FAIR TRADING COMMISSION

CONSULTATION PAPER

Application from Renewstable (Barbados) Inc. for a Rate for a Baseload Renewable Power Plant at Harrow Plantation, St. Philip

Document No.: FTCUR/CONS/RSB/2024-01 **Date of Issue: March 11, 2024**

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LIST OF ABBREVIATIONS

BLPC	Barbados Light & Power Company Limited
BNEP	Barbados National Energy Policy
CIA	Connection Impact Assessment
CO_2	Carbon-dioxide
COD	Commercial Operation Date
ELPA	Electric Light and Power Act, 2013-21
EPC	Engineering, Procurement and Construction
FIT	Feed-in-Tariff
FTCA	The Fair Trading Commission Act, CAP. 326B
FTCA 2020	The Fair Trading Commission (Amendment) Act, 2020
GoB	Government of Barbados
HDF	Hydrogène de France
IPPs	Independent Power Producers
LCOE	Levelised Cost of Electricity
O&M	Operation and Maintenance
PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable Energy
RSB	Renewstable (Barbados) Inc.; The Applicant
SCADA	Supervisory Control and Data Acquisition
SPV	Special Purpose Vehicle
The Commission	Fair Trading Commission
URA	Utilities Regulation Act CAP. 282
URA 2020	Utilities Regulation (Amendment) Act, 2020
W_p	Watt peak

PURPOSE OF DOCUMENT

Introduction

This document outlines the application from RSB ("Applicant"), a division of HDF in partnership with Rubis, for a tariff that provides remuneration for a baseload RE power plant at Harrow Plantation, St. Philip ("Application"). It will also describe the Commission's proposed methodology for arriving at a fair and reasonable tariff for the Applicant's project.

There are a number of notable issues that will be highlighted herein. These include, *inter alia*:

- The proposed technologies to be used at the facility and the appropriateness thereof;
- The prudence and reasonableness of the proposed capital expenditures ("CAPEX") and operating expenditures ("OPEX"); and
- The reasonableness of the Commission's proposed tariff derivation methodology.

The intent of this consultation is to solicit and assess comments, views and proposals from stakeholders and other interested parties on these and any other related issues. This will assist the Commission in coming to a fair and reasonable determination on the Application.

Public participation remains a crucial feature of the decision-making process and the Commission therefore invites written submissions from the general public, the Barbados Light & Power Company (BLPC) Limited, RE producers, Government agencies, the business community, public consumer bodies or advocates, Non-governmental Organisations (NGOs), educational institutions, and any other interested party.

Structure of Paper

The sections of this paper are presented as follows.

- Section 1 provides some background with respect to the energy transition.
- Section 2 outlines and explains the legal and regulatory authority of the Commission.
- Section 3 outlines the Applicant's project description and proposals.
- Section 4 outlines and discusses the Commission's proposed tariff derivation methodology.
- Section 5 presents a list of questions for stakeholders.

Responding to this Document

In order to assist the Commission in expediting the assessment of submissions, responses to this paper should provide a rationale that is clear and concise to the specific question posed. Responses can also include any other related issues you consider to be important but not addressed herein.

A copy of this document may be accessed on the Commission's website at, http://www.ftc.gov.bb.

Submissions

This consultation period will commence on March 11, 2024 and end on April 5, 2024 at 4:00 p.m.

Electronic submissions in the form of a Microsoft Word format or Portable Document format ('.PDF') should be accompanied by a cover letter and be sent to info@ftc.gov.bb and copied to Mr. Kevin Webster, General Legal Counsel and Commission Secretary at kwebster@ftc.gov.bb.

Mailed or hand delivered responses should be addressed to the Commission Secretary at:

Fair Trading Commission
Good Hope
Green Hill
St. Michael
BB12003
BARBADOS

All responses to this paper must be submitted within the allocated timelines above. No extensions will be granted. The Commission is unable to accept or consider submissions made after 4:00 p.m. on April 5, 2024.

TREATMENT OF SUBMITTED COMMENTS

Staff will review, analyse and discuss with stakeholders the responses to this consultation paper where appropriate. Subsequently, staff will consider the information received during this consultative process and together with its assessment of relevant best practice and jurisdictional context will make recommendations towards a final determination.

SUBMISSION OF CONFIDENTIAL INFORMATION

The Commission advises that an email disclaimer which appends a standard confidentiality statement at the end of an email will not be accepted as a formal request for confidentiality. If a respondent classifies submitted information as commercially sensitive[1], a formal request should be made to the Commission pursuant to Section 11 of the FTCA. The Commission in discharge of its functions under this review will exercise discretion with regard to the request for confidentiality.

[1] Commercially sensitive information can be described as information that, if disclosed publicly or otherwise, could potentially prejudice a supplier's commercial interests and cause irreparable harm. Examples of this type of information includes but is not limited to: content and design of a tender, trade secrets and 'know-how' new ideas, material and equipment quotes for products and services.

SECTION 1 ENERGY TRANSITION

1.1 Background

The Government of Barbados (GoB) has set the country on a course to be a fully carbon neutral economy by 2030. Government's RE vision is further premised on supporting climate adaptation through its revised National Determined Contributions (NDC[2]) in compliance with the Paris Agreement of 2015[3]. As a result of the RE vision, there is currently a total RE capacity of approximately 102.6 MW-AC online, of which 92.6 MW-AC is customer owned and 10 MW-AC is utility owned. The technologies associated with these capacities are predominantly intermittent RE sources, which introduce reliability and stability concerns into the power system, leading to a need for mitigation measures, such as energy storage.

Barbados ranks 84/166 countries with regard to achieving sustainability targets[4]. Target 7 (Affordable and Clean Energy) reflects an upward trend for Barbados which is encouraging. The thrust towards RE is also recognised as a key pillar towards local enfranchisement for investment in the RE market. However, the transition to a net-zero carbon economy with appropriate built-in resilience by 2030 is expected to entail significant capital outlay. Based on current estimates, this amount is likely to be in the order of BDS $2 billion.[5]

1.2 Data Collection Process

The Commission aims to collect accurate and reliable data to develop and determine rates that are reflective of the local RE market. Key attributes of rate setting are that rates must be set at an adequate level to allow the IPP to cover its operating and investment costs, provide an

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[2] National Determined Contributions is an action plan which is targeted towards the reduction of Greenhouse Gas emissions. This report can be viewed here
Government of Barbados. 2022. "NDC Registry (Interim)." NDC Registry. January 12. Accessed January 12, 2022. [2021 Barbados NDC update - 21 July 2021.pdf (unfccc.int)].

[3] The Paris Agreement is an international treaty on climate change which was ratified by 196 countries in December 2015. This concordat was effectuated in November 2016.

[4] Sachs, J.D., Lafortune, G., Fuller, G., Drumm, E. (2023). Implementing the SDG Stimulus. Sustainable Development Report 2023. Paris: SDSN, Dublin: Dublin University Press, 2023. 10.25546/102924

[5] Scenario 3 of the IRRP estimates an undiscounted billed cost of BDS $2.6 billion through 2030. Also see International Monetary Fund, IMF Country Report No. 23/241, July 2023 https://www.imf.org/en/Search#sort=relevancy&f:type=[PUBS,COUNTRYREPS]

opportunity to realise a reasonable return on investment, and meet policy objectives. This ratemaking process requires that a delicate balance be struck between the interests of the investor, the electricity consumer, and attainment of policy objectives. Given these considerations, emphasis must be placed on the validity and veracity of RE project data, in-order to arrive at an appropriate determination.

SECTION 2 LEGISLATIVE FRAMEWORK

2.1 Introduction

The Commission, as the economic regulator of utility services, has a mandate under the Fair Trading Commission Act ('FTCA') of the Laws of Barbados to "safeguard the interests of consumers, to regulate utility services supplied by service providers, to monitor and investigate the conduct of service providers, renewable energy producers and business enterprises, to promote and maintain effective competition in the economy, and for related matters."

""Principles" means the formula, methodology or framework for determining a rate for a utility service".

By virtue of the **Section 2** of the FTCA and the URA:
"'Rates', include:

(a) *every rate, fare, toll, charge, rental or other compensation of a service provider or renewable energy producer;*
(b) *a rule, practice, measurement, classification or contract of a service provider or renewable energy producer relating to a rate; and*
(c) *a schedule or tariff respecting a rate;".*

Additionally**, Section 2** of the FTCA states that, *"'Independent power producer' means a commercial entity other than an electric utility, which;*

(a) produces or stores; and
(b) supplies

electricity using renewable energy resources for sale to the public grid;
"public grid" means the grid to which the public has access for the supply of electricity;
"renewable energy producer" includes a generator, distributor or person who stores and supplies electricity generated from a renewable energy resource for sale to the public grid;"".

Pursuant to **Section 4(3)** of the FTCA the Commission has the regulatory authority to:

(a) establish principles for arriving at rates to be charged by service providers and renewable energy producers;

(b) set the maximum rates to be charged by service providers and renewable energy producers;

(c) monitor the rates charged by service providers and renewable energy providers to ensure compliance;

(d) …………;

(e) ………..;

(f) carry out periodic reviews of the rates and principles for setting rates of service providers and renewable energy producers;".

The Commission's duty to consult with the public on the aforementioned is stipulated under subsection (4) which states that:

"The Commission shall, in performing its functions under subsection (3)(a), (b), (d), (f) and (g), consult with service providers, renewable energy producers, representatives of consumer interest groups and other parties that have an interest in the matter before it."

2.2 Information Gathering

Subsection (4A) of the FTCA empowers the Commission to request data in the performance of its functions:

"The Commission shall, in performing its functions under subsections (3)(a),(b), (c) ,(d), (e), (f) and (g), request

(a) a service provider;

(b) a renewable energy producer; or

(c) a licensee under the Telecommunication Act, 282B or the Electric Light and Power Act (2013-21)

to provide the Commission with information relating to its operations, finances or such other information as the Commission may consider necessary to perform its functions."

Similarly, under section 3 (2A) of the URA the Commission can request data from a service provider. This section states that, *"In performing it functions under subsection (1), the Commission*

may request a service provider to provide the Commission with information relating to its operations, finances or such other information as the Commission may consider necessary to perform its functions."
Section 24B (1) of the URA stipulates that, "The functions of the Commission, in relation to a renewable energy producer entering into an interconnection agreement or other agreement to supply electricity to the public grid, are to

(a) establish principles for arriving at the rates to be charged;
(b) set the terms and conditions of the agreements;
(c) set the maximum rates to be charged under the agreements; and
(d) direct renewable energy producers to submit the proposals for the rates and terms and conditions relating to their agreements."

2.3 Duty to Consult

Section 24B (2) states that:
"the Commission shall consult with renewable energy producers, representatives of consumer interest groups and other interested parties and shall have regard to:

(a) the national energy policy;
(b) the national environmental policy;
(c) *the requirement to promote renewable energy and to enhance the security, affordability, safety and reliability of the supply of electricity."*

Additionally, subsection (3) outlines what the Commission is required to consider as it executes its functions set out in subsection (1) (a); subsection (3) provides that "the Commission shall have regard to:

(a) the promotion of efficiency on the part of renewable energy producers;
(b) ensuring that an efficient renewable energy producer will be able to finance its functions by earning a reasonable return on capital;
(c) such other matters as the Commission may consider appropriate."

SECTION 3 PROJECT DESCRIPTION AND PROPOSALS

3.1 Background

In order to drive the transition to 100% RE by 2030, investment from IPPs is required. Consequently, projects like the RSB baseload facility are potentially very important. As alluded to on page eight (8) of this paper, the existing grid remains susceptible to operability, reliability and stability issues given the level of intermittent RE currently servicing demand. As a result, the GoB has identified energy storage as an appropriate means of mitigating the effects of these intermittent resources.

The Applicant submitted its Application via correspondence dated May 12, 2023. On June 2, 2023, by way of response, the Commission requested additional detailed information including, *inter alia*, a full project description, proposed CAPEX and OPEX and an environment impact assessment ("EIA").

The Applicant is an SPV owned jointly by Rubis and HDF Energy. HDF is an experienced IPP based in France that specialises in the implementation of hydrogen-based RE technologies, with projects in French Guiana, Zimbabwe and Sardinia among others in various stages of development. The RE solution utilised around the world by HDF, and proposed here with the RSB facility, comprises the generation of RE from intermittent sources, i.e., solar PV, combined with hydrogen based long-term storage and BESS short-term storage to create a plant that supplies firm RE capacity to the grid. The facility is to be built at Harrow Plantation in St. Philip. The parcel of land has been acquired under a 28-year lease and is 181 acres in size, with over 140 acres of this area dedicated to the solar panel array and a grazing area for black belly sheep. The hydrogen and battery storage will be roughly in the centre of this area. The plant is expected to boast a minimum lifetime of twenty-five (25) years with commercial operation commencing in 2025.

The project is meant to have the following features:

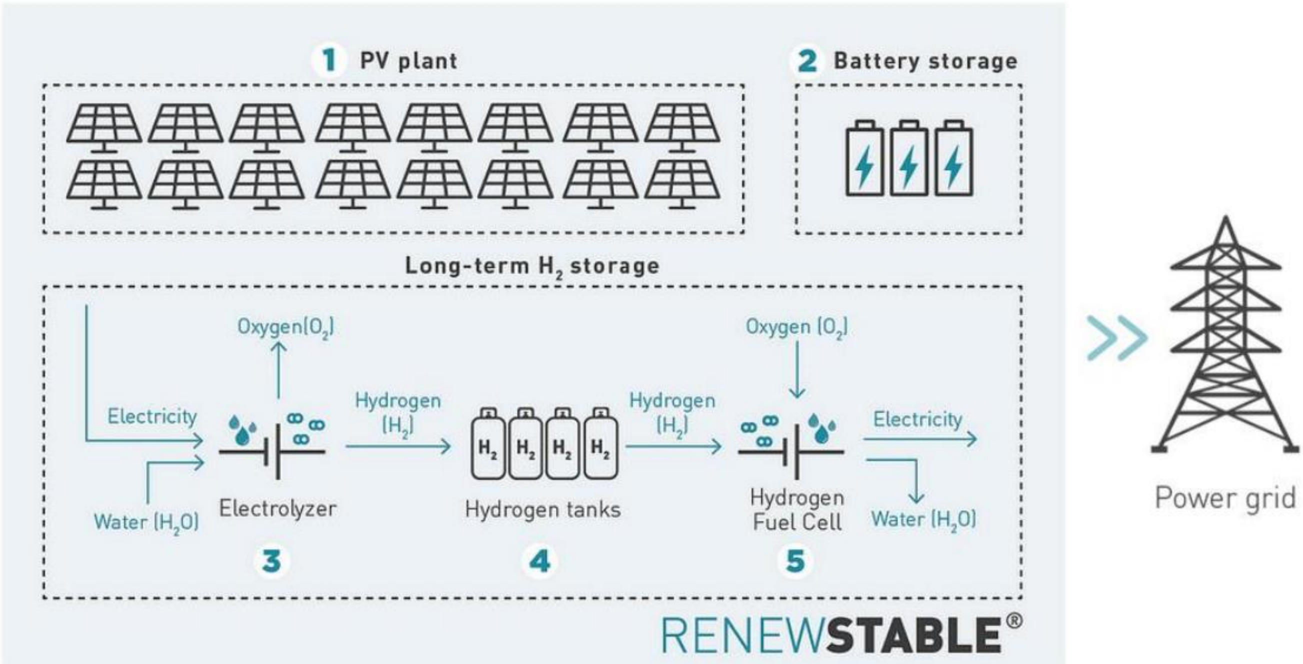
- A ground-mounted 50MWp or 38.5MWac solar PV plant, which is the primary source of carbon-free electricity generation;
- A 90MWh long-term hydrogen-based energy storage solution that includes 16 MW of electrolysers, a gaseous hydrogen storage tank farm and a 3MW fuel cell system;
- A 14 MW short-term battery energy storage solution; and
- A commercial Black Belly sheep farm specifically intended to be financially viable and environmentally sustainable over the long run, focusing on both the local and export markets.

The Applicant contends that the proposed facility will deliver 13 MW of firm RE daily between the hours of 8 a.m. and 5 p.m. as well as 7 p.m. and 9 p.m. This second two-hour period is meant to meet end-of-day peak demand. At all other times, the plant will produce 3 MW of firm renewable power. Moreover, the Applicant claims that the facility will have an average capacity factor over its lifetime of 85%, roughly equivalent to that of a conventional thermal power plant. Additionally, the Applicant contends that maintenance will be similar to that of many RE generation plants including cleaning of components and customary corrective and preventative maintenance i.e. changing of fuses, cables and inspection of inverters. The Applicant also expects to have a long-term service agreement ("LTSA") with the suppliers for the maintenance of the critical sub-systems of the facility. The power plant is expected to provide fifteen (15) to twenty (20) jobs with respect to its daily operations and will require 24-hour monitoring through a remote control centre. It is expected to comprise built-in redundancy and undergo scheduled maintenance at times to ensure no interruption of service.

3.2 Technology Overview

The technology to be used in the RSB project is meant to avoid the instability issues inherent in the use of intermittent RE sources as it has built in long-term and short-term energy storage solutions which allow both the delivery of clean and firm power. The Applicant has indicated its intention to utilize a 50 MWp solar plant and states that the solar array is designed to meet the topographical and climatic conditions that are specific to Caribbean territories such as Barbados, with limited land area, ample solar exposure and hurricane vulnerability.

Figure 1 - The technology process employed by HDF



The panels are to be fixed-tilt south-oriented in order to maximize power generation. According to the Applicant, the sizing of the plant has been based on twenty (20) years of solar irradiation data from SolarGIS, an internationally acclaimed consultancy.

Figure 2 - Example of fixed tilt panel orientation

The project also employed the use of the simulation tool PVSyst to determine the best possible configuration, given certain limitations such as module performance and topography. The Applicant has indicated that the modules, inverters, transformers and structures for the PV plant will be sourced from tier-1 suppliers, i.e. competitive companies with proven track records and products that are well adapted to the specifics of the Barbados environment.

The Applicant has also stated that it intends to use a 16MW H_2 electrolyser[6] coupled with a 90MWh storage system, a 14MW Li-Ion battery (BESS) and a 3MW H_2 fuel cell. The BESS is meant to support the provision of end-of-day peak power to meet demand when solar is unavailable and in combination with the hydrogen storage, provide stability to the system. Due to its high responsiveness, the BESS will be able to balance out any drop in power that may occur due to cloudy conditions. The BESS setup would be based on easily integrated plug-and-play preassembled enclosures with built-in safety features. The Applicant expects to obtain the battery and its components from tier-1 manufacturers such as Sunglow, Saft and others.

The electrolyser is the component that would be used to convert the electricity to hydrogen through the process of electrolysis, which will require demineralized water. The hydrogen produced from this reaction will be used to store the generated RE. The Applicant has indicated that the leading manufacturers of electrolysers are located in Europe, the United States of America and Asia and purports that electrolyser performance and reliability is expected to increase in years to come as production scales upward.

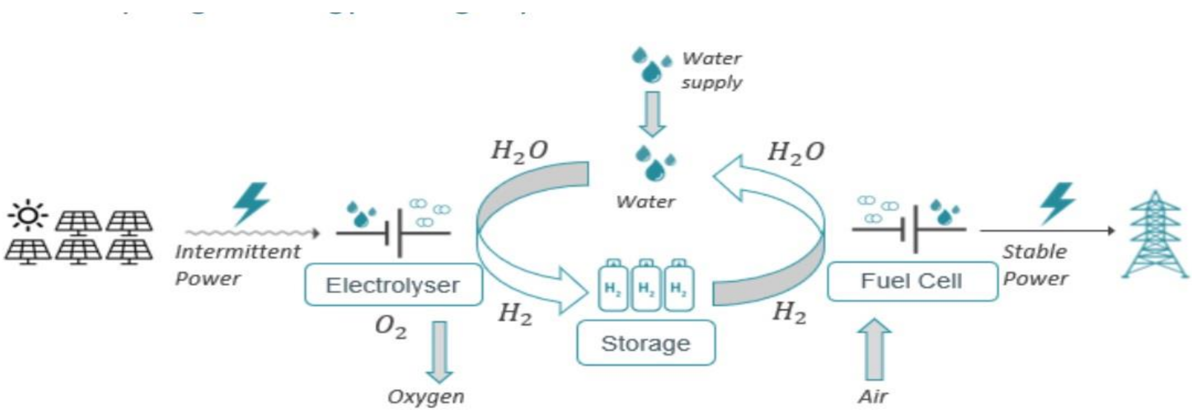
The Applicant has stated that the hydrogen will be stored in gaseous form in metal tanks and further claims that in order for electricity to be produced in a safe and cost-effective manner, the hydrogen will need to be stored at low pressure in volumes between $50m^3$ and $110m^3$. The storage vessels are to be made from a special type of steel specifically designed for hydrogen storage. This aligns with what is used in the industrial chemical and petrochemical sectors. These types of storage vessels are sourced from manufacturers such as Calvera and Faurencia.

[6] H_2 is the symbol and atomic number for Hydrogen.

The component that would be used to turn the stored hydrogen into electricity is the fuel cell. The Applicant describes fuel cell technology as being integral to the clean energy transition worldwide for decades because of its applications in backup power generation, mobility, industry, etc. The Applicant claims to have a high-power fuel cell dedicated to stationary utility scale applications. This was developed in partnership with Canadian company Ballard Power Systems, whose stack technology is called Polymer Electrolyte Membrane ("PEM") technology. The Applicant contends that PEM has been proven highly reliable in mobility applications as it is used on approximately 80% of the hydrogen buses across Europe. PEM operates at relatively low temperatures e.g. 60° C and as such, has commendable levels of durability.

With respect to the operation of the system, the PV array generates electricity which is absorbed into electrolysers. These then use that energy to split water molecules into hydrogen and oxygen, in an electro-chemical reaction called water electrolysis. The hydrogen is stored in the aforementioned tanks while the oxygen is released into the atmosphere. At the other end of the system the fuel cell reverses the process by combining the hydrogen and oxygen to then produce power and water. It must be noted that based on the two (2) by-products of this process i.e. oxygen and water, there appear to be no harmful associated environmental effects. In parallel, energy is also stored in the aforementioned series of lithium-ion BESS units.

Figure 3 - System Operation



1. **What are your views on the appropriateness of the technology and associated processes the Applicant proposes to employ to produce firm power? Please give reasons for your answer.**

3.2 Safety Considerations

Hydrogen has been used internationally in industry for more than a century. It has applications as fuel for conventional engines, fuel cells and as a carrier of energy. It must be noted that hydrogen is a highly flammable gas and as such, for a facility such as the one proposed herein, safety needs to be a paramount concern. Hydrogen is flammable at varied concentrations in air and can ignite more easily than gasoline or natural gas. As a consequence, adequate ventilation and leak detection are required to ensure safety in hydrogen based systems. Moreover, it burns with an invisible flame and as such special flame detection systems are also necessary.

There are well established safety standards for industrial uses of hydrogen. The National Fire Protection Association (NFPA) and the Compressed Gas Association (CGA) have published safety standards that apply to the use, storage and handling of hydrogen for industrial use[7].

[7] C. Rivkin, R. Burgess, and W. Buttner, Hydrogen Technologies Safety Guide, National Renewable Energy Laboratory (NREL) January 2015

These standards specify the distance between storage containers, the volume within said containers and the piping and tubing to be used.[8] The EIA submitted by the Applicant indicates that the safety systems and processes used by the Applicant with respect to hydrogen are in compliance with the NFPA. Moreover, the EIA indicates that that hydrogen and battery storage systems will be centrally located within the project site on an area almost four (4) acres in size. This area will be specifically designed to mitigate the risks of explosion or fire due to battery malfunction or hydrogen leak. There is proposed a significant setback with a radius greater than 200 metres between the area in question and the property boundary. This is proposed as a safety zone and signals further efforts by the Applicant to implement protections for both project personnel and the surrounding community.

2. **Do you agree with the Applicant's use of accepted safety standards as established by the NFPA? What other safety requirements, codes, and standards should be considered for this type of project configuration? Please give reasons for your answer.**

3.3 Tariff Considerations

The Applicant has provided estimated project costs based on preliminary discussions with suppliers. However, it is expected that these figures will be solidified with the resolution of ongoing O&M and EPC tenders. The Commission has analysed these costs with a view to deriving an appropriate rate for the project. The actual figures are excluded here as the Applicant has deemed them to be commercially sensitive and thus, confidential. However, the following is a description of the various cost categories submitted.

3.3.1 EPC Costs

The EPC costs and associated contingency costs comprise the bulk of the overall CAPEX. The Applicant has indicated that HDF Energy has extensive experience in successful tendering with respect to EPC and O&M contractors. These costs are estimates based on ongoing tender processes and the Applicant is confident it will select the appropriate contractor with a

[8] https://www.colorado.edu/firelifesafety/content/storage-compressed-hydrogen-pdf

suitably lengthy track record with respect to the implementation of large international renewable and storage projects. The chosen contractor is expected to have the financial viability to provide the requisite performance guarantees.

The eventual EPC contractor will be fully responsible for all aspects of the start-up of the facility including, equipment procurement, logistics, site works, PV plant construction, construction of required buildings and mechanical components, commissioning and electrical integration. There is an EPC contingency cost which refers to a lender-imposed requirement to have 8% of the total EPC costs funded during construction.

Development Management and Studies

These are costs related to a project management contract that the Applicant has executed. Activities include an environmental impact assessment, feasibility and other studies and financial and legal support.

Local Tax

The Applicant has assumed zero local tax. This refers an exemption from value added tax ("VAT") and import duties implemented by the GoB for inputs into RE and energy efficient systems, including "Solar photovoltaic systems (solar electric systems including inverters, charge controllers and batteries), solar lights, solar radios[9]".

Connection Costs

The Applicant has indicated it is engaged in ongoing discussions with the BLPC with respect to the likely costs of interconnecting with the grid. The estimates provided in this document are a result of those discussions.

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[9] Division of Energy and Telecommunications Prime Minister's Office Government of Barbados, Renewable Energy and Energy Efficiency Fiscal Incentives Booklet for Individuals and Companies, Division of Energy and Telecommunications, 2017

SPV Costs

This refers to staffing costs and fees to external advisors.

Insurance

The assumption with respect to insurance comprises 1.2% of construction costs during the construction period and 0.6% per annum during operation. This is based on other projects within the region and preliminary estimates from the Applicant's insurance broker.

The Applicant also submitted estimated operating cost categories which are described below.

3.3.2 Power Plant O&M

These costs are related to a LTSA to be executed with an appropriate contractor who will be responsible for the day-to-day operations of the facility, whether on-site or remotely. The O&M contractor will be providing and managing all the required resources for the plant's daily operations in accordance with the contract and is expected to have the requisite qualifications and the wherewithal to provide performance guarantees. The O&M contractor will also be responsible for supervising and monitoring plant performance and performing all corrective and preventative maintenance.

Rent

This refers to the lease for the land on which the project is to be situated. The Applicant has advised that the parcel of land is currently under a binding reservation agreement or option to lease. According to the Applicant, once all commercial agreements are concluded, including its IPP license and EPC contracts, this arrangement will end and be replaced by the aforementioned twenty-eight (28) year lease.

Insurance

The assumptions for insurance during operation are as indicated above.

Local Taxes

In this instance, this refers to corporation taxes applicable.

Utilities

These are the customary major utilities required for the functioning of any business i.e., water, telecommunications and ancillary electricity needs.

Interest on Green Climate Funding

The financing from the Green Climate Fund (GCF) is being provided at an interest rate of 2.25% over a period of eighteen (18) years. There is a moratorium on principal payments for the first of those two (2) years of that term. Any other concessionary financing will be considered in the determination of a final tariff.

3.4 Proposed Remuneration Structure

The Applicant's proposed general methodology consists of fixed capacity payments based on the plant's availability, assuming a PPA life of twenty-five (25) years. The fundamental structure is in keeping with best practices and is known to the Commission for its common use in this type of ratemaking. According to the Applicant it is also common for baseload and peaking facilities that provide firm capacity to the grid. This methodology is meant to calculate a tariff that would be sufficient to cover the following:

- Fixed O&M costs, adjusted for inflation;
- The initial CAPEX investment, subject to linear depreciation;
- Planned major maintenance; and
- A fair and reasonable rate of return

The fixed capacity payments are calculated by amortising the sum total of the above components annually over 25 years. Each of these annual capacity payments are then divided by the expected annual energy production to derive an indicative rate in BBD$/MWh. The Applicant indicated that its requested rate of return, which it claims is in line with what obtains within the region, is 10.4%. The Applicant explained that its method of deriving the requested rate comprised of the following:

- The yield-to-maturity ("YTM") of Barbados sovereign bonds that reflects international investors' perception of country risk, which was assumed to be 7.8%;
- An estimated risk premium for renewable projects at 1.5%; and

- A regionally-based equity risk premium for comparable projects estimated at 3.6%.

The Applicant states that the requested rate of return is a weighted average of the above considering a debt-to-equity ratio of 70%/30%. Moreover, in justifying the requested rate the Applicant contends that the French regulator, Commission de régulation de l'énergie ("CRE") developed a methodology for the determination of rates of return for baseload generation facilities that receive availability payments, situated outside of France. According to the Applicant, this methodology would lead to the requested rate for the RSB project being between 13% and 14%. It considers:

- An estimated risk-free rate based on the YTM of the sovereign bonds of the territory;
- A fixed premium of 400 basis points;
- A premium between 100 and 400 basis points depending on the territory; and
- A further premium of no more than 300 basis points based on the regulator's assessment of the risk.

Reasonableness of the Requested Rate of Return

Baseload RE projects generally require higher all-in costs than the associated LCOE. Generally, variable RE resources alone, such as solar and wind, can achieve capacity factors of approximately 25%, though it should be noted that there is some location specificity to be considered. In some locations capacity factors for solar can be as high as 50%. Conversely, fossil fuel or thermal plants can achieve 85%[10].

The higher costs required to firm up the RE plant usually involve the addition of energy storage assets to allow the RE plant to match the reliability and service factors of conventional plants. This scaling up of RE plants in this manner can lead to capital costs of up to ten (10) times more than that of a conventional plant. Arbogast et al. (2018) conducted a study to determine the wholesale price that a project developer would require when tasked with using various forms of RE to provide baseload power. The study defined baseload using a few scenarios, with scenario 1 being a reference case "using a 650MW Natural Gas Combined Cycle (NGCC) plant operating at 85% nameplate capacity annually and meeting a 10.5% ROE

[10] Arbogast et al, Measuring Renewable Energy as Baseload Power, The University of North Carolina at Chapel Hill, March 2018

obligation"[11]. It considers that this reference case is a baseload standard for the industry. This may be viewed as an indication that the Applicant's requested rate of return for the proposed baseload RE facility is in line with what is considered standard for the industry.

The Applicant has confirmed its receipt of funding from the GCF. It comprises an eighteen (18) year loan of USD$40M and a one (1) year grant of USD$1M. According to the Applicant, the upside of this with respect to the requested rate of return is that this funding will result in a reduction of the requested rate of return from 10.4% to 9%. The interest to be paid on this loan is considered in the OPEX of the project. Both this and the reduction in the required rate of return will impact the calculation of the final tariff.

3. **Given the scope of this unique project, what level ROE would be applicable to this type of project? Please give reasons for your answer.**

4. **Do you believe that the Applicant's general methodology and cost categories are prudent and reasonable? Please give reasons for your answer.**

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[11] Ibid

SECTION 4 THE COMMISSION'S PROPOSED METHODOLOGY

4.1 Overview

The Commission received technical assistance from experienced consultants in the development of a tariff derivation methodology that can be applied to various projects, including that proposed by the Applicant. The consultants, in conjunction with the Commission, prepared a methodology that is based on international best practices. This methodology or alternatively, model, provides remuneration to prospective project developers to cover CAPEX, OPEX and to provide a reasonable rate of return on project developers' investments i.e. the CAPEX.

The model considers two (2) types of projects: (1) standard and (2) special. For standard projects, the proposed model groups together projects with similar characteristics e.g. size, technology and location. It then assigns standard input costs, investment values and other relevant variables to each of these groupings. The result is that a number of similar projects that are appropriately grouped together would receive the same remuneration or tariff. For comparative purposes, this concept is somewhat similar to the capacity bands utilized by the Commission in its existing Feed-in-Tariff programme. For special projects, where there are unique characteristics that preclude the inclusion of these projects into the pre-determined groupings, the model features various adjustments to the calculation of the remuneration for CAPEX, OPEX and the rate of return. Whereas adjustments are made to arrive at the results, it is worth noting that the substantive underlying basis is the same as for the standard projects, i.e. cost recovery for CAPEX and OPEX with allowance on a reasonable rate of return on investment.

The model also features other terms and incentives aimed at fostering cost efficiency and regulatory oversight. These include, *inter alia*:

- The establishment of regulatory periods;
- A profit-sharing mechanism; and
- Various production and cost efficiency incentives.

Included in this proposed methodology is the use of regulatory periods. This is a concept with which the Commission is familiar as many of its current regulatory frameworks include these set periods where a particular iteration of the framework runs up until a review is required. Examples include, the Price Cap Plan, the Standards of Service and the Feed-in-Tariff. In the proposed model, at the end of each period, which the consultants suggested could be six (6) years, a review would be conducted to determine whether actual costs are in alignment with approved costs i.e. costs projected by the developer and thereafter approved by the regulator. Adjustments may then be made to the approved costs of a project for the upcoming regulatory period. The implication here is that from one regulatory period to another, the tariff received by project developers can change.

The model also provides for a profit-sharing mechanism whereby both the project developer and the overall system benefit from any cost efficiencies achieved. This may be effected at the point where a review is conducted at the end of the period. The project developer is allowed to keep a percentage of cost savings achieved in the period under review, with 50% being the maximum. The other 50% would be shared to the benefit of consumers.

Additionally, there is an incentive for the project developer to contribute to the reduction in generation costs on a macro-level i.e. across the entire system. If the project is found to have generation costs that are a specific fraction of the overall generation costs of the system, then in addition to its approved remuneration or tariff, it can receive a premium or extra income.

The model proposes various other incentives including measures to ensure that plants meet a minimum level of annual operating hours, and where possible, extend their useful lives beyond the approved regulatory life to ensure that they consistently produce the required output of electricity.

The Commission considers this proposed methodology to be well thought out and aligns with the fundamental principles of tariff derivation and best practices. It is also ambitious and boasts features which seek to give the regulator an appropriate level of control. It may however be prudent for the Commission to adjust these regulatory parameters and incentives so that they are in alignment with the Barbados market.

4.2 Specifics of the Model

Taking into account the summary above, the proposed methodology aims at calculating the regulated remuneration (R) for **a particular plant "j" in year "n"** using the following general equation:

$\mathbf{R^j_n = IR^j_n + OR^j_n + Extra\_Inc^j_n + Extension\_Inc^j_n}$

Where:

$\mathbf{IR^j_n}$ = remuneration to cover investment costs or CAPEX.

$\mathbf{OR^j_n}$ = remuneration to cover operating costs or OPEX.

$\mathbf{Extra\_Inc^j_n}$ = an extra incentive received by the project developer that corresponds to their plant's contribution to the reduction of overall electricity costs in Barbados in a specific year.

$\mathbf{Extension\_Inc^j_n}$ = an incentive received by the project developer whose plant is still fully operational beyond the end of its regulatory useful life. This is meant to reduce the impact of decommissioning costs, both financial and potentially environmental.

CAPEX Remuneration

In the equation above the term IR^j_n is used to refer to the recovery of the initial CAPEX plus a reasonable return on said investment. It includes a depreciation term along with the estimated quantum of the financial return for the particular year. The depreciation term allows the project developer to fully recover the approved (by the regulator) CAPEX for the plant. This model proposes to use the straight-line depreciation method.

Key concepts to understand here are the regulatory investment value ("RIV") and the useful life ("UL"). These are both used in the determination of depreciation, which is a vital part of any ratemaking exercise. The RIV is the investment value for a specific plant that is recognized by the regulator in a specific year. The determination of the RIV is important and is handled differently for standard projects and special projects. The UL is simply the useful life of the plant as determined by the regulator. For standard projects that are grouped according to their similar characteristics, the regulator is able to assign them a common unit investment value, which is then used to obtain the RIV depending on the installed capacity of the particular project. This is expressed in $/MW.

For special projects, there is of course no standard grouping and thus the regulator needs to have mechanisms that allow for monitoring and control of project costs. This model proposes the following steps in the determination of the RIV for special projects:

- The project developer submits detailed estimated costs and other financial information. This needs to be reviewed and approved by the regulator prior to the start of construction. This is known as the approved budget.
- Upon commissioning, the project will be paid the approved tariff based on the approved budget.
- At the end of that first year the regulator would conduct a review to determine the actual costs incurred by the project.
- The proposed methodology then calls for a cost-efficiency sharing mechanism whereby the RIV is based on the average between the initial estimates and the actual realized costs.
- A cap is implemented so that the RIV does not exceed the actual costs by a significant amount.

With respect to the proposed cap, the RIV should not be allowed to exceed the approved budget by any amount greater than 25%. In the event that actual costs are found to be significantly different from cost estimates, the project developer must submit a claim that includes a clear justification for said difference to the regulator. If the submitted claim is approved, then the RIV calculation may be adjusted to account for this difference.

5. **Do you believe that the process proposed to handle the value of special projects is reasonable? Please explain your response.**

6. **What is your view about the reasonableness of a maximum cap of 25%? Please give reasons for your answer and if possible, propose alternatives.**

OPEX Remuneration

As previously indicated, the model also considers remuneration for OPEX. Provision is made for covering a project's O&M costs. These costs can be stratified into fixed, variable and extraordinary costs. Fixed costs tend to be stable and therefore easily measurable and predictable, such as regular maintenance and activities that are required for the operation of the plant. Variable costs for generation plants typically tend to be fuel costs. However, most RE facilities, save for biomass for example, do not require fuel. Extraordinary costs are generally unpredictable and include sudden breakdowns, faults or other similar events.

As with CAPEX, the methodologies for standard projects and special projects are somewhat different. For standard projects, there are again common values that are defined and applied to the standard groupings. For special projects i.e., those which do not easily fit into any of the standard groupings, the project developer must submit cost estimates which must then be approved by the regulator. In both instances, costs are subject to review in between regulatory periods.

For standard projects, the process is similar to what has come before whereby each standard grouping is associated with approved operating costs. Considered here are fixed operating costs that would be expected for an efficiently operated plant. These may include human resource costs, maintenance and conservation costs, insurance, taxes, rents and other similar costs. Fixed operating costs will be based on standard annual operating hours. Thus, there is an incentive to ensure that the plant meets and even surpasses the standard operating hours as doing so leads to extra income earned. Where the project uses a generation technology that requires fuel, the cost for the standard grouping will be based on an appropriate cost reference for this input. In terms of the inclusion of extraordinary costs, the project developer must submit a claim for the regulator to approve.

For special projects, the developer must, as customary, submit cost estimates for the first regulatory period to be approved by the regulator. These are then subject to review at the end of the regulatory period. The length of the regulatory periods is at the discretion of the regulator. The proposed model provides for an associated profit-sharing mechanism where any positive differences between estimated costs and actual costs revealed post-review, are shared between the developer and the overall system. The review is important as it allows the regulator to set the appropriate cost remuneration for the following regulatory period based on empirical data from the previous period. To this end, the methodology considers the average between real operating costs and those approved for remuneration during the previous period.

To determine the operating costs for the first regulatory period, there are a number of steps. These include:

- Submission of estimated operating costs for all years of the regulatory period in addition to the investment costs; and
- Submission of the expected number of operating hours for the plant, based on a practical and reasonable reference, which are also subject to approval by the regulator.

In order to promote efficiency, included here is an incentive that provides extra income for the developer if the plant achieves greater operating hours than the minimum amount approved. If the plant operates fewer hours than what was approved, no incentive would apply.

For the first year of the next regulatory period, approved operating costs are determined by considering the average of the sum of the actual and allowed operating cost remuneration of each of the latter three (3) years of the previous regulatory period multiplied by a profit-sharing factor, to be determined by the regulator. It also includes inflation and efficiency parameters that again are determined by the regulator. The efficiency parameter, expressed as a percentage, is at the discretion of the regulator and is used where the regulator has determined that a particular project ought to be achieving more efficiencies. It can therefore impact the allowed operating costs if, for example, it becomes evident that there were cost overruns due to inefficiencies, reducing the allowed operating costs by said efficiency parameter and lessening the impact on ratepayers. If the profit-sharing factor is set at 50%, which the consultants recommended as the maximum, then it implies that going forward the project would only benefit from 50%, on average, of the cost efficiencies it achieved in the previous regulatory period. This is a feature that allows for the integration of actual costs and can benefit the overall system. However, if actual costs achieved turn out to be higher than the allowed costs, then the project and the system share equally in those inefficiencies. However as indicated above, this can be mitigated by the application of an efficiency parameter.

7. **What are your views on the treatment of OPEX for special projects? Please give reasons for your response.**

Incentives and other Regulatory Tools

Proposed within the model is an incentive whereby projects could earn a premium on the regulated tariff or remuneration if they contribute significantly to a reduction in the overall system generation costs. It is understood that RE projects have a tendency to put downward pressure on variable costs, as there is no fuel to be purchased, with the notable exception of biomass facilities. Conversely, conventional generation is predominantly fossil fuel based, and those variable costs consisted almost exclusively of fuel imports which are highly volatile. This incentive seeks to reward those RE projects that meet a particular threshold in contributing to those cost savings.

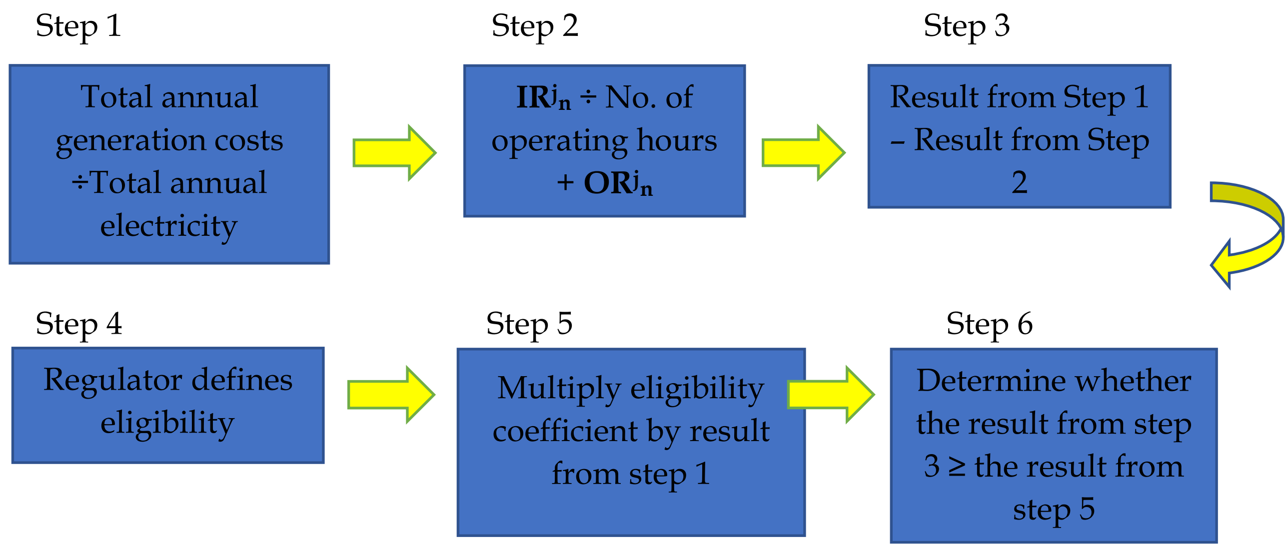
It is a slightly complicated process, which has the following steps:

- Step 1 is to divide the total annual variable generation costs of the overall system by the total electricity generated in the particular year.
- Step 2 is to divide the investment remuneration of a particular project by its applicable number of operating hours and add that result to its operating costs remuneration.
- Step 3. Once the result of step 2 is found, this is subtracted from the result from step 1.
- Step 4. The regulator must define a coefficient that will determine the threshold at which the project would begin to be eligible for the incentive. For example, if this is set at 0.5 then a plant whose operating costs is at least 50% lower than the overall system variable cost would be eligible to earn the premium. In this instance, this coefficient is not empirically derived but the Commission's consultants have advised that it is commonly accepted practice for regulators to set the maximum value at 0.5 or 50%. This provides a measure of balance between the project developer and the ratepayers. The Commission's consultants have advised that values above 50% are not typical as this would allow the project developer to collect a majority of any efficiencies achieved. Therefore it was considered prudent to set 0.5 or 50% as the maximum value. This is borne out by examples referenced on pages 35 and 36 of this paper in the section entitled Regulatory Case studies. The TOTEX scheme in the UK is said to have a complex

method of calculating its profit-sharing threshold. However, the Commission's consultants have also described a similar mechanism from Italy which includes a symmetric cost sharing mechanism where there is no expressed specific method for calculating the 50% threshold.

- Step 5. Once this coefficient is determined, this step involves multiplying this by the result from step 1.
- Step 6. In this final step an assessment is made to determine if the result from step 3 is more than or equal to the result from step 5. In other words, when the costs for a particular plant are subtracted from the variable costs of the overall system, the plant is only eligible for the premium if the result of said subtraction is at least equal to the threshold as determined by the regulator. If a project's generation costs are low enough then the chances of its eligibility are higher.

Figure 4 - Flow chart of the system costs incentive.



Related to this is the determination of the actual quantum of the premium, should a plant be eligible. To calculate this, the third step as outlined above is multiplied by another coefficient that is determined by the regulator. This again is not empirically determined but is at the discretion of the regulator as it involves a judgement call as to the appropriate size of any incentive, given the balance required between project developers and ratepayers. If the regulator determines that the coefficient is 0.1, this means that the incentive or premium would be equal to 10% of the difference between the overall system variable costs and the investment and operating costs of the particular plant.

8. **Do you believe that an incentive for contributing to the overall reduction in the generation costs of the entire system is reasonable? Please give reasons for your response.**

Another regulatory tool included in the proposed model comes in the form of a safeguard that ensures that projects operate sufficient hours per year in order to have the best opportunity of providing an appropriate amount of electricity into the system. Projects that do not meet an approved level of minimum operating hours per year will not receive the full remuneration and in fact, if they are found to be below a certain threshold, they may receive nothing. The main purpose of this is to guard against projects that may collect the tariff while not contributing enough output due to a lack of hours in operation. In cases where remuneration is linked to energy production, this type of safeguard could indeed be included in the associated PPA. However, in this case the remuneration is linked to available capacity and as such it is unlikely that the PPA between the offtaker and the project developer could include such as safeguard.

The model thus provides for a minimum level of operating hours and an operating threshold. For standard projects that are grouped together in their various groupings, these values are pre-defined for each grouping. For special projects, the developer must submit proposed minimum operating hours etc., for regulatory approval. This process involves the use of a few terms as outlined below:

Nh^j_n = actual number of operating hours of plant "j" in year "n", calculated as the ratio between actual energy produced in the year in MWh and the plant's installed capacity in MW
Nh^j_{min} = minimum approved operating hours pre-defined for a standard project or approved upon submission for a special project.
T^j_0 = operating threshold pre-defined for a standard project or approved upon submission for a special project. This value is always lower than Nh^j_{min}
The applicable scenarios here are:

- If Nh^j_n is greater than Nh^j_{min} then the project will receive its full remuneration.
- If $Nh^j_{min} > Nh^j_n > T^j_0$ the remuneration is reduced by a factor determined by the regulator.
- If $Nh^j_n < T^j_0$ the project receives no remuneration.

There is also a provision in the model for maximum operating hours to prevent projects from operating more than is appropriate. This is a control on operating costs but due to natural limitations, e.g., unavailability of sunlight due to cloud cover or nightfall, it is not applicable to solar or wind facilities. It is more suited to a biomass facility.

9. **Is an incentive for projects to meet minimum operating hours reasonable? Please give reasons for your response.**

Finally, the model includes an extension incentive for projects which continue to operate beyond the approved regulatory useful life. This is built into the model from the beginning and comprises multiplying the operating remuneration by a factor to be determined by the regulator. As a reminder, the general equation of the model outlined above is:

$$\mathbf{R^j_n = IR^j_n + OR^j_n + Extra\_Inc^j_n + Extension\_Inc^j_n}$$

The term $\mathbf{Extension\_Inc^j_n}$ refers to this incentive. This term would be zero during the regulatory useful life of the plant and only become relevant when this period is concluded. It is conceivable that even after the regulatory useful life has expired, a plant could still be fully operational and able to continue providing energy. It would no longer receive investment remuneration as that cost would have been fully covered. However, it would still be eligible to have its operating costs covered. Ostensibly this incentive promotes the avoidance of decommissioning costs, both financial and environmental.

10. **Do you believe that the incentive for project that operate beyond their regulatory useful life is reasonable? Please give reasons for your response.**

Regulatory Case Studies

The Commission has found instances of regulatory authorities in other jurisdictions that utilize frameworks with features that are similar to what is proposed herein. The examples found apply in markets that are closely regulated as opposed to being fully liberalised. As such, the various methods used may also be applicable in the Barbados context. It should also be noted that while all these cases may not specifically be within the RE sector, the idea is to illustrate that the features proposed herein are generally accepted in ratemaking and tariff setting applications and are not exclusive to RE facilities.

In the United Kingdom ("UK") the Office of Gas and Electricity Markets ("OfGEM") developed a remuneration framework for regulated activities e.g., distribution and transmission of gas and electricity. It is referred to as RIIO (Revenue = Incentives + Innovation + Output)[12]. This framework also involves the use of a profit-sharing mechanism. The TOTEX[13] Incentive Mechanism ("TIM") is designed to improve the efficiency of network companies and ensure that these efficiencies are fairly shared with consumers. Essentially, a company is granted a TOTEX allowance based on its forecasts and this is then compared with actual TOTEX. Any differences are shared between the company and consumers.

In Spain, The Spanish National Markets and Competition Commission (CNMC), which is the agency that monitors all markets to ensure proper operation in the interests of both consumers and companies, established a remuneration mechanism that features an extra incentive for facilities that continue to operate beyond their regulatory lifespan. This incentive is based on a percentage of the facility's OPEX remuneration that would apply after the expiration of its regulatory useful life and is added in addition to regular remuneration. The percentage depends on the number of years that have elapsed since the end of the facility's regulatory useful life. This mechanism is known as the Compensation for Extended Useful Life of Facilities (REVU)[14].

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[12] Decision on a mid-period review for RIIO-T1 and GD1 (ofgem.gov.uk), Date accessed November 29, 2023

[13] Please note: the source of this information was not explicit as to the definition of TOTEX but the contextual use indicates that it refers to total expenses

[14] CNMC, **CIRCULAR 5/2019, OF 5 DECEMBER, ESTABLISHING THE METHODOLOGY FOR CALCULATING THE REMUNERATION OF THE ELECTRICITY TRANSMISSION ACTIVITY**, 2019, Date accessed November 29, 2023

There is an ongoing programme within the European Union ("EU") where the regulatory authority has called for proposals for a RE financing mechanism. The EU insists that participants must produce a minimum level of output. Specifically, during the period where the mechanism is active, a participating facility must generate a minimum of "850 Full Load Hours per year"[15] based on its installed capacity.

The examples presented above illustrate that the Commission's proposed approach aligns well with industry standard principles that continue to be in use in mature markets.

4.3 Final Proposals

The Commission proposes the utilisation of the cost estimates provided by the Applicant within the proposed methodology as described above, and accounting for the approval of the GCF funding leading to a reduction in the required rate of return and inclusion of interest payments, to calculate an appropriate rate. Additionally, it is recognized that the Applicant has thus far provided cost estimates and has indicated that certain matters remain pending, such as the land lease and generation license. Consequently, the Commission finds it prudent that any rate calculated prior to the conclusion of these matters and submission of confirmed costs be considered a provisional rate. The final rate would be conditional on the final confirmed costs and proof of generation license.

The Commission further recommends full use of the methodology outlined above with two (2) exceptions, namely:

- The use of regulatory periods of three (3) years. This aligns well with other regulatory tools currently in use by the Commission such as the Price Cap Plan and the Standards of Service. Consequently, the Commission finds this to be a reasonable time period.
- Removal of the extra incentive for projects that continue to operate beyond their regulatory useful life. The Commission considers that the normal OPEX remuneration should be sufficient. This recommendation also encourages consideration that a

[15] Call for proposals for the EU Renewable Energy Financing Mechanism (europa.eu), Date accessed November 29, 2023

proliferation of incentives that provide extra income for projects can become burdensome to ratepayers.

11. **What are your views on the general equation for the proposed methodology? Please explain your answer.**

12. **What are your views on the Commission's overall proposed approach to the Applicant's project? Please give reasons for your response.**

SECTION 5 CONSULTATION QUESTIONS

1. **What are your views on the prudence and reasonableness of the technology and associated processes the Applicant proposes to employ? Please give reasons for your answer.**

2. **Do you agree with the Applicant's use of accepted safety standards as established by the NFPA? What other safety requirements, codes, and standards should be considered for this type of project configuration? Please give reasons for your answer.**

3. **Given the scope of this unique project, what level ROE would be applicable to this type of project? Please give reasons for your answer.**

4. **Do you believe that the Applicant's general methodology and cost categories are prudent and reasonable? Please give reasons for your answer.**

5. **Do you believe that the process proposed to handle the value of special projects is reasonable? Please explain your response.**

6. **What is your view about the reasonableness of a maximum cap of 25%? Please give reasons for your answer and if possible, propose alternatives.**

7. **What are your views on the treatment of OPEX for special projects? Please give reasons for your response.**

8. **Do you believe that an incentive for contributing to the overall reduction in the generation costs of the entire system is reasonable? Please give reasons for your response.**

9. **Is an incentive for projects to meet minimum operating hours reasonable? Please give reasons for your response.**

10. **Do you believe that the incentive for project that operate beyond their regulatory useful life is reasonable? Please give reasons for your response.**

11. **What are your views on the general equation for the proposed methodology? Please explain your answer.**

12. **What are your views on the Commission's overall proposed approach to the Applicant's project? Please give reasons for your response.**