FAIR TRADING COMMISSION

DECISION

The Barbados Light & Power Company Limited's Application for Preapproval of Investments and Cost Recovery through the Clean Energy Transition Rider

Document No.: FTCUR/DECCETP1/2024-1 Date of Issue: May 6, 2024

DOCUMENT NUMBER:
FTCUR/DECCETP1/2024-1

DOCUMENT TITLE: The Barbados Light & Power Company Limited's Application for Preapproval of Investments and Cost Recovery through the Clean Energy Transition Rider

ANTECEDENT DOCUMENTS

Document Number	Description	Issue Date
FTCUR/DECCETR/ BLPC/2023-02	DECISION on The Barbados Light & Power Company Limited (BLPC) Application to Establish a Clean Energy Transition Rider as a Cost Recovery Mechanism	2023-05-31

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List Of Abbreviations

AGC	Automatic Generation Control
BESS	Battery Energy Storage System
BLPC	Barbados Light & Power Company Limited
BNEP	Barbados National Energy Policy 2019 – 2030
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CETP	Clean Energy Transition Plan
CETR	Clean Energy Transition Rider
COD	Commercial Operation Date
COSR	Cost of Service Regulation
DER	Distributed Energy Resource
DES	Distributed Energy Storage
DRE	Distributed Renewable Energy
ELPA	Electric Light and Power Act, 2013-21
ESD	Energy Storage Device
EV	Electric Vehicle
FCA	Fuel Clause Adjustment
FTCA 2020	The Fair Trading Commission Act, CAP. 326B, as amended
GoB	Government of Barbados
IBS	Inverter Based Systems
IPPs	Independent Power Producers
IRRP	Integrated Resource and Resiliency Plan
KVARh	Kilovolt-Ampere Reactive hour
KVAr	Kilovolt-Ampere Reactive
LCOS	Levelised Cost of Storage
MCM	Thousand Circular Mils
MEB	Ministry of Energy and Business
MESBE	Ministry of Energy, Small Business and Entrepreneurship
MW	Megawatt
MVAr	Megavolt-Ampere Reactive
OEM	Original Equipment Manufacturer

PPA	Power Purchase Agreement
PV	Photovoltaic
RE	Renewable Energy
RFP	Request for Proposals
ROE	Return on Equity
ROR	Rate of Return
SCO	Synchronous Condenser
SDG	Sustainable Development Goal
STATCOM	Static Synchronous Compensator
The Commission	Fair Trading Commission
T&D	Transmission and Distribution
URA 2020	Utilities Regulation Act CAP. 282, as amended
URPR	Utilities Regulation (Procedural) Rules (the URPR).
USOA	Uniform System of Accounts
V2G	Vehicle-to- Grid
WACC	Weighted Average Cost of Capital

EXECUTIVE SUMMARY

On October 5, 2023 the Barbados Light & Power Company Limited (the "BLPC" or the "Applicant") submitted to the Fair Trading Commission (the "Commission") an Application for preapproval of investments and cost recovery through the Clean Energy Transition Rider (CETR) ("the Application") pursuant to item 1, paragraph 7.1 of the Commission's Decision on the BLPC's Application to Establish a Clean Energy Transition Rider as a Cost Recovery Mechanism, dated and issued on May 31, 2023 under Document **# No. FTCUR/DECCETR/BLPC/2023-02** that established the CETR. The Application seeks approval for the recovery of costs associated with the capacity and transmission & distribution resources which form its first Clean Energy Transition Plan (CETP) Project. The resources in CETP Project 1 for which the costs are to be invested over a three-year period are:

a. Interconnection infrastructure to facilitate the integration of Independent Power Producers (IPPs) onto the public grid;

b. 90 MW of Battery Energy Storage Systems;

c. Distributed Energy Resources Aggregation & Control platform ("the pilot");

d. Automatic Generation Control (AGC) systems; and

e. Synchronous Condensers.

After consideration of the BLPC's Application, intervenors' submissions, and the Commission's own research, the Commission makes the following determination:

A. 90 MW OF BATTERY ENERGY STORAGE SYSTEMS (BESS)

(1) The recovery of CAPEX associated with the total 15 MW (1 × 10 MW and 5 × 1 MW) BESS earmarked to be commissioned in 2024 is approved. The remainder is not approved.

(2) The BLPC shall be required to provide the following information to the Commission:

(i) The total estimated installed costs for the 15 MW BESS based on the accepted costs from the selected vendor no later than one (1) month after accepting said costs;

(ii) **The actual CAPEX[1] of each asset, no later than one (1) month after commissioning of the total BESS capacity that is earmarked for the calendar year;**

(iii) **Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying each BESS asset that is scheduled for a calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the total BESS capacity that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;**

(iv) **For each BESS, a single line connection diagram, a copy of the OEM operations manual, specification document, and OEM warranty sheet no later than one (1) month after commissioning of the total BESS capacity scheduled the calendar year;**

(v) **A copy of the pre and post commissioning report for the BESS assets no later than one (1) after commissioning;**

(vi) **A unique identifier for each BESS asset based on its location and include in its quarterly regulatory reporting, monthly information on:**

  a. **Details of, and actual operation and maintenance costs for each BESS;**
  b. **Minimum state of charge;**
  c. **Energy Charged (kWh-AC);**
  d. **Energy Discharged (kWh-AC);**
  e. **Reactive Power absorbed (KVAR -AC);**
  f. **Reactive Power delivered (KVAR-AC;**
  g. **Reactive Power absorbed (KVARh -AC);**
  h. **Reactive Power delivered (KVARh-AC; and**
  i. **Round Trip Efficiency (%).**

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[1] The Commission has determined that "Actual CAPEX costs" shall be defined as the Commission has determined that "Actual CAPEX costs" shall be defined as the total costs required to procure, build, and commission the project.

This information shall be submitted to the Commission no later than one (1) month after the end of each quarter;

(vii) Information for each BESS on the following:

a. **Maximum Energy Capacity (kWh-AC measured);**
b. **Maximum Power Capacity (kW -AC measured);**
c. **State of Health (%);**
d. **Capacity Ratio (%);**
e. **System Efficiency (%); and**
f. **Cycle Life.**

BLPC shall include this information in its annual regulatory reporting no later than one (1) month after the end of the calendar year;

(viii) A maintenance programme for the BESS assets based on the OEM's guidelines, industry best practice, and the operating environment, for approval of the Commission, no later than three (3) months prior to the commissioning of the BESS;

(ix) Ad-hoc reports for exigency events no later than seven (7) working days of occurrence of the event; and

(x) Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.

(3) The BLPC can commence recovery of the actual CAPEX and associated costs for the BESS assets as determined by the Commission, six (6) months after commissioning.

B. <u>AUTOMATIC GENERATION CONTROL (AGC) SYSTEMS</u>

(1) The recovery of CAPEX and associated costs for the proposed AGC system is approved.

(2) The BLPC shall be required to provide the following information to the Commission:

(i) The total estimated installed costs for the AGC system based on the accepted costs from the selected vendor no later than one (1) month after accepting said costs;

(ii) Actual CAPEX for the AGC system no later than one (1) month after its commissioning for the calendar year;

(iii) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying the AGC system that is scheduled for the calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the AGC system that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

(iv) A copy of the OEM operations manual, specification document, and OEM warranty sheet for the AGC system no later than one (1) month after its commissioning;

(v) A copy of the pre and post commissioning report for the AGC system no later than one (1) month after commissioning;

(vi) A performance report for the first six (6) months of operation of the AGC system. The report shall be submitted to the Commission one (1) month after commissioning;

(vii) A maintenance regime for the AGC system in accordance with the OEM's guidelines, industry best practice, and the operating environment and submit for the approval of the Commission, no later than two (2) months after the commissioning of the AGC system;

(viii) Details of the operating and maintenance costs for the AGC system for each month, in its quarterly reporting no later than one (1) month after the end of the quarter;

(ix) Maintenance and operating reports for the AGC system on an annual basis no later than one (1) month after the end of the calendar year;

(x) **Ad-hoc reports for exigency events no later than seven (7) working days after the occurrence of the event; and**

(xi) **Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.**

(3) **The BLPC can commence recovery of the actual CAPEX and associated costs for the AGC as determined by the Commission, six (6) months after commissioning.**

C. <u>FOUR (4) SYNCHRONOUS CONDENSERS (SCO)</u>

Recovery of costs for the proposed investment for the SCOs is not approved.

D. <u>DISTRIBUTED ENERGY RESOURCES AGGREGATION AND CONTROL PLATFORM ("THE PILOT")</u>

(1) **The recovery of CAPEX and associated costs for the proposed pilot is approved.**

(2) **The BLPC shall be required to provide the following information to the Commission:**

(i) **The total estimated installed cost for the pilot based on the accepted costs from the selected vendor no later than one (1) month after accepting said costs;**

(ii) **Actual CAPEX for the pilot no later than one (1) month after its commissioning for the calendar year;**

(iii) **Copies of all invoices in relation to the actual CAPEX of the asset justifying the costs actually incurred in deploying the pilot that is scheduled for the calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the pilot that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;**

(iv) **A copy of the OEM operations manual, specification document, and OEM warranty sheet for the pilot no later than one (1) month after its commissioning;**

(v) **A copy of the pre and post commissioning report for the pilot, no later than one (1) month after commissioning;**

(vi) **A performance report for the first six (6) months of operation of the pilot. The report shall be submitted to the Commission no later than one (1) month after commissioning;**

(vii) **A maintenance regime for the pilot system in accordance with the OEM's guidelines, industry best practice, and the operating environment and submit for the approval of the Commission, no later than two (2) months after the commissioning of the pilot;**

(viii) **Maintenance reports to the Commission on an annual basis, no later than one (1) month after each anniversary of commissioning;**

(ix) **In its quarterly reporting, details of the operating and maintenance costs for the pilot, no later than one (1) month after the end of the quarter;**

(x) **In its annual regulatory reporting, details of the operating and maintenance costs for the pilot on an annual basis no later than one (1) month after the end of the calendar year;**

(xi) **Ad-hoc reports for exigency events no later than seven (7) working days after the occurrence of the event; and**

(xii) **Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.**

(3) The BLPC can commence recovery of the actual CAPEX and associated costs for the pilot as determined by the Commission, six (6) months after commissioning.

E. INTERCONNECTION INFRASTRUCTURE

(1) The recovery of costs associated with the Interconnection Infrastructure is approved.

(2) The BLPC shall be required to provide the following information to the Commission:

(i) The total estimated installed costs for the infrastructural upgrades based on the accepted costs from the selected vendors no later than one (1) month after accepting said costs;

(ii) Actual CAPEX information for the infrastructural upgrades and a statement of works, no later than one (1) month after completion of the upgrade;

(iii) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying each upgrade that is scheduled for a calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the total upgrades that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

(iv) Schedules for network upgrades, demarcated by year, location, duration, commencement and completion on a quarterly basis. This information shall be submitted one (1) month following the end of the quarter;

(v) A copy of a queue connection register for planned interconnections for each year, no later than one month (1) after issuance of this CETR Decision;

(vi) A list of RE projects scheduled for interconnection requests on a quarterly basis. This information shall be submitted no later than one (1) month after the end of the quarter;

(vii) A list of the status of RE interconnections on an annual basis, no later than one (1) month after the end of the calendar year;

(viii) The status of IPP negotiations on a bi-annual basis. This information is required no later than one (1) month following the end of the first half and second half of the calendar year; and

(ix) A copy of the final draft interconnection agreement template to the Commission no later than four (4) months after the issuance of the Commission's Decision.

F. FORMAT

Where appropriate the above information should be submitted in Excel Spreadsheet format with appropriate tabs.

G. CYBERSECURITY

The BLPC shall exercise industry best practice with regard to use, management, confidentiality, availability, and integrity of customer data in order to mitigate against cybersecurity threats and risk.

H. TRACKER FORMULA

The rider shall be calculated using the following equation[2]:

$$\boldsymbol{CETR_n = \frac{\sum_1^j[(RC_j - D_j) * RoR_j + EDT_j]}{Sales} \qquad \$/kWh}$$

Where:

j refers to the asset commissioned
Sales = Electricity Sales (kWh)
RC_j = Resource Costs of approved equipment for asset j
D_j = Accumulated Depreciation for asset j
RoR_j = Allowed Rate of Return for asset j
EDT_j = Expenses (ie. O&M, Depreciation & taxes) for asset j

[2] The unit of measurement being dollars per kwh ($/kWh)

I. MONITORING

(1) The utility is required to submit the regulatory reports on utility earnings inclusive of all utility costs on a quarterly basis to the Commission. The regulatory reports must include those costs that are proposed to be recovered through the rider, including costs associated with acquisition, construction, administration, operation, maintenance, any other costs incurred and any further information which the Commission may request from time to time.

(2) The Commission will monitor the quantum of costs allowed to pass through the CETR Mechanism on a quarterly basis. Where it is evident that the BLPC has over/under recovered, the Commission reserves the right to reconcile the indicative costs.

(3) **The Commission reserves the right to conduct audits on the performance of the BLPC and the use and usefulness of the assets approved pursuant to this Decision from time to time in the Commission's sole discretion. Where it is found that the BLPC's performance is unsatisfactory, the Commission shall take the appropriate actions to ensure compliance with this Decision.**

SECTION 1 INTRODUCTION

BACKGROUND

1. As outlined in the Barbados National Energy Policy (BNEP) issued in 2019 the GoB established its vision to transition Barbados to a fully decarbonised nation by 2030, where 100% of energy would be generated by renewable energy (RE) sources[3]. The targets set out in that policy included goals for 205 MW of centralised solar photovoltaic (PV), 105 MW of distributed solar PV, 105 MW each of onshore and offshore wind, and 200 MW of energy storage technologies. This decarbonisation strategy was further formalised in the 2021 Integrated Resource and Resiliency Plan (IRRP)[4], which schedules annual capacity allocations for each RE technology investment over the short to medium term in anticipation of achieving a 100% RE powered nation.

2. To date, some progress has been made towards achieving these goals. This is evidenced by the growth in installed capacity of RE technologies on the electricity grid. As of February 1, 2024, a total of 94 MW of RE capacity had been installed on the electricity grid, with a further 32.3 MW awaiting installation by the BLPC. Additionally, 240 MW of capacity had a Connection Impact Assessment (CIA) completed by BLPC.

3. In order for the RE sector to continue to grow in a manageable manner and in consideration of the 2021 IRRP and BNEP 2019 mandate, critical investments are required in the electricity grid. This has been evidenced by the position taken by the BLPC to limit current connection of RE systems to the electricity grid unless these projects include storage. Wind and solar PV technologies are inherently intermittent and variable, and thus require further investments by the utility in order to mitigate against these characteristics.

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[3] Barbados National Energy Policy 2019 – 2030 Government of Barbados. (2023). Resiliency Plan for Barbados. Retrieved from Official Website of The Barbados Government- Ministry of Energy and Business: https://energy.gov.bb/download/national-energy-policy-2019-2030/

[4] Integrated Resource and Resiliency Plan Government of Barbados. (2023). Resiliency Plan for Barbados. Retrieved from Official Website of The Barbados Government- Ministry of Energy and Business: https://energy.gov.bb/download/mm_iadb_final-irrp-report_activity-b/

THE APPLICATION

4. On May 31, 2023, the Commission issued its decision on the BLPC's application for approval to establish a clean energy transition rider, referred to as a CETR to recover the cost of proposed investments associated with its CETP. The Commission's decision required that the BLPC submit individual applications for the recovery of costs of each asset/project through the cost recovery mechanism[5] (CETR Decision). Furthermore, each application is required to meet specific minimum criteria as follows[6]:

   a) *Prior notice of application at least thirty (30) business days before making an application;*
   b) *Description of tracker formula to be implemented;*
   c) *Itemised description and computation to reflect updated rate base;*
   d) *Type, updated costs and function of each asset per CETP;*
   e) *Allocation of assets in CETP to conform to the USOA;*
   f) *Cost benefit analysis for asset(s) where applicable;*
   g) *Summary and calculation of individual proposed/actual annual costs, incremental revenue requirement, rate of return, rate and bill impact per CETP;*
   h) *Summary and calculation of cumulative proposed/actual annual costs, revenue requirement, rate of return, rate and bill impact under COSR framework;*
   i) *Statement of the effect on the number of rate case filings, with increases or decreases in rates;*
   j) *Computation of the effect on all rate classes; and*
   k) *Where appropriate the above information should be submitted in Excel Spreadsheet format with appropriate tabs.*

5. On October 5, 2023 the BLPC submitted an application to the Commission seeking preapproval of capacity and transmission & distribution resources which form its first Clean Energy Transition Plan (CETP) Project ("CETP Project 1") pursuant to the CETR Decision.

6. The application requested the recovery of costs for the following proposed investments:
   a. *Interconnection infrastructure to facilitate the integration of independent Power Producers (IPPs) onto the public grid;*

[5] Decision on The Barbados Light & Power Company Limited Application to Establish a Clean Energy Transition Rider as a Cost Recovery Mechanism Document No. FTCUR/DECCETR/BLPC/2023-02 dated May 31, 2023
[6] See page 5 of the CETR Decision dated May 31, 2023

b. 90-megawatt of battery Energy Storage Systems;

c. Distributed Energy Resources Aggregation & Control platform ("the pilot");

d. Automatic Generation Control (AGC) systems; and

e. Synchronous Condensers.[7]

7. The estimated costs of the proposed assets over the three years are summarised in Table 1.

Table 1 – Summary of Investments Costs

INVESTMENTS	2024 ($)	2025 ($)	2026 ($)	TOTAL ($)
BESS	107,940,915	224,046,588	227,812,325	599,799,828
Synchronous Condensers		25,140,100	25,140,100	50,280,200
Automatic Generation Control	3,580,855			3,580,855
IPP Interconnection	13,419,928	22,308,721	34,239,364	69,968,013
DER Aggregation & Control	1,172,943			1,172,943
TOTAL	**126,114,641**	**271,495,409**	**287,191,789**	**684,801,839**

[7] See paragraph 1 of the BLPC's Application, dated October 5, 2023.

SECTION 2 LEGISLATIVE FRAMEWORK

POWER TO SET RATES

a) The Utilities Regulation Act, Chapter 282 of the Laws of Barbados (the "URA") and the Fair Trading Commission Act, Chapter 326B of the Laws Barbados, (the "FTCA") together empower the Commission to set and monitor rates for the supply and distribution of electricity in the RE sector of Barbados. More particularly, pursuant to Section 4(3) of the FTCA, the Commission has the responsibility to, inter alia:

   (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) …

8. The Commission also has these duties under Section 3(1) of the URA, which states:

   "The functions of the Commission under this Act are, in relation to service providers, to (a) Establish principles for arriving at the rates to be charged;

   (b) Set the maximum rates to be charged;

   (c) Monitor the rates charged to ensure compliance

   (d) ….".

PRINCIPLES AND RATES

9. Section 2 of the FTCA and Section 2 of the URA both define "principles" as the "formula, methodology or framework for determining a rate for a utility service", and stipulate that "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; an©(c) a schedule or tariff respecting a rate.

PROCEDURAL DIRECTIONS

10. Procedural Directions were issued on November 23, 2023, and February 19, 2024 in accordance with Rule 4 of the Utilities Regulation (Procedural) Rules, 2003 as amended (the "URPR") which states:

    "The Commission may issue procedural directions, which shall govern the conduct of proceedings before the Commission and shall prevail over any provision of these Rules that is inconsistent with those directions."

SECTION 3 INTERVENORS AND SUBMISSIONS

11. On November 8, 2023, the Commission issued a public notice of application requesting that interested parties submit letters of intervention to the Commission no later than November 17, 2023.

12. Following this request, intervenor status was conferred on the following parties:
    a. The intervenor team of Ms. Tricia Watson and Mr. David Simpson
    b. The Barbados Renewable Energy Association (BREA);
    c. Mr. Kenneth Went;
    d. Mr. John Hall;
    e. Barbados Association of Retired Persons (BARP) represented by the Office of Public Counsel; and
    f. Mr. Walter Maloney represented by the Office of Public Counsel.

13. Procedural Direction No. 1 was issued to all parties to the Application in accordance with Rule 4 of the Utilities Regulation (Procedural) Rules (the URPR). All parties were advised of the requisite timelines and conditions for making submissions with respect to the BLPC Application.

14. The BLPC requested extensions of time to respond to interrogatories on December 6, 2023, to December 15, 2023 and December 22, 2023 to January 5, 2024, citing its inability to provide the extensive information requested in a limited timeframe as the reason. The Commission granted these requested extensions of time and on February 19, 2024, Procedural Direction No. 2 was issued to all parties detailing further procedural guidelines. Intervenors were required to make final submissions by March 4, 2024, and the BLPC was permitted to provide their final submission by March 8, 2024. The intervenor team of Tricia Watson and David Simpson requested an extension of time to submit written submissions. The Commission granted the extension of time from March 4, 2024 to March 13, 2024 for the intervenor team to make its written submissions.

GROUNDS OF APPLICATION

15. In its application BLPC asserts that the assets and projects have been submitted for approval on the grounds that[8]:

    (1) The costs are unpredictable and volatile, reoccurring, and outside the BLPC's manageable costs within the meaning of the CETR Decision;

    (2) Those costs are prudently incurred transitionary and grid modernization costs within the meaning of the Decision; and

    (3) The acquisition of the resources identified for its CETP Project 1, are preconditions to achieve the objectives of the BNEP and are critical to maintaining the reliability of the national grid and constitute necessary changes, extensions and improvements to BLPC's network and service required to ensure BLPC's provision of a safe, adequate, efficient and reasonable service to the public.

[8] See paragraph 2 of the BLPC's Application.

SECTION 4 THE ANALYSIS

INTRODUCTION

16. The BLPC proposes a suite of initial investments under its CETP Project 1; these are considered prerequisites for resilience and reliability of the grid, and essential for the fulfilment of the BNEP goal towards 100% RE by 2030.[9] These suggested investments are stated in the Application to be in recognition of the need to support the transition to an energy mix with a dominant RE resource component and to mitigate the operational challenges that intermittent RE present for the existing electricity grid.

17. The Commission accepts that the BLPC is obligated to comply with Government's mandated IRRP 2021. As a key stakeholder, BLPC's participation in the execution of Government's energy plans creates a level of certainty to further develop the operating environment towards fully decarbonising the electricity grid.

18. The Commission also accepts that given the adoption of a clean energy pathway the achievement of the BNEP goals requires clarity, market certainty, careful planning, significant capital investments and the implementation of said investments to meet the objectives of Government. This ambition brings into perspective that certain activities are needed to fully transition the existing power system to facilitate the integration of RE into the grid safely.

19. The Commission, having reviewed the BLPC's Application therefore presents an assessment of these operational and technical considerations related to each of the proposed investments that motivated the conclusions stated below.

20. This assessment relates to certain infrastructural and operational aspects of the proposed investments in terms of timing, need and prudence.

[9] Barbados Light and Power Company Limited (BLPC), Application for Preapproval of Investments and Cost Recovery through the Clean Energy Transition Rider, BLPC, Bridgetown: BLPC, 2023, Paragraph 12 page 5

INTERCONNECTION INFRASTRUCTURE TO FACILITATE THE INTEGRATION OF INDEPENDENT POWER PRODUCERS (IPPS) ONTO THE PUBLIC GRID

BACKGROUND

21. The capability of the electricity grid remains central to achieving Government's RE goal. It can be generally accepted that a prudent utility would be expected to modernise the electricity grid to facilitate the magnitude of RE integration that is contemplated under the BNEP. Additionally, this modernisation is required to manage the interconnections for the specified RE technologies that would evolve from the IRRP 2021 annual capacity schedules, in a well-coordinated manner.

22. While this argument holds true, the successful execution of Government's policy imposes a significant responsibility on the grid operator considering the operation of the BLPC's original business model as the only load serving entity. Due to Government's energy vision, the BLPC will be required to fully facilitate two-way energy flows online from competing IPP and customer-sited generators. The change in energy flows from an engineering perspective implies that certain thermal limits of feeders, switchgear and other equipment will be impacted with mitigation. Additionally, the injection and timing of non-firm energy, variable and intermittent generation into the grid, can present operational challenges for the BLPC in meeting certain minimum service standards and adequate level of service. Consequently, the contingency planning of the BLPC must be modified to ensure continuous security of supply and safe operation.

23. This shift in the BLPC's grid operation suggests that the management of the grid would need to be enhanced, the frequency of monitoring improved, additional technical resources integrated and generally would require that physical infrastructure be retrofitted. These anticipated changes and potential impacts also suggest that significant capital investments would be warranted to achieve full actualisation.

24. The BLPC explained in the Application that 14 large IPPs have expressed an interest in constructing RE projects (146 MW in total capacity) and being connected to the grid[10]. Further, an additional 150 MW of intermittent RE are also awaiting grid connection[11].

25. Considering this development, BLPC pointed out that the Highway 2A corridor from St. Thomas to Trents and the North substations were identified as areas of high RE penetration demand. Service coverage in that area is provided via a double circuit, 132 KV underground cable and a single 24 KV underground cable[12].

26. However, a 336 MCM[13], 24 KV overhead transmission line which provides access to IPPs will need to be retrofitted to a 795 MCM[14], a higher amperage cable, to accommodate interconnections on this circuit.

27. Similarly, upgrades are required on the 11 KV distribution circuits owing to increased RE penetration demand. The conductors on these circuits should be replaced with a 336 MCM conductor, a higher rated amperage cable to match the overall feeder size, thus providing access for more RE deployment in these areas.[15]

28. New IPPs[16] also require access to the grid to connect RE projects. Not all RE projects are the same and the extent of the needed interconnection equipment will be project specific. Therefore, the nuances associated with these project types will need to be accommodated.

29. The BLPC is mandated under the Commission's Decision on Feed-in-Tariffs (FIT) for RE technologies up to and including 1 MW and above 1 MW and up to 10 MW that were issued December 30 and 31, 2022, respectively, to be responsible for 75% of the

[10] Ibid, paragraph 104, page 25.
[11] Ibid, paragraph 105
[12] Ibid, paragraph 108.
[13] MCM is a designation for cables which means thousands of circular mils and the latter is the area equivalent of a circle 1/1000 inch in diameter.
[14] The conductor designation indicates higher current capability. For example, a 336 MCM Oriole cable is rated at 535 Amps while a 795 MCM Millard, is rated at 918 Amps.
[15] Ibid, page 26, paragraph 109. Service cables to customers are sized according to load requirements.
[16] These are non-utility generators contracted to provide utility scale power. Utility scale in the Barbados energy context is considered above 1 MW.

interconnection costs not covered in the FITs. This portion of interconnection costs are to be recovered through the CETR mechanism.[17]

APPRAISAL OF PROPOSED INVESTMENT

30. In order to reach a position on the quantum of costs proposed in relation to the interconnection of the fourteen (14) IPP's as stated above, the Commission questioned the BLPC on their level of certainty with regard to the proposed 146 MW of cumulative RE projects.

31. The BLPC asserted that PPA negotiations between BLPC and these IPPs were at an advanced stage of completion with ten (10) of the fourteen (14) IPPs. Similarly, discussions between the Banker's Association and PPA Working Group[18] had occurred to seek agreement between stakeholders for clarity on essential terms and conditions within PPAs for the sector.

32. Additionally, discussions on Interconnection Agreements were also being conducted along with the ongoing PPA negotiations. Initial drafts of the Interconnection Agreement and the final draft of PPAs were shared with the IPPs[19].

33. The Commission was also concerned about the number of circuits on the distribution system requiring upgrade and the priority areas for upgrades. Specifically, the BLPC explained that the lateral feeders of these circuits covering North Point, Six Mens and Carrington will be upgraded to 336 MCM over a three-year period. The estimated cost of the upgrades total $69,998,586.14[20].

34. The Commission generally accepts that upgrades are necessary to facilitate greater RE integration. Surveillance will be required to monitor the uptake of RE generation along

[17] See paragraph 2, page 22 of the FIT Decision for RE Technologies up to 1 M issued December 30, 2022 and item IX on page 26 of the Fit Decision for RE Technologies above 1 MW and up to 10 MW issued December 31, 2022.
[18] Select steering Committee set-up by the Minister of Energy and Business to address and report on PPA matters.
[19] See the BLPC's responses to the FTC's interrogatories Exhibit "AC2" page 6.
[20] This estimate refers to the total net plant amount for 2024 - 2026 that was used in the revenue requirement computation. See paragraph 115, page 27 of the BLPC's Application.

the suggested priority areas of the grid where retrofits are needed[21]. Despite negotiations being claimed to be at an advanced stage, the Commission asserts that the actual costs to be incurred by the BLPC will also depend on the readiness of RE projects to be connected on the circuits identified.

35. The Commission notes that the incurred costs should allow the uptake of more RE on the distribution and the transmission system. This process is expected to be well coordinated by the BLPC to ensure that the proposed investments materialise since this is equally dependent on the readiness of the initial 10 IPP projects mentioned[22] and other smaller RE projects to be connected online. The Commission is also cognizant that the estimated cost stated can change based on timing and circumstances.

36. As a consequence, utility customers can expect increased utilization of RE considering the additional RE capacity expected over the three-year period. Additionally, increased local participation is expected at the distribution and transmission level given the increased access to the grid.

37. The Commission is generally of the view that the costs are to be incurred to meet customers' needs over the medium term. These costs are also driven by the BNEP, IRRP 2021, and national RE programmes as well as other policy initiatives in order to modernise the island grid.

38. The investments are also necessary to provide adequate service given the changing function of the grid in light of the energy transition. Implementation of the BNEP means that the function of the grid must be modernised to facilitate alternative indigenous energy sources, therefore increasing competition in the generation space.

39. The Commission also notes that the proposed investments are contingent on the actualization of IPP projects, and the completion of infrastructural upgrades stated over the time horizon. Hence, the proposed upgrades would eventually only be considered "used and useful" when the intended purpose of the upgrades are actually achieved. This implies that the necessary upgrades must be available to provide access to IPPs in

[21] See BLPC's response to question 13), vii on page 6 of the Commission's interrogatories dated December 7, 2023.
[22] See BLPC's response to question 13), ii on page 5 of the Commission's interrogatories dated December 7, 2023.

accordance with the specified milestones that would be set out in the signed PPA (FIT Agreement) and Interconnection Agreements, thus allowing those projects to meet the prescribed Commercial Operation Date (COD). While the Commission notes that the respective PPA will hold the parties (the BLPC and IPP signatories) to account based on the agreed milestones established to ensure the COD, the Commission must be in a position to ensure that the costs to be incurred by the BLPC for interconnection are prudently incurred and are accounted for.

40. Hence for accounting and operational efficiency purposes, the BLPC is required to develop an interconnection queue registry for all new RE interconnections. As an example, the register should identify each specific generator by project developer, the type, size, location, domain level of the intended connection, details of costs incurred, status of connection, and date of connection. The contents of the register shall be submitted to the Commission on a quarterly basis as part of the BLPC's regulatory reporting. The information shall be submitted to the Commission in an appropriate Microsoft Excel software format. An annual report is also required.

41. Furthermore, when the Commission approves the PPAs and Interconnection Agreements associated with the 10-14 IPPs mentioned, a proper assessment of costs to be incurred will be verified at that point. Additionally, given the proposed investments stated to upgrade the grid, it is expected that ratepayers should benefit not only from upgrades but also the cumulative effect of other proposed investments functioning effectively.

42. Ratepayers should therefore expect to be provided greater access to the electricity grid as well as improved service since the potential to stress the network would be reduced.

CONCLUSION

43. Based on the Commission's assessment, the recovery of the costs associated with the Interconnection Infrastructure is approved.

The BLPC shall be required to provide the following information to the Commission:

a) The total estimated installed costs for the infrastructural upgrades based on the accepted costs from the selected vendors no later than one (1) month after accepting said costs;
b) Actual CAPEX[23] information for the infrastructural upgrades and a statement of works, no later than one (1) month after completion of the upgrade;
c) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying each upgrade that is scheduled for a calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the total upgrades that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;
d) Schedules for network upgrades, demarcated by year, location, duration, commencement and completion on a quarterly basis. This information shall be submitted one (1) month following the close of the quarter;
e) A copy of a queue connection register for planned interconnections for each year, no later than one month (1) after issuance of this CETR Decision;
f) A list of RE projects scheduled for interconnection requests on a quarterly basis. This information shall be submitted no later than one (1) month after the end of the quarter;
g) A list of the status of RE interconnections on an annual basis, no later than one (1) month after the end of the calendar year;
h) The status of IPP negotiations on a bi-annual basis. This information is required no later than one (1) month following the end of the first half and second half of the calendar year; and
i) A copy of the final draft interconnection template to the Commission no later than four (4) months after the issuance of the Commission's Decision.
j) Expected costs for network upgrades prior to execution and actual costs incurred should be submitted in Microsoft Excel format.

[23] The Commission has determined that "Actual CAPEX costs" shall be defined as the Commission has determined that "Actual CAPEX costs" shall be defined as the total costs required to procure, build, and commission the project.

44. The Commission is of the view that the cost estimates provided for upgrades are driven by national policy and in this context it can be considered outside of BLPC's normal operational costs. Furthermore, the Commission insists that due to the shift in market competition, specifically in the power generation domain, the BLPC is required to facilitate increasing bi-directional energy flows and indirectly, this warrants the grid modifications stated.

90-MEGAWATT (MW) OF BATTERY ENERGY STORAGE SYSTEMS ("BESS")

BACKGROUND

45. The implementation of BESS in the grid ecosystem is expected to unlock the full integration of RE online. BESS offers the opportunity for crucial ancillary grid service provisions to be exploited for operational efficiency, operational flexibility, and interoperability benefits. BESS also paves the way for EV inclusion, demand side management programme development and the evolution of microgrids.

46. The overall benefits to be derived from BESS can result in significant cost savings through the manipulation of availability of cheaper RE and utilizing this when the grid demands it.

47. Despite the function of BESS is multifaceted, and its actions are acute to grid events, it does not provide rotating inertia. Investment in BESS on a large scale is also expensive.

48. The inclusion of non-firm RE in Barbados' energy mix makes BESS an ideal candidate to harden the grid from a reliability perspective. Government's IRRP 2021 recognises the inherent challenges RE brings to management of the power grid and BESS was recommended for implementation to mitigate these.

49. The BLPC proposes investments for 90 MW of Lithium-ion BESS with an estimated cost of $558.9[24]. An RFP was conducted in 2022, and thus allowed the value for this investment to be proposed. The Commission notes that the price point for Lithium-ion technology BESS fluctuates on the international market. There is also the recognition that the

[24] This estimate refers to the total net plant value for 2024 – 2026 that was used to compute the revenue requirement. See paragraph 58, page 16 of the BLPC's Application.

proposed costs for 90 MW BESS may vary from the actual purchase price, this being premised on existing market conditions. The Commission will need to exercise due diligence through a regulatory monitoring initiative in light of this following any pre-approval.

50. The proposed investment in 4-hour duration BESS comprises eight (8) × 10 MW systems and ten (10) × 1 MW systems. One (1) × 10 MW and five (5) × 1 MW BESS are expected to be in operation in 2024 at a cost of $107.8 million, three (3) × 10 MW and five (5) × 1 MW BESS are expected to be commissioned by 2025 at a cost of $223.7 million, and four (4) × 10 MW are to be commissioned by 2026 at a cost of $227.4 million.[25]

51. According to BLPC, Government's IRRP 2021, scenario 3 necessitates 204 MW of BESS to be implemented by 2030[26]. Similarly, 84 MW of distributed solar PV and 144 MW of BESS were scheduled to be installed by 2025[27].

52. By the end of August 2023, the targeted IRRP solar PV capacity was exceeded, based on the total RE capacity online, 87 MW. Conversely, the capacity for BESS remained at 5 MW, which is utility owned. On this basis BLPC argues that BESS be allowed to be implemented in accordance with the mandate of the IRRP 2021 in order to support the proliferation of intermittent RE expected online as firm power is retired. The deployment of BESS while supporting the energy transition will boost grid reliability[28].

APPRAISAL OF PROPOSED INVESTMENTS

53. The Commission reviewed the proposed 90 MW BESS investment to determine whether the costs were unpredictable and volatile, reoccurring, and outside BLPC's manageable costs. The following highlights the Commission's findings and its concluding arguments.

54. The Commission asserts that the energy transition warrants investments in BESS to mitigate the impact of increasing RE on the grid. This position, consequently, is premised on the fact that electronic based inverter systems, such as solar PV do not constitute

[25] Ibid, paragraph 59.
[26] See paragraph 48, page 14 of the BLPC's Application.
[27] Ibid, paragraph 49
[28] Ibid, paragraph 51, page 15.

spinning inertia needed to maintain grid stability unlike thermal power plants. The Commission accepts that the deployment of BESS can be responsive to the imbalance in energy supply and that energy demanded. This imbalance can be precipitated by a significant increase in RE penetration on the grid. The quick action by BESS to arrest such an event, not only mitigates the impact of the event, but also can be programmed to manage the deficit or surplus in energy flows that would exist on the system.

55. The Commission notes that by the end of December 2023, the total customer-owned generators online reached 93 MW, 10 MW more than the August 2023 figure stated by the BLPC in its Application. Furthermore, in December 2023 the Commission was advised by the MEB that pursuant to a GOB Cabinet decision, that there would be a temporary pause in licencing RE systems in consideration of the need for storage.

56. In response to the Commission's question on the allocation of BESS, the BLPC indicated that the ten (10) × 1 MW/4hr BESS were specifically designed for ten (10) 11 KV[29] feeders across Barbados, these feeders having reached their thermal limit. Additionally, BLPC explained that the eight (8) × 10 MW BESS were selected to be allocated among eight (8) of the eighteen (18) existing substation sites for cost effectiveness rather than acquiring new sites. Siting was based on RE buildout, planning and zoning constraints.

57. The Commission raised concerns in its interrogatories about the alternatives which were explored to confirm the adoption of the BESS sizes stated. In response the BLPC stated that existing sites were preferred to minimise cost and processing due to planning requirements[30]. While the Commission acknowledges that this perspective is based on the requirements of the IRRP 2021, other than hydro-pumped storage, the BLPC did not provide sufficient details of the implications of use of other alternatives.

58. Additionally, the Commission questioned the BLPC's rationale for selecting utility scale BESS to be sited at Spring Garden and Seawell generation plants. In response, the BLPC informed that its study revealed that the fault current level at Spring Garden, in particular was being exceeded under the conditions evaluated. Seawell was considered an

[29] See response to question 17 of the Commission Interrogatories dated December 7, 2023.
[30] See page 10 -11 for BLPC's response to the Commission's Interrogatories on BESS dated December 7, 2023.

appropriate site based on the results of the studies as well[31]. Based on the Commission's review of this study, a question was raised about the upgrade cost for the switchgear at Spring Garden. The BLPC indicated that the cost associated with the replacement of the switchgear at Spring Garden would amount to $5.2 million[32]. However, there was no indication in the report as to whether this recommendation would be explored. The Commission notes however, that it may be a very complex operation to execute upgrades at this central generation plant without the potential for significant disruptions.

59. In terms of the function of BESS, the BLPC argues that the utility scale BESS would be utilised for energy arbitrage, reserve management, and frequency control, while the intent of the 1 MW BESS would serve to reduce feeder congestion on the network[33].

60. The Commission also questioned how the BESS proposal will impact the storage requirements of IPPs. In response, the BLPC stated that the BESS proposal is in fulfilment of the portion of storage required under the 2021 IRRP, while IPPs would provide their own storage to allow RE project integration according to interconnection requirements.

61. Based on the use case for the BESS, BLPC does not anticipate any fuel cost savings to accrue to ratepayers but a premium to be paid given Government's adoption of scenario 3[34], in the IRRP 2021.

62. The Commission finds that based on the cost estimate for the 90 MW BESS, the use cases identified should generally benefit utility customers by:

a) Facilitating more RE systems to be deployed to meet the energy transition needs;
b) Increasing local investment opportunities in the RE sector;
c) Improving grid reliability;

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[31] See Analysis of the Deployment of Battery Energy storage Systems for Barbados.
[32] See Exhibit "AC10" for the BLPC's response to question 8 of the Commission's interrogatories dated February 9, 2024.
[33] See Exhibit "AC2" for the BLPC's response to question 17) vi. of the Commission's interrogatories dated November 23, 2023. Also see the BLPC's response to question 17) ix.
[34] Ibid xvi. Also see page 12-13 of the IRRP 2021. Scenario 3 is described as Forced Firm Renewable Scenario (FRES) where carbon price is internalised into plant build out and dispatch actions. Under this scenario, two (2), 10 MW Biomass plants are expected with at least one being commissioned by 2025. Five, 1 MW land fill gas plants are expected between 2023 to 2025. Additionally, one waste to energy plant or 8 MW to be built by 2025. Scenario 3 also achieves the lowest decarbonization result owing the firm renewables expected and the aggressive retirement of fossil fuel plant.

d) Utilizing RE in a cost-effective manner; and

e) Allowing demand side management programmes to be implemented such as V2G.

63. Scheduled BESS deployment is mandated by the IRRP 2021, and the Commission is of the view that the 90 MW BESS is in partial fulfilment of Government's 2021 IRRP[35]. The IRRP indicates energy planning requirements to meet the 2030 horizon. The Market Monitor (Ministry with oversight for energy) determines participants in the BESS space[36]. In keeping with the multi-criteria approach expressed in the BNEP, participation in the BESS market space would be expected. Participation by the BLPC is also expected given its central role in the facilitating RE integration. While the need for 90 MW is a reasonable position raised by the BLPC, it is the position of the Commission that the BLPC has an obligation as a prudent utility should, to justify sufficiently, that all alternatives and costs were effectively considered to arrive at the capacity of BESS proposed.

64. The Commission also notes that although a cost benefit analysis was presented that compared BESS and Hydro-pumped Storage, the study in the Commission's view did not address sufficiently, all the details with respect to other crucial costs. As an example, the deferral of costs associated with transmission and distribution (T&D) and T&D upgrades were not examined.

65. The BLPC asserts that, these proposed investments are essential to provide stability to the grid in anticipation of the increase RE deployment under the energy transition.

66. The cost estimates based on the Commission's research suggests that the total system cost of 90 MW BESS for 2024 -2026 is about $395 million[37]. This cost does not include the cost for interconnection, shipment, and other infrastructural building costs. Further, the Commission finds that the total cost projections beyond 2024 are expected to decline below the 2024 figure. The Commission is cognizant that market conditions can change at any time and that actual costs, however, may not be in line with projected costs. The Commission therefore will need to verify all cost associated with BLPC's BESS

[35] See Table G11 and G12 on page 212 -213 of IRRP 2021. Note that BESS scheduled allocations for 2022 (43 MW/4h), for 2023 (50 MW/3h, 50 MW/4h), 2024 (2MW/4h), 2028 (1MW/4h), 2029 (29MW/4h), and 2030 (29MW/4h). Cumulatively, this results in a 203 MW.

[36] The established licensing regime provides the eligibility for market participants.

[37] Cost estimate based on overnight costs through 2024 – 2026.

deployment when said cost are incurred. The Commission is also aware that the actual costs of BESS will depend on the financial arrangements made with the supplier and the logistical costs to be incurred by the BLPC due to the jurisdiction of the supplier.

67. Despite this being the case, the Commission submits that the cost could be accepted as reasonable based on present market cost trends. The review of BESS costs from a United States project database reference suggests that this is trending downward[38]. The BLPC's cost estimate for BESS appears higher. This is expected given the market assessment for BESS prior to 2023.[39]

68. The Commission notes that the proposed investment for 90 MW BESS would be considered as "used and useful" investments at the point of commissioning and thereafter on the basis that these are used to meet the needs of the grid. In light of this the BLPC shall include in its regulatory reporting, details of the BESS operation on a quarterly basis.

69. The Commission has determined that appropriate regulatory requirements are necessary for monitoring of BESS and to account for the extent BESS provides service to customers and ensure the integrity of the grid.

CONCLUSION

70. The Commission's review of the 90 MW BESS estimated CAPEX[40] suggests that this cost is significant. Based on the Commission's assessment of the BESS proposed investment, the total cost for the investment is considered to be beyond BLPC's manageable cost. The impetus for this sizeable investment is driven by the objectives of Government policy, namely, the BNEP, IRRP 2021, and BCESEVP[41]. While the estimate computed by the Commission is lower than the proposed cost by the BLPC, this value is still quite large. The large cost is associated with the outlay needed to strengthen the grid and allow the

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[38] Cole, Wesley and Akash Karmakar. 2023. Cost Projections for Utility-Scale Battery Storage: 2023 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85332. https://www.nrel.gov/docs/fy23osti/85332.pdf.

[39] Cost estimates for BESS in 2021 were in the range of $900/kWh - $1000/kWh for 1 MW/4hr and $820/kWh - $920/kWh for 10 MW. See 2022 Grid Energy Storage Technology Cost and Performance Assessment by Vilayanur Viswanathan et al. Pacific Northwest National Laboratory.

[40] CAPEX here refers to costs required to procure, build, and commission the project.

[41] Government of Barbados. (2021). Barbados Clean Energy Storage and EV Policy. Bridgetown Barbados: Government of Barbados.

integration of more RE online, this being to support Government's energy transition agenda.

71. This cost estimate for BESS also represents a large percentage of the total CETP Project 1 CAPEX compared to the other proposed investments. Market conditions also suggest that these costs are unpredictable based on the maturity of the technology.

72. Despite the aforementioned, the lack of adequate assessment of other critical costs[42] makes it extremely difficult for the Commission to grant approval for the full CAPEX associated with the 90 MW BESS.

73. In light of this, the Commission has determined that the recovery of the CAPEX and associated costs for the total of 15 MW (1× 10 MW, 5 × 1 MW) of BESS that are expected to be commissioned at their intended locations and provide service in 2024 is approved.

74. As it relates to the cost estimates for (3 × 10 MW and 5 × 1 MW) BESS scheduled to be commissioned for 2025 and the (4 × 10 MW) BESS scheduled for 2026, the Commission has determined that an appropriate CBA which addresses clearly, consideration of other costs, namely, costs associated with T&D deferrals and T&D upgrades is required.

75. With regard to the treatment of BESS, the BLPC is required to provide:

a) The total estimated installed costs for the 15 MW BESS based on the accepted costs from the selected vendor no later than one (1) month after the BLPC's acceptance of said costs;

b) Actual CAPEX details for the 15 MW BESS no later than one (1) month after its commissioning for the calendar year.

c) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying each BESS asset that is scheduled for a calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the total BESS capacity that is earmarked for the calendar year. Copies of invoices

[42] It is unclear whether consideration was given to the costs associated with T&D deferral that would confirm the BESS as the optimized solution in all cases.

shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

d) For each BESS, a single line connection diagram, a copy of the Original Equipment Manufacturer (OEM) operations manual, specification document, and OEM warranty sheet, no later than one (1) month after commissioning of the total BESS capacity scheduled for the calendar year;

e) A unique identifier for each BESS asset based on its location and include in its quarterly regulatory reporting, monthly information on:

    i. Details of, and actual operation and maintenance costs for each BESS;
    ii. Minimum state of charge;
    iii. Energy Charged (kWh-AC);
    iv. Energy Discharged (kWh-AC);
    v. Reactive Power absorbed (KVAR -AC);
    vi. Reactive Power delivered (KVAR-AC;
    vii. Reactive Power absorbed (KVARh -AC);
    viii. Reactive Power delivered (KVARh-AC; and
    ix. Round Trip Efficiency (%).

    This information shall be submitted to the Commission no later than one (1) month after the end of each quarter.

f) As part of its annual regulatory reporting, information for each BESS on the following:
    i. Maximum Energy Capacity (kWh-AC measured);
    ii. Maximum Power Capacity (kW -AC measured);
    iii. State of Health (%);
    iv. Capacity Ratio (%);
    v. System Efficiency (%); and
    vi. Cycle Life.

    BLPC shall include this information in its annual regulatory reporting no later than one (1) month after the end of the calendar year;

g) Details for a developed maintenance programme for the BESS assets based on the OEM's guidelines, industry best practice, and the operating environment, and submit for approval of the Commission, no later than three (3) months prior to the commissioning of the BESS; and

h) Ad-hoc reports for exigency events no later than seven (7) workings days of occurrence of the event; and

i) Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.

SYNCHRONOUS CONDENSERS (SCOS)

BACKGROUND

76. SCOs are devices which are electrically configured to absorb and provide reactive power to an electrical grid. These devices do not provide active power. However, when placed at strategic points along the transmission network, these can improve the efficient flow of electrical energy on the grid by providing grid services such as dynamic voltage regulation, enhance inertia for the grid, allow for more intermittent RE to be connected, and improve short circuit flow.

77. The BLPC refers to the recommendation in the IRRP 2021 for four (4) SCOs. Research by the BLPC supports the need for four (4) SCOs rated at 20 MVar[43] for grid stability. The BLPC states its rationale for the proposed siting of three (3) SCOs for active operation with a fourth device to become available as the facilitation of an appropriate maintenance regime and the provision of backup capability[44]. The BLPC estimates that the initial two (2) SCOs valued at $25,140,100 are expected to be commissioned in 2025 followed by the remaining two (2) SCOs valued at $25,140,100 to be commissioned in 2026[45].

[43] Mega Volt-amps reactive
[44] Ibid, page 21, paragraph 85.
[45] Ibid, page 21, paragraph 86.

78. The Commission accepts that increasing variable and intermittent DRE resources can make the electricity grid more susceptible to instability and lead to unintended consequences, which may further compromise the reliability and operational flexibility of the existing generation assets.

79. The function of SCOs online is required to address the grid stability issues. Additionally, to date the scheduled integration of RE systems as stated in the IRRP 2021 have been exceeded. This situation, in BLPC's view, necessitates the application of the proposed ratings for the SCOs.

APPRAISAL OF PROPOSED INVESTMENTS

80. Variable and intermittent RE generators and inverter-based systems (IBS) depend on electronics-oriented controls to regulate their output; these lack the capability to provide real system inertia and fault current.

81. The Commission notes that the proposed investment for four (4) SCOs is expected to strengthen the operational capability of the electricity grid in anticipation of higher RE penetration over the short to medium term. These special purpose devices are engineered to boost system inertia, short-circuit level, voltage stability and reactive power capability at the specified locations identified for optimal grid performance.

82. As a consequence, SCOs mitigate grid system frequency variability and therefore improve grid access and grid availability. These attributes of SCOs make the grid more robust to system disturbances and system events.

83. With a more robust grid, it is expected that utility customers will experience fewer service interruptions, less system outages, and shorter recovery periods when disturbances occur.

84. The Commission asserts that the proposed investment in SCOs is necessary to provide adequate service to utility customers, prosumers, and IPPs and by extension, is critical to the advancement of the energy transition. The inclusion of SCOs will also facilitate the unlocking of greater investment in the RE sector.

85. As Government envisions 100% RE supply by 2030, reliance on variable and intermittent energy sources alone will not allow this objective to be met. The Commission therefore accepts that the transition away from a fossil fuel-based energy supply to a dependable RE supply, warrants the utilization of SCOs.

86. The Commission is generally of the view that the proposed investment to procure the four (4) SCOs will enhance service delivery.

87. The Commission assessed the costs associated with the proposed investments to understand whether these costs are reasonable. Research showed that the cost for new SCOs from 2021 to 2023 increased. SCOs cost $300,000/ MVAr in 2021 to $322,800/MVAr in 2023. Based on these estimates, two (2), 20 MVAr SCOs would be $12,912,000[46]. The average maintenance cost associated with these devices range from $0.8/KVAr to $1.6/KVAr per year. Normally, new SCOs are more expensive than retrofitting an existing synchronous generator. Retrofit cost estimates can vary depending on the circumstances and range between $40,000 to $100,000/MVAr.[47] These statistics imply that maximum retrofit cost is about $2,000,000. The expected useful life of the retrofitted asset versus that of a new asset will also have to be considered. Despite that the price point for a retrofit will be dependent on many considerations, the option to pursue a retrofit is a significantly cheaper alternative.

88. Some technical considerations for repurposing a soon to be retired/ retired generator would depend on the state of the existing transformer and generator, the starting method to be used- clutch or motor, the state of the existing foundation, cooling and lubrication system, ease of automation, and the ability of the generator to retain inertia. Under Section 20 of the URA, the BLPC is required to ensure a supply that is safe, adequate, efficient and reasonable. In light of the energy transition needs, the Commission further notes that investments in SCOs will allow the BLPC to meet this regulatory obligation. It is also expected that the BLPC will continue to be responsible for the reliability of electricity service.

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[46] These cost estimates do not include other equipment and interconnection costs.

[47] See Markets and Markets Report- Synchronous Condenser Market Size accessed from https://www.marketsandmarkets.com/Market-Reports/synchronous-condenser-market-189197147.html, Share | 2022-2030 (marketsandmarkets.com) on March 8, 2024.

89. The Commission reviewed the BLPC's studies which justified the proposed sizes for new SCOs. While these studies show that this technology rivalled BESS and STATCOM[48] in terms of performance and need, it did not assess less cost intensive approaches.

90. On this point, the BLPC should assess whether investments in new SCOs would be more cost effective than repurposing retired or soon to be retired generators as SCOs. The Commission is of the view that the cost estimates are reasonable for new SCO investments.

91. There is no evidence that, as recommended in the IRRP 2021 Policy[49] and referenced, that the BLPC explored a retrofit alternative. The Commission is cognisant of the Government's IRRP 2021 recommendations for SCOs, in terms of type, size and urgency. However, the Commission questions whether BLPC's selection of the SCOs were based on the most cost-effective option.

92. Additionally, while "BLPC Synchronous Condensers Technical Review and System Studies" informed why SCOs would be more appropriate than a Static Synchronous Compensator and BESS, in terms of location, space and zoning, the study did not assess retrofits of generators to function as SCOs. The Commission is of the view that this is needed to determine whether such an alternative should be exploited for cost effectiveness.

93. The Commission notes that the BLPC's CAPEX for the four (4) SCOs appear to be associated with investments for new SCOs. The Commission is not opposed to the proposed investments in new SCOs provided that the repurposing of retired plant as SCOs is determined by a CBA to be infeasible.

94. It is the Commission's determination that quantifiable information must be provided to confirm that the alternatives as set out in the IRRP 2021 were considered and that the most cost-effective solution was taken.

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[48] Static Synchronous Compensator.

[49] See Section 10.6, page 128 of the IRRP 2021.

95. Further, with regard to the actualization of the SCOs being utilised in the power system, regulatory reporting requirements shall be instituted on the BLPC to account for the use and usefulness of the SCOs at their specified locations.

<u>CONCLUSION</u>

96. It is the position of the Commission that as stated in the IRRP 2021, the BLPC is required to assess the feasibility of repurposing retired generators as SCOs before the estimated costs for the new SCOs is approved. If the outcome of that assessment confirms that the alternative is impractical, then new cost estimates will be required for review. A copy of that assessment would be required for the Commission's review.

97. At this point, the Commission has determined that the BLPC has not demonstrated that new SCOs is an optimised solution. The Commission also notes that this recommendation to examine the retrofit of retired generators to SCOs was supported by intervenor Mr. Kenneth Went[50]. BREA also questioned the BLPC as to whether retired or retiring generators can be repurposed cost effectively as SCOs. To this the BLPC indicated that the costs associated with repurposing is being assessed to determine feasibility[51].

98. A CBA which considers the option of the repurposing of thermal generation to SCOs is required to adequately assess SCOs as an optimised solution.

99. The proposed investments for the four (4) new SCOs is not approved for recovery through the CETR mechanism.

AUTOMATIC GENERATION CONTROL (AGC)

<u>BACKGROUND</u>

100. The BLPC proposes investment in AGC systems to mitigate the potential imbalance between energy supply and demand that is expected as more RE is brought onto the grid. This technology solution includes the communication, sensors, control and measurement devices to achieve this objective.

[50] See paragraph 21-23 of the Affidavit of Mr. Kenneth Went dated April 4, 2024.
[51] See the BLPC's response, Exhibit "AC5" to question DI.3 1. of BREA's Interrogatories dated December 8, 2023.

101. According to the BLPC, the utilisation of AGC systems will enhance its existing approach to frequency regulation, this being primary and secondary control[52]. This proposed investment in AGC systems will incorporate control of IPP generators that are dispatchable and available to participate in frequency control.

102. The BLPC underscored the need for AGC systems, as it automates the output of conventional generators and BESS in response to the variation in intermittent RE generation. This core function of the AGC system will seek to attenuate issues that are concomitant with variable and intermittent RE generation, avert occurrence of potential outages, and maintain grid stability and reliability[53].

103. Additionally, the BLPC in its application also underscores the need for AGC systems was recommended by the IRRP 2021 in order to achieve BNEP targets. The BLPC expects that this investment will be implemented by 2024.

104. Cost estimates for the AGC system were established through a competitive RFP process and evaluated by the BLPC's internal team in accordance with the World Bank's guidance evaluation criteria[54]. The estimated costs of this proposed investment is $3,580,855 and the AGC would require $60,000 annually to cover operation and maintenance expenses[55]. The cost estimate for the AGC comprises the cost of the network, switches, firewalls, fibre network, hardware, software and labour for installation and integration[56].

105. According to the BLPC, the AGC systems will provide frequency surveillance capabilities to the grid thereby allowing conventional plant and BESS to mitigate mismatch between supply and demand – energy flow imbalances caused by RE generation[57].

106. Currently the BLPC utilises primary, secondary, and tertiary frequency response tools, coupled with load shedding to respond to grid disturbances. This capability though not

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[52] Primary frequency control is executed within the domain of select generators, while secondary control is activated through grid operator manual intervention.
[53] See paragraph 69 – 80 of Application.
[54] See BLPC's response to question 1 of FTC's interrogatories Exhibit "AC10" dated February 9, 2024
[55] See paragraph 77 of the BLPC's Application. Also see Exhibit AGC-1 for the O&M cost estimate.
[56] See BLPC's response to 15) e. of the FTC's interrogatories Exhibit "AC2" dated November 23, 2023, on page 8.
[57] See paragraph 70 page 18 of the BLPC's Application.

entirely automatic, relies on the injection of or extraction of power into/from the grid to remedy system disturbances, remedial action executed to quell a disturbance, or the resurgence of disturbance is based on the availability and dependability of firm capacity, and the urgency of response. AGC systems are therefore considered a suite of tools required to respond, manage, and control the aggregation of energy flows from all generation assets online efficiently.

APPRAISAL OF PROPOSED INVESTMENT

107. Total RE generation online, including customer owned and utility owned systems was registered to be approximately 103 MW by the end of December 2023. The Commission submits that with unfettered increasing volume of intermittent and variable RE online, this will present operational security risks for the power grid and threatens the stability of supply, weakening grid reliability, and further eroding resiliency.

108. The Commission also notes that the IRRP 2021 mandates total capacity allocations of 286 MW of solar PV and 166 MW of wind energy systems to meet the 2030 target of 100% RE. The existing power system is predominantly fossil fuel-based, 234.1 MW-AC of capacity. These units participate in various operational modes to mitigate system disturbances online. The aforementioned increase in RE complicates the operability and controllability of the existing power system in the absence of further mitigation action. Non-firm RE such as solar PV and wind energy sources which are the predominant sources to date are prone to variability in output and are thus unpredictable. These inherent characteristics of these weather dependent energy sources make RE on the grid difficult to control and threatens the capacity of the grid operator to maintain normal stability and security of supply demanded from the grid ecosystem.

109. From a grid operations perspective, the transition to a dominant supply from weather dependent energy sources will require a control system that can respond to the interchange in energy flows, managing a number of various assets online, increase monitoring capability and surveillance, interoperability, communication and control events. An increase in weather- based energy systems online will not result in the provision of real inertia and therefore a computerised management system is warranted.

110. The Commission notes that a management system must have real time control and capability to track and correct deviations in the normal operating frequency of the grid. It is established that the impact of increasing intermittent and variable RE systems on the power grid increases the occurrence of system frequency excursion events as more thermal generation is displaced or retired.

111. The Commission is of the view that the existing and future operation of the electricity grid warrants the implementation of AGC systems to ensure effective frequency regulation and maintain equilibrium in the power system. Given the added complexities afforded by increased RE penetration, and the impact of service restoration, the use of AGC systems is expected to remove the existing deficiencies in response to variable power online.

112. The BNEP and IRRP 2021 supports the need for new infrastructure in order to implement a RE dominant power supply. The proposed investment by BLPC for AGC systems is expected to support Government's policy in fulfilment of 100% RE by 2030. The estimated cost of the AGC i.e. $3,580,855 is driven by RE uptake and though not volatile is considered outside of BLPC's normal operating cost required to provide service to customers, in particular, utility customers – prosumers and IPPs.

113. The implementation of AGC will allow more customer-owned generation and BESS to be deployed online and allow BLPC to address the challenges these bring to the power system. This proposed investment will also facilitate the needs of customers by allowing the BLPC wide area control capability of the grid and ensure greater grid stability and security of supply.

114. The demands of the existing and future grid require investment to modernise its functionality, operability, and flexibility given its hybrid generation composition and future transition to a dominant RE supply. Without AGC implementation, adequate service provision is expected to deteriorate with increase RE supply. AGC is therefore an important segment to provide adequate service to customers under the existing and future RE penetration beyond 2030.

115. The Commission examined the cost estimate provided by the BLPC for AGC systems and the evaluation summary from the RFP process. The criteria for selection of final cost

appears reasonable. The Commission also researched cost estimates provided by various sources for this type of equipment and concludes that the total cost estimate appears reasonable given the size of our island grid.

116. Considering the central function of AGC in relation to the management of the grid it is expected that this proposed investment will be used and useful when implemented, given that effective frequency regulation is contingent on adequate power generation. The Commission expects that with the proposed investment in AGC, customers should experience fewer service interruptions. The Commission also notes that the AGC solution is a recommendation of the Government's IRRP 2021.

CONCLUSION

117. The Commission understands that AGC is a software solution and an important tool for power system surveillance and management and this system is crucial to enhance the efficient dispatch and energy management of energy production assets online.

118. AGC systems form part of a utility's power system monitoring and management arsenal for system frequency regulation.

119. The cost associated with the implementation of AGC can be considered costs driven by the BNEP. The quantum of the costs estimated can be considered manageable costs. Given that this estimated cost is policy driven, and that this technology is important for the evolution of a modern grid to facilitate RE deployment, it is the Commission's view that the nature of costs is outside the BLPC's normal cost required to provide service.

120. The CAPEX and associated costs for the proposed ACG system shall be allowed to be recovered through the CETR mechanism.

121. The Commission determines that BLPC is required to:

a) Submit the cost estimates for the AGC system based on the accepted costs from the selected vendor no later than one (1) month of accepting said costs;
b) Submit actual CAPEX for the AGC system no later than one (1) month after its commissioning for the calendar year;

c) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying the AGC system[58] that is scheduled for the calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the total AGC system that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;
d) Provide to the Commission a copy of the OEM operations manual, specification document, and OEM warranty sheet for the AGC one (1) month after its commissioning;
e) Submit a copy of the pre and post commissioning report for the AGC system one (1) month after commissioning;
f) Submit a performance report for the first six (6) months of operation of the AGC system. The report shall be submitted to the Commission one (1) month after commissioning;
g) Develop a maintenance regime for the AGC system in accordance with the OEM's guidelines, industry best practice, and the operating environment and submit for the approval of the Commission, no later than two (2) months after the commissioning of the AGC system;
h) Details of the operating and maintenance costs for the AGC system for each month, in its quarterly reporting no later than one (1) month after the end of the quarter;
i) Maintenance and operating reports for the AGC system on an annual basis no later than one (1) month after the end of the calendar year;
j) Submit Ad-hoc reports for exigency events no later than seven (7) workings days of occurrence of the event; and
k) Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.

The BLPC can commence recovery of the actual CAPEX and associated costs for the AGC as determined by the Commission, six (6) months after commissioning.

[58] Refers to AGC System at paragraph 77 of the BLPC's Application

The Commission will conduct audits on the performance and "use and usefulness" of the AGC system where this is deemed necessary.

DISTRIBUTED ENERGY RESOURCE AGGREGATION AND CONTROL PLATFORM ("THE PILOT")

BACKGROUND

122. The BLPC foresees the need for a DER Management System, which is essentially a dedicated, software solution with dynamic capability of real-time monitoring and control for a modern utility grid.

123. The motivation for investment in this solution will be to aggregate the volume of RE and BESS assets that are expected online and to control how these assets can be best utilised in consideration of the energy transition. Additionally, the need for such a platform is also occasioned by the issuance of the Commission's June 2023 Decision on Energy Storage Framework and Tariffs[59].

124. In light of these expectations, the BLPC proposes a platform that can optimise the use of these assets online to ensure grid stability, achieve operational flexibility, interoperability, and provide real-time capability and control of DER. Based on the BLPC's description of the platform, the software solution will provide resource management capability, resource optimisation, ensure market participation, and confirmation of commercial settlement.

125. It is proposed in the Application that through this small-scale pilot, the information or intelligence acquired would facilitate the aggregation of multiple BESS and RE systems to optimise their use online[60].

126. The estimated cost of this proposed investment is $1,172,943[61] and the BLPC presumes that this software solution will be operational in 2024.

127. The BLPC provided a summary of the evaluation report which details the ranking and criteria used for selection of the bidders for the associated RFP. The BLPC cautioned that the total cost estimate quoted for the DER management solution under the CETP Project

[59] See paragraph 94 – 96, page 22 of the BLPC's Application.
[60] Ibid paragraph 97 – 98, page 23.
[61] Ibid paragraph 101.

1 is a combination of the platform's cost and other costs necessary to provide a full-scale solution beyond that in the RFP[62].

128. The proposed investment for "the pilot" is expected to ensure a safe and reliable operation of DER and BESS, by improving the BLPC's ability to communicate, control, and manage the DER and BESS proliferation that is contemplated under the BNEP and the IRRP 2021.

APPRAISAL OF PROPOSED INVESTMENT

129. The Commission foresees that a RE management and aggregation platform would be appropriate to achieve successful decarbonization of the utility grid. Considering the increase in RE systems and implementation of BESS expected to come online in light of the energy transition, the Commission notes that this digitised solution would allow the portion of RE online to be utilised efficiently – ensuring energy is available to meet demand at times when intermittent and variable RE is inadequate and storing RE when it is excessive.

130. The Commission appreciates that the proposed investment aims to monitor energy production, integrate energy sources, optimise energy resources based on situational awareness online, and coordinate operation of assets[63]. In consideration of these attributes, the Commission submits that the proposed software solution would result in better utilization of DER and BESS online. Additionally, with improved capability and grid visualization, it is expected that this software solution would also provide utility customers, prosumers, and IPPs (customer owned generation and BESS) with confirmation of services and their respective settlement. Overall, it is expected that customers would benefit from improved reliable power and cost efficiency.

131. The Commission also submits that in the absence of a DER software solution under an increasing Inverter Based System (IBS) scenario, the management and operation of the utility grid would become more onerous as the utility will need to dedicate more resources to the management of grid stability and maintenance of a reliable electricity service.

[62] See Appendix PLA2 "Distributed Energy Resources Aggregation Platform – Evaluation Report"

[63] GE Vernova, Jesse, Gantz and Heather Tat, GridOS DERMS, ADMs & DERMs: Orchestrating DERs at the Grid Edge, 2024 accessed March 01, 2024, GEA35380 ADMS + DERMS - Orchestrating DERs at the Grid Edge WP_R5

Consequently, the proposed DER management system therefore aims to unlock the further potential of the grid, promote RE deployment, EV uptake, and expandability towards catering to microgrid applications for the future, in a cost-effective manner.

132. The Commission therefore concludes that "the pilot" is necessary to improve the existing and future electricity service to customers given the expected growth in RE generation through 2030.

133. The Commission also conducted research on similar software solutions to determine the reasonableness of the estimated cost ($1,172,943) provided for the platform. Research suggests that the price point is about $600,000 – $1,000,000[64]. Therefore, the Commission concludes that the cost estimate appears to be reasonable.

134. The Commission views the application and implementation of the proposed investment as crucial for greater adoption of DER and BESS. Based on this premise, the software solution will be expected to aid in achieving this intended objective.

135. The Commission therefore anticipates that with the implementation of the DER management system, its application should warrant being used and useful after the actual cost is incurred and investment is being used from the date of commissioning and thereafter for an incubation test period not exceeding six (6) consecutive months of continuous operation. This test period would allow the Commission to assess further the BLPC's operation and gauge the actual benefits to customers. The Commission determines that the BLPC is required to submit test reports to the Commission on conclusion of this period of testing.

136. Further, the Commission asserts that with the implementation of the DER management system, ratepayers can anticipate a more reliable electricity service since the BLPC would benefit from enhanced capability and oversight to manage and control the negative consequences associated with weather dependent energy systems such as solar and wind.

[64] Cost estimate show relates to 2020 prices.

CONCLUSION

137. The Commission submits that the DER management system platform ("the pilot") is one of the components outlined in the IRRP 2021 Roadmap to be executed and assessed on a pilot basis. The implementation of this segment will require a software solution to operationalise best practices and data extraction for decision making.

138. The Commission notes that the execution of "the pilot" relates to the implementation of a segment of Barbados Clean Energy Storage and EV Policy (BCESEVP) and the IRRP 2021 which prompts the need for such a software solution to be implemented to accelerate decarbonization of the grid.

139. The Commission is of the view that the costs to be incurred through the implementation of "the pilot" can be considered prudent on the premise that the intent of the proposed investment will provide the level of aggregation, operational flexibility, interoperability for DER and BESS deployment, and facilitate the commercial settlement expected.

140. It is also the view of the Commission that the cost estimate for the proposed investment can be considered reasonable.

The Commission has determined the following as it relates to the DER management ("the pilot") system:

a) The recovery of CAPEX and associated costs for the proposed pilot is approved.
b) The CAPEX and associated costs of the proposed pilot shall be allowed recovery through the CETR mechanism**;**
c) As a consequence, the BLPC shall:
d) Submit the cost estimate for the ("the pilot") based on the accepted costs from the selected vendor no later than one (1) month after accepting said costs;

e) Submit to Commission the actual CAPEX for the ("the pilot") no later than one (1) month after its commissioning for the calendar year;

f) Copies of all invoices in relation to the actual CAPEX of the asset justifying the costs actually incurred in deploying the pilot asset that is scheduled for the calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the total pilot that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

g) Provide to the Commission a copy of the OEM operations manual, specification document, and OEM warranty sheet for the ("the pilot") one (1) month after its commissioning;

h) Submit a copy of the pre and post commissioning report for the ("the pilot") one (1) month after commissioning;

i) Submit a performance report for the first six (6) months of operation of "the pilot". The report shall be submitted to the Commission one (1) month after commissioning;

j) Develop a maintenance regime for "the pilot" system in accordance with the OEM's guidelines, industry best practice, and the operating environment and submit for the approval of the Commission, no later than two (2) months after the commissioning of "the pilot";

k) Include in its quarterly reporting, details of the operating and maintenance costs of "the pilot" for each month, no later than one (1) month after the quarter;

l) Submit to the Commission a maintenance and operating reports for "the pilot" on an annual basis no later than one (1) month after the end of the calendar year;

m) Submit Ad-hoc reports for exigency events no later than seven (7) workings days of occurrence of the event; and

n) Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.

The BLPC can commence recovery of the actual CAPEX and associated costs for the pilot as determined by the Commission, six (6) months after commissioning.

141. Overall, the Commission posits that in light of the proposed investments under the CETP Project 1, it can be concluded that the operation and management of the power grid will improve beyond the current level of reliability. Utility customers can expect RE to be utilised efficiently and the grid should be more accessible to facilitate further RE integration.

142. The Commission also concludes that the cost estimates associated with the proposed investments are beyond the normal manageable costs of the BLPC and are largely driven by the BNEP and IRRP 2021 and not by the BLPC.

143. While the proposed investments should improve the grid significantly, the Commission is mindful that a safeguard should be implemented to manage the effect of the magnitude of investments. The Commission determines that the volume of cost through the CETP Project 1 should be capped at 80% as a layer of contingency to shield ratepayers from the full impact of these costs. The remaining 20% is to be addressed at the next rate case.

OTHER ASSESSMENTS

Table 1 – Life Cycle and Depreciation Rates

Proposed Investments	Estimated Life Years	Depreciation rate assumed
90 MW BESS	10	10.00%
Substation Building - BESS	49	2.06%
Substation Equipment - BESS	44	2.29%
AGC Systems	25	3.94%
Synchronous Condenser - Civil Works	49	2.06%
Synchronous Condenser – Equipment	44	2.29%
DER	21	4.83%
Interconnection Infrastructures	34	2.90%

144. All of the assets fall under the category of fixed assets and as such are normally depreciated over the lifetime of the asset. Pricing for fixed assets do not fluctuate in the same manner as pricing for inventory such as fuel, which is used up on a daily basis and changes continually based on conditions in the international oil market. Fuel costs are a

pass-through cost and justifiably recovered through the fuel cost adjustment. This compares to fixed assets, which are long term assets and generally used to generate income. The estimated life of these proposed investments are set out in Table 2. These range from 10 years for the BESS to 49 years for BESS - substation buildings and synchronous condensers– civil works. Except for the BESS, all other assets have an expected lifecycle of over twenty (20) years.

145. The lifecycle of equipment used within an electrical substation, such as switchgear, and battery storage systems can vary widely based on several factors, including the type of equipment, manufacturer specifications, operational conditions, and maintenance practices. The lifecycle of transformers can vary, typically lasting between 25 to 40 years. Similarly, the lifecycle of switchgear can have a lifespan of 20 to 30 years. Modern switchgear designs with vacuum or SF6 (sulfur hexafluoride) as the interrupting medium may offer longer service lives and higher reliability.

146. Control systems and communication equipment: these components, which are essential for the automated and remote control of substation operations, generally have a shorter lifecycle, often around 10 to 15 years. Technological advancements and cybersecurity requirements may necessitate more frequent updates or replacements. For specific equipment, manufacturers often provide detailed lifecycle estimates and maintenance cycles. The lifecycle estimates provided by the BLPC have been found to be generally reasonable.

147. There is some defence for the argument that the pricing of the assets are unpredictable. Battery storage costs have varied significantly over the past years and continue to change in response to international market conditions. Furthermore, the cost of batteries is impacted by materials availability and costs, market size and demand, and policy factors[65]. Additionally, the impact of supply chain expansions or constraints may result in uncertainty in the cost of the assets. Such impacts also affect the cost of other equipment necessary for the RE roll out, such as switch gear, control gear and transformers.

[65] Cole, Wesley and Akash Karmakar. 2023. Cost Projections for Utility-Scale Battery Storage: 2023 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85332. https://www.nrel.gov/docs/fy23osti/85332.pdf.

148. Proper management of the roll out of the assets would ensure that the BLPC can adequately plan for the required investments, thus ensuring that the required costs are reasonably predictable. Additionally, the fluctuations in costs of these assets cannot be considered in a similar manner to the fluctuations in costs of fuel (a major input of the BLPC) that the utility would experience with the dynamic changes in fuel prices. However, the volatility in the price of an asset may be representative of significant changes in the market which affects the supply and/or demand of that asset. Alternatively, the same extreme changes in market characteristics may affect the lead time for the procurement of the asset.

149. Generally, the Commission contends that it is logical to expect that the costs of some of these proposed assets will be unpredictable or volatile. However, these considerations are superseded by the knowledge that the proposed investments are required to support the electricity sector as it transitions to 100% RE and these investments are being made to benefit the general public.

MANAGEABILITY OF COSTS

150. At paragraph 19 of its Application, the BLPC informs of the need to make the investments outlined in the CETP Project 1 and states that the recovery of the costs in a timely manner are necessary to "*safeguard the financial integrity of the utility*".

151. In assessing the inability of the utility to manage these proposed investments, consideration must be given to the ability of the BLPC to have the opportunity to earn a reasonable rate of return on its investments. This is an accepted regulatory principle. Assuming that the proposed investments are considered to be prudent, the manageability is assessed by considering how the BLPC's rate of return will be impacted if it were to invest in the proposed assets without being able to recover the costs of those assets. We therefore considered a rate of return that includes the proposed assets with cost recovery. Specifically, consideration is given to the impact on the rate of return for the individual asset grouping.

BESS

152. If the utility is not allowed to recover the cost and expenses of the investments made, then BLPC's operating revenue will be reduced commensurate with the actual costs related to these assets as those costs will still be incurred. The calculated rate of return on these assets will be negative and getting increasingly smaller with each new investment.

Table 2 - BESS Rate of Return[66]

BESS	2024 Projected
CETR Net Plant	$107,940,915
CETR Cost of Service	$12,305,903
Total Rate Base (Projected)	$1,008,914,311
Estimated Operating Income	$26,076,023
Projected Rate of Return	2.58%

153. Consolidating these additional costs into the present financial situation for assessment, the BLPC, would be projected to earn a rate of return of 2.58% in 2024. This compares unfavourably with an approved rate of return previously allowed in the 2010 Rate Review of 10% and the pending 2023 Rate Review Decision which determined the rate of return to be 7.47%.

AUTOMATIC GENERATION CONTROL

154. The AGC solution requires an investment of $3.6 million in 2024 only. Without the opportunity to recover the cost of this asset, the projected rate of return for 2024 is estimated at 4.22%.

Table 3 - Automatic Generation Control Rate of Return[67]

Automatic Generation Control	2024 Projected
CETR Net Plant	$3,580,855
Cost of Service	$213,358
Total Rate Base	$904,554,593
Estimated Operating Income	$38,168,568
Projected Rate of Return	4.22%

[66] These projections are the Commission's own estimates assuming that the BLPC invest in 15 MW of BESS in 2024 and is not allowed to recover the costs and expenses.

[67] These projections are the Commission's own estimates

SYNCHRONOUS CONDENSER

155. The requested cost of investments in the SCOs is estimated at $25.1 million in 2025 and 2026 with revenue requirement of $3.4 million each year. However, as noted in the appraisal of these proposed assets, the recovery of any costs related to investment in synchronous condensers is dependent on whether investment in new or retrofitted synchronous condensers is more feasible. At this point, the impact on the BLPC's rate of return is not considered.

Table 4 - Synchronous Condenser

Synchronous Condenser	2025 Projected	2026 Projected
CETR Net Plant	$25,140,100	$25,140,100
Cost of Service	$1,127,515	$1,127,515

IPP INTERCONNECTION

Table 5 - IPP Interconnection Rate of Return[68]

IPP Interconnection	2024 Projected	2025 Projected	2026 Projected
CETR Net Plant	$13,419,928	$22,308,721	$34,239,364
Cost of Service	$410,876	$1,095,174	$2,153,196
Total Rate Base	$914,393,324	$936,702,045	$970,941,909
Estimated Operating Income	$37,971,050	$37,286,752	$36,228,730
Projected Rate of Return	**4.15%**	**3.98%**	**3.73%**

156. The IPP Interconnection assets are projected to cost between $13.4 million in 2024 to $34.2 million in 2026. The projected rate of return falls from 4.15% in 2024 to 3.73% without the ability to recover the costs of the asset. The projected rate of return that would result if the BLPC invest in these assets without the ability to recover the costs compares unfavourably with the approved rate of return in the 2023 Rate Review Decision and supports the concept of the investment being unmanageable.

[68] Ibid

DISTRIBUTED ENERGY RESOURCES AGGREGATION & CONTROL PLATFORM

157. The cost of this investment is estimated at $1.2 million in 2024. The projected rate of return will fall by 0.01% to 4.25% at year-end 2024. If the BLPC is not allowed to recover the cost and expenses related to this proposed investment, the impact on the utility's projected rate of return is not significant, and hence considered a manageable investment.

158. Cumulatively, the three asset groupings require investments totalling $126 million in 2024, increasing to $271 million and $287 million in 2025 and 2026 respectively. The corresponding cost of service are $13 million in 2024, more than doubling to $27.5 million in 2025, further increasing to $28.2 million in 2026. If the BLPC is not allowed to earn a revenue so that it may recover these expenses, its opportunity to earn a reasonable rate of return is severely challenged.

Table 6 - CETP Project 1 Request: Summary[69]

CETP Project 1	2024 Projected	2025 Projected	2026 Projected
CETP Net Plant	$126,114,641	$271,495,409	$287,191,789
Cost of Service	$12,990,551	$27,879,707	$30,429,295
Total Rate Base	$1,027,086,278	$1,298,630,099	$1,585,870,800
Estimated Operating Income	$25,391,375	$10,502,219	$7,952,631
Projected Rate of Return	2.47%	0.81%	0.50%

159. There is a reasonable argument that the BLPC may be able to manage one of these individual projects without cost recovery from the point of commissioning in place, but BLPC may encounter some difficulty in managing to secure funding for the investments as well as the increase in cost of service that would come with the investment of all of the proposed investments presented without a suitable cost recovery mechanism in place.

160. Additionally, without the opportunity to recover the cost of the proposed investments in a timely manner, the utility may struggle to attract financing for these new investments, and result in higher cost of capital. This is not beneficial to the customer as it may ultimately be passed on.

[69] Ibid

161. The Applicant proposes to invest this $684.9 million over a period of three (3) years to support the GoB's vision of 100% RE and ensure that the Barbadian customer can continue to receive a service that is safe and reliable. Having appraised the proposed investments, the assets that will be included for cost recovery are presented in Table 8. In is noted that the 15MW the assets approved for 2024 include the 15 MW of BESS, the AGC, IPP Interconnection costs and the DER Pilot. Further IPP Interconnection costs are approved for 2025 and 2026. The revised expected revenue requirement, that is the total revenue that is targeted through collections to cover the costs of the proposed investments is estimated at $31.4 million in the three (3) year programme and presented in Table 9.

Table 7 - Summary of Approved Investment Costs (**Estimated**)

INVESTMENTS	2024 ($)	2025 ($)	2026 ($)	TOTAL ($)
BESS	107,940,915			107,940,915
Automatic Generation Control	3,580,855			3,580,855
IPP interconnection	13,419,928	22,308,721	34,239,364	69,968,013
DER Aggregation & Control	1,172,943			1,172,943
TOTAL	**126,114,641**	**271,495,409**	**287,191,789**	**182,662,726**

Table 8 - Summary of Approved Revenue Requirement (**Estimated**)

Revenue Requirement	2024 ($)	2025 ($)	2026 ($)	TOTAL($)
BESS	22,171,702	-	-	22,171,702
Automatic Generation Control	540,679	-	-	540,679
IPP interconnection	1,637,458	2,723,315	4,187,546	8,548,319
DER Aggregation & Control	167,429	-	-	167,429
TOTAL	**24,517,268**	**2,723,315**	**4,187,546**	**31,428,129**

162. The implementation of a cost tracker mechanism is generally used on a case-by-case basis when:

a) the cost being considered is large enough to pose a threat to the financial integrity of the utility;

b) the cost is highly volatile and cannot be reasonably managed;

c) there is potential for substantial financial instability in the absence of an appropriate recovery mechanism and significant under/overcharging to ratepayers[70].

163. It is important therefore to consider:

a) the reasonableness of the weighted average cost of capital (WACC) and the transfer of risk from the utility to the ratepayer; and

b) the rider, its calculation and how it will work.

<u>REASONABLENESS OF PROPOSED WACC</u>

164. In paragraphs 35 to 36 of the Application, the Applicant noted that the February 15, 2023 Decision[71] of the Commission determined the return on equity (ROE) to be 11.75% and the accepted that ROE as the applicable cost of equity financing for this Application[72]. In paragraph 37 of the Application, the BLPC requests a WACC of 9.14%.

165. The BLPC contends that based on market scans on interest rates, its cost of debt would increase to 5.96% on long term debt[73]. This is more than double the cost of debt noted in the 2021 BLPC Rate review application which was 2.78%[74].

166. Intervenor Mr. Kenneth Went submitted that the WACC is too high and should be closer to 7.9% instead of the 9.14% based on his own calculation. He implied that the 5.96% cost of debt was justified based on the high cost of US denominated debt. However, based on a comparison of the WACC used for Hydro pumped storage, applying a gross up for 15% tax[75] he contends that the WACC requested is "excessive"[76].

167. This differential in WACC raises a concern on the sharing of risk that may occur with the implementation of piecemeal riders for cost recovery. Every attempt must be made to

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[70] The Electricity Consumers Resource Council (ELCON). 2024. Cost Trackers. Accessed March 10, 2024. https://elcon.org/cost trackers/#:~:text=A%20cost%20tracker%20is%20a,costs%20without%20any%20regulatory%20review

[71] Fair Trading Commission's Decision on an Application by the BLPC for a review of the Electricity Rates issued on February 15, 2023

[72] See Paragraph 35 of the Application

[73] See paragraph 36 of the Application

[74]See Page 92 of The Decision and Order of No. 01/2023 2023-02-15_commission_decision_BLPC_rate_review.pdf (ftc.gov.bb)

[75] See Went & Team Submission on BLPC's Application for Preapproval of Investment And Cost Recovery Through the CERT dated March 4, 2024

[76] IBID paragraph 25 - 29

maintain the integrity of the ratemaking process to ensure that the risk is fairly allocated between the utility and consumers.

168. Though the BLPC will incur increased cost, it does not mean that the BLPC should automatically be approved for the same level of WACC when accounting for the new assets. One should consider that the calculation of the revenue requirement attributed to these specific assets may be offset by reductions in the expenses in other aspects of the operations. When a rate review is undertaken to determine the tariffs to be applied for the recovery of an asset, a total assessment of the utility expenses is considered including the operation of that new asset. Without this assessment, it is difficult to assess any potential offset. While the assumptions presented show an estimated revenue requirement, a full assessment including the new asset would highlight where improvements in efficiencies could result in revenue growth overall and lower marginal costs.

169. Failure to recognise these potentially offsetting cost changes could create opportunities for the BLPC to over earn on these proposed investments. There must be awareness that the BLPC may benefit from offsetting reductions in expenses in the total operation, resulting in the potential for the utility to over-earn.

170. Having completed a full rate review in 2023, which used an adjusted 2020 test year, it can be said that a benchmark of utility costs has been established. The Commission notes that an appropriate benchmark for future assessment could be the test year data used in the 2023 rate review. A continuous assessment of these costs is imperative, because this helps to mitigate against the risk of the BLPC over earning on these investments under the CETP Project 1. The information that is gathered on those costs recovered in rates will provide greater confidence that the riders more reasonably track increase in unit costs as long as any potential offsets are also considered.

171. The reduction of regulatory lag is effected by not having to complete a rate review after the assets have been commissioned as well as the BLPC being able to recover its costs sooner through the CETP mechanism rather than later. The BLPC has already indicated that it will seek to recover the undepreciated portion of these assets in the next rate review. The possibility therefore arises that the approval of riders may result in the opportunity for the BLPC to over-earn, especially without enhanced scrutiny of the utility on a more

regular basis. This means that risk may be shifted to the ratepayer and away from the BLPC, who would be more able to bear the risk.

Table 9 - WACC Assumptions

	Approved in 2010[77]	Approved February 2023[78]	Proposed[79]
Cost Of Equity	12.75%	11.75%	11.75%
Cost of Debt	5.25%	2.78%	5.76%[80]
ROR	10.00%	7.47%	9.14%

172. The approval of a WACC in line with the pending 2023 Rate Decision may encourage a utility to seek the approval of rate recovery through riders, thus avoiding full rate cases. While on an individual basis there might be sufficient justification, caution still needs to be considered as it relates to the BLPC potentially reducing its own risk at the expense of the ratepayer. The BLPC is encouraged to procure its debt in an efficient manner as any accesses are passed on to the consumer. This is especially noted given that the procurement of US denominated loans is currently at a higher interest rate than debt denominated in Barbados dollars.

173. The Commission determines that increased monitoring of utility costs is required, with greater scrutiny of the company's earnings report in order to facilitate a more thorough review. To this end, the level of detail provided in the annual report is now required to be provided on a quarterly basis. This detail must include those costs that are proposed to be recovered through the rider, including costs associated to acquisition, construction, administration, operation, maintenance, and any other costs incurred. If, on review of the information provided, the evidence provided suggests that there are significant savings that should be passed on to the consumer, then the Commission reserves the right to mandate a revision of the rider to make an adjustment which accounts for any significant over recovery of costs. Additionally, there will be an in-depth assessment at the next rate

[77] Fair Trading Commission's Decision on the Application by the BLPC for a review of electricity rates issued January 25, 2010
[78] Fair Trading Commission's Decision on an Application by the BLPC for a review of the Electricity Rates issued on February 15, 2023
[79] The BLPC's Application paragraphs 35 to 37
[80] The cost of debt represents the actual interest paid to finance the new assets.

review to determine if there should be any reconciliation in relation to excesses or deficits in costs paid by the ratepayer. Furthermore, the BLPC indicates that it intends to request that these assets are moved to rate base at the next rate review. The BLPC proposes in a response to the Commission's interrogatory that costs related to the CETP Project 1 will only be recovered through the CETR for the duration of the period between general rate review applications. The CETR will be reset to zero, and the undepreciated portion of the assets within the CETP Project 1 will at that time be included in the BLPC's rate base to determine any adjustments to base rate tariffs.[81]

TRACKER ASSESSMENT

174. In determining the calculation of the rider used to recover the cost of the assets, the BLPC considered standard revenue requirement as set out in the Commission's CETR Decision[82]. The costs that it seeks to recover include a return on its invested capital and all costs associated with the acquisition, construction, administration, operation and maintenance of the assets used in the supply of electricity[83].

175. The Commission's CETR Decision indicated that the recovery methodology under the existing COSR, the recalibration of and adjustment to rates are determined on verification of all prudently incurred costs associated with the formula:

$$\mathbf{RR=E + D+T + (RB * ROR)} \qquad \text{Equation 1}$$

Where:

Revenue Requirement (RR),
Operation and Maintenance Expenses (E),
Depreciation Expenses (D),
Taxes (T),
Rate Base (RB) and
Rate of Return (ROR)[84]

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[81] See Exhibit AC2 "Responses to FTC's Interrogatories Dated November 23, 2023" - dated December 7, 2023
[82] CETR Decision / Decision on The Barbados Light & Power Company Limited Application to Establish a Clean Energy Transition Rider as a Cost Recovery Mechanism Document No. FTCUR/DECCETR/BLPC/2023-02 dated May 31, 2023
[83] See paragraph 31 of the Application.
[84] See Page 25 CETR Decision / Decision on The Barbados Light & Power Company Limited Application to Establish a Clean Energy Transition Rider as a Cost Recovery Mechanism Document No. FTCUR/DECCETR/BLPC/2023-02 dated May 31, 2023

176. The BLPC has used this general formula to recommend the structure of the cost trackers in its usage, satisfying the requirements as set out in the Application.

177. Intervenor BREA noted in its submission that the BLPC's equation does not account for reconciliation of actual costs to be in line with the period in which the various elements should apply and recommends the inclusion of a balancing adjustment to account for any under or over recovery of costs[85].

178. The Commission has highlighted that one of the shortfalls of the use of a rider as a cost recovery mechanism is the potential for over recovery of cost by the utility. While the use of this recovery mechanism suggested can provide some value, the position of doing the reconciliation at the next rate review also assists in accounting for reconciliation of costs. This option also allows the analysis of the operation of the new assets in the total system and adjustments made at that time.

179. The calculation of a new rider will be based on actual costs of an investment at the time of commissioning. Changes in variable costs will be monitored by the Commission on a quarterly basis. This calculation will account for the actual cost of the asset, inclusive of the actual cost of debt. The allowed rate of return is thus derived using the interest rate that the BLPC is able to negotiate to finance the asset. As each new asset is commissioned, the rider is expected to increase as the investments increase.

180. The form of the equation proposed by the utility is consistent with the CETR Decision approved. However, the detail presented at paragraph 41 of the Application does not show, as noted in the Application that the CETR will be "adjusted based on the date the investments go into service"[86].

181. With the commissioning of each asset (asset "j[87]"), a test year revenue requirement is determined based on the actual resource cost of the asset with all applicable expenses and the applicable rate of return using actual cost of debt. This revenue requirement is used to

[85] See paragraphs 13 Exhibit SW1 Affidavit of Mr. Stephen Worme dated March 4, 2024
[86] See paragraph 42 of the Application
[87] "j" refers to a new asset

calculate a new rider value. Intense scrutiny is required of the rider in highlighting where significant changes in the variable expenses may be at the detriment of the ratepayer.

182. The Commission approves the following rider equation:

$$CETR_n = \frac{\sum_1^j [(RC_j - D_j) * RoR_j + EDT_j]}{Sales} \qquad \$/kWh \qquad \text{Equation 2}$$

Where:

j refers to the asset commissioned
Sales = Electricity Sales (kWh)
RC_j = Resource Costs of approved equipment for asset j
D_j = Accumulated Depreciation for asset j
RoR_j = Allowed Rate of Return for asset j
EDT_j = Expenses (ie. O&M, Depreciation & taxes) for asset j

CUSTOMER IMPACT

183. The expected cost impact, assuming the estimated costs of these projects are as summarised below. It is expected that the proposed assets will not be all commissioned at the same time, and as the assets are proven used and useful, the rider is recalculated and revised upwards. As a result, the impact of the investments on the customers is moderated to some degree.

184. Assuming the estimated costs of the total projects, the CETR is $0.026/kWh in 2024, $0.029/kWh for 2025 and $0.033/kWh for 2026. For a domestic customer using 200 kWh per month, whose bill before the implementation of the rider is $128.45[88] before VAT, the inclusion of the rider results in an increase of $5.20 or 4% in 2024, $5.78 more in 2025 and $6.69 more in 2026. A secondary voltage customer using 22,409 kWh expects a pre-rider bill of $13,683.59[89] before VAT. This inclusion of the rider results is an increase of $576.92 or 4% in 2024.

185. As discussed in this document, the assets, when commissioned, do not function in a vacuum. but as components of the entire plant. With the introduction of the proposed

[88] This bill is calculated assuming a fuel clause adjustment of 0.388271
[89] This bill is calculated assuming a fuel clause adjustment of 0.388271

software, the increased monitoring of the utility operation may highlight opportunities to make improvements based on ongoing data received. This may result in opportunities for lower marginal costs for the BLPC. Given that rates would already be approved, the potential benefits of lower marginal costs would be paid for by the ratepayer. An assessment of any potential savings that would not be passed on to the ratepayer cannot be assessed at this time as these potential savings depend on decisions that are made on an ongoing basis, especially decisions that are driven by changing market conditions and increased data.

186. The proposed investments are expected to facilitate the continued roll out of variable RE investments onto the grid. This results in the opportunity for increased participation in the RE sector thus realising the objectives of BNEP. The knock-on effects of this include economic growth and opportunities for job creation. There is also the expectation of optimisation of RE resources. The integration of battery storage along with the integrating of the proposed investments by the BLPC provides multiple benefits that impact not only the ratepayer, but also the people of Barbados as a whole. It is expected that there is a resultant reduction in fossil fuel importation and usage, resulting in a long-term savings in foreign exchange. With a reduced reliance in fossil fuel, consumers can also expect improvements in air quality and general public health as the harmful emission associated with burning fossil fuels decline. Additionally, with the investments in place, the grid is expected to experience less congestion resulting in improved service to electricity customers – fewer service interruptions, less system outages, and shorter recovery periods when disturbances occur.

187. Further benefits to the customer also come in the form of security of supply that arises from the increased sourcing of locally sourced energy generation, specifically, energy generated from wind and solar. Additionally, as the investment in RE increases and the potential reduction in fossil fuel usage is realised, the impact of the volatility in international fuel prices currently experienced is reduced. Customers therefore are able to better predict their electricity costs on a monthly basis.

SECTION 5 DETERMINATION

188. The Commission having reviewed the Application of BLPC for approval of costs associated with the capital and T&D of the proposed investments under its CETP Project 1, to be recovered through the CETR mechanism, makes the following determination:

A. 90 MW OF BATTERY ENERGY STORAGE SYSTEMS (BESS)

(1) The recovery of CAPEX associated with the total 15 MW (1 × 10 MW and 5 × 1 MW) BESS earmarked to be commissioned in 2024 is approved. The remainder is not approved.

(2) The BLPC shall be required to provide the following information to the Commission:

a) The total estimated installed costs for the 15 MW BESS based on the accepted costs from the selected vendor no later than one (1) month after accepting said costs;

b) The actual CAPEX of each asset, no later than one (1) month after commissioning of the total BESS capacity that is earmarked for the calendar year;

c) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying each BESS asset that is scheduled for a calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the total BESS capacity that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

d) For each BESS, a single line connection diagram, a copy of the OEM operations manual, specification document, and OEM warranty sheet no later than one (1) month after commissioning of the total BESS capacity scheduled for the calendar year;

e) **A copy of the pre and post commissioning report for the BESS assets no later than one (1) month after commissioning;**

f) **A unique identifier for each BESS asset based on its location and include in its quarterly regulatory reporting, monthly information on:**

i. **Details of, and actual operation and maintenance costs for each BESS;**
ii. **Minimum state of charge;**
iii. **Energy Charged (kWh-AC);**
iv. **Energy Discharged (kWh-AC);**
v. **Reactive Power absorbed (KVAR -AC);**
vi. **Reactive Power delivered (KVAR-AC;**
vii. **Reactive Power absorbed (KVARh -AC);**
viii. **Reactive Power delivered (KVARh-AC; and**
ix. **Round Trip Efficiency (%).**

This information shall be submitted to the Commission no later than one (1) month after the end of the quarter;

g) **Information for each BESS on the following:**

i. **Maximum Energy Capacity (kWh-AC measured);**
ii. **Maximum Power Capacity (kW -AC measured);**
iii. **State of Health (%);**
iv. **Capacity Ratio (%);**
v. **System Efficiency (%); and**
vi. **Cycle Life.**

BLPC shall include this information in its annual regulatory reporting no later than one (1) month after the end of calendar year;

h) **A maintenance programme for the BESS assets based on the OEM's guidelines, industry best practice, and the operating environment, for approval of the Commission, no later than three (3) months prior to the commissioning of the BESS;**

i) Ad-hoc reports for exigency events no later than seven (7) working days of occurrence of the event; and

j) Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.

(3) The BLPC can commence recovery of the actual CAPEX and associated costs for the BESS assets as determined by the Commission, six (6) months after commissioning.

B. AUTOMATIC GENERATION CONTROL (AGC) SYSTEMS

(1) The recovery of CAPEX and associated costs for the proposed AGC system is approved.

(2) The BLPC shall be required to provide the following information to the Commission:

a) The total estimated installed costs for the AGC system based on the accepted costs from the selected vendor no later than one (1) month after accepting said costs;

b) Actual CAPEX for the AGC system no later than one (1) month after its commissioning for the calendar year;

c) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying the AGC system that is scheduled for the calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the full AGC system that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

d) A copy of the OEM operations manual, specification document, and OEM warranty sheet for the AGC system no later than one (1) month after its commissioning;

e) A copy of the pre and post commissioning report for the AGC system no later than one (1) month after commissioning;

f) A performance report for the first six (6) months of operation of the AGC system. The report shall be submitted to the Commission one (1) month after commissioning;

g) A maintenance regime for the AGC system in accordance with the OEM's guidelines, industry best practice, and the operating environment and submit for the approval of the Commission, no later than two (2) months after the commissioning of the AGC system;

h) Details of the operating and maintenance costs for the AGC system for each month, in its quarterly reporting no later than one (1) month after the end of the quarter;

i) Maintenance and operating reports for the AGC system on an annual basis no later than one (1) month after the end of the calendar year;

j) Ad-hoc reports for exigency events no later than seven (7) working days after the occurrence of the event; and

k) Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.

(3) The BLPC can commence recovery of the actual CAPEX and associated costs for the AGC system, six (6) months after commissioning.

C. FOUR (4) SYNCHRONOUS CONDENSERS (SCO)

Recovery of costs for the proposed investment for the SCOs is not approved.

D. DISTRIBUTED ENERGY RESOURCES AGGREGATION AND CONTROL PLATFORM ("THE PILOT")

(1) The recovery of CAPEX and associated costs for the proposed pilot is approved.

(2) The BLPC shall be required to provide the following information to the Commission:

a) The total estimated installed cost for the pilot based on the accepted costs from the selected vendor no later than one (1) month after accepting said costs;

b) Actual CAPEX for the pilot no later than one (1) month after its commissioning for the calendar year;

c) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying the pilot that is scheduled for the calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the pilot that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

d) A copy of the OEM operations manual, specification document, and OEM warranty sheet for the pilot no later than one (1) month after its commissioning;

e) A copy of the pre and post commissioning report for the pilot, no later than one (1) month after commissioning;

f) A performance report for the first six (6) months of operation of the pilot. The report shall be submitted to the Commission no later than one (1) month after commissioning;

g) A maintenance regime for the pilot system in accordance with the OEM's guidelines, industry best practice, and the operating environment and submit for the approval of the Commission, no later than two (2) months after the commissioning of the pilot;

h) Maintenance reports to the Commission on an annual basis, no later than one (1) month after each anniversary of commissioning;

i) In its quarterly reporting, details of the operating and maintenance costs for the pilot, no later than one (1) month after the end of the quarter;

j) In its annual regulatory reporting, details of the operating and maintenance costs for the pilot on an annual basis no later than one (1) month after the end of the calendar year;

k) Ad-hoc reports for exigency events no later than seven (7) working days after the occurrence of the event; and

l) Ad-hoc reports for the assets can be requested from time to time by the Commission and the same shall be provided to the Commission no later than seven (7) working days after the receipt of such a request.

(3) The BLPC can commence recovery of the actual CAPEX and associated costs for the pilot, six (6) months after commissioning.

E. INTERCONNECTION INFRASTRUCTURE

(1) The recovery of costs associated with the Interconnection Infrastructure is approved.

(2) The BLPC shall be required to provide the following information to the Commission:

a) The total estimated installed costs for the infrastructural upgrades based on the accepted costs from the selected vendors no later than one (1) month after accepting said costs;

b) Actual CAPEX information for the infrastructural upgrades and a statement of works, no later than one (1) month after completion of the upgrade;

c) Copies of all invoices in relation to the actual CAPEX of an asset justifying the costs actually incurred in deploying the upgrades that is scheduled for the calendar year shall be submitted to the Commission no later than one (1) month after commissioning of the full upgrades that is earmarked for the calendar year. Copies of invoices shall be cross-referenced with the details of

actual purchases and signed by the BLPC's Managing Director or the Finance Director as to the correctness of the details contained therein;

d) Schedules for network upgrades, demarcated by year, location, duration, commencement and completion on a quarterly basis. This information shall be submitted one (1) month following the end of the quarter;

e) A copy of a queue connection register for planned interconnections for each year, no later than one month (1) after issuance of this CETR Decision;

f) A list of RE projects scheduled for interconnection requests on a quarterly basis. This information shall be submitted no later than one (1) month after the end of the quarter;

g) A list of the status of RE interconnections on an annual basis, no later than one (1) month after the end of the calendar year;

h) The status of IPP negotiations on a bi-annual basis. This information is required no later than one (1) month following the end of the first half and second half of the calendar year; and

i) A copy of the final draft interconnection template agreement to the Commission no later than four (4) months after the issuance of the Commission's Decision.

F. FORMAT

Where appropriate the above information should be submitted in Excel Spreadsheet format with appropriate tabs.

G. CYBERSECURITY

The BLPC shall exercise industry best practice with regard to use, management, confidentiality, availability, and integrity of customer data in order to mitigate against cybersecurity threats and risk.

H. TRACKER FORMULA

The rider shall be calculated using the following equation:

$$CETR_n = \frac{\sum_1^j [(RC_j - D_j) * RoR_j + EDT_j]}{Sales} \quad \$/kWh$$

Where:

j refers to the asset commissioned
Sales = Electricity Sales (kWh)
RC_j = Resource Costs of approved equipment for asset j
D_j = Accumulated Depreciation for asset j
RoR_j = Allowed Rate of Return for asset j
EDT_j = Expenses (i.e. O&M, Depreciation & taxes) for asset j

I. MONITORING

(1) The utility is required to submit the regulatory reports on utility earnings inclusive of all utility costs on a quarterly basis to the Commission. The regulatory reports must include those costs that are proposed to be recovered through the rider, including costs associated to acquisition, construction, administration, operation, maintenance, any other costs incurred and any further information which the Commission may request from time to time.

(2) The Commission will monitor the quantum of costs allowed to pass through the CETR Mechanism on a quarterly basis. Where it is evident that the BLPC has over/under recovered, the Commission reserves the right to reconcile the indicative costs.

(3) The Commission reserves the right to conduct audits on the performance of the BLPC and the use and usefulness of the assets approved pursuant to this Decision from time to time in the Commission's sole discretion. Where it is found that the BLPC's performance is unsatisfactory, the Commission shall take the appropriate actions to ensure compliance with this Decision.

Dated this 6th day of May, 2024

Original signed by

……..……………………………..
Donley Carrington
Hearing Chairman

Original signed by

……..……………………………..
John Griffith
Commissioner

Original signed by

……..……………………………..
Ruan Martinez
Commissioner

Original signed by

……..……………………………..
Ankie Scott-Joseph
Commissioner

Original signed by

……..……………………………..
Samuel Wallerson
Commissioner

APPENDIX 1

SUMMARY OF SUBMISSIONS

1. BREA

BREA indicated their support for the instant Application and includes recommendations on how they believe that the application can be implemented. Their support is grounded in their assessment that the equipment for which pre-approval has been requested is required to move the energy sector forward and achieve the objectives of the BNEP. BREA highlights evidence of what they express as "bottlenecks" that prevent the continued connection of RE projects to the electricity grid, citing 500 MW of applications for PV systems made to the MEB and 105 MW of licensed PV systems that cannot be connected into the grid without it becoming unstable[90]. BREA indicates that a number of its members have encountered financial difficulties as a result of this stagnation.

BREA notes the absence of analysis to quantify fuel savings or other benefits for the systems and postulates that the absence of direct savings to consumers is offset by the facilitation of additional PV and wind systems, which may itself provide savings in fuel costs and over time, operational costs associated with the existing fossil fuel plant. BREA suggests that at the end of the second year, some analysis on this is carried out, with the expectation that information is collated on "what ongoing annual benefits could look like"[91].

BREA compares this rider with the determination of the fuel clause adjustment, pointing out that the CETR would be calculated based on actual capital and operating costs, in comparison with the fuel clause adjustment (FCA) which is based on fuel costs and sales. BREA addresses the risk of over or under recovery by the utility by recommending a mechanism that is claims is similar to the FCA, that a reconciliation adjustment is done at the end of a period and incorporated in the following period.

BREA highlights a shortcoming in the BLPC' s equation for the calculation of the rider noting that it does not indicate the different periods in which its components should apply and

[90] See paragraph 4 of Exhibit SW1 Barbados Renewable Energy Association's Written Submission dated March 4, 2024

[91] IBID Paragraph 11

suggest an adjustment to the equation to allow for any under or over recovery Costs incurred in the year will be applied in bills issued in the following January or February, if January is not feasible.

BREA further suggests that the CETR be incorporated as an automatic mechanism similar to the FCA, to be used annually between rate cases.

2. TEAM WATSON/SIMPSON ("THE TEAM")

The Team asserts in its intervenor request, that the CETR is "the single biggest rate application filed by the BLPC in its history"[92]. The team opines that the CETR is "predicated" on a rate of return mechanism, and that mechanism "provides weak incentives for companies to operate efficiently, provides incentive to over invest, can result in distortion of investment decisions, can result in over-recovery on the rate of return"[93].

The Team requires the inclusion of a cost allocation model and methodology and seeks cost causality. The Team notes that there are no efficiency targets or performance incentives arising from the rate base additions. The application excludes any fuel cost savings or other monetary benefits for ratepayers. The intervenors estimate that the CETR translates to a 66% increase in the average electricity tariff and an increase cost to ratepayers of approximately $138 million per year for an unstated period.

The Team notes the absence of any cost containment measures that may arise from the rate base additions and these, the team expects, should be included. There is an absence of compliance rules and procedures, an absence of cost benefit analysis as requested, an absence of depreciation schedules and depreciation rates. The application does not include data on the retirement of fossil fuel assets.

The Team highlights that the BLPC's licence is soon retiring and states that there is no granular detail on the O&M expenses. The team asks the question, "How do the assets meet the requirements as set out – volatile, unmanageable, unpredictable?" There is a lack of service

[92] See paragraph 1.2 of Application for Intervenor Status in the Application by the Barbados Light & Power Company Limited for approval to acquire capacity and transmission& distribution resources and to allow the recovery of their costs through the Clean Energy Transition Rider (CETR) mechanism dated December 8, 2023
[93] Ibid see paragraph 1.4

standards for the CETR and there is no cost-of-service study provided. There is no rate design included and this, the Team opines, will result in a misallocation of costs to the detriment of lower usage domestic customers. The BLPC's operations study has not be done.

3. MR. KENNETH WENT

Mr. Went supports the proposed upgrades required on the network to facilitate RE integration. He advises that for areas where existing 11 KV infrastructure remains adequate, BLPC should continue serving customers in order to reduce the proposed upgrade costs of $69,998,586.

With regard to the 90 MW BESS, he accepts that storage capacity is needed on the grid. However, he points out that the proposed investment in BESS represents 81% of total costs of proposed investments under the CETP Project 1. Additionally, he expressed concern about the short service life of BESS and the need to replace these after 10 years. If more BESS are required under future CETR Projects, in his view, these will continue to be expensive. He implied that hydro-pumped storage which have longer service life (50 years) should be considered instead of BLPC's BESS strategy.

He also accepts that the RE and BESS escalation expected online warrants a platform to optimise utilization of these resources and supports the proposal for this pilot. In his view the Commission should audit the pilot to ensure the findings and recommendations are implemented.

Further Mr. Went also supports the need for synchronous condensers online to encourage RE deployment. However, he argues that retired or soon to be retired fossil fuel plant should be repurposed as SCOs as a cost-effective measure. Mr. Went reasoned that since these generation plant already have accounts in rate base, additions for recovery would be in accordance with regulatory policy approved by the Commission.

In Mr. Went's opinion, AGC is required for stability and reliability of the grid. However, he was concerned that BLPC's generators were not AGC compliant. Despite this, he supports the proposal for AGCs.

In terms of the WACC used by BLPC, Mr. Went claims that the 9.14% appears excessive. This claim is based on the fact that the high interest rate 8.5% implies that the cost of debt (5.96%)

is more than doubled the 2.78% stated. Computation of the WACC showed that this should be 7.9% instead 9.14%. Reference was made to the pre-tax WACC (5%) used by BLPC in their CBA study for BESS and considering applying a 15% tax rate, the cost of capital should be 5.75%; this further supports that 9.14% is excessive.

The accrual of cost savings from BESS was a benefit Mr. Went expects. He argues that based on BLPC's analysis of Deployment of Battery Storage Systems for Barbados fuel cost reductions are evident. He advises that given the large revenue requirement, BLPC must be required to quantify the savings to offset costs.

Considering the CETP Project 1, the total investments amount to $684,904,562 and a revenue requirement of $131,266,265, Mr. Went is of the view that the revenue requirement is excessive and warrants assessment by the Commission.

With regard to the impact of the CETP Project 1 on customer bills, Mr. Went claims that based on his assessment the average customer bill will experience an increase between 20.7% and 26.2%.