more evenly, BT reduces the peak in demand and has to devote less resources to building new power stations whose number is determined by peak usage.

In some cases regulators can use a hybrid approach, which uses a combination of marginal and average allocation of costs. For example, average historical costs could be used to allocate the revenue requirement to customer categories (eliminating the need to close the marginal cost revenue gap at the class level) and marginal costs could be used for tariff design within a category (with the gap closing done at the tariff component level).

After determining the System Revenue Requirement, a Cost of Service (COS) for each customer class is developed to determine the specific costs to serve each class. Customer class revenues are compared to class revenue requirements to evaluate the current rate's abilities to recover costs. Utilities usually analysed the cost to serve each customer class based on the revenue requirement developed from the elements outlined in the revenue requirement equation.

Once completed, the COS results indicate the degree to which existing rates recover the cost to serve customers. The COS results are then used to design new electricity rates.

The COS analyses relied on the following key supporting data and analysis:

- Test Year reported revenue requirements and revenues based on current rates;
- Total System and customer class demand and energy requirements;

- Actual and assumed customer service characteristics; and
- Information obtained from customer accounts and records.

3.1.3.1 Principles of a Cost-of-Service Study

In performing an allocated cost of service study, the overall objective is to allocate costs fairly and equitably to all customers. This objective is accomplished when the resulting allocated cost of service study reflects "cost causation". "Cost causation" is the fundamental and essential principle underlying the development of any cost-of-service study. "Cost causation" addresses the question as to which customers or groups of customers caused the Company to incur a particular type of cost, i.e., it establishes a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. "Cost causation" focuses upon the selection and development of an allocation methodology that recognizes the relationships between customer requirements, load profiles and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other.

"Cost causation" becomes intuitively obvious when a specific cost can be directly linked and specifically assigned to an individual customer, as in the case of plant and facilities related to the street lighting. However, since a significant amount of PES' costs are joint or common costs, and have been incurred to serve all customers, there are few opportunities to specifically assign costs.

3.1.3.2 Developing Allocated Cost-of-Service Study

Typically, there are three fundamental steps required to develop a cost-of-service study of any type. These are:
• functionalization; • classification; and • allocation.

Functionalization

This first step separates the investment and expenses of the Company into specific categories based upon utility operations involved in providing electric service. For PES in The Bahamas, the functional investment categories associated with providing electric service are production, transmission, distribution, and general plant. The functional expense categories include production, transmission, distribution, customer services, and administrative and general expenses.

Classification

The second step, classification, identifies the "cost causative" characteristics of the investment and expenses within each function. Typically, these "cost causative" characteristics are:

- Energy-related —those costs that vary with the customers' energy consumption; this generally refers to costs incurred by the utility that vary with the megawatt-hours (MWh) of energy consumed by the customer.

- Demand-related—those costs that are incurred as a consequence of the loads imposed on the system by all customers; this generally refers to costs incurred by the utility in order to provide the capacity necessary to serve the customers' maximum load throughout the year.

- Customer-related—those costs that vary with the number of customers; this generally refers to costs incurred by the utility just to connect a customer to the distribution system, and for customer metering, customer billing and administrative costs.

Allocation

The third and final step is the allocation of costs that have been functionalised and classified as previously described.

- Energy costs—energy costs are associated exclusively with non-fuel costs and the variable operations and maintenance expenses related to the production function. These costs are allocated based on the annual MWh consumed by the customers in the various rate classes, adjusted for losses.
- Demand costs—demand costs are associated with the production, transmission and distribution functions. Demand costs at each respective service level are allocated based on the MW demand imposed by the customers in the various rate classes, adjusted for losses.
- Customer costs—customer costs are associated with the customer component of certain distribution facilities along with the costs associated with the customer service function. The customer component of distribution facilities is that portion of costs that vary with the number of customers. Thus, the number of poles, conductors, transformers, service drops and meters are directly related to the number of customers on the utility's system. Customer service costs are also associated with meter reading, customer accounting, collections, uncollectible expenses, etc. Customer costs are analysed on an account-by-account basis to determine the rate classes that cause these costs to be incurred.

The functionalization, classification and allocation steps are necessary and essential to the preparation of any cost-of-service study, and the process is fundamentally the same whether analysing gross plant, accumulated provisions for depreciation, materials and supplies, other rate base items, revenues, operation and maintenance expenses, depreciation expenses, taxes, etc. Items that can be specifically identified with a particular customer class are so assigned, as in the case of rate revenues. All other costs are of a joint use nature and must be functionalized and classified in order to insure that the final allocation of costs reflect "cost causation."

Since the revenue requirement is in large part a function of investments made in the past, an embedded cost study essentially attempts to define each class' responsibility for historical costs.

In contrast, a marginal cost[12] study analyses how the system is planned and operated in order to determine how costs would change if there were a small increase (or decrease) in energy used in a given period, in load in critical hours, in number of customers of a particular type, etc. It is a forward looking and hypothetical exercise – as it looks at the cost of the next unit produced (or the savings from a small decrement in expected use)[13]. A marginal cost tariff analysis includes the following steps:

[12] Marginal Cost is the change in total cost incurred to supply a very small increment of service.

[13] Note that all customers are responsible for the utility's marginal costs; therefore, every customer is a marginal consumer. If load growth requires expansion of the network, existing customers are just as responsible as new customers for the new investment because they choose to continue to consume at their prior level. Moreover, an industrial customer that consumes at a steady level across the hours of the day consumes energy in the peak hours of the day when market price are high and should face tariff charges that reflect these high market prices. This customer will benefit from purchases of large amounts of energy in the offpeak hours, when market prices are low.

- Unit Cost Estimation: Changes in costs generation, transmission, distribution, and supply costs that vary with level of service (kW; kWh; number of customers) given a sufficient time horizon is estimated. All non-marginal costs are ignored.
- Marginal Cost Revenue: The unit marginal costs per kWh, kW and customer identified in the first step are multiplied by the corresponding units for each customer class to establish category (and total) marginal cost revenue. Because marginal costs are forward-looking, whereas the revenue requirement is largely determined by decisions made in the past, it would be only by coincidence that charging marginal costs would produce the allowed revenue. Consequently, an additional step is required.
- Revenue Reconciliation: The unit marginal costs are adjusted to produce charges that will generate the revenue requirement and meet other tariff objectives.

3.1.3.3 Rate Design

The foundation of rate design is COS results in tandem with policy considerations important to the electricity sector.

Rate design is the culmination of a COS study where the rates and charges for each customer classification are established in such a manner that the total revenue requirements of the utility will be recovered in the most equitable manner and consistent, to the extent reasonable and practical, in accordance with National Energy Policy. Consideration must be given to the recovery of fixed costs in the customer and demand charges, as well as the phasing in the proposed rates over time.

Rate design structures that are developed to be submitted to the regulator should meet the following objectives and best practices.

- Rates should be equitable among customer classes and individuals within classes, taking into consideration the costs incurred to serve each customer class.
- Rates may take into consideration other important factors such as competitive concerns, policies, etc.
- Rates should be simple and understandable.

3.1.3.4 Electricity Rate Structure

In general, electric rate structure ought to include a customer charge, energy charge and demand charge where applicable. The customer charge should be designed to recover customer related costs and the energy charge[14] should be designed to recover all non-fuel and applicable power production costs. Additionally, the demand charge should be designed to recover demand-related costs. The customer charge, energy and demand charges are commonly referred to as "base rates".

[14] the energy charge should be designed to recover all fuel and applicable power production costs but in utilities that have fuel pass-through mechanism, the energy charge should be designed to recover all non-fuel and applicable power production costs.

Customer and demand charges collect revenues that covers utilities fixed costs. However, energy may collect revenues to recover both fixed and variable costs. For customer classes that do not have demand charges a large portion of the fixed costs are collected through the energy charge. COS results allow the utility to assess if the various charges are adequate, too low or too high.

Tariff Categories

Tariff categories are classes of customers with common/shared characteristics that are grouped together for ease and consistency of charging. While categories may be based on a number of shared characteristics, tariff categories are usually defined by one or more of the following criteria:

a) type of consumer (e.g., domestic, commercial, industrial, street lighting);
b) usage characteristics (e.g., load factor, percent of use on-peak);
c) quality of service (e.g., firm or interruptible; type of distribution layout);
d) voltage level of service;
e) location (e.g., geographical area).

Utilities often times offer special non-fuel charges to specific customer groups as outlined below:

Lifeline Rates— as a social policy objective, utilities may adopt a universal lifeline tariff structure within the rate Residential rate class category, which allows all residential customers to get reduced energy charge for the first 100 kWh of electricity consumed, regardless of total consumption. Only the energy charge is discounted for the "lifeline" customer. That is, the customer charge and fuel charge is the same regardless of total consumption for the month.

Time-of-Use Rates—these rates are an optional rate classification and are applicable to non-residential customers only. Time of Use (TOU) rates are designed to reflect the fact that utility's cost to provide electricity to consumers varies according to the time of the day the electricity is produced. At the peak time, for instance, an utility incurs its highest costs since it is during this time that peaking plants, which operate at higher cost than the base load plants, are brought onto the system. Conversely, the utility's cost is at its lowest during the "off-peak" hours when only the base load plants are in operation. A customer under this TOU option will have to demonstrate proper load management to effectively see savings on its bills relative to the standard (flat) rate option.

Standby Rates—these rates were designed for those companies who own and operate generating equipment capable of meeting their own power requirement. These companies may at times find it necessary to take power from the utility when demand exceeds their supply, including times of either planned or forced outages of their generating plant.

Rate Class Rationalization are also common feature of rate review process. Customers are categorized into different rate classes on the basis of their demand profile and the voltage level at which they are connected to the utility electric system. This is done against the background that customers with similar demand and voltage characteristics impose a similar cost on the utility and as such should bear the same charges.

4 APPROACH TO TARIFF REVIEW IN THE REGION

There is no single uniformed approach to tariffs in the region nor a specific tariff-setting methodology that is uniformly applied throughout. There is no clear tendency towards marginal cost-pricing model for example in the application of different cost concepts and there are varying approaches to incentive base regulation. The lack of uniformity is itself a function of the different physical properties of electricity systems in the region and the different scope of provided services provided by utility companies.

In general however, tariffs among the Region Member Islands are composed of the following elements:

- Regulatory methodology
- Cost of Service and Revenue Requirement components
- Cost allocation
- Rate design

Three methodologies have generally been adopted towards price control regulation

- Jamaica, – Hybrid Price Cap (2001 – 2016), Revenue Cap since 2017
- Barbados, St Lucia – Rate of Return
- Bermuda – Price Cap

Revenue Requirement (RR) determination

- Jamaica - RR determination based on future expected revenue
- Barbados, St Lucia, Bermuda – RR determination based on embedded cost

Basis of Revenue Requirement calculation

- Barbados, St Lucia, Bermuda - Historical “Test year”
- Jamaica - future test year

Cost of service framework

- Barbados, St Lucia, Bermuda – Average cost pricing
- Jamaica – both Marginal and Average cost pricing

Tariff Design

- Jamaica, Barbados, St. Lucia, Bermuda - Cost allocation based on cost driver causation and functionalization

Tariff Structure

- Jamaica, Barbados, St, Lucia, Bermuda - Capacity/demand charges
- Jamaica, Barbados, Bermuda - Time of Use charges;
- Jamaica, Barbados, St. Lucia, Bermuda - Energy charges.
- Jamaica, Bermuda - Bulk Tariff charges

Tariff Categories, type of consumer

Jamaica, Barbados, St, Lucia, Bermuda	- (e.g., domestic, commercial, industrial, street lighting)
Jamaica	– Lifeline Rates, Time of Use Rates, Standby Rates

5 URCA PROPOSED TARIFF REVIEW FRAMEWORK

This section outlines URCA's proposed framework and methodology for negotiating and establishing tariffs that both accords with the Public Electricity Supply Licence (PESL) and meets standards for good regulatory practice. The proposed methodology clarifies the process for resetting tariffs in the future, determines a regulatory methodology and establishes an appropriate financial model to be used for tariff resets.

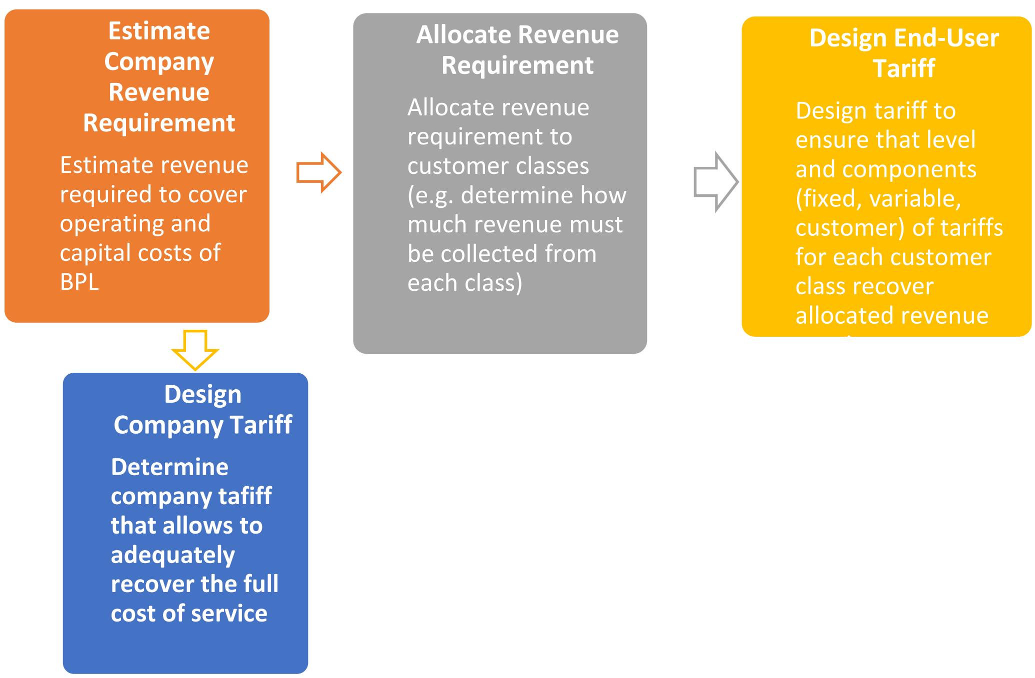

Figure 1: Proposed Methodology for Tariff Setting Process Regulation

URCA believes that the revenue required to operate the utility ought to match the revenue collected from customers. Some difference between the revenue requirement for the utility and the revenue from customers is to be expected every year because of uncertainty in demand, supply availability and costs. This mismatch in revenue and cost caused by inflation and fluctuating demand overtime can result in under or over-recovery of revenue for PES. It is URCA's remit to ensure that PES receive the required revenue and customers are not overcharged for service.

5.1 PROPOSED COST OF SERVICE FRAMEWORK

The cost of service review will focus on developing an estimate of the reasonable cost of service for electricity services in The Bahamas served by PES. On the basis of the estimate of what constitutes reasonable costs for providing services, the minimum revenue requirement for the utility to provide safe and reliable service will be determined. This review process/framework will clarify a number of the issues that will be of interest to rate payers, such as the connection between costs and the tariff levels of electricity in The Bahamas. URCA proposes that the framework outlining the cost of service ought to provide estimates for the actual cost of service for supplying electricity to consumers. Further, the cost of service report to be submitted for review by URCA should provide relevant supporting documentation and analysis.

URCA proposes that PESs adopt the average cost approach to estimate the cost of service. This entails taking the expenses actually being incurred or allowed by the energy regulator and a return on capital invested in the past as a starting point. This bucket of revenue is classified as being related to demand, energy consumption, and number of customers being served. The classified costs are then allocated across the various customer classes based on measures of their demand, energy use, and customer counts. The classified and allocated costs are then converted to tariff charges by dividing the identified costs of customer group categories by billing units (e.g. kWh, customer-months). URCA believes that this approach is the least complex and most transparent of the two approach described in section 3, namely, Marginal cost approach and Average cost approach.

Additionally, URCA proposes that a PES demonstrates to the regulator that the tariff process incorporates a cost of service study.

Typically, there are three fundamental steps required to develop a cost of service study of any type. These are:

• functionalization • classification; and • allocation.

Functionalization

This first step separates the investment and expenses of the Company into specific categories based upon utility operations involved in providing electricity service. For a PES in The Bahamas, the functional investment categories associated with providing electric service are production, transmission, distribution, and general plant. The functional expense categories include production, transmission, distribution, customer services, and administrative and general expenses.

Classification

The second step, classification, identifies the "cost causative" characteristics of the investment and expenses within each function. Typically, these "cost causative" characteristics are:

- Energy-related —those costs that vary with the customers' energy consumption; this generally refers to costs incurred by the utility that vary with the megawatt-hours (MWh) of energy consumed by the customer.
- Demand-related—those costs that are incurred as a consequence of the loads imposed on the system by all customers; this generally refers to costs incurred by the utility in order to provide the capacity necessary to serve the customers' maximum load throughout the year.

- Customer-related—those costs that vary with the number of customers; this generally refers to costs incurred by the utility just to connect a customer to the distribution system, and for customer metering, customer billing and administrative costs.

Allocation

The third and final step is the allocation of costs that have been functionalised and classified as previously described.

- Energy costs—energy costs are associated exclusively with non-fuel costs and the variable operations and maintenance expenses related to the production function. These costs are allocated based on the annual MWh consumed by the customers in the various rate classes, adjusted for losses.
- Demand costs—demand costs are associated with the production, transmission and distribution functions. Demand costs at each respective service level are allocated based on the MW demand imposed by the customers in the various rate classes, adjusted for losses.
- Customer costs—customer costs are associated with the customer component of certain distribution facilities along with the costs associated with the customer service function. The customer component of distribution facilities is that portion of costs that vary with the number of customers. Thus, the number of poles, conductors, transformers, service drops and meters are directly related to the number of customers on the PES's system. Customer service costs are also associated with meter reading, customer accounting, collections, uncollectible expenses, etc. Customer costs are analysed on an account-by-account basis to determine the rate classes that cause these costs to be incurred.

The functionalization, classification and allocation steps are necessary and essential to the preparation of any cost-of-service study, and the process is fundamentally the same whether analysing gross plant, accumulated provisions for depreciation, materials and supplies, other rate base items, revenues, operation and maintenance expenses, depreciation expenses, taxes, etc. Items that can be specifically identified with a particular customer class are so assigned, as in the case of rate revenues. All other costs are of a joint use nature and must be functionalized and classified in order to insure that the final allocation of costs reflect "cost causation."

Consultation Question 1

Stakeholders are invited to comment on URCA's proposed cost of service framework in conducting the tariff review as outlined in this section. Which approach do you propose and why?

5.2 Revenue Requirement determination

URCA proposed that the Revenue Requirement shall be the non-fuel cost (Cost of Service) that the PES should recover through the non-fuel rates. This is so because the fuel cost with attendant adjustments is passed on directly to customers through a separate rate.

URCA proposed that Revenue Requirement which approximates the Cost of Service shall comprise four (4) main elements:

(1) Return on Investment (ROI)

(2) Electricity Rate Reduction Bond Financing Liabilities(RRB)[15]
(3) Cost of Debt in respect of interest and or principal of money borrowed by a PES, whether or not there is a continuing economic return on the money borrowed; and
(4) Recovery of all prudently incurred expenses of the Licensed Business including:
    a. Non-fuel operating costs/expenses
    b. Depreciation
    c. Cost of Securities issued by a PES and interest charges

The Revenue Requirement is proposed as follows:

RR = ROI + RRB+DI&P+ (OPEX+D+S&I)

Where:

RR = Revenue Requirement

ROI = Return on Investment

RRB = Rate Reduction Bond financing liabilities

DI&P = Debt obligations in respect of Interest or Principal

OPEX = Non-fuel operating costs/expenses (prudently incurred)

D = Depreciation

S&I = Cost of issuing Securities

The five components of the Revenue Requirements are proposed and will be examined, encompassing the Return on Investment (ROI), Rate Reduction Bond Financing Liabilities, Debt obligation in respect of Interest or Principal followed by the Non-Fuel Operating Costs/Expenses.

5.2.1 Return on Investment (ROI) and Rate Base

PES's rate base is essentially the utility's "prudent" capital investment, net of accumulated depreciation. Stated differently, it is the value of the net investment in the Licensed Business. PES's Rate Base includes the assets that are in use, will be expected to be in use over the Rate Review period, and are deemed useful in providing electricity services to its customers. From a regulatory standpoint, Rate Base is usually approved and determined by the Utility regulator. The rate base is the sum of the following:

– The residual value of the assets;
– Near-term investments expected to be included in the rate base; and
– An allowance for working capital.

URCA proposes that the ROI shall be as follows;

The ROI is the product of the utility's Rate Base (RB) and its Weighted Average Cost of Capital (WACC). Mathematically, this may be expressed as:

[15] RRB is determined exogenously in accordance with and is subject to requirements of the Rate Reduction Bond Act, 2015

$ROI = RB \times WACC$

Where:

RB = Rate Base

WACC = Weighted Average Cost of Capital

WACC combines the approved rate of return (ROR) of all category of funds in the business in proportion to each funds' contribution to the actual or deemed capital structure to yield a single ROR for the company. WACC (pre-tax) may be expressed as[16]:

$(pre-tax) = (D/D+E) + r_E/(1-t)(E/D+E)$

Where:

r_D = Cost of debt

r_E = Rate of return on equity (or ROE)

D = Value of debt in the capital structure

E = Value of equity in the capital structure

t = Tax rate.

Costs of debt and equity. The costs of debt and equity determine the return the energy companies are allowed to earn on their rate bases. This is determined by the following:

– The respective costs of debt and equity allowed by the URCA; and

– The mix of debt and equity financing used.

As the occasion arises, URCA proposes to use a "cash needs" approach for calculating the revenue required to cover debt service for specific large investments financed on concessional terms. When this approach is taken, investments financed from concessional loans are recovered through an annual debt service charge and not included in the rate base. For example, URCA proposes not to use a rate base in estimates of the revenue requirement for investment in plants if the plants have been 100 percent financed with a concessional loan and capital costs are therefore recovered through an explicit debt service charge.

Alternatively, URCA believes that a PES should be allowed to recover its revenue requirement by applying a deemed or benchmark WACC to the value of its net investment. URCA proposes that a PES be allowed to earn a Return on Investment (ROI). Thus, the rate base value will be a key variable in the determination of a PES's revenue requirement. URCA proposes to use comparative utilities in the Caribbean region as the basis of benchmarking WACC.

[16] Note, $(D/D+E)$ represents the 'gearing ratio'.

Alternatively, URCA believes that a PES should be allowed to recover its revenue requirement by applying a deemed or benchmark capital structure[17] and an estimated Cost of Equity using CAPM[18] method and international benchmark data. The WACC derived from this alternative is then applied to the appropriate Rate Base. URCA proposes to adopt the method of comparative utilities in the Caribbean region as the basis of estimating WACC.

Rate Base shall be based on the approved net book value of the company's assets for the tariff review period and should be informed by the PES's Business Plan.

For vertically integrated electric utilities such as BPL, rate base generally includes generation, transmission and distribution infrastructure; but when it comes to valuing rate base, there can be many other items that are included in, or used to offset, the net value of the utility's plant and equipment.

$$\boldsymbol{Rate\ Base} = \boldsymbol{Property\ Plant\ and\ Equipment} + \boldsymbol{Intangible\ Assets} + \boldsymbol{Working\ Capital} + \boldsymbol{Long\ Term\ Receivables} + \boldsymbol{Other\ Assets} - \boldsymbol{offsets}$$

[19]The components of the Rate Base identified in the above formula shall be as follows**:**

i. The Property Plant and Equipment ("PPE") ; along with the net book value of the company's assets this shall also include construction work in progress; offset by impaired assets, customer financed assets (including electricity efficiency improvement fund assets), rural electrification assets, less revaluation balance/capital reserve;
ii. Intangible Assets (i.e. assets that are not physical in nature e.g. copyright, software licences)
iii. The working capital (i.e. accounts receivable + cash & short term deposits + tax recoverable + inventory – account payable – customer deposits – bank overdraft – short term loans) deployed;
iv. Long Term Receivables;
v. Other Assets; and
vi. Offsets which, refer to:
    a. Employee benefit obligations; and
    b. Deferred revenue.

Consultation Question 2

Stakeholders are invited to comment on URCA's proposed WACC in the determination of Revenue Requirement as outlined in this section. Which approach do you propose and why?

[17] Represents the amount of debt relative to the equity shareholding. Capital structure is the proportion of each source of funding used to support the utility's rate base

[18] is a popular pricing model that describes the relationship between systematic (market) risk and expected return and that is used to calculate the required rate of return for any risky asset.

[19] Reference: Regulatory Assistance Project (RAP); "Revenue Regulation and Decoupling: A Guide to theory and Application" November 2016. http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decouplingguide-second-printing-2016-november.pdf

5.2.2 Rate Reduction Bond financing liabilities (RRB)[20]

The RRB Act and attendant legislations will determine the level of liabilities recoverable.

5.2.3 Debt obligation in respect of interest or principal (DI&P)

Section 20 of the EA mandates that BPL be allowed to recover revenues due to costs associated with debt obligations in respect of interest or principal whether or not there is a continuing economic return on the money borrowed. URCA proposed to treat DI&P as a legitimate cost of service item in determining PES's RR to be recovered in tariff rates. In presenting information on the cost of debt for the tariff review period, URCA proposes that a PES be required to provide a schedule showing the weighted average interest rates and principal amount. The schedule shall be based on the company's latest audited financial position and shall include:

(a) A list of all its long-term debt and their corresponding amounts;

(b) The associated interest rate for each loan;

c) The computation of the weighted average interest rate; and

d) Prudently incurred costs associated with the issuance of debt such as commitment fees, arrangement fees, due diligence fees, breakage costs and refinancing fees should be included in the non-fuel operating expenses.

5.2.4 Non-Fuel Operating Costs/Expenses

In keeping with section 20 of the EA, URCA is proposing that prudently incurred non-fuel operating costs means:

- All prudently incurred costs which are not directly associated with investments in capital plant and other operating costs, which shall include but not be limited to, salaries and other costs related to employees;
- operating costs of generation, transmission and distribution and supply facilities; power purchase costs and other related costs including but not limited to working capital and credit support charges incurred under approved PPAs, fuel supply agreements and other related infrastructure arrangements;
- interest and other financial costs on other borrowings and working capital requirements not associated with capital investment; foreign exchange results loss/(gain);
- rents and leases on property associated with the Licensed Business; and
- taxes which the Licensee is required to pay other than income taxes of the Licensee; and other costs which are determined to be reasonably incurred in connection with the Licensed Business.

From a regulatory perspective any item of cost to be included in a PES's OPEX for the purposes of establishing the Revenue Requirement, must be necessary and prudently incurred. In addition, URCA is proposing that in a new Tariff Review it is expected that BPL will achieve operational efficiencies over time. In light of this, a PES shall be required to clearly identify the improvement in efficiencies it expects to attain on its OPEX; and, the same shall be reflected in the Business Plan to be submitted to URCA as information requirement for the Tariff Review process.

[20] Rate Reduction Bond Administration is independent of URCA's regulatory remit but represents a recoverable item from Customer as per RRB Act and other supporting legislation.

5.2.5 Taxes

URCA proposes that if a PES is required to pay a variety of taxes, including Value Added Tax (VAT), import taxes, income taxes and property taxes, then these taxes are all included in allowed operating expenses since they are payable under the law.

5.2.6 Power Purchase Cost

Power purchase costs are a component of the non-fuel operating costs and URCA proposed that these cost be treated correctly as an operating expense. However, it is recognized that operating expenses can be classified into two categories; “production” and “non-production” costs. For reasons of transparency and accuracy in the attribution of cost, it is sometimes necessary to separate these costs by way of a decoupling mechanism. One purpose for employing such a mechanism is to isolate the cost over which the utility actually has control in the short run (i.e. the period between rate reviews)[21].

Given that the non-fuel power purchase cost is recognized as a part of a PES’s OPEX, even though it is out of the control of the PES operations’ control, it should be decoupled from other non-fuel costs and treated as a direct pass through on customers’ monthly bill.

5.2.7 Depreciation

The regulatory literature defines depreciation, essentially, as the decline in or loss of value in an asset. Depreciation is also a systematic and rational accounting process that is used to allocate (not valuate) tangible capital assets less salvage value (if any), over the estimated useful life of the item. These costs are allowed operating expenses, which result in the reduction of the Rate Base[22].

In summary, URCA is proposing that a PES in presenting its Non-fuel operating costs/expenses (OPEX) shall:

(a) Clearly identify the improvement in efficiencies it expects to attain on it OPEX over the Rate Review period and the Business Plan shall clearly delineate the PES’s plan to improve efficiency over the rate review period.
(b) Exclude from its OPEX any component associated with random events.
(c) Provide details of all taxes payable by the company
(d) Provide details on its power purchase costs which shall be decoupled from other operating expense to allow for a direct pass-through to customers
(e) Perform its depreciation calculation on the basis of a revised deprecation schedule approved by URCA based on a most recent depreciation study done by the company.
(f) Provide detailed calculations of the increases in depreciation expenses in 2021 and beyond in order that they may be taken into account in the Rate Review.

<u>Consultation Question 3</u>

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[21] Regulatory Assistance Project (RAP); “Revenue Regulation and Decoupling: A Guide to theory and Application” November 2016. http://www.raponline.org/wp-content/uploads/2016/11/rap-revenue-regulation-decouplingguide-second-printing-2016-november.pdf

[22] Neither statues, the EA and the PESL did not prescribed for BPL to allow a return on Rate Base

Stakeholders are invited to comment on the extent to which the elements making up the RR is adequate and appropriate.

5.3 PROPOSED RATE DESIGN

URCA believes that the foundation of rate design is COS results in tandem with policy considerations important to the electricity sector.

Rate design is the culmination of a COS study where the rates and charges for each customer classification are established in such a manner that the total revenue requirements of the utility will be recovered in the most equitable manner and consistent, to the extent reasonable and practical, in accordance with National Energy Policy. Consideration must be given to the recovery of fixed costs in the customer and demand charges, as well as the phasing in the proposed rates over time.

URCA proposes that the rate design structures that are developed should meet the following objectives and best practices:

- Rates should be equitable among customer classes and individuals within classes, taking into consideration the costs incurred to serve each customer class.
- Rates should be affordable to the most vulnerable and economically challenged.
- Rates may take into consideration other important factors such as competitive concerns, policies, etc.
- Rates should be simple and understandable.

Some objectives may seem contradictory, but the overall objectives should serve the public interest.

5.3.1 Proposed Electricity Rate Structure

In general electricity rate structure ought to include a customer charge, energy charge and demand charge where applicable. The customer charge should be designed to recover customer related costs and energy charge should be designed to recover all non-fuel and applicable power production costs. Additionally, the demand charge should be designed to recover demand-related costs.

A PES should ensure that customer and demand charges collect revenues that are attributable to the utility’s fixed costs. However, energy charge may collect revenues to recover both fixed and variable costs. This is often the case for Residential customer classes that do not have demand charges. A large portion of the fixed costs are collected through the energy charge for this customer class. URCA believes that COS results will allow the PES to assess if the various charges are adequate, or too low or high.

5.3.1.1 Proposed Tariff Categories

Tariff categories are classes of customers with common/shared characteristics that are grouped together for ease and consistency of charging. URCA proposes that while categories may be based on a number of shared characteristics, tariff categories shall be defined by one or more of the following criteria:

a) type of consumer (e.g., domestic, commercial, industrial, street lighting);
b) usage characteristics (e.g., load factor, percent of use on-peak);
c) quality of service (e.g., firm or interruptible; type of distribution layout);

d) voltage level of service;
e) location (e.g., geographical area)

PESs must offer special non-fuel charges to specific customer groups as outlined below:

Lifeline Rates— as a social policy objective to take care of the most vulnerable and economically challenged consumers are , PES shall adopt a universal lifeline tariff structure within the Residential rate class category, which allows all residential customers to get reduced energy charge for the first 0 - 200kWh[23] of electricity consumed, regardless of total consumption. Only the energy charge is discounted for the "lifeline" customer. That is, the customer charge and fuel charge is the same regardless of total consumption for the month. This

Additionally, URCA proposes that PES can also offer special non-fuel charges to specific customer groups as outlined below:

Time-of-Use Rates—these rates are an optional rate classification and should be applicable to all customers. Time of Use (TOU) rates are designed to reflect the fact that the utility's cost to provide electricity to consumers varies according to the time of the day the electricity is produced. At the peak time, for instance, a utility incurs its highest costs since it is during this time that peaking plants, which operate at higher cost than the base load plants, are brought onto the system. Conversely, the utility's cost is at its lowest during the "off-peak" hours when only the base load plants are in operation. A customer under this TOU option will have to demonstrate proper load management to effectively see savings on its bills relative to the standard (flat) rate option.

Standby Rates—these rates should be designed for those companies who own and operate generating equipment capable of meeting their own power requirement, particularly as it may pertain to renewable energy programs participants. These companies may at times find it necessary to take power from the utility when demand exceeds their supply, including times of either planned or forced outages of their generating plant.

Consultation Question 4

a)	Do stakeholders believe that the foundation of rate design should necessitate a Cost of Service (COS) results? If not why not?
b)	Do stakeholders agree with URCA's proposed rate structure and proposed tariff categories? If not, explain why. Do stakeholders believe that the Lifeline block rate of 0 – 200 kWh is adequate for vulnerable customers, explain?

5.4 Proposed Regulatory Options for adjusting Rates

Any price control system will be designed to serve customers by preventing the PES from increasing prices excessively. While doing this it should:

- **encourage efficient production** – since prices must be related to costs, the regulator must ensure PES keeps costs down;

[23] This represents the current Lifeline block rate for BPL customers

- **keep prices close to costs** (including reasonable net operating revenue) – this is important for three reasons:

  - if prices are persistently above costs, customers will complain, and the resulting political and social pressure will cause regulatory instability;

  - if prices are persistently below costs, the company will not invest, and will eventually go bankrupt. This is bad for customers. The risk that prices would be held below costs will deter RRB investors; and

  - if prices diverge from costs in either direction, customers will no longer get good signals about the value of the resources they are consuming.

- **be stable and predictable** – customers do not like volatile prices. Even more importantly, if RRB investors cannot predict what prices will be, they will put a high risk premium on PES. This will reduce the value of PES assets and by increasing the cost of capital for new investment, necessitate steeper tariff increases than would otherwise be necessary.

In addition, the regulatory approach should give a PES the incentive to comply with regulatory requests and reveal accurate information to the regulator.

5.4.1 Options

The incentive to minimize costs is essentially determined by the design of the regulatory regime. The tariff regime is the set of rules by which tariffs are updated and modified over time. This is the key to the incentives the utility faces for productive efficiency. There are three main types of regulatory regimes:

- Rate of Return
- Price or revenue caps
- Hybrids

Rate of Return and Price or Revenue Cap are at opposite ends of the same spectrum. It is possible to combine elements of the two and produce a **Hybrid regime**.

Rate of Return regulation ensures that prices are align with costs each year. However, since all costs can be passed on in price, the PES would have little incentive to become more efficient. URCA could review costs to ensure that they are reasonable, as happened in the US, but this is a demanding task as information asymmetry will make a fair assessment by the URCA most difficult. That is to say, the PES holds all the information and can outwit URCA.

Price cap regulation allows the operator to change its price level according to an index that is typically comprised of an inflation measure, Consumer Price Index (CPI), and a “productivity offset,” which is more commonly called the X-factor. Typically with price cap regulation, the regulator groups services into price or service baskets and establishes an CPI-X index, called a price cap index, for each basket. Establishing price baskets allows the operator to change prices within the basket as the operator sees fit as long as the average percentage change in prices for the services in the basket does not exceed the price cap index for the basket. **Revenue cap regulation** is similar to price cap regulation in that the regulator establishes a CPI-X index, which in this case is called a revenue cap index, for service baskets and allows the operator to change prices within the basket so long as the percentage change in revenue does not exceed the revenue cap index. Revenue cap regulation is more appropriate than price cap regulation when costs do not vary appreciably with units of sales.

Price cap and revenue cap regulation are forms of incentive regulation, which is the use of rewards and penalties to induce the utility company to achieve desired goals and in which the operator is afforded some discretion in achieving goals. With price cap regulation, the company's average price increase is restricted by a price index that generally includes an inflation measure (example, Consumer Price Index of The Bahamas) and an offset that generally reflects expected changes in the company's productivity. Revenue cap regulation is the same as price cap regulation except that the company's revenue is restricted by the inflation-productivity index. With pure price caps, the regulator never directly observes the operator's profits. This form of price caps is rare and indeed may never be practiced except in instances where the regulator is prohibited by law from observing costs and adjusting prices. Most price cap regimes base prices on past costs or expected costs, and prohibit the regulator from adjusting prices according to new information for a set period—typically, 4-6 years.

URCA proposes a tariff review every five years, consistent with the requirement of the EA.

Price caps were first developed in the United Kingdom in the 1980s to be the regulatory framework for the country's newly privatized utilities. The basic idea behind the country's price cap regulation was that the regulator would be at an information disadvantage relative to the utilities in terms of knowing how efficiently the utilities could operate. By adopting price cap regulation and allowing utilities to keep for a period of time profits they received by improving efficiency, the government believed that the companies would reveal their efficiency capabilities. In turn, this would allow the regulator eventually to set regulated prices that reflected the companies' true abilities. Price cap regulation did not work out entirely as planned, so adjustments have been made to the point that the United Kingdom's price cap regulation looks a lot like U.S. rate of return regulation. Excellent summaries of the U.K. experience can be found in several studies. A critical difference between U.S.-style rate of return regulation and U.K.-style price cap regulation is that the U.K. regimes have fixed time periods between price reviews, whereas under rate of return regulation, price reviews are triggered by high or low earnings [relative to the cost of capital].

Underlying theory

The Regulator and other policymakers have certain energy goals for the countries, including near-universal availability of service, affordable prices, and quality service. Achieving these goals requires that utilities incur costs and exert effort. The difficult question for the regulator is how much cost and effort will be required. Utilities generally know more about the answers to these questions than regulators do. A company generally knows more than its regulator about how much it would cost to provide a certain level and quality of network expansion, for example. This is because the regulator cannot directly observe the operator's innate abilities and its degree of effort. These problems are called information asymmetry. An information asymmetry arises from the PES's having information—namely, about the utility's innate ability to achieve performance goals at a specific cost and the amount of effort the employees exert—that the regulator does not have. The regulator has goals that the PES must achieve, given its remit. The PES may agree with some of the regulator's goals, but PESs generally have other interests, such as maximizing operating revenues for their shareholders or on behalf of the Government and limiting the amount of effort exerted. To solve these problems, the regulator offers the PESs financial rewards for controlling costs and/or exerting effort.

Hybrid regimes. In between these two regimes, there are a large number of intermediary solutions used in practice that add some guaranteed reimbursement to incentive based regimes or that add incentives to some cost based regime. The most common is a *price caps* with automatic pass-through of some costs to users. The adoption of a hybrid regime is generally justified by the existence of costs uncontrolled by the operators combined with the need to introduce incentives. The more volatile or unpredictable these uncontrolled costs are, the more important the need to adopt a regime that reduces the risks for the operator. The specific hybrid regime design decides how much of this risk can be passed on to users.

URCA remit and primary objective is to preserve the efficiency incentives of a price cap while keeping prices related to costs in the longer term. URCA proposes a hybrid approach whereby prices are initially set to allow the PES to recover its cost of service. Thereafter, prices are adjusted on average at the rate of inflation, less an offset, namely

$$\% \text{ adj.} \leq \text{CPI} - X;$$

where % adj is the average percentage change in prices allowed in a year, CPI. is the inflation index, and X is the offset.

Additionally, URCA proposes that the offset, X which represent the X-factor in price cap regimes remain zero until a comprehensive study on X factor is established.

The key issues are: What is the “offset”? What is the measure of inflation? And, what does it mean that prices are allowed to rise on average.

Prices rise when production costs unavoidably rise. Prices decline with productivity increases. As a result, in a competitive economy, the economy-wide inflation rate reflects unavoidable increases in production costs and accounts for productivity gains. If the regulated company is just like the average firm in the economy, its prices should rise at the general rate of inflation.

The X-factor should represent the difference between the regulated firm and the average firm in the economy. There are two key differences to consider— namely, the regulated company’s ability to improve productivity and changes in its input costs. If the regulated company can improve its productivity more than the average firm in the economy, or if the regulated company’s input prices increase less than input prices for the average firm, this would imply $X > 0$. The opposite situations would imply $X < 0$. If the regulated firm is just like the average firm, this would imply $X=0$.

To establish an appropriate X-factor for the PES will require a comprehensive total factor productivity (TFP) study. URCA proposes that a TFP study and the appropriate methodology be establish for the ensuing tariff review period.

Consultation Question 5

Do you agree with URCA’s proposed regulatory options for adjusting rates?
Stakeholders are invited to comment on the URCA’s proposed regulatory options for adjusting rates between rate review periods, giving reasons for your agreement and/or disagreements.

6 INFORMATION AND SUPPORTING DOCUMENTS

In undertaking this proposed framework for the tariff review, the following activities are proposed:

In accordance with sections 20(2) of the EA URCA proposes that the PES provide URCA with all relevant accounts and statistical statements in support of the rate review application. The data and supporting documents to be submitted by PES shall contain all inputs data used to estimate the proposed revenue requirement, cost of service study, tariff design and structure and tariff rates categories. This data shall be used to establish the reasonable rates and charges for electricity supply. The information to be submitted by PES shall be disaggregated for each cost component. URCA also propose the collection of information from the PES on their internal operational practices which will assist the URCA in its assessment of costs.

6.1 DEMAND ANALYSIS

URCA is proposing that a PES develop and submit to URCA its demand analysis as part of the tariff review process. URCA will review and assess current and future projected demand profiles and corresponding supply expansion plans and costs. A PES is expected to use the demand analysis to develop appropriate financial models. In assessing a PES's demand URCA will review historic growth rates, together with the PES's demand projections, and analyze demand growth against other key growth rates including population, income, and tariffs, to derive projections for the future. Following development of the demand forecasts, URCA is proposing that a PES develops a number of expansion planning scenarios where possible. These scenarios may include a base-case expansion plan as well as a number of alternative expansion scenarios, including options for the inclusion of various alternative sources of energy. All this information will feed into the determination of the cost of service for revenue requirements for the utility, including for investments, at present and into the future

6.2 FINANCIAL MODEL AND REGULATORY ACCOUNTS

URCA proposes that PESs produce a financial model as part of their tariff submission. Additionally, the conditions of the Licence requires a PES to include in its Reporting Obligations, the latest audited financial accounts[24].

Critical to the effective regulation of infrastructure services, such as electricity, is a framework which facilitates the periodic publication of accounting statements that explicitly support the regulatory function. In modern utilities, financial reporting involves the presentation of aggregate information that is designed primarily to meet the needs of management and shareholders. These reports, while useful in a general way, do not provide sufficient details for the regulator. Consequently, it is essential that utilities generate reports that allow for the analysis of costs and revenues, as well as the evaluation of assets employed, in a way that is consistent with effective regulation.

URCA proposes that a PES shall be required to submit, along with its Audited Financial Accounts, a set of Regulatory Accounts in ensuing tariff reviews. According to Condition 54 of the PESL:

[24] Condition 24.1 of the PESL and Condition 23.1 of the APESL

" To assist in setting tariffs, the Licensee shall maintain separated accounts for generation, transmission, distribution and supply services."

" If so determined by URCA, the Licensee shall within a separated period by URCA:

a) Prepare and maintain accounting records in a form that enables the activities of any business unit specified by URCA to be separately identifiable; and
b) The accounts shall be maintained according to internationally comparable standards and prepared according to rules approved by URCA."

6.3 COST OF SERVICE AND PERFORMANCE BENCHMARKING

URCA proposes that a PES is required to submit an Average Cost of Service study to support its tariff design in an upcoming Rate Review application.

The starting point in assessing the reasonableness of the rates to be charged by a utility is to evaluate the cost of providing the services through a cost of service study. The objective of the cost of service study is to apportion all costs required to serve customers among each customer class in a fair and equitable manner. There are two broad approaches to conducting a cost of service study: (1) the historical average cost of service approach; and, (2) the marginal cost of service approach.

A historical average cost of service study takes the total Revenue Requirement and allocates it among customer classes. The marginal cost study analyzes how the cost of the System would change to provide an incremental increase in service. Typically, marginal cost is below average cost and thus, pricing at marginal cost would not allow the utility to recover its full cost. Therefore, a revenue reconciliation to the approved Revenue Requirement of the company is also required.

Historical average cost is the approach that URCA has proposed for rate design in this Rate Review framework and, as such, a PES is required to submit an Average Cost of Service study to support its tariff design in an upcoming Rate Review application. URCA proposes the transition to Long Run Marginal Cost (LRMC) of service study to support tariff design in ensuing Rate Review applications.

6.4 BUSINESS PLAN

The EA stipulates a tariff review every 4 – 5 years as such PESs rates are to be set based on the company's five (5) year outlook outlined in the Business Plan. This is critical for three (3) main reasons:

a) It provides a PES with a tool that aligns its activities with its goals within the regulatory framework;
b) It is a means of holding the company accountable for its actions in the Rate Review period;
c) It provides an objective basis for the regulator to assess whether the utility is efficient in the management of its resources and prudent in its operations.

It is expected that the Business Plan will present a market analysis, sales and customers service strategies, corresponding funding requirement, and financial projection. Table 06 below shows some of the issues URCA expects a PES to address in the Business Plan.

Table 06 – proposed information to be included in a PES's Business Plan

Features	Components
Performance Review	• Operational Performance – Reliability, Quality, Heat Rate, System Losses • Asset Performance – Production, T&D Plant maintenance and asset condition • Efficiency – Organization and Financial Performance
Strategic Direction of the Utility	
Capital Expenditure and Investment Forecast	Capital Program Summary - Generation - Transmission - Distribution - IT - General Plant • Program Development and Investment Drivers (e.g. growth, replacement/maintenance, enhancements, statutory, efficiency improvement) • Program Development Methodology • Cost Estimation Methodology - Capital cost estimation • Key Assumptions
Operations and Maintenance Budget Forecast	• Overview of Budgeted O&M Cost Components (e.g. Payroll & Employee Benefits, Third Party Services etc.) • HR Resource Strategy • Procurement Strategy
Financial Strategy	• Financing Requirements • Financing the Plan • Risk and Uncertainty Management
Customer and Stakeholder Impact	• Bill Impact • Other Customer Benefits/Cost

In addition, for regulatory purposes, the Business Plan shall conform to the conditions delineated in Condition 24 of the PESL.

6.4.1 Operational and procurement practices

URCA proposed to undertake an assessment of operational and procurement practices will be performed in key areas. These will include fuel procurement, and any areas of operations where benchmarking may indicate scope for efficiency gains. The URCA will consider these comparisons to assess performance adequacy in The Bahamas. Where inadequacies are found, URCA will identify the source based upon these comparisons.

6.4.2 Cost of unregulated services

URCA proposes the review and assessment the cost of unregulated services, such as customer extensions, the operation of public street lights, and connection requirements. URCA will develop appropriate regulations or recommend adjustments where necessary, to ensure that customers do not suffer due to uncompetitive pricing for the examined services. In undertaking this activity, the URCA will compare a PES's costs and fees for these services against the costs and fees charged by third party contractors for the same work, as follows: – Through information requests, establish a PES's actual costs for selected unregulated services – Where possible, establish independent contractors' costs and fees for the same work in the same locations – Where this is not possible, establish baseline costs and fees for the same work in similar geographies, especially in similar Caribbean Island nations – Compare these costs and fees to the fees that BPL charges.

Consultation Question 6

Stakeholders are invited to comment on the URCA's proposed list of information and supporting documents in support of the Tariff Review. Do you believe the items outlined are adequate or not? Explain.

6.5 SERVICE STANDARD REVIEW

The service standard review task will focus on a review of and an assessment of current service obligations and reliability performance standards for electricity services. This review process will determine whether service standards are currently being met. As part of this task the URCA will assess, if necessary, whether any adjustments to the current service standards are required. For example, it may not be economic for all Islands to have the same level of reliability. In undertaking this service standard review, the following activities are proposed:

6.5.1 Information and data collection

Similar to the initial cost of service review, and in accordance with sections 40 of the EA the URCA will seek the PES's assistance in providing URCA with all relevant accounts and statistical statements. URCA proposes to review current service standards and determine appropriate service standards to be applied in the future. This data will be used to establish the level of service for a PES's customers and assist URCA in determining the level of service currently being achieved.

6.5.2 Performance benchmarking

In undertaking an assessment of the performance of a PES against a number of other comparable island utilities, URCA will seek to establish whether there is scope for improvement on key indicators for electricity supply standards. A comparison of a PES's performance against that of similar utilities, taking into account differences in the operating environment between the PES and the selected benchmarked utilities. Key indicators that will be benchmarked include, but are not limited to the following: – Complaints per 1,000 customers – Customer average interruption duration index (CAIDI)2 – System Average Interruption Duration Index (SAIDI)

Consultation Question 7

What comments, if any, do you have as a stakeholder pertaining to the proposed service standard reviews? Stakeholders are invited to comment on the proposed service standard review.

7 PROPOSED TARIFF RATE REVIEW PROCEDURE

The rate application reviews are governed by a process that is set out in the URCA consultation procedure guidelines[25] . The procedures which will be utilized by URCA to engage stakeholders in respect of various issues affecting the regulated sectors, licensees and consumers. The procedures relate to the manner in which consultation are to be conducted, guidelines for the persons who are interested in participating as well as the procedures to be carried out by the parties to a consultation. The public nature of rate review consultations allows stakeholders - consumer interest groups, members of the general public, and consumers of regulated utility services, business entities as well as the regulated utility companies themselves - to be involved in the consultation. According to the EA and the PES licenses the regulated utility company may initiate a rate review, this in keeping with tradition.

The content of the Rate Application as submitted by the regulated PES is subject to the consultation procedure guidelines. It must contain a clear and concise statement of the facts, the grounds on which the Application is made as well as the nature of the order or decision that is applied for. Consequently, the regulated PES's role is to outline its needs and demonstrate that the Application is warranted.

Once an application is received by URCA the following activities are proposed to be completed over four (4) months;

- Review submission and clarify/validate process to follow for resetting tariff
- Public Notice is proposed to be placed in the local newspapers that summarises the application and tells the public where the application documents may be examined and/or collected.
- Clarified and agree on information required from PES
- PES present their tariff review proposal to the public through public forums outlining the justification for such proposal
- Public Consultation and assessment of public responses to PES tariff review proposal
- Review and assess the application in accordance with the final determination on PES Tariff Framework and procedure.

To ensure public participation, URCA may use various media platforms periodically to remind persons wishing to provide comments of the deadline for submitting their application with all the necessary documentation.

During the utility rate review URCA proposed that the utility ought to be required to make its case for the application to the public directly through the appropriate medium. This as part of the consultation procedure and URCA will facilitate to ensure that the PES is given the opportunity to hear from their customers as they make justified the application through this transparency.

Ultimately, it is URCA which has to determine whether or not an application for an increase in rates, which is normally the basis for the application, is warranted. In carrying out this function, URCA's role is to balance the interests of the various stakeholders which means ensuring that the interests of consumers are protected, and

[25] https://www.urcabahamas.bs/wp-content/uploads/2017/07/URCA-052017-Statement-of-Results-and-Final-Decision-URCA-Consultation-Procedure-Guidelines.pdf

that reasonable rates which reflect the promotion of efficiency are being applied for. URCA must also ensure that the company will be able to adequately finance its operations.

Consultation Question 8

Stakeholders are invited to comment on the proposed Rate Review Procedure

8 CONCLUSION AND NEXT STEPS

The rationale for the tariff review is to assess the continuing appropriateness of tariffs, both in terms of their level and structure. As the regulator URCA's aims is to find the right balance between the interests of the consumers, of the utility, and of the Government. In short,

- consumers should not pay more than necessary to receive electricity service of a given standard;
- the utility should be able to charge tariffs in such a manner that it can cover all its costs, and this includes operating, maintenance and investment costs; and finally,
- the government needs to keep the long-term growth and economic development of The Bahamas in view, and thus wants present tariffs to support improvements and future investments in electricity supply.

The process and methodology URCA proposes, to assess whether tariffs are appropriate to balance the concerns of all stakeholders takes the following form:

- the costs of the utility are reviewed in order to determine what the minimum revenue requirement is for electricity supply to operate in a commercially viable manner;
- the cost information gathered from the PES to inform what level of expenses are associated with the provision of services will be cross-checked by URCA staff/Consultant on the basis of known and measurable costs and using benchmarking information. This will allow the URCA to assess PES's costs of electricity supply compared to other similar countries;
- the appropriateness of costs is intimately linked to the quality and reliability of service that consumers request, and the level of safety that is imposed. Service standards are therefore reviewed for their appropriateness at the same time as company costs;
- in order to determine whether the medium to long term growth and development concerns are addressed, a forward-looking assessment of consumer demand (commercial and residential) and future network investments is undertaken; and
- regarding forward-looking investments it is also highly relevant to assess renewable generation technologies such as wind or solar.

Given all elements above, required revenues to cover present and future costs of electricity supply will be calculated by the URCA. The instrument to calculate the revenues will be a financial and economic model tailored to The Bahamas and should be provided by a PES as part fulfilment of the submission of a tariff proposal.

A PES required revenues indicate the total amount of money the utility is anticipated to need to meet its cost obligations for operations, maintenance and forward-looking investment and it also needs to include a compensation for the cost of capital at disposal for the construction of the network. URCA proposes that it has the remit to carry out an analysis of tariff levels and tariff structure needs to be undertaken in order to determine how the total amount of required revenues is generated by different consumer groups. The PES model should allow analysing the current contributions of different users and ought to allow assessing alternative tariff levels and structure.

The use of a model will allow testing for different scenarios. Questions that can be addressed in this manner include how the revenue requirement changes if higher or lower quality standard are imposed, or faster or slower expansion/replacement plans are implemented. Trade-offs will thus become transparent and can be submitted to the stakeholders for final decision: better or more services imply higher costs and a higher revenue requirement which might in turn translate into higher tariffs conditional on demand and technology developments.

URCA intends to use the methodology set out in this tariff review to establish a transparent framework for future tariff adjustments and periodic reviews.

8.1 Tariff structure assessment

URCA's work on the tariff structure, will consider questions such as:

- Is the current lifeline block an appropriate way of meeting social objectives to help low income consumers?
- Is there an appropriate and cost-reflective split between fixed and variable charges?
- Are the differentials in charges between the various types of customer justified?
- What is the usefulness of the implicit cross-subsidies between customer categories? How effective would potential alternatives be?

The URCA will assess, in consultation with PESs, alternative fuel cost adjustment mechanisms for electricity. The current tariff structure is designed to automate monthly adjustments to the electricity tariff to ensure that changes in fuel prices which are outside of the control of the electricity provider are passed through to consumers. To allow for, and encourage, greater use of renewable energy, the URCA expects the main focus will not necessarily be on the structure of tariffs, but on how tariffs will be indexed and reset. For example, one approach would be to reduce the extent of fuel-price indexation. Another approach would be to adopt forward-looking periodic reviews of prices.

In addition, URCA will review any implicit cross-subsidies between rate classes, to assess the effect of reduced tariffs and investment growth, and to determine alternatives for encouraging access. URCA proposes to conduct this cross subsidy review as a component of the tariff structure analysis, because an assessment of the effects of these cross-subsidies will be integral to developing a comprehensive understanding of current tariff structures, and how they can be made more efficient.

Further, URCA aims to clarify the process to follow for resetting tariffs. This process will be built upon the experience with utility regulation in other jurisdictions with similar characteristics. URCA's proposed approach for the tariff reset process is based upon the —methodical approach, which is described below.

In consultation with PESs, the Government and key stakeholders, the URCA will develop tariff adjustment alternatives that will incentivize the PES to share efficiency and sales volume gains with customers, and will promote cost reduction options such as demand management and distributed generation. The URCA considers that exploration of these tariff adjustment alternatives will be an integral part of the tariff structure review, and these considerations will be integrated into the outputs of the tariff review process in the future.

Building upon the experience with utility regulation in other island countries, URCA will seek to recommend the application of a financial model that meets with international standards for good regulatory practice. The proposed financial model will be based upon previous international experience with financial models as described in the — Methodology Diagram below.

Figure 2: Methodical approach to setting the price controls