THE BARBADOS LIGHT & POWER COMPANY LIMITED

APPLICATION

PURSUANT TO SECTION 16

OF

THE UTILITIES REGULATION ACT

CAP. 282 OF THE LAWS OF BARBADOS

FOR A REVIEW OF ELECTRICITY RATES

VOLUME 4

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M

MEMORANDUM ON STANDARDS OF SERVICE

1. As part of the application to the Fair Trading Commission ("the Commission") for a review of electricity rates, The Barbados Light & Power Company Limited ("BLPC" or "the Company") submits herewith its Memorandum for Standards of Service.

2. Standards of Service were introduced in 2002 as a function of the Commission under the **Utilities Regulation Act** ("the Act"). Specifically, section 3 states in part:

"The functions of the Commission under this Act are, in relation to service providers, to:

…

(d) determine the standards of service applicable;

(e) monitor the standards of service supplied to ensure compliance; and

(f) carry out periodic reviews of the rates and principles for setting rates and standards of service."

3. The close connection between rates and Standards of Service is highlighted by section 4 of the Act which states:

"In determining standards of service, the Commission shall have regard to:

(a) the rates being charged by the service provider for supplying a utility service;

(b) ensuring that consumers are provided with universal access to the services supplied by the service provider;

(c) the national environmental policy; and

(d) such other matters as the Commission may consider appropriate."

4. This close connection between rates and Standards of Service is also highlighted by rule 63 (1) of the **Utilities Regulation (Procedural) Rules**, 2003 which states:

"Where a service provider makes an application for a rate review, proposed service standards must be presented as part of that request."

REVIEW OF STANDARDS OF SERVICE

5. The Company conducts annual surveys to better understand its customers' needs and continues to seek ways in which it can improve its operations to enhance the quality of service. The implementation of Standards of Service has been a positive influence in this regard.

6. Section 15 (1) of the Act states:

"The Commission may fix a period of time not exceeding 5 years in respect of which

(a) the rates for the supply of a utility service;

(b) the principles for determining rates for the supply of a utility service; and

(c) the standards of service will apply"

7. Notwithstanding section 15(1) above, section 15(2) of the Act allows for a review at any time should the Commission consider that there has been a fundamental change in circumstances which warrant this.

EXISTING STANDARDS OF SERVICE

8. On April 3, 2017 the Commission issued a Consultation Paper entitled *"Review of The Barbados Light & Power Company Ltd. Standards of Service 2014 - 2017"*, ("the Consultation Paper") which included results for the period July 2014 to December 2016. This is found at Schedule M-1.

9. In response to the Consultation Paper referred to above and found at Schedule M-1, the Company on May 2, 2017 submitted its comments to the Commission. The Company's submission is included at Schedule M-2.

10. On September 29, 2017, the Commission issued its Decision on Standards of Service 2018 to 2020 for the Company. This is shown at Schedule M-3. These Standards of Service came into effect on January 1, 2018 and included Guaranteed Standards of Service and Overall Standards of Service.

11. On July 19, 2019 the Commission issued its Standard of Service Report on the Performance of the Company for the period April 2018 to March 2019. This is found at Schedule M-4.

12. The results for the Standards of Service as prepared by the Company for the reporting period April 2018 to March 2021 is found at Schedule M-5.

13. The Company continues to comply with and follow the Fair Trading Commission's Decision for The Barbados Light & Power Company Limited's Standards of Service 2018-2020 Document No: FTCUR/DECSOS/BL&P-2017-02 issued on September 29, 2017.

14. In its Annual Report 2019, the Commission in reporting on BLPC's Standards of Service performance highlighted that the Company achieved ***"reasonably high levels of performance for the review period."*** The Commission further stated that ***"the BL&P's reliability of service figures exceeded the stipulated benchmarks. The electricity grid was available to end-users 99.99 percent of the year."***

15. Further, in its Analysis of BLPC Annual Standards of Service Report for the period April 1, 2018 to March 31, 2019, the Commission stated that ***"the compliance level registered by the majority of Standards ranged from 96% to 99%; only two (2) categories registered compliance below 93%."***

16. The existing Standards of Service 2018 – 2020 were due for review in 2020. However, on December 11, 2020 the Commission issued a Statement on Extension of Standards of Service 2018 – 2020 indicating its intention to extend the 2018 – 2020 Standards of Service. On February 12, 2021 the Commission published its Notice advising of the implementation of the extension of the 2018 – 2020 Standards of Service until June 30, 2021. On July 1, 2021 the Commission published its Notice advising that the Standards of Service 2018 – 2020 had been further extended until June 30, 2022.

PROPOSED STANDARDS OF SERVICE

17. BLPC's current application is premised upon the current Standards of Service, with the financial and staff resources required to assure compliance with those standards.

18. If the FTC issues new Standards of Service that include significant changes which will affect the financial and staff resources needed to assure compliance, BLPC reserves the right to file an amended application to address those changes.

19. However, until such time that the Commission decides on revised Standards of Service, the Company will continue to operate under the existing Standards of Service. The Company considers these Standards of Service to be consistent with the electricity rates being applied for in this application.

Dated this 30th day of September, 2021

Paper prepared by:

Roger Blackman
Managing Director
The Barbados Light & Power Company Limited

M-1

FAIR TRADING COMMISSION

CONSULTATION PAPER

REVIEW OF
BARBADOS LIGHT & POWER COMPANY LIMITED
STANDARDS OF SERVICE
2014 - 2017

Document No.: FTC/UR/CONSOS/BL&P-2017-02 **Date of Issue: April 03, 2017**

DOCUMENT NUMBER: FTC/UR/CONSOSBL&P 2017 – 02

DOCUMENT TITLE: Review of the Barbados Light & Power Company Limited Standards of Service

ANTECEDENT DOCUMENTS

Document Number	**Description**	**Date Issued**
FTC/UR/2014-01	Decision on BL&P Standards of Service 2014 - 2017	May 09, 2014
FTC/URD/CONS 2013-01	Consultation Paper - Review of the BL&P Standards of Service	October 25, 2010
FTC/UR/2010-03	Decision on BL&P Standards of Service 2010- 2013	February 22, 2010
FTC/CONS 2008-02	Consultation Paper – Review of the BL&P Standards of Service	October 29, 2008
FTC/UR/2006-2	Decision on BL&P Standards of Service 2006 - 2009	February 28, 2006

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PURPOSE OF DOCUMENT

This consultation document outlines the Fair Trading Commission's (the Commission) review process of the Standards of Service Decision 2014 - 2017 for the Barbados Light & Power Company Limited (the BL&P), pursuant to Section 4 (3) of the Fair Trading Commission Act , CAP. 326B (FTCA) and Sections 3 and 4 of the Utilities Regulation Act CAP. 282 (URA) of the Laws of Barbados.

The Commission considers that public participation is a key component to its decision-making process and therefore invites submissions from interested parties concerning its review.

This consultation document is intended to solicit comments relating to:

(a) The appraisal of the BL&P's Guaranteed and Overall Standards of Service performance;
(b) The adequacy of these Standards;
(c) Amendments of the existing Standards of Service;
(d) Affixing reliability targets to the current reliability indices;
(e) Additions to existing reliability indices; and
(f) Amendments to the mode of compensation.

Submissions may not be confined to questions posed but may relate to any matter raised in the document. The consultation document may be accessed via the Commission's website, http://www.ftc.gov.bb.

The consultation period will commence on **April 3, 2017** and conclude on **May 2, 2017** at 4:00pm.

STRUCTURE OF PAPER

This paper consists of eight sections:

- Section 1 provides an update on the electricity sector.
- Section 2 presents the legal framework and functions of the Commission relating to the Standards of Service.
- Section 3 offers an evaluation of the BL&P's performance for the period July 2014 – December 2016.
- Section 4 lists proposed amendments to the existing Standards of Service.
- Section 5 lists Force Majeure and other exemption conditions.
- Section 6 details the role of the Commission with regard to the monitoring and enforcement of Standards of Service.
- Section 7 presents the list of consultation questions.
- Section 8 describes the consultation process.

SECTION 1 BACKGROUND

Market competition plays a vital role in the delivery of service quality which in turn influences consumer preference. The competitor who succeeds in offering a price and quality of product that the consumer is willing to pay and accept can dominate the market. In the absence of competition, the behaviour of monopolies is constrained by regulatory institutions like the Commission. As monopolies are not subject to market competition, they may be inclined to trade price against quality of service. Given this, the Commission is obligated to ensure that a minimum accepted level of service exists for regulated services, thus the establishment of Standards of Service.

The BL&P is a vertically integrated company, that is, it generates, transmits and distributes electricity for its consumer base of 126,190 customers[1]. The BL&P provides electricity to Domestic Service (D), General Service (GS), Secondary Voltage Power (SVP) and Large Power (LP) customer classes; there is also a class for employees. Electricity is currently produced mainly from fossil fuel (95%) and Renewable Energy (RE) sources (5%).

During the 2014 - 2016 period, opportunities for Supply Side Management (SSM) continued to be exploited. These were namely Time-of-Use (TOU), Interruptible Service Rider (ISR), Utility Scale Distributed Solar and a permanent Renewable Energy Rider (RER) programme.

The ISR provides the BL&P with the option to interrupt a customer's supply of electricity, thereby reducing the peak load demand and generation costs. Participants receive a monthly credit for agreeing to allow the temporary interruption of their electricity, as required by the Company.

The TOU programme is a pilot programme which incentivises Large Power (LP) customers to consume electricity during off-peak hours. Both the BL&P and its customers

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[1] Emera Incorporated, "*Preliminary Short Form Prospectus*," accessed January11, 2016, http://investors.emera.com/Cache/36953824.PDF?Y=&O=PDF&D=&FID=36953824&T=&OSID=9&IID=4072693.

benefit – the latter through bill savings from the lower cost of off-peak consumption and the former from reduced peak generation, which is at a higher cost.

The Electric Light and Power Act (2013 – 21) (ELPA), of the Laws of Barbados allows for competition in the electricity sector by opening the market to Renewable Energy (RE) generators.

The BL&P's RER programme continues to facilitate the sale of excess electricity to the grid through the participation of distributed photovoltaic (PV) and wind generating systems. By design, the use of these can offset the amount of electricity consumed from the grid. The current RER rate structure is delinked from fossil fuel, with electricity generation from solar PV and wind systems attracting rates of $0.416/kWh and $0.315/kWh, respectively. This new rate structure took effect from July 26, 2016[2].

In August 2016, the BL&P commissioned its 10MW alternating current (AC) utility scale solar plant at Trents, St. Lucy. The plant represents the first of the BL&P's RE projects as outlined in its 2013 Integrated Resource Plan (IRP).

[2] Fair Trading Commission, "*Motion to Review the Renewable Energy Rider*", accessed January 10, 2017, http://www.ftc.gov.bb/library/2016-07- 5_commission_decision_motion_to_review_rer_revised.pdf.

SECTION 2 LEGISLATIVE FRAMEWORK

Authority to Establish Standards of Service

The Commission holds the view that Standards of Service are an important tool in ensuring that the BL&P provides a safe, efficient and reliable service to its consumers.

According to the FTCA, Standards of Service is defined at Section 2 as '*the quality and extent of service supplied by service providers*'.

Section 4(3) of the FTCA and Sections 3(1) and 4 of the URA set out the Commission's authority to determine the Standards of Service for a regulated entity and the considerations that must be given when determining the same. Rule 63(2) of the Utilities Regulation Procedural Rules 2003, S.I. 2003 No.104 (URPR) of the Laws of Barbados details the issues that may be included in the development of these Standards of Service. Together, these pieces of legislation provide the over-arching framework necessary for the development and establishment of the Standards of Service for a regulated sector.

Section 4(3) of the FTCA states, *inter alia*:

"The Commission shall, in the performance of its functions and in pursuance of the objectives set out in subsections (1) and (2),

(a) …
(d) determine the standards of service applicable to service providers;
(e) monitor the standards of service supplied by service providers to ensure compliance;
(f) carry out periodic reviews of … standards of service of service providers;"

Section 3(1) (d) (e) (f) of the URA states, *inter alia:*

"The functions of the Commission under this Act are, in relation to service providers, to

(a) ...

(d) determine the standards of service applicable;

(e) monitor the standards of service supplied to ensure compliance; and

(f) carry out periodic reviews of the … standards of service."

In exercising these functions, the Commission is charged with the responsibility, as stipulated in Section 3(3) (b) to:

(a) protect the interest of consumers by ensuring that service providers supply to the public service that is safe, adequate, efficient and reasonable; and

(b) hear and determine complaints by consumers regarding billings and the standards of service supplied."

Additionally, Section 4 of the URA states:

"In determining standards of service, the Commission shall have regard to

(a) the rates being charged by the service provider for supplying a utility service;
(b) ensuring that consumers are provided with universal access to the services supplied by the service provider;
(c) the national environmental policy; and
(d) such other matters as the Commission may consider appropriate."

Rule 63 (2) of the URPR speaks to issues that may be considered when setting Standards of Service. It specifically indicates that:

"Service standards may include issues such as

(a) universality of service;
(b) the provision of new services;
(c) the extension of services to new customers;
(d) the maximum response time permitted for responding to customer complaints and queries; and
(e) standards related to service quality which are specific to each sector."

Requirement to Consult

The power of the Commission to consult with interested parties is derived from Section 4 (4) of the FTCA which dictates that, when exercising its powers to determine Standards of Service, the Commission must consult with specific parties.

Section 4(4) of the FTCA requires that:

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

Fines and Penalties

These Standards of Service are binding on the BL&P. Sections 21, 31 and 38 of the URA, as well as Section 43 of the FTCA, prescribe the penalties that accrue where the utility fails to comply with the prescribed targets under the Guaranteed Standards of Service (GES) and the Overall Standards of Service (OES). Where there is a continuous failure to attain a target, the Commission will require an explanation from the BL&P. If the BL&P continues to be non-compliant, the Commission reserves the right to impose a penalty, pursuant to Section 38(c) (i) of the URA.

Section 21 of the URA indicates that:

> *"Where a service provider fails to meet prescribed standards of service, the service provider shall make to any person who is affected by the failure such compensation as may be determined by the Commission."*

Section 38 of the URA stipulates that:

> *"The Commission may make*
> *(a) rules;*
> *(b) regulations; and*
> *(c) orders with respect to*
> *(i) imposing penalties for non-compliance with prescribed standards of service; and*
> *(ii) prescribing amounts to be paid to the person referred to in section 21 for failure to provide a utility service in accordance with the standards of service set by the Commission."*

Section 43 (1) of the FTCA, which is mirrored at Section 31 of the URA, stipulates that a service provider will be guilty of an offence for failure to comply with an order of the Commission and is liable to a fine of $100,000 if convicted.

Section 31(1) of the URA asserts that:

> *"Every service provider which fails or refuses to obey an order of the Commission made under this Act is guilty of an offence and is liable on summary conviction to a fine of $100,000 and, in the case of a continuing offence, to a further fine of $10,000 for each day or part thereof during which the offence continues."*

Section 43(1) of the FTCA states that:

> *"Every service provider or business enterprise that fails or refuses to obey an order of the Commission made under this Act is liable on summary conviction to a fine of $100,000 and, in the case of a continuing offence, to a further fine of $10,000 for each day or part thereof during which the offence continues."*

SECTION 3 PERFORMANCE REVIEW

3.1 Objectives

The BL&P's Standards of Service are intended to set a minimum benchmark for the delivery of electricity service. These Standards allow the Commission to monitor the performance of the BL&P.

The Commission seeks to:

- Optimise customer service communication;
- Maximise accessibility to customers; and
- Reduce inconvenience to customers.

The Standards of Service are divided into two categories - Guaranteed Standards of Service (GES) and Overall Standards of Service (OES) - which define minimum, mandatory levels of service standards for the BL&P.

3.2 Guaranteed Standards of Service

Guaranteed Standards of Service outline the minimum levels of service which the BL&P must meet in the delivery of electricity supply. Failure to meet the level of service stated requires the BL&P to compensate individually affected customers; this is subject to specific exemptions, which are presented later.

The levels of compensation are intended to act as an incentive for the BL&P to improve service delivery. Compensation is currently automatic for five (5) of the eight (8) Guaranteed Standards of Service.

Automatic compensation, in respect of a breach by the BL&P, appears as a credit on the customer's next bill, once eligibility is verified.

An assessment of the BL&P's performance over the three-year period was conducted based on the information submitted quarterly to the Commission; the results are presented in Table 1 on pages 13 - 15.

Overall, the BL&P's level of performance was acceptable in the majority of the categories. Fault Repair Customer's Service (GES 1), which is defined as the time taken to restore supply after a fault occurs on an individual customer's service, was met by the BL&P for the periods July 2014 to March 2015 and April to December 2016. The period April 2015 to March 2016 marginally fell short of this trend by 0.43%.

With respect to the time taken to restore multiple customers' supply - Fault Repair Distribution System (GES 2) – this trended similarly to the GES 1 Standard with the minimum target being met for both the abovementioned periods, while the 2015 – 2016 year missed the compliance mark by 0.18%.

The investigation of Voltage Complaints (GES 3) showed a high level of compliance with improvements in its subcategories. Notably, for GES 3 (a), the target was marginally missed for the last two years of the period under review. An average of 99.44% of those customers were visited within three (3) working days of receipt of the complaint. The Assessment of Complaints, GES 3 (b), registered consistent, 100% compliance in the 2015 – 2016 and April to December 2016 periods. This reflected a marked improvement of 22.22% since its inception in July 2014. The BL&P's performance for the time taken to rectify voltage issues, GES 3 (c), was stable and registered 100% compliance over the first two years of the review period.

Simple Service Connections (GES 4) - Connections made to customer's premises within 30 meters of the connection point - registered a high level of compliance over the three-year review period. The service level for July 2014 to March 2015 and the period (April to December) 2016, were marginally below the compliance mark by 1.26% and 1.6%, respectively; the period (April 2015 to March 2016), however, showed a larger variance of 4.49% from the 100% mark.

For Complex Connections which required a cost estimate (GES 5), the BL&P consistently met the compliance level over the three-year period in review.

Additionally, the BL&P mirrored a similar trend for Connect or Transfer of Service (GES 6) and Reconnection (GES 7). Both categories recorded high levels of service performance which average 99.72% and 99.93%, respectively.

The BL&P's level of compliance pertaining to Response to Billing Complaints (GES 8) showed a significant improvement over the reporting period – the performance level for the July 2014 to March 2015 year was marginally above the 75% mark; however, this improved in 2015-2016 by 21.44% and closed at 100% in December 2016.

Table 1: The BL&P's Guaranteed Standard Performance Assessment 2014-2016

STANDARD	TARGET	COMPENSATORY PAYMENT	AVERAGE % COMPLIANCE JULY 2014 – MAR. 2015	AVERAGE % COMPLIANCE APR. 2015 - MAR. 2016	AVERAGE % COMPLIANCE APR. 2016 - DEC. 2016
GES 1 **Fault Repair - Customer's Service** This refers to the time it takes to restore supply after fault on customer' service (single customer)	Within 12 hours	\$45.00 (D); \$90.00 (GS); \$215.00 (SVP/LP) **Prorated on an hourly basis**	100	99.57	100
GES 2 **Fault Repair - Distribution System** This refers to the time it takes to restore supply after fault on the distribution system (multiple customers)	Within 12 hours	\$45.00 (D); \$90.00 (GS); \$215.00 (SVP/LP) **Prorated on an hourly basis**	100	99. 82	100
GES 3 **Voltage Complaint** This refers to the investigation of voltage complaints	(a) Visit within 3 working days of receipt of complaint	\$45.00 (D); \$90.00 (GS); \$215.00 (SVP/LP)	100	98.90	99.42
	(b) Assessment within 15 days of receipt of complaint		77.78	100	100
	(c) Correct within 3 months of receipt of complaint		100	100	N/A[3]
GES 4 **Simple Service Connection** This refers to the time it takes to provide a single service	Within 12 working days	Refund of installation fee **Automatic compensation**	98.74	95.51	98.40

[3] N/A – no corrective action was required.

STANDARD	TARGET	COMPENSATORY PAYMENT	AVERAGE % COMPLIANCE JULY 2014 – MAR. 2015	AVERAGE % COMPLIANCE APR. 2015 - MAR. 2016	AVERAGE % COMPLIANCE APR. 2016 - DEC. 2016
connection (connection point within 30 meters) after signing the contract for connection and the presentation of a valid certificate of inspection from the Government Electrical Engineering Department (GEED) by the customer					
GES 5 **Complex Connection – Cost Estimate** This refers to the time it takes to provide cost estimate for complex connection requiring a service visit	Within 3 months	\$45.00 (D); \$90.00 (GS); \$215.00 (SVP/LP)	100	100	100
GES 6 **Connect or Transfer of Service** This refers to the time it takes to connect or transfer service from one location to another location which has an existing installation	Within 2 working days	\$45.00 (D) \$90.00(G S) \$215.00 (SVP/LP) **Automatic compensation**	99.82	99.62	99.73
GES 7 **Reconnection** This refers to the time for reconnection of service on settling the bill	Within 1 working day	Refund of reconnection fee	99.93	99.90	99.95

STANDARD	TARGET	COMPENSATORY PAYMENT	AVERAGE % COMPLIANCE JULY 2014 – MAR. 2015	AVERAGE % COMPLIANCE APR. 2015 - MAR. 2016	AVERAGE % COMPLIANCE APR. 2016 - DEC. 2016
after disconnection at the meter					
<u>**GES 8**</u> **Response to Billing Complaints** This refers to the timeframe in which the BL&P responds to customer billing complaints	Provide assessment within 15 working days of receipt of complaint if service visit is required; for other matters the BL&P is to respond within 5 working days	\$45.00 (D); \$90.00 (GS); \$215.00 (SVP/LP)	77.84	99.28	100

Key: D – Domestic; GS – General Service; SVP – Secondary Voltage Power; LP - Large Power

3.3 Customer Claims

Manual claiming for compensation under the Guaranteed Standards of Service continues to be unutilised by customers. The Commission remains concerned about this trend, since customers generally only receive compensation when it is automatic. It was observed that, in some instances, eligible manual claims remained unpaid at the end of the period. It was also noted that some automatic payment of claims were not being done in a timely manner. A summary of customer compensation is given in Table 2. The volume of customers eligible for compensation and actually receiving compensation fluctuated over the three-year period (2014 – 2016). The number of claims eligible for compensation peaked at 94 for the July 2014 to March 2015 year, but the subsequent years, 2015 – 2016 and April to December 2016, registered a decline of 23.40% and 59.72%, respectively.

The Commission notes that for the period July 2014 to March 2015, 17.02% of eligible customers received automatic compensation, while thirteen (13) of the seventy-six (76) eligible manual claims received were not paid. The Commission further notes that the unpaid status on these claims has continued throughout the reporting period. During the period April to December 2016, eighteen (18) of the thirty-four (34) claims which were paid, related to the reporting period (2015 – 2016); these claim payments were made more than three (3) months outside of the reporting period. As a result, the period April –

December 2016 registered the highest resolution rate (117.24%), compared to the 2014 - 2015 and the 2015 - 2016 periods, which were 17.02% and 58.33%, respectively. The Commission further emphasises the need to pay claims in a timely manner. The Commission proposes that all claims received by the BL&P which are eligible for compensation should be settled within one (1) month of receipt for automatic form of compensation and within two (2) months for manual verified claims.

Table 2: Customer Compensation for 2014 - 2016

CATEGORY	Jul. 2014 – Mar. 2015		Apr. 2015 – Mar. 2016		Apr. – Dec. 2016	
	A	M	A	M	A	M
Persons eligible for compensation **(Automatic and Manual)**	18	76	71	1	29	0
Persons actually receiving compensation **(Automatic and Manual)**	16	0	42	0	34	0
Percentage of eligible customers receiving compensation **(Automatic only)**	17.02%		58.33%		117.24%	

Key: A – Automatic; M – Manual

3.4 Overall Standards of Service

The Overall Standards of Service (OES) are designed to reflect the general performance of the BL&P on an island-wide basis and are not defined by the individual service a customer receives. No compensation is given to customers for failure to meet Overall Standards. The Commission, however, has the legislative power to impose penalties for non-compliance to the OES targets. An assessment of the BL&P's performance under the Overall Standards of Service for the period 2014 – 2016 follows at Table 3 on pages 18 - 19.

3.5 The BL&P's Performance under the Overall Standards of Service

The analysis revealed that the BL&P, under Meter Reading (OES 1), registered 96.35% and 97.23% average compliance in the domestic and commercial customer class categories over the 2014 – 2016 period. During this time, compliance remained relatively stable (approximately 96.79%), but this fell short of meeting the 100% target required. Breaches by the BL&P in this category continue to be a major concern of the Commission, since this potentially affects customers in managing their consumption and budgets. The Commission acknowledges the BL&P's Advanced Metering Infrastructure (AMI) project[4], which was initiated in 2016. The BL&P proposes to leverage AMI deployment to the operational and service benefit of customers and itself alike. Benefits include remote meter readings, improved responsiveness to billing queries, fault reporting and reliability. The Commission anticipates that such technological advancements should result in a marked improvement in this service category as this technology allows for meters to be read remotely.

The BL&P's performance under Voltage Complaint (OES 2) and Outage Notice (OES 3) registered high compliance, averaging 99.87% and 99.64%, respectively, over the three-year period; in both cases the performance was stable and well above the 95% target level assigned.

With regard to Response to Claims (OES 4), the BL&P has reported on a consistent basis that it has not received any written claims. The Commission is of the view that claims received by the BL&P in respect of GES 2, GES 5 and GES 8 should be recorded and accounted for under the OES 4 category. Submitted data suggests that a disconnect exists between the breaches and claims under the Guaranteed Standards of Service and what is reported under OES 4. The Commission remains concerned that this category under the OES framework continues to be unutilised. The Commission recognises the importance of public education with regard to Standards of Service and will continue to ensure that this role is executed by both the BL&P and itself. Additionally, it is proposed that this category be broadened to explicitly indicate written and verbally communicated claims.

Call Centre Answering (OES 5) provides another measure of the BL&P's customer service performance. The timeframe within which calls are answered by a BL&P's representative remained stable during the first two years of the three-year period under review. During

[4] The BL&P's AMI roll out is scheduled to conclude on December 31, 2019 and targets 130,000 customers. More information can be viewed at the link: http://www.blpc.com.bb/images/watts-new/Graphics_BLPC_Newsletter_Nov2016.pdf.

the period (April to December) 2016, there was a 6.95% improvement in the number of calls responded to within one (1) minute. However, this fell short of meeting the required target mark. Failure to meet the 85% target by the BL&P continues to be of concern to the Commission, which is of the view that customers' calls should be answered promptly.

The BL&P's performance remained relatively stable and above the required 95% rate set for the Billing Period Standard (OES 6) – compliance averaged 96.33% over the three-year period under review.

Table 3: The BL&P's Overall Standards Performance Assessment (2014-2016)

STANDARD	TARGET	AVERAGE % COMPLIANCE JULY 2014 – MAR. 2015	AVERAGE % COMPLIANCE APR. 2015 – MAR. 2016	AVERAGE % COMPLIANCE APR. – DEC. 2016
OES 1 **Meter Reading** Frequency of meter reading	(a) 100% of Domestic/ General Service customers' meters to be read every two months	97.66	97.55	93.85
	(b) 100% of Secondary Voltage Power and Large Power customers' meters to be read monthly	97.30	97.13	97.25
OES 2 **Voltage Complaints** Response to Complaint of high/low voltage	95% of complaints to be responded to within five working days	100	99.67	99.93
OES 3 **Outage Notice** Prior notice of outages	95% of customers to be notified 48 hours before planned outages	98.91	100	100
OES 4 **Response to Claims** Response to Written Claims related to Standards of Service	100% of customers to receive acknowledgement of receipt of claim within 10 working days	None received	None received	None received
OES 5 **Call Centre Answering** Billing and Trouble Centre calls answered by a customer service	85% of calls answered by a representative within one (1) minute	73.71	73.08	80.03

STANDARD	TARGET	AVERAGE % COMPLIANCE JULY 2014 – MAR. 2015	AVERAGE % COMPLIANCE APR. 2015 – MAR. 2016	AVERAGE % COMPLIANCE APR. – DEC. 2016
representative				
<u>**OES 6**</u> **Billing Period** The period between two meter readings whether interim, estimated or actual	At least 95% of customers in each billing period shall be invoiced for no more than 33 days	96.20	96.61	96.18

Q 1: **Should the current target levels for the Guaranteed Standards of Service be amended?**

Q 2: **Should the current target levels for the Overall Standards of Service be amended?**

Q 3: **Should automatic compensation be assigned to all of the Guaranteed Standards of Service?**

Q 4: **Is the level of compensation adequate under each of the Guaranteed Standard of Service categories?**

Q 5: **What are your views on implementing a proposed target time of one (1) month for the automatic form of payment of claims and two (2) months for verified manual claims under GES 2, GES 5 and GES 8?**

Q 6: **Are there any other areas or issues which should be covered under the Guaranteed or Overall Standards of Service?**

Q 7: **What are your views on imposing penalties where the BL&P fails to meet the targets under the Guaranteed Standards and Overall Standards of Service?**

3.6 Reliability Performance

The Commission considers that, in addition to the evaluation of overall performance metrics, reliability indices[5] provide a measure of system-wide service delivery to its customers. These are derived from the duration and number of power outages experienced and the number of affected customers. The length of time and the number of times a customer is without electricity relates to sustained outages, i.e. where customers experience a loss in supply or interruption beyond a specified period, typically greater than one minute in duration. A sustained outage refers to any interruption which is not classified as a momentary event and these typically last more than five (5) minutes.

Utilities classify these outages based on different times between one (1) to five (5) minutes. The Institute of Electrical and Electronic Engineers (IEEE) has adopted the five (5) minute criteria. The BL&P currently uses the IEEE's five (5) minute definition for sustained outages. The Commission notes that this definition varies across electricity suppliers and jurisdictions. Due to this inconsistency, the criteria and methodology used to determine Major Event Days[6] differ as well. This creates a challenge in comparing reliability performance with other utilities. Definitions of the indices currently used to monitor the BL&P's performance are given below.

System Average Interruption Duration Index (SAIDI) – the average number of minutes that a customer is without an electricity supply over a specified time period (e.g. monthly). This is computed as the sum of the duration, pertaining to each sustained interruption (in hours), divided by the total number of customers. SAIDI excludes momentary interruptions[7] (one minute or less). Mathematically, this is represented by:

$$\textbf{SAIDI} = \frac{\textbf{Total Customer Hours Interruptions}}{\textbf{Total Number of Customers Served}}$$

[5] See the, Institute of Electrical and Electronic Engineers, *Institute of Electrical and Electronic Engineers (IEEE) Guide for Electric Power Distribution Reliability Indices, 1366-2003, 2004 ed. (USA: IEEE, 2004).*

[6] IEEE 1366 Standard determines Major Event Days (MEDs) – these are days which exceed the threshold computed and the event(s) excluded from the indices calculation. The BL&P currently employs this method for SAIDI determination.

[7] The (IEEE) 1366 standards, (2004), page 3 defines a momentary interruption as a single operation of an interrupting device that results in a voltage zero. Typically, these are outages which occur and last 5 minutes or less. These can cause voltage spikes and impact sensitive electronic equipment.

System Average Interruption Frequency Index (SAIFI) – the average number of times a customer's supply is interrupted (e.g. each month). It is calculated as the sum of each sustained customer interruption divided by the total number of customers. SAIFI excludes momentary interruptions. Mathematically, this is represented by:

$$\textbf{SAIFI} = \frac{\textbf{Total Customer Interruptions}}{\textbf{Total Number of Customers Served}}$$

Customer Average Interruption Duration Index (CAIDI) – is the average duration of each supply interruption per customer. CAIDI is computed as the sum of the duration of each sustained customer interruption (in hours) divided by the total number of sustained customer interruptions (SAIDI divided by SAIFI). CAIDI excludes momentary interruptions. Mathematically, this is represented by:

$$\textbf{CAIDI} = \frac{\textbf{Total Customer Hours of Interruption}}{\textbf{Total Number of Customer Interruptions}}$$

The above reliability indices can be computed on any time basis - daily, weekly, monthly or yearly. The Commission reviews and monitors submitted reports from the BL&P on a quarterly basis, broken down by month. An assessment of reliability performance allows the Commission to determine whether there was an improvement or deterioration in the system-wide delivery of electricity. Table 4 shows the BL&P's reliability performance over the period 2014 – 2016.

The analysis shows that the number of hours a customer was without an electricity supply (SAIDI), on average, was less than two (2) hours during the 2014 – 2015 period, compared to the latter two years of the review period, which recorded over three (3) hours. This represents an 83.76% increase for the 2015 – 2016 period, indicating that customers were without an electricity supply for an additional one (1) hour and thirty-nine (39) minutes on average. However, at the end of the third period, customers' average outage time was down thirty-five (35) minutes (16.30%), to register an improvement over the previous period.

Table 4: BL&P's Reliability Performance for the Period 2014 - 2016

SYSTEM RELIABILITY METRICS	ASSESSMENT PERIOD		
	Jul. 2014 – Mar. 2015	Apr. 2015 – Mar. 2016	Apr. – Dec. 2016
SAIDI (Hours per Customer)	1.97	3.62	3.03
SAIFI (Outages per Customer)	4.64	6.32	3.67
CAIDI (Hours per Affected Customer)	0.42	0.57	0.83

The SAIFI metric indicated that the average number of times per year a BL&P customer experienced a power outage varied over the period in review. The periods July 2014 to March 2015 and April to December 2016 registered lower incidences of outages per year, fewer than five (5) and four (4), respectively, compared to the 2015 – 2016 period, which was more than six (6) outages per year. At the end of the three-year period, BL&P's customers experienced a decline in the number of outages, an improvement of 41.93% over the previous period (2015 – 2016). On average, a customer who experienced a power outage was out of service (CAIDI) for twenty-five (25) minutes (0.42 hours) during the 2014 - 2015 period; conversely, this time increased by 9.00 and 15.60 minutes, respectively, for the latter reporting periods.

The Commission considers that, based on the breadth of data thus far collected on these indices from April 2008 to December 2016, it is in a position to set targets in this area. It is proposed that targets be set based on the average of the BL&P's historical performance, i.e. the recent five year period, since some anomalies were reported in prior years. Similar targets are used by St. Lucia Electricity Services Limited (LUCELEC)[8], Grand Power Bahama Power Company Limited (GBPC)[9] and in the State of Hawaii[10].

[8] St. Lucia Electricity Services Limited, "*2015 Annual Report: In Transition*," 2016, 8 -10, http://www.lucelec.com/sites/default/files/documents/LUCELEC-2015-AnnualReport.pdf.

[9] The Grand Bahama Port Authority, "Regulatory Framework," Grand Bahamas Port Authority Web, accessed January 20, 2017, http://gbpa.com/index.php/city-services/gb-power-regulation/regulatory-framework.

[10] The State of Hawaii report indicates examples of reliability indices that are widely used in the energy sector worldwide; SAIDI, SAIFI, CAIDI and ASIA remain the modal choices for indicating system delivery. Reliability Standards used by utilities aim for an ASIA above 99.98%, a SAIFI less than 1 and a CAIDI less than 2. See more information at, http://puc.hawaii.gov/?s=reliability+report.

Q 8: Are the current reliability indices used to evaluate the BL&P's service delivery performance adequate?

Q 9: What other reliability indices should be considered to monitor the level of service performance by the BL&P?

SECTION 4 PROPOSED CHANGES

4.1 Overview

In reviewing the Standards of Service, the Commission considered, *inter alia*: the complaints registered with the Commission; the performance of the BL&P under the present Standards of Service; local, regional and international developments within the sector; and the BL&P's capabilities. In addition, geography, customer base, customer density, type of plant, grid infrastructure, energy demand and the regulatory framework also influenced the proposals herein.

Where possible, the Commission sought to benchmark the BL&P's performance against that of its regional counterparts. This information is presented in Appendices 1 and 2 on pages 43 – 47.

Consequently, where the BL&P has reported to have consistently met the targets in the Standards of Service, the Commission is proposing to amend the same in order to encourage improved performance. Where there are breaches, the Commission reserves the right to impose penalties.

4.2 Proposed Amendments to Guaranteed Standards of Service

Fault Repair - Customer's Service (GES 1)

The Commission proposes to amend the target time for the restoration of supply to an individual customer after experiencing a fault on an individual customer's service line. Based on the information provided, the BL&P has consistently met the minimum target over the three (3) year period. The Commission therefore recommends that the restoration time be reduced from twelve (12) to seven (7) hours. The Commission also notes that some regional utilities e.g. St. Lucia Electricity Service Limited (LUCELEC)[11] and Dominica Electric Power Company (DOMLEC)[12] have much lower target times.

[11] LUCELEC recommends that, where the fault is in the service cable, supply should be restored within 6 hours. For more information see: http://www.lucelec.com/content/lucelecs-customer-service-charter.

[12] DOMLEC corrects the fault within 4 hours: Please see Appendix 1, page 43 for more information.

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
<u>**GES 1**</u> **Fault Repair Customer's Service** This refers to the time it takes to restore supply after fault on a customer's service (single customer)	Within 7 hours of receipt of complaint	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic; GS – General Service; SVP – Secondary Voltage Power; LP - Large Power

Fault Repair - Distribution System (GES 2)

The Commission recognises that there is a significant economic loss and inconvenience associated with faults on the distribution system due to the fact that multiple customers are affected. The Commission also notes that the BL&P reported that it was consistently able to perform well in relation to GES 2. Hence, the Commission is proposing to adjust the restoration time from twelve (12) hours to six (6) hours in order to further improve performance.

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
<u>**GES 2**</u> **Fault Repair Distribution System** This refers to the time it takes to restore supply after fault on the distribution system (multiple customers)	Within 6 hours of receipt of report	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic; GS – General Service; SVP – Secondary Voltage Power; LP - Large Power

Voltage Complaint (GES 3)

The Commission proposes to amend GES 3 (a), (b) and (c), which specifies the time required by the BL&P to respond, assess and correct voltage complaint problems. The Commission recognises that when a voltage problem is not rectified in a timely manner, the likelihood exists for greater damage to occur at a customer's premises. Hence, such circumstances necessitate urgency in responding. Shorter target times are mandated in the service standards of some regional jurisdictions[13]. The Commission also notes that, over the three-year period under review, the BL&P reported that it was required to respond to GES 3 (b) and (c) on a maximum of nine (9) and three (3) times, respectively and its

[13] In Trinidad and Tobago, a 24-hour time frame speaks to the urgency in addressing these types of complaints. For more information, refer to Appendix 1, Table A1, pages 43 – 45.

performance based on the submitted data has been satisfactory. The low number of complaints under this category should facilitate speedier resolution of issues arising. The Commission therefore proposes to amend GES 3 (a), (b) and (c) as follows:

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
GES 3 **Voltage Complaint** This refers to the investigation and correction of voltage complaints	(a) Visit within twenty-four (24) hours of receipt of the complaint (b) Provide an assessment within three (3) working days of receipt of complaint (c) Correct within five (5) working days of receipt of complaint	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic; GS – General Service; SVP – Secondary Voltage Power; LP - Large Power

Complex Connection – Cost Estimate (GES 5)

As with GES 3, the Commission also recognises the importance of electricity access as it relates to the time taken in providing cost estimates for connections in this category. The Commission notes that historically, the target has been met consistently. Therefore the Commission is of the view that this target should be adjusted from three (3) months to ten (10) working days. Some regional utilities have adopted a similar target time[14].

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
GES 5 **Complex Connection – Cost Estimate** This refers to the time it takes to provide cost estimate for complex connection requiring a service visit	Within ten (10) working days of receipt of request	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic, GS – General Service, SVP – Secondary Voltage Power, LP - Large Power

[14] LUCELEC states that cost estimates are provided within fifteen (15) days of receipt of the request. See more information at http://www.lucelec.com/content/lucelecs-customer-service-charter. Jamaica Public Service Company Limited (JPS) provides cost estimates within 10 working days. Refer to Appendix 1, page 43 for more information.

Connect or Transfer of Service (GES 6)

The Commission proposes to amend the time required to connect or transfer an electricity service where an existing service line is present. The Commission considers that the BL&P's reported performance was satisfactory in this category and proposes that the target be moved from two (2) working days to twelve (12) working hours of receipt of request.

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
<u>**GES 6**</u> **Connect or Transfer of Service** This refers to the time it takes to connect or transfer service from one location to another location which has an existing installation	Within 12 working hours of receipt of request	\$45.00 (D) \$90.00 (GS) \$215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic, GS – General Service, SVP – Secondary Voltage Power, LP - Large Power

Reconnection (GES 7)

The Commission acknowledges that, according to the data submitted by the BL&P, that its historical performance has been satisfactory in this category. Therefore, the Commission proposes to move this target from one (1) working day to six (6) working hours.

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
<u>**GES 7**</u> **Reconnection** This refers to the time for reconnection of service on settling the bill after disconnection at the meter as verified by the BL&P. The customer should notify the BL&P of the settlement using the bill receipt number when carried out other than at its offices.	Within 6 working hours of receipt of request	\$45.00 (D) \$90.00 (GS) \$215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic, GS – General Service, SVP – Secondary Voltage Power, LP - Large Power

Response to Billing Complaints (GES 8)

Billing complaints, which may include billing errors and the absence of a bill over an extended period, can inconvenience customers. Consequently, the Commission is of the view that the onus is on the BL&P to ensure that electricity bills are provided in a timely manner and are accurate. The Commission therefore proposes the following changes: Where the BL&P is required to make a site visit to determine the cause, an assessment must be provided and the matter resolved within ten (10) working days of receipt of complaint. For other matters not requiring the BL&P to visit, it must resolve the matter within three (3) working days of receipt of complaint.

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
<u>**GES 8**</u> **Response to Billing Complaints** This refers to the timeframe to which the BL&P responds to customer billing complaints	a) If service visit is required provide an assessment and resolution within ten (10) working days of receipt of complaint b) For all other matters not requiring a service visit, the BL&P is required to satisfactorily resolve these within three (3) working days of receipt of complaint	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic; GS – General Service; SVP – Secondary Voltage Power; LP - Large Power

Q 10: Do you agree with the proposed changes to the target levels for GES 1, GES 2, GES 3, GES 5, GES 6, GES 7 and GES 8?

Timely Payment of Compensation (GES 9) - New Guaranteed Standard of Service

The Commission is seeking to introduce a new Guaranteed Standard of Service to monitor the payment of compensation to eligible customers. The Commission acknowledges that, despite the fact that the majority of the Guaranteed Standards of Service require automatic compensation for breaches, there is a need to establish a timeframe for the disbursement of compensation. The Commission is therefore proposing that all eligible claims be paid within one (1) month for breaches to Standards requiring automatic compensation and for manual claims, payment be made within two (2) months of receipt of the claim. Automatic compensation is also recommended for this category.

STANDARD	PROPOSED TARGET	COMPENSATORY PAYMENT
GES 9 (New) **Timely payment of compensation relevant to the Standards of Service**	a) All claims to be credited to the customer's account within one (1) month of its acceptance for automatic form of breaches.	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**
	b) For manual claims customer's account to be credited within two (2) month of receipt of claim	

Key: D – Domestic; GS – General Service; SVP – Secondary Voltage Power; LP - Large Power

Q 11: Do you agree with the proposed new Standard of Service for the payment of compensation?

Q 12. Are there any other areas which should be covered under the Guaranteed Standards of Service?

4.3 Proposed Amendments to the Overall Standards of Service

Voltage Complaints (OES 2)

The Commission considers that there is a need to decrease the complaint response time, having recognised the possible severity of voltage problems. The Commission proposes to increase the target to 100%, with a target time of three (3) working days.

STANDARD	PROPOSED TARGET
OES 2 **Voltage Complaints** Response to complaint of high/low voltage	100% of complaints to be responded to within three (3) working days

Outage Notice (OES 3)

The Commission proposes that, based on the information provided by the BL&P, the target for this Standard be raised from 95% to 100% of all instances of planned outages; the forty-eight (48) hour notification will be retained. The proposed change is as a result of the BL&P continuously demonstrating that it can meet and surpass the target over the three-year review period. Additionally, the Commission proposes that the BL&P utilise a variety of media when notifying potentially affected customers.

STANDARD	PROPOSED TARGET
OES 3 **Outage Notice** Prior notice of outages	In 100% of instances of planned outages, potentially affected customers are to be notified 48 hours before the outage in each section of the media, e.g. television, radio, print, online (website), social media

Response to Complaints and Claims (OES 4)

The Commission sees merit in increasing the range of OES 4 to include orally submitted claims relating to Standards of Service. The Commission recognises that not all customers who report a fault or make a request and/or query are aware of the existing Standards of Service and the associated claim forms and procedures. Therefore, the Commission is of the view that the onus resides with the BL&P to inform the customer of the claims procedure when a complaint is made. Furthermore, where claims are submitted, the BL&P must acknowledge receipt as stipulated herein.

Given the aforementioned, the Commission is proposing that this Standard of Service be amended as follows:

STANDARD	PROPOSED TARGET
OES 4 **Response to Complaints and Claims** Response to written and oral claims related to Standards of Service	100% of customers' complaints and claims to be acknowledged within five (5) working days of receipt

Response to Damage Claims (OES 7) - New Overall Standard of Service

The Commission is concerned that equipment and appliance damage which may result from the BL&P's electricity supply can inconvenience customers, i.e. loss of use of equipment and unexpected financial burden. The Commission is proposing that the BL&P acknowledge a damage claim from a customer immediately on receipt. Additionally, the Commission recognises the negative impact customers face with regard to the time in which damage claims are settled and it is therefore proposed that 95% of eligible damage claims be settled within thirty (30) working days of receipt of the claim.

STANDARD	PROPOSED TARGET
<u>(NEW) OES 7</u> **Response to Damage Claims** Acknowledgement and settlement of claims	(a) Acknowledge 95% of damage claims immediately on receipt of oral claims and for written claims, within five (5) working days of receipt.
	(b) Settle 95% of damage claims within thirty (30) working days' of receipt of written or oral claim

<u>**Tracking Complaints and Queries**</u>

With regards to a customer making a request, query and or a complaint to the BL&P whether written or orally, the BL&P is to issue a tracking number to the customer. The issuance of the tracking number will facilitate the monitoring of complaints.

Q 13: Do you agree with the proposed changes to the Overall Standards of Service for OES 2, OES 3 and OES 4?

Q 14: Should Response to Damage Claims be included in the Overall Standards of service?

Q 15: What other areas would you suggest be included in the Overall Standards of service?

4.4 Reliability Indices

The Commission is proposing to include an Average Service Availability Index (ASAI) in the reliability indices. This measures the percentage of time that a customer receives an electricity service over a defined reporting period[15]. An indication of availability of electricity service is an important feature of a utility's reliability. Mathematically, this is represented by:

$$\text{ASAI} = \frac{\textit{Customer Hours Service Availabilty}}{\textit{Customer Hours Service Demand}}$$

[15] ASAI is usually reported annually; it should be noted that a normal calendar year has 8760 hours, whereas a leap year has 8784 hours. See IEEE 1366 Standards 2003, p 6.

International best practice suggests that reporting ASAI should be done to three or four decimal places[16]. An annual ASAI of 99.994 %[17] of the electricity distribution system represents a good measure of service availability. The Commission notes that since the ASAI takes into account the SAIDI value, it can be readily computed.

Additionally, the Commission is proposing to assign reliability targets to the SAIDI, SAIFI, CAIDI and ASAI indices. The targets being proposed were developed based on the five-year historical annual performance average[18]. The Commission is of the view that these targets[19] would allow further assessment of the BL&P's system delivery. The methodology proposed is internationally recognised and based on the premise that the BL&P should, at minimum, not perform worse than its average performance. The Commission is also of the view that the assignment of targets would act as a benchmark and should encourage greater efficiency. The targets proposed are outlined in Table 5. Additionally, a comparison of Barbados' SAIDI and SAIFI performance with other jurisdictions is presented in Appendix 2 on page 47.

Table 5: Summary of Proposed Annual Targets

METRIC	TARGET
SAIDI (Hours per year)	3.68
SAIFI (Outages per year)	5.84
CAIDI (Hours per year)	0.67
ASAI (Service availability)	99.957%

Q 16: What are your views on the addition of the proposed ASAI index and its target?

[16] View an example of reporting on reliability indices by New Mexico Regulatory Commission at: http://www.nmprc.state.nm.us/utilities/reliability-indices.html and Hawaii Public Utilities Commission at https://puc.hawaii.gov/wp-content/uploads/2013/07/Hawaiian-Electric-Companies-Annual-Service-Reliability-Reports-for-2015.pdf.

[17] An ASAI of 99.994% equates to a total outage duration of thirty (30) minutes per year.

[18] A variety of methodologies are suggested in the literature to determine targets and benchmarks for Reliability Indices. Using the average of the utility's own annual historical data is reflective of its own unique operating circumstances. This provides insight on the baseline performance of service quality and also identifies performance indicator goals. For more information view the following sources:
Pacific Economics Group Research, LLC, "*Service Reliability Standards in Ontario: Analysis of Options*," accessed January 09, 2017, http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/OEB_Reliability_Standards_Report.pdf.
Additional information can be viewed at:
http://www.brattle.com/system/publications/pdfs/000/004/670/original/Approaches_to_Setting_Electric_Distribution_Reliability_Standards_and_Outcomes_Hesmondhalgh_Zarakas_Brown_Jan_2012.pdf?1378772119.

[19] Grand Bahamas Power also use targets to monitor system performance. For 2015, SAIDI, SAIFI and CAIDI targets were 3.6 hours, 7.29 outages and 0.6 hours respectively.

Q 17: Should targets be set for the current reliability indices used?

SECTION 5 GENERAL EXEMPTIONS

The Commission acknowledges that the failure to meet the Guaranteed Standards of Service may be driven by circumstances or events beyond the control of the BL&P. In these circumstances, the BL&P is under no obligation to make compensatory payments, where such would give rise to a breach. The term used to define these events is *Force Majeure*. Black's Law Dictionary (2009) defines *Force Majeure*[20] as:

> *"An event or effect that can be neither anticipated nor controlled. The term includes both acts of nature (e.g. floods and hurricanes) and acts of people (e.g. riot, strikes and wars)."*

Under the current Standards of Service framework, the following risks are considered to be *Force Majeure*:

(a) An act of war (whether declared or not), hostile invasion, act of foreign enemies, terrorism or civil disorder;

(b) A strike or strikes and or other industrial action or blockade or embargo or any other form of civil disturbance (whether lawful or not);

(c) Landslides, lightning, hurricanes, floods, storm, earthquake, tsunami or any other natural disaster.

(d) Riots;

(e) Civil commotion;

(f) Acts or threats of terrorism;

(g) Insurrections;

(h) Epidemics;

(i) Trade restrictions;

(j) Inability to obtain any requisite Government permits; and

(k) Breakdown of machinery or equipment or any other force or cause of similar nature not within the control of the BL&P and which by the exercise of diligence it is unable to avoid, prevent or mitigate.

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[20] Bryan Garner, *Black's Law Dictionary* (United States: Thomson Reuters, 2009), 718.

Other Exemptions and Conditions

The Commission is cognisant that other circumstances may exist from time to time which might impede the BL&P's ability to meet the prescribed Standards of Service. In such circumstances, where a customer is dissatisfied with the BL&P's application of an exemption, that customer may seek the Commission's guidance. Thereafter the Commission may authorise the BL&P's action or require it to honour the claim.

The situations which might fall into this category may include but are not limited to the following:

(a) Inability to gain access to the customer's premises or the BL&P's facilities;

(b) Where the customer's installation does not meet the BL&P's requirements for installation or is considered unfit for service. (The BL&P's installation requirements are published in its Information and Requirements booklet and on its website);

(c) Where the customer or the customer's agent fails to fulfil his obligations;

(d) Where the customer informs the BL&P in writing that he does not want further action to be taken on a matter;

(e) Where the customer requests, in writing, that the BL&P take action at a later date than required by the Standards of Service;

(f) Where an offence has been committed through interference with the BL&P's metering equipment;

(g) Where the customer's electricity account remains unpaid after the BL&P has given the customer notice of its intention to disconnect the supply for non-payment;

(h) Where the BL&P is requested by a public authority to provide emergency electricity supply to assist in emergency action and the provision of such service restricts the connection of a customer to a specified service or the rectification of a fault or service difficulty;

(i) Where the customer is required to pay a charge to the BL&P for connection to the service or for the use of the service and the BL&P has reasonable grounds to believe, based on the customer's prior debt service record, that the customer would be unwilling or unable to pay the charge as it becomes due;

(j) Other unforeseeable circumstances beyond the control of the Parties against which it would have been unreasonable for the affected party to take precautions and which the affected party could not foresee by using its best efforts; and

(k) Where there are legal constraints that may prevent the BL&P from meeting the Standards of Service.

It is proposed that these aforementioned, established, extenuating conditions be maintained.

Q 18: Should the stated exemptions be revised? What other exemptions should be added to the list?

SECTION 6 MONITORING AND ENFORCEMENT OF STANDARDS

The Commission has established a monitoring system for the Standards of Service which requires the BL&P to submit quarterly regulatory reports. These reports shall include information on:

- The number of breaches under each Guaranteed Standards of Service category;
- The actual average times taken to respond to and/or rectify issues referred to under each Guaranteed Standards of Service category;
- The level of compliance of each Overall Standard of Service category as a percentage; and
- Details of any extenuating circumstances that would have prohibited the BL&P from achieving the targets under the Overall Standards of Service.

The BL&P is required to submit to the Commission annual reports which, in addition to the information above, provide information on:

- The number of customers eligible for compensation during the reporting financial year;
- The total value of eligible compensation;
- The number of customers who actually received compensation; and
- The value of compensation remitted.

The Standards of Service reporting period begins on April 1 of the existing year and concludes on March 31 in the following year, which corresponds with the Commission's financial period.

Q 19: What recommendations would you make as it pertains to the Commission's monitoring and reporting on the Standards of Service?

The Commission reserves the right to conduct independent investigations to determine the extent to which the BL&P is meeting the Standards of Service.

Enforcement of Standards

If the BL&P continually fails to meet an Overall Standard of Service, particularly to the point where service is severely hampered and it appears that no reasonable effort has been made to rectify the breach, the BL&P shall provide an explanation to the Commission.

That notwithstanding, the Commission reserves the right to make any rules, regulations and orders in respect of penalties for non-compliance of the relevant Standards of Service in accordance with Section 38 of the URA, which states the following:

"The Commission may make

a) rules;
b) regulations; and
c) orders with respect to

i) imposing penalties for non-compliance with prescribed Standards of Service; and

ii) prescribing amounts referred to in section 21 for failure to provide a utility service in accordance with the Standards of Service set by the Commission."

Public disclosure of information

Information related to the level of compliance by the BL&P, with the herein prescribed Guaranteed and Overall Standards of Service, will be made available to the public on an annual basis.

Public Education

The BL&P shall make a detailed list of the approved Guaranteed and Overall Standards of Service available to its customers. This list shall include information on the service categories, target times and compensatory payments, where applicable.

The BL&P's fault reporting process will also be made known to the public and the appropriate contact numbers included.

The BL&P shall also widely publicise the means via which compensation for breaches may be sought. The Commission is of the view that this can be readily advertised on the customer's electricity bill.

SECTION 7 LIST OF QUESTIONS

Q 1: **Should the current target levels for the Guaranteed Standards of Service be amended?**

Q 2: **Should the current target levels for the Overall Standards of Service be amended?**

Q 3: **Should automatic compensation be assigned to all of the Guaranteed Standards of Service?**

Q 4: **Is the level of compensation adequate under each of the Guaranteed Standard of Service categories?**

Q 5: **What are your views on implementing a proposed time of one (1) month for the automatic form of payment of claims and two (2) months for verified manual under GES 2, GES 5 and GES 8?**

Q 6: **Are there any other areas or issues which should be covered under the Guaranteed or Overall Standards of Service?**

Q 7: **What are your views on imposing penalties where the BL&P fails to meet the targets under the Guaranteed Standards and Overall Standards of Service?**

Q 8: **Are the current reliability indices used to evaluate the BL&P's service delivery performance adequate?**

Q 9: **What other reliability indices should be considered to monitor the level of service performance by the BL&P?**

Q 10: **Do you agree with the proposed changes to the target levels for GES 1, GES 2, GES 3, GES 5, GES 6, GES 7 and GES 8?**

Q 11: **Do you agree with the proposed new Standard of Service for the payment of compensation?**

Q 12: **Are there any other areas which should be covered under the Guaranteed Standards of Service?**

Q 13: **Do you agree with the proposed changes to the Overall Standards of Service for OES 2, OES 3 and OES 4?**

Q 14: **Should Response to Damage Claims to be included in the Overall Standards of Service?**

Q 15: **What other areas would you suggest be included in the Overall Standards of Service?**

Q 16: **What are your views on the addition of the proposed ASAI index and its targets?**

Q 17: Should targets be set for the currently reliability indices used?

Q 18: Should the stated exemptions be revised? What other exemptions should be added to the list?

Q 19: What recommendations would you make as it pertains to the Commission's monitoring and reporting on the Standards of Service?

SECTION 8 CONSULTATION PROCESS

The consultation paper includes a series of specific questions for which the Commission is seeking comments. To ease the task of analysing comments, respondents should reference the relevant question numbers in the document. If they consider it appropriate, respondents may wish to address other aspects of the consultation paper for which the Commission has not prepared specific questions. There is no obligation to respond to all of the questions. Failure to provide answers to all questions will in no way reduce the consideration given to the entire response. Commercially sensitive material should be clearly marked as such and included in an annex to the response.

Responding to the Consultation Paper

The Commission invites and encourages written responses, in the form of views or comments on the matters discussed in the Consultation Paper, from all interested parties including the BL&P, other regulated or soon to be regulated utilities, other licensed operators, government ministries, non-governmental organisations, customer representatives, residential customers, businesses and academics.

The consultation period will begin on **April 3, 2017** and end on **May 2, 2017** at **4:00 p.m.** All written submissions should be submitted by this deadline. The Commission is under no obligation to consider comments received after 4:00p.m on May 2, 2017.

The Consultation Paper may be downloaded from the Commission's website at http://www.ftc.gov.bb. Copies of the Consultation Paper may also be collected between the hours of 9:00 a.m. to 4:00 p.m., Monday to Friday, during the consultation period, from the Commission's offices at the following address:

Fair Trading Commission
2nd Floor, Cedar Court
Wildey Industrial Park
Wildey
St. Michael
BARBADOS

Responses to the Consultation Paper may be submitted in electronic format. The Commission would prefer that emailed responses be prepared as Word documents, attached to an email cover letter and forwarded to: info@ftc.gov.bb.

Responses may also be faxed to the Commission at (246) 424-0300. Mailed or hand delivered responses should be addressed to the Chief Executive Officer

Confidentiality

The Commission is of the view that this consultation is largely of a general nature. The Commission expects to receive views from a wide cross section of stakeholders and believes that views and comments received should be shared as widely as possible with all respondents.

Respondents should therefore ensure that they indicate clearly to the Commission any response or part of a response that they consider to contain confidential or proprietary information.

Analysis of Responses

The Commission expects, as in most consultations, to receive a range of views. In such circumstances, it would be impossible for the Commission to agree with all respondents. Through its decision, the Commission will seek to explain the basis for its judgments and, where it deems appropriate, give the reasons why it agrees with certain opinions and disagrees with others. Sometimes analysis of new evidence presented to the Commission will cause it to modify its view. In the interest of transparency and accountability, the reasons for such modifications will be set out and, where the Commission disagrees with major responses or points that were commonly made, it will, in most circumstances, provide an explanation thereto.

APPENDIX 1

COMPARISON OF STANDARDS OF SERVICE IN BARBADOS WITH OTHER JURISDICTIONS

Table A1: Comparison of Barbados' Guaranteed Standards of Service with Selected Regional and International Jurisdictions

Description of Standard	Proposed Target	Jamaica[21]	Trinidad & Tobago[22]	Dominica[23]	United Kingdom[24]
GES 1 This refers to the time it takes to restore supply after fault on customer's service (single customer)	Within 7 hours of receipt of complaint	Unavailable	Unavailable	Must respond and correct problem within 4 hours	Within 12 hours
GES 2 This refers to the time it takes to restore supply after fault on the distribution system (multiple customers)	Within 6 hours of receipt of report	Unavailable	Within 10 hours	Unavailable	Within 24 hours
GES 3 This refers to the investigation of voltage complaints	(a) Visit within 24 hours of receipt of complaint	Voltage complaints are not singled out; all complaints are addressed. Acknowledgements within 5 days; investigations are completed within 30 working days; 60 working days for third parties.	Complaint responded to within 24 hours	Respond and commit to solution within 15 working days of receipt	Investigate within 7 working days
	(b) Provide assessment within 3 working days of receipt of complaint		Unavailable		Provide an explanation within 5 working days
	(c) Correct within 5 working days of receipt of complaint		All Complaint to be rectified within 15		

[21]Jamaica Public Service Company Limited, "*Tariff Review for Period 2014-2019,*" 333 – 334, accessed January 03, 2017, http://www.our.org.jm/ourweb/sites/default/files/C-JPS%20Tariff%20Review%20for%20Period%202014-2019_Determination%20Notice.compressed.pdf.

[22] Regulated Industries Commission (RIC), "*Quality of Service Standards Annual Performance Report 2014: Electricity, Transmission and Distribution Sector*," accessed January 03, 2017, http://www.ric.org.tt/wp-content/uploads/2015/10/QSS-Annual-Report-2014-rev_4-20151022.pdf.

[23] Independent Regulatory Commission (IRC), "*Quality of Service Standards for Electricity Supply*, "accessed January 23, 2017, http://www.ircdominica.org/files/downloads/2012/10/Decision-Paper-for-QSS-FINAL.pdf.

[24] M & S Energy, *Guide to Service Standards 2015/2016: A guide to service standards you can expect as a customer*, accessed January 12, 2017, https://www.mandsenergy.com/uploadedFiles/CoreMarketingSites/Assets/Documents/MandS/GuideToServiceStandardsMandS.pdf.

Description of Standard	Proposed Target	Jamaica[21]	Trinidad & Tobago[22]	Dominica[23]	United Kingdom[24]
			days		
GES 5 This refers to the time it takes to provide cost estimate for complex connection requiring a service visit	Within 10 working days of receipt of request	(i) estimate within ten (10) working days (ii) connection within thirty (30) working days after payment	Unavailable	***This standard does not specify a time period** Must make a commitment in writing, (and keep the commitment), as to the completion of the works	Within 10 days for a connection less than 10MVA capacity; 20 working days for a connection of 1MVA capacity or more.
GES 6 This refers to the time it takes to connect or transfer service from one location to another location which has an existing installation	Within 12 working hours of receipt of request	Connections within four (4) working days after establishment of contract where supply and meter are already on premises	Unavailable		
GES 7 This refers to the time for reconnection of service on settling the bill after disconnection at the meter as verified by the BL&P	Within 6 working hours of receipt of request	Reconnection within twenty-four (24) hours of payment of overdue amount and reconnection fee	Time to restore supply after payment is made - within 24 hours	Within 24 hours	Unavailable
GES 8 This refers to the timeframe in which BL&P responds to customer or billing complaints	a) If service visit is required provide an assessment and resolution within ten (10) working days of receipt of complaint b) For all other matters not requiring a service visit, the BL&P is required to satisfactorily resolve these within three (3) working	Where necessary, customer must be billed for adjustment within three (3) months of identification of error, or subsequent to replacement of faulty meter	Substantive reply within fifteen (15) working days.	**This standard, though similar, refers to queries.** Substantive reply within 15 working days	

Description of Standard	Proposed Target	Jamaica[21]	Trinidad & Tobago[22]	Dominica[23]	United Kingdom[24]
	days of receipt of complaint				
NEW (GES 9) This refers to the time it takes to pay claims related to the Standards of Service	Customer's account to be credited within one month of its acceptance				

Table A2: Comparison of Barbados' Overall Standards of Service with Selected Regional and International Jurisdictions

Description of Standard	Proposed Target	Jamaica[25]	Trinidad & Tobago[26]	Dominica[27]	United Kingdom[28]
OES 2 Response to Complaint of high/low voltage	100% of complaints to be responded to within three (3) working days	Unavailable		Unavailable	
OES 3 Prior notice of outages	In 100% of instances of planned outages, potentially affected customers are to be notified 48 hours before the outage in each section of the media, e.g. television, radio, print, online (website), social media	100% of planned outages for which at least forty-eight hours advance notice is provided	At least 3 days advance notice of planned outages 100% of the time	3 days prior notice of planned interruption s, 100%	

[25]Jamaica Public Service Company Limited, "*Tariff Review for Period 2014-2019*," 333 - 334, accessed January 03, 2017, http://www.our.org.jm/ourweb/sites/default/files/C-JPS%20Tariff%20Review%20for%20Period%202014-2019_Determination%20Notice.compressed.pdf.

[26] Regulated Industries Commission (RIC), "*Quality of Service Standards Annual Performance Report 2014: Electricity, Transmission and Distribution Sector*," accessed January 03, 2017, http://www.ric.org.tt/wp-content/uploads/2015/10/QSS-Annual-Report-2014-rev_4-20151022.pdf.

[27] Independent Regulatory Commission (IRC), "*Quality of Service Standards for Electricity Supply*, "accessed January 23, 2017, http://www.ircdominica.org/files/downloads/2012/10/Decision-Paper-for-QSS-FINAL.pdf.

[28] M & S Energy, *Guide to Service Standards 2015/2016: A guide to service standards you can expect as a customer*, accessed January 12, 2017, https://www.mandsenergy.com/uploadedFiles/CoreMarketingSites/Assets/Documents/MandS/GuideToServiceStandardsMandS.pdf.

Description of Standard	Proposed Target	Jamaica[25]	Trinidad & Tobago[26]	Dominica[27]	United Kingdom[28]
			This is a separate standard, which addresses written complaints: Substantive response within 10 working days and communicat-ing final position within 30 working days.	Unavailable	
New (OES 7) Acknowledgement and settlement of Damage Claims	(a) Acknowledge 95% of damage claims immediately on receipt of oral claims and for written claims five (5) working days of receipt. (b) Settle 95% of damage claims within thirty (30) working days of receipt of written or qualified claim	90% of calls answered within 20 seconds	Unavailable	Unavailable	

APPENDIX 2

COMPARISON OF RELIABILITY INDICES OF BARBADOS AND OTHER JURISDICTIONS

The information presented in the following table describes the reliability performances of European Union (EU) countries, with major events[29] included. The table is intended to give an indication of the general operating sphere, not a utility peer-to-peer comparison.

Table A3. Comparison of Barbados' SAIDI and SAIFI Performance with other Jurisdictions[30]

Country	SAIDI (Hours per year)	SAIFI (Outages per year)
Austria	0.58	0.69
Barbados[31]	4.80	6.50
Denmark	0.25	0.40
France	1.00	0.89
Germany	0.27	0.28
Grand Bahamas[32]	3.50	8.50
Italy	0.76	1.74
Netherlands	0.45	0.32
Switzerland	0.35	0.34
United Kingdom	0.92	0.60
United States[33]	2.39	1.40

[29] Note that EU territories define a power outage as lasting longer than 3 minutes in contrast to the IEEE 1366, 5 minutes' standard. This suggests that index values may not uniquely compare fairly across different jurisdictions. Another consideration is that major or exceptional events differ between jurisdictions as well. For more details, view: Council of European Energy Regulators, *5th Benchmarking Report on the Quality of Electricity Supply 2011*, accessed January 23, 2017, http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/Tab/CEER_Benchmarking_Report.pdf.

[30] Council of European Energy Regulators (CEER), *CEER Benchmarking Report 5.1 on the Continuity of Electricity Supply Data Update*, accessed January 11, 2017, http://www.ceer.eu/portal/page/portal/EER_HOME/EER_PUBLICATIONS/CEER_PAPERS/Electricity/Tab3/C13-EQS-57-03_BR5.1_19-Dec-2013_updated-Feb-2014.pdf.

[31] Fair Trading Commission, "*Analysis of Barbados Light & Power Company Limited Annual Standards of Service Report 2015 – 2016*," accessed January 17, 2017, http://www.ftc.gov.bb/library/sos/2016-08-23_blandp_%20annual_report.pdf.

[32] Reliability information extracted refers to the 2014 year. For more details, view: The Grand Bahamas Port Authority Limited, "Regulatory Framework: Reliability," The Grand Bahamas Port Authority Website, accessed January 23, 2017, http://gbpa.com/index.php/city-services/gb-power-regulation/regulatory-framework.

[33] Peter Larsen, James Sweeney, Kristina Hamachi-LaCommare, and Joseph Eto, "*Exploring the Reliability of U.S. Electric Utilities*," accessed January 17, 2017, http://www.usaee.org/usaee2014/submissions/OnlineProceedings/IAEE_ConferencePaper_01Apr2014.pdf.

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THE BARBADOS
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COMPANY LIMITED

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May 2, 2017

Mrs. Sandra Sealy
Chief Executive Officer
The Fair Trading Commission
Cedar Court
Wildey
St. Michael

Attention: Dr. Marsha Atherley-Ikechi – Director of Utilities Regulation

Dear Mrs. Sealy,

Review of Barbados Light & Power Co. Ltd. Standards of Service 2014 - 2017

Further to correspondence to The Barbados Light & Power Company Limited (the Company), reference FTC/UR/CONSOS/BL&P-2017-02 issued April 3, 2017, the Company submits its responses in the attached document.

Yours sincerely,
THE BARBADOS LIGHT & POWER CO. LTD.

ACarter

Adrian Carter
Senior Analyst

AC/my

Enc.

cc: Roger Blackman – Managing Director
Kim Griffith Tang-How – Director Customer Solutions

RESPONSES TO CONSULTATION PAPER ON REVIEW OF THE BARBADOS LIGHT & POWER COMPANY LIMITED STANDARDS OF SERVICE 2014 - 2017

Q 1: Should the current target levels for the Guaranteed Standards of Service be amended?
Q 2: Should the current target levels for the Overall Standards of Service be amended?

Response

The Barbados Light & Power Company (BL&P) allocates considerable resources to ensure the consistent achievement of the current target levels for the Guaranteed and Overall Standards of Service. Our success at performing at high standards is demonstrated in our customer satisfaction levels, high benchmarking among regional peer utilities and our generally consistent achievement of the service standards targets established by the Commission. It is important that targets set are practical for implementation in our current business environment and provide a fair balance between customer expectations regarding the service and their willingness to pay for higher service levels. Targets that will require speedier adjustments to our operational processes will represent a cost to the BL&P, which may ultimately flow through to the consumes.

Q 3: Should automatic compensation be assigned to all of the Guaranteed Standards of Service?

Response

The assignment of automatic compensation to all of the Guaranteed Standards of Service would be very challenging for BL&P to efficiently implement under its current business processes. The challenge arises mainly due to our inability to identify the customer account to which a credit should be applied in the situation of GES5 where there is no specific account related to the individual or entity requesting the estimate. Further, in the case of GES2, it is difficult to accurately identify specific customers affected by the fault whose supply restoration extended beyond target level. In similar circumstances where it is operationally onerous to identify customers who experienced breaches of service standards, manual claims for compensation would be the more appropriate compensation mechanism.

Q 4: Is the level of compensation adequate under each of the Guaranteed Standard of Service categories?

Response

BL&P views the compensation appropriate to the magnitude of the violation and has no objections to the current compensation levels.

Q 5: What are your views on implementing a proposed time of one (1) month for the automatic form of payment of claims and two (2) months for verified manual under GES 2, GES 5 and GES 8?

Response

In principle, BL&P is not opposed to the implementation of a timeframe for making automatic and manual compensation payments. However, the requirement that automatic payment be applied within one month of the breach would require additional administrative resources to daily monitor when breaches occur. For example, under current administrative processes, a breach that occurs on the first of the month would be identified through our end of the month reporting procedures. BL&P's understanding of the proposed standard as it is currently worded, would require compensation be applied by the first of the following month, which would be an impractical timeframe to acquire necessary internal approvals for the disbursement of compensation. BL&P humbly recommends that the wording of the target be amended to allow for the application of compensation by the end of the subsequent month from which the breach occurred. This wording amendment would achieve the Commission's objective of setting a target for timely payment of compensation and limit BL&P's additional administrative costs to meet the standard.

Q 6: Are there any other areas or issues which should be covered under the Guaranteed or Overall Standards of Service?

Response

BL&P considers that the Commission has been thorough in the issues and areas covered under the Guaranteed and Overall Standards of Service.

Q 7: What are your views on imposing penalties where the BL&P fails to meet the targets under the Guaranteed Standards and Overall Standards of Service?

Response

BL&P believes that where its actions or inactions have disadvantaged customers under the guaranteed standards of service, that the imposition of penalties proportional to the magnitude of the violation is appropriate.

Q 8: Are the current reliability indices used to evaluate the BL&P's service delivery performance adequate?

Response

BL&P considers the system reliability metrics of SAIFI, SAIDI and CAIDI currently being monitored by the Commission to be adequate in evaluating BL&P's service performance in the delivery of the electricity supply.

Q 9: What other reliability indices should be considered to monitor the level of service performance by the BL&P?

Response

BL&P considers the system reliability metrics of SAIFI, SAIDI and CAIDI to be adequate indices to monitor the level of service performance within an island grid.

Q 10: Do you agree with the proposed changes to the target levels for GES 1, GES 2, GES 3, GES 5, GES 6, GES 7 and GES 8?

Response

BL&P notes the Commission's finding that BL&P has consistently achieved target levels for the service standards. The consistent achievement of the existing target times requires BL&P to allocate substantial amounts of effort and resources. In general, BL&P does not consider the target times proposed by the Commission to be achievable given the current resources of the utility. The achievement of the proposed target times may require significant manpower and technology additions, which could inevitably translate into higher costs to customers. BL&P appreciates the Commission's desire to challenge the company towards higher service performance, however target times should be set to achieve an appropriate balance between ensuring higher performance of the utility, practicality and maintaining stable and affordable rates for customers. BL&P's recommendations of an approach for the adjustments of the targets that would not require substantial resource additions are outlined in Appendix A.

Q 11: Do you agree with the proposed new Standard of Service for the payment of compensation?

Response

In principle BL&P does not oppose the new Standard of Service for the payment of compensation, however, we recommend the wording of the target be amended to allow for the application of compensation by the end of the subsequent month from which the breach occurs, in the case of automatic compensation.

Q 12: Are there any other areas which should be covered under the Guaranteed Standards of Service?

Response

BL&P considers that the Commission has be very thorough in its breadth of Guaranteed Standards of Service proposals and can identify no further recommendations.

Q 13: Do you agree with the proposed changes to the Overall Standards of Service for OES 2, OES 3 and OES 4?

Response

BL&P offers its comments and recommendations for the proposed changes to the Overall Standards of Service in Appendix B, for the Commission's consideration.

Q 14: Should Response to Damage Claims to be included in the Overall Standards of Service?

Response

BL&P does not oppose the inclusion of the response to damage claims as an Overall Standard of Service once reasonable time targets are instituted for both acknowledgement and settlement of claims. BL&P views the proposed targets do not provide a reasonable amount of time and offers its further comments and recommendations in Appendix C.

Q 15: What other areas would you suggest be included in the Overall Standards of Service?

Response

BL&P considers that the Commission has been very thorough in its breadth of Overall Standards of Service proposals and can identify no further recommendations.

Q 16: What are your views on the addition of the proposed ASAI index and its targets?

Response

BL&P notes that the proposed ASAI index conveys similar information to the SAIDI index and queries the need for two matrices that communicate similar information. The ASAI index is a derivation of the SAIDI index and calculated as $ASAI = 1 - \frac{SAIDI}{8760}$.

Q 17: Should targets be set for the currently reliability indices used?

Response

BL&P does not oppose the inclusion of reliability targets once they are set at reasonable levels. BL&P recommends adopting SAIFI, SAIDI and CAIDI benchmark targets using a five-year rolling average based on historical data, inclusive of one standard deviation above the 5-year. This approach to setting the reliability targets is consistent with international best practice and may best account for the variability in reliability performance.

Q 18: Should the stated exemptions be revised? What other exemptions should be added to the list?

Response

BL&P has no further recommendations as it pertains to the stated exemptions.

Q 19: What recommendations would you make as it pertains to the Commission's monitoring and reporting on the Standards of Service?

Response

BL&P has no further recommendations as it pertains to the Commission's monitoring and reporting on the Standards of Service.

APPENDIX A

GUARANTEED STANDARDS OF SERVICE PROPOSALS

STANDARD	SERVICE CATEGORY	EXISTING TARGET	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
GES1	**Fault Repair Customer's Service** This refers to the time it takes to restore supply after fault on customer's service (single customer)	Within 12 hours	Within 7 hours of receipt of complaint	**Within 10 hours of receipt of complaint**	GES1, GES2 and GES3 are currently competing for the same resources. The lowering of the target times for any of these standards will impact the ability to meet the target times for the other standards. The achievement of the Commission's proposed target times will require the employment of additional service crews. Given the long lead times to adequately train a new service crew the achievement of the proposed target is not practical. BL&P submits that a lower target time to 10 hours of receipt of complaints is achievable without requiring substantial resource additions.

STANDARD	SERVICE CATEGORY	EXISTING TARGET	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
GES2	**Fault Repair Distribution System** This refers to the time it takes to restore supply after fault on the distribution system (multiple customers)	Within 12 hours	Within 6 hours of receipt of report	**Within 10 hours of receipt of complaint**	As per comments in GES1, GES2 competes with resources employed to meet the service standards associated with GES1 & GES3. The achievement of the Commission's proposed target times would not be practical with existing resources. BL&P submits that it can make improvements in processes to lower the target time to 10 hours of receipt of complaints without requiring substantial resource additions.
GES3	**Voltage Complaint** This refers to the investigation of voltage complaints	Visit within 3 working days of receipt of the complaint	(a)Visit within twenty-four (24) hours of receipt of the complaint	**(a)Visit within 3 working days of receipt of the complaint**	Priority is given to these complaints especially when there appears to be associated safety concerns. Reports of voltage issues is often the most frequent complaint reported by customers. To reduce the targeted time to within twenty-four (24) hours is not achievable given the nature and volume of such complaints. The current target time of within 3 working days is a challenging target and continues to be an appropriate target for our operating environment.

STANDARD	SERVICE CATEGORY	EXISTING TARGET	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
		Provide assessment within 15 working days of receipt of complaint	(b) Provide an assessment within three (3) working days of receipt of complaint	**(b1)Provide simple assessment and correction within 5 working days of receipt of complaint**	Assessment can vary in complexity, therefore BL&P recommends that the assessment target be split into two categories consisting of simple and complex assessments.
				(b2)Provide complex assessment within 15 working days of receipt of complaint	The time required to complete an assessment of a voltage complaint is dependent on the nature of the complaint. In general, detailed assessments would require the installation of measuring devices to monitor line loads and voltages. These devices are normally employed for in excess of three working days at the particular location. This would support the need for longer periods facilitate the provision of complex assessments.
		Correct within 3 months of receipt of complaint	(c)Correct within five (5) working days of receipt of complaint	**(c) Correct within 3 months of receipt of complaint**	Correction may be as simple of removing corrosion from a connection or as involved as restringing lines or the installation of new transformers. In those situations, where significant infrastructure replacement is needed correction actions may take months rather than days to schedule and complete.

THE BARBADOS LIGHT & POWER COMPANY LIMITED

STANDARD	SERVICE CATEGORY	EXISTING TARGET	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
GES5	**Complex Connection – Cost Estimate** This refers to the time it takes to provide cost estimate for complex connection requiring a service visit	Within 3 months	Within ten (10) working days of receipt of request	**Within 40 working days of receipt of request**	Estimates vary in complexity: from small line extensions to large residential and commercial developments. A period of 40 working days would be considered a reasonable target time to account for revisions and information discovery. In some instances, multiple versions of cost estimates are required at the customer's request.
GES6	**Connect or Transfer of Service** This refers to the time it takes to connect or transfer service from one location to another location which has an existing installation	Within 2 working days	Within 12 working hours of receipt of request	**Within 2 working days**	These service calls require a minimum of two (2) full working days to be scheduled and assigned.
GES7	**Reconnection** This refers to the time for reconnection of service on settling the bill after disconnection at the meter as verified by the BL&P. The customer should notify the	Within 1 working day	Within 6 working hours of receipt of request	**Within 1 working day**	Challenges in meeting this standard arises mainly after working hours when a customer makes payment late in the night utilizing a payment facility such as Surepay. Afterhour reconnections compete for the same resources responding to issues related to GES1,

STANDARD	SERVICE CATEGORY	EXISTING TARGET	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
	BL&P of the settlement using the bill receipt number when carried out other than at its offices.				GES2 & GES3. BL&P is already challenged to achieve the 1 working day target.
GES8	**Response to Billing Complaints** This refers to the timeframe in which BL&P responds to customer billing complaints	Provide assessment within 15 working days of receipt of complaint if service visit is required; for other matters the company is to respond within 5 working days	(a)If service visit is required provide an assessment and resolution within ten (10) working days of receipt of complaint	**(a)If service visit is required provide an assessment and resolution within fifteen (15) working days of receipt of complaint**	BL&P notes the Commission's changes to the wording of this target. The proposed requirement to also include resolution within a shorter target time would be difficult to achieve. The resolution process may require the involvement of the Commission and further negotiation with the customer. BL&P recommends that additional time be allocated to facilitate complaint resolution.
			(b)For all other matters not requiring a service visit, the BL&P is required to satisfactorily resolve these within three (3) working days of receipt of complaint	**(b)For all other matters not requiring a service visit, the BL&P is required to satisfactorily resolve these within five (5) working days of receipt of complaint**	BL&P will unlikely be able to acquire the necessary resources and make the changes to its current business processes to meet the lower target time within the limited period for implementation of the new standards.

APPENDIX B

OVERALL STANDARDS OF SERVICE PROPOSALS

STANDARD	SERVICE CATEGORY	EXISTING TARGET	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
OES2	**Voltage Complaints** Response to Complaint of high/low voltage	95% of complaints to be responded to in five working days	100% of complaints to be responded to within three (3) working days	**Standard and target be removed**	BL&P notes that this standard is made redundant by GES3 and recommends its removal from the overall standards.
OES3	**Outage Notice** Prior notice of outages	All potentially affected customers to be notified of planned outages 48 hours before outage in 95% of instances	In 100% of instances of planned outages, potentially affected customers are to be notified 48 hours before the outage in each section of the media, e.g. television, radio, print, online (website), social media	**In 100% of instances of planned outages, potentially affected customers are to be notified 48 hours before the outage.**	BL&P proposes that wider media notification of a planned outage not be included in the standard due to its costs and security implications. BL&P recommends that it notifies only customers that may be affected by the planned outage.

STANDARD	SERVICE CATEGORY	EXISTING TARGET	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
OES4	**Response to Claims** Response to Written Claims related to Standards of Service	100% of customers to receive acknowledgement of receipt of claim within 10 working days	100% of customers' complaints and claims to be acknowledged within five (5) working days of receipt	**100% of customers' complaints and claims to be acknowledged within five (5) working days of receipt**	BL&P does not oppose the proposed changes to this standard

APPENDIX C

NEW OVERALL STANDARDS OF SERVICE PROPOSAL

STANDARD	SERVICE CATEGORY	COMMISSION PROPOSED TARGET	BL&P RECOMMENDED TARGET	COMMENTS
OES7 (NEW)	**Response to Damage Claims** Acknowledgement and settlement of claims	(a)Acknowledge 95% of damage claims immediately on receipt of oral claims and for written claims, within five (5) working days of receipt.	**(a) Acknowledge 95% of damage claims immediately on receipt of oral claims and for written claims, within seven (7) working days of receipt.**	The processing of internal mail generally requires a minimum of seven (7) days for action.
		(b) Settle 95% of damage claims within thirty (30) working days of receipt of written or oral claim	**(b) Settle 95% of damage claims within two (2) months of receipt of written or oral claim**	The settlement of the claims depends on the complexity of the claim and the level of investigation required. The investigation and assessment of claims process would generally extend beyond thirty days.

M-3

FAIR TRADING COMMISSION

DECISION

The Barbados Light and Power Company Limited
Standards of Service
2018 - 2020

Document No.: FTCUR/DECSOS/BL&P–2017-02 **Date of Issue: September 29, 2017**

DOCUMENT NUMBER: FTCUR/DECSOS/BL&P-2017-02
DOCUMENT TITLE: DECISION – The Barbados Light & Power Company Limited Standards of Service 2017 - 2020

ANTECEDENT DOCUMENTS

Document Number	Description	Date
FTC/UR/CONSOSBL&P 2017-02	Consultation Paper – Review of the BL&P Standards of Service	April 3, 2017
FTC/DECSOSB/2014-01	Decision on BL&P Standards of Service 2014 - 2017	May 7, 2014
FTC/CONSOSB 2013/01	Consultation Paper – Review of the BL&P Standards of Service	October 25, 2013
FTC/UR/2010-03	Decision on BL&P Standards of Service 2010-2013	February 22, 2010
FTC/CONS 2008/02	Consultation Paper – Review of the BL&P Standards of Service	October 29, 2008
FTC/UR/2006-2	Decision on BL&P Standards of Service 2006 - 2009	February 28, 2006

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SECTION 1 EXECUTIVE SUMMARY

On April 3, 2017, the Fair Trading Commission (Commission) commenced the review of the Standards of Service for the Barbados Light and Power Company Limited (BL&P) Decision 2014 - 2017, in accordance with Section 4(3) of the Fair Trading Commission Act, CAP. 326B (FTCA) and Sections 3(1) and 4 of the Utilities Regulation Act, CAP. 282 (URA) of the Laws of Barbados.

The Commission's obligation to consult was executed by publication of the BL&P Standards of Service Consultation Paper. An invitation was extended to all stakeholders and interest groups to submit written responses by May 2, 2017. The Commission holds the view that Standards of Service are an important tool in ensuring that the BL&P provides a safe, efficient and reliable service to its customers and that intermittent review and appropriate amendment can facilitate improved performance.

Having completed the review process, the Commission has determined that the Standards of Service shall be amended as follows:

Guaranteed Standards of Service

- The targets for Fault Repair - Customer's Service (GES 1) and Fault Repair - Distribution System (GES 2) shall be restoration of service within eight (8) hours;
- The targets for Voltage Complaint (GES 3) categories shall be: GES 3 (a) - the BL&P is to visit the site within twenty-four (24) hours; GES 3 (b) - provide an assessment within five (5) working days; and GES 3 (c) - resolve the issue within thirty (30) working days of receipt of complaint;
- The target for Complex Connection (GES 5) shall be to provide a cost estimate within thirty (30) days of receipt of request;
- The target for Connect or Transfer of Service (GES 6) shall be completion of service within fourteen (14) working hours of receipt of request;
- The target for Reconnection (GES 7) shall be to reconnect the customer within six (6) working hours of request;

- The targets for Response to Billing Complaints (GES 8) categories shall be: GES 8 (a) - assess and resolve billing issues where a site visit is required within ten (10) working days; and GES 8 (b) - all other issues to be resolved within three (3) working days; and
- The target for Timely Payment of Compensation (GES 9 (New)) shall be to credit the customer's account within two (2) months from the occurrence of the breach for automatic compensation, and within two (2) months of acceptance of customer initiated claims.

Overall Standards of Service

- The target for Voltage Complaint (OES 2) shall be to respond within twenty-four (24) working hours of receipt of complaint;
- The target for Outage Notice (OES 3) shall be notification of affected customers forty-eight (48) hours before planned outage;
- The target for Response to Complaints and Claims (OES 4) shall be all complaints and claims to be acknowledged within five (5) working days of receipt; and
- The targets for Response to Damage Claims (OES 7 (New)) categories: OES 7 (a) – 95% of oral claims to be acknowledged immediately and within five (5) working days for written claims; and OES 7 (b) – 95% of written or oral claims to be settled within two (2) months of receipt.

System Reliability Indicators

- The targets for reliability indices shall be:
  - System Average Interruption Duration Index (SAIDI) – 3.68 hours/customer/year;
  - System Average Interruption Frequency Index (SAIFI) – 5.84 outages/customer/year;
  - Customer Average Interruption Duration Index CAIDI – 0.63 hours/customer/year; and
  - Average System Availability Index (ASAI) (NEW) – 99.958%

General Administration

- The BL&P shall comply with the following:
  - Disseminate fault reporting and damage claim procedures to customers;

- Issue a tracking number to each customer reporting a fault;
- Publicise the Standards of Service and Claim form via its website;
- Advertise the Standards of Service in the media once every six months; and
- Include the web link to the aforementioned information on customers' utility bills.

All other Standards of Service not mentioned shall remain the same as that of the 2014 - 2017 Decision.

The Standards of Service for the BL&P shall come into effect on January 1, 2018 and continue until December 31, 2020 or until such time as a new Standards of Service Decision is issued. These Standards of Service are subject to review by the Commission, at which time amendments to the Standards, target times or compensation may be made.

SECTION 2 INTRODUCTION

2.0 Background

The BL&P's Standards of Service framework sets out the minimum levels of service to be provided to electricity customers. The timely review of the Standards of Service ensures that the quality of service and the service categories are appropriate and effective in achieving their intended objective of continuous improvement.

The purpose of a standards of service programme is: to ensure that a minimum quality of service is maintained; to provide incentives for improvement in the quality of service; to create conditions for customer satisfaction; to monitor service quality; and generally to protect the interests of consumers of electricity.

There are two (2) Standards of Service categories: Guaranteed Standards of Service and Overall Standards of Service. The Guaranteed Standards of Service describe the minimum service level criteria which the BL&P is required to provide to individual customers. Where the BL&P is in breach of the Guaranteed Standards of Service, the affected customer is entitled to compensation as prescribed under each service category. The Overall Standards of Service, however, speak to service delivery at the national level. Individual customers are not compensated for breaches but where the Commission observes continued breach, it may impose penalties under the URA and the FTCA.

This Decision also includes details of exemptions. Exemptions refer to situations where the Commission considers that failure to meet the Standards is due to circumstances outside the control of the BL&P.

2.1 Legislative Framework

Authority to Establish Standards of Service

According to the FTCA, "Standards of Service" is defined at Section 2 as '*the quality and extent of service supplied by service providers*'.

Section 4(3) of the FTCA and Sections 3(1) and 4 of the URA set out the Commission's authority to determine the Standards of Service for a regulated entity and the considerations that must be given when determining the same. Rule 63(2) of the Utilities

Regulation Procedural Rules 2003, S.I. 2003 No.104 (URPR), details the issues that may be included in the development of these Standards of Service. Together, these pieces of legislation provide the over-arching framework necessary for the development and establishment of the Standards of Service for a regulated sector.

Section 4(3) of the FTCA states inter alia:

> *"The Commission shall, in the performance of its functions and in pursuance of the objectives set out in subsections (1) and (2),...*
>
> *(d) determine the standards of service applicable to service providers;*
> *(e) monitor the standards of service supplied by service providers to ensure compliance;"*

Section 3(1) of the URA states inter alia:

> *"The functions of the Commission under this Act are, in relation to service providers, to...*
>
> *(d) determine the standards of service applicable;*
>
> *(e) monitor the standards of service supplied to ensure compliance; and*
>
> *(f) carry out periodic reviews of the ... standards of service."*

Additionally, Section 4 of the URA states inter alia:

> *"In determining standards of service, the Commission shall have regard to*
>
> *(a) the rates being charged by the service provider for supplying a utility service;*
>
> *(b) ensuring that consumers are provided with universal access to the services supplied by the service provider;*
>
> *...*
>
> *(d) such other matters as the Commission may consider appropriate."*

Rule 63(2) of the URPR states:

> *"Service standards may include issues such as*
>
> *(a) universality of service;*
> *(b) the provision of new services;*
> *(c) the extension of services to new customers;*
> *(d) the maximum response time permitted for responding to customer complaints and queries; and*
> *(e) standards related to service quality which are specific to each sector."*

Requirement to Consult

The Commission is required to consult with interested parties in accordance with Section 4(4) of the FTCA, which states:

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

Fines and Penalties

These Standards of Service are binding on the BL&P. Sections 21, 31(1) and 38 of the URA, together with Section 43(1) of the FTCA, state as follows:

Section 21 of the URA:

> *"Where a service provider fails to meet prescribed standards of service, the service provider shall make to any person who is affected by the failure such compensation as may be determined by the Commission."*

Section 31(1) of the URA:

> *"Every service provider which fails or refuses to obey an order of the Commission made under this Act is guilty of an offence and is liable on summary conviction to a fine of $100,000 and, in the case of a continuing offence, to a further fine of $10,000 for each day or part thereof during which the offence continues."*

Section 38 of the URA:

> *"The Commission may make*
>
> *(a) rules;*
> *(b) regulations; and*
> *(c) orders with respect to*
> *(i) imposing penalties for non-compliance with prescribed standards of service; and*
> *(ii) prescribing amounts to be paid to the person referred to in section 21 for failure to provide a utility service in accordance with the standards of service set by the Commission."*

Section 43(1) of the FTCA:

> *"Every service provider or business enterprise that fails or refuses to obey an order of the Commission made under this Act is liable on summary conviction to a fine of $100,000 and, in the case of a continuing offence, to a further fine of $10,000 for each day or part thereof during which the offence continues."*

2.2 Consultation Process

Stakeholders were invited to comment on the BL&P's Standards of Service Consultation Paper during the consultation period April 3, 2017 to May 2, 2017. The BL&P was the only party to submit comments on the consultation.

The Commission wishes to thank the BL&P for its participation in the consultative process.

These amended Standards of Service come into effect from **January 1, 2018** and continue until **December 31, 2020** or until such time as a new Standards of Service Decision is issued.

SECTION 3 ELECTRICITY SECTOR

The BL&P is a vertically integrated company which owns and controls the generation, transmission and distribution systems. Approximately 126,190 customers[1] are served by the BL&P's electricity service, which is produced from ninety-five percent (95%) fossil fuel and five percent (5%) Renewable Energy (RE) sources.

The BL&P's provision of electricity is supported by its Supply Side Management (SSM) portfolio, which incorporates Time-of-Use (TOU) and Interruptible Service Rider (ISR) programmes. The BL&P commissioned a 10 MW AC[2] Utility Scale Solar Photovoltaic plant at Trents, St. Lucy in August 2016. It also has a permanent Renewable Energy Rider (RER) programme which allows distributed generators to export excess RE electricity to the grid.

Given the monopolistic nature of Barbados' electricity market, the development of the Standards of Service, which establish basic minimum levels of service, is crucial. Monitoring of the BL&P's performance under these minimum Standards allows the Commission to ensure that the quality of service the customer receives is reasonable.

The periodic review of the Standards of Service facilitates the assessment of their individual applicability and allows for amendments where necessary.

[1] Emera Incorporated, "*Preliminary Short Form Prospectus,*" accessed April 10, 2017, http://investors.emera.com/Cache/36953824.PDF?Y=&O=PDF&D=&FID=36953824&T=&OSID=9&IID=4072693.

[2] AC – Alternating Current

SECTION 4 THE DETERMINATION

4.0 General

The Commission considered the BL&P's responses, reviewed publicly available information on electricity Standards of Service and compared the existing Standards of Service with those from regional and extra-regional jurisdictions. Having exhausted this process, the Commission has determined that:

- The continued application of Guaranteed and Overall Standards of Service for the delivery of electricity service is appropriate;
- Penalties may be imposed for breaches of the Standards of Service;
- Amendment of the Guaranteed and Overall Standards of Service is appropriate;
- The BL&P shall include a statement on the customer's electricity bill, which identifies the web link to the Guaranteed Standards of Service and its related compensation policy;
- The BL&P shall make known its fault reporting and damage claim procedures, through its Customer Care Representatives and website. The web link to the damage claim guidelines shall be included on the electricity bill; and
- The BL&P shall publicise its compensation policy pertaining to breaches of the Guaranteed Standards of Service in the media and via its website.

The following sections set out the specific Guaranteed and Overall Standards of Service which will come into effect on January 1, 2018.

4.1 Guaranteed Standards of Service for the BL&P

The determination on the Guaranteed Standards of Service for the BL&P is summarised and presented in Table 1, followed by a more detailed definition for each Standard of Service and the applicable exemptions. The term 'compensation' herein refers to a credit to the customer's account.

Table 1: Guaranteed Standards of Service for the BL&P

STANDARD	SERVICE CATEGORY	TARGET	COMPENSATION
GES 1 (Amended)	**Fault Repair - Customer's Service** This refers to the time it takes to restore supply after fault on a consumer's service (single customer).	Within eight (8) hours of receipt of complaint.	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **For each additional eight (8) hours Prorated on an hourly basis** **Automatic Compensation[3]**
GES 2 (Amended)	**Fault Repair - Distribution System** This refers to the time it takes to restore supply after fault on the distribution system (multiple customers).	Within eight (8) hours of receipt of complaint.	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **For each additional eight (8) hours Prorated on an hourly basis** **Customer Initiated Claim Required[4]**
GES 3 (Amended)	**Voltage Complaint** This refers to the investigation and correction of voltage complaints.	(a) Visit within twenty-four (24) hours of receipt of the complaint.	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**
		(b) Provide an assessment within five (5) working days[5] of receipt of complaint.	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**
		(c) Correct within thirty (30) working days of receipt of complaint.	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**

[3] Automatic Compensation refers to the initiation of the compensation process by the BL&P where a breach has occurred and is granted on confirmation of the breach by the BL&P. It is administered as a credit on the customer's bill for the following month.

[4] For Compensation which requires customer initiated claims, customers must fill out a claim form and submit it to the BL&P in order to receive any credit which is due.

[5] "Working Days" refers to Mondays to Fridays from 8:00 a.m. to 4:00 p.m. only and excludes public holidays and weekends. In measuring the response time for targets expressed in terms of working days, the day the complaint is made is excluded. Any other reference to days means calendar days.

STANDARD	SERVICE CATEGORY	TARGET	COMPENSATION
GES 4	**Simple Service Connection** This refers to the time it takes to provide a simple service connection (connection point within thirty (30) metres) after the customer signs the contract for connection and presents a valid certificate of inspection from the Government Electrical Engineering Department (GEED).	Within twelve (12) working days of receipt of request.	Credit of installation fee **Automatic Compensation**
GES 5 (Amended)	**Complex Connection – Cost Estimate** This refers to the time it takes to provide a cost estimate for a complex connection requiring a service visit from the time of provision of all the requisite information.	Within thirty (30) workings days of receipt of request.	\$45.00 (D) \$90.00 (GS) \$215.00 (SVP/LP) **Customer Initiated Claim Required**
GES 6 (Amended)	**Connect or Transfer of Service** This refers to the time it takes to connect or transfer service from one location to another location which has an existing installation.	Within twelve (12) working hours[6] of receipt of request.	\$45.00 (D) \$90.00 (GS) \$215.00 (SVP/LP) **Automatic Compensation**
GES 7 (Amended)	**Reconnection** This refers to the time for reconnection of service on settling the bill after disconnection at the meter, as verified by the BL&P.	Within six (6) working hours of receipt of payment.	Credit of reconnection fee **Automatic Compensation**
GES 8 (Amended)	**Response to Billing Complaints** This refers to the timeframe in which the BL&P responds to customers' billing complaints.	(a) Where a service visit is required, provide an assessment and resolution within ten (10) working days of receipt of complaint.	\$45.00 (D) \$90.00 (GS) \$215.00 (SVP/LP) **Customer Initiated Claim Required**
		(b) For all other matters not requiring a service visit, the BL&P is required to resolve these within three (3) working days of receipt of complaint.	\$45.00 (D) \$90.00 (GS) \$215.00 (SVP/LP) **Customer Initiated Claim Required**

[6] "Working hours" are between 8:00 a.m. and 4:00 p.m. on a working day.

STANDARD	SERVICE CATEGORY	TARGET	COMPENSATION
GES 9 (New)	**Timely Payment of Compensation** This refers to the time in which the BL&P shall apply a credit to a customer's account on acceptance of a claim.	(a) All credits to be applied to the customers' accounts within two (2) months of occurrence of a breach where automatic compensation is applicable and within two (2) months of acceptance of a Customer Initiated Claim, where applicable.	$45.00 (D) $90.00 (GS) $215.00 (SVP/LP) **Automatic Compensation**

Key: D – Domestic; GS – General Service; SVP – Secondary Voltage Power; LP – Large Power

Guaranteed Standards of Service Definition and Specific Exemptions

GES 1 – Fault Repair – Customer Service (Restore supply after a fault on the customer's service) (Amended)

Definition

The BL&P shall restore the electricity supply within eight (8) hours of a fault being reported on an individual customer's service. The qualifying fault events include but are not limited to problems or defects at the metering point, broken or defective service wires.

Where the BL&P breaches the fault repair target, it shall credit the affected customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP). Thereafter, the same level of compensation is applicable for each additional eight (8) hours the customer remains without service or prorated on an hourly basis where appropriate.

Specific Exemptions:

- Where it is discovered that the customer's equipment is defective, e.g. defective meter socket base, load ends, underground cables; and
- Where adverse weather conditions exist or are imminent.

GES 2 – Fault Repair – Distribution System (Restore supply after fault on the electrical distribution system (multiple customers) (Amended)

Definition

Where a fault on a distribution system affects multiple customers, the BL&P shall restore the electricity supply within eight (8) hours of receipt of the report.

Where the BL&P breaches the target for the restoration of supply, it shall credit each affected customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP). Thereafter, the same level of compensation is applicable for each additional eight (8) hours the customer remains without service or prorated on an hourly basis where appropriate.

Specific Exemptions:

- Where the loss of the customer's supply is unknown to the BL&P subsequent to restoring the supply at the distribution level;
- Where the outage is due to a fault on an underground cable and the prevailing conditions are such that it is not practical for the BL&P to be able to locate, excavate and repair the fault within the stipulated time frame; and
- Where adverse weather conditions exist or are imminent.

GES 3 – Voltage Complaint (Investigation of voltage complaint) (Amended)

Definition

The BL&P shall investigate voltage issues within twenty-four (24) hours of receipt of the report. Where the voltage supplied to the customer is discovered to be outside of the permitted power quality standard (±6.0%) of nominal voltage and cannot be rectified immediately, the BL&P is required to provide an assessment of the problem within five (5) working days. The BL&P shall rectify the problem within thirty (30) working days of receipt of the original complaint.

Failure of the BL&P to investigate, provide assessment and resolve voltage complaints within the times specified will require the BL&P to credit the affected customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP) in each instance.

Specific Exemptions:

- Where the customer's electricity demand has increased significantly and was not made known to the BL&P;
- Where it is discovered that a customer on the local feeder is operating heavy equipment (e.g. welding equipment, large motors) on a service for which it was not designed;

- Where defects exist in the customer's installation (e.g. grounding, wiring, unbalanced loads, harmonics or transient voltages);
- Where defects in the customer's equipment exist; and
- Where work delays may result due to obtaining permission from the property owners or the Town and Country Development Planning Office.

GES 4 – Simple Service Connection (Provide a simple service connection – connection point within 30 metres)

Definition

The BL&P shall connect all new services, which are within thirty (30) metres of an existing circuit, within twelve (12) working days of a customer signing the contract for connection and presenting a valid certificate of inspection from the GEED.

Where the BL&P fails to connect the customer within the time specified, it shall credit that customer's account with the applicable installation fee.

Specific Exemptions:

- Where adverse weather conditions exist or are imminent; and
- Where the incorrect address/directions are given.

GES 5 – Cost Estimate (Provide a cost estimate for complex connections requiring a service visit) (Amended)

Definition

The BL&P shall provide a cost estimate for a new or altered supply within thirty (30) working days of a customer's request. Where the BL&P breaches this target, it shall credit the affected customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP).

Specific Exemptions:

- Where the customer fails to provide the requisite information for the determination of the estimated costs; and
- Where delays occur due to difficulties in obtaining the required permissions from property owners and/or the Town and Country Development Planning Office.

GES 6 – Connect or Transfer of Service (Connect or transfer of a service to an existing installation) (Amended)

Definition

The BL&P shall connect or transfer an electricity service where there is a meter already installed on the premises, within twelve (12) working hours of the customer signing the requisite service contract.

Where the BL&P breaches the target, it shall credit the customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP).

Specific Exemptions:

- Where the service has been disconnected for more than six (6) months and/or requires a valid certificate of inspection from the GEED before it can be connected; and
- Where adverse weather conditions exist or are imminent.

GES 7 – Reconnection (Reconnection of service on settling the bill after disconnection at the meter) (Amended)

Definition

The BL&P shall reconnect the electricity service within six (6) working hours after payment of the bill and the reconnection fee at the BL&P's office. Where payments are made at an external agency after working hours, the customer must notify the BL&P's customer service department and provide proof of payment (receipt number for the bill payment and reconnection fee), in order to benefit from the six (6) working hour target.

Where the BL&P fails to reconnect a customer within the time allocated, it shall credit the customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP).

Specific Exemptions:

- Where a customer fails to provide proof of payment to the BL&P; and
- Where adverse weather conditions exist or are imminent.

GES 8 – Response to Billing Complaints (The time frame in which the BL&P responds to customer billing complaints) (Amended)

Definition

The BL&P shall provide resolution to written or emailed billing complaints within three (3) working days of receipt of complaint. Where the BL&P considers that a service visit is required, the BL&P shall provide an assessment and resolution within ten (10) working days of receipt of the complaint. A response is deemed to have been provided when the BL&P communicates its findings to the customer orally, in writing or electronically. The findings of the investigation shall include what provisions are being made to rectify the problem and a time frame for rectification. A tracking number shall be issued to each complainant for ease of reference.

Where the BL&P breaches the target for resolution of written or emailed billing complaints or fails to visit the customer where appropriate, it shall credit the customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP) in each instance.

Specific Exemptions:

- Where access to the customer's premises is restricted, e.g. locked gate, aggressive/unrestrained animals, etc.; and
- Where adverse weather conditions exist or are imminent.

GES 9 – Timely Payment of Compensation (New)

Definition

This refers to the timely payment of compensation for breaches. Where the BL&P is in breach of the Guaranteed Standards of Service and automatic compensation is required, the assigned compensation shall be credited to the customer's account within two (2) months of confirmation of the breach. Where the breach requires the affected customer to initiate a claim, the BL&P shall credit the customer's account within two (2) months of acceptance of the claim.

Where the BL&P breaches the applicable target, it shall credit the affected customer's account $45.00 (D), $90.00 (GS) or $215.00 (SVP/LP).

<u>Specific Exemption:</u>

- Where a circumstance exists, beyond the control of the BL&P that prevents/inhibits the timely processing of the claim.

4.2 Overall Standards of Service for the BL&P

The Commission has also made the following determination on the Overall Standards of Service. The Standards are presented in Table 2, followed by a detailed definition for each Standard of Service and the applicable exemptions.

Table 2: Overall Standards of Service for the BL&P

STANDARDS	DESCRIPTION	TARGET
OES 1	**Meter Reading** Frequency of meter reading.	(a) 100% of Domestic/General Service customers' meters to be read every two months. (b) 100% of Secondary Voltage Power and Large Power customers' meters to be read monthly.
OES 2 (Amended)	**Voltage Complaints** Response to complaint of high/low voltage.	100% of complaints to be responded to within twenty-four (24) working hours of receipt.
OES 3 (Amended)	**Outage Notice** Prior notice of outages.	In 100% of instances of planned outages, all potentially affected customers are to be notified forty-eight (48) hours before the outage.
OES 4 (Amended)	**Response to Complaints and Claims** Response to written and oral complaints and claims related to Standards of Service.	100% of customers' complaints and claims to be acknowledged within five (5) working days of receipt.
OES 5	**Call Centre Answering** Billing and Trouble Centre Calls answered by a customer service representative.	85% of calls to be answered within one (1) minute.
OES 6	**Billing period** The period between two meter readings whether interim, estimated or actual.	At least 95% of customers in each billing period shall be invoiced for no more than thirty-three (33) days.
OES 7 (New)	**Response to Damage Claims** Acknowledgement and settlement of claims.	(a) Acknowledge 95% of damage claims immediately on receipt of oral claims and for written claims, within five (5) working days of receipt. (b) Settle 95% of damage claims within two (2) months of receipt of written or oral claim.

Overall Standards of Service Definitions and Specific Exemptions

OES 1 – Meter Reading (Frequency of meter reading)

Definition

The BL&P shall read all Domestic and General Service meters at least once every two (2) months. All Secondary Voltage Power and Large Power meters shall be read monthly.

Specific Exemptions:

- Where access to the customer's premises is restricted, resulting in the meter being inaccessible to the meter reader (e.g. aggressive/unrestrained animals or a locked gate). In these cases, the BL&P shall inform the customer of the situation and arrange to have the situation corrected; and
- Where adverse weather conditions exist or are imminent.

OES 2 – Voltage Complaints (Response to Complaint of high/low voltage) (Amended)

Definition

All voltage complaints shall be responded to within twenty-four (24) working hours of receipt.

Specific Exemption:

- Where adverse weather conditions exist or are imminent.

OES 3 – Outage Notice (Prior notice of outages) (Amended)

Definition

All potentially affected customers shall be notified of a planned outage at least forty-eight (48) hours before the outage is instituted.

OES 4 – Response to Complaints and Claims (Response to Written Claims related to Standards of Service) (Amended)

Definition

All written complaints and claims for breaches of the Standards of Service shall be acknowledged within five (5) working days of receipt of the claim.

OES 5 – Call Centre Answering (Billing and Trouble Centre calls answered by a customer service representative)

Definition

At least 85% of all calls to the BL&P's Billing and Trouble Centre shall be answered within one (1) minute.

Specific Exemption:

- Where the volume of calls received during the period of an outage on one (1) or more feeders does not permit them to be answered within the required time (e.g. during major outages).

OES 6 – Billing Period (Period between two meter readings whether interim, estimated or actual)

Definition

At least 95% of bills issued to customers in any billing period shall be invoiced for no more than thirty-three (33) days of service.

Specific Exemptions:

- Where access to the premises is restricted or the meter is inaccessible to the meter reader (e.g. aggressive/unrestrained animals or a locked gate). In these cases, the BL&P shall inform the customer of the situation and arrange to have the situation corrected; and
- Where adverse weather conditions exist or are imminent.

OES 7 – Response to Damage Claims (Acknowledgement and settlement of claims) (New)

Definition

The BL&P shall acknowledge 95% of damage claims immediately on receipt of oral claims and within five (5) working days for written claims. A minimum of 95% of the damage claims to be settled within two (2) months of receipt of written or oral claims.

Specific Exemption:

- Where the lack of access to the customer's equipment hinders the BL&P's investigation. In such a case, the BL&P shall inform the customer of the situation and arrange to have it corrected.

4.3 System Reliability Indicators

The Commission has determined that it is appropriate, at this time, to establish targets for the reliability indices. The institution of reliability targets allows for the creation of a benchmark against which reliability performance may be gauged. The Commission recognises that the assessment of the reliability performance of the BL&P can provide insights into the drivers[7] of such performance. The determined performance targets for the reliability measures are presented in Table 3, followed by their standard definitions.

Table 3: The BL&P's Reliability Indicator Targets

METRIC	TARGETS
SAIDI (Hours per year per customer)	3.68
SAIFI (Outages per year per customer)	5.84
CAIDI (Hours per year per customer)	0.63
ASAI (Percentage System Availability per year)	99.958

The Commission has determined that the reliability targets shall be based on the average of the BL&P's reported historical performance of the most recent five (5) years (2012 - 2016).

The definitions of the reliability indices are as follows:

System Average Interruption Duration Index (SAIDI)

This index indicates the total duration of interruption for the average customer during a predefined period of time (e.g. monthly/yearly) and is measured in customer hours of interruption.

$$\text{SAIDI} = \frac{\text{Total Customer Hours Interruptions}}{\text{Total Number of Customers Served}}$$

System Average Interruption Frequency Index (SAIFI)

This indicates how often the average customer experiences an interruption over a predefined period of time (e.g. monthly/yearly).

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

[7] Assessment of electricity reliability can highlight the factors impacting on reliability performance. These include the frequency of breakdown of distribution equipment.

Customer Average Interruption Duration Index (CAIDI)

This represents the average time taken in hours to restore a customer's electricity service. CAIDI is expressed as the ratio of SAIDI to SAIFI for a specified time (e.g. monthly/yearly).

$$\text{CAIDI} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

$$= \frac{\text{Total Customer Hours Interruption}}{\text{Total Number of Customer Interruptions}}$$

Average System Availability Index (ASAI)

This measures the percentage of time a customer receives an electricity service over a defined period (e.g. monthly/yearly).

$$\text{ASAI} = \frac{\text{Customer Hours Service Availability}}{\text{Customer Hours Service Demand}}$$

$$\text{ASAI} = \frac{8760 - \text{SAIDI}}{8760} = 1 - \frac{\text{SAIDI}}{8760}$$

The ASAI index provides specific information on the continuity of supply and the extent to which the BL&P's electricity service to customers is sustained. While the SAIFI and SAIDI indices are driven by the frequency and duration of interruptions and are systems oriented, the ASAI index is based on the fraction of the demand satisfied. Therefore, the ASAI directly measures the generation and system adequacy and complements the other reliability indices. Additionally, the ASAI measure requires no additional information for computation. Together, these indices provide comprehensive indicators of the reliability performance of the electricity network.

The BL&P shall continue to adopt the Institute of Electrical and Electronic Engineers (IEEE) 1366 Standard for determining System Reliability.

4.4 Power Quality Standard

Power Quality is another measure of electricity system reliability. The BL&P's permitted voltage tolerance on its distribution network is (±6%) of the nominal voltage.

Compensation for damage to equipment may be warranted when the supplied voltage falls outside of this range. The decision on whether the BL&P is liable will be made in accordance with the BL&P's policies and procedures for handling damage claims.

Where the customer is not satisfied with the recourse given by the BL&P, the customer reserves the right to make representation to the Commission.

SECTION 5 GENERAL EXEMPTIONS

5.0 Force Majeure

Apart from the specific exemptions listed in the previous section, the Standards of Service do not apply where conditions outside the control of the BL&P make it impossible to meet the targets. The term used to define these events is *force majeure*. Black's Law Dictionary (2009) defines *force majeure*[8] as:

> *"An event or effect that can be neither anticipated nor controlled; esp., an unexpected event that prevents someone from doing or completing something that he or she had agreed or officially planned to do. The term includes both acts of nature (e.g. floods and hurricanes) and acts of people (e.g. riot, strikes and wars)."*

The *force majeure* conditions under which the exemptions from the Standards of Service may be granted are:

(a) A threat or act of war (whether declared or not), hostile invasion, terrorism or civil disorder;

(b) A strike and/or other industrial action or blockade or embargo or any other form of civil disturbance;

(c) Landslides, lightning, hurricanes, floods, storm, earthquake, tsunami or any other natural disaster;

(d) Epidemics;

(e) Trade restrictions;

(f) Inability to obtain any requisite Government permits; and

(g) Breakdown of machinery or equipment through causes not within the control of the BL&P and which by the exercise of diligence it is unable to avoid, prevent or mitigate.

5.1 Other Exemptions and Conditions

The Commission is cognisant that other circumstances may exist from time to time, which might impede the BL&P's ability to meet the prescribed Standards of Service. In such circumstances, where a customer is dissatisfied with the BL&P's application of an

[8] Bryan Garner, Black's Law Dictionary (United States: Thomson Reuters, 2009), 718.

exemption, that customer may seek the Commission's assistance. Thereafter, the Commission may sanction the BL&P's action or require an alternative approach.

The situations in this category may include but are not limited to the following:

(a) Where the BL&P is unable to gain access to the customer's premises at the prearranged time;

(b) Where inadequate directions have been provided by the customer;

(c) Where the customer's installation does not meet the BL&P's requirements for installation or is considered unfit for service. (The BL&P's installation requirements are published in its Information and Requirements booklet and on its website);

(d) Where the customer or the customer's agent fails to fulfil the customer's obligations;

(e) Where the customer informs the BL&P, in writing, that no further action should be taken on a matter;

(f) Where the customer requests, in writing, that the BL&P take action at a later date than required by the Standards of Service;

(g) Where the Commission reasonably considers that the customer's request or complaint is frivolous or vexatious;

(h) Where an offence has been committed through interference with the BL&P's metering equipment;

(i) Where the customer's electricity account remains unpaid after the BL&P has given the customer notice of its intention to disconnect the supply for non-payment;

(j) Where the BL&P is requested, by a public authority, to provide emergency electricity supply to assist in emergency action and the provision of such services restricts the connection of a customer to a specified service or the rectification of a fault or service difficulty;

(k) Where there is a negligent or willful act by the customer;

(l) Where the customer is required to pay a charge to the BL&P for connection to the service or for the use of the service and the BL&P has reasonable grounds to believe, based on the customer's prior debt service record, that the customer would be unwilling or unable to pay the charge as it becomes due;

(m) Other unforeseeable circumstances beyond the control of the parties against which it would have been unreasonable for the affected party to take precautions and which the affected party cannot foresee by using its best efforts; and

(n) Where there are legal constraints that may prevent the BL&P from meeting the Standards of Service.

SECTION 6 REASONS FOR DECISION

6.0 General

The Commission reviewed and analysed the response submitted by the BL&P, considered customer complaints and queries received and also examined information related to electricity Standards of Service from regional and extra-regional jurisdictions. The reasons for the Decision are as follows.

6.1 Amendments to the Standards of Service

In concert with the general tenets of utility regulation, the Commission is of the view that targets should be refined, where appropriate, to incentivise continuous improvement in the BL&P's service delivery, particularly where it is evident that the current targets no longer present a challenge. Despite the BL&P's satisfactory performance under the 2014 – 2017 Guaranteed and Overall Standards of Service, there were instances where the target description required adjustment due to issues arising from customer queries and complaints, as well as other specific matters which warranted the introduction of new standards. This section addresses these issues in concert with the BL&P's responses and sets out the Commission's determination.

GES 1 - Fault Repair - Customer's Service

The BL&P recommends that the target for this Standard be set at ten (10) hours from receipt of complaint, citing that GES 2 and GES 3 Standards of Service compete for the same resources and that a lower target would require additional staff.

The Commission's Analysis

The Commission considers that the BL&P's reported historical performance in this Standard has been commendable. Notwithstanding this, the Commission also considered the number of fault repair requests made and the essential nature of an electrical service, as well as the need to reduce the customer's dislocation when a fault occurs. The Commission acknowledges that where the fault results from defects in the customer's own installation, such circumstances tend to increase the service restoration time. Therefore these circumstances should not be considered in the determination of the restoration time. The Commission, having weighed these circumstances, determines that the target shall be set at eight (8) hours.

GES 2 - Fault Repair - Distribution System

The BL&P submitted that a target time below ten (10) hours was not achievable since the GES 1 and GES 3 Standards compete for the same resources as GES 2.

The Commission's Analysis

The Commission notes that reported faults under this Standard affect a larger number of customers and, if not rectified in a reasonable time, could impact a wide cross-section of the customer base and negatively impact the productivity of business enterprises, resulting in substantial economic loss.

The BL&P has indicated that the resources used for this Standard are also utilised by other Standards and as such, this creates a challenge in meeting the proposed target. However, the BL&P has not provided evidence to substantiate its recommendation. The Commission understands that finite resources are allocated to multiple tasks. Nevertheless, it considers that greater emphasis should be placed on restoring electricity to multiple customers in a reasonable time-frame. Having considered the varied use of resources by the BL&P and its historically good performance, the Commission determines that a target of eight (8) hours is appropriate.

GES 3 - Voltage Complaint

The BL&P has advised that voltage complaints are frequently reported and that, given the characteristics of these complaints and the large number of cases, this presents a difficulty in meeting the proposed target, which requires that the site be visited within twenty-four (24) hours. However, the BL&P's response did not include any proof to suggest that this target was not achievable. With regard to the assessment of voltage complaints, the BL&P recommends that the two targets for this category – simple assessment and complex assessment - should be completed within five (5) and fifteen (15) working days from receipt of complaint, respectively. The BL&P proposes that the existing three (3) month target be retained for the resolution of voltage complaints.

The Commission's Analysis

The Commission understands the serious nature of voltage problems and recognises the need for urgency in addressing these matters. The Commission notes that although the BL&P cited a high level of voltage complaints, it does not appear to be challenged under this Standard, as demonstrated by its high compliance level. However, its comments suggest the need for prompt attention to such issues. The Commission acknowledges that timely attention must be given to GES 3 (a) issues. This requires the BL&P to visit the site of an incident promptly. It is noted that most complaints are resolved at this stage. The Commission considers that the twenty-four (24) hour target is appropriate and therefore shall remain.

The BL&P's response to the assessment of voltage complaints asserts that the nature of complaints range from simple to complex. With regard to the assessment of voltage complaints GES 3 (b), the Commission notes that the earlier voltage problems are assessed, the greater the benefit to both the customer and the BL&P. The Commission also notes that the number of reported assessments for GES 3 (b) on an annual basis, over the period 2014 - 2017, ranged from nine (9) to two (2). The Commission therefore considers that the target of five (5) working days for the assessment of voltage complaints is justified. Similarly, as with GES 3 (b), the Commission reviewed the number of incidents requiring resolution in the GES 3 (c) Standard category. Annually, these ranged from three (3) to zero (0) over the period 2014 - 2017.

The Commission further emphasises that voltage issues require prompt investigation to determine the urgency of the matter. Where the analysis of the voltage problem reveals complexities requiring major infrastructure replacement, the Commission also is of the view that these should be rectified within the shortest possible time. The Commission considers that the target of thirty (30) working days to resolve voltage issues is justified given the small number of cases in this category. Therefore, the Commission determines that the target is now set at thirty (30) working days.

GES 4 - Simple Service Connection

The Commission is of the view that there was no need to amend the target time of twelve (12) working days for this Standard given that the BL&P has consistently not met the target over the three (3) year review period. However, the Commission considers that the language used in the standard description should be modified for clarity. The Commission therefore determines that the GES 4 Standard target shall remain to connect a simple service within twelve (12) workings days of receipt of request.

GES 5 - Complex Connection – Cost Estimate

The BL&P recommends that a forty (40) day period would allow for the request of cost estimates for complex connections to be satisfied, noting that such requests may include revisions and multiple versions depending on the scale of the project (residential to large commercial). These often require third party involvement and the provision of site plans where appropriate.

The Commission's Analysis

The Commission recognises that requesting parties may not provide all of the requisite information to the BL&P at the time of requesting a cost estimate. In such circumstances, this delays the processing of the request. The BL&P should advise customers of required information before the formal request is acknowledged. The Commission notes the BL&P's response to this target and in particular the revisions and multiple versions of the required documents. The Commission further notes that the BL&P has not substantiated its recommended target for this Standard. The Commission therefore determines that a target period of thirty (30) days shall apply to the BL&P's provision of a cost estimate for a complex connection from the time that all the requisite information has been presented.

GES 6 - Connect or Transfer of Service

The BL&P recommends that the existing target of two (2) working days be retained, since this time allows for the scheduling and assignment of connection or transfer of service requests.

The Commission's Analysis

Performance data submitted by the BL&P has consistently shown compliance exceeding 99% over the period 2014 - 2017. The Commission considers that based on this performance, the target is no longer optimally efficient and currently does not provide any incentive to improve performance. The Commission notes that the work required does not refer to new connections and therefore the effort involved is not complex. The

Commission also notes that the deployment of the Advanced Metering Infrastructure (AMI) equipment by the BL&P will allow for gradual improvement in this Standard as some of its functionalities is expected to provide compensatory benefits in other areas. It is common practice for targets to be amended to reflect the anticipated impact of ongoing or near-term system investment. Therefore, the Commission determines that the target of twelve (12) working hours shall apply.

GES 7 – Reconnection

The BL&P recommends that the target of one (1) working day for Request for Reconnections should be retained on the basis that, when customers pay for this service after working hours at contracted payment facilities, the BL&P would have challenges meeting the proposed target. Additionally, the BL&P has reported that this challenge creates a case for competing resources with the GES 1 Standard.

The Commission's Analysis

Based on the reported data from the BL&P on this Standard, a high compliance level was evident. The Commission recognises the BL&P's challenge of meeting customers' requests for reconnections when payment is made after working hours. The Commission is of the view that when these requests are made, the BL&P shall accede to the customers' request, from the start of the next working day. Additionally, the Commission notes that with the gradual roll out of the BL&P's AMI resources, the task of manual reconnection will be reduced over time as AMI remote disconnection and reconnection increases. The Commission is of the view that this capability will reduce the requirement for additional resources, therefore, the six (6) working hour target shall apply.

GES 8 - Response to Billing Complaint

The BL&P has submitted that the proposed target of ten (10) working days for the assessment and resolution of complaints would be difficult to achieve and recommends a target of fifteen (15) days. The BL&P suggests that the additional time would allow for resolution of complaints. The BL&P further asserts that the proposed three (3) working day target to resolve issues not requiring a service visit would be difficult to achieve.

The Commission's Analysis

The Commission acknowledges that the BL&P has historically performed well under this Standard. It is anticipated that with the roll out of the BL&P's AMI programme, improvement in this Standard will be gradually realised. The Commission acknowledges that deployment has commenced and is scheduled to conclude by December 31, 2019[9]. The Commission determines that the targets shall be to provide an assessment and resolution within ten (10) working days of receipt of complaint (GES 8 (a)) and for all other matters not requiring a service visit, the BL&P is required to resolve these within three (3) working days of receipt of complaint (GES 8 (b)).

GES 9 (New) - Timely Payment of Compensation

The BL&P recommends that under the proposed GES 9 Standard, the time frame for the payment of compensation in automatic form should be two (2) months from occurrence of the breach.

The Commission's Analysis

The Commission is of the view that compensation for breaches of the Standards of Service should be promptly credited to the customer's account. Based on the historical data submitted to the Commission, it is evident that the BL&P has not been paying compensation in a timely manner for some Standards of Service which require automatic compensation. Additionally, the Commission is of the view that the payment of Customer Initiated Claims also requires prompt payment. The Commission acknowledges the points raised by the BL&P concerning the automatic payment of claims and concurs with its recommendation. Therefore, for Standards of Service requiring automatic compensation, the credit shall be applied to the customer's account within two (2) months of occurrence of the breach. For Standards of Service which require the customer to initiate a claim, compensation shall be credited to the customer's account within two (2) months of its acceptance.

[9] Refer to the link for more information - https://www.blpc.com.bb/images/watts-new/Graphics_BLPC_Newsletter_Nov2016.pdf.

OES 1 – Meter Reading (Frequency of meter reading)

The Commission considered that amendment to this Standard was not required. Further, it is considered that the impact of the BL&P's gradual rollout of the AMI program will result in improved performance. The Commission therefore determines that the targets of the 2014 – 2017 Decision shall be retained – (a) 100% of Domestic/General Service customers' meters shall be read every two (2) months and (b) 100% of Secondary Voltage Power and Large Power customer's meters shall be read monthly.

OES 2 - Voltage Complaints

The BL&P recommends that this Standard and target be removed from the Overall Standards of Service, citing that it mirrors the purpose of Guaranteed Standard GES 3 and is unnecessary.

The Commission's Analysis

The provision for the response to Voltage Complaints under the Overall Standards of Service allows the Commission to evaluate the BL&P's performance at a national level, since voltage issues are particularly problematic and can result in damage and/or the loss of customers' equipment. While GES 3 addresses the impact this issue has at the individual customer level, a measure of how well the BL&P addresses voltage complaints at the system level will provide further insight into the overall safety of the BL&P's service delivery. The Commission's view is that this Standard offers an indicator of the level of attention given to these complaints and hence it shall be retained. The Commission determines that the target for this Standard shall be all voltage complaints to be responded to within twenty-four (24) workings hours of receipt of a complaint.

OES 3 - Outage Notice

The BL&P's response suggests that only those affected customers should be notified of instances of planned outages, as having the information widely publicised in the media would pose a security risk and additional cost.

The Commission's Analysis

The Commission is of the view that customers must be informed of planned outages so that they may plan their activities accordingly. It acknowledges that widely publicised, planned outages can present security risks. The Standard shall therefore be amended to reflect that in all instances of planned outages, all potentially affected customers are to be notified forty-eight (48) hours before the institution of the outage.

OES 4 - Response to Complaints and Claims

The BL&P did not oppose the proposed changes to this Standard.

OES 5 - Call Centre Answering (Billing and Trouble Centre calls answered by a customer service representative)

The Commission recognises that the BL&P's historical performance in this Standard over the review period did not meet the required 85% compliance level. The Commission is of the view that improvements in this Standard is warranted since the answering of customer calls is a direct indicator of customer service. Therefore, the Commission determines that the target for this Standard shall be retained as reflected in the 2014 - 2017 Decision - 85% of all calls shall be answered within one (1) minute.

OES 6 – Billing Period

The BL&P's performance marginally exceeded the required target for this Standard over the three (3) year review period. The Commission considers that there is merit in retaining the target, at this time, but recognises that the deployment of the AMI will allow for regularisation of the billing period. The Commission therefore determines that the existing target shall be retained - at minimum, 95% of the customers in each billing period shall be invoiced for no more than thirty-three (33) days.

OES 7 (New) - Response to Damage Claims

The BL&P did not oppose the introduction of the new standard provided the targets are reasonable. The BL&P recommends that the target for acknowledgment of damage claims should be within five (5) working days of receipt of the claim and that these should be settled within two (2) months of receipt of claims.

The Commission's Analysis

The Commission recognises the inconvenience that damaged equipment and an inordinately lengthy damage claim process can pose to customers. The Commission, having reviewed the queries and complaints it received on this subject, considers there is a need to monitor damage claim processing to ensure its efficient operation. The

Commission acknowledges the BL&P's recommendation and agrees that the settlement of damage claims should be completed within two (2) months of receipt. The Commission has determined that for oral claims, the target shall be 95% of damage claims to be acknowledged immediately on receipt and for written claims, the target shall be within five (5) workings days. At least 95% of the damage claims shall be settled within two (2) months of receipt of written or oral claims.

6.2 System Reliability Indicators

The BL&P has indicated that the current use of reliability indices is appropriate and adequate. The BL&P recommends that the targets assigned to these indices be based on a five (5) year rolling average, inclusive of one (1) standard deviation.

The Commission's Analysis

The Commission is aware of the various reliability benchmarking methodologies and their uses based on specific performance objectives. The Commission considers that the proposed reliability targets, which are based on the BL&P's historical average performance of the most recent five (5) years, is an accepted practice. The Commission notes that the use of this benchmarking standard provides an impetus for improved reliability performance. The Commission notes that the recommended target methodology proposed by the BL&P does not actively incentivise improvement. It is of the view that its own proposed reliability targets are reasonable. The Commission has determined that the annual reliability targets for SAIDI, SAIFI, CAIDI and ASAI shall be 3.68 hours/customer, 5.84 outages/customer, 0.63 hours/customer and 99.958%, respectively.

SECTION 7 ADMINISTRATION

7.0 Monitoring and Enforcement of Standards

The BL&P is required to submit quarterly Standards of Service reports within one (1) month of conclusion of the last quarter, including information on:

- The number of breaches under each Guaranteed Standard of Service (GES 1 to GES 9) and percentage compliance;
- The level of compliance, as a percentage, of each Overall Standard of Service (OES 1 to OES 7) ;
- ASAI (Average System Availability Index);
- CAIDI (Customer Average Interruption Duration Index);
- SAIDI (System Average Interruption Duration Index);
- SAIFI (System Average Interruption Frequency Index); and
- Details of any extenuating circumstances that would have prevented it from achieving the targets for the Overall Standards of Service.

The first reporting quarter will be January 1 to March 31, 2018. Thereafter, the reporting periods will be the four (4) consecutive quarters of 2018, 2019 and 2020, respectively.

In addition to the above information, the BL&P is required to submit annual Standards of Service reports for 2018, 2019 and 2020, which also include information on:

- The number of customers eligible for compensation during the reporting period (except for GES 2 Standard);
- The total amount of eligible compensation (except for GES 2 Standard);
- The number of customers actually receiving compensation;
- The amount of compensation actually paid; and
- The value of compensation attributable to each Guaranteed Standard of Service.

Compliance with the Standards of Service will be evaluated on a monthly basis and annual reports shall be submitted no later than two (2) months after the end of the applicable reporting year.

The Commission reserves the right to conduct independent investigations that seek to determine the extent to which the BL&P is meeting the Standards of Service.

The Commission further issues an Order pursuant to Section 38(c) (ii) of the URA. This Order is attached hereto.

Where an Overall Standard is not met, the BL&P shall provide an explanation to the Commission. Where the BL&P continually fails to meet an Overall Standard, and it appears that no reasonable effort has been made to rectify the breach, Section 43 of the FTCA and Sections 31 and 38 of the URA may be invoked.

7.1 Public Disclosure of Information

The Commission shall make public the yearly statistics related to the BL&P's performance in attaining these Guaranteed and Overall Standards of Service.

7.2 Public Education

The BL&P shall make available to its customers by post or electronically, within two (2) months of the implementation of this Decision, the Table of Guaranteed Standards of Service as set out herein.

In addition, the BL&P is required to educate its customers, as stipulated in this Decision about its fault reporting processes, including the publication of contact numbers and e-mail addresses for making complaints. The BL&P shall also place its claim forms and official complaint forms on its website and where the information can be accessed. Further, the BL&P shall also place the claim form at its head office.

7.3 Implementation and Review

The Standards of Service for the BL&P as herein outlined shall come into effect from January 1, 2018 and continue until December 31, 2020 or until such time as a new Standards of Service Decision is issued. These Standards of Service will be subject to review by the Commission.

Dated this 27th day of September 2017

Jefferson Cumberbatch
Chairman

Philmore Alleyne
Commissioner

Dawood Pandor
Commissioner

Andrew Willoughby
Commissioner

M-4

Fair Trading Commission

ANALYSIS OF BARBADOS LIGHT & POWER COMPANY LIMITED ANNUAL STANDARDS OF SERVICE REPORT

April 1, 2018 – March 31, 2019

Date: July 19, 2019

INTRODUCTION

The Fair Trading Commission (the Commission) is empowered under the Fair Trading Commission Act, CAP. 326B (FTCA) and the Utilities Regulation Act, CAP. 282 (URA) of the Laws of Barbados to determine, monitor and review Standards of Service applicable to regulated utilities. The Standards of Service regime comprises regulatory instruments which mandate the Barbados Light & Power Company Limited (BL&P) to provide minimum Standards of quality, customer service and reliability in its delivery of electricity service.

This report evaluates the BL&P's performance for the period April 1, 2018 to March 31, 2019 relative to the Standards of Service Decision 2018 – 2020, which was issued September 29, 2017. This revised Standards of Service framework resulted in amendments to the targets of seven (7) of the Guaranteed Standards of Service and the addition of one (1) new Standard which addresses the timely payment of claims. Similarly, for the Overall Standards of Service, the targets of three (3) of these Standards were amended and one (1) new Standard was added to incentivise the timely payment of damage claims. Additionally, one (1) new metric was added to the three (3) existing reliability metrics; these now include performance targets. These Standards came into effect from January 1, 2018.

There are three (3) Sections contained herein. Section 1 provides an assessment of the BL&P's performance under the Guaranteed Standards of Service. This also includes a synopsis of the BL&P's efficiency relative to the processing of claims. Section 2 assesses the BL&P's performance under the Overall Standards of Service. Section 3 provides an appraisal of the BL&P's submitted reliability performance.

SECTION 1 – GUARANTEED STANDARDS OF SERVICE

The Guaranteed Standards of Service are outlined below. Failure to meet these Standards requires that the BL&P compensate each affected customer via automatic or customer initiated credit, except under force majeure conditions. The Standards of Service which require customer initiated claims are GES 2 Fault Repair - Distribution System, GES 5 Complex Connection – Cost Estimate and GES 8 Response to Billing Complaints. The compliance level registered by the majority of Standards ranged from 96% to 99%; only two (2) categories registered compliance below 93%. Table 1 below summarises BL&P's performance for each Standard.

Table 1: Guaranteed Standards of Service

GUARANTEED STANDARD	TARGET	AVERAGE (%) COMPLIANCE
		April 1, 2018 – March 31, 2019
GES 1 **Fault Repair - Customer's Service** This refers to the time it takes to restore supply after fault on customer's service (single customer).	Within 8 hours.	91.33
GES 2 **Fault Repair - Distribution System** Restore supply after fault on distribution system (multiple customers).	Within 8 hours.	98.76
GES 3 **Voltage Complaint** This refers to the investigation of voltage complaint.	a) Visit within 24 working hours of receipt of complaint.	98.14
	b) Provide assessment within 5 working days[1] of receipt of complaint.	99.36
	c) Correct within 30 working days of receipt of complaint.	92.86

[1] "Working Days" refers to Mondays to Fridays from 8:00 a.m. to 4:00 p.m. only and excludes public holidays and weekends. In measuring the response time for targets expressed in terms of working days, the day the complaint is made is excluded. Any other reference to days means calendar days.

GUARANTEED STANDARD	TARGET	AVERAGE (%) COMPLIANCE April 1, 2018 – March 31, 2019
GES 4 **Simple Service Connection** This refers to the time it takes to provide a simple service connection (connection point within 30 metres) after signing the contract for connection and the presentation of a valid certificate of inspection from the Government Electrical Engineering Department (GEED) by the customer.	Within 12 working days of receipt of request.	96.09
GES 5 **Complex Connection – Cost Estimate** This refers to the time it takes to provide cost estimate for complex connection requiring a service visit.	Within 30 working days of receipt of request.	100.00
GES 6 **Connect or Transfer of Service** This refers to the time it takes to connect or transfer service from one location to another location which has an existing installation.	Within 12 working hours of receipt of request.	96.77
GES 7 **Reconnection** This refers to the time for reconnection of service on settling the bill after disconnection at the meter.	Within 6 working hours of receipt of payment.	98.95
GES 8 **Response to Billing Complaints** This refers to the timeframe in which BL&P responds to customer billing complaints.	a) Provide an assessment and resolution within 10 working days of receipt of complaint if service visit is required.	99.36
	b) For all other matters the company is to respond within 3 working days of receipt of complaint.	100.00
GES 9 **Timely Payment of Compensation** This refers to the time in which the BL&P shall apply compensation to a customer's account on acceptance of a claim.	a) All credits to be applied to the customers' accounts within 2 months of occurrence of a breach where automatic compensation is applicable and within 2 months of acceptance of a Customer Initiated Claim, where applicable.	96.24

GES 1 – Fault Repair - Customer's Service

Under this Standard, service was restored to 91.33% of individual customers impacted by a fault on their electricity service within the target of eight (8) hours. Overall, fifteen (15) breaches occurred during the review period.

GES 2 – Fault Repair - Distribution System

For the period under review, a 98.76% compliance level was achieved for restoring service to multiple customers impacted by a fault on the distribution system, within the eight (8) hour target time. The number of breaches during this period was seven (7).

GES 3 – Voltage Complaint

With regard to Visit to Site of Complaint (GES 3 (a)), which requires that sites impacted by voltage issues be visited within the twenty-four (24) working hours, the BL&P achieved this target 98.14% of the time; breaches occurred in thirty-two (32) instances.

Similarly, for the category Assessment of Voltage Complaint (GES 3(b)), the BL&P submitted that, of the total complaints received, 99.36% were evaluated within three (3) working days of receipt; this resulted in eleven (11) breach occurrences being recorded for the period.

In terms of Resolution of Voltage Complaint (GES 3 (c)), the BL&P reported that 92.86% of these were reconciled within the target time of thirty (30) working days of receipt; only two (2) breaches occurred under this category.

GES 4 – Simple Service Connection

During the period under review, six hundred and forty (640) customer service connection requests were received by the BL&P; 96.06% of these were connected to the distribution system within the target of twelve (12) working days of receipt of request. By the end of the review period, twenty-five (25) breaches had been recorded.

GES 5 – Complex Connection – Cost Estimate

The BL&P attained perfect compliance (100%) for this Standard which measures the time the BL&P takes to provide cost information against the benchmark of thirty (30) working days.

GES 6 – Connect or Transfer of Service

The BL&P breached the target time of twelve (12) working hours seventy-nine (79) times under this Standard, in fulfilment of two thousand, four hundred and forty-four (2,444) customer connect or transfer service requests. As a consequence, the average compliance returned for the period was 96.77%. While the number of breaches recorded were the second highest amongst the Standards, the compliance statistics suggest that the BL&P's performance was generally consistent. The BL&P commented that competing resource allocations at the time contributed to the rise in these breach statistics.

GES 7 - Reconnection

The BL&P indicated that ninety-seven (97) of the nine thousand, two hundred and thirty-one (9,231) customer reconnection requests received were not completed within six (6) working hours target. Breaches were highest under this Standard and more than 71% of the breaches occurred during the first quarter of the review period. As a result, the average compliance level returned for the period in review was 98.95%.

GES 8 - Response to Billing Complaints

The BL&P attained 99.36% compliance for the category Assessment and Resolution (GES 8 (a)) where customers' complaints must be assessed and resolved within ten (10) working days of receipt of complaint if a site visit is required. The statistics for this Standard over the period suggest that compliance was consistent and reasonable. For the category Response to all other matters (GES 8 (b)), which requires complaints to be resolved within three (3) working days, where a site visit is not required, the BL&P achieved perfect (100%) compliance.

GES 9 – Timely Payment of Claims (New)

This Standard measures the time within which the BL&P must credit customers' accounts, i.e. within two (2) months of receipt where claims are automatically generated and customer initiated. The BL&P registered a compliance level of 96.24% and a total of twelve (12) breaches for the period. The statistics submitted for this new Standard indicates that reasonable level of compliance was maintained over the period.

Overall, the aggregate number of breaches recorded for all Guaranteed Standards for the period was two hundred and eighty-three (283). The highest number of breaches occurred under GES 7 (34.28%), followed by GES 6 (27.92%), GES 3 (a) (11.31%) and GES 4 (8.83%). The aforementioned statistics for the Guaranteed Standards indicate that the BL&P's compliance was satisfactory, as ten (10) of the twelve (12) Standards registered a performance level above 95%.

Customer Claims Summary

A summary of the breaches and the requisite compensation incurred under the Guaranteed Standards of Service is presented in Table 2 below.

Table 2: Customer Claims Summary April 1, 2018 – March 31, 2019

Category	Mode of Compensation	
	Automatic	Manual
Number of customers eligible for compensation	321	10
Number of customer claims received	321	3
Number of customer claims paid	304	3
Percentage of eligible customers claims paid	94.70%	30%

The claims information referenced above suggests that these were processed with a high degree of efficiency. At the end of the previous review period (March 31, 2018), the number of claims outstanding was forty-eight (48).

For the period in review, a total of two hundred and eighty-three (283) claims were eligible for compensation; considering the aforementioned aggregate number of unpaid claims registered by the end of March 2018, the number of eligible claims totalled three hundred and thirty-one (331). The statistics in Table 2 also indicate that three hundred and twenty-one (321) claims were automatically generated, compared to ten (10) which required the customer to initiate them.

However, 97.89% of the total three hundred and twenty-four (324) claims were received over the period in review, while compensation was paid to three hundred and seven (307) of the claims received. This value 94.75% of the total claims received and 92.75% of the total eligible claims.

An observation, however, is that the aggregate number of customer initiated claims which were eligible for compensation, were not submitted to the BL&P.

By the end of March 31, 2019, a total of seventeen (17) automatically generated claims were outstanding. This small number of claims represents 5.25% of the total claims received and is indicative of the extent to which processed claims were managed.

SECTION 2 – OVERALL STANDARDS OF SERVICE

Overall Standards of Service assess BL&P's countrywide performance in relation to its delivery of service at the system level. Unlike Guaranteed Standards, if the BL&P breaches any of these seven (7) Standards, compensation to individual customers is not required. However, where a breach of the Overall Standards persists, the Commission may, at its discretion, invoke Section 43 of the FTCA and Sections 31 and 38 of the URA, which refer to the imposition of fines. The BL&P's performance under the Overall Standard of Service for the review period was reasonable, given the compliance level (97% or higher) returned by the majority of the Standards.

Table 3 below provides a summary of the BL&P's performance under the Overall Standards of Service.

Table 3: Overall Standards of Service

OVERALL STANDARD	TARGET	AVERAGE (%) COMPLIANCE
		April 1, 2018 – March 31, 2019
OES 1 **Meter Reading** Frequency of meter reading.	a) 100% of Domestic/General Service customers' meters to be read every 2 months.	97.66
	b) 100% of Secondary Voltage Power and Large Power customers' meters to be read monthly.	97.10
OES 2 **Voltage Complaints** Response to complaint of high/low voltage.	100% of complaints to be responded to within 24 working hours of receipt.	98.61
OES 3 **Outage Notice** Prior notice of outages.	In 100% of instances of planned outages, all potentially affected customers are to be notified 48 hours before the outage.	100.00
OES 4 **Response to Complaints and Claims** Response to written and oral complaints and claims related to Standards of Service.	100% of customers' complaints and claims to be acknowledged within 5 working days of receipt.	100.00

OVERALL STANDARD	TARGET	AVERAGE (%) COMPLIANCE
		April 1, 2018 – March 31, 2019
OES 5 **Call Centre Answering** Billing and Trouble Centre calls answered by a customer service representative.	85% of calls to be answered within 1 minute.	83.37
OES 6 **Billing Period** The period between two meter readings whether interim, estimated or actual.	At least 95% of customers in each billing period shall be invoiced for no more than 33 days.	97.60
OES 7 **Response to Damage Claims** Acknowledgement and settlement of claims.	a) Acknowledge 95% of damage claims immediately on receipt of oral claims and for written claims, within 5 working days of receipt.	100.00
	b) Settle 95% of damage claims within 2 months of receipt of written or oral claim.	100.00

OES 1 - Meter Reading

The BL&P's performance in the categories Domestic/General Service Customers (OES 1(a)) and Secondary Voltage Power and Large Power Customers (OES 1 (b)) which requires all customer meters to be read monthly, for the former, and monthly, for the latter, registered compliance levels of 97.66% and 97.10%, respectively. These levels resulted from improvements in compliance throughout the review period. Despite attaining the satisfactory compliance levels above, historically the benchmarks for this Standard have never been achieved. The BL&P has indicated that 80,000 new meters have been rolled out under its Advanced Metering Infrastructure (AMI) project to date. The BL&P anticipates this project will now conclude by mid-2020. The shift from the previous project completion date of December 2019 arose from a shortage of AMI meters from suppliers.

The Commission expects that improvement in this Standard will be realised on full deployment and will continue to monitor the BL&P's compliance with this Standard as the AMI Project progresses.

OES 2 – Voltage Complaint

This Standard stipulates that the BL&P must respond to all customer complaints concerning high/low voltage within twenty-four (24) working hours of receipt. BL&P achieved an average compliance level of 98.61% and, generally, performance statistics over the review period conveyed improved compliance levels.

OES 3 – Outage Notice

During the review period, the BL&P maintained perfect compliance (100%) under this Standard, which requires that forty-eight (48) hours' notification be given to all customers who may be affected by planned outages.

OES 4 – Response to Claims

During the review period under review, BL&P registered perfect compliance (100%) under this Standard which requires that all customer complaints and claims be acknowledged within five (5) working days of receipt.

OES 5 – Call Centre Answering

With regard to Call Centre Answering (OES 5), compliance with this Standard remains a challenge; the compliance level achieved for the prompt answering of billing and trouble queries by the BL&P's customer representative within one (1) minute was 83.37%. Historically, the BL&P has not met the 85% target for this Standard overall. However, during the review period, the compliance level peaked at 88.83% in the second quarter and remained above 83% during the first and fourth quarters. These statistics are evident of improvements returned during the review period. The BL&P indicated that challenges with available human resources contributed to its inability to meet the benchmark.

OES 6 – Billing Period

Under this Standards, at least 95% of customers in each billing period shall be invoiced for no more than thirty-three (33) days. The BL&P exceeded this Standard's benchmark and attained 97.60% compliance.

OES 7 – Response to Damage Claims (New)

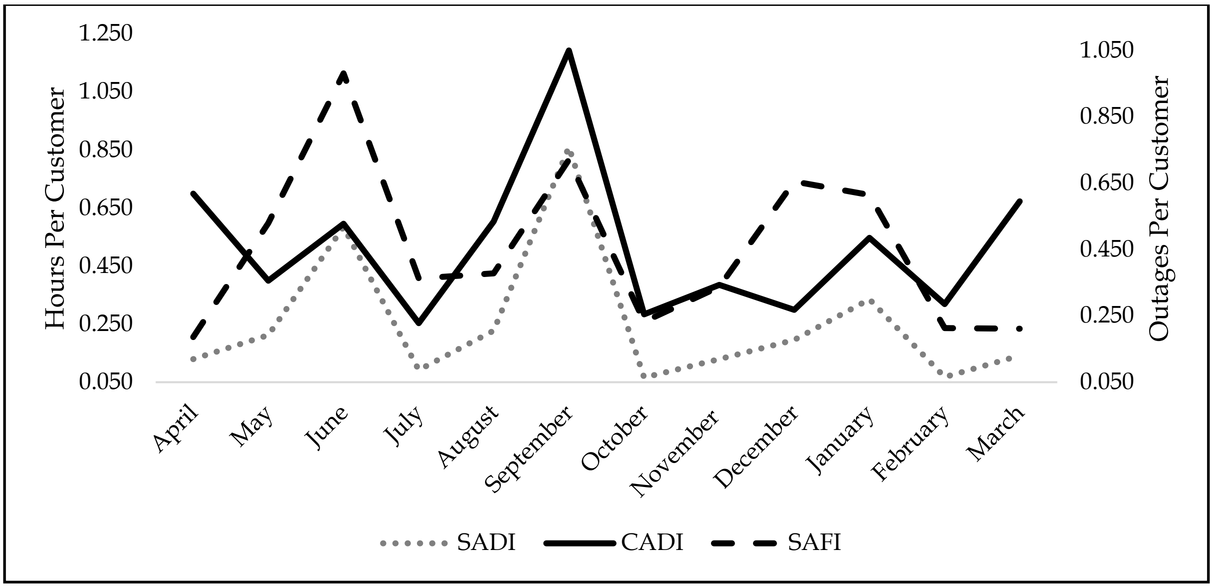
During the period under review, the BL&P achieved perfect (100%) for both Acknowledgement (OES 7 (a)) and Settlement (OES 7 (b)) of damage claims.

SECTION 3 – SYSTEM RELIABILITY PERFORMANCE

Reliability of power supply will remain an essential measure of the quality of electricity service delivered to customers. It is anticipated that sustained levels of high grid reliability will be challenged further, where higher shares of variable renewable energy (RE) generation are to be utilised. This inevitable circumstance and the evolution of a more digitised electrical grid can impact grid availability and interoperability of distributed RE assets. These issues potentially make the integrated electrical network susceptible to cybersecurity threats and grid resilience concerns.

The BL&P's reliability performance for April 2018 to March 2019 is based on the benchmarks for the metrics: System Average Interruption Index (SAIDI); System Average Interruption Frequency Index (SAIFI); Customer Average Interruption Duration Index (CAIDI) and the Average System Availability Index (ASAI). These metrics provide a measure of robustness of the integrated electrical supply. Statistics of the BL&P's reliability system performance is presented in the following graph.

Figure 1: The BL&P's Reliability Performance for April 1, 2018 – March 31, 2019



The SAIDI performance for the year under review (Figure 1) was 3.05 hours per customer on average; this was 17.26% better than the standard of 3.68[2] hours per customer.

The SAIFI trend (Figure 1) shows the average number of power outages experienced by each customer; the cumulative interruption events for the review period returned was 5.42 on average. Outage records suggest that customers experienced at least one (1) service interruption over a three (3) month period. The frequency of outages per average customer, exceeded the target of 5.84 interruptions per year by 7.16%.

The statistics depicted for CAIDI (Figure 1) suggests that on average, a customer's service was restored within 0.56 hours; customers therefore benefitted from this improvement, which was approximately four (4) minutes better than the stipulated target of 0.63 hours.

In terms of service availability (ASIA), this was sustained at a high level throughout the review period; the provision of electrical power to customers exceeded the 99.958% benchmark, to maintain available power at 99.965% of the time.

Overall, the BL&P's performance met and exceeded the targets for the aforementioned metrics.

[2]Annual Reliability Targets: SAIDI – 3.68 hours per customer, SAIFI – 5.84 Outages per customer, CAIDI – 0.63 Hours per customer and ASAI – 99.958% System Availability.

SUMMARY

This report assessed BL&P's performance as it relates to the Standards of Service set by the Commission. With respect to both the Guaranteed and Overall Standards of Service for the period April 1, 2018 to March 31, 2019, Staff concludes that, based on data submitted by the BL&P, satisfactory compliance was attained.

Notably, compliance with the Guaranteed Standards GES 1 Fault Repair - Customer's Service and GES 3 (c) Voltage Complaint was below 95%. These performances, as well as those in the other categories in the Guaranteed Standards which fell short of the stipulated targets, signal the need for improved performance. Where claims arose, the Commission is satisfied that these were reasonably managed over the review period based on the low ratio of outstanding claims compared to the number of claims received.

In terms of the Overall Standards of Service, the BL&P's performance in OES 1 Meter Reading was moderate despite not meeting the benchmarks. Similarly, performance under OES 2 Response to Voltage Complaint, also warrants improvement. The Commission anticipates that improved performance statistics will be realised with the culmination of the BL&P's AMI project by the end of the first six (6) months of 2020. Additionally, while improvement was observed in OES 5 Call Centre Answering, greater compliance is required given that the BL&P has not historically met this benchmark on an annual basis. The BL&P expressed that increased customer calls during system disturbances, challenge existing resources to meet the stipulated target.

The establishment of the new Standard, OES 7 Response to Damage Claims, appears to be functioning adequately.

Reliability of the BL&P's electricity service exceeded stipulated thresholds for all metrics. Outage durations and their occurrences trended downwards while restoration times were generally low for most of the review period. Owing to declining outage duration times, grid availability remained consistently high overall.

The Commission expects incremental improvements in the BL&P's performance under the Standards of Service framework will be contingent on the AMI features to be activated in the meters.

The Commission will continue to monitor and assess the BL&P's performance and make the requisite recommendations.

M-5

BARBADOS LIGHT & POWER COMPANY LIMITED

STANDARDS OF SERVICE RESULTS APRIL 2018 – MARCH 2021

1. As part of the Application to the Fair Trading Commission ("the Commission") for a review of electricity rates, The Barbados Light & Power Company Limited ("the Company") submits herewith Schedule M-5 associated with its Memorandum for Standards of Service.

2. This report reviews the Company's compliance with the Standards of Service Decision 2018-2020 issued by the Commission on September 29, 2017. The current Standards of Service took effect from January 1, 2018, and the period under review spans the years April 2018 – March 2019, April 2019 – March 2020 and April 2020 – March 2021. The first section reviews compliance under the Guaranteed Standards of Service, section two assesses performance related to the Overall Standards of Service and section three reviews the System Reliability Indices.

3. The results demonstrate that the Company attained satisfactory compliance rates for most Standards of Service. While there are cases where compliance dropped, the poor performance was either a result of the impact of COVID-19 lockdown measures in 2020 and 2021 or the highly unusual island wide outages which occurred on November 18 and 19, 2019. Hence, failure to meet compliance targets is a reflection of the challenges presented by these isolated events and not an indication of the Company's willingness and capacity to meet stipulated Standards of Service.

Guaranteed Standards of Service

4. The Company performed reasonably well in most of the Guaranteed Standards of Service over the review period (see Table 1). Compliance scores of 96% or greater were reported for five (5) of the nine (9) Standards of Service for all three (3) years. These five (5) Standards of Service are:

- GES5 – Complex Connection Cost Estimate
- GES6 – Connection or Transfer of Service
- GES7 – Reconnection of Service
- GES8 – Response to Billing Complaints and

- GES9 – Timely Payment of Compensation.

5. Conversely, less than satisfactory compliance was reported for some of the Standards of Service in this category. The island-wide power outages, which occurred on November 18 and 19, 2019, resulted in GES2 – Fault Repair of Distribution System compliance falling from 98.76% in April 2018 – March 2019 to 77.05% in April 2019 to March 2020; however, the Company met 96.4% compliance by the end of the April 2020 - March 2021 period. Compliance for GES1 - Fault Repair of Customers' Service and GES4 - Simple Service Connection fell by 2.1 and 9.9 percentage points respectively during April 2020 – March 2021. This outturn reflects the negative impact of the 24-hour emergency curfew in 2020 and 2021 on the Company's ability to meet these standards.

Table 1: Guaranteed Standards of Service

GUARANTEED STANDARDS	TARGET	% Compliance		
		Apr, 2018 - Mar, 2019	Apr, 2019 - Mar, 2020	Apr, 2020 - Mar, 2021
GES1: Fault Repair Customer's Service This refers to the time it takes to restore supply after fault on customer's service (single customer).	Within 8 hours	91.33	93.28	91.18*
GES2: Fault Repair Distribution System Restore supply after fault on distribution system (multiple customers).	Within 8 hours	98.76	77.05	96.37
GES3: Voltage Complaint This refers to the investigation of voltage complaints.	a) Visit within 24 working hours of receipt of complaint	98.14	95.09	96.69
	b) Provide assessment within 5 working days of receipt of complaint	99.36	98.02	99.28
	c) Correct within 30 working days of receipt of complaint	92.86	95.65	90.0

GUARANTEED STANDARDS	TARGET	% Compliance		
		Apr, 2018 - Mar, 2019	Apr, 2019 - Mar, 2020	Apr, 2020 - Mar, 2021
GES4: Simple Service Connection This refers to the time it takes to provide a simple service connection (connection point within 30 meters) after signing the contract for connection and the presentation of a valid certificate of inspection from the Government Electrical Engineering Department (GEED) by the customer.	Within 12 working days of receipt of request.	96.09	92.00	82.11*
GES5: Complex Connection – Cost Estimate This refers to the time it takes to provide cost estimate for complex connection requiring a service visit.	Within 30 working days of receipt of request	100.00	100.00	100.00
GES6: Connect or Transfer of Service This refers to the time it takes to connect or transfer service from one location to another location which has an existing installation	Within 12 working hours of receipt of request	96.77	99.02	99.61
GES7: Reconnection This refers to the time for reconnection of service on settling the bill after disconnection at the meter.	Within 6 working hours of receipt of payment	98.95	99.65	100.00
GES 8: Response to Billing Complaints This refers to the timeframe in which BL&P responds to customer billing complaints	a) Where visit is required, assessment & resolution in ten (10) working days	99.36	N/A[1]	100.00
	b) For all other matters the company is to respond within 3 working days of receipt of complaint	100.00	100.00	100.00
GES 9: Timely Payment of Compensation This refers to the time in which the BL&P shall apply compensation to a customer's account on acceptance of a claim.	Within 2 months of occurrence/claim	96.24	100.00	99.48

Notes:

[1]N/A: Not applicable represents cases of no reported activity.

** The COVID-19 lockdown measures limited the Company's response time and its ability to meet these Service Standards*

Overall Standards of Service

6. The Company performed well in four (4) of the seven (7) Standards of Service under this category (see Table 2). Of these four (4) Standards, 100% compliance was achieved for OES3 – Planned Outage Notice and OES4 – Response to Claims for all three years of the review period. OES2 – Response to Voltage Complaints and OES6 – Billing Period, averaged a compliance score greater than 97% in each year of the review period.

7. As mentioned in the Guaranteed Standards section, the performance in some of the Overall Standards was also impacted by the national curfews in 2020 and 2021, and the island wide outages that occurred on November 18 and 19, 2019. The Company was able to achieve above 95% compliance in OES1 – Meter Reading for secondary voltage and large power customers but, due to COVID-19 curfew restrictions, compliance for domestic and general service customers fell from 97.6% to 94.7% during April 2020 - March 2021. Similarly, there was a dip in compliance for OES5 – Call Centre Answering in April 2020 – March 2021. The sudden shift to work-from-home arrangements since the national lockdown in 2020 presented initial challenges to the operation of the Call-Centre.

Table 2: Overall Standards of Service

OVERALL STANDARD	TARGET	% Compliance		
		Apr, 2018 - Mar, 2019	Apr, 2019 - Mar, 2020	Apr, 2020 -Mar, 2021
OES 1: Meter Reading Frequency of meter reading	(a) 100% of Domestic/General Service customer meters read every 2 months	97.66	97.64	94.73*
	(b) 100% of Secondary Voltage Power and Large Power customer meters to be read monthly.	97.10	97.36	97.82
OES 2: Voltage Complaints Response to Complaints of high/low voltage	100% of complaints to be responded to within 24 working hours of receipt	98.61	97.65	99.28

<table>
<tr><th rowspan="2">OVERALL STANDARD</th><th rowspan="2">TARGET</th><th colspan="3">% Compliance</th></tr>
<tr><th>Apr, 2018 - Mar, 2019</th><th>Apr, 2019 - Mar, 2020</th><th>Apr, 2020 -Mar, 2021</th></tr>
<tr><td>OES 3: Outage Notice

Prior notice of outages.</td><td>In 100% of instances of planned outages, all potentially affected customers are to be notified 48 hours before the outage</td><td>100.00</td><td>100.00</td><td>100.00</td></tr>
<tr><td>OES 4: Response to Claims

Response to Written Claims related to Standards of Service.</td><td>100% of customers' complaints and claims to be acknowledged within 5 working days of receipt</td><td>100.00</td><td>100.00</td><td>100.00</td></tr>
<tr><td>OES 5: Call Centre Answering
Billing and Trouble Centre calls answered by a customer service representative.</td><td>85% of calls to be answered in one minute.</td><td>83.37</td><td>83.75</td><td>63.52*</td></tr>
<tr><td>OES 6: Billing Period
The period between two meter readings whether interim, estimated or actual.</td><td>At least 95% of customers in each billing period shall be invoiced for no more than 33 days</td><td>97.60</td><td>97.70</td><td>99.00</td></tr>
<tr><td rowspan="2">OES 7: Response to Damage Claims

Acknowledgement and settlement of claims.</td><td>a) Acknowledge 95% of damage claims immediately on receipt of oral claims and for written claims, within 5 working days of receipt.</td><td>100.00</td><td>100.00</td><td>100.00</td></tr>
<tr><td>b) Settle 95% of damage claims within 2 months of receipt of written or oral claim.</td><td>100.00</td><td>78.18</td><td>94.49</td></tr>
</table>

Notes:
** The COVID-19 lockdown measures limited the Company's response time and its ability to meet these Service Standards*

System Reliability Indices

8. The Company's reliability of electricity supply over the review period is based on the benchmarks for the metrics: System Average Interruption Duration Index (SAIDI); System Average Interruption Frequency Index (SAIFI); Customer Average Interruption Duration Index (CAIDI) and the Average System Availability Index (ASAI) (see Table 3). The SAIDI measures the average duration of interruption per customer and the SAIFI indicates how often a

customer experiences service interruptions on average. The CAIDI metric measures the average time the Company takes to restore service after disruption per customer and the ASAI indicates the percentage of time electricity supply is available.

The metrics for the SAIDI, SAIFI and CAIDI indicate the Company achieved good system reliability over the review period. The SAIDI and the SAIFI remained below the benchmarks of 3.68 hours of system interruptions per customer and 5.84 interruptions per customer for each year, respectively. The ASAI index shows that electricity supply was available more than the stipulated benchmark of 99.958% of the time over the entire review period. Conversely, the CAIDI suggests the Company took 0.728 hours to restore affected customers' service, representing 15% over the benchmark time (0.63 hours per affected customer). The increase in the CAIDI was a direct result of the island wide outages in November, 2019. The CAIDI has since fallen back in line with its benchmark at the end of April 2020 – March 2021.

Table 3: System Reliability Indices

System Reliability Metrics	**Target**	**Apr, 2018 - Mar, 2019**	**Apr, 2019 - Mar, 2020**	**Apr,2020 - Mar, 2021**
SAIDI: System Average Interruption Duration Index (Hours per Customer)	***3.68***	3.050	3.367	3.086
SAIFI: System Average Interruption Frequency Index (Outages per Customer)	***5.84***	5.420	4.330	5.179
CAIDI: Customer Average Interruption Duration Index (Hours per Affected Customer)	***0.63***	0.560	0.728	0.596
ASAI: Average System Availability Index (Percent System Availability)	***99.958***	99.965	99.997	99.965

N

THE BARBADOS LIGHT & POWER COMPANY LIMITED
N STATEMENT OF EARNINGS COVERAGE TESTS
December 31, 2020

	As at 31-Dec-20	Adjustment	Sch.	Test Year Earnings coverage 31-Dec-20
Income before interest charges	34,266,539	(7,433,703)	D-1	26,832,836
Depreciation	52,300,244	5,329,128	D-5	57,629,372
Deferred income taxes	161,757	(629,252)	D-3	(467,495)
	$ 86,728,541	(2,733,827)		**$ 83,994,713**
Aggregate sum payable in the following year:				
Loan repayments - current portion	12,148,058			12,148,058
Interest on long term loans	6,208,845			6,208,845
Interest on other customer deposits	2,433,956			2,433,956
	$ 20,790,859			**$ 20,790,859**
Earnings coverage ratio	**4.17**			**4.04**

O

THE BARBADOS LIGHT & POWER COMPANY LIMITED
O STATEMENT OF DIVIDENDS
At December 31, 2020

	2020
Common shares at January 1	60,000,000
Repurchased during the year	
Issued during the year	
Balance at December 31	60,000,000

Dividends Paid (Common Shares)	**$**	**-**

RB

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003 as amended by the Utilities Regulation (Procedural) (Amendment) Rules 2009;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF ROGER BLACKMAN

I ROGER BLACKMAN, of No. 12 Stepney, St. George, in this island, being duly sworn, **MAKE OATH** and say as follows:

1. I am the Managing Director of The Barbados Light & Power Company Limited (the “BLPC”, “the Company” or “the Applicant”), a vertically integrated utility company incorporated on May 6, 1955 and for which a certificate of continuance was granted on December 30, 1986 under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situate at Garrison Hill in the parish of St. Michael. I am duly authorized to depose to the following facts and matters in this Affidavit on behalf of BLPC and the statement of facts herein are within my personal knowledge unless otherwise stated.

EDUCATION AND PRIOR PROFESSIONAL EXPERIENCE

2. I am a mechanical engineer by profession. I hold a Bachelor of Science degree in Engineering which I obtained from the University of the West Indies, St. Augustine Campus in Trinidad & Tobago, in 1991 and a Master in Business Administration from Durham University in England which I obtained in 2008.

3. I joined BLPC in 1991 as a Trainee Generation Engineer and was appointed to the position of Generation Engineer in 1996 on completion of my engineering training and professional registration. In 2002 I was appointed as Senior Planning Engineer. In 2010 I was appointed as Business Development Manager with the Applicant and later in 2014 was appointed as Senior Business Development Director at Emera Inc.

4. In July 2016, I was appointed the Managing Director of BLPC and in my capacity as Managing Director, I am responsible to the Board of Directors of BLPC for the overall management of BLPC. I set the overall strategic direction of BLPC and work with the management and senior staff members to achieve the desired objectives. I also establish the policies for BLPC and I am responsible for compliance by BLPC with all the regulations and laws which are applicable to BLPC.

5. The purpose of my Affidavit is to introduce and provide an overview of the Application for a review of electricity rates ("the Application") which has been made by the Applicant and the General Memorandum, the Memorandum on Test Year, Memorandum on Standards of Service and the supporting Schedules accompanying the Memoranda, which are found at Schedules A, B and M of the application for a review of electricity rates filed by the Applicant ("the Application"). In the preparation of the Memoranda I had access to the Applicant's financial and technical data. I also had access to studies prepared by the Applicant's consultants and other information supplied by them and the management of the Applicant. To the best of my knowledge, information and belief, the facts and matters set out in this Affidavit and each Memorandum are true. They form part of my written evidence in these proceedings.

THE APPLICATION

6. By Decision dated January 25th, 2010 ("Decision") the Fair Trading Commission ("Commission") pursuant to its powers under section 10 of the Utilities Regulation Act, set rates for the BLPC. During the over ten years since the Commission's Decision the BLPC has worked diligently to continue its supply of safe reliable and high quality electricity while the Company pursued rigorous efforts to control costs to facilitate compliance with the rate structure set by the Commission.

7. Additionally, over the last ten years, BLPC has made necessary investments in its infrastructure and processes, undertaken grid modernisation and absorbed inflation. However, the BLPC is no longer able to defer an application for rate adjustments which is critically necessary as the rates established by the Commission's Decision are no longer sufficient to cover the Applicant's costs of providing service which is safe, adequate, efficient and reasonable and do not adequately support the transitioning to a cleaner energy future for the country which is in concert with the Barbados National Energy Policy (BNEP) 2019 - 2030

8. The Application is supported by the following various memoranda, studies and/or affidavits prepared by members of the Company's management team and experts:

    a. Roger Blackman, Managing Director;
    b. Ricaido Jennings, Director, Finance;
    c. Adrian Carter, Manager of Regulatory Affairs;
    d. Rohan Seale, Director Asset Management;
    e. Johann Greaves, Director Operations;
    f. Dr. Bente Villadsen, Principal of the Brattle Group;
    g. Dr. Phil Hanser, Principal of the Brattle Group;

GENERAL MEMORANDUM

9. The Applicant has achieved universal service and contributed to Barbados' reputation of proper infrastructure and reliability. However, there is a need to ensure that there is a continuation of a secure and reliable supply of electricity. Such continuity can only be achieved through expansion and continued modernization, adequate financing and adapting to the ever changing market environment.

10. In the General Memorandum I present an overview of the Application and:
    a. outline the reasons for the Application;
    b. analyse electricity prices vis a vis the consumer price index and electricity rates in the region;
    c. discuss the BLPC's operating and financial performance as well as the present and proposed rates;
    d. address the impact on the BLPC's business of the new market and license structure as created by the Government of Barbados' energy market reforms;
    e. discuss the ongoing transition to clean energy including the present and ongoing investments which support this objective while ensuring grid reliability; and
    f. discuss customer experience, operational excellence and the BLPC's continued efforts to maintain high levels of service reliability, system efficiency and standards of service.

11. The Applicant is only proposing a partial rebalancing of the rates. The Applicant is cognizant of the need to produce a basic supply of electricity at reasonable rates and especially to low-income customers. In the case of the domestic tariff, the proposed rates are designed to cushion the impact of the overall revenue increase to customers in the lower income bracket.

MEMORANDUM ON TEST YEAR

12. The Applicant with the permission of the Commission has selected 2020 as the Test Year for the measurement of total costs incurred in conducting operations over a twelve month period with adjustments for known and measurable changes.

13. As part of the Memorandum on the Test Year at Schedule B, the Applicant addresses the impact of the Covid-19 pandemic.

MEMORANDUM ON STANDARDS OF SERVICE

14. As part of the Application, the Applicant submits its proposal for Standards of Service as outlined in the Memorandum on Standards of Service at Schedule M.

15. The Applicant continues to comply with and follow the Commission's Decision for the Barbados Light & Power Company Limited's Standards of Service 2018-2020 Document No: FTCUR/DECSOS/BL&P-2017-02 issued on September 29, 2017 and which was extended until June 30th 2022, until such time as the Commission issues revised Standards of Service.

16. The results for the Standards of Service as prepared by the Applicant for the reporting period April 2018 to December 2020 is found at Schedule M-5. The Applicant conducts regular surveys to better understand its customers' needs and continues to seek ways in which it can improve its operations and quality of service.

CONCLUSION

17. The Applicant provides a safe, reliable and high quality service in the supply of electricity to its customers. However, in order to continue to provide this type of service, it requires an adjustment in electricity rates. In the circumstances, the Applicant respectfully requests that the Commission approves the proposed new tariffs as set out in the Memorandum of Proposed Tariffs, Schedule K of the Application.

SWORN TO by **ROGER BLACKMAN**) ………………………………………………...
this 30th day of September 2021)

Before me:

…………………………………………………

ATTORNEY-AT-LAW

RJ

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003 as amended by the Utilities Regulation (Procedural) (Amendment) Rules 2009;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF RICAIDO JENNINGS

I RICAIDO JENNINGS, of Prior Park in the parish of St. James in this island, being duly sworn hereby **MAKE OATH** and say as follows:

1. I am the Director, Finance at The Barbados Light & Power Company Limited ("the Applicant" or the "BLPC" or the "Company"), a company registered under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situated at Garrison Hill in the parish of St. Michael. I am a Certified Accountant and a member of the Institute of Chartered Accountants of Barbados.

2. I am duly authorized to depose to the following facts and matters in this Affidavit and the statement of facts herein are within my personal knowledge unless otherwise stated.

PROFESSIONAL EXPERIENCE AND RESPONSIBILITIES

3. I first joined the Applicant in 2009 as Financial Controller before leaving in 2013 and rejoining in late 2014 as Manager of Finance. In 2016 I was appointed Director, Finance. In my capacity as the Director, Finance of the Applicant I have primary and direct responsibility for:

    (i) financial reporting which concerns the preparation of the budgets, forecasts, monthly and annual financial reporting including annual external audits;

    (ii) Treasury and Payroll which concerns the management of (i) the cash flow of the Applicant, (ii) the maintenance of the relationship with our lenders and compliance with our financial covenants; and (iii) the payments which are made to our suppliers and employees;

    (iii) Supply Chain which involves responsibility for procurement, logistics and warehousing of materials for the Applicant; and

    (iv) Customer Care which concerns the preparation of customer bills, receipt of customer payments and responding to customer queries.

4. I also ensure that there are appropriate internal control procedures and adherence to International Financial Reporting Standards.

THE APPLICATION

5. The Applicant has applied for a review of its existing rates and is seeking regulatory approval for adjustment to the said rates by the Fair Trading Commission ("Commission") pursuant to the Commission's powers under section 10 of the Utilities Regulation Act. In support of the Applicant's application, I have prepared the Memorandum on Rate Base, the Memorandum on Income Statement, the Memorandum on Rate of Return, the Memorandum on Revenue Requirement, the Memorandum on Five Year Financial Forecasts Memorandum, the Statement of Earnings Coverage Test and Statement of Dividends which are found at Schedules C, D, F, G, L, N and O respectively of the Application. The said Memoranda and Statements were prepared after my review and analysis of the financial and technical data of the Applicant and upon receiving advice from the Applicant's consultants. I confirm that the facts stated in each Memorandum and accompanying statement are accurate to the best of my knowledge, information and belief. They form part of my written evidence in these proceedings.

6. The Applicant bases its accounts on the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts.

7. The Applicant's accounts are audited annually and the current Auditors are Ernst & Young. The last audited Financial Statements were prepared by Ernst & Young for the year ended December 31, 2020 are provided in **Appendix III**.

8. The purpose of my evidence is to provide an overview of the matters which I address in each Memorandum and the related Schedules referenced at paragraph 5.

MEMORANDUM ON RATE BASE

9. Rate Base is the value of utility plant financed by the Applicant and investors that is prudently incurred and "used and useful" in public service. The Rate Base is valued on the original or historic cost basis.

10. The Applicant sought and obtained the Commission's permission to use the year ended December 31, 2020 as its Test Year with adjustments for known and measurable changes. As such, the calculation of the Rate Base, as shown in Schedule C-1 is computed for the Test Year[1] based on the audited financial statements for the year ended December 31, 2020 with adjustments for known and measurable changes.

11. The Applicant has only included in the Rate Base plant which it has determined to be "used and useful". The accumulated provision for depreciation for the 2020 Test Year is deducted from the historic cost to determine net total plant. There are also deductions from rate base for funding sources other than investors such as customer contributions for construction work not yet started and net accumulated deferred income taxes. The Company's proposed rate base of **$825,891,134** as shown in Schedule C-1 of the Memorandum on Rate Base provides for the inclusion of cash working capital, materials, supplies, prepayments and an amount of construction work in progress (CWIP).

[1] The test year is discussed in the document 'Memorandum on Test Year'

MEMORANDUM ON INCOME STATEMENT

12. The Memorandum on Income Statement explains the Income Statement at Schedule D-1 of the Application. The Income Statement provided in Schedule D-1 records all electricity revenue (basic and fuel adjustment clause revenue) and miscellaneous income and from this the expenses (fuel expenses, operating and maintenance expenses, depreciation, finance costs and taxation) incurred in those revenues are deducted to arrive at the net income. The Income Statement is based on the audited financial statements for the year ended December 31, 2020 with adjustments for known and measurable changes.

13. The total revenues for the year ended December 31, 2020 is $395,456,966 and consist of the following: basic revenue $186,038,177; fuel revenue $202,978,824; miscellaneous revenue $4,700,692; investment income $326,939; and other income $1,412,333.

14. The Commission by decision dated April 13, 2018 permitted revenue from the 5MW Energy Storage Device (ESD) as calculated in accordance with the Commission's decision[2]. The Company now requests to recover the unrecovered cost of the ESD through base rates. The revenue from the ESD has therefore been removed from miscellaneous revenue and included in the basic revenue requirement in this application as reflected in Schedule D-1. This adjustment is detailed in Schedule D-7.

15. The operating and maintenance expenses for the year ended December 31, 2020 are $363,230,050 and consist of the following: fuel expense $202,978,824; insurance $8,198,082; depreciation $52,300,244; lease amortization $406,353; generation expenses $44,620,745; distribution expenses $10,746,662; and general expenses $43,979,139. Schedule D-2 provides a statement of the Operating & Maintenance expenses by business unit.

<u>Insurance</u>

16. Based on a trend of increasing insurance premiums, the cost of insurance in the 2020 Test Year is expected to be insufficient to cover the cost in the coming years due to general price increases for insurance premiums. The Company therefore requests that

[2] Refer to Decision of the FAIR TRADING COMMISSION Re The Barbados Light & Power Company Limited Application to Recover the Costs of the 5MW Energy Storage Device through the Fuel Clause Adjustment FTCUR/DECESD/BL&P-2018-02

a reasonable amount to cover the cost of insurance premiums be included in determining the revenue requirement.

Depreciation

17. The rates and methodology used in the Income Statement are those included in the Depreciation Application currently being heard by the Commission and have been applied to the 2020 Test Year. The Company is nearing completion of the construction of the CEB which is expected to be used and useful by the end of 2021. The Company therefore requests that the depreciation charge associated with the CEB be included in determining the revenue requirement. Schedule D-5 provides the Statement of Depreciation Expense and the relevant adjustment is listed on Schedule D-7.

18. The Applicant's adjustments to operating income is explained in Schedule D-7.

The Clean Energy Bridge (CEB)

19. Construction of the CEB has required significant investment and expenditure to date. The Company is nearing completion of the construction of the CEB which is expected to be used and useful by the end of 2021, as such the Company requests the annual operating and maintenance expenses associated with the CEB be included in determining the revenue requirement. Further, the Company requests the Taxes other than on income and other financial impacts associated with the CEB be included in determining the revenue requirement.

20. The adjustments to the revenue requirement, taxes and interest associated with the CEB are listed at Schedule D-7.

MEMORANDUM ON RATE OF RETURN

21. The Applicant seeks a rate of return which is fair, reasonable and accords with established standards and principles on good utility regulation relative to rate of return.

22. The Rate of Return on Rate Base realized by the Applicant under existing rates for the Financial Year 2020 using the audited financial statements prepared in accordance with International Financial Reporting Standards (IFRS), before adjustments, was 4.23% and 3.31% after adjustments for known and measureable changes in the Test Year 2020 and is well below the allowed 10% rate of return determined in Commission's Decision.

23. Based on advice from Dr. Bente Villadsen Principal of the Brattle Group ("Brattle") in a study entitled "Cost of Equity and Weighted Average Cost of Capital (WACC) for BLPC" dated September 20, 2021, (hereinafter called "the Study") the Applicant requests permission to earn an overall Rate of Return on Rate Base of 8.79%. This Rate of Return has been analysed by Brattle which recommends the same, as a conservative rate.

24. The existing rate of return on rate base of 3.31% constitutes a significant shortfall for the Company when compared to the rate of return of 8.79% recommended as fair and reasonable in the Study.

25. The Memorandum on Rate of Return also discusses the Applicant's cost of debt, return on equity, dividend payout and capital structure.

MEMORANDUM ON REVENUE REQUIREMENT

26. The Memorandum on Revenue Requirement details the Applicant's revenue requirement. The Applicant's revenue requirement has been developed with the intent to allow it to recover its prudently incurred costs for providing utility services and to provide it with an opportunity to earn an appropriate return on invested capital including a fair and reasonable return on equity.

MEMORANDUM ON FIVE YEAR FINANCIAL FORECASTS

27. The Applicant prepares a budget and five year financial forecast as part of its planning cycle. Recently, the Government of Barbados has indicated its intention to implement a new electricity market structure, the details or operationalization of which has not yet been fully settled. The intended new electricity market structure has increased the Company's difficulty in preparing a five year forecast as it introduces a greater level of uncertainty.

28. Notwithstanding such uncertainty, the financial forecast has been prepared taking into consideration the projected annual demand for electricity, the requirement for new plant and equipment to meet the growth as well as to replace plant due to be retired and assumptions regarding changes and the costs of other inputs, for example labour and

materials, as well as the Company's anticipated role in safely delivering that demand under the developing new electricity market structure and the Barbados National Energy Policy.

29. The Five Year Forecast, based on proposed rates, shows that if the Application is granted even though the Applicant will be given the opportunity to improve its rate of return, it will still fall short of the requested rate of return during the five year period due to capital investment required to maintain the existing plant and new investments required to support the transition to 100% RE sources. It is likely therefore, that the Company will require additional rate relief within the five year period to maintain a reasonable rate or return and remain financially healthy in order to attract investment at reasonable cost to continue to provide the level of service demanded of a modern utility and to fulfill its obligations to lenders, investors, customers and the public.

SWORN TO by the said **RICAIDO JENNINGS**) Ricaido Jennings
……………………………………….

this 30th day of September 2021)

Before me:

……………………………………………

ATTORNEY-AT-LAW

RS

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003 as amended by the Utilities Regulation (Procedural) (Amendment) Rules 2009;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF ROHAN SEALE

I ROHAN SEALE, of 32 Walkers Park East in the parish of St. George in this Island, being duly sworn hereby **MAKE OATH** and say as follows:

1. I Rohan Seale am the Director Asset Management at the BLPC, a Company registered under the Companies Act, Chapter 308 of the Laws of Barbados (the "Companies Act") with its registered office situate at Garrison Hill in the parish of St. Michael. I am duly authorized to depose to the following facts and matters in this Affidavit on behalf of the Applicant and the statement of facts herein is within my personal knowledge unless otherwise stated.

2. I joined the Applicant in 1996 and have been with the Applicant for over 25 years. I joined the Applicant as a trainee engineer in the Distribution and Planning Departments where I remained for a number of years until I was assigned to the role of Senior Distribution Engineer in 2005 and then Distribution Manager in 2008 with responsibility for Transmission and

Distribution operations. In 2013, I was appointed to the role of Customer Services Manager where I was actively involved in the Applicant's commercial operations and establishing relationships with key customers and other stakeholders. During that time, I was involved in modifications to the Renewable Energy Rider (RER) program, the update and review of the Grid Code as well as Standards of Service as it relates to the electric utility's operations. In 2016, I was appointed to the role of Director Asset Management of the Applicant with responsibility for long-term capital planning, life cycle management of assets and the integration of renewables onto the electric grid. I am the holder of a degree in Electrical Engineering from the University of the West Indies and a Master of Science in Electrical Power Systems from the University of Bath.

3. I was the main contributor to the preparation of the Memorandum on Capital Expansion and the supporting Schedules accompanying the Memorandum found at Schedule I of the Application. In the preparation of the Memorandum I had access to the Applicant's financial and technical data, which I reviewed and analysed. I also had access to studies prepared by the Applicant's consultants and other information supplied by them. To the best of my knowledge, information and belief, the facts and matters set out in this Affidavit and the Memorandum are true. They form part of my written evidence in these proceedings

4. The purposes of this Affidavit are principally to: (i) give an overview of the Applicant's 5-year investment plan which includes investments in generation, transmission and distribution, substations and systems including Information and Communication Technology (ICT) enhancements and maintenance to existing plant and (ii) provide general information about the Applicant's assets that are "used and useful" in rendering service to its customers and which are included in the rate base.

<u>MEMORANDUM ON CAPITAL EXPANSION</u>

5. The Applicant as at December 31, 2020 served a total of 131,522 customers with a peak demand of 141 MW and had an installed capacity of 256.1MW of generating plant. The Applicant transmits power to its customers through the

generating stations at 69,000 volts and 24,000 volts to 18 substations across the Island.

6. Annually, capital investments are made for sustainability of existing assets, due to statutory, environmental, insurance and other compliance requirements. In addition, the Company continues to pursue expansion plans to facilitate continued provision of reliable electricity, meet customer demands as well as support the following:

    - the Barbados National Energy Policy 2019 – 2030 (BNEP);
    - the accelerated RE Policy of the Government of Barbados and
    - the BLPC 100/100 Clean Energy strategy

7. Since the Decision of the Commission in 2010, the Company has continued to invest significantly in its generation plant, transmission and distribution network, general property and ICT. Such investments have spanned the gamut of the Company's operations and include investments in its substations, the Clean Energy Bridge (CEB), the transmission infrastructure, information technology enhancements, conventional and renewable generation assets among other investments.

8. One of the Company's significant investments is the 33 MW CEB. Construction of the CEB is expected to be completed in 2021. The CEB will facilitate the transition to renewable energy, is in alignment with the national renewable energy 2030 goals and is projected to result in significant savings of expenditure on fossil fuels, thus reducing the drain on much needed foreign exchange and helping to stabilize electricity rates with savings being passed directly to customers through the Fuel Clause Adjustment (FCA).

9. The Company is also pursuing its clean energy agenda through a proposed utility scale wind farm at its Lamberts St. Lucy site and the development of a 7.5 MW Solar Photovoltaic Plant on 29 acres of land at Lower Estate, St. Michael.

10. In addition to its generation investments, the Company continues to operate a transmission network that is highly efficient with losses which are among the lowest in the region and comparable to that in North America.

11. Expansion of the transmission network is being pursued via:

    a. the Northern Underground Transmission project which will provide a reliable and redundant high capacity link from the generating plant in Trents St. Lucy to the St. Thomas substation;

    b. the establishment of a link from St. Thomas to Warrens which will provide improved reliability by extending this link into the existing 69,000 V transmission network between Spring Garden and Central substations via an intertie at Warrens substation.

12. Such expansion of the transmission network is critical to support the increased generation development in the north, support new load growth and tourism projects.

13. Technological investments have also supported efficient network operation and shored up the Company's disaster resiliency posture. Such investments have included upgrades to the Supervisory Control And Data Acquisition (SCADA) system, implementation of a Disaster Recovery Site (DRS) which tested successfully in the Covid-19 environment, Automatic Metering Infrastructure (AMI) and Distribution Automation (DA).

14. System stability is also being pursued through battery storage and Synchronous Condensers (SCOs). These investments also further the Company's ability to meet the BNEP's 2030 target and have already achieved resultant benefits to customers both in terms of fuel savings as well as the ancillary services the battery provides in terms of smoothing solar PV output and frequency response.

15. During 2018, the Company commenced this process by commissioning its first battery Energy Storage Device (ESD), based on recommendations of GE Consulting in its updated Wind and Solar Penetration Study commissioned during 2015. The said study also recommended the use of SCOs for their contribution to improved system inertia capability. The Company intends to make the necessary investment in SCOs to support system stability and to enable very high penetration levels of variable renewable generation. This is in furtherance of the cleaner energy objective in light of the upcoming retirement of the Steam Station and ultimately other rotating assets. The initial investment

plan for 2021-2023 proposes the installation of 3 x 10MVA SCOs comprising 20 MVA at Spring Garden and 10 MVA at Temple Yard or Whitepark Substations.

Sales Growth Projections and Planning criteria for the Company's expansion plan

16. The uncertainty over the future of oil prices and the projected slowdown in world economies suggest that the most likely near term scenario is one of low load growth. Further analysis as detailed in the Memorandum on Sales Projection at Schedule H also supports this lower projected growth. Therefore, the five year expansion plan is based on the low load growth scenario.

17. The goal of the Company's expansion plan is to determine the least-cost solution required to provide electricity service which meets the specified levels of reliability. The Company's aim is to achieve the right balance between cost and system reliability. The Company uses a loss-of-load probability (LoLP) as its main planning criteria for generation reliability.

18. The following input data was used to determine the need for and type of new plant to be purchased:
    - Target levels of system reliability.
    - Electricity sales projections.
    - Expected growth in peak demand.
    - System load factor.
    - The existing generating plant types and the options available for new plant (candidate plant).
    - Proposed retirement schedule for existing plant.
    - Availability, reliability, fuel type and efficiency of existing and candidate plant.
    - Estimated capital cost of candidate plant.
    - Operating and Maintenance (O&M) cost of existing and candidate plant.
    - Fuel price projections.

19. As part of its planning process, the Company in 2018 retained Mott McDonald, to prepare a System expansion study, Barbados Generation and Transmission Masterplan (the 2020 Study) which took into account the island's goal of 100%

renewable energy by 2030. A copy of the 2020 Study was made available at the Depreciation Hearing held before the Commission.

20. The 2020 Study identified the 5 year investment plan for a 1.3% annual average growth under the scenario where the energy mix allowed for forced IPPs, along with imported bio-fuels allowed as shown in Table 2 of the Memorandum on Capital Expansion.

CONCLUSION

21. The Company over the years has demonstrated its commitment to leading innovations that has resulted in significant customer benefits and efficiencies. The Company's capital expansion plans align with the BNEP and are geared towards stabilizing rates for our customers. However, the Company's expansion plans being pursued have been developed in a financially prudent manner having regard to efficiencies, cost and the projected low load growth in sales.

SWORN TO by **ROHAN SEALE**) ……………………………………………..

)

this 30th day of September 2021)

Before me:

…………………………………………….

ATTORNEY-AT-LAW

JG

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003 as amended by the Utilities Regulation (Procedural) (Amendment) Rules 2009;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF JOHANN GREAVES

I JOHANN GREAVES, of 21 The Rock, in the Parish of St. Peter in this Island, being duly sworn hereby **MAKE OATH** and say as follows:

1. I Johann Greaves am the Director Operations of The Barbados Light & Power Company Limited ("the Applicant" or "the Company" or "BLPC"), a company registered under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situated at Garrison Hill in the parish of St. Michael. I am duly authorized to depose to the facts and matters in this Affidavit and the statement of facts herein are within my personal knowledge unless otherwise stated.

2. I joined the Applicant in 2002 and have been with the Applicant for over 19 years. I joined the Applicant as a Trainee Engineer. On completion of my training period, I assumed responsibility for the daily operations of the generation plants. In 2011, I was appointed to the position of Senior Generation Engineer where I was responsible for the maintenance of the generating units before being transferred to the System Planning and Performance Department in 2012. In 2014, I was appointed to the position of Manager, System Planning and Performance where my duties included responsibility for long term electricity planning and performance monitoring of company assets. In 2016 I was appointed as the Director Operations. I am the holder of a Bachelor of Science Degree in Mechanical Engineering from the University of the West Indies, St. Augustine and a Master of Business Administration from the University of Wales.

3. In my capacity as Director Operations of the Applicant I have primary responsibility for the areas of generation, distribution and transmission. I have overseen the operations of the electric plant over the last 5 years.

4. I contributed some of the information used in the preparation of the Memorandum on Capital Expansion and the supporting Schedules accompanying the Memorandum found at Schedule I of the Application. In the preparation of the information I had access to the Applicant's financial and technical data, which was reviewed and analysed. I also had access to studies prepared by the Applicant's consultants and other information supplied by them. To the best of my knowledge, information and belief, the facts and matters set out in this Affidavit and the Memorandum are true.

SWORN TO by **JOHANN GREAVES**) ……………………………………………..
)
this 30 day of September 2021)

Before me:

…………………………………………….

ATTORNEY-AT-LAW

AC

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003 as amended by the Utilities Regulation (Procedural) (Amendment) Rules 2009;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF ADRIAN CARTER

I ADRIAN CARTER, of #8 Diamond Corner, in the parish of St. Peter in this island, being duly sworn hereby **MAKE OATH** and say as follows:

1. I am the Manager of Regulatory Affairs at The Barbados Light & Power Company Limited ("the Applicant" or "the Company or "the BLPC"), a company registered under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situate at Garrison Hill in the parish of St. Michael. I am duly authorized to depose to the facts and matters in this Affidavit and the statement of facts herein are within my personal knowledge unless otherwise stated.

EDUCATIONAL & PROFESSIONAL EXPERIENCE AND CURRENT POSITION

2. I hold a Bachelor of Science in Economics from the University of the West Indies, a Master of Business Administration from the University of Surrey, England and a Doctor of Philosophy in Economics from the University of the West Indies.

3. I joined the Applicant in 2007 and have been with the Applicant for over 13 years. I joined the Applicant in the position of Market Analyst and was appointed to the position of Manager, Regulatory Affairs in 2018, with responsibility for coordinating the regulatory activities of the Applicant.

4. I have prepared the Memoranda on Sales Projections, Proposed Tariffs and the supporting Schedules accompanying the Memoranda, which are found at Schedules H and K of the Application for a review of electricity rates filed by the Applicant ("the Application"). In the preparation of the Memoranda I had access to the Applicant's financial and technical data. I also had access to studies prepared by the Applicant's consultants and other information supplied by them and the management of the Applicant. To the best of my knowledge, information and belief, the facts and matters set out in this Affidavit and each Memorandum are true. They form part of my written evidence in these proceedings.

5. The purpose of my Affidavit is to provide an overview on the matters which I address in each Memorandum and the related Schedules referenced at paragraph 4 herein.

MEMORANDUM ON SALES PROJECTIONS

6. The Company has prepared electricity sales projections over the period 2021 to 2025 as set out in the Memorandum on Sales Projections. These projections served as the Company's best estimate of future electricity sales and forms the basis by which total energy required to serve customers and the associated revenues and expenses is estimated.

7. The Company's expectation of future economic growth and its impact on electricity sales is conservative, and aligns with the Central Bank of Barbados' guidance that there is increased uncertainty regarding a post Covid-19 economic recovery.

8. The Company projects that electricity sales will not return to pre-Covid-19 levels until 2023 for Domestic Service customers, or even 2025 for the Secondary Voltage Power and Large Power customers, when the econometric models assume a return to typical tourism activities and stronger economic

recovery. The forecast assumes an accelerated lifting of domestic and international travel restrictions in 2021. However, new waves and variants of the Covid-19 virus and the speed and actual efficacy of vaccinations are concerns to the Company's outlook for the growth of electricity sales. This is reinforced by the Company's actual sales over the period January to August, 2021 which declined by 1.1% when compared to the same period for 2020.

MEMORANDUM ON PROPOSED TARIFFS

9. The Memorandum on Proposed Tariffs presents the electricity tariffs that are being proposed by the Company in its Application to the Commission and the rationale for the rate design. The Company also proposes the establishment of a permanent Time-of-Use (TOU) tariff and the disaggregation of the current Fuel Clause Adjustment (FCA) to allow for the establishment of a Renewable Purchased Power Adjustment (RPPA) clause to recover the cost of renewable energy purchases. The schedules of proposed tariffs and riders are shown in schedules K-1 to K-11.

10. The BLPC analyzed the results of the COS study as presented in the Affidavit of Dr. Philip Hanser of the Brattle Group to guide the revenue allocation and rate design process. The BLPC also had regard to factors such as revenue adequacy, efficiency and fairness and rate stability.

11. The Company has used the COS study as a guide in developing the new tariffs, but has not moved to full cost of service in order to mitigate bill impact. The expected impact is discussed in more detail in the Memorandum on Proposed Tariffs.

12. The proposed rates are designed to recover the Test Year's (2020) revenue increase of $46.475 million, as supported by the embedded cost of service study. The proposed rate design reduces the overreliance on volumetric charges such as energy charges for fixed cost recovery to facilitate the sustainable transition towards the nation's 100% renewable energy generation target as outlined in the Barbados National Energy Policy 2019-2030 (BNEP). Bill increases have been capped not to exceed $6 per month for customers with usage up to 150 kWh, which account for 35% of the Domestic Service tariff, in anticipation of the disproportionate number of low income customers with usage up to 150 kWh.

13. The typical bill increase resulting from the proposed rates are estimated to range from 5% to 20% depending on the tariff on which customers receive their service. This increase is expected to be mitigated by lower fuel charges as a result of the commissioning of the Clean Energy Bridge in 2021.

14. Given prices within in the economy have risen by over 38% since 2010, the effective cost of electricity under the proposed rates represents a decline relative to the other costs in the economy.

15. It is the Applicant's view that the proposed rate designs fairly and reasonably reflect the objectives that guided the rate design. The Applicant therefore respectfully requests that the proposed tariffs, riders, FCA, street light rate of return and service charges be approved.

SWORN TO by **ADRIAN CARTER**) ……………………………………...

)

this 30th day of September 2021)

Before me:

…………………………………………

ATTORNEY-AT-LAW

BV

BARBADOS **Ref:**

THE FAIR TRADING COMMISSION

IN THE MATTER of the Application by the Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF BENTE VILLADSEN

I BENTE VILLADSEN, of 17 Burnham Cove Rd., Boothbay, ME 04537 in the country of the United States, being duly sworn hereby **MAKE OATH** and say as follows:

1. I am a Principal of The Brattle Group and have more than 20 years of consulting and litigation experience in the energy industry. I specialize in regulatory finance and accounting, especially for electric and gas utilities, in areas such as cost of capital, capital structure, credit issues, cost and capital recovery. I have experience in financial analyses including the estimation of cost of equity, business risk analyses, credit metrics analysis, risk management analyses, and the accounting treatment of costs, revenues, and capital expenditures in a regulated setting. I also provide consulting and expert testimony regarding the implementation of U.S. Generally Accepted

Accounting Principles and International Financial Reporting Standards for capital intensive industries.

2. The Brattle Group is an economics consulting firm with offices in Canada, the U.S., Europe, and Australia. The company serves a multitude of clients including regulated utilities in the electric, natural gas, and water industry.

EDUCATIONAL AND PROFESSIONAL EXPERIENCE

3. I hold a Ph.D. with a concentration in accounting from Yale University and a joint degree in economics and mathematics from University of Aarhus, Denmark.

4. Before joining The Brattle Group, I held teaching positions at the University of Iowa, University of Michigan, and Washington University in St. Louis. I taught classes in accounting and corporate finance and undertook research.

5. I have appeared as an expert witness before the U.S. Federal Energy Regulatory Commission (FERC), the U.S. Surface Transportation Board, Canadian provincial regulators in Alberta and Quebec and many U.S. state public utility commissions (including those in Alaska, Arizona, California, Hawaii, Illinois, Michigan, New York, Ohio, Oregon, and Washington) as well as before arbitration panels and U.S. courts. A complete list of my appearances is included in my resume (Exhibit BV1). I have filed expert reports on cost of capital with regulators in Australia, Canada, Italy, Mexico and the Netherlands.

6. I am a lead author of the text, "Risk and Return for Regulated Industries"[1] and a frequent speaker on cost of capital and related issues. For the past several years I have taught cost of capital for Edison Electric Institute in its Advanced Rates Course and capital structure and risk management for the

[1] Villadsen, Bente et al., *Risk and Return for Regulated Industries*, Academic Press, 2017.

American Gas Association and Edison Electric Institute's joint Public Utility Accounting Courses.

7. A copy of my resume is attached hereto and marked as Exhibit "BV1."

ASSIGNMENT AND SCOPE OF EVIDENCE

8. In October 2018, The Brattle Group was retained by the BLPC to provide Rate Case Assistance, which included a cost of capital study. With the assistance of my colleague, Mr. Josh Figueroa, The Brattle Group and I prepared the report attached in Exhibit "BV2," which estimates the cost of equity capital and WACC for BLPC as well as recommends a return on equity and WACC for the Company. The analyses underlying my estimates and recommendations are presented in Exhibit BV2 to BV4.

9. The purpose of my testimony is to present our analysis of the cost of equity for an electric utility located in Barbados as well as the inputs and models relied upon. My testimony also presents a discussion of the business risk of BLPC and the WACC necessary to meet investors cost of capital requirement.

EXECUTIVE SUMMARY

10. I calculate the cost of equity and the Weighted Average Cost of Capital ("WACC") for the Barbados Light and Power Company Ltd. ("BLPC" or "the Company") using a comparable sample of electric and gas utilities and standard financial estimation methods. Additionally, I consider BLPC's

business risks when determining an appropriate cost of equity and WACC. Notably, BLPC is facing a new regulatory regime, which will award separate licenses for segments of the business and require an accounting separation of the businesses. Once each business segment is regulated on a stand-alone basis, there is no reason to expect that the cost of equity is the same for all segments or that the weighted average of the cost of equity for the segments add to the cost of equity for the consolidated company.[2] Additionally, BLPC operates in an island environment and is expected to engage in substantial capital expenditures to ensure Barbados achieve its Barbados National Energy Policy which aims to achieve 100% renewable energy and to be carbon neutral by 2030.[3] These risks impact the recommended cost of equity, but I note up front that my recommendation assumes that BLPC will be granted its applied for Clean Energy Transition Rider ("CETR").

11. As BLPC is a regulated electric utility as is the majority of the proposed businesses under the new licenses I select a group of publically traded regulated electric utilities as my proxy group. While these electric utilities ideally would operate in Barbados / the Caribbean, there is currently insufficient data on Caribbean utilities to create a proxy group. Therefore, I create a proxy group using US electric utilities.[4] In addition, I also consider

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[2] Weighted average means that the cost of equity is weighted by the relative size of equity used to finance the regulated rate base or assets.

[3] The Barbados Government, Barbados National Energy Policy (BNEP), accessed March 18, 2021, https://energy.gov.bb/publications/barbados-national-energy-policy-bnep/.

[4] There are no investment-grade electric generation businesses in the U.S. at this time.

a proxy group of U.S. natural gas local distribution companies ("LDCs") as a sensitivity check.

12. I apply standard financial models to the proxy group to obtain an estimate on investors' required return. Specifically, I apply the Capital Asset Pricing Model ("CAPM") as well as the Empirical CAPM ("ECAMP") along with two versions of the Discounted Cash Flow ("DCF") model, and a risk premium model. To obtain a reasonable estimate for a utility with the same capital structure as BLPC, I calculate the ROE that would be consistent for the sample at BLPC's capital structure.[5] Finally, I apply a Country Risk Premium ("CRP") to my estimates to obtain an appropriate ROE for BLPC.

13. Having determine the appropriate ROE for the proxy groups, I evaluate BLPC's business risk and place BLPC within the calculated range. Specifically, I find that BLPC is a small electric utility facing substantial risk from changes to the regulatory regime and from being regulated as an even smaller company through the split of the one license into three. Based on the publication of Duff & Phelps BLPC's size alone would merit a non-trivial increase to the ROE and the size effect will be magnified as BLPC starts operating three licenses instead of the current single license.

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[5] I apply two methods for the CAPM and ECAPM: First, I assume the WACC is constant over a broad range of capital structures and then determine the ROE for a company at BLPC's capital structure. Second, for the CAPM / ECAPM, I rely on the Hamada method to unlever the betas to those of a 100 percent equity financed company and then relever the betas to BLPC's equity percentage.

14. Further, BLPC faces significant capital investments over the coming years as demonstrated in the Capital Expenditures Memorandum submitted as part of BLPC's application, which will support the transition to renewable energy in Barbados. The need for such capital investments will increase BLPC's fixed cost and (i) capital expenditures creates construction risk and (ii) high fixed costs increases business risks as any variation in revenue will increase with an increase in the proportion of fixed costs. The increase in risk is further elevated by the increasing demand competition from independent power producers as indicated in recent government documents. Lastly, BLPC operates in an island environment, which means it cannot import power, but must rely on imported fuel for firm capacity and potentially needed parts – most of which must be imported.

15. Based on my sample companies, I find a range for the average sample company is 11.3 to 13.3 percent and find that BLPC should be placed in the upper half of the range from 12¼ to 13¼ percent and recommend a point estimate of 12½ percent.

16. Lastly, based on BLPC's regulatory capital structure and embedded cost of debt, I find a WACC of 8.79 percent is consistent with BLPC's regulatory capital structure including equity, long-term debt, customer deposits, deferred investment tax credits, and deferred manufacturers' allowance.

ESTIMATING THE COST OF EQUITY

A. PROXY GROUP SELECTION

17. BLPC is a regulated electric utility as is the majority of the proposed businesses under the new licenses albeit in some jurisdictions the Generation and Storage License portion as well as the Sales part of Transmission, Distribution and Sales license are not regulated. Therefore, publically traded regulated electric utilities is an appropriate starting point for selecting a proxy group of companies with comparable business risk. Ideally, these electric utilities would operate in Barbados / the Caribbean. However, there is currently insufficient data on Caribbean utilities to create a proxy group. Therefore, I create a proxy group using US electric utilities.[6] In addition, I also consider a proxy group of U.S. natural gas local distribution companies ("LDCs"). I do so as a sensitivity and to check the reasonableness of my US electric utility sample's CAPM/ECAPM and DCF results. While BLPC does not provide natural gas service to its customers, natural gas LDCs are similar to electric utilities in that they operate highly regulated infrastructure networks designed to delivery energy to end users, are highly capital intensive, and face the need to maintain and upgrade aging infrastructure. Additionally, gas LDCs are highly regulated and hence comparable to a regulated business. Thus, the business risk characteristics of the electric utility and Gas LDC sample are broadly similar. I apply the

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[6] There are no investment-grade electric generation businesses in the U.S. at this time.

following steps to identify utilities suitable for inclusion in the electric and natural gas proxy groups.

18. First, I start with the universe of publicly traded companies reported by Value Line Investment Analyzer (Value Line). I narrow down this universe of companies to those that Value Line identifies as electric utilities or natural gas utilities and include those that have at least 50% of their assets dedicated to regulated electric or natural gas utility activities. Within this group of companies, I apply further screening criteria to eliminate companies with recent significant events that could affect the market data necessary to perform cost of capital estimation. The selection process produces a proxy group of 30 regulated electric utilities and a second proxy group of 9 regulated gas LDCs. Figure 1 and Figure 2 below list the electric utilities and regulated gas LDCs in my proxy groups, respectively, and their selected financial characteristics.

Figure 1

Electric Utility Proxy Group

Company	Annual Revenue (Q2 2021) ($MM)	Regulated Assets	Market Cap. (Q2 2021) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	$1,289	MR	$3,625	0.90	BBB	6.6%
Alliant Energy	$3,455	R	$14,347	0.85	A-	5.4%
Amer. Elec. Power	$15,785	R	$42,056	0.75	A-	6.1%
Ameren Corp.	$5,994	R	$21,367	0.85	BBB+	7.4%
Avista Corp.	$1,364	R	$3,074	0.95	BBB	6.3%
Black Hills	$1,839	R	$4,338	1.00	BBB+	4.9%
CMS Energy Corp.	$7,014	R	$17,225	0.80	BBB+	6.4%
CenterPoint Energy	$7,965	R	$14,896	1.15	BBB+	5.4%
Consol. Edison	$12,941	R	$26,470	0.75	A-	2.7%
Dominion Energy	$14,036	R	$61,192	0.85	BBB+	6.0%
Duke Energy	$24,406	R	$77,403	0.90	BBB+	5.6%
Edison Int'l	$14,076	R	$21,642	1.00	BBB	4.6%
Entergy Corp.	$10,941	R	$21,010	0.95	BBB+	4.6%
Evergy Inc.	$5,460	R	$14,375	0.95	A-	5.0%
Eversource Energy	$9,526	R	$27,898	0.90	A-	6.9%
Exelon Corp.	$34,775	MR	$44,361	0.95	BBB+	4.4%
Hawaiian Elec.	$2,617	MR	$4,709	0.85	BBB-	3.5%
IDACORP Inc.	$1,417	R	$5,038	0.85	BBB	3.9%
MGE Energy	$570	R	$2,731	0.75	AA-	4.9%
NextEra Energy	$16,833	MR	$144,657	0.95	A-	9.2%
NorthWestern Corp.	$1,293	R	$3,216	0.95	BBB	3.6%
OGE Energy	$3,396	R	$6,877	1.05	BBB+	4.8%
Otter Tail Corp.	$1,010	R	$2,029	0.90	BBB	7.4%
Pinnacle West Capital	$3,692	R	$9,471	0.95	A-	3.2%
Public Serv. Enterprise	$9,535	MR	$30,474	0.95	BBB+	3.2%
Sempra Energy	$11,815	R	$43,601	1.00	BBB+	5.7%
Southern Co.	$21,845	R	$65,986	0.95	A-	6.9%
Unitil Corp.	$440	R	$829	0.85	BBB+	6.5%
WEC Energy Group	$7,952	R	$28,673	0.80	A-	6.6%
Xcel Energy Inc.	$12,738	R	$36,328	0.80	A-	6.2%
Electric Sample	$8,867		$26,663	0.90	BBB+	5.5%

Sources and Notes:
[1]: Bloomberg as of August 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of August 31, 2021.
[6]: See Schedule No. BV-5.

Figure 2

Natural Gas LDC Proxy Group

Company	Annual Revenue (Q2 2021) ($MM)	Regulated Assets	Market Cap. (Q2 2021) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
Atmos Energy	$3,314	R	$12,959	0.80	A-	7.0%
Chesapeake Utilities	$541	R	$2,113	0.80	BBB+	6.1%
New Jersey Resources	$2,024	MR	$4,025	1.00	BBB+	4.9%
NiSource Inc.	$4,645	R	$9,947	0.85	BBB+	8.6%
Northwest Natural	$818	R	$1,643	0.85	A	5.0%
ONE Gas Inc.	$1,670	R	$4,062	0.80	BBB+	5.9%
South Jersey Inds.	$1,733	R	$3,017	1.05	BBB	9.0%
Southwest Gas	$3,413	R	$3,860	0.95	BBB+	6.7%
Spire Inc.	$2,197	R	$3,804	0.85	A-	5.7%
Gas Sample	$2,262		$5,048	0.88	BBB+	6.5%

Sources and Notes:
[1]: Bloomberg as of August 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of August 31, 2021.
[6]: See Schedule No. BV-5.

B. FINANCIAL RISK ADJUSTMENT

19. Taking the level of financial risk or leverage into account is necessary to reflect the fact that different capital structure ratios have different levels of financial risk. Specifically, all else equal, higher levels of debt financing increases the risk faced by equity investors. Therefore, investors require higher ROEs from companies with more debt than from comparable business risk companies with less debt. To reflect the effect of capital structure on the cost of equity, I adjust the cost of equity estimates I obtain from applying the models to the market data of the proxy companies. I do so using two different approaches: (1) the overall cost of capital approach and

(2) the Hamada approach. Details of these two approaches are provided in the Appendix A to Exhibit BV2.

20. I estimate BLPC's cost of equity using the company's policy-based capital structure of 65% equity and 35% debt. The Company's regulatory capital structure includes additional sources of capital such as customer deposits, deferred manufacturing tax credits, and deferred investment tax credits. This results in a regulatory capital structure with 59% equity, 32% debt. Figure 3 below demonstrates the differences between BLPC's policy-based capital structure and regulatory capital structure.

Figure 3

BLPC Capital Structure

Policy Based Capital Structure

	Amount (BDS$)	Share (%)
Equity	508,826,918	65%
Debt	273,983,725	35%
Total	**782,810,643**	**100%**

Regulatory Capital Structure

	Amount (BDS$)	Share (%)
Equity	508,826,918	59%
Debt	273,983,725	32%
Customer Deposits	47,401,616	5%
Deferred Investment Tax Credits	17,232,462	2%
Deferred Manufacturing Tax Credit	19,078,160	2%
Total	**866,522,880**	**100%**

Source: Barbados Light & Power, year-end 2020

21. The Commission in its 2010-01-22 decision regarding BLPC approved the use of a hypothetical capital structure including 65 percent equity,[7] which is the policy based capital structure used in this report.

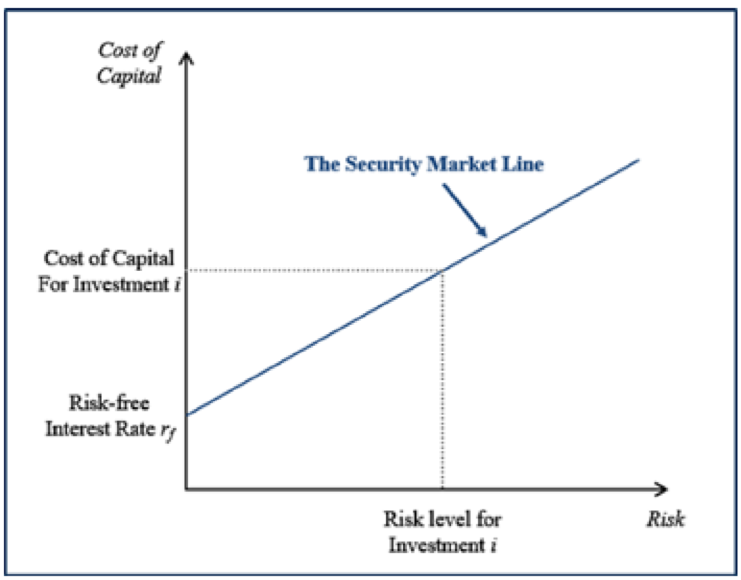
7 Decision and Order, No. 0002/09, ¶104.

C. CAPM/ECAPM APPROACH AND COST OF EQUITY ESTIMATES

CAPM Approach

22. The CAPM is a "risk-positioning model" that models the direct relationship between risk and return illustrated in the Security Market Line (see Figure 4 below). More precisely, the CAPM states that the cost of capital for an investment, S (e.g., a particular common stock), is determined by the risk-free rate plus the stock's systematic risk multiplied by the market risk premium (MRP).

Figure 4: Security Market Line



23. Mathematically, the relationship is shown by the following formula:

$$r_s = r_f + \beta_s \times MRP \qquad (1)$$

where r_S is the cost of capital for investment S;

r_f is the risk-free interest rate;

$\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and

$\boldsymbol{MRP}$ is the market equity risk premium.

ECAPM Approach

24. Another risk-positioning model is the Empirical CAPM (ECAPM), which builds upon he CAPM. Empirical research has found that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. The ECAPM corrects for this by adjusting the CAPM using the formula below:

$$\boldsymbol{r_S = r_f + \alpha + \beta_S \times (MRP - \alpha)} \qquad (2)$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant; and

$\boldsymbol{r_S}$, $\boldsymbol{\beta_S}$, and $\boldsymbol{MRP}$ are defined in formula (2) above.

25. The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 4, which results in a Security Market Line that more closely matches the results of empirical tests. The impact on the Security Market Line is illustrated in Figure 5 below. In the ECAPM implementation, I use an alpha of 1.5 based on academic research documenting the magnitude of alpha.[8]

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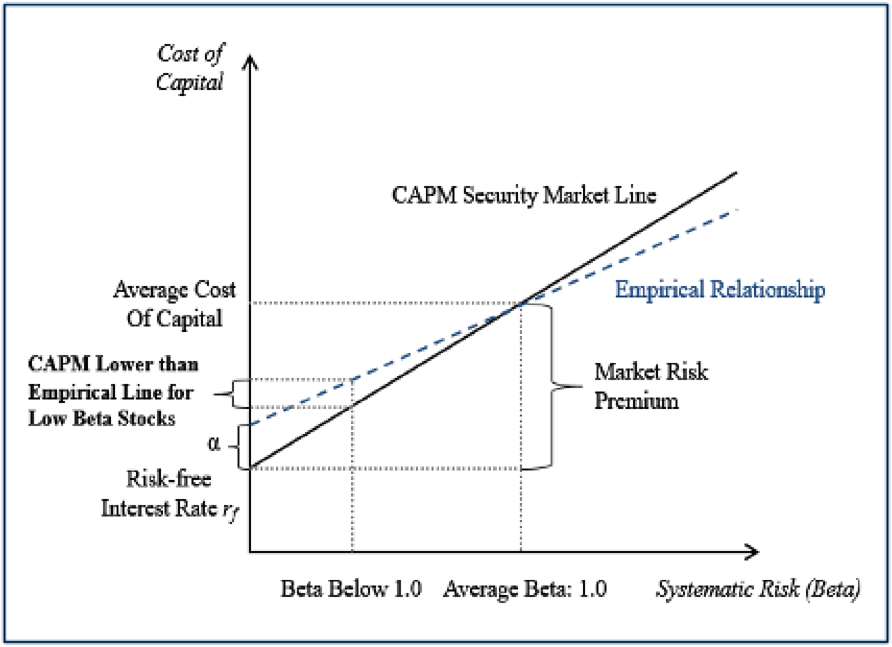
[8] See Appendix A to Exhibit BV2 for details.

Figure 5

The Empirical Security Market Line



CAPM/ECAPM Cost of Equity Estimates

26. I performed the CAPM/ECAPM analysis using different sensitivities to obtain a range of cost of equity estimates. Specifically, I use an unadjusted historic MRP in one scenario; whereas, in the second Scenario I use a forward looking estimate of MRP from Bloomberg.

27. In Scenario 1, I use a long-term historical MRP of 7.25% and a forecasted risk-free rate of 2.97%.[9] In Scenario 2, I present a sensitivity using a forecasted MRP of 8.57% and a forecasted risk-free rate of 2.97%.[10]

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[9] The MRP of 7.25% is sourced directly from Duff & Phelps Cost of Capital Navigator 2020. The risk-free rate is derived from the August 2021 and March 2021 Blue Chip Economic Indicators (BCEI) forecasted 10-year Treasury yield average over 2022 to 2026 plus 53 bps, which is the spread between the 30-year and the 10-year Treasury yield..

[10] The MRP sourced from Bloomberg and estimated over a 30-year Treasury yield.

Scenario 2 considers that the MRP has increased relative to the historical long-run average.

28. Additionally, I apply a two-step approach to adapt the CAPM/ECAPM cost of equity estimates for BLPC. First, I use a standard approach to estimate the cost of equity for a U.S. electric utility using the proxy group shown in Figure 1 and, as a sensitivity, a gas LDC proxy group shown in Figure 2. Second, I apply a Caribbean region-specific risk premium to better estimate the cost of equity for an electric utility or natural gas utility located in this region. I bound the region-specific risk premiums from a low of 2.78% to a high of 4.19%,[11] but note that the 2.78% is an absolute minimal CRP as it is measured using debt instruments rather than equity instruments. Consequently, a more realistic CRP is somewhat above the 2.78%, so that a range of, for example, the range of 3.49% (the average of 2.78% and 4.19%) to 4.19% is more reasonable. The financial risk adjusted CAPM/ECAPM estimates are presented in Figure 6 (Electric Utility Sample) and Figure 7 (Gas LDC Sample) below.

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11 Based on Caribbean region-specific risk premium derived from Aswath Damodaran's "Country Default Spreads and Risk Premiums."

Figure 6

Electric Utility SAMPLE - CAPM/ECAPM Cost of Equity Estimates at 65% Equity Capital Structure

Estimated Return on Equity	Country Risk Premium (2.78%) Scenario 1 [1]	Country Risk Premium (2.78%) Scenario 2 [2]	Country Risk Premium (4.19%) Scenario 1 [3]	Country Risk Premium (4.19%) Scenario 2 [4]
Electric Sample				
Overall Cost of Capital Adjustment				
CAPM	11.7%	12.8%	13.1%	14.2%
ECAPM (α = 1.5%)	11.8%	12.9%	13.2%	14.3%
Hamada Adjustment Without Taxes				
CAPM	11.7%	12.8%	13.1%	14.2%
ECAPM (α = 1.5%)	12.0%	13.0%	13.4%	14.5%
Hamada Adjustment With Taxes				
CAPM	11.7%	12.8%	13.1%	14.2%
ECAPM (α = 1.5%)	12.0%	13.1%	13.4%	14.5%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 2.78%.
[2]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 2.78%.
[3]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 4.19%.
[4]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 4.19%.

29. Based on the results in Figure 6 above, a reasonable range for the ROE of the comparable sample applied to a Barbados-based electric utility is 12 ¼ to 13 ½ percent for a point estimate of 12 ¾ percent.[12]

30. Using the gas LDC sample, shown in Figure 2 above, I performed a sensitivity of the CAPM/ECAPM model. The CAPM/ECAPM results range from 11.9% to 14.7%. This generally aligns with the CAPM/ECAPM results from the electric utility sample, shown in Figure 6.

12 The point estimate is derived as the average of the upper half of the range rounding to the nearest ¼ percent.

Figure 7

Gas Utility SAMPLE - CAPM/ECAPM Cost of Equity Estimates

at 65% Equity Capital Structure

Estimated Return on Equity	Country Risk Premium (2.78%)		Country Risk Premium (4.19%)	
	Scenario 1 [1]	Scenario 2 [2]	Scenario 1 [3]	Scenario 2 [4]
Gas Sample				
Overall Cost of Capital Adjustment				
CAPM	11.9%	13.1%	13.3%	14.5%
ECAPM ($\alpha = 1.5\%$)	12.1%	13.2%	13.5%	14.6%
Hamada Adjustment Without Taxes				
CAPM	11.9%	13.0%	13.3%	14.4%
ECAPM ($\alpha = 1.5\%$)	12.1%	13.3%	13.5%	14.7%
Hamada Adjustment With Taxes				
CAPM	11.9%	13.0%	13.3%	14.4%
ECAPM ($\alpha = 1.5\%$)	12.1%	13.3%	13.5%	14.7%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 2.78%.
[2]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 2.78%.
[3]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 4.19%.
[4]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 4.19%.

31. The results for the gas LDC sample are slightly higher than those for the electric sample and thus affirms that the reasonable range and point estimate for the electric sample is reasonable and conservative.

D. DCF APPROACH AND COST OF EQUITY ESTIMATES

32. There are two variations of the DCF model, the single-stage DCF and multi-stage DCF, as explained below.

Single-Stage DCF Approach

33. The single-stage DCF model assumes that the current market price of a stock is equal to the present value of the dividends that its owners expect to

receive. The expected stream of future dividends is discounted at a risk-appropriate rate to arrive at the present value of the dividends, represented by the current stock price. In this application of the DCF, the risk-appropriate rate is the cost of equity. Mathematically, the DCF model is shown in the formula below:

$$\boldsymbol{P_0} = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T} \tag{3}$$

where $\boldsymbol{P_0}$ is the current market price of the stock;

$\boldsymbol{D_t}$ is the dividend expected at the end of period $\boldsymbol{t}$;

$\boldsymbol{T}$ is the last period in which a dividend is to be received; and

$\boldsymbol{r}$ is the cost of equity capital.

34. Formula (3) implies that if one knows the current market price of a stock and its expected stream of future dividends, then it is possible to solve for the cost of equity, r. The single-stage DCF model assumes that the stream of future dividends will grow at a constant rate into perpetuity. This assumption allows formula (3) to be algebraically rearranged into the formula below to directly estimate the cost of equity:

$$\boldsymbol{r} = \frac{D_1}{P_0} + \boldsymbol{g} = \frac{D_0}{P_0} \times (\boldsymbol{1} + \boldsymbol{g}) + \boldsymbol{g} \tag{4}$$

where $\boldsymbol{D_0}$ is the current dividend; and

$\boldsymbol{g}$ is the constant growth rate of the current dividend.

35. Another variation of the DCF model relaxes the restrictive constant growth rate assumption and instead, allows the dividend to grow at different rates

at different points in time. This variation is known as the multi-stage DCF model and is further explained below.

Multi-Stage DCF Approach

36. The multi-stage DCF accommodates different dividend growth rates at different points in time. Specifically, in the implementation of the multi-stage DCF, I assume three different growth rate phases. In the first phase, companies grow their dividend for five years at the forecasted company-specific rate of earnings growth. In the second phase, the company-specific growth rate incrementally steps down (or steps up) to the overall growth rate of the economy, represented by the long-term GDP growth rate. Finally, in the third phase, companies grow their dividend at the long-term GDP growth rate into perpetuity. This latter part could be problematic as it is plausible that the GDP growth rate in Barbados is higher than that of the U.S. either because real growth is higher or because inflation is higher. My approach of using the U.S. growth rate implicitly assumes that the country risk premium will account for any differences in growth patterns.

DCF Cost of Equity Estimates

37. The financial risk adjusted single- and multi-stage DCF cost of equity estimates for the electric utility sample are presented in Figure 8 below. The DCF results from the electric utility sample range from 9.7% to 12.3%.

Figure 8

Electric Utility Sample - DCF Cost of Equity Estimates at 65% Equity Capital Structure

	Country Risk Premium (2.78%) [1]	Country Risk Premium (4.19%) [2]
Simple	10.9%	12.3%
Multi-stage	9.7%	11.2%

38. Based on the results in Figure 8 a reasonable range for the average sample company is 10 ¾ to 12 ¼ percent with a point estimate of 11 ½ percent.

39. The results from the natural gas LDC sample are presented in Figure 9 below. The DCF results range from 9.8% to 13.0%. The results are generally in-line with the electric utility sample DCF results.

Figure 9

Gas Utility Sample - DCF Cost of Equity Estimates at 65% Equity Capital Structure

	Country Risk Premium (2.78%) [1]	Country Risk Premium (4.19%) [2]
Simple	11.6%	13.0%
Multi-stage	9.8%	11.3%

E. RISK PREMIUM APPROACH AND COST OF EQUITY ESTIMATES

40. The Risk Premium approach adds a "risk premium" to the current risk-free rate to estimate the current cost of equity, as shown in formula (5) below.

$$\textbf{\textit{Cost of Equity}} = r_f + \textbf{\textit{Risk Premium}} \tag{5}$$

41. The risk premium component of formula (5) is estimated using the allowed ROEs and prevailing risk-free rates from past electric utility rate cases. In our implementation, I calculate the risk premium as the difference between allowed ROEs and the prevailing quarterly 30-year Treasury bond yield over the period 1990-2021. This difference represents the compensation for risk allowed by regulators. I use the statistical technique of ordinary least squares (OLS) regression to estimate the parameters of the linear equation:

$$\textbf{\textit{Risk Premium}} = A_0 + A_1 \times (r_f) \tag{6}$$

where A_0 and A_1 are parameters to be estimated by the regression technique; and r_f is the risk-free rate as measured by the 30-year Treasury bond yield.

42. The regression analysis finds that the risk-free rate has a high degree of statistical explanatory power in capturing changes in the risk premium. The negative coefficient A1 reflects the empirical fact that regulators grant lower risk premiums–and by extension, lower allowed ROEs–when the risk-free rate is higher. This is consistent with the observation that investors require a higher risk premium to hold equities over government bonds as bond yields decline. I then use the parameters from the regression analysis, A0 and A1,

to estimate the cost of equity using the Scenario 1 and Scenario 2 risk-free rates.

43. Applying the calculated risk premium and a risk-free rate of 2.97% to formula (5) above results in an estimated cost of equity of 9.8% for U.S. electric utilities.

44. Next, I apply a financial risk adjustment and a country risk premium of 2.78% and 4.19% to the U.S. electric utility cost of equity estimate. These two adjustments result in cost of equity estimates for a Barbados based electric utility with a capital structure of 65% equity (and 35% debt) of 11.0 to 12.4 percent. Based on these figures, a reasonable range for the cost of equity is 11 to 12 ½ for a point estimate of about 11 ¾ percent.

45. The three models, CAPM, DCF, and risk premium, have been used in BLPC's prior proceedings before the Commission.[13]

BARBADOS LIGHT AND POWER COMPANY DEBT

46. Regarding BLPC's embedded cost of debt, Figure 10 shows that BLPC's embedded cost of debt as of year-end 2020 is 2.78%. This is below the current borrowing rate for utilities in the U.S. or Canada. As of August 31,

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13 See, for example, Decision and Order, No. 0002/09.

2021, the yield on 30-year U.S. BBB rated utility bonds was 3.16%, so BLPC's embedded cost of debt is approximately 38 basis points lower.

Figure 10

BLPC Weighted Average Cost of Debt

	Rate	Per 2020 Financials	Adjustments	2020 Rate Base	Weighted Rate
BNS USD	4.50%	20,952,696		20,952,696	0.41%
NIS 1	3.50%	20,000,000		20,000,000	0.31%
NIS 2	5.88%	20,000,000		20,000,000	0.51%
BNS 1	2.25%	51,000,000		51,000,000	0.50%
BNS 2	2.05%	76,894,489	33,105,511	110,000,000	0.99%
RBC	4.00%	3,520,379		3,520,379	0.06%
LED	0.00%	3,351,974		3,351,974	0.00%
		195,719,538		228,825,049	2.78%

Source: Barbados Light & Power Company, year-end 2020.

CONCLUSION

47. The cost of equity estimates resulting from our analysis range from 9.7% to 14.5%, as summarized in Figure 11 below, but a reasonable cost of equity is higher as discussed above. Specifically, as discussed above, the best point estimate is 12 ½ percent. I note that the recommendation of 12 ½ percent assumes that the Clean Energy Transition Rider (CETR) is approved. If CETR were not approved, a higher ROE would be warranted to account for the higher business risk faced by the Company.

Figure 11[14]

Summary of Cost of Equity Estimates at 65% Equity capital Structure

	Low Estimate	High Estimate	Point Estimate
CAPM	11.7%	14.2%	12.75%
ECAPM	11.8%	14.5%	12.75%
DCF	9.7%	12.3%	11.50%
Risk Premium	11.0%	12.4%	11.75%
Median	11.3%	13.3%	12.25%

48. As noted previously, the low end of the CRP is underestimating the cost of equity because it is based on the premium required for debt. As a point of comparison, I note that recently independent power producers (IPPs) in Barbados were awarded a cost of equity of up to 14%,[15] as part of BLPC's Feed-in-Tariffs for renewable energy resources.[16] While, the risks IPPs face are higher than those regulated utilities face, the median results in the upper half of the range are 70 to 167 basis points lower than the ROE awarded to IPPs. Taken together with BLPC's unique business risk factors, I find that BLPC should be placed in the upper half of the range at approximately 12.25% to 13.25%.

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[14] Based on results from electric utility proxy sample.

[15] Based on a 50% and 60% debt capitalization for solar PV and land-based wind projects greater than 1MW, respectively. For solar, wind, and other technologies less than 1MW, 14% is based on 50% to 80% debt capitalization.

[16] Fair Trading Commission, "Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1 MW," September 24, 2019, FTCUR/DECFIT/2019-04, pp. 28-30.

Fair Trading Commission, "Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies above 1MW and up to 10MW," September 30, 2020, FTCUR/DECFIT/2020-01, p. 22.

49. BLPC is a small electric utility facing substantial risk from changes to the regulatory regime and from being regulated as an even smaller company through the split of the one license into three. Specifically, based on BLPC's annual revenue of USD$197 million and total assets of USD$467 million,[17] the Company is smaller than the average electric utility with revenue of USD$8,867 million and total assets of USD$47,484 million. According to Duff & Phelps Size Premium Study[18], BLPC is in the 25th portfolio (out of 25) in terms of annual revenue and the 25th portfolio in terms of total asset, compared to the average electric proxy company which is in the 8th and 3rd portfolio, respectively.[19] Duff & Phelps estimates that the return premium demanded by investors to invest in a company the size of BLPC is 6.0% to 7.0% relative to a company the size of the average proxy electric utility.[20] The size effect will be magnified as BLPC starts operating three licenses instead of the current single license. Consequently, the recommendation of placing BLPC in the upper end of the estimates for the sample is conservative.

50. Further, BLPC faces significant capital investments over the coming years as demonstrated in the Capital Expenditures Memorandum submitted as

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17 BLPC Non-consolidated Financial Statements Year Ended December 31, 2020. Barbados dollars converted to USD at a ratio of 2:1, as per the Central Bank of Barbados http://www.centralbank.org.bb/_economic-insightbb/protecting-our-dollar

18 Duff & Phelps Cost of Capital Navigator, Supplementary Risk Premium Report Study Data, 2021 p. 6 and p. 8.

19 Average gas LDC proxy company is in the 17th portfolio for annual revenues and 9th portfolio for total assets.

20 Premium is 3.0% to 5.5% relative to the average proxy gas LDC company.

part of BLPC's application, which will support the transition to renewable energy in Barbados. The need for such capital investments will increase BLPC's fixed cost and (i) capital expenditures creates construction risk and (ii) high fixed costs increases business risks as any variation in revenue will increase with an increase in the proportion of fixed costs. The increase in risk is further elevated by the increasing demand competition from independent power producers as indicated in recent government documents.[21]

51. Additionally, BLPC operates in an island environment, which means it cannot import power, but must rely on imported fuel for firm capacity and potentially needed parts. This increases BLPC's exposure to outages due to weather, technical failures, or other causes.

52. Because of BLPC's higher than average business risk and plausible added risks going forward, I recommend a ROE of 12 ½ percent, which in the light of BLPC's unique circumstances and the ROE allowed power producers in recent decisions is very reasonable.

53. Next I estimate BLPC's after-tax weighted average cost of capital ("WACC") using the cost of equity estimates shown in Figure 11, the marginal tax rate of 2.6%, and BLPC's embedded cost of debt (see Figure 10). The weighted

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[21] Ibid.

average cost of capital (after-tax WACC) results are shown in Figure 12 below.

Figure 12

After Tax WACC at 2.78% Cost of Debt and 65% Equity Capital Structure

	Low Estimate	High Estimate
CAPM	8.5%	10.2%
ECAPM	8.6%	10.4%
DCF	7.3%	9.0%
Risk Premium	8.1%	9.0%
Median	8.3%	9.6%

54. As for the WACC, it is appropriate to place BLPC in the upper half of this range at approximately 9 to 9 ½ percent (rounding to the nearest ¼ %).

55. Finally, I have also calculated BLPC's WACC using its regulatory capital structure, which includes additional sources of capital (as shown above in Figure 3). As shown in Figure 13, using the recommended cost of equity for BLPC of 12.5% and BLPC's embedded cost of debt results in a WACC of 8.79%.

Figure 13

After Tax WACC – Regulatory Capital Structure[22]

	Amount (BDS$)	Share (%)	Cost Rate	Weighted Cost Rate
Equity	508,826,918	59%	12.50%	7.34%
LT Debt	273,983,725	32%	2.78%	0.88%
Customer Deposits	47,401,616	5%	3.50%	0.19%
Deferred Investment Tax Credits	17,232,462	2%	9.10%	0.18%
Deferred Manufacturing Tax Credit	19,078,160	2%	9.10%	0.20%
Total	**866,522,880**			**8.79%**

SWORN TO by **BENTE VILLADSEN**)

Bente Villadsen)

at Damariscotta)

this day of September 30, 2021)

Before me:

Sally Kenniston

NOTARY PUBLIC

Sally Kenniston
Notary Public, Maine
My Commission Expires, March 11, 2023

[22] Numbers may not add exactly due to rounding.

BV1

Exhibit BV1: Resume of Dr. Bente Villadsen

Dr. Bente Villadsen's work concentrates in the areas of regulatory finance and accounting. Her recent work has focused on accounting issues, damages, cost of capital and regulatory finance. Dr. Villadsen has testified on cost of capital and accounting, analyzed credit issues in the utility industry, risk management practices as well the impact of regulatory initiatives such as energy efficiency and de-coupling on cost of capital and earnings. Among her recent advisory work is assisting entities in the acquisition of regulated utilities regarding issues such the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Dr. Villadsen's accounting work has pertained to disclosure issues and principles including impairment testing, fair value accounting, leases, accounting for hybrid securities, accounting for equity investments, cash flow estimation as well as overhead allocation. Dr. Villadsen has estimated damages in the U.S. as well as internationally for companies in the construction, telecommunications, energy, cement, and rail road industry. She has filed testimony and testified in federal and state court, in international and U.S. arbitrations and before state and federal regulatory commissions on accounting issues, damages, discount rates and cost of capital for regulated entities.

Dr. Villadsen holds a Ph.D. from Yale University's School of Management with a concentration in accounting. She has a joint degree in mathematics and economics (BS and MS) from University of Aarhus in Denmark. Prior to joining The Brattle Group, Dr. Villadsen was a faculty member at Washington University in St. Louis, University of Michigan, and University of Iowa.

She has taught financial and managerial accounting as well as econometrics, quantitative methods, and economics of information to undergraduate or graduate students. Dr. Villadsen serves as the president of the Society of Utility Regulatory Financial Analysts for 2016-2018.

AREAS OF EXPERTISE

- Regulatory Finance
  - Cost of Capital
  - Cost of Service (including prudence)
  - Energy Efficiency, De-coupling and the Impact on Utilities Financials
  - Relationship between regulation and credit worthiness
  - Risk Management
  - Regulatory Advisory in Mergers & Acquisitions
- Accounting and Corporate Finance
  - Application of Accounting Standards
  - Disclosure Issues
  - Forensics
  - Credit Issues in the Utility Industry
- Damages and Valuation (incl. international arbitration)
  - Utility valuation

- Lost Profit for construction, oil&gas, utilities
- Valuation of construction contract
- Damages from the choice of inaccurate accounting methdology

EXPERIENCE

Regulatory Finance

- Dr. Villadsen has testified on cost of capital and capital structure for many regulated entities including electric and gas utilities, pipelines, railroads, water utilities and barges in many jurisdictions including at the FERC, the Surface Transportation Board, the states of Alaska, Arizona, California, Hawaii, Illinois, Michigan, New Mexico, New York, Oregon, and Washington as well as in the provinces of Alberta and Ontario.
- On behalf of the Association of American Railroads, Dr. Villadsen appeared as an expert before the Surface Transportation Board (STB) and submitted expert reports on the determination of the cost of equity for U.S. freight railroads. The STB agreed to continue to use two estimation methods with the parameters suggested.
- On behalf of two taxpayers, Dr. Villadsen has testified on the methodology used to estimate the discount rate for the income approach to property valuation in Utah district court.
- For several electric, gas and transmission utilities as well as pipelines in Alberta, Canada, Dr. Villadsen filed evidence and appeared as an expert on the cost of equity and appropriate capital structure for 2015-17. Her evidence was heard by the Alberta Utilities Commission.
- For potential acquirers of electric, natural gas, and water utilities, Dr. Villadsen has conducted regulatory due diligence in the form of an assessment of the regulatory environment in the jurisdictions at issue including the ability to earn the allowed return and recover costs associated with operations or capital expenditures. Her evaluations also involved an assessment of needed capital expenditures and the recovery of such expenditure through rates or specific adjustment clauses. Her prior work includes more than 15 US states, the FERC, and several Canadian provinces.
- Dr. Villadsen has estimated the cost of capital and recommended an appropriate capital structure for natural gas and liquids pipelines in Canada, Mexico, and the US. using the jurisdictions' preferred estimation technique as well as other standard techniques. This work has been used in negotiations with shippers as well as before regulators.

- For the Ontario Energy Board Staff, Dr. Villadsen submitted evidence on the appropriate capital structure for a power generator that is engaged in a nuclear refurbishment program.
- Dr. Villadsen has advised many acquirers and potential acquirers of regulated utilities regarding the return on equity, capital structure, recovery of costs and capital expenditures, growth opportunities, and regulatory environments as well as the precedence for regulatory approval in mergers or acquisitions. Her work has pertained to many jurisdiction in the U.S. and Canada including more than 20 states and three provinces as well as the Federal Energy Regulatory Commission. She has worked on electric, natural gas, pipeline, transmission, and water utility acquisitions.
- She has estimated the cost of equity on behalf of entities such as Anchorage Municipal Light and Power, Arizona Public Service, Portland General Electric, Anchorage Water and Wastewater, NW Natural, Nicor, Consolidated Edison, Southern California Edison, American Water, California Water, and EPCOR in state regulatory proceedings. She has also submitted testimony before the FERC on behalf of electric transmission and natural gas pipelines as well as Bonneville Power Authority. Much of her testimony involves not only cost of capital estimation but also capital structure, the impact on credit metrics and various regulatory mechanisms such as revenue stabilization, riders and trackers.
- In Australia, she has submitted led and co-authored a report on cost of equity and debt estimation methods for the Australian Pipeline Industry Association. The equity report was filed with the Australian Energy Regulator as part of the APIA's response to the Australian Energy Regulator's development of rate of return guidelines and both reports were filed with the Economic Regulation Authority by the Dampier Bunbury Pipeline. She has also submitted a report on aspects of the WACC calculation for Aurizon Network to the Queensland Competition Authority.
- In Canada, Dr. Villadsen has co-authored reports for the British Columbia Utilities Commission and the Canadian Transportation Agency regarding cost of capital methodologies. Her work consisted partly of summarizing and evaluating the pros and cons of methods and partly of surveying Canadian and world-wide practices regarding cost of capital estimation.
- Dr. Villadsen worked with utilities to estimate the magnitude of the financial risk inherent in long-term gas contracts. In doing so, she relied on the rating agency of Standard & Poor's published methodology for determining the risk when measuring credit ratios.

- She has worked on behalf of infrastructure funds, pension funds, utilities and others on understanding and evaluating the regulatory environment in which electric, natural gas, or water utilities operate for the purpose of enhancing investors ability to understand potential investments. She has also provided advise and testimony in the approval phase of acquisitions.
- On behalf of utilities that are providers of last resort, she has provided estimates of the proper compensation for providing the state-mandated services to wholesale generators.
- In connection with the AWC Companies application to construct a backbone electric transmission project off the Mid-Atlantic Coast, Dr. Villadsen submitted testimony before the Federal Energy Regulatory Commission on the treatment the accounting and regulatory treatment of regulatory assets, pre-construction costs, construction work in progress, and capitalization issues.
- On behalf of ITC Holdings, she filed testimony with the Federal Energy Regulatory Commission regarding capital structure issues.
- For a FERC-regulated entity, Dr. Villadsen undertook an assessment of the company's classification of specific long-term commitments, leases, regulatory assets, asset retirement obligations, and contributions / distributions to owners in the company's FERC Form 1.
- Testimony on the impact of transaction specific changes to pension plans and other rate base issues on behalf of Balfour Beatty Infrastructure Partners before the Michigan Public Service Commission.
- On behalf of financial institutions, Dr. Villadsen has led several teams that provided regulatory guidance regarding state, provincial or federal regulatory issues for integrated electric utilities, transmission assets and generation facilities. The work was requested in connection with the institutions evaluation of potential investments.
- For a natural gas utility facing concerns over mark to market losses on long term gas hedges, Dr. Villadsen helped develop a program for basing a portion of hedge targets on trends in market volatility rather than on just price movements and volume goals. The approach was refined and approved in a series of workshops involving the utility, the state regulatory staff, and active intervener groups. These workshops evolved into a forum for quarterly updates on market trends and hedging positions.
- She has advised the private equity arm of three large financial institutions as well as two infrastructure companies, a sovereign fund and pension fund in connection with their acquisition of regulated transmission, distribution or integrated electric assets in the U.S. and Canada. For these clients, Dr. Villadsen evaluated the regulatory climate and the treatment of

acquisition specific changes affecting the regulated entity, capital expenditures, specific cost items and the impact of regulatory initiatives such as the FERC's incentive return or specific states' approaches to the recovery of capital expenditures riders and trackers. She has also reviewed the assumptions or worked directly with the acquirer's financial model.

- On behalf of a provider of electric power to a larger industrial company, Dr. Villadsen assisted in the evaluation of the credit terms and regulatory provisions for the long-term power contract.
- For several large electric utility, Dr. Villadsen reviewed the hedging strategies for electricity and gas and modeled the risk mitigation of hedges entered into. She also studies the prevalence and merits of using swaps to hedge gas costs. This work was used in connection with prudence reviews of hedging costs in Colorado, Oregon, Utah, West Virginia, and Wyoming.
- She estimated the cost of capital for major U.S. and Canadian utilities, pipelines, and railroads. The work has been used in connection with the companies' rate hearings before the Federal Energy Regulatory Commission, the Canadian National Energy Board, the Surface Transportation Board, and state and provincial regulatory bodies. The work has been performed for pipelines, integrated electric utilities, non-integrated electric utilities, gas distribution companies, water utilities, railroads and other parties. For the owner of Heathrow and Gatwick Airport facilities, she has assisted in estimating the cost of capital of U.K. based airports. The resulting report was filed with the U.K. Competition Commission.
- For a Canadian pipeline, Dr. Villadsen co-authored an expert report regarding the cost of equity capital and the magnitude of asset retirement obligations. This work was used in arbitration between the pipeline owner and its shippers.
- In a matter pertaining to regulatory cost allocation, Dr. Villadsen assisted counsel in collecting necessary internal documents, reviewing internal accounting records and using this information to assess the reasonableness of the cost allocation.
- She has been engaged to estimate the cost of capital or appropriate discount rate to apply to segments of operations such as the power production segment for utilities.
- In connection with rate hearings for electric utilities, Dr. Villadsen has estimated the impact of power purchase agreements on the company's credit ratings and calculated appropriate compensation for utilities that sign such agreements to fulfill, for example, renewable energy requirements.
- Dr. Villadsen has been part of a team assessing the impact of conservation initiatives, energy efficiency, and decoupling of volumes and revenues on electric utilities financial performance.

Specifically, she has estimated the impact of specific regulatory proposals on the affected utilities earnings and cash flow.

- On behalf of Progress Energy, she evaluated the impact of a depreciation proposal on an electric utility's financial metric and also investigated the accounting and regulatory precedent for the proposal.
- For a large integrated utility in the U.S., Dr. Villadsen has for several years participated in a large range of issues regarding the company's rate filing, including the company's cost of capital, incentive based rates, fuel adjustment clauses, and regulatory accounting issues pertaining to depreciation, pensions, and compensation.
- Dr. Villadsen has been involved in several projects evaluating the impact of credit ratings on electric utilities. She was part of a team evaluating the impact of accounting fraud on an energy company's credit rating and assessing the company's credit rating but-for the accounting fraud.
- For a large electric utility, Dr. Villadsen modeled cash flows and analyzed its financing decisions to determine the degree to which the company was in financial distress as a consequence of long-term energy contracts.
- For a large electric utility without generation assets, Dr. Villadsen assisted in the assessment of the risk added from offering its customers a price protection plan and being the provider of last resort (POLR).
- For several infrastructure companies, Dr. Villadsen has provided advice regarding the regulatory issues such as the allowed return on equity, capital structure, the determination of rate base and revenue requirement, the recovery of pension, capital expenditure, fuel, and other costs as well as the ability to earn the allowed return on equity. Her work has spanned 12 U.S. states as well as Canada, Europe, and South America. She has been involved in the electric, natural gas, water, and toll road industry.

Accounting and Corporate Finance

- For an electric utility subject to international arbitration, Dr. Villadsen submitted expert testimony on the application of IFRS as it pertains to receivables, the classification of liabilities and contingencies.
- In international arbitration, she submitted an expert report on IFRS' requirements regarding carve out financials, impairment, the allocation of costs to segments, and disclosure issues.

- On behalf of a construction company in arbitration with a sovereign, Dr. Villadsen filed an expert report report quantifying damages in the form of lost profit and consequential damages.
- In arbitration before the International Chamber of Commerce Dr. Villadsen testified regarding the true-up clauses in a sales and purchase agreement, she testified on the distinction between accruals and cash flow measures as well as on the measurement of specific expenses and cash flows.
- On behalf of a taxpayer, Dr. Villadsen recently testified in federal court on the impact of discount rates on the economic value of alternative scenarios in a lease transaction.
- On behalf of a taxpayer, Dr. Villaden has provided an expert report on the nature of the cost of equity used in regulatory proceedings as well as the interest rate regine in 2014.
- In an arbitration matter before the International Centre for Settlement of Investment Disputes, she provided expert reports and oral testimony on the allocation of corporate overhead costs and damages in the form of lost profit. Dr. Villadsen also reviewed internal book keeping records to assess how various inter-company transactions were handled.
- Dr. Villadsen provided expert reports and testimony in an international arbitration under the International Chamber of Commerce on the proper application of US GAAP in determining shareholders' equity. Among other accounting issues, she testified on impairment of long-lived assets, lease accounting, the equity method of accounting, and the measurement of investing activities.
- In a proceeding before the International Chamber of Commerce, she provided expert testimony on the interpretation of certain accounting terms related to the distinction of accruals and cash flow.
- In an arbitration before the American Arbitration Association, she provided expert reports on the equity method of accounting, the classification of debt versus equity and the distinction between categories of liabilities in a contract dispute between two major oil companies. For the purpose of determining whether the classification was appropriate, Dr. Villadsen had to review the company's internal book keeping records.
- In U.S. District Court, Dr. Villadsen filed testimony regarding the information required to determine accounting income losses associated with a breach of contract and cash flow modeling.

- Dr. Villadsen recently assisted counsel in a litigation matter regarding the determination of fair values of financial assets, where there was a limited market for comparable assets. She researched how the designation of these assets to levels under the FASB guidelines affect the value investors assign to these assets.
- She has worked extensively on litigation matters involving the proper application of mark-to-market and derivative accounting in the energy industry. The work relates to the proper valuation of energy contracts, the application of accounting principles, and disclosure requirements regarding derivatives.
- Dr. Villadsen evaluated the accounting practices of a mortgage lender and the mortgage industry to assess the information available to the market and ESOP plan administrators prior to the company's filing for bankruptcy. A large part of the work consisted of comparing the company's and the industry's implementation of gain-of-sale accounting.
- In a confidential retention matter, Dr. Villadsen assisted attorneys for the FDIC evaluate the books for a financial investment institution that had acquired substantial Mortgage Backed Securities. The dispute evolved around the degree to which the financial institution had impaired the assets due to possible put backs and the magnitude and estimation of the financial institution's contingencies at the time of it acquired the securities.
- In connection with a securities litigation matter she provided expert consulting support and litigation consulting on forensic accounting. Specifically, she reviewed internal documents, financial disclosure and audit workpapers to determine (1) how the balance's sheets trading assets had been valued, (2) whether the valuation was following GAAP, (3) was properly documented, (4) was recorded consistently internally and externally, and (5) whether the auditor had looked at and documented the valuation was in accordance with GAAP.
- In a securities fraud matter, Dr. Villadsen evaluated a company's revenue recognition methods and other accounting issues related to allegations of improper treatment of non-cash trades and round trip trades.
- For a multi-national corporation with divisions in several countries and industries, Dr. Villadsen estimated the appropriate discount rate to value the divisions. She also assisted the company in determining the proper manner in which to allocate capital to the various divisions, when the company faced capital constraints.
- Dr. Villadsen evaluated the performance of segments of regulated entities. She also reviewed and evaluated the methods used for overhead allocation.

- She has worked on accounting issues in connection with several tax matters. The focus of her work has been the application of accounting principles to evaluate intra-company transactions, the accounting treatment of security sales, and the classification of debt and equity instruments.
- For a large integrated oil company, Dr. Villadsen estimated the company's cost of capital and assisted in the analysis of the company's accounting and market performance.
- In connection with a bankruptcy proceeding, Dr. Villadsen provided litigation support for attorneys and an expert regarding corporate governance.

Damages and Valuation

- For the Alaska Industrial Development and Export Authority, Dr. Villadsen co-authored a report that estimated the range of recent acquisition and trading multiples for natural gas utilities.
- On behalf of a taxpayer, Dr. Villadsen testified on the economic value of alternative scenarios in a lease transaction regarding infrastructure assets.
- For a foreign construction company involved in an international arbitration, she estimated the damages in the form of lost profit on the breach of a contract between a sovereign state and a construction company. As part of her analysis, Dr. Villadsen relied on statistical analyses of cost structures and assessed the impact of delays.
- In an international arbitration, Dr. Villadsen estimated the damages to a telecommunication equipment company from misrepresentation regarding the product quality and accounting performance of an acquired company. She also evaluated the IPO market during the period to assess the possibility of the merged company to undertake a successful IPO.
- On behalf of pension plan participants, Dr. Villadsen used an event study estimated the stock price drop of a company that had engaged in accounting fraud. Her testimony conducted an event study to assess the impact of news regarding the accounting misstatements.
- In connection with a FINRA arbitration matter, Dr. Villadsen estimated the value of a portfolio of warrants and options in the energy sector and provided support to counsel on finance and accounting issues.

- She assisted in the estimation of net worth of individual segments for firms in the consumer product industry. Further, she built a model to analyze the segment's vulnerability to additional fixed costs and its risk of bankruptcy.

- Dr. Villadsen was part of a team estimating the damages that may have been caused by a flawed assumption in the determination of the fair value of mortgage related instruments. She provided litigation support to the testifying expert and attorneys.

- For an electric utility, Dr. Villadsen estimated the loss in firm value from the breach of a power purchase contract during the height of the Western electric power crisis. As part of the assignment, Dr. Villadsen evaluated the creditworthiness of the utility before and after the breach of contract.

- Dr. Villadsen modeled the cash flows of several companies with and without specific power contract to estimate the impact on cash flow and ultimately the creditworthiness and value of the utilities in question.

BOOKS

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"*Managing Price Risk for Merchant Renewable Investments: Role of Market Interactions and Dynamics on Effective Hedging Strategies*," (with Onur Aydin and Frank Graves), Brattle Whitepaper, January 2017.

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Report on "Cost of Capital for Telecom Italia's Regulated Business" with Stewart C. Myers and Francesco Lo Passo before the *Communications Regulatory Authority of Italy* ("AGCOM"), March 2014. *Submitted in Italian.*

"Alternative Regulation and Ratemaking Approaches for Water Companies: Supporting the Capital Investment Needs of the 21st Century," (with J. Wharton and H. Bishop), prepared for the *National Association of Water Companies*, October 2013.

"Estimating the Cost of Debt," (with T. Brown), prepared for the Dampier Bunbury Pipeline and filed with the *Economic Regulation Authority*, Western Australia, March 2013.

"Estimating the Cost of Equity for Regulated Companies," (with P.R. Carpenter, M.J. Vilbert, T. Brown, and P. Kumar), prepared for the Australian Pipeline Industry Association and filed with the *Australian Energy Regulator* and the *Economic Regulation Authority*, Western Australia, February 2013.

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"Survey of Cost of Capital Practices in Canada," (with Michael J. Vilbert and Toby Brown), prepared for *British Columbia Utilities Commission*, May 2012.

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"IFRS and You: How the New Standards Affect Utility Balance Sheets," (with Amit Koshal and Wyatt Toolson), *Public Utilities Fortnightly*, December 2010.

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"Building Sustainable Efficiency Businesses: Evaluating Business Models," (with Joe Wharton and Peter Fox-Penner), *Edison Electric Institute*, August 2008.

"Understanding Debt Imputation Issues," (with Michael J. Vilbert and Joe Wharton and *The Brattle Group* listed as an author), *Edison Electric Institute*, June 2008.

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"FERC's new ROE methodology for pipelines and electric transmission," (with Michael J. Vilbert) *UBS Fireside Chat*, June 24, 2020.

"Managing Price Risk for Merchant Renewable Investments," (with Onur Aydin) *EIA Electricity Pricing Workgroup* (webinar), April 30, 2019.

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BV2

Cost of Equity and WACC for BLPC

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Barbados Light & Power Company, Ltd.

SEPTEMBER 20, 2021

Brattle

Notice

- This report was prepared for The Barbados Light & Power Company, in accordance with The Brattle Group's engagement terms and is intended to be read and used as a whole and not in parts.

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Table of Contents

I. Introduction

The report presents the cost of equity methodology and estimates for Barbados Light and Power Company Ltd. ("BLPC" or "the Company") as well as the resulting Weighted Average Cost of Capital ("WACC"). Section II defines the cost of capital, which includes the cost of debt and cost of equity. The section explains the techniques for estimating the cost of equity in the context of utility rate regulation. Section III explains the cost of equity analyses and presents the results. Section IV discusses BLPC specific issues relevant to the cost of equity analyses. Notably, BLPC is facing a new regulatory regime, which will award separate licenses for segments of the business and require an accounting separation of the businesses. Once each business segment is regulated on a stand-alone basis, there is no reason to expect that the cost of equity is the same for all segments or that the weighted average of the cost of equity for the segments add to the cost of equity for the consolidated company.[1] Additionally, BLPC operates in an island environment and is expected to engage in substantial capital expenditures to ensure Barbados achieves the goals of its Barbados National Energy Policy, which aims to achieve 100% renewable energy and to be carbon neutral by 2030.[2] Finally, Section V concludes with a recommended range and point estimate for the return on equity ("ROE") and after-tax weighed average cost of capital ("WACC") for BLPC.

Note that the recommendation assumes that BLPC will be granted its applied for Clean Energy Transition Rider.

II. Cost of Capital Principles and Approach

A. Risk and the Cost of Capital

The cost of capital is defined as the expected rate of return in capital markets on investments of equivalent risk. Cost of capital theory illustrates the direct relationship between risk and the expected rate of return – the higher the risk, the higher the cost of capital required. This relationship is represented in the "security market risk-return line" (or "Security Market Line" for short), which is depicted in Figure 1 below.

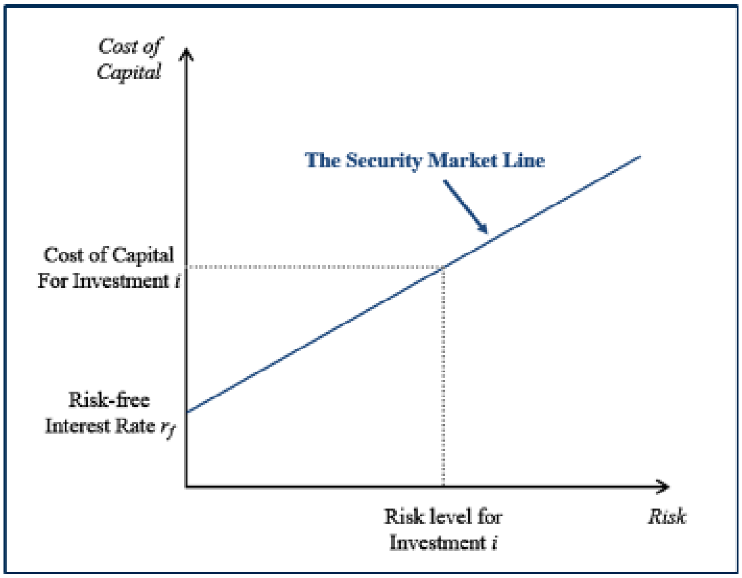
The cost of capital is comprised of the cost of debt and equity. Specifically, when estimating the cost of equity for a given asset or business, two categories of risk are important: (1) business risk and (2)

1 Weighted average means that the cost of equity is weighted by the relative size of equity used to finance the regulated rate base or assets.

2 The Barbados Government, Barbados National Energy Policy (BNEP), accessed March 18, 2021, https://energy.gov.bb/publications/barbados-national-energy-policy-bnep/.

financial risk. Business risk reflects the degree to which the cash flows generated by a business (and its assets) vary in response to moves in the broader market. Financial risk reflects the risk from the level of debt within a business.

FIGURE 1
THE SECURITY MARKET LINE



To analyze the cost of equity for BLPC, I evaluate companies of comparable business risk by choosing a proxy group of publicly traded regulated electric utilities and adjust for differences in financial risk. As a sensitivity, I also consider a sample of regulated natural gas utilities as a check on my electric results. Specifically, I use three models to analyze the cost of equity for BLPC: (1) the Capital Asset Pricing Model (CAPM) as well as an Empirical version hereof, the ECAPM, (2) Discounted Cash Flow (DCF) models, and (3) Risk Premium. Section II explains the analyses and results.

III. Estimating the Cost of Equity

A. Proxy Group Selection

BLPC is a regulated electric utility as is the majority of the proposed businesses under the new licenses albeit in some jurisdictions the Generation and Storage License portions as well as the Sales part of Transmission, Distribution and Sales licenses are not regulated. Therefore, publically traded regulated electric utilities is an appropriate starting point for selecting a proxy group of companies with comparable business risk. Ideally, these electric utilities would operate in Barbados or the Caribbean. However, there is currently insufficient data on Caribbean utilities to create a proxy group. Therefore, I create a proxy group using U.S. electric utilities.[3] In addition, I also consider a proxy group of U.S. natural gas local distribution companies ("LDCs"). I do so as a sensitivity and to check the reasonableness of my U.S. electric utility sample's CAPM/ECAPM and DCF results. While BLPC does not provide natural gas service to its customers, natural gas LDCs are similar to electric utilities in that they operate highly regulated infrastructure networks designed to delivery energy to end users, are highly capital intensive, and face the need to maintain and upgrade aging infrastructure. Additionally, gas LDCs are highly regulated and hence comparable to a regulated business. Thus, the business risk characteristics of the electric utility and gas LDC samples are broadly similar. I apply the following steps to identify utilities suitable for inclusion in the electric and natural gas proxy groups.

First, I start with the universe of publicly traded companies reported by Value Line Investment Analyzer (Value Line). Next, I narrow down this universe of companies to those that Value Line identifies as electric utilities or natural gas utilities. Then, I review business descriptions and financial reports of these companies and eliminate those that have less than 50% of their assets dedicated to regulated electric or natural gas utility activities. Within this group of companies, I apply further screening criteria to eliminate companies with recent significant events that could affect the market data necessary to perform cost of capital estimation.

Specifically, I eliminate companies that have cut dividends or engaged in substantial merger and acquisition (M&A) activities over the prior five years. I eliminate companies with such dividend cuts because the announcement of a cut may produce disturbances in the stock prices and growth rate expectations in addition to potentially being a signal of financial distress. I generally eliminate companies with significant M&A activities because such events typically affect a company's stock price in ways that are not representative of how investors perceive its business and financial risk characteristics. For example, a utility's stock price will commonly jump upon the announcement of an acquisition to match the acquirer's bid.

Additionally, I require companies have an investment grade credit rating and more than $300 million market capitalization for liquidity purposes. I also eliminate two companies for unusual recent activities that led to substantial drops in the stock price.[4] A final, and fundamental, requirement is that the proxy companies have the necessary data available for estimation. The selection process produces a proxy group of 30 regulated U.S. electric utilities and a second proxy group of 9 regulated U.S. gas LDCs. Figure 2 and Figure 3 below list the electric utilities and regulated gas LDCs in my proxy groups, respectively, and their selected financial characteristics.

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3 There are no investment-grade electric generation businesses in the U.S. at this time.

4 FirstEnergy and Portland General Electric.

FIGURE 2
ELECTRIC UTILITY PROXY GROUP

Company	Annual Revenue (Q2 2021) ($MM)	Regulated Assets	Market Cap. (Q2 2021) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	$1,289	MR	$3,625	0.90	BBB	6.6%
Alliant Energy	$3,455	R	$14,347	0.85	A-	5.4%
Amer. Elec. Power	$15,785	R	$42,056	0.75	A-	6.1%
Ameren Corp.	$5,994	R	$21,367	0.85	BBB+	7.4%
Avista Corp.	$1,364	R	$3,074	0.95	BBB	6.3%
Black Hills	$1,839	R	$4,338	1.00	BBB+	4.9%
CMS Energy Corp.	$7,014	R	$17,225	0.80	BBB+	6.4%
CenterPoint Energy	$7,965	R	$14,896	1.15	BBB+	5.4%
Consol. Edison	$12,941	R	$26,470	0.75	A-	2.7%
Dominion Energy	$14,036	R	$61,192	0.85	BBB+	6.0%
Duke Energy	$24,406	R	$77,403	0.90	BBB+	5.6%
Edison Int'l	$14,076	R	$21,642	1.00	BBB	4.6%
Entergy Corp.	$10,941	R	$21,010	0.95	BBB+	4.6%
Evergy Inc.	$5,460	R	$14,375	0.95	A-	5.0%
Eversource Energy	$9,526	R	$27,898	0.90	A-	6.9%
Exelon Corp.	$34,775	MR	$44,361	0.95	BBB+	4.4%
Hawaiian Elec.	$2,617	MR	$4,709	0.85	BBB-	3.5%
IDACORP Inc.	$1,417	R	$5,038	0.85	BBB	3.9%
MGE Energy	$570	R	$2,731	0.75	AA-	4.9%
NextEra Energy	$16,833	MR	$144,657	0.95	A-	9.2%
NorthWestern Corp.	$1,293	R	$3,216	0.95	BBB	3.6%
OGE Energy	$3,396	R	$6,877	1.05	BBB+	4.8%
Otter Tail Corp.	$1,010	R	$2,029	0.90	BBB	7.4%
Pinnacle West Capital	$3,692	R	$9,471	0.95	A-	3.2%
Public Serv. Enterprise	$9,535	MR	$30,474	0.95	BBB+	3.2%
Sempra Energy	$11,815	R	$43,601	1.00	BBB+	5.7%
Southern Co.	$21,845	R	$65,986	0.95	A-	6.9%
Unitil Corp.	$440	R	$829	0.85	BBB+	6.5%
WEC Energy Group	$7,952	R	$28,673	0.80	A-	6.6%
Xcel Energy Inc.	$12,738	R	$36,328	0.80	A-	6.2%
Electric Sample	$8,867		$26,663	0.90	BBB+	5.5%

Sources and Notes:
[1]: Bloomberg as of August 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of August 31, 2021.
[6]: See Schedule No. BV-5.

FIGURE 3
NATURAL GAS LDC PROXY GROUP

Company	Annual Revenue (Q2 2021) ($MM)	Regulated Assets	Market Cap. (Q2 2021) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
Atmos Energy	$3,314	R	$12,959	0.80	A-	7.0%
Chesapeake Utilities	$541	R	$2,113	0.80	BBB+	6.1%
New Jersey Resources	$2,024	MR	$4,025	1.00	BBB+	4.9%
NiSource Inc.	$4,645	R	$9,947	0.85	BBB+	8.6%
Northwest Natural	$818	R	$1,643	0.85	A	5.0%
ONE Gas Inc.	$1,670	R	$4,062	0.80	BBB+	5.9%
South Jersey Inds.	$1,733	R	$3,017	1.05	BBB	9.0%
Southwest Gas	$3,413	R	$3,860	0.95	BBB+	6.7%
Spire Inc.	$2,197	R	$3,804	0.85	A-	5.7%
Gas Sample	$2,262		$5,048	0.88	BBB+	6.5%

Sources and Notes:
[1]: Bloomberg as of August 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of August 31, 2021.
[6]: See Schedule No. BV-5.

B. Financial Risk Adjustment

Taking the level of financial risk or leverage into account is necessary to reflect the fact that different capital structure ratios have different levels of financial risk. Specifically, all else equal, higher levels of debt financing increases the risk faced by equity investors. Therefore, investors require higher ROEs from companies with more debt than from comparable business risk companies with less debt. To reflect the effect of capital structure on the cost of equity, I adjust the cost of equity estimates I obtain from applying the models to the market data of the proxy companies. I do so using two different approaches: (1) the overall cost of capital approach and (2) the Hamada approach. Details of these two approaches are provided in Appendix A.

I estimate BLPC's cost of equity using the company's policy-based capital structure of 65% equity and 35% debt. The Company's regulatory capital structure includes additional sources of capital such as customer deposits, deferred manufacturing tax credits, and deferred investment tax credits. This results in a regulatory capital structure with 59% equity, 32% debt. Figure 4 below demonstrates the differences between BLPC's policy-based capital structure and regulatory capital structure.

FIGURE 4
BLPC CAPITAL STRUCTURE

Policy Based Capital Structure

	Amount (BDS$)	Share (%)
Equity	508,826,918	65%
Debt	273,983,725	35%
Total	**782,810,643**	**100%**

Regulatory Capital Structure

	Amount (BDS$)	Share (%)
Equity	508,826,918	59%
Debt	273,983,725	32%
Customer Deposits	47,401,616	5%
Deferred Investment Tax Credits	17,232,462	2%
Deferred Manufacturing Tax Credit	19,078,160	2%
Total	**866,522,880**	**100%**

Source: Barbados Light & Power, year-end 2020

The Commission in its January 2010 decision regarding BLPC approved the use of a hypothetical capital structure including 65 percent equity,[5] which is the policy based capital structure used in this report.

C. CAPM/ECAPM Approach and Cost of Equity Estimates

1. CAPM Approach

The CAPM is a "risk-positioning model" that models the direct relationship between risk and return illustrated in the Security Market Line (see Figure 1 above). More precisely, the CAPM states that the cost of capital for an investment, S (e.g., a particular common stock), is determined by the risk-free rate plus the stock's systematic risk multiplied by the market risk premium (MRP). Mathematically, the relationship is shown by the following formula:

[5] Decision and Order, No. 0002/09, ¶104.

$$r_s = r_f + \beta_s \times MRP \tag{1}$$

where r_S is the cost of capital for investment S;

r_f is the risk-free interest rate;

β_S is the beta risk measure for the investment S; and

MRP is the market equity risk premium.

2. ECAPM Approach

Another risk-positioning model is the Empirical CAPM (ECAPM), which builds upon the CAPM. Empirical research has found that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted. The ECAPM corrects for this by adjusting the CAPM using the formula below:

$$r_S = r_f + \alpha + \beta_S \times (MRP - \alpha) \tag{2}$$

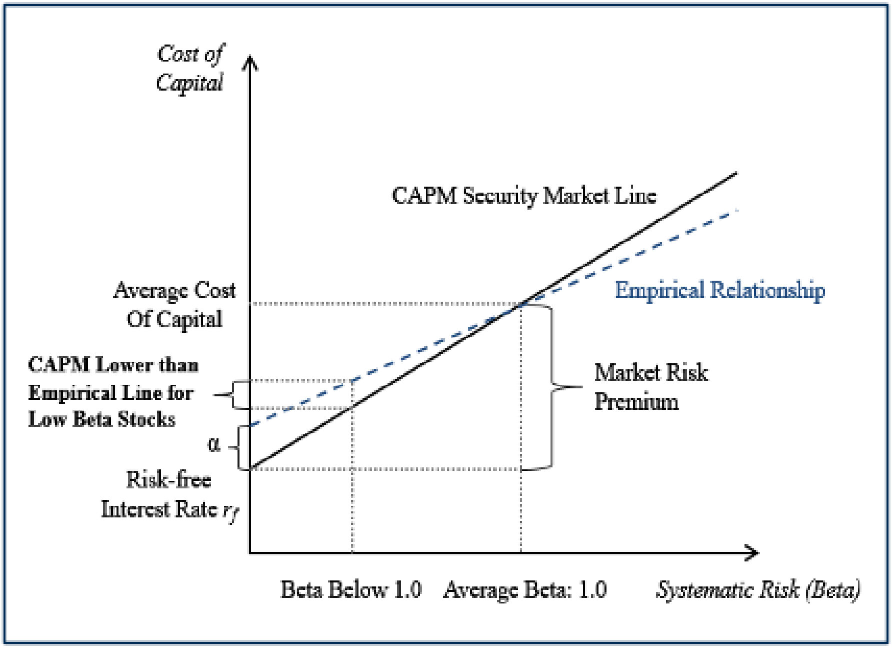
where α is the "alpha" adjustment of the risk-return line, a constant; and

r_S, β_S, and MRP are defined in formula (1) above.

The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 1, which results in a Security Market Line that more closely matches the results of empirical tests. The impact on the Security Market Line is illustrated in Figure 5 below. In the ECAPM implementation, I use an alpha of 1.5 based on academic research documenting the magnitude of alpha.[6]

[6] See Black, Fisher. 1993. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18; Black, Fisher, Michael C. Jensen, and Myron Scholes. 1972. The Capital Asset Pricing Model: Some Empirical Tests. *Studies in the Theory of Capital Markets*, edited by Michael C. Jensen, pp. 79-121. New York: Praeger; Fama, Eugene F. and James D. MacBeth. 1972. Risk, Returns and Equilibrium: Empirical Tests. *Journal of Political Economy* 81 (3): pp. 607-636; Fama, Eugene F. and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): pp. 427-465; Fama, Eugene F. and Kenneth R. French. 2004. The Capital Asset Pricing Model: Theory and Evidence. *Journal of Economic Perspectives* 18 (3): pp. 25-46.

FIGURE 5
THE EMPIRICAL SECURITY MARKET LINE



3. CAPM/ECAPM Cost of Equity Estimates

I performed the CAPM/ECAPM analysis using different sensitivities to obtain a range of cost of equity estimates. Specifically, I use an unadjusted historic U.S. MRP in one scenario; whereas, in the second scenario I use a forward looking estimate of U.S. MRP from Bloomberg.

In Scenario 1, I use a long-term historical MRP of 7.25% and a forecasted risk-free rate of 2.97%.[7] In Scenario 2, I present a sensitivity using a forecasted MRP of 8.57% and a forecasted risk-free rate of 2.97%.[8] Scenario 2 considers that the MRP has increased relative to the historical long-run average. Figure 6 below shows the different inputs used in Scenario 1 and Scenario 2.

7 The MRP of 7.25% is sourced from Duff & Phelps Cost of Capital Navigator 2020. The risk-free rate is derived from the August 2021 Blue Chip Economic Indicators (BCEI) forecasted 10-year Treasury yield forecast for 2022 and the March 2021 BCEI long-term 10-year Treasury yield forecast average over 2023 to 2026. My analysis relies on the 30-year Treasury yield as a measure of the risk-free rate. Therefore, I adjust the BCEI forecasted 10-year Treasury yield to approximate a 30-year Treasury yield by adding a maturity premium of 53 bps to the BCEI forecast Figure A-3 in the Appendix A shows the derivation of the 53 bps maturity premium, which result in a risk-free rate of 2.97%.

8 The MRP sourced from Bloomberg and estimated over a 30-year Treasury yield.

FIGURE 6
SCENARIOS FOR CAPM/ECAPM ANALYSIS

	Scenario 1	Scenario 2
Risk-Free Interest Rate	2.97%	2.97%
Market Risk Premium	7.25%	8.57%

Additionally, I apply a two-step approach to adapt the CAPM/ECAPM cost of equity estimates for BLPC. First, I use a standard approach to estimate the cost of equity for a U.S. electric utility using the proxy group shown in Figure 2 and, as a sensitivity, a gas LDC proxy group shown in Figure 3. Second, I apply a Caribbean region-specific risk premium to better estimate the cost of equity for an electric utility or natural gas utility located in this region. I bound the region-specific risk premiums from a low of 2.78% to a high of 4.19%,[9] but note that the 2.78% are an absolute minimal CRP as it is measured using debt instruments rather than equity instruments. Consequently, a more realistic CRP is somewhat above the 2.78%, so that a range of 3.49% (the average of 2.78% and 4.19%) to 4.19% is more reasonable. The financial risk adjusted CAPM/ECAPM estimates are presented in Figure 7 (Electric Utility Sample) and Figure 8 (Gas LDC Sample) below.

9 Based on Caribbean region-specific risk premium derived from Aswath Damodaran's "Country Default Spreads and Risk Premiums" estimates from January 2017 to July 2021. In my review of the country risk premia, I focused on the average of risk premium for (a) Caribbean countries with an investment grade bond ratings and (b) all Caribbean countries over the January 2017 to July 2021 time period. This resulted is risk premia of 1.91% and 4.19% respectively. The lower bound was adjusted upwards to 2.78%, which reflects the BLPC's weighted average cost of debt (see Figure 13 below). I also checked these figures against those provided in Duff & Phelps, Cost of Capital Navigator, Guide to International Cost of Capital.

FIGURE 7

ELECTRIC UTILITY SAMPLE - CAPM/ECAPM COST OF EQUITY ESTIMATES AT 65% EQUITY CAPITAL STRUCTURE

Estimated Return on Equity	Country Risk Premium (2.78%) Scenario 1 [1]	Country Risk Premium (2.78%) Scenario 2 [2]	Country Risk Premium (4.19%) Scenario 1 [3]	Country Risk Premium (4.19%) Scenario 2 [4]
Electric Sample				
Overall Cost of Capital Adjustment				
CAPM	11.7%	12.8%	13.1%	14.2%
ECAPM (α = 1.5%)	11.8%	12.9%	13.2%	14.3%
Hamada Adjustment Without Taxes				
CAPM	11.7%	12.8%	13.1%	14.2%
ECAPM (α = 1.5%)	12.0%	13.0%	13.4%	14.5%
Hamada Adjustment With Taxes				
CAPM	11.7%	12.8%	13.1%	14.2%
ECAPM (α = 1.5%)	12.0%	13.1%	13.4%	14.5%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 2.78%.
[2]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 2.78%.
[3]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 4.19%.
[4]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 4.19%.

Based on the results in Figure 7 above, a reasonable range for the ROE of the comparable sample applied to a Barbados-based electric utility is 12 ¼ to 13½ percent for a point estimate of 12 ¾ percent.[10]

Using the gas LDC sample, shown in Figure 3 above, I performed a sensitivity of the CAPM/ECAPM model. The CAPM/ECAPM results range from 11.9% to 14.7%. This generally aligns with the CAPM/ECAPM results from the electric utility sample, shown in Figure 7.

[10] The point estimate is derived as the average of the upper half of the range rounding to the nearest ¼ percent.

FIGURE 8

GAS LDC SAMPLE - CAPM/ECAPM COST OF EQUITY ESTIMATES AT 65% EQUITY CAPITAL STRUCTURE

Estimated Return on Equity	Country Risk Premium (2.78%) Scenario 1 [1]	Country Risk Premium (2.78%) Scenario 2 [2]	Country Risk Premium (4.19%) Scenario 1 [3]	Country Risk Premium (4.19%) Scenario 2 [4]
Gas Sample				
Overall Cost of Capital Adjustment				
CAPM	11.9%	13.1%	13.3%	14.5%
ECAPM (α = 1.5%)	12.1%	13.2%	13.5%	14.6%
Hamada Adjustment Without Taxes				
CAPM	11.9%	13.0%	13.3%	14.4%
ECAPM (α = 1.5%)	12.1%	13.3%	13.5%	14.7%
Hamada Adjustment With Taxes				
CAPM	11.9%	13.0%	13.3%	14.4%
ECAPM (α = 1.5%)	12.1%	13.3%	13.5%	14.7%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 2.78%.
[2]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 2.78%.
[3]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 7.25%, Country Risk Premium of 4.19%.
[4]: Long-Term Risk Free Rate of 2.97%, Long-Term Market Risk Premium of 8.57%, Country Risk Premium of 4.19%.

The results for the gas LDC sample is higher than those for the electric sample and thus affirms that the reasonable range and point estimate for the electric sample is reasonable and conservative.

D. DCF Approach and Cost of Equity Estimates

The DCF model estimates the cost of capital for a given company directly, rather than based on its risk relative to the market as the CAPM does. There are two variations of the DCF model, the single-stage DCF and multi-stage DCF, as explained below.

1. Single-Stage DCF Approach

The single-stage DCF model assumes that the current market price of a stock is equal to the present value of the dividends that its owners expect to receive. The expected stream of future dividends is discounted at a risk-appropriate rate to arrive at the present value of the dividends, represented by the current stock price. In this application of the DCF, the risk-appropriate rate is the cost of equity. Mathematically, the DCF model is shown in the formula below:

$$\boldsymbol{P_0} = \frac{\boldsymbol{D_1}}{\boldsymbol{1+r}} + \frac{\boldsymbol{D_2}}{(\boldsymbol{1+r})^2} + \frac{\boldsymbol{D_3}}{(\boldsymbol{1+r})^3} + \cdots + \frac{\boldsymbol{D_T}}{(\boldsymbol{1+r})^T} \tag{3}$$

where $\boldsymbol{P_0}$ is the current market price of the stock;

D_t is the dividend expected at the end of period t;

T is the last period in which a dividend is to be received; and

r is the cost of equity capital.

Formula (3) implies that if one knows the current market price of a stock and its expected stream of future dividends, then it is possible to solve for the cost of equity, r. The single-stage DCF model assumes that the stream of future dividends will grow at a constant rate into perpetuity. This assumption allows formula (3) to be algebraically rearranged into the formula below to directly estimate the cost of equity:

$$r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1 + g) + g \tag{4}$$

where D_0 is the current dividend; and

g is the constant growth rate of the current dividend.

Another variation of the DCF model relaxes the restrictive constant growth rate assumption and instead, allows the dividend to grow at different rates at different points in time. This variation is known as the multi-stage DCF model and is further explained below.

2. Multi-Stage DCF Approach

The multi-stage DCF accommodates different dividend growth rates at different points in time. Specifically, in the implementation of the multi-stage DCF, I assume three different growth rate phases. In the first phase, companies grow their dividend for five years at the forecasted company-specific rate of earnings growth. In the second phase, the company-specific growth rate incrementally steps down (or steps up) to the overall growth rate of the economy, represented by the long-term GDP growth rate. Finally, in the third phase, companies grow their dividend at the long-term GDP growth rate in perpetuity. This latter part could be problematic as it is plausible that the GDP growth rate in Barbados is higher than that of the U.S. either because real growth is higher or because inflation is higher. My approach of using the U.S. growth rate implicitly assumes that the country risk premium will account for any differences in growth patterns.

3. DCF Cost of Equity Estimates

The financial risk adjusted single- and multi-stage DCF cost of equity estimates for the electric utility sample are presented in Figure 9 below. The DCF results from the electric utility sample range from 9.7% to 12.3%.

FIGURE 9

ELECTRIC UTILITY SAMPLE - DCF COST OF EQUITY ESTIMATES AT 65% EQUITY CAPITAL STRUCTURE

	Country Risk Premium (2.78%)	Country Risk Premium (4.19%)
	[1]	[2]
Simple	10.9%	12.3%
Multi-stage	9.7%	11.2%

Based on the results in Figure 9 a reasonable range for the average sample company is 10 ¾ percent to 12 ¼ percent with a point estimate of 11 ½ percent.

The results from the natural gas LDC sample are presented in Figure 10 below. The DCF results range from 9.8% to 13.0%. The results are generally in-line to slightly higher than the electric utility sample DCF results.

FIGURE 10

GAS LDC SAMPLE - DCF COST OF EQUITY ESTIMATES AT 65% EQUITY CAPITAL STRUCTURE

	Country Risk Premium (2.78%)	Country Risk Premium (4.19%)
	[1]	[2]
Simple	11.6%	13.0%
Multi-stage	9.8%	11.3%

E. Risk Premium Approach and Cost of Equity Estimates

The Risk Premium approach adds a "risk premium" to the current risk-free rate to estimate the current cost of equity, as shown in formula (5) below.

$$\boldsymbol{Cost\ of\ Equity = r_f + Risk\ Premium} \quad (5)$$

The risk premium component of formula (5) is estimated using the allowed ROEs and prevailing risk-free rates from past electric utility rate cases. In our implementation, I calculate the risk premium as the difference between allowed ROEs and the prevailing quarterly 30-year Treasury bond yield over the period 1990-2021.[11] This difference represents the compensation for risk allowed by regulators. I use the statistical technique of ordinary least squares (OLS) regression to estimate the parameters of the linear equation:

$$\boldsymbol{Risk\ Premium} = \boldsymbol{A_0} + \boldsymbol{A_1} \times (\boldsymbol{r_f}) \tag{6}$$

where $\boldsymbol{A_0}$ and $\boldsymbol{A_1}$ are parameters to be estimated by the regression technique; and
$\boldsymbol{r_f}$ is the risk-free rate as measured by the 30-year Treasury bond yield.

The parameters estimated by regression analysis (i.e., OLS) are shown in Figure 11 below. Additionally, the regression analysis finds that the risk-free rate has a high degree of statistical explanatory power in capturing changes in the risk premium. The negative coefficient A1 reflects the empirical fact that regulators grant lower risk premiums–and by extension, lower allowed ROEs–when the risk-free rate is higher. This is consistent with the observation that investors require a higher risk premium to hold equities over government bonds as bond yields decline. I then use the parameters from the regression analysis, A0 and A1, to estimate the cost of equity using the Scenario 1 and Scenario 2 risk-free rates (shown in Figure 6 above).

Specifically, applying the calculated risk premium and a risk-free rate of 2.97% to formula (5) above results in an estimated cost of equity of 9.8% for U.S. electric utilities. The cost of equity results for U.S. electric utilities is reported in Figure 11 below.

[11] I rely on the 30-year government bond to be consistent with the analysis using the CAPM to avoid confusion about the risk-free rate. While it is important to use a long-term risk-free rate to match the long-lived nature of the assets, the exact maturity is a matter of choice.

FIGURE 11

ELECTRIC UTILITY - IMPLIED RISK PREMIUM MODEL ESTIMATE

Risk Premium = A_0 + (A_1 x Treasury Bond Rate)

R Squared	0.846
Estimate of Intercept (A_0)	8.37%
Estimate of Slope (A_1)	-0.528

Predicted Risk Premium		Exp. Treasury Bond Rate		Est. Cost of Equity for All Electric Gas Utilities
6.80%	+	2.97%	=	9.8%

Sources and Notes:

[1]: Authorized ROE data from S&P Market Intelligence as of 09/14/2021.

[2]: March and August 2021 Blue Chip consensus forecast for 2022-2026 10 year T-bill yield + maturity premium between 10 year and 30 year U.S. Government bonds.

See Regression Results for derivation of regression coefficients A_0 and A_1

Next, I apply a financial risk adjustment and a country risk premium of 2.78% and 4.19% to the U.S. electric utility cost of equity estimate. These two adjustments result in cost of equity estimates for a Barbados based electric utility with a capital structure of 65% equity (and 35% debt). The adjusted risk premium cost of equity estimates for an electric utility with 65% equity are shown in Figure 12 below.

FIGURE 12

ELECTRIC UTILITY - IMPLIED RISK PREMIUM MODEL ESTIMATES

Country Risk Premium (2.78%)	Country Risk Premium (4.19%)
11.0%	12.4%

Based on the results in Figure 12 above, a reasonable range for the cost of equity is 11 percent to 12 ½ percent for a point estimate of about 11 ¾ percent.

The three models, CAPM, DCF, and risk premium, have been used in BLPC's prior proceedings before the Commission.[12]

[12] See, for example, Decision and Order, No. 0002/09.

IV. Barbados Light and Power Company Specific Circumstances

A. Debt

Regarding BLPC's embedded cost of debt, Figure 13 shows that BLPC's embedded cost of debt as of year-end 2020 is 2.78%. This is below the current borrowing rate for utilities in the U.S. or Canada. As of August 31, 2021, the yield on 30-year U.S. BBB rated utility bonds was 3.16%, so BLPC's embedded cost of debt is approximately 38 basis points lower.

FIGURE 13
BLPC WEIGHTED AVERAGE COST OF DEBT

	Rate	Per 2020 Financials	Adjustments	2020 Rate Base	Weighted Rate
BNS USD	4.50%	20,952,696		20,952,696	0.41%
NIS 1	3.50%	20,000,000		20,000,000	0.31%
NIS 2	5.88%	20,000,000		20,000,000	0.51%
BNS 1	2.25%	51,000,000		51,000,000	0.50%
BNS 2	2.05%	76,894,489	33,105,511	110,000,000	0.99%
RBC	4.00%	3,520,379		3,520,379	0.06%
LED	0.00%	3,351,974		3,351,974	0.00%
		195,719,538		228,825,049	2.78%

Source: Barbados Light & Power Company, year-end 2020.

V. Conclusion

The cost of equity estimates resulting from our analysis range from 9.7% to 14.5%, as summarized in Figure 14 below, but a reasonable cost of equity is higher as discussed above. Specifically, as discussed above, the best point estimate is 12 ½ percent. I note that the recommendation of 12 ½ percent assumes that the Clean Energy Transition Rider (CETR) is approved. If CETR were not approved, a higher ROE would be warranted to account for the higher business risk faced by the Company.

FIGURE 14[13]

SUMMARY OF ELECTRIC COST OF EQUITY ESTIMATES AT 65% EQUITY CAPITAL STRUCTURE

	Low Estimate	High Estimate	Point Estimate
CAPM	11.7%	14.2%	12.75%
ECAPM	11.8%	14.5%	12.75%
DCF	9.7%	12.3%	11.50%
Risk Premium	11.0%	12.4%	11.75%
Median	11.3%	13.3%	12.25%

As noted previously, the low end of the CRP is underestimating the cost of equity because it is based on the premium required for debt. As a point of comparison, I note that recently independent power producers (IPPs) in Barbados were awarded a cost of equity of up to 14%,[14] as part of BLPC's Feed-in-Tariffs for renewable energy resources.[15] While, the risks IPPs face are higher than those regulated utilities face, the median results in the upper half of the range are 70 to 167 basis points lower than the ROE awarded to IPPs. Taken together with BLPC's unique business risk factors, I find that BLPC should be placed in the upper half of the range of 12.25% to 13.25%.

BLPC is a small electric utility facing substantial risk from changes to the regulatory regime and from being regulated as an even smaller company through the split of the one license into three. Specifically, based on BLPC's annual revenue of USD$197 million and total assets of USD$467 million[16], the Company is smaller than the average electric utility with revenue of USD$8,867 million and total assets of USD$47,484 million.[17] According to Duff & Phelps Size Premium Study[18], BLPC is in the 25th portfolio (out of 25) in terms of annual revenue and the 25th portfolio in terms of total assets, compared to the average electric proxy company which is in the 8th and 3rd portfolios, respectively.[19] Duff & Phelps

13 Based on results from electric utility proxy sample.

14 Based on a 50% and 60% debt capitalization for solar PV and land-based wind projects greater than 1MW, respectively. For solar, wind, and other technologies less than 1MW, 14% is based on 50% to 80% debt capitalization.

15 Fair Trading Commission, "Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies up to and Including 1 MW," September 24, 2019, FTCUR/DECFIT/2019-04, pp. 28-30.

Fair Trading Commission, "Decision and Order on Feed-in-Tariffs for Renewable Energy Technologies above 1MW and up to 10MW," September 30, 2020, FTCUR/DECFIT/2020-01, p. 22.

16 BLPC Non-consolidated Financial Statements Year Ended December 31, 2020. Barbados dollars converted to USD at a ratio of 2:1, as per the Central Bank of Barbados http://www.centralbank.org.bb/search/article/10354/sir-courtney-a-leader-extraordinaire-a-visionary-and-a-believer-in-humanity.

17 Similarly, I note the average gas LDC proxy company has annual revenue of USD$2,262 million and total assets of USD$9,527.

18 Duff & Phelps Cost of Capital Navigator, Supplementary Risk Premium Report Study Data, 2021.

19 The average gas LDC proxy company is in the 17th portfolio for annual revenues and 9th portfolio for total assets.

estimates that the return premium demanded by investors to invest in a company the size of BLPC is approximately 6.0% to 7.0% relative to a company the size of the average proxy electric utility.[20] The size effect will be magnified as BLPC starts operating three licenses instead of the current single license. Consequently, the recommendation of placing BLPC in the upper end of the estimates for the sample is conservative.

Further, BLPC faces significant capital investments over the coming years as demonstrated in the Capital Expenditures Memorandum submitted as part of BLPC's application, which will support the transition to renewable energy in Barbados. The need for such capital investments will increase BLPC's fixed cost and (i) capital expenditures creates construction risk and (ii) high fixed costs increases business risks as any variation in revenue will increase with an increase in the proportion of fixed costs. The increase in risk is further elevated by the increasing demand competition from independent power producers as indicated in recent government documents.[21]

Additionally, BLPC operates in an island environment, which means it cannot import power, but must rely on imported fuel for firm capacity and potentially needed parts. The lack of access to power, should the need arise, increases BLPC's exposure to outages due to weather, technical failures, or other causes. Further, any needed fuel sources or parts must be imported and such imports are commonly paid in foreign currency, which may cause a liquidity problem; especially if Barbados' economy declines.

Because of BLPC's higher than average business risk and plausible added risks going forward, I recommend a ROE of 12 ½ percent, which in the light of BLPC's unique circumstances and the ROE allowed power producers in recent decisions is very reasonable and perhaps conservative.

Next I estimate BLPC's after-tax weighted average cost of capital ("WACC") using the cost of equity estimates shown in Figure 14, the marginal tax rate of 2.6%, and BLPC's embedded cost of debt (see Figure 13). The weighted average cost of capital (after-tax WACC) results are shown in Figure 15 below.

[20] Premium is approximately 3.0% to 5.5% relative to the average proxy gas LDC company.

[21] Ibid.

FIGURE 15

AFTER TAX WACC AT 2.78% COST OF DEBT AND 65% EQUITY CAPITAL STRUCTURE

	Low Estimate	High Estimate
CAPM	8.5%	10.2%
ECAPM	8.6%	10.4%
DCF	7.3%	9.0%
Risk Premium	8.1%	9.0%
Median	8.3%	9.6%

As for the WACC, it is appropriate to place BLPC in the upper half of this range at approximately 9 to 9 ½ percent (rounding to the nearest ¼ %).

Finally, I have also calculated BLPC's WACC using its regulatory capital structure, which includes additional sources of capital (as shown above in Figure 4). As shown in Figure 16, using the recommended cost of equity for BLPC of 12.50% and BLPC's embedded cost of debt results in a WACC of 8.79%.

FIGURE 16

AFTER TAX WACC – REGULATORY CAPITAL STRUCTURE[22]

	Amount (BDS$)	Share (%)	Cost Rate	Weighted Cost Rate
Equity	508,826,918	59%	12.50%	7.34%
LT Debt	273,983,725	32%	2.78%	0.88%
Customer Deposits	47,401,616	5%	3.50%	0.19%
Deferred Investment Tax Credits	17,232,462	2%	9.10%	0.18%
Deferred Manufacturing Tax Credit	19,078,160	2%	9.10%	0.20%
Total	**866,522,880**			**8.79%**

[22] Numbers may not add exactly due to rounding.

Appendix A: Financial Risk and the Cost of Equity

A. Financial Risk and the Cost of Equity

A common issue in regulatory proceedings is how to apply data from a benchmark set of comparable securities when estimating a fair return on equity for the target/regulated company.[23] It may be tempting to simply estimate the cost of equity capital for each of the proxy companies (using one of the above approaches) and average them. After all, the companies were chosen to be comparable in their business risk characteristics, so why would an investor necessarily prefer equity in one to the other (on average)?

The problem with this argument is that it ignores the fact that underlying asset risk (i.e., the risk inherent in the lines of business in which the firm invests its assets) for each company is typically divided between debt and equity holders. The firm's debt and equity are therefore financial derivatives of the underlying asset return, each offering a differently structured claim on the cash flows generated by those assets. Even though the risk of the underlying assets may be comparable, a different capital structure splits that risk differently between debt and equity holders.

The relative structures of debt and equity claims are such that higher degrees of debt financing increase the variability of returns on equity, *even when the variability of asset returns remains constant*. Consequently, otherwise identical firms with different capital structures will impose different levels of risk on their equity holders. Stated differently, increased leverage adds financial risk to a company's equity.[24]

1. The Effect of Financial Leverage on the Cost of Equity

To develop an intuition for the manner in which financial leverage affects the risk of equity, it is helpful to consider a concrete example. Figure A-1 and Figure A-2 below demonstrate the impact of leverage on the risk and return for equity by comparing equity's risk when a company uses no debt to finance its assets, and when it uses a 50-50 capital structure (i.e., it finances 50% of its assets with equity, 50% with debt). For illustrative purposes, the figures assume that the cash flows will be either $5 or $15

23 This is also a common valuation problem in general business contexts.

24 I refer to this effect in terms of financial risk because the additional risk to equity holders stems from how the company chooses to finance its assets. In this context, financial risk is distinct from and independent of the business risk associated with the manner in which the firm deploys its cash flow generating assets. The impact of leverage on risk is conceptually no different than that faced by a homeowner who takes out a mortgage. The equity of a homeowner who finances his home with 90% debt is much riskier than the equity of one who only finances with 50% debt.

and that these two possibilities have the same chance of occurring (e.g., the chance that either occurs is ½).

FIGURE A-1: ALL EQUITY CAPITAL STRUCTURE

	Probability	Asset Cash Flow	Debt Service	Equity Dividend	ROE	
\$100	½	\$15	\$0	\$15	15/100 =	15%
	½	\$5	\$0	\$5	5/100 =	5%
					E(ROE)=	*10%*
					σ(ROE)=	*5%*

FIGURE A-2: 50/50 CAPITAL STRUCTURE

	Probability	Asset cash flow	Debt Service	Equity Dividend	ROE	
\$100	½	\$15	\$2.50	\$12.50	12.50/50 =	25%
	½	\$5	\$2.50	\$2.50	2.50/50 =	5%
					E(ROE)=	*15%*
					σ(ROE)=	*10%*

In the figures, E(ROE) indicates the mean return and σ(ROE) represents the standard deviation. This simple example illustrates that the introduction of debt increases both the mean (expected) return to equity holders and the variance of that return, even though the firm's expected cash flows—which are a property of the line of business in which its assets are invested—are unaffected by the firm's financing choices. The "magic" of financial leverage is not magic at all—leveraged equity investors can only earn a higher return because they take on greater risk.

B. Methods to Account for Financial Risk

1. Cost of Equity Implied by the Overall Cost of Capital

If the companies in a proxy group are truly comparable in terms of the systematic risks of the underlying assets, then the overall cost of capital of each company should be about the same across companies (except for sampling error), so long as they do not use extreme leverage or no leverage. The intuition here is as follows. A firm's asset value (and return) is allocated between equity and debt holders.[25] The expected return to the underlying asset is therefore equal to the value weighted average of the expected returns to equity and debt holders – which is the overall cost of capital (***r****), or the expected return on the assets of the firm as a whole.[26]

25 Other claimants can be added to the weighted average if they exist. For example, when a firm's capital structure contains preferred equity, the term $\frac{P}{V} \times r_p$ is added to the expression for the overall cost of capital shown in Equation (A-1), where P refers to the market value of preferred equity, r_P is the cost of preferred equity and $V = E + D + P$. In the case of BLPC, there is no preferred equity, but refer to Figure 16 for a description of the components used for regulatory purposes.

26 As this is on an after-tax basis, the cost of debt reflects the tax value of interest deductibility. Note that the precise formulation of the weighted average formula representing the required return on the firm's assets independent of financing (sometimes called the *unlevered* cost of capital) depends on specific assumptions made regarding the value of tax shields from tax-deductible corporate debt, the role of personal income tax, and the cost of financial distress. See Taggart, Robert A.,

$$r^* = \frac{E}{V} \times r_E + \frac{D}{V} \times r_D(1 - \tau_c) \quad \text{(A-1)}$$

where r_D is the market cost of debt,

r_E is the market cost of equity,

τ_c is the corporate income tax rate,

D is the market value of the firm's debt,

E is the market value of the firm's equity, and

$V = E + D$ is the total market value of the firm.

Since the overall cost of capital is the cost of capital for the underlying asset risk, and this is comparable across companies, it is reasonable to believe that the overall cost of capital of the underlying companies should also be comparable, so long as capital structures do not involve unusual leverage ratios compared to other companies in the industry.[27]

The notion that the overall cost of capital is constant across a broad middle range of capital structures is based upon the Modigliani-Miller theorem that choice of financing does not affect the firm's value. Franco Modigliani and Merton Miller eventually won Nobel Prizes in part for their work on the effects of debt.[28] Their 1958 paper made what is in retrospect a very simple point: if there are no taxes and no risk to the use of excessive debt, use of debt will have no effect on a company's operating cash flows (i.e., the cash flows to investors as a group, debt and equity combined). If the operating cash flows are the same regardless of whether the company finances mostly with debt or mostly with equity, then the value of the firm cannot be affected at all by the debt ratio. In cost of capital terms, this means the overall cost of capital is constant regardless of the debt ratio, too.

Obviously, the simple and elegant Modigliani-Miller theorem makes some counterfactual assumptions: no taxes and no cost of financial distress from excessive debt. However, subsequent research, including some by Modigliani and Miller,[29] showed that while taxes and costs to financial

"Consistent Valuation and Cost of Capital Expressions with Corporate and Personal Taxes," *Financial Management*, 1991; 20(3) for a detailed discussion of these assumptions and formulations. Equation (A-1) represents the overall weighted average cost of capital to the firm, which can be assumed to be constant across a relatively broad range of capital structures.

27 Empirically, companies within the same industry tend to have similar capital structures, while typical capital structures may vary between industries, so whether a leverage ratio is "unusual" depends upon the company's line of business.

28 Franco Modigliani and Merton H. Miller (1958), "The Cost of Capital, Corporation Finance and the Theory of Investment," *American Economic Review*, 48, pp. 261-297.

29 Franco Modigliani and Merton H. Miller (1963), "Corporate Income Taxes and the Cost of Capital: A Correction," *American Economic Review*, 53, pp. 433-443.

distress affect a firm's incentives when choosing its capital structure as well as its overall cost of capital,[30] the latter can still be shown to be constant across a broad range of capital structures.[31]

This reasoning suggests that one could compute the overall cost of capital for each of the proxy companies and then average to produce an estimate of the overall cost of capital associated with the underlying asset risk. Assuming that the overall cost of capital is constant, one can then re-arrange the overall cost of capital formula to estimate what the implied cost of equity is at the target company's capital structure on a book value basis.[32]

2. Unlevered and Relevering Betas in the CAPM (Hamada Adjustment)

An alternative approach to account for the impact of financial risk is to examine the impact of leverage on beta. Notice that this means working within the CAPM framework as the methodology cannot be applied directly to the DCF models. Recognizing that under general conditions, the value of a firm can be decomposed into its value with and without a tax shield, we obtain:[33]

$$V = V_U + PV(ITS) \tag{A-2}$$

Where $V = E + D$ is the total value of the firm as in Equation (A-1), V_U is the "unlevered" value of the firm—its value if financed entirely by equity, and $PV(ITS)$ represents the present value of the interest tax shields associated with debt. For a company with a fixed book-value capital structure and no additional costs to leverage, it can be shown that the formula above implies:

$$r_E = r_U + \frac{D}{E}(1 - \tau_c)(r_U - r_D) \tag{A-3}$$

30 When a company uses a high level of debt financing, for example, there is significant risk of bankruptcy and all the costs associated with it. The so-called costs of financial distress that occurs when a company is over-leveraged can increase its cost of capital. In contrast, a company can generally decrease its cost of capital by taking on reasonable levels of debt, owing in part to the deductibility of interest from corporate taxes.

31 This is a simplified treatment of what is generally a complex and on-going area of academic investigation. The roles of taxes, market imperfections and constraints, etc. are areas of on-going research and differing assumptions can yield subtly different formulations for how to formulate the weighted average cost of capital that is constant over all (or most) capital structures.

32 Market value capital structures are used in estimating the overall cost of capital for the proxy companies.

33 This follows development in Fernandez (2003). Other standard papers in this area include Hamada (1972), Miles and Ezzell (1985), Harris and Pringle (1985), Fernandez (2006). (See Fernandez, P., "Levered and Unlevered Beta," IESE Business School Working Paper WP-488, University of Navarra, Jan 2003 (rev. May 2006); Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock," Journal of Finance, 27, May 1972, pp. 435-452; Miles, J.A. and J.R. Ezzell, "Reformulating Tax Shield Valuation: A Note," Journal of Finance, XL5, Dec 1985, pp. 1485-1492; Harris, R.S. and J.J. Pringle, "Risk-Adjusted Discount Rates Extensions form the Average-Risk Case," Journal of Financial Research, Fall 1985, pp. 237-244; Fernandez, P., "The Value of Tax Shields Depends Only on the Net Increases of Debt," IESE Business School Working Paper WP-613, University of Navarra, 2006.) Additional discussion can be found in Brealey, Myers, and Allen (2014).

Where r_U is the "unlevered cost of capital"—the required return on assets if the firm's assets were financed with 100% equity and zero debt—and the other parameters are defined as in Equation (A-1).

Replacing each of these returns by their CAPM representation and simplifying them gives the following relationship between the "levered" equity beta β_L for a firm (i.e., the one observed in market data as a consequence of the firm's actual market value capital structure) and the "unlevered" beta β_U that would be measured for the same firm if it had no debt in its capital structure:

$$\beta_L = \beta_U + \frac{D}{E}(1 - \tau_c)(\beta_U - \beta_D) \qquad \text{(A-4)}$$

Where β_D is the beta on the firm's debt. The unlevered beta is assumed to be constant with respect to capital structure, reflecting as it does the systematic risk of the firm's assets. Since the beta on an investment grade firm's debt is much lower than the beta of its assets (i.e. $\beta_D < \beta_U$), this equation embodies the fact that increasing financial leverage (and thereby increasing the debt to equity ratio) increases the systematic risk of levered equity (β_L).

An alternative formulation derived by Harris and Pringle (1985) provides the following equation that holds when the market value capital structures (rather than book value) are assumed to be held constant:

$$\beta_L = \beta_U + \frac{D}{E}(\beta_U - \beta_D) \qquad \text{(A-5)}$$

Unlike Equation (A-4), Equation (A-5) does not include an adjustment for the corporate tax deduction. However, both equations account for the fact that increased financial leverage increases the systematic risk of equity that will be measured by its market beta. And both equations allow an analyst to adjust for differences in financial risk by translating back and forth between β_L and β_U. In principal, Equation (A-4) is more appropriate for use with regulated utilities, which are typically deemed to maintain a fixed book value capital structure. However, I employ both formulations when adjusting the CAPM estimates for financial risk, and consider the results as sensitivities in the analysis.

It is clear that the beta of debt needs to be determined as an input to either Equation (A-4), or Equation (A-5). Rather than estimating debt betas, I rely on the standard financial textbook of Professors Berk & DeMarzo, who report a debt beta of 0.05 for A rated debt and a beta of 0.10 for BBB rated debt.[34]

Once a decision on debt betas is made, the levered equity beta of each proxy company can be computed (in this case by Value Line) from market data and then translated to an unlevered beta at the company's market value capital structure. The unlevered betas for the proxy companies are comparable

[34] Berk, J. & DeMarzo, P., *Corporate Finance, 2nd Edition.* 2011 Prentice Hall, p. 389.

on an "apples to apples" basis, since they reflect the systematic risk inherent in the assets of the proxy companies, independent of their financing. The unlevered betas are averaged to produce an estimate of the industry's unlevered beta. To estimate the cost of equity for the regulated target company, this estimate of unlevered beta can be "re-levered" to the regulated company's capital structure, and CAPM reapplied with this levered beta, which reflects both the business and financial risk of the target company.

Hamada adjustment procedures—so-named for Professor Robert S. Hamada who contributed to their development[35] —are ubiquitous among finance practitioners when using the CAPM to estimate discount rates.

C. Supplemental Figures

For clarity, the risk-free rate forecast was derived as shown in Figure A-3 below

FIGURE A-3
RISK-FREE RATE AND MATURITY

BCEI Forecast of 10 year U.S. Treasury Yield	**[a]**	**2.44%**
Long-run Average of 30 year U.S. Treasury Yield	[b]	4.72%
Long-run Average of 10 year U.S. Treasury Yield	[c]	4.19%
Maturity Premium	**[d] = [b] - [c]**	**0.53%**
Base Projection of 30 year U.S. Treasury Yield	**[e] = [a] + [d]**	**2.97%**

Sources and Notes:
[a]: Blue Chip Economic Indicators, March 2021 and August 2021. Average of projection of 2022-2026 Yield.
[b], [c]: Bloomberg as of 8/31/2021, see Workpaper #1 to Schedule No. BV-9.

35 Hamada, R.S., "The Effect of the Firm's Capital Structure on the Systematic Risk of Common Stock", The Journal of Finance, 27(2), 1971, pp. 435-452.

PH

BARBADOS

AFFIDAVIT

THE FAIR TRADING COMMISSION

IN THE MATTER of the Application by the Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF PHILIP Q. HANSER

I, PHILIP Q. HANSER, of 40 Cedar Street, Newton, MA 02459 in the country of the United States, being duly sworn hereby **MAKE OATH** and say as follows:

EDUCATIONAL AND PROFESSIONAL EXPERIENCE

1. I am a Principal Emeritus of The Brattle Group and have nearly forty years of consulting and litigation experience in the energy industry. I specialize in regulatory and financial economics, especially for electric and gas utilities, in areas such as retail tariffs, transmission pricing, marginal and avoided costs, and integrated resource planning. I have consulted on environmental issues, forecasting, marketing and demand-side management, and other complex management and financial matters. I have also consulted on statistical topics, including sample design and data analysis.

2. I have appeared as an expert witness before the U.S. Federal Energy Regulatory Commission (FERC) and numerous state public utility commissions, environmental agencies, Canadian utility boards, arbitration

panels, and federal and state courts. In 1990 – 1995 and 2009 - 2019, I taught industry professionals about the principles and practice of cost of service calculations and rate design on behalf of the Edison Electric Institute in its Advanced Rates Course. I served for six years on the American Statistical Association's Advisory Committee to the Energy Information Administration (EIA). I am a member of the Institute of Electronics and Electrical Engineers (IEEE), the International Association for Energy Economics (IAEE) and the American Statistical Association(ASA).

3. Before joining The Brattle Group, I held teaching positions at the University of the Pacific, the University of California at Davis, and Columbia University. I have served as a guest lecturer at the Massachusetts Institute of Technology, Stanford University, and the University of Chicago. I was a Senior Associate in the Mossavar-Rahmani Center for Business and Government at the Harvard Kennedy School. At HKS, I co-led the Masters in Public Policy Business and Government concentration seminar in public policy analysis. I am currently a Lecturer in Northeastern University's Department of Economics. I was a Lecturer in Boston University's Questrom School of Business's Markets, Public Policy, and Law department and am a Senior Fellow at B.U.'s Institute for Sustainable Energy. I served as the manager of the Demand-Side Management Program at the Electric Power Research Institute (EPRI) and have been published widely in leading industry and economic journals. A copy of my resume is attached hereto and marked as Exhibit "PH01".

4. The purpose of my testimony is to provide an updated Cost of Service Study (COSS) for use in the BLPC's general rate case.

ASSIGNMENT AND PURPOSE OF TESTIMONY

5. I am testifying on behalf of The Barbados Light & Power Company ("the BLPC," or the "Company") in support of its rate case filing with the Fair Trading Commission ("FTC"). I am sponsoring the Company's Cost of Service Study ("COSS"), whose primary purpose is to allocate the BLPC's costs of providing service to different customer classes. I have been assisted in the development of the COSS by my colleague T. Bruce Tsuchida of The Brattle Group and Lucas Bressan of Bressan Analytics.

6. This Affidavit summarizes the principles, methodology, and data used in the present COSS. Additional details are provided in the Cost of Service Report marked as Exhibit “PH02”.

7. The BLPC and its consultant in 2009 prepared the most recent COSS before this one, and since then, some of the factors that drive the Company's cost of providing service have changed. This study incorporates updated information using data available as of December 31, 2020. We understand BLPC's goal is to move towards cost allocations and rate design that more closely reflect current cost causation to further Barbados's 100/100 Vision transition to 100% renewable power by 2030. The methodology used in this study is consistent with that used in the 2009 COSS conducted by BLPC. In a few cases, there were changes in the allocators selected for specific accounts, with a minimal effect on the results of the COSS. The primary difference in methodology relates to the accounts considered for the computation of customer-related costs.

COSS METHODOLOGY

METHODOLOGY SUMMARY

8. A COSS analyzes the components of the utility's total cost of service. It aims to determine the portion attributable to each Rate Class under the principle of cost-causation. A Rate Class is a relatively homogeneous group of customers with similar energy consumption characteristics, load and end-use patterns, delivery voltage, and metering characteristics. Typical Rate Classes include domestic service, commercial or general service, and industrial power, among others.

9. The starting point of a COSS is the utility's Revenue Requirement, the total revenue that the Company must generate to recover its total cost of providing service. The COSS is used to calculate the costs of individual services based on the cost that each service requires the utility to expend. These costs are then attributed to different categories of customers based on how the customers cause the utility to incur these costs. Once the costs of providing services are allocated among the Rate Classes using cost causation as the driver, the utility can establish rates that ensure it fairly recovers all its costs.

10. It is important to note that a COSS does not dictate the total revenue that the utility must recover. Instead, a COSS supports the development of rates by informing how the utility has incurred these costs due to its customers' behaviour. The fundamental step in a COSS is to develop allocators that capture the relationship between the costs of providing service and the drivers of those costs as accurately as possible.

11. The present study closely follows the principles of cost allocation outlined in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC") and is consistent with industry standards. The investments and expenses incurred by BLPC are

primarily recorded following the FERC's Uniform System of Accounts. These investments and expenses cannot, for the most part, be directly attributed to specific Rate Classes. As a result, there is a need to separate the costs into a series of components to appropriately apportion costs to each Rate Class consistent with the class's cost responsibility. In this way, the BLPC allocates plant investments and operating expenses so that customers in each Rate Class pay for the costs they cause the BLPC to incur.

12. This report relies on financial and operational data provided by BLPC staff, which includes BLPC's computation of the Revenue Requirements for Test Year 2020. Financial data consists of existing and proposed plant additions, operational expenses, and return requirements. The Company provided these data and grouped in a manner consistent with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts. The account numbers used by BLPC generally align with the account numbers used by the FERC. In the cases where the account numbering convention used by BLPC does not match that used by the FERC, we map account numbers to ensure consistency. This approach is necessary because we apply the COS principles set forth by NARUC on an account by account basis. Operational data includes sales, customer counts, and peak demand data. Appendix B describes the mapping for individual accounts.

13. The present study carries out the three steps of the cost of service process, namely functionalization, classification, and allocation, described in more detail below. The COSS was performed using an Excel-based spreadsheet model that facilitates computations. The methodology used is the same as that used in the 2009 COSS, with minor changes in the allocators selected for specific accounts.

COST OF SERVICE STUDY PROCEDURAL STEPS

14. Typically a COSS study progresses through three separate steps - functionalization, classification, and allocation. In the functionalization step, costs and investments are divided among the utility's service functions, including generation/power supply, transmission, and distribution.

15. The second step is called classification and consists of dividing the functionalized costs into categories based on what caused them to be incurred. The three typical categories are demand, energy, and customer. Demand-related costs are associated with the maximum requirements of the utility's customers. Energy-related costs are those costs that vary with the amount of electricity that the customers consume. Customer-related costs are those required to serve a customer with minimal usage within each Rate Class. They are primarily driven by the number of customers rather than by the amount of electricity consumed.

16. The third step is called allocation and consists of apportioning the previously functionalized, classified costs among the Rate Classes. Costs are allocated consistent with the relationship between costs and their drivers for each Rate Class. For example, costs driven by electricity use volume are allocated among the Rate Classes based on each class's relative share of electricity consumed.

17. The allocators used in this study were developed using BLPC's financial and operational data. Appendix B contains the allocators and their derivation

18. The following sections describe the allocation methodology.

ALLOCATION OF THE RATE BASE

19. The term rate base refers to a utility's investments in plant and other assets to serve customers. Consistent with groupings in the FERC's Uniform System of Accounts, the present study groups the accounts that make up the rate base into categories to facilitate discussion. These rate base groupings are discussed in more detail below.

20. Production plant includes investments used in connection with electricity generation, including both fossil and renewable facilities. Production plant is sized to meet maximum daily demand. It has been functionalized to generation, classified to demand, and allocated among Rate Classes based on the relative demands of each Rate Class on the 12-month average coincident peak ("12 C.P.")[1]. This approach is consistent with the allocation methodology used in the 2009 COSS.

21. Financial records for Transmission and Distribution plant are combined into a single category by the BLPC. In the functionalization step described later, we use functionalization factors provided by the BLPC to separate financial data into the Transmission and Distribution functions.

22. Transmission plant consists primarily of investments in facilities to transport electricity. Like production plant, transmission plant is sized to meet maximum daily demand and has been functionalized to transmission, classified to demand, and allocated among Rate Classes on a 12 C.P. basis.

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[1] Coincident peak (CP) methods consider the extent to which a class imposes a demand at the time of (coincident with) system peak. The Coincident Peak is computed by identifying the hour with the single highest load for each month, and then determining each class' demand during that hour in each month. The single coincident peak, or "1CP", for each class is the demand of that class at the time of the highest measured one-hour demand. Similarly, the "12CP" can be computed by averaging the demands of each class across 12 months.

23. Distribution plant includes a variety of assets found downstream of the transmission system. It includes such assets as poles, conductors, transformers, services, meters, and specific accounts related to street lighting. Poles, conductors, transformers, and services were functionalized to distribution and classified to demand and customer using individually-developed classification factors. The portion classified as demand-related was allocated among the Rate Classes based on the 1-month non-coincident peak ("1 NCP")[2]. The part that was classified as customer-related was allocated among the Rate Classes based on customer count. Meter costs were allocated among the Rate Classes based on a cost-weighted customer count, which captures the difference in the cost of meters used to serve customers in different Rate Classes. Items grouped under FERC Account 373 (street lighting and signal systems) were classified as customer-related and directly attributed to Street Lighting customers.

24. General plant items include structures, office furniture and equipment, transportation, communication, and miscellaneous equipment tools. These assets support more than one function and were functionalized, classified and allocated among Rate Classes primarily based on transmission and distribution plant investment, reflecting common utility practice.

25. Construction work in progress includes only those assets expected to go into service within 12 months of the end of the test year used in the present study. Construction work in progress and depreciation reserve were functionalized, classified and allocated among Rate Classes in the same ratio as the related assets.

---

[2] Non-coincident peak (NCP) methods consider the peak of the individual rate class, irrespective of whether this peak takes place at the time of the system peak. The class NCP is computed in a similar fashion as the CP, except that it considers the highest monthly load for each class, irrespective of when the system peaks.

26. Working capital represents cash and inventories that BLPC needs in the ordinary course of business. These items were functionalized and classified in proportion to BLPC's plant. Items classified as generation and transmission demand-related were allocated on a 12 C.P. basis, items classified as distribution demand-related were allocated on a 1 NCP basis, and items classified as customer-related were allocated based on customer count.

ALLOCATION OF EXPENSES

27. The expenses are allocated into the categories below. These categories include production, transmission, distribution, customer accounts, service and informational expenses, administrative and general, depreciation expenses, taxes and credits, interest on long-term debt, return requirement, and other revenues and expenses.

28. Production expenses are related to operations and maintenance of electric generation facilities and purchasing fuel or power to fulfil BLPC customer loads. Production plant is sized to meet maximum daily demand. Thus, the costs of operating BLPC's production plant have been functionalized to generation, classified to demand, and allocated among Rate Classes based on the relative demands of each Rate Class using the 12-month average C.P. Certain costs of operating and maintaining these facilities, including the cost of water, lubricants, ash handling expenses, and production supplies, are primarily driven by the amount of electricity produced. As a result, these were functionalized to production, classified as energy-related, and allocated among Rate Classes based on their relative share of energy sales. Fuel costs are passed through directly to customers, and as a result, they were assigned based on the relative share of expected fuel-related revenues. The BLPC provided: 1) fuel revenues, 2) the allocation factors in the expected electricity consumption from customers in different Rate Classes, and 3) the anticipated power purchase costs that BLPC incurs to provide credits to customers who produce and sell electricity to the grid.

29. Transmission expenses are the costs associated with operating transmission facilities designed and operated to meet peak demand requirements. Related costs were functionalized to transmission, classified as demand, and allocated among Rate Classes on a 12 C.P. basis.

30. Distribution costs include various expenses related to the operation and maintenance of the distribution system, including overhead and underground lines, transformers, service drops, and meters. Distribution expenses are driven by non-coincident demand and were allocated among Rate Classes in proportion to the BLPC 1 NCP. Consistent with the allocation of meter plant, meter maintenance costs were allocated in proportion to the cost of meters for each Rate Class.

31. Customer accounts costs relate to maintaining customer records and collection, meter reading, uncollectible accounts, and other miscellaneous costs. Customer records, customer service, and information expenses were functionalized to distribution, classified to customer, and allocated among the Rate Classes using a customer service allocator. This allocator intends to capture the demands that each customer class places on these areas of the Company. Meter reading expenses were functionalized to distribution, classified consistent with the classification of meter assets, and allocated using an allocator that captures the difference in meter readings costs for different customer types. Uncollectible accounts were functionalized to distribution, classified as customer-related, and allocated among Rate Classes based on their revenue share. Because the most significant proportion of uncollectible bills can be attributed to the domestic service and general service Rate Classes, uncollectible amounts are allocated only to these classes and in proportion to their relative share of total revenue.

32. Administrative and general expenses include administrative and general salaries, office supplies and expenses, and employee pensions and benefits.

Administrative and general expenses were allocated using a salaries and wages allocator, which captures the salaries and wages of BLPC staff. Property insurance was allocated to the Rate Classes in proportion to the Rate Base. Depreciation expenses were allocated among Rate Classes in the same ratios as plant in service. Taxes other than income taxes and corporation tax were functionalized, classified and allocated among Rate Classes in proportion to their responsibility for investments in the rate base.

COMPUTATION OF CUSTOMER-RELATED COSTS

33. Customer-related costs are the costs incurred to connect a customer to the distribution system, the capital costs and expenses associated with metering their usage, and the costs to maintain the customer's account and provide customer service. Customer-related costs vary primarily due to the number of customers served and do not typically depend on customers' electricity consumption.

34. Some cost categories are unambiguously driven by a customer's presence and vary in proportion to customer counts. Examples include the cost of the customer connection or service drop, the cost of metering, and the costs related to customer accounting and sales. These costs are considered to be customer-related in the present study.

35. Utilities also consider a share of the distribution system to be customer-related. Certain parts of the distribution system, such as the number of poles, miles of wire, and customer transformers, vary in proportion to the number of customers. As a result, the present study includes a portion of the costs associated with these parts of the distribution system in the computation of customer-related costs. The inclusion of these distribution system costs is the only modification relative to the methods used in the 2009 COSS. This enhancement is appropriate because these costs are driven in part by the number of customers the utility has to serve.

36. The monthly fixed customer charge is typically calculated by dividing the total customer-related costs by the number of customers in each Rate Class. The present COSS revealed that the current BLPC customer charges are significantly lower than the customer-related costs. Current customer-related costs are substantially higher than the customer charge currently in place on a cost causation basis. Increasing the customer charge moves rates to reflect the fixed nature of the costs related to serving individual customers more closely.

37. Collecting customer-related costs via a fixed customer charge reflects these customer costs' invariance to consumption changes that this charge aims to recover. A fixed customer cost reduces the BLPC's inability to recover these costs in the face of changes in consumption, reducing recovery risk for fixed costs.

DESCRIPTION OF RESULTS TABLES

38. The current COSS assigns BLPC's Revenue Requirement among the Race Classes based on cost causation. This assignment was based on data provided by BLPC, which included historical financial data on plant and expenses, revenue data, sales and demand data, and other operating characteristics for the Test Year. Appendix A of the Cost of Service Report marked as Exhibit “PH02” includes detailed results tables, which are described below.

39. Table 1 - Allocated Rate Base and Income Statement: shows utility plant in service, revenue at current rates, and O&M expenses allocated on a cost of service basis. This table also compares revenue at current rates to the total Revenue Requirement and Tariff Revenue Requirement to determine the extent to which each Rate Class contributes to its cost responsibility.

40. Table 2 - Summary Results by Functional Classification: shows the results of allocating the Tariff Revenue Requirement by functional classification. It also computes the customer-related, demand-related, and energy-related costs on a unit basis.

41. Table 2A - Summary of Unit Charges: shows the customer, demand, and energy unit charges resulting from the COSS.

42. Table 3 - Allocation Results by FERC Account: shows detail of the allocation of each FERC account to the Rate Classes.

43. Table 4 - Allocation Factor Values: shows allocation values, as % for each Rate Class.

44. Table 5 - Classification Results by FERC Account: shows detail of the classification of each FERC account to the Rate Classes.

45. Table 6 - Classification Factor Values: shows classification values, as % for each Rate Class.

46. Table 7 - Functionalization Results by FERC Account: shows detail of the functionalization of each FERC account to the Rate Classes.

47. Table 8 - Functionalization Factor Values: shows functionalization values, as % for each Rate Class.

48. Table 9 - Factors Used by FERC Account: The factors used in the classification, functionalization, and allocation steps of the present COSS.

SWORN TO by PHILIP Q HANSER)

at Newton, MA)

this 30th day of September, 2021)

Before me:

NOTARY PUBLIC

MIN GURUNG
MY COMMISSION EXPIRES SEPTEMBER 27, 2024
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS

MIN GURUNG
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Philip Q Hanser is a principal emeritus of The Brattle Group and has nearly forty years of consulting and litigation experience in the energy industry. He specializes in regulatory and financial economics, especially for electric and gas utilities, in areas such as retail tariffs, transmission pricing, marginal and avoided costs, and integrated resource planning. He is experienced in environmental issues, forecasting, marketing and demand-side management, and other complex management and financial matters. He also provides assistance in statistical matters including sample design and data analysis.

He has appeared as an expert witness before the U.S. Federal Energy Regulatory Commission (FERC), and numerous state public utility commissions, environmental agencies, Canadian utility boards, as well as arbitration panels, and in federal and state courts. Since 2008, Mr. Hanser has taught industry professionals about the principles and practice of cost of service calculations and rate design on behalf of the Edison Electric Institute in its Advanced Rates Course. He served for six years on the American Statistical Association's Advisory Committee to the Energy Information Administration (EIA). He is a member of Institute of Electronics and Electrical Engineers (IEEE), International Association for Energy Economics (IAEE), the American Statistical Association (ASA) and was a member of Conseil International des Grands Reseaux Electriques (CIGRE).

Before joining The Brattle Group, he held teaching positions at the University of the Pacific, the University of California at Davis, and Columbia University. He has also served as a guest lecturer at the Massachusetts Institute of Technology, Stanford University, and the University of Chicago. He was a Senior Associate in the Mossavar-Rahmani Center for Business and Government at the Harvard Kennedy School. At HKS, he co-led the Masters in Public Policy Business and Government concentration seminar in public policy analysis. He is currently a Lecturer in Northeastern University's Department of Economics and was a Lecturer in Boston University's Questrom School of Business's Markets, Public Policy, and Law department. He is a Senior Fellow in B.U.'s Institute for Sustainable Energy. He served as the manager of the Demand-Side Management Program at the Electric Power Research Institute (EPRI) and has been published widely in leading industry and economic journals.

EDUCATION

Ph.D. Candidacy Requirements Completed, Columbia University, NY	1975
Phil.M. (Economics and Mathematical Statistics) Columbia University	1975

A.B. (Economics and Mathematics) The Florida State University, FL 1971

The University of California at Berkeley Engineering Extension Course
Time Series and Econometric Forecasting September 1979

Data Analysis and Regression, American Statistical Association
Short Course, San Diego, CA August 1978

ACADEMIC POSITIONS

Northeastern University, Lecturer
Department of Economics 2020 - present

Boston University, Questrom School of Business, Institute for Sustainable Energy
Senior Fellow 2017-2020

Boston University, Questrom School of Business, Markets, Public Policy, and Law
Lecturer 2017-present

Harvard Kennedy School
Senior Associate in the Mossavar-Rahmani Center for Business and Government
Co-Leader BGP-150Y Business and Government Policy Analysis Concentration Seminar 2012-2017

Massachusetts Institute of Technology, Cambridge, MA
Guest Lecturer, Energy Laboratory Short Courses 1997-1998

University of California, Davis; Davis, CA
Visiting Lecturer, Department of Economics 1981-1982

University of the Pacific, Stockton, CA
Assistant Professor, Departments of Economics and Mathematics 1975-1980

CONSULTING EXPERIENCE

Analysis of Electricity Generation, Contracts, and Wholesale Markets

- Provided expert testimony in Massachusetts state court on the impacts of alleged violations of a wholesale power contract on a supplier in ISO-NE.

- For the California Department of Water Resources, provided expert testimony in federal bankruptcy court concerning the public interest standard to be applied to Calpine Corporation's rejection of its contracts. This assignment included a valuation of the contract over time through the use of an original simulation model of the California market, as well as an assessment of the potential reliability implications for the California market.
- For the California Department of Water Resources and the California Attorney General's Office, provided expert testimony on damages resulting from Sempra Energy Resources breaches of its power purchase agreement in both arbitration hearings and before the California state court. I analyzed two years of hourly data on energy deliveries, market prices, ISO charges, and invoice charges to identify and evaluate performance violations and invoice overcharges. Assisted counsel in developing the theory of the case and provided general litigation support in preparation for and during the arbitration.
- For Dominion Electric Marketing, Inc. (DEMI), assisted in their response to a complaint by United Illuminating (UI) regarding their wholesale supply contract. The dispute centred on the allocation of reliability must-run costs between UI as a load-serving entity and DEMI as a wholesale supplier.
- For the California Department of Water Resources, reviewed the California ISO's proposed implementation of locational marginal pricing (LMP) and analyzed implications for "seller's choice" supply contracts. Developed a framework for quantifying the incremental congestion costs that ratepayers would face if suppliers delivered power to the lowest priced nodes, and estimated potential additional contract costs using a third party's GE-MAPS market simulations. Provided recommendations to the CAISO regarding how to address the issue.
- Provided expert testimony in Massachusetts state court on the damages incurred by a power plant developer as a result of alleged contractual violations by a supplier for a plant constructed in ISO-NE.
- For a Florida utility, provided a confidential expert report evaluating the benefits of the power from a co-generator and its potential rate implications, and assisted in the negotiation of a co-generation contract with a large industrial customer.
- Assisted a US electric utility in the preparation of a bid proposal to an industrial firm for the leasing of a new power plant. The assignment included risk analysis of the proposal, assessment of financial and rate impacts, and market assessment of competitors' potential offerings.
- For a merchant generation company, provided testimony on the fairness of a resource procurement action.

Resource Planning and Procurement

- For the Edison Electric Institute, co-authored a report on the general inapplicability of standard financial portfolio theory to the resource portfolios of utilities.
- For the investor-owned utilities of Wisconsin, provided testimony before the Public Service Commission of Wisconsin on cost of capital issues for use in its statewide resource planning exercise.
- For an international development bank, evaluated generation resource needs for an Eastern European country as well as providing a determination of alternative means to meet those generation needs. This assignment included analysis of the impact of privatization on the country's economy, its import and export sectors, and the future development of electricity and gas resources.
- For a western utility, developed an assessment of its resource options, with a particular view towards future environmental regulation.
- For a southern utility, assessed the value of adding a gas-fired generating station.

Environment

- For an eastern US utility with substantial coal-generating facilities, provided advice concerning maintenance procedures and risk exposure to New Source Review standards under the Clean Air Act Amendments.
- For a western generator with substantial coal-generating facilities, assisted its response to allegations by the Environmental Protection Agency of failure to comply with the New Source Review standards under the Clean Air Act Amendments.
- For Illinois Power Company, provided expert testimony in federal court on the regulatory and rate base implications of the Clean Air Act Amendments, in support of the calculation of noncompliance economic damages arising from New Source Review.
- For a gas utility, assisted in the development of potential manufactured gas liabilities for use in insurance recovery and in estimating possible recovery under a variety of insurance allocation theories and estimated risk distribution.
- For a gas utility, assisted in its assessment of the announcement effect of environmental liabilities on its cost of capital. This assignment included estimating changes in market betas for pre- and post- environmental liability announcement.

Energy Efficiency, Demand-Side Management, and Renewables

- For a large utility in the southern United States, prepared expert report investigating alternative cost allocation approaches for generation capacity, fuel, and demand-side management (DSM) costs, both through a review of the methods, surveys of practice, as well as the financial impacts on the utility. The cost allocation assessment included cost allocation across jurisdictions as well as within a jurisdiction.
- For Central Vermont Public Service, provided expert testimony on the impact of its DSM programs before the Vermont Public Service Board.
- For Ameren/UE's Illinois subsidiaries, provided expert testimony on the potential for gas DSM and resulting potential rate implications.
- For a northeastern utility, developed an assessment of the potential penetration rate of microturbines. For the utility service territories under consideration, evaluated the back-up generation rates and connection charges likely to be incurred for such systems to determine customer costs and benefits.
- For a utility located in the Western Electric Coordinating Council (CC), procuring renewable resources, provided a system integration study for a range of renewable project proposals. Used production costing and power flow models to estimate the "deliverability" of various proposals, including estimating locational marginal prices (LMPs) and potential congestion costs. Ranked the proposed renewable power projects by their estimated benefits and costs and delivered a formal presentation to the utility's executives at the project's completion.
- For a power marketer and developer of independent power projects in Great Britain, assisted in the preparation of comments on proposals by the UK pool regarding the role of demand-side bidding and the pricing of transmission losses.
- For a Texas utility, provided expert testimony regarding breach of contract claims made against it by an industrial participant in an energy efficiency project. Reviewed the energy efficiency impacts of the program. Calculated the net present value of the project under various rate options and market prices.
- For Connecticut Light and Power, provided testimony in support of its Application for a Certificate of Environmental Compatibility and Public Need for the construction of a 345-kV electric transmission line and reconstruction of an existing 115-kV electric transmission line. At issue was the use of distributed resources to substitute for the proposed lines.

Analysis of Market Power

- For the California Parties, provided litigation support and testimony regarding manipulation of energy and ancillary service market prices and the outage behaviour of gas-fired power plants during 2000-01. The proceeding, before the Federal Energy Regulatory Commission, involved Enron, Dynegy, Mirant, Reliant, Williams, and other suppliers in the US and Canada. The analyses focused on the use by suppliers of generation outages to affect market prices through physical withholding, as well as the use of pricing to yield economic withholding.
- For the California Parties, provided litigation support and testimony regarding Enron's transmission and ancillary services market manipulation strategies, including 'Death Star' and 'Get Shorty.'
- For Southern California Edison, submitted testimony before the FERC describing the implications of manipulation of gas market prices on the electricity market.
- For Sierra Pacific Resources Company, provided expert testimony before the Public Utilities Commission of Nevada and the FERC regarding the market power implications of generation asset divestiture required for the merger of Sierra Pacific Power and Nevada Power Company, developed a Cournot market model to assess the market power implications of selling off alternative groupings of generation.
- For the Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM), co-authored the annual report on the state of its markets. The report included an assessment of the market's competitiveness and potential structural deficiencies and identified potential instances of market abuse.
- For PJM, developed an ensemble of metrics for assessing market power in its markets. The metrics included an early warning system to permit PJM interventions into market abuse at the most initial possible stage.
- For PJM, developed software for unilateral market power assessment and assisted PJM in its preliminary implementation. Its use was validated through an incident involving potential market power abuse by PJM members.

R.T.O. Design and Participation

- For Northeast Utilities, provided testimony before the FERC about the economics of imposing local installed capacity (LICAP) requirements on ISO-NE. Also provided expert testimony before the FERC in support of its applications for market-based rate authority.

- For NSTAR, provided testimony before the FERC on several matters: first, the necessity of imposing bid caps on the New England electricity market; second, replacement energy rates for generators when the transfer capability into a transmission-constrained zone was reduced because of system upgrades; and third, the appropriateness of granting market-based rate authority to a generator in a transmission-constrained zone. Developed a Cournot market model to forecast the potential impact on market prices in the transmission-constrained zone in which the majority of NSTAR's service territory is located.
- For Nevada Power Company, provided expert testimony before the FERC for its market-based rate authority application.
- For Otter Tail Power Company, provided an affidavit to the FERC assessing how the Midwest ISO's proposed Transmission and Energy Market Tariff would affect Otter Tail Power, both operationally and financially. Based on the strategies that were pursued by some market participants during the 2001 California electricity market crisis, demonstrated the potential to pursue similar strategies in MISO and harm Otter Tail and its customers.
- For Edison Mission Energy's subsidiary, Midwest Gen provided expert testimony to the FERC for its market-based rate authority application.
- For a Midwest utility, examined the implications of alternative configurations of the independent system operator (ISO) on potential market power concerns. The issue particularly examined was the question of seams and how different ISO configurations affected the costs of transactions.
- Co-authored a report for the New York Independent System Operator assessing the reliability implications of modifying its rules regarding installed capacity.
- Submitted testimony to the Public Utilities Commission of Texas (PUCT) regarding a proposed rule to allocate the costs of procuring replacement reserves to market participants in ERCOT.
- For the Edison Electric Institute, authored a report on standard market design and its implications for utilities within regional transmission organizations.

Forecasting and Weather Normalization

- For the Pennsylvania-New Jersey-Maryland Interconnection, LLC (PJM), co-authored an assessment of its forecasting model
- For Florida Power and Light Co., provided testimony before the Florida Public Service Commission concerning its forecasting methodology.
- For an electric utility in the Southeast, reviewed the existing weather normalization process and diagnosed problems with weather data and regression models. Developed alternative daily and monthly normalization models, improved degree-day specification, selection of weather stations, and regression specification to double prediction accuracy and enhance the stability of the weather-normalization process.
- For PJM, conducted a review of models for forecasting peak demand and re-estimated new models to validate recommendations. Models were developed for 18 individual transmission zones as well as for the entire PJM system.
- For a Southwestern utility, developed models for forecasting monthly sales and loads for residential, commercial and industrial customer classes using primary data on customer loads, weather conditions, and economic activity.
- For the Public Service Company of New Mexico, provided expert testimony before the Public Utilities Commission of New Mexico regarding the forecasted growth of the El Paso, Texas and Juarez, Mexico markets and their electricity requirements.
- For a Southeastern utility, developed a model for forecasting monthly demand that incorporated the impacts of its significantly declining housing market and which served as the basis for its treasurer's revenue forecast.

Rate Design and Related Issues

- Expert report on behalf of the Newfoundland and Labrador Board of Commissioners of Public Utilities: Review of Existing and Proposed Network Additions Policies for Newfoundland and Labrador Hydro, with Agustin Ros and Peal Donohoo-Vallet, November 19, 2019
- Testimony before the Virginia Corporation Commission, Case No. PUR-2019-00104, on behalf of the Virginia Electric Power Company on cost allocation of utility-scale solar projects, July 1, 2019, with Agustin Ros.

- Expert report on behalf of the Newfoundland and Labrador Board of Commissioners of Public Utilities: Embedded and Marginal Cost of Service Review, with Agustin Ros, T. Bruce Tsuchida, Pearl Donohoo-Vallet, and Lynn Zang, May 3, 2019.
- For a Midwest utility, provided support for its rate designs, including its cost of service development and certification of conformance with state regulations.
- For an industrial customer, provided testimony before a state public utility commission on the appropriate cost allocation and rate design approach for a municipal water utility.
- For a utility in PJM, performed a marginal cost/avoided cost study to be used in evaluating its demand-side management energy efficiency programs, demand-responsive rates, and seasonal and time-of-use rates. The study included a geographic-specific assessment of its marginal distribution and transmission costs.
- For intervenors in Toronto Hydro-Electric System Limited (THESL), provided testimony on cost allocation issues concerning THESL's suite metering program.
- For Ameren/UE's Missouri subsidiary provided expert testimony on its rate design before the Missouri Public Utility Commission. Assisted the development of company witnesses' rationale for the choice of cost of service allocation method, developed benchmarks for the rate increase against similarly situated utilities, as well for other commodities' escalations, and evaluated proposed demand-side management programs and rate options.
- For Ameren/UE's Illinois subsidiaries, provided expert testimony on the potential for gas demand-side management. The testimony discussed the potential rate implications of such programs on the revenue of the utilities.
- For the Edison Electric Institute, co-authored a series of papers concerning issues facing utilities. The reports covered the topics of fuel adjustment clauses, mitigating significant rate increase impacts, and the Energy Policy Act of 2005.
- For the City of Vernon, California, submitted testimony to the FERC regarding its revenue requirements for transmission and provided testimony regarding its formula rates.
- For the Edison Electric Institute, served as an instructor in the Advanced Rates School on the topics of cost allocation, rate design, and marginal costs.
- For the ISO-NE, served as an instructor on retail cost allocation and ratemaking.
- For Hydro Québec, provided testimony before the Régie d'Énérgie regarding the conformance of its Open Access Transmission Tariff with US FERC regulations.

- Before staff members of the FERC, assisted in the development of a review of the implications of the restructuring in transmission assets' cost of capital and wholesale rates.
- For a power marketer and developer of independent power projects in Great Britain, assisted in the preparation of comments on proposals by the UK pool regarding the pricing of transmission losses and the role of demand-side bidding.
- For a utility in PJM with multiple jurisdictions provided an assessment of alternative demand and energy cost allocation procedures. The report included separate assessments for each jurisdiction as well as an assessment for generation and transmission assets commonly shared by all jurisdictions.
- For a European transmission company, provided an analysis of the likely development of the European electricity market and assessed market implications for the transmission company of modifications to the transmission grid.
- For Hydro Québec, provided expert testimony before the Régie d'Énérgie regarding whether a set of privately held transmission facilities constituted a looped transmission system and, thus, was subject to requests for transmission service.
- For Omaha Public Power District, assisted in the performance of its cost of service study, retail and wholesale rate designs. Also redesigned its cost of service models. Also provided support in the redesign of its formula rates for the Southwest Power Pool.
- For Arizona Public Service, provided assistance in the development of a cost of service basis for separating its residential customers with rooftop solar photovoltaic into a separate rate class.
- For Nevada Power, provided assistance in the development of a cost of service basis for separating its residential customers with rooftop solar photovoltaic into a separate rate class.
- For Pacific Gas and Electric, redesigned the marginal cost of service models, as well as their software implementation, for revenue cycle services and distribution system costs.
- For Wolverine Power Cooperative, provided testimony to the FERC supporting its request for formula transmission rates.
- For the Hawaii Electric Company, assessed alternative performance incentive mechanisms in a report which was submitted to the Hawaii Public Utility Commission.
- For FirstEnergy/Jersey Central Power and Light, assisted in the development of their cost of service study submitted to the New Jersey Board of Public Utilities.
- For National Grid, assessed alternative performance incentive mechanisms in a report which was submitted to the Massachusetts Department of Public Utilities.

- For Salt River Project, assisted with its current OATT compliance with FERC regulations.

Plant Performance and Strategy

- For the Keystone-Conemaugh Project Office, performed a benchmarking analysis to identify the areas in which Keystone and Conemaugh coal units were better performing or under-performing compared to other units with similar characteristics. The study involved comparing the historical operational and cost performance of the Keystone and Conemaugh coal units against their peer groups; identifying the areas where the performance of the Keystone and Conemaugh coal units were above and below the average quartile of their peer groups, and developing metrics and methodologies to combine the results of individual comparisons across the operational and cost performance assessments.
- For a US electric utility, assisted in the development of a legislative and regulatory strategy concerning restructuring. This assignment included generation asset valuation in a competitive market, development of stand-alone transmission and distribution rates under cost-of-service and performance-based regulation, and estimation of stranded costs.

Utility Financial Issues

- For the Edison Electric Institute, co-authored a report on the general inapplicability of standard financial portfolio theory to the resource portfolios of utilities.
- For a gas utility, assisted in the assessment of the announcement effect of environmental liabilities on its cost of capital. This assignment included estimating changes in market betas pre- and post-environmental liability announcement.
- For the investor-owned utilities of Wisconsin, provided testimony before the Public Service Commission of Wisconsin on cost of capital issues for use in its statewide resource planning exercise.
- For the developer of a synthetic natural gas plant in Indiana, provided testimony before the Indiana Utility Regulatory Commission on the appropriate approach to assessing financial risk for the plant.
- For the developer of a synthetic natural gas plant in Illinois provided a series of testimonies before the Illinois Commerce Commission on the appropriate cost of equity for the plant.
- For the developer of a synthetic natural gas plant in Illinois, provided testimony before the Illinois Construction Development Board on the appropriate range of capital costs and operations and maintenance expenses.

Other Energy Experience

- For the Edison Electric Institute, conducted its annual workshop for Electric Rate Advanced Course, "Introduction to Efficient Prices," University of Wisconsin, Madison, July 2009 - 2019.
- For the Edison Electric Institute, conducted its annual workshop for Electric Rate Advanced Course, "Rate Class Cost Allocation," University of Wisconsin, Madison, July 2009 - 2019.
- For the Edison Electric Institute, conducted its annual workshop for Electric Rate Advanced Course, "Ratemaking by Objective: It Can Be Done," University of Wisconsin, Madison, July 2009 - 2019.
- For the Edison Electric Institute, conducted Pre-Course Workshop for Electric Rate Advanced Course, "Traditional Embedded Costing and Pricing Concepts," University of Wisconsin, Madison, July 26, 2009.
- For the Edison Electric Institute, conducted a workshop for its Electric Rate Advanced Course, "Unbundling Methodologies," University of Wisconsin, Madison, July 26, 2009.
- For the Edison Electric Institute, conducted webinar "Long-Term Energy Forecasts: Challenges and Approaches," June 17, 2009.
- For the Indiana Energy Conference, presented "It Ain't Your Father's IRP, Meeting Today's Challenges," October 2, 2008.
- For the NEPOOL Forecasting Committee Summer Meeting, presented "I'm a Forecaster – And You Can Too!," July 17, 2008.
- For the Electric Power Research Institute (EPRI), developed and directed a research program to provide electric utilities with the following capabilities: marketing research, pricing and rate design, integrated resource planning, capital budgeting, environmental impacts of electric utilities and end-use technologies, load research, forecasting, and demand-side management through software tools, database development, and technology development. Assisted in the development of the Load Management Strategy Testing Model (LMSTM) and served as its project manager, served as the project manager for the development of DSManager, a software for assessing efficiency programs for electric, gas, and water utilities, enhancements to the Electric Generation Expansion Analysis Model (EGEAS). Co-wrote reports on the environmental impacts of electric technologies, environmental externalities, cost-benefit analysis of DSM programs, rate design and costing, integrated resource planning, operational impacts of interruptible and curtailable rates,

product differentiation, activity-based costing, DSM program evaluation, efficiency program development for electric, gas, and water utilities and others.

- For EPRI, I served as project manager of the Edison Electric Institute (EEI), National Rural Electric Cooperatives Association (NRECA), American Public Power Association (APPA.), and National Association of Regulatory Utility Commissioners (NARUC) jointly sponsored Electric Utility Rate Design Study (EURDS). Represented the Institute before various regulatory commissions, federal agencies, and utility executives. Also for EPRI, served on the Environmental Protection Agency's advisory committee for the Clean Air Act Amendments and as the operating agent for Annex IV, Improved Methods for Integrating Demand-Side Options into Utility Resource Planning, of the International Energy Agency Agreement on Demand-Side Management.
- For a California utility, supervised short- and long-term forecasts of sales and peak demand for use in resource and corporate planning. Supervised and helped prepare forecast documentation for public hearings before the California Energy Commission and represented the utility to the Commission on the forecast. Managed the design and implementation of long-term strategic planning and financial models, and prepared both marginal and embedded cost of service studies for the utility and assisted in their use for the design of customer rates. Evaluated the impact of energy conservation programs and legislation on long-term system resource requirements. Designed and implemented the residential survey of appliance holdings and commercial customer equipment survey.

Statistics and Sampling

- Designed a statistically valid database sampling procedure for assessing the validity of insurance claims arising from mass tort actions. The database contained summary information on the claims, and, for each claim, there was, at times, voluminous information on the individual cases. The sampling procedure was used to determine which records would be chosen and assessed the individual's claim eligibility. That would then serve as a basis for calculating an appropriate rate per dollar claim.
- Assessed the liability risk of an insurance company that provided coverage relevant to a mass tort suit. Developed a Markov chain model to estimate the size of the potential population, and then a risk model was developed to calculate potential exposure.
- Developed a time to failure model to test the claims of generators during the California Electricity Crisis that their outage rates were not abnormal.

- Submitted testimony in bankruptcy court regarding the estimation of inventory subject to reclamation by a wholesale pharmaceuticals supplier, which was sold to a bankrupt retail drug chain. The retail chain failed to maintain proper inventory records. Developed a statistical approach to estimate inventory levels, which used a combination of data on overall inventory and the shipment and replenishment records of the supplier.

TESTIMONY AND REGULATORY FILINGS

Expert report on behalf of the Newfoundland and Labrador Board of Commissioners of Public Utilities: Review of Existing and Proposed Network Additions Policies for Newfoundland and Labrador Hydro, with Agustin Ros and Pearl Donohoo-Vallet, November 19, 2019.

Before the New York Department of Public Service, Granular Distribution Marginal Costs for Orange and Rockland Utilities, July 2019

Testimony before the Virginia Corporation Commission, Case No. PUR-2019-00104, on behalf of the Virginia Electric Power Company on cost allocation of utility-scale solar projects, July 1, 2019, with Agustin Ros. (Incorporates previously unfiled report for Virginia Electric Power.)

Expert report on behalf of the Newfoundland and Labrador Board of Commissioners of Public Utilities: Embedded and Marginal Cost of Service Review, with Agustin Ros, T. Bruce Tsuchida, Pearl Donohoo-Vallet, and Lynn Zhang, May 3, 2019.

Before the Salt River Project Board of Directors, Board Advisor report regarding SRP management's proposed rates, December 2018

Before the New York Department of Public Service, Granular Distribution Marginal Costs for Consolidated Edison with T. Bruce Tsuchida, July 2018

Before the Pennsylvania Public Utility Commission, Class Cost of Service Analysis for Philadelphia Gas Works, February 2017.

Before The Minnesota Public Utilities Commission, Docket No. E017/CG-16-1021, Expert Testimony on Behalf of Otter Tail Power, In the Matter of a Complaint by Red Lake Falls Community Solar Hybrid, LLC Regarding Potential Purchased Power Agreement (PPA) Terms and Pricing with Otter Tail Power Company.

Prepared Expert Report on Behalf of Nova Scotia Power Incorporated (NSPI), regarding the review and assessment of performance measures, July 13, 2016.

Before the New Jersey Board of Public Utilities, filed "Prepared Direct Testimony of Philip Q Hanser on behalf of Jersey Central Power & Light Company," regarding Cost of Service/Class Allocation, April 2016.

Before the United States District Court for The District of Montana Billings Division, Case no: CV 13-32-BLG-DLC-JCL, filed "Expert Report of Philip Q Hanser on Behalf of Defendants," regarding the evaluation of potential impacts of capital maintenance, repair and replacement projects on emissions from four Colstrip Units, November 14, 2014.

Before the Hawai'i Public Utilities Commission, Docket No. 2013-0141, filed "Targeted Performance Incentives: Recommendations to the Hawaiian Electric Companies" with William P. Zarakas, regarding the analysis of the Application of performance incentives to electric utilities, September 15, 2014.

Before the Federal Energy Regulatory Commission, Docket No. ER15-249-000, filed "Prepared Direct Testimony of Philip Q Hanser on behalf of Wolverine Power Supply Cooperative, Inc." regarding a Request for Change in Rates to Distribution Cooperative Member-Owners, October 30, 2014.

Before the Public Utilities Commission of the State of Colorado, Proceeding No. 13F-0145E, "Answer Testimony and Exhibits of Philip Q Hanser on behalf of Tri-State Generation and Transmission Association, Inc.," regarding an Analysis of Complaining Parties' Responses to Tri-State Generation and Transmission Association, Inc., September 10, 2014.

Before the Public Service Commission of Wisconsin, Docket No. 3720-WR-108, filed "Direct Rebuttal and Surrebuttal Testimony of Philip Q Hanser on behalf of MillerCoors LLC" regarding the Application of Milwaukee Water Works for Authority to Increase Water Rates, June 2014.

Before the District Court for the Eastern District of Missouri, Civil Action No. 4:11-cv-00077-RWS, filed "Expert Report of Philip Q Hanser on behalf of Ameren Missouri," regarding the New Source Review enforcement case, May 16, 2014.

Before the Illinois Commerce Commission of the State of Illinois, Docket No. 13-0387, filed "Rebuttal Testimony of Philip Q Hanser on behalf of Commonwealth Edison Company," regarding their tariff filing to present the Illinois Commerce Commission with an opportunity to consider revenue-neutral tariff changes related to rate design authorized by subsection 16-108.5(e) of the Public Utilities Act, August 19, 2013.

Before the Public Utilities Commission of the State of South Dakota, EL 11-006, filed "Wind Integration Services - Summary of Industry Practices in North America, on behalf of NorthWestern Energy," in the Matter of the Complaint by Oak Tree Energy LLC against NorthWestern Energy for refusing to enter into a Purchase Power Agreement, July 8, 2013.

Before the Régie de l'énergie, R-3848-2013, filed "Direct Testimony of Philip Q Hanser on Behalf of Hydro-Québec Distribution" regarding their Application for approval of characteristics of Wind Integration Services and acquisition analysis of other wind integration services, June 2013, January 2014.

Before the Federal Energy Regulatory Commission, "Prepared Direct Testimony of Philip Q Hanser on behalf of NV Energy Operating Companies," regarding whether the use of a 12-CP cost allocation method is appropriate for the NV Energy transmission system from a cost allocation perspective, May 2013.

Before the Federal Energy Regulatory Committee, Prepared Direct and Rebuttal Testimony and Exhibits of Philip Q Hanser in Support of the Refund Claims of the City of Seattle, Washington, for the Period January 1, 2000 through December 24, 2000, on behalf of the City of Seattle, Washington, EL01-10-085, March 12, 2013, June 3, 2013, July 26, 2013.

Before the Commonwealth of Massachusetts Department of Public Utilities, "Review and Analysis of Service Quality Plan Structure In the Massachusetts Department of Public Utilities Investigation Regarding Service Quality Guidelines for Electric Distribution Companies and Local Gas Distribution Companies," with David E. M. Sappington and William P. Zarakas, as part of the Initial Comments of National Grid, DPU12-120, March 2013.

Before the Bonneville Power Administration, Direct and Rebuttal Testimony of Philip Q Hanser, John D. Martinsen, Felicienne NG, James M. Russell, and Paul Wrigley on Behalf of Benton County Public Utility District No. 1, Iberdrola Renewables, LLC, Tacoma Power, Seattle City Light, and Snohomish County Public Utility District No. 1, Docket No. BP-14-E-JP12-01, January 28, 2013, March 11, 2013.

Before the Illinois Commerce Commission, Report of Philip Q Hanser on Behalf of Chicago Clean Energy, LLC, on the Reasonableness of Chicago Clean Energy's Cost of Equity, October 2011; Supplemental Report on Behalf of Chicago Clean Energy, LLC, November 2011; Response Report of Philip Q Hanser on Behalf of Chicago Clean Energy, November 2011, Certified Affidavit on Behalf of Chicago Clean Energy, LLC, December 2011.

Before the Louisiana Public Service Commission, Direct Testimony of Philip Q Hanser on Behalf of Calpine Corporation, Docket No. U-31971, November 22, 2011. (Testimony was withdrawn as part of the settlement between Calpine and Entergy.)

Before the Illinois Construction Development Board, Supplemental Report of Philip Q Hanser on Behalf of Chicago Clean Energy, LLC, on the Reasonableness of Chicago Clean Energy's Estimate of Capital Costs, November 2011. Supplemental Report of Philip Q Hanser on Behalf of Chicago Clean Energy, LLC, on the Reasonableness of Chicago Clean Energy's Estimate of Operations and Maintenance Expenses, November 2011.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony of Philip Q Hanser on Behalf of Indiana Gasification, LLC, IURC Case No. 43976, June 2011.

Before the State of Illinois Commerce Commission, Prepared Direct Testimony of Philip Q Hanser on behalf of Interstate Power and Light Company with regard to their Petition For Approval Of Sale of Utility Assets Pursuant to Sections 7-102 Of The Public Utilities Act; and Approve the Discontinuance of Service Pursuant to 8-508 of the Public Utilities Act, 2011.

Before the Federal Energy Regulatory Commission, Supplemental Comments, Re: Notice of Proposed Rulemaking regarding Demand Response Compensation in Organized Wholesale Energy Markets," Docket Nos. RM10-17-000 and EL09-68-0, October 4, 2010, May 13, 2010.

Before the Régie de l'énergie, Prepared Expert Report of Philip Q Hanser on Behalf of Hydro-Québec TransÉnergie ("HQT"), Regarding HQT's Methodology for ATC Coordination, June 2010.

Before the Commonwealth of Massachusetts Trial Court, testified on behalf of MMWEC regarding the management and ownership of investor-owned utilities ("IOUs"), MMWEC, and municipal light departments ("Municipals") in Massachusetts before and after the passage of the Electric Industry Restructuring Act of 1997, as well as the impact of electric industry restructuring in Massachusetts on IOUs, MMWEC, and Municipals with respect to contract buyouts in the matter of MASSPOWER v. Massachusetts Municipal Wholesale Electric Company (MMWEC), Civil Case No. 07-3243 BLS2, March 2010.

Before the Ontario Energy Board, Prepared Witness Statement on Behalf of the Smart Sub-Metering Working Group in the Matter of Toronto Hydro-Electric System Limited's 2010 Electricity Distribution Rate Application, December 15, 2009.

Before the Superior Court of the State of California for the County of San Diego, Prepared Second Addendum Report to Expert Report of Philip Q Hanser, for the Office of the Attorney General of the State of California on Behalf of California Department of Water Resources, Case No. GIC 789291, September 30, 2009.

Before the Florida Public Service Commission on behalf of Florida Power and Light Company, Prepared Rebuttal Testimony of Philip Q Hanser, Docket No. 080677-EI, August 6, 2009.

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PROFESSIONAL AFFILIATIONS

Association of Energy Service Professionals, Board Member 1991-1995

Journal of A.DSMP., Editor 1995

American Statistical Association 1974-current

Member of A.S.A. Committee on Energy Statistics 1993-1999

Conseil International des Grands Reseaux Electriques (C.I.G.R.E.) 2005-2019

Working Group C5-8, Working Group on Renewables and

Energy Efficiency in a Deregulated Market 2008-2009

Institute of Electrical and Electronics Engineers (IEEE) 1986-current

International Association for Energy Economics 1986-current

ACADEMIC HONORS AND FELLOWSHIPS

Teaching Incentive Award, University of the Pacific 1979

Teaching Assistantship in Econometrics, Columbia University 1974

National Science Foundation Research Traineeship 1972 – 1974

Undergraduate and Graduate Research Assistantships, Florida State University 1968 – 1972

Omicron Delta Epsilon, Economics Honor Society 1971

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Technical Assessment Guide (T.A.G.), Vol.4: Cost-Benefit Analysis of End-Use Technologies

Impact and Process Assessment of Energy Efficiency Technologies

Innovative Rate Design

Integrated Value-based Resource Planning

SELECTED PRESENTATIONS

"The Impact of Global Warming on Electric Utility Operations," National Climate Data Center, National Oceanic and Atmospheric Administration Conference on "The New Weather Normals," Asheville, North Carolina, November 2016

"Smart E.D.U.: Smart Technology, Smart Data, Smart Prices," S.G.I.P. Inaugural Conference Progress through Collaboration, Palm Beach Gardens, Florida, November 6, 2013.

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PH02

Allocated Class Cost of Service Study

TEST YEAR ENDED DECEMBER 31, 2020

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September 2021

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Notice

- This report was prepared for The Barbados Light & Power Company, in accordance with The Brattle Group's engagement terms, and is intended to be read and used as a whole and not in parts.
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Table of Contents

I. Introduction

At the request of The Barbados Light & Power Company ("BLPC", or the "Company"), The Brattle Group ("Brattle") has conducted a Cost of Service Study ("COSS"), whose primary purpose is to allocate the BLPC's costs of providing service to different customer classes. The purpose of this report is to describe the principles, methodology, and data used in the present COSS.

The most recent COSS prior to this one was prepared by BLPC and its consultant in 2009, and since then some of the factors that drive the Company's cost of providing service have changed. This study incorporates updated information (using data available as of December 31, 2020) aimed to support BLPC's and its goal to move towards cost allocations and rate design that more closely reflect current cost causation and further provides for Barbados to transition towards its 100/100 Vision targeting 100% renewable power by 2030.

The methodology used in this study is consistent with that used in the 2009 COSS conducted by BLPC. In a few cases there were changes in the allocators selected for certain accounts, with very small effect on the results of the COSS. The primary difference in methodology relates to the accounts that are considered for the computation of customer related costs. This is discussed in detail in Section II.E. The remainder of this document provides details on the methodology used in the COSS as well as detailed results tables.

II. Methodology

A COSS analyzes the components of the utility's total cost of service and aims to determine the portion that can be attributed to each Rate Class on the principle of cost-causation. A Rate Class is a relatively homogeneous group of customers that possess similar characteristics in terms of their energy consumption, load and end use patters, delivery voltage, and metering characteristics. Typical Rate Classes include domestic service, commercial or general service, and industrial power, among others.

The starting point of a COSS is the utility's Revenue Requirement, which is the total amount of revenue that the company must generate in order to recover its total cost of providing service. The COSS is used to calculate the costs of individual types of services based on the cost that each service requires the utility to expend. These costs are then attributed to different categories of customers based on how the customers cause these costs to be incurred. Once the costs of providing services are allocated among the Rate Classes, the utility can establish rates that ensure that it recovers all its costs.

It is important to note that a COSS does not dictate the total amount of revenue that the utility must recover. Instead, a COSS supports the development of rates by informing how these costs should be recovered from customers in each Rate Class. The fundamental step in a COSS is to develop allocators that capture the relationship between the costs of providing service and the drivers of those costs as accurately as possible.

The present study closely follows the principles of cost allocation set forth in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC"). The investments and expenses incurred by BLPC are mostly recorded in accordance with the FERC's Uniform System of Accounts. These investments and expenses cannot, for the most part, be directly attributed to specific Rate Classes, and as a result there is a need to separate the costs into a series of components in order to appropriately apportion costs to each Rate Class in relation to the class's cost responsibility. In this way, plant investments and operating expenses are allocated in such a way that customers in each Rate Class pay for the costs that they cause the utility to incur.

This report relies on financial and operational data provided by BLPC staff, which includes BLPC's computation of the Revenue Requirement for Test Year 2020. Financial data consists of existing and proposed plant additions, operational expenses, and return requirements. These data were provided by the Company and grouped in a manner consistent with the Federal Energy Regulatory Commission's ("FERC") Uniform System of Accounts. The account numbers used by BLPC generally align with the account numbers used by the FERC. In the cases where the account numbering convention used by BLPC does not match that used by the FERC, we map account numbers in order to ensure consistency. This is necessary because we apply the COS principles set forth by NARUC on an account by account basis. Operational data includes sales, customer counts, and peak demand data.

The present study carries out the three steps of the cost of service process, namely functionalization, classification, and allocation, which are described in more detail below. The COSS was performed using an Excel-based spreadsheet model that facilitates computations. The methodology used is the same as that used in the 2009 COSS, with minor changes in the allocators selected for certain accounts.

A. Cost of Service Study

Typically a COSS study consists of three steps, namely functionalization, classification, and allocation.

In the functionalization step, costs and investments are separated by the utility's service functions which include generation/power supply, transmission, and distribution.

The second step is called classification and consists of dividing the functionalized costs into groups based on what caused them to be incurred. The three typical groups are demand, energy, and customer. Demand-related costs are associated with the maximum requirements of the utility's customers. These are costs that are related to designing, installing and maintaining facilities operating such that they can accommodate the largest level of demand that customers could place on the system. For this reason they are typically assigned to Rate Classes based on their relative contribution to demand during the peak season or peak day demands. Energy-related costs are those costs that vary with the amount of electricity that the customers consume. Customer-related costs are those required to serve a customer with minimal usage within each Rate Class. These costs include the costs of connecting a customer to the system, metering their electric usage, and maintaining the customer's account. They are largely driven by the number of customers, rather than by the amount of electricity consumed.

The third step is called allocation, and consists of apportioning the previously functionalized, classified costs among the Rate Classes. These costs are allocated in such a way as to capture the relationship between the costs and the drivers that caused the costs to be incurred for each Rate Class. For example, costs that are driven by the volume of electricity consumed would be allocated among the Rate Classes based on the relative share of electricity consumed by each class.

In a few cases, certain plant investments and costs are incurred exclusively to serve a specific customer or group of customers. In such cases these costs can be directly assigned to those customers. However, most utility investments and costs are incurred to serve many different groups of customers. For this reason, without the allocation process it is not possible to assign responsibility for common costs to the different Rate Classes. If each cost could be attributed specifically to each customer group, then there would exist no need for the class allocation step of the cost of service study.

The allocators used in this study were developed using BLPC's financial and operational data. The allocators and their derivation are shown in Appendix B, and a description of the allocation methodology used is included in the sections that follow.

The present study performs cost allocation to the following rate classes:

- Domestic Service
- Employees
- General Service
- Large Power
- Secondary Voltage Power
- Time of Use
- Street Lights

B. Allocation of the Rate Base

The term rate base refers to a utility's investments in plant and other assets to serve customers. Consistent with groupings in the FERC's Uniform System of Accounts, the present study groups the accounts that make up the rate base into categories to facilitate discussion. These groupings are: fossil production plant, renewable production plant, transmission and distribution plant, general plant, construction work in progress, working capital and other adjustments, and accumulated depreciation. The computation of the gross and net rate base in the present study is consistent with the computation of the rate base in BLPC's filing with the Fair Trading Commission in December 2018.[1] Net Rate Base is computed as follows: sum of a) total plant in service, b) construction work in progress expected to come in service within twelve months of the end of the Test Year, c) working capital, materials, and supplies, minus d) customer advances for construction, e) deferred income taxes, and f) accumulated depreciation. These rate base groupings are discussed in more detail below.

Production plant includes investments used in connection with the generation of electricity, and includes both fossil and renewable facilities. Production plant is sized to meet maximum daily demand and has been functionalized to generation, classified to demand, and allocated among Rate Classes based on relative demands of each Rate Class on the 12-month average coincident peak ("12 CP")[2]. This is consistent with the allocation methodology used in the 2009 COSS.

Financial records for Transmission and Distribution plant are combined into a single category by BLPC. In the functionalization step described later, we use functionalization factors provided by BLPC in order to separate financial data into the Transmission and Distribution functions.

Transmission plant consists primarily of investments in facilities to transport electricity. Similarly to production plant, transmission plant is sized to meet maximum daily demand and has been functionalized to transmission, classified to demand, and allocated among Rate Classes on a 12 CP basis.

Distribution plant includes a variety of assets that are found downstream of the transmission system. It includes such assets as poles, conductors, transformers, services, meters, and certain accounts related to street lighting. Poles, conductors, transformers, and services were functionalized to distribution and classified to demand and customer using individually-developed classification factors. The portion that was classified as demand-related was allocated among the Rate Classes based on the 1-month non-coincident peak ("1 NCP")[3]. The portion that was classified as customer-related was allocated among the Rate Classes based on customer count. Meter costs were allocated among the Rate Classes based on a cost-weighted customer count, which captures the difference in the cost of meters used to serve customers in different Rate Classes. Items grouped

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[1] The Barbados Light & Power Company Limited, Annual Operations & Financial Report to the Fair Trading Commission for period ending December 31, 2018.

[2] Coincident peak (CP) methods consider the extent to which a class imposes a demand at the time of (coincident with) system peak. The Coincident Peak is computed by identifying the hour with the single highest load for each month, and then determining each class' demand during that hour in each month. The single coincident peak, or "1CP", for each class is the demand of that class at the time of the highest measured one-hour demand. Similarly, the "12CP" can be computed by averaging the demands of each class across 12 months.

[3] Non-coincident peak (NCP) methods consider the peak of the individual class, irrespective of whether this peak takes place at the time of the system peak. The class NCP is computed in a similar fashion as the CP, except that it considers the highest monthly load for each class, irrespective of when the system peaks.

under FERC Account 373 (street lighting and signal systems), were classified as customer related and can be directly attributed to Street Lighting customers.

General plant items include structures, office furniture and equipment, as well as transportation, communication, and miscellaneous equipment tools. These assets support more than one function, and were functionalized, classified and allocated among Rate Classes primarily based on transmission and distribution plant investment, reflecting common utility practice.

Construction work in progress includes only those assets that were expected to go into service within 12 months of the end of the test year used in the present study. Construction work in progress and depreciation reserve were functionalized, classified and allocated among Rate Classes in the same ratio as the related assets.

Working capital represents cash and inventories that BLPC needs in the normal course of business. These items were functionalized and classified in proportion to BLPC's plant. Items classified as generation and transmission demand-related were allocated on a 12 CP basis, items classified as distribution demand-related were allocated on a 1 NCP basis, and items classified as customer-related were allocated based on customer count.

C. Allocation of Expenses

The allocation of expenses is grouped into categories below. These categories include production, transmission, distribution, customer accounts, service, and informational expenses, administrative and general, depreciation expense, taxes and credits, interest on long term debt, return requirement, and other revenues and expenses.

Production expenses are related to operations and maintenance of electric generation facilities as well as purchasing fuel or power to fulfil BLPC customer loads. Production plant is sized to meet maximum daily demand and thus the costs of operating BLPC's production plant has been functionalized to generation, classified to demand, and allocated among Rate Classes based on relative demands of each Rate Class on the 12-month average CP. Certain costs of operating and maintaining these facilities, including the cost of water, lubricants, ash handling expenses, and production supplies are largely driven by the amount of electricity produced. As a result these were functionalized to production, classified as energy-related, and allocated among Rate Classes based on their relative share of energy sales. Fuel costs are passed through directly to customers, and as a result they were allocated based on the relative share of expected fuel-related revenues. Fuel revenues were provided by BLPC and factor in the expected electricity consumption from customers in different Rate Classes, as well as the expected power purchase costs that BLPC incurs in the form of providing credits to customers who produce and sell electricity to the grid.

Transmission expenses are the costs associated with operating transmission facilities, which are designed and operated to meet peak demand requirements. Related costs were functionalized to transmission, classified as demand, and allocated among Rate Classes on a 12 CP basis.

Distribution costs include a variety of expenses related to operation and maintenance of the distribution system, including overhead and underground lines, transformers, service drops, and meters. Distribution expenses are driven by non-coincident demand and were allocated among Rate Classes in proportion to the BLPC 1 NCP. Consistent with the allocation of meter plant, meter maintenance costs were allocated in proportion to the cost of meters for each Rate Class.

Customer accounts costs relate to maintaining customer records and collection, meter reading, uncollectible accounts, and other miscellaneous costs. Customer records, customer service, and information expenses were functionalized to distribution, classified to customer, and allocated among the Rate Classes using a customer service allocator. This allocator intends to capture the demands that each customer class places on these areas of the Company. Meter reading expenses were functionalized to distribution, classified consistent with the classification of meter assets, and allocated in using an allocator that captures the difference in meter readings costs for different customer types. Uncollectible accounts were functionalized to distribution, classified as customer, and allocated among Rate Classes based on the share of revenue. Because the vast majority of uncollectible bills can be attributed to the domestic service and general service Rate Classes, uncollectible amounts are allocated only to these classes, and in proportion to their relative share of revenue.

Administrative and general expenses include administrative and general salaries, office supplies and expenses, and employee pensions and benefits. Administrative and general expenses were allocated using a salaries and wages allocator, which captures the salaries and wages of BLPC staff. Property insurance was allocated to the Rate Classes in proportion to the Rate Base. Depreciation expenses were allocated among Rate Classes in the same ratios as plant in service. Taxes other than income taxes and corporation tax were functionalized, classified and allocated among Rate Classes in proportion to their responsibility for investments in rate base.

D. Computation of Revenues

Revenues were grouped in two categories. “Revenues from Sales” are those that BLPC receives as a result of providing services to its customers, while “Other Revenues” include miscellaneous service revenues and interest on dividend income.

Revenues play an important role in the present COSS and their proper allocation is essential to measuring the extent to which each Rate Class recovers sufficient revenue to cover its respective cost of service. Revenues from Sales include revenue from the monthly service charge, demand charge, and volumetric charge, as well as fuel charges that are directly passed through to customers. Revenues from Sales for each Rate Class were provided by BLPC. Revenues in the Other Revenue category play the role of reducing the Revenue Requirement that needs to be collected from BLPC customers, and include miscellaneous service revenues and interest and dividend income. Miscellaneous service revenues were allocated based on the number of customers, while interest and dividend income was allocated in proportion to the rate base.

E. Computation of Customer-related costs

Customer-related costs are the costs incurred to connect a customer to the distribution system, the capital costs and expenses associated with metering their usage, and the costs to maintain the customer's account and provide customer service. Customer-related costs vary largely due to the number of customers served and do not typically depend on customers' electricity consumption.

Some cost categories are unambiguously driven by a customer's presence and vary in proportion to customer counts. Examples include the cost of the customer connection or service drop, the cost of metering, and the costs related to customer accounting and sales. These costs are considered to be customer-related in the present study.

Utilities also consider a share of the distribution system to be customer-related. Certain parts of the distribution system, such as the number of poles, miles of wire, and customer transformers, vary in proportion to the number of customers. As a result, the present study includes a portion of the costs associated with these parts of the distribution system in the computation of customer-related costs. The inclusion of these distribution system costs is the only modification relative to the methods used in the 2009 COSS. This enhancement is appropriate because these costs are driven in part by the number of customers the utility has to serve.

The monthly fixed customer charge is typically calculated by dividing the total customer-related costs by the number of customers in each Rate Class. The present COSS revealed that the current BLPC customer charges are significantly lower than the customer-related costs. Current customer-related costs are substantially higher than the customer charge currently in place on a cost causation basis. Increasing the customer charge moves rates to reflect the fixed nature of the costs related to serving individual customers more closely.

It is appropriate to collect customer-related costs via a fixed customer charge because a fixed charge reflects these customer costs' invariance to consumption changes that this charge aims to recover. A fixed customer cost enhances BLPC's ability to recover these costs in the face of changes in consumption, reducing recovery risk for fixed costs.

F. Description of Results Tables

The current COSS assigns BLPC's Revenue Requirement among the Race Classes on the basis of cost causation. This assignment was based on data provided by BLPC, which included historical financial data on plant and expenses, revenue data, sales and demand data, as well as other operating characteristics for the Test Year. Appendix A includes detailed results tables, which are described below.

Table 1 - Allocated Rate Base and Income Statement: shows utility plant in service, revenue at current rates, and O&M expenses allocated on a cost of service basis. This table also compares revenue at current rates to the total Revenue Requirement and Tariff Revenue Requirement, to determine the extent to which each Rate Class contributes to its cost responsibility.

Table 2 - Summary Results by Functional Classification: shows the results of allocating the Tariff Revenue Requirement by functional classification. It also computes the customer-related, demand-related, and energy-related costs on a unit basis.

Table 2A - Summary of Unit Charges: shows the customer, demand, and energy unit charges resulting from the COSS.

Table 3 - Allocation Results by FERC Account: shows detail of the allocation of each FERC account to the Rate Classes.

Table 4 - Allocation Factor Values: shows allocation values, as % for each Rate Class.

Table 5 - Classification Results by FERC Account: shows detail of the classification of each FERC account to the Rate Classes.

Table 6 - Classification Factor Values: shows classification values, as % for each Rate Class.

Table 7 - Functionalization Results by FERC Account: shows detail of the functionalization of each FERC account to the Rate Classes.

Table 8 - Functionalization Factor Values: shows functionalization values, as % for each Rate Class.

Table 9 - Factors Used by FERC Account: shows the factors used in the classification, functionalization, and allocation steps of the present COSS.

III. Appendix A: COS Study Results

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 1: Allocated Rate Base and Income Statement

Dollars in Thousands

Line	Item	Total	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
	Utility Plant in Service								
1	***Total Utility Plant in Service***	***1,462,100***	***532,438***	***2,548***	***96,996***	***255,575***	***464,060***	***35,095***	***75,388***
2	Construction Work in Progress Capitalized FY2019	143,005	40,869	204	9,678	31,311	56,503	3,942	497
3	Less Accumulated Depreciation	(815,590)	(290,944)	(1,400)	(54,512)	(148,829)	(267,258)	(20,385)	(32,262)
4	***Total Net Plant***	***789,515***	***282,363***	***1,352***	***52,162***	***138,057***	***253,304***	***18,652***	***43,623***
5	Total Current Asset and Liability Adjustment	36,376	13,290	64	2,428	6,477	11,622	898	1,598
6	**Net Rate Base**	**825,891**	**295,653**	**1,416**	**54,590**	**144,534**	**264,927**	**19,550**	**45,221**
	Revenue from Sales at Current Rates								
7	***Total Revenue from Sales at Current Rates***	***389,017***	***145,984***	***639***	***24,128***	***67,454***	***134,425***	***12,074***	***4,313***
8	Miscellaneous Revenue and Other Income	4,748	3,169	13	345	61	228	8	923
9	**Total Revenue**	**393,765**	**149,153**	**652**	**24,474**	**67,515**	**134,653**	**12,082**	**5,237**
	Operating and Maintenance Expenses								
10	***Total Operating and Maintenance Expenses***	***305,481***	***119,439***	***607***	***17,835***	***51,441***	***102,820***	***9,207***	***4,131***
	Depreciation and Taxes								
11	Depreciation Expense	57,629	21,168	101	3,845	10,203	18,305	1,418	2,590
12	Taxes and Credits	3,354	1,201	6	222	587	1,076	79	184
13	***Total Depreciation and Taxes***	***60,984***	***22,368***	***107***	***4,066***	***10,790***	***19,381***	***1,498***	***2,773***
14	**Total Expenses and Taxes before Interest**	**366,465**	**141,808**	**715**	**21,901**	**62,231**	**122,201**	**10,705**	**6,904**
15	**Operating Income at Current Rates**	**27,300**	**7,345**	**(62)**	**2,573**	**5,284**	**12,452**	**1,377**	**(1,668)**
16	**Return on Rate Base at Current Rates**	3.31%	2.48%	-4.39%	4.71%	3.66%	4.70%	7.04%	-3.69%
17	Return Requirement at Target Rate of Return of 8.79%	72,610	25,993	124	4,799	12,707	23,292	1,719	3,976
18	Additional revenue required as a result of rate increase	1,165	417	2	77	204	374	28	64
19	**Tariff Revenue Requirement at Target Rate of Return of 8.79%**	**435,492**	**165,049**	**828**	**26,432**	**75,081**	**145,638**	**12,443**	**10,021**
20	***Total Revenue Requirement at Target Rate of Return of 8.79%***	***440,240***	***168,218***	***841***	***26,778***	***75,142***	***145,866***	***12,451***	***10,944***
21	**COS Ratio at Current Rates**	**0.90**	**0.90**	**0.79**	**0.93**	**0.90**	**0.92**	**0.97**	**0.52**
22	**Increase (Decrease) Necessary to Meet Target Rate of Return of 8.8%**	**46,475**	**19,066**	**189**	**2,304**	**7,627**	**11,214**	**369**	**5,707**

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 2: Summary Results by Functional Classification

Dollars in Thousands	Total	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
GENERATION								
Demand Costs	108,391	33,492	165	7,277	22,170	40,211	2,846	2,230
Energy Costs	210,868	81,055	433	11,815	38,886	69,738	7,507	1,434
Energy Costs, Excluding Fuel	*7,889*	*3,060*	*16*	*443*	*1,473*	*2,538*	*289*	*69*
Generation	***319,259***	***114,547***	***598***	***19,092***	***61,056***	***109,949***	***10,353***	***3,664***
TRANSMISSION								
Demand Costs	10,478	3,623	17	696	1,904	3,501	254	482
Transmission	***10,478***	***3,623***	***17***	***696***	***1,904***	***3,501***	***254***	***482***
DISTRIBUTION								
Demand Costs	51,819	20,149	97	3,175	7,900	17,159	1,267	2,073
Customer Costs	53,935	26,730	115	3,469	4,221	15,029	569	3,802
Distribution	***105,755***	***46,879***	***212***	***6,644***	***12,121***	***32,189***	***1,836***	***5,874***
TARIFF REVENUE REQUIREMENT								
Customer Costs	53,935	26,730	115	3,469	4,221	15,029	569	3,802
Demand Costs	170,689	57,264	279	11,148	31,974	60,871	4,368	4,785
Energy Costs	210,868	81,055	433	11,815	38,886	69,738	7,507	1,434
Tariff Revenue Requirement	**435,492**	**165,049**	**828**	**26,432**	**75,081**	**145,638**	**12,443**	**10,021**
Monthly Customer Average								
Customer Count	159,836	110,335	460	11,707	133	4,457	17	32,727
Customer Months	1,918,032	1,324,020	5,520	140,484	1,596	53,484	204	392,724
Customer-Related Costs, $/month	**$28.12**	**$20.19**	**$20.87**	**$24.70**	**$2,644.83**	**$281.00**	**$2,788.39**	**$9.68**
Billing Demand - Average, kVA	146,871	0	0	0	44	97	6	0
Demand-Related Costs, $/kVA-month					**$60.19**	**$52.27**	**$65.61**	
Annual Energy Sales, kWh	889,943,723	345,229,145	1,851,785	49,959,785	166,151,481	286,286,657	32,635,154	7,829,716
Energy-Related Costs, $/kWh	**$0.2369**	**$0.2348**	**$0.2341**	**$0.2365**	**$0.2340**	**$0.2436**	**$0.2300**	**$0.1832**
Energy Costs, Excluding Fuel, $/kWh	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089	$0.0089
SUMMARY OF UNIT CHARGES								
Customer Charge, $/month		20.19	20.87	24.70	2,644.83	281.00	2,788.39	9.68
Demand Charge, $/kVA-month					60.19	52.27	65.61	
Energy Charge, $/kWh (incl. demand-related costs for non-demand rate classes)		0.1747	0.1596	0.2320	0.0089	0.0089	0.0089	0.6200

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 2A: Summary of Unit Charges

	Customer Charge, $/month	Demand Charge, $/kVA	Energy Charge, $/kWh
Domestic	$20.19		$0.1747
Employees	$20.87		$0.1596
General Service	$24.70		$0.2320
Large Power	$2,644.83	$60.19	$0.0089
Secondary Voltage Power	$281.00	$52.27	$0.0089
Time of Use	$2,788.39	$65.61	$0.0089
Street Lights	$9.68		$0.6200

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 3: Allocation Results by FERC Account

Dollars in Thousands

FERC Account Description	Account Code	Total	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
I. ELECTRIC PLANT IN SERVICE									
A. STEAM PRODUCTION PLANT									
Structures and improvements	311	53,008	14,894	75	3,590	11,737	21,186	1,470	55
Boiler plant equipment	312	543,885	152,823	765	36,838	120,429	217,380	15,088	562
Miscellaneous power plant equipment	316	33,378	9,379	47	2,261	7,391	13,341	926	34
Subtotal - Steam Production Plant	304-316	630,271	177,097	887	42,690	139,557	251,906	17,484	651
B. RENEWABLE PRODUCTION PLANT									
Generators	344	38,921	10,936	55	2,636	8,618	15,556	1,080	40
Energy Storage Equipment - Production	348	16,448	4,622	23	1,114	3,642	6,574	456	17
Subtotal - Renewable Production Plant	344-348	55,369	15,558	78	3,750	12,260	22,130	1,536	57
C. TRANSMISSION AND DISTRIBUTION PLANT									
Structures and improvements	361	22,099	6,637	35	1,374	4,789	8,230	743	291
Station equipment	362	94,693	28,255	149	5,941	20,564	35,526	3,127	1,131
Poles, towers and fixtures	364	109,183	59,143	263	7,410	9,197	17,170	1,562	14,438
Overhead conductors and devices	365	43,472	19,528	93	2,770	5,951	10,278	1,049	3,802
Underground conductors and devices	367	209,608	86,323	414	13,544	32,633	57,160	5,226	14,308
Line transformers	368	56,531	33,857	148	4,350	0	9,944	0	8,232
Services	369	43,094	23,358	105	2,870	3,675	6,671	683	5,730
Meters	370.1	5,763	4,193	18	443	510	534	65	0
AMI Meters	370.2	44,400	32,302	138	3,415	3,929	4,118	499	0
Street lighting and signal systems	373	21,193	0	0	0	0	0	0	21,193
Subtotal - Transmission and Distribution Plant	361-387	650,035	293,595	1,362	42,119	81,248	149,631	12,954	69,125
D. GENERAL PLANT									
Land and land rights	389	17,362	6,343	30	1,159	3,091	5,547	429	763
Structures and improvements	390	27,239	9,951	48	1,818	4,850	8,703	672	1,197
Office furniture and equipment	391	17,438	6,371	31	1,164	3,105	5,572	430	766
Transportation equipment	392	13,238	4,836	23	883	2,357	4,229	327	582
Communication equipment	397	2,498	913	4	167	445	798	62	110
Miscellaneous equipment	398	48,650	17,774	85	3,247	8,662	15,544	1,201	2,138
Subtotal - General Plant	389-399	126,425	46,188	221	8,437	22,510	40,393	3,120	5,555
TOTAL UTILITY PLANT IN SERVICE	300-399	1,462,100	532,438	2,548	96,996	255,575	464,060	35,095	75,388

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 3: Allocation Results by FERC Account

Dollars in Thousands

FERC Account Description	Account Code	Total	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
II. CONSTRUCTION WORK IN PROGRESS									
Construction work in progress - Generation	107.1	138,592	38,942	195	9,387	30,687	55,392	3,845	143
Construction work in progress - Transmission	107.2	1,074	302	2	73	238	429	30	1
Construction work in progress - Distribution	107.3	2,851	1,447	7	185	299	526	56	331
Construction work in progress - General	107.4	488	178	1	33	87	156	12	21
Total Construction Work in Progress		143,005	40,869	204	9,678	31,311	56,503	3,942	497
TOTAL UTILITY PLANT		1,605,105	573,307	2,752	106,674	286,887	520,563	39,037	75,885
III. CURRENT ASSET AND LIABILITY ADJUSTMENT									
Cash working capital	131	13,580	4,961	24	906	2,418	4,339	335	597
Materials, supplies, and prepayments	165	29,323	10,713	51	1,957	5,221	9,369	724	1,288
Customer advances for construction	252	(3,171)	(1,159)	(6)	(212)	(565)	(1,013)	(78)	(139)
Accumulated deferred income taxes	190	(3,356)	(1,226)	(6)	(224)	(598)	(1,072)	(83)	(147)
Total Current Asset and Liability Adjustment	0	36,376	13,290	64	2,428	6,477	11,622	898	1,598
GROSS RATE BASE (UTILITY PLANT + WORKING CAPITAL)		1,641,481	586,597	2,816	109,102	293,363	532,185	39,935	77,483
IV. ACCUMULATED DEPRECIATION									
Accumulated Depreciation - Generation	108.1	421,503	118,436	593	28,549	93,331	168,466	11,693	435
Accumulated Depreciation - Transmission	108.2	0	0	0	0	0	0	0	0
Accumulated Depreciation - Transmission and Distributior	108.3	320,055	145,461	678	21,022	42,317	75,139	6,865	28,574
Accumulated Depreciation - General	108.4	74,031	27,047	130	4,941	13,181	23,653	1,827	3,253
Total Accumulated Depreciation	108	815,590	290,944	1,400	54,512	148,829	267,258	20,385	32,262
NET RATE BASE (GROSS RATE BASE NET OF DEPRECIATION)		825,891	295,653	1,416	54,590	144,534	264,927	19,550	45,221

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 3: Allocation Results by FERC Account

Dollars in Thousands

FERC Account Description	Account Code	Total	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
I. OPERATION & MAINTENANCE EXPENSE									
A. PRODUCTION EXPENSES									
1. Power Generation - Steam									
Operation supervision and engineering	500	14,864	4,177	21	1,007	3,291	5,941	412	15
Fuel	501	202,979	77,995	417	11,372	37,413	67,200	7,217	1,365
Water, Lubricants, and Ash Handling	502	7,866	3,051	16	442	1,469	2,530	288	69
Miscellaneous steam power expenses (Major only)	506	279	78	0	19	62	112	8	0
Production Supplies	508	23	9	0	1	4	7	1	0
Maintenance of structures (Major only)	511	824	232	1	56	182	329	23	1
Maintenance of boiler plant (Major only)	512	507	143	1	34	112	203	14	1
Maintenance of electric plant (Major only)	513	13,016	3,657	18	882	2,882	5,202	361	13
Maintenance of miscellaneous steam plant (Major only)	514	1,447	407	2	98	320	578	40	1
Maintenance of steam production plant (Nonmajor only)	515	2,879	809	4	195	638	1,151	80	3
Subtotal - Power Production - Steam	500-515	244,685	90,557	481	14,105	46,374	83,254	8,445	1,469
Subtotal - Power Production and Purchased Power Expens	500-557	244,685	90,557	481	14,105	46,374	83,254	8,445	1,469
B. TRANSMISSION AND DISTRIBUTION EXPENSES									
Operation supervision and engineering	580	3,057	968	5	176	650	1,069	118	71
Load dispatching (Major only)	581	1,903	601	3	110	405	667	73	43
Miscellaneous distribution expenses	588	460	146	1	26	98	161	18	11
Maintenance of structures (Major only)	591	361	108	1	22	78	134	12	5
Maintenance of station equipment (Major only)	592	911	281	2	55	196	329	33	16
Maintenance of overhead lines (Major only)	593	3,056	1,401	7	194	404	695	73	282
Maintenance of underground lines (Major only)	594	217	89	0	14	34	59	5	15
Maintenance of line transformers	595	194	116	1	15	0	34	0	28
Maintenance of street lighting and signal systems	596	91	0	0	0	0	0	0	91
Maintenance of meters	597	949	690	3	73	84	88	11	0
Maintenance of miscellaneous distribution plant	598	69	22	0	4	15	24	3	2
Subtotal - Transmission and Distribution Expenses	580-598	11,268	4,422	22	689	1,964	3,261	345	564
TOTAL OPERATION & MAINTENANCE EXPENSES		255,952	94,980	503	14,794	48,338	86,514	8,790	2,033

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 3: Allocation Results by FERC Account

Dollars in Thousands

FERC Account Description	Account Code	Total	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
II. CUSTOMER ACCOUNTS, SERVICE, AND INFORMATIONAL EXPENSES									
Supervision (Major only)	901	1,008	561	2	60	10	340	1	33
Meter reading expenses	902	419	206	1	22	4	125	0	61
Customer records and collection expenses	903	2,958	1,647	7	175	30	998	4	98
Uncollectible accounts	904	363	305	0	33	0	25	0	0
Miscellaneous customer accounts expenses (Major only)	905	845	470	2	50	9	285	1	28
Customer service and informational expenses (Nonmajor	906	(6)	(3)	(0)	(0)	(0)	(2)	(0)	(0)
Supervision (Major only)	907	1,716	955	4	101	17	579	2	57
Customer assistance expenses (Major only)	908	2,932	1,633	7	173	30	989	4	97
Informational and instructional advertising expenses (Maj	909	1,150	640	3	68	12	388	1	38
Subtotal - Customer Accounts, Service, and Informational	901-910	11,384	6,414	25	681	110	3,728	14	411
TOTAL CUSTOMER ACCOUNTS, SERVICE & INFORMATIONAL EXPENSES		11,384	6,414	25	681	110	3,728	14	411
III. ADMINISTRATIVE & GENERAL EXPENSES									
A. LABOR RELATED									
Administrative and general salaries	920	10,421	5,781	24	613	105	3,503	13	383
Office supplies and expenses	921	8,108	4,497	19	477	81	2,725	10	298
Outside services employed	923	1,088	603	3	64	11	366	1	40
Property insurance	924	12,349	4,421	21	816	2,161	3,961	292	676
Employee pensions and benefits	926	2,703	1,499	6	159	27	908	3	99
Subtotal - Labor Related A&G	920-926	34,668	16,801	73	2,130	2,385	11,463	321	1,496
B. OTHER A&G									
Regulatory commission expenses	928	2,217	794	4	147	388	711	52	121
General advertising expenses	930.1	1,031	369	2	68	180	331	24	56
Miscellaneous general expenses	930.2	228	82	0	15	40	73	5	13
Subtotal - Other A&G	927-932	3,476	1,245	6	230	608	1,115	82	190
TOTAL ADMINISTRATIVE & GENERAL EXPENSES		38,144	18,045	79	2,360	2,993	12,578	403	1,686
TOTAL OPERATING EXPENSES (Excluding Dep, Tax)	OP_EX	305,481	119,439	607	17,835	51,441	102,820	9,207	4,131
IV. DEPRECIATION EXPENSE									
Production Depreciation Expense	403-GEN	32,827	9,224	46	2,223	7,269	13,120	911	34
Transmission Depreciation Expense	403-TRANS	0	0	0	0	0	0	0	0
Distribution Depreciation Expense	403-DIST	20,279	10,291	47	1,319	2,129	3,739	396	2,357
General Depreciation Expense	403-GRAL	4,524	1,653	8	302	805	1,445	112	199
Subtotal - Depreciation Expense	403	57,629	21,168	101	3,845	10,203	18,305	1,418	2,590

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 3: Allocation Results by FERC Account

Dollars in Thousands

FERC Account Description	Account Code	Total	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
V. TAXES AND CREDITS									
Taxes other than income taxes, utility operating income	408.1	6,135	2,196	11	406	1,074	1,968	145	336
Corporation tax expense	409.2	0	0	0	0	0	0	0	0
Deferred taxes	410.2	(467)	(167)	(1)	(31)	(82)	(150)	(11)	(26)
Deferred investment tax credit and manufacturers tax cre	411.4	(2,313)	(828)	(4)	(153)	(405)	(742)	(55)	(127)
Subtotal - Taxes and Credits		3,354	1,201	6	222	587	1,076	79	184
TOTAL EXPENSES		366,465	141,808	715	21,901	62,231	122,201	10,705	6,904
I. REVENUES FROM SALES									
Revenue - Service	440.1	15,306	12,210	0	1,483	481	1,070	62	0
Revenue - Demand	440.2	40,334	0	0	0	11,185	27,952	1,198	0
Revenue - Volumetric	440.3	135,257	57,252	230	11,425	19,707	39,853	3,753	3,037
Revenue - Fuel	440.4	202,979	77,995	417	11,372	37,413	67,200	7,217	1,365
Adjustment-Unbilled	440.5	(805)	100	1	76	(575)	(345)	(8)	(53)
Revenue - Early Payment Credit	440.6	(3,457)	(1,341)	(7)	(194)	(645)	(1,112)	(127)	(30)
Revenue - Interruptible Credit	440.7	(597)	(231)	(1)	(33)	(111)	(192)	(22)	(5)
Revenue - Renewable Credit	440.8	0	0	0	0	0	0	0	0
Subtotal - Electric Revenues		389,017	145,984	639	24,128	67,454	134,425	12,074	4,313
II. OTHER REVENUES									
Miscellaneous Service Revenues	451	4,421	3,052	13	324	4	123	0	905
Interest and dividend income	419	327	117	1	22	57	105	8	18
Subtotal Non-Operating Income	Non-Op-Inc	4,748	3,169	13	345	61	228	8	923
TOTAL REVENUE AT CURRENT RATES		393,765	149,153	652	24,474	67,515	134,653	12,082	5,237
Required Return	999	72,610	25,993	124	4,799	12,707	23,292	1,719	3,976
Additional income taxes resulting from rate increase	409.3	271	97	0	18	47	87	6	15
Provisions for deferred income taxes	410.3	894	320	2	59	156	287	21	49
Additional revenue required as a result of rate increase		1,165	417	2	77	204	374	28	64
Tariff Revenue Requirement		435,492	165,049	828	26,432	75,081	145,638	12,443	10,021
NET INCOME AT CURRENT RATES		27,300	7,345	(62)	2,573	5,284	12,452	1,377	(1,668)
Required Increase (Decrease)		45,310	18,648	187	2,227	7,423	10,840	342	5,643

Barbados Light & Power Company

Allocated Class COS Study — Test Year Ended December 31, 2020

Table 4: Allocation Factor Values

Allocator Name	Domestic	Employees	General Service	Large Power	Secondary Voltage Power	Time of Use	Street Lights
Customers	69.03%	0.29%	7.32%	0.08%	2.79%	0.01%	20.48%
Customer Service	55.68%	0.23%	5.91%	1.01%	33.74%	0.13%	3.30%
Meter Cost	72.75%	0.31%	7.69%	8.85%	9.27%	1.12%	0.00%
Meter Reading	49.18%	0.21%	5.22%	0.89%	29.80%	0.11%	14.59%
Customers - Excl. Primary	69.09%	0.29%	7.33%	0.00%	2.79%	0.00%	20.49%
Energy Sales - Total	38.79%	0.21%	5.61%	18.67%	32.17%	3.67%	0.88%
12 CP	28.10%	0.14%	6.77%	22.14%	39.97%	2.77%	0.10%
1 NCP	31.96%	0.18%	5.66%	21.20%	34.52%	3.95%	2.53%
12 CP - Excl. Primary	37.42%	0.19%	9.02%	0.00%	53.23%	0.00%	0.14%
1 NCP - Excl. Primary	42.70%	0.24%	7.57%	0.00%	46.12%	0.00%	3.38%
Revenue - Total	37.04%	0.17%	6.26%	17.41%	34.86%	3.14%	1.12%
Revenue - Service	79.77%	0.00%	9.69%	3.14%	6.99%	0.41%	0.00%
Revenue - Demand	0.00%	0.00%	0.00%	27.73%	69.30%	2.97%	0.00%
Revenue - Volumetric	42.33%	0.17%	8.45%	14.57%	29.46%	2.77%	2.25%
Revenue - Fuel	38.43%	0.21%	5.60%	18.43%	33.11%	3.56%	0.67%
Revenue - Unbilled	-12.41%	-0.06%	-9.39%	71.38%	42.91%	1.03%	6.55%
Uncollectibles	84.00%	0.00%	9.00%	0.00%	7.00%	0.00%	0.00%
Street Lighting	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	100.00%
Total Plant	36.42%	0.17%	6.63%	17.48%	31.74%	2.40%	5.16%
Rate Base	35.80%	0.17%	6.61%	17.50%	32.08%	2.37%	5.48%
Salaries and Wages	55.47%	0.23%	5.89%	1.00%	33.61%	0.13%	3.67%

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 5: Classification Results by FERC Account

Dollars in Thousands		Generation					Transmission					Distribution					
FERC Account Description	Account Code	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Demand-Pr	Demand-Se	Customer
I. ELECTRIC PLANT IN SERVICE																	
A. STEAM PRODUCTION PLANT																	
Structures and improvements	311	53,008	Demand	53,008	0	0	0	None	0	0	0	0	None	0	0	0	0
Boiler plant equipment	312	543,885	Demand	543,885	0	0	0	None	0	0	0	0	None	0	0	0	0
Miscellaneous power plant equipment	316	33,378	Demand	33,378	0	0	0	None	0	0	0	0	None	0	0	0	0
Subtotal - Steam Production Plant	304-316	630,271		630,271	0	0	0		0	0	0	0		0	0	0	0
B. RENEWABLE PRODUCTION PLANT																	
Generators	344	38,921	Demand	38,921	0	0	0	None	0	0	0	0	None	0	0	0	0
Energy Storage Equipment - Production	348	16,448	Demand	16,448	0	0	0	None	0	0	0	0	None	0	0	0	0
Subtotal - Renewable Production Plant	344-348	55,369		55,369	0	0	0		0	0	0	0		0	0	0	0
C. TRANSMISSION AND DISTRIBUTION PLANT																	
Structures and improvements	361	0	None	0	0	0	11,049	Demand	11,049	0	0	11,049	Demand	11,049	0	0	0
Station equipment	362	0	None	0	0	0	52,081	Demand	52,081	0	0	42,612	Demand	42,612	0	0	0
Poles, towers and fixtures	364	0	None	0	0	0	10,918	Demand	10,918	0	0	98,265	364_CLA	31,722	0	0	66,543
Overhead conductors and devices	365	0	None	0	0	0	4,347	Demand	4,347	0	0	39,125	365_CLA	23,475	0	0	15,650
Underground conductors and devices	367	0	None	0	0	0	62,882	Demand	62,882	0	0	146,726	367_CLA	88,035	0	0	58,690
Line transformers	368	0	None	0	0	0	11,306	Demand	11,306	0	0	45,225	368_CLA	6,146	0	0	39,079
Services	369	0	None	0	0	0	0	None	0	0	0	43,094	369_CLA	17,237	0	0	25,856
Meters	370.1	0	None	0	0	0	0	None	0	0	0	5,763	370_CLA	2,881	0	0	2,881
AMI Meters	370.2	0	None	0	0	0	0	None	0	0	0	44,400	370_CLA	22,200	0	0	22,200
Street lighting and signal systems	373	0	None	0	0	0	0	None	0	0	0	21,193	Custome	0	0	0	21,193
Subtotal - Transmission and Distribution Plant	361-387	0		0	0	0	152,585		152,585	0	0	497,450		245,358	0	0	252,092
D. GENERAL PLANT																	
Land and land rights	389	8,913	Demand	8,913	0	0	1,983	Demand	1,983	0	0	6,466	DIST_PT	3,189	0	0	3,277
Structures and improvements	390	13,983	Demand	13,983	0	0	3,112	Demand	3,112	0	0	10,145	DIST_PT	5,004	0	0	5,141
Office furniture and equipment	391	8,952	Demand	8,952	0	0	1,992	Demand	1,992	0	0	6,495	DIST_PT	3,203	0	0	3,291
Transportation equipment	392	6,795	Demand	6,795	0	0	1,512	Demand	1,512	0	0	4,930	DIST_PT	2,432	0	0	2,498
Communication equipment	397	1,282	Demand	1,282	0	0	285	Demand	285	0	0	930	DIST_PT	459	0	0	471
Miscellaneous equipment	398	24,973	Demand	24,973	0	0	5,558	Demand	5,558	0	0	18,119	DIST_PT	8,937	0	0	9,182
Subtotal - General Plant	389-399	64,898		64,898	0	0	14,443		14,443	0	0	47,085		23,224	0	0	23,861
TOTAL UTILITY PLANT IN SERVICE		750,537		750,537	0	0	167,027		167,027	0	0	544,535		268,582	0	0	275,953
II. CONSTRUCTION WORK IN PROGRESS																	
Construction work in progress - Generation	107.1	138,592	Demand	138,592	0	0	0	None	0	0	0	0	None	0	0	0	0
Construction work in progress - Transmission	107.2	0	None	0	0	0	1,074	Demand	1,074	0	0	0	None	0	0	0	0
Construction work in progress - Distribution	107.3	0	None	0	0	0	0	None	0	0	0	2,851	DIST_PT	1,406	0	0	1,445
Construction work in progress - General	107.4	250	Demand	250	0	0	56	Demand	56	0	0	182	DIST_PT	90	0	0	92
Total Construction Work in Progress	107	138,842		138,842	0	0	1,130		1,130	0	0	3,033		1,496	0	0	1,537
TOTAL UTILITY PLANT		889,379		889,379	0	0	168,157		168,157	0	0	547,568		270,078	0	0	277,490

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 5: Classification Results by FERC Account

Dollars in Thousands		**Generation**					**Transmission**					**Distribution**					
FERC Account Description	Account Code	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Demand-Pr	Demand-Se	Customer
III. CURRENT ASSET AND LIABILITY ADJUSTMENT																	
Cash working capital	131	6,971	Demand	6,971	0	0	1,551	Demand	1,551	0	0	5,058	DIST_PT	2,495	0	0	2,563
Materials, supplies, and prepayments	165	15,052	Demand	15,052	0	0	3,350	Demand	3,350	0	0	10,921	DIST_PT	5,387	0	0	5,534
Customer advances for construction	252	(1,628)	Demand	(1,628)	0	0	(362)	Demand	(362)	0	0	(1,181)	DIST_PT	(583)	0	0	(599)
Accumulated deferred income taxes	190	(1,723)	Demand	(1,723)	0	0	(383)	Demand	(383)	0	0	(1,250)	DIST_PT	(616)	0	0	(633)
Total Current Asset and Liability Adjustment		18,673		18,673	0	0	4,156		4,156	0	0	13,548		6,682	0	0	6,866
GROSS RATE BASE (UTILITY PLANT + WORKING CAPITAL)		908,052		908,052	0	0	172,312		172,312	0	0	561,116		276,760	0	0	284,356
IV. ACCUMULATED DEPRECIATION																	
Accumulated Depreciation - Generation	108.1	421,503	Demand	421,503	0	0	0	None	0	0	0	0	None	0	0	0	0
Accumulated Depreciation - Transmission	108.2	0	None	0	0	0	0	Demand	0	0	0	0	None	0	0	0	0
Accumulated Depreciation - Transmission and Distributio	108.3	0	None	0	0	0	74,887	Demand	74,887	0	0	245,168	DIST_PT	120,925	0	0	124,244
Accumulated Depreciation - General	108.4	38,002	Demand	38,002	0	0	8,457	Demand	8,457	0	0	27,572	DIST_PT	13,599	0	0	13,973
Total Accumulated Depreciation	108	459,506		459,506	0	0	83,344		83,344	0	0	272,740		134,524	0	0	138,216
NET RATE BASE (GROSS RATE BASE NET OF DEPRECIATION)		448,547		448,547	0	0	88,968		88,968	0	0	288,376		142,236	0	0	146,140
I. OPERATION & MAINTENANCE EXPENSE																	
A. PRODUCTION EXPENSES																	
1. Power Generation - Steam																	
Operation supervision and engineering	500	14,864	Demand	14,864	0	0	0	None	0	0	0	0	None	0	0	0	0
Fuel	501	202,979	Energy	0	202,979	0	0	None	0	0	0	0	None	0	0	0	0
Water, Lubricants, and Ash Handling	502	7,866	Energy	0	7,866	0	0	None	0	0	0	0	None	0	0	0	0
Miscellaneous steam power expenses (Major only)	506	279	Demand	279	0	0	0	None	0	0	0	0	None	0	0	0	0
Production Supplies	508	23	Energy	0	23	0	0	None	0	0	0	0	None	0	0	0	0
Maintenance of structures (Major only)	511	824	Demand	824	0	0	0	None	0	0	0	0	None	0	0	0	0
Maintenance of boiler plant (Major only)	512	507	Demand	507	0	0	0	None	0	0	0	0	None	0	0	0	0
Maintenance of electric plant (Major only)	513	13,016	Demand	13,016	0	0	0	None	0	0	0	0	None	0	0	0	0
Maintenance of miscellaneous steam plant (Major only)	514	1,447	Demand	1,447	0	0	0	None	0	0	0	0	None	0	0	0	0
Maintenance of steam production plant (Nonmajor only)	515	2,879	Demand	2,879	0	0	0	None	0	0	0	0	None	0	0	0	0
Subtotal - Power Production - Steam	500-515	244,685		33,817	210,868	0	0		0	0	0	0		0	0	0	0
Subtotal - Power Production and Purchased Power Expen	500-557	244,685		33,817	210,868	0	0		0	0	0	0		0	0	0	0
B. TRANSMISSION AND DISTRIBUTION EXPENSES																	
Operation supervision and engineering	580	0	None	0	0	0	245	Demand	245	0	0	2,813	Demand	2,813	0	0	0
Load dispatching (Major only)	581	0	None	0	0	0	190	Demand	190	0	0	1,713	Demand	1,713	0	0	0
Miscellaneous distribution expenses	588	0	None	0	0	0	37	Demand	37	0	0	424	Demand	424	0	0	0
Maintenance of structures (Major only)	591	0	None	0	0	0	180	Demand	180	0	0	180	Demand	180	0	0	0
Maintenance of station equipment (Major only)	592	0	None	0	0	0	273	Demand	273	0	0	638	Demand	638	0	0	0
Maintenance of overhead lines (Major only)	593	0	None	0	0	0	153	Demand	153	0	0	2,903	365_CLA	1,742	0	0	1,161
Maintenance of underground lines (Major only)	594	0	None	0	0	0	65	Demand	65	0	0	152	367_CLA	91	0	0	61
Maintenance of line transformers	595	0	None	0	0	0	39	Demand	39	0	0	155	368_CLA	21	0	0	134
Maintenance of street lighting and signal systems	596	0	None	0	0	0	0	None	0	0	0	91	Custome	0	0	0	91
Maintenance of meters	597	0	None	0	0	0	0	None	0	0	0	949	369_CLA	380	0	0	569
Maintenance of miscellaneous distribution plant	598	0	None	0	0	0	6	Demand	6	0	0	64	Demand	64	0	0	0
Subtotal - Transmission and Distribution Expenses	580-598	0		0	0	0	1,188		1,188	0	0	10,080		8,064	0	0	2,016
TOTAL OPERATION & MAINTENANCE EXPENSES		244,685		33,817	210,868	0	1,188		1,188	0	0	10,080		8,064	0	0	2,016

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 5: Classification Results by FERC Account

Dollars in Thousands		Generation					Transmission					Distribution					
FERC Account Description	Account Code	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Demand-Pr	Demand-Se	Customer
II. CUSTOMER ACCOUNTS, SERVICE, AND INFORMATIONAL EXPENSES																	
Supervision (Major only)	901	0	None	0	0	0	0	None	0	0	0	1,008	Custome	0	0	0	1,008
Meter reading expenses	902	0	None	0	0	0	0	None	0	0	0	419	Custome	0	0	0	419
Customer records and collection expenses	903	0	None	0	0	0	0	None	0	0	0	2,958	Custome	0	0	0	2,958
Uncollectible accounts	904	0	None	0	0	0	0	None	0	0	0	363	Custome	0	0	0	363
Miscellaneous customer accounts expenses (Major only)	905	0	None	0	0	0	0	None	0	0	0	845	Custome	0	0	0	845
Customer service and informational expenses (Nonmajor	906	0	None	0	0	0	0	None	0	0	0	(6)	Custome	0	0	0	(6)
Supervision (Major only)	907	0	None	0	0	0	0	None	0	0	0	1,716	Custome	0	0	0	1,716
Customer assistance expenses (Major only)	908	0	None	0	0	0	0	None	0	0	0	2,932	Custome	0	0	0	2,932
Informational and instructional advertising expenses (Ma	909	0	None	0	0	0	0	None	0	0	0	1,150	Custome	0	0	0	1,150
Subtotal - Customer Accounts, Service, and Informational Expenses		0		0	0	0	0		0	0	0	11,384		0	0	0	11,384
TOTAL CUSTOMER ACCOUNTS, SERVICE & INFORMATIONAL EXPENSES		0		0	0	0	0		0	0	0	0		0	0	0	0
III. ADMINISTRATIVE & GENERAL EXPENSES		0		0	0	0	0		0	0	0	11,384		0	0	0	11,384
A. LABOR RELATED																	
Administrative and general salaries	920	0	None	0	0	0	0	None	0	0	0	10,421	DIST_PT	5,140	0	0	5,281
Office supplies and expenses	921	0	None	0	0	0	0	None	0	0	0	8,108	DIST_PT	3,999	0	0	4,109
Outside services employed	923	0	None	0	0	0	0	None	0	0	0	1,088	DIST_PT	536	0	0	551
Property insurance	924	0	None	0	0	0	0	None	0	0	0	12,349	DIST_PT	6,091	0	0	6,258
Employee pensions and benefits	926	0	None	0	0	0	0	None	0	0	0	2,703	DIST_PT	1,333	0	0	1,370
Subtotal - Labor Related A&G		0		0	0	0	0		0	0	0	34,668		17,099	0	0	17,569
B. OTHER A&G																	
Regulatory commission expenses	928	0	None	0	0	0	0	None	0	0	0	2,217	DIST_PT	1,094	0	0	1,124
General advertising expenses	930.1	0	None	0	0	0	0	None	0	0	0	1,031	DIST_PT	509	0	0	522
Miscellaneous general expenses	930.2	0	None	0	0	0	0	None	0	0	0	228	DIST_PT	113	0	0	116
Subtotal - Other A&G		0		0	0	0	0		0	0	0	3,476		1,715	0	0	1,762
TOTAL ADMINISTRATIVE & GENERAL EXPENSES		0		0	0	0	0		0	0	0	38,144		18,814	0	0	19,330
TOTAL OPERATING EXPENSES (Excluding Dep, Tax)		244,685		33,817	210,868	0	1,188		1,188	0	0	59,609		26,878	0	0	32,731
IV. DEPRECIATION EXPENSE																	
Production Depreciation Expense	403-GEN	32,827	Demand	32,827	0	0	0	None	0	0	0	0	None	0	0	0	0
Transmission Depreciation Expense	403-TRANS	0	None	0	0	0	0	Demand	0	0	0	0	None	0	0	0	0
Distribution Depreciation Expense	403-DIST	0	None	0	0	0	0	None	0	0	0	20,279	DIST_PT	10,002	0	0	10,277
General Depreciation Expense	403-GRAL	2,322	Demand	2,322	0	0	517	Demand	517	0	0	1,685	DIST_PT	831	0	0	854
Subtotal - Depreciation Expense		35,149		35,149	0	0	517		517	0	0	21,963		10,833	0	0	11,130
V. TAXES AND CREDITS																	
Taxes other than income taxes, utility operating income	408.1	3,149	PROD_PT	3,149	0	0	701	Demand	701	0	0	2,285	DIST_PT	1,127	0	0	1,158
Corporation tax expense	409.2	0	PROD_PT	0	0	0	0	Demand	0	0	0	0	DIST_PT	0	0	0	0
Deferred taxes	410.2	(240)	PROD_PT	(240)	0	0	(53)	Demand	(53)	0	0	(174)	DIST_PT	(86)	0	0	(88)
Deferred investment tax credit and manufacturers tax cr	411.4	(1,187)	PROD_PT	(1,187)	0	0	(264)	Demand	(264)	0	0	(862)	DIST_PT	(425)	0	0	(437)
Subtotal - Taxes and Credits		1,722		1,722	0	0	383		383	0	0	1,249		616	0	0	633
TOTAL EXPENSES		281,556		70,688	210,868	0	2,088		2,088	0	0	82,821		38,327	0	0	44,494

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 5: Classification Results by FERC Account

Dollars in Thousands		**Generation**					**Transmission**					**Distribution**					
FERC Account Description	Account Code	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Energy	Customer	Total	Factor	Demand	Demand-Pr	Demand-Se	Customer
I. REVENUES FROM SALES																	
Revenue - Service	440.1	0	None	0	0	0	0	None	0	0	0	15,306	Custome	0	0	0	15,306
Revenue - Demand	440.2	0	None	0	0	0	0	None	0	0	0	40,334	Demand	40,334	0	0	0
Revenue - Volumetric	440.3	135,257	Energy	0	135,257	0	0	None	0	0	0	0	None	0	0	0	0
Revenue - Fuel	440.4	202,979	Energy	0	202,979	0	0	None	0	0	0	0	None	0	0	0	0
Adjustment-Unbilled	440.5	(805)	Energy	0	(805)	0	0	None	0	0	0	0	None	0	0	0	0
Revenue - Early Payment Credit	440.6	(3,457)	Energy	0	(3,457)	0	0	None	0	0	0	0	None	0	0	0	0
Revenue - Interruptible Credit	440.7	(597)	Energy	0	(597)	0	0	None	0	0	0	0	None	0	0	0	0
Revenue - Renewable Credit	440.8	0	Energy	0	0	0	0	None	0	0	0	0	None	0	0	0	0
Subtotal - Electric Revenues		333,377		0	333,377	0	0		0	0	0	55,640		40,334	0	0	15,306
II. OTHER REVENUES																	
Miscellaneous Service Revenues	451	0	None	0	0	0	0	None	0	0	0	4,421	Custome	0	0	0	4,421
Interest and dividend income	419	168	PROD_PT	168	0	0	37	Demand	37	0	0	122	DIST_PT	60	0	0	62
Subtotal Non-Operating Income	Non-Op-Inc	168		168	0	0	37		37	0	0	4,543		60	0	0	4,483
TOTAL REVENUE AT CURRENT RATES		333,545		168	333,377	0	37		37	0	0	60,183		40,394	0	0	19,789
Required Return	999	37,273	PROD_PT	37,273	0	0	8,295	Demand	8,295	0	0	27,043	DIST_PT	13,338	0	0	13,704
Additional income taxes resulting from rate increase	409.3	139	PROD_PT	139	0	0	31	Demand	31	0	0	101	DIST_PT	50	0	0	51
Provisions for deferred income taxes	410.3	459	PROD_PT	459	0	0	102	Demand	102	0	0	333	DIST_PT	164	0	0	169
Additional revenue required as a result of rate increase		598		598	0	0	133		133	0	0	434		214	0	0	220
Tariff Revenue Requirement		319,259		108,391	210,868	0	10,478		10,478	0	0	105,755		51,819	0	0	53,935
NET INCOME AT CURRENT RATES		51,989		(70,520)	122,509	0	(2,050)		(2,050)	0	0	(22,638)		2,067	0	0	(24,705)
Required Increase (Decrease)		(14,716)		107,793	(122,509)	0	10,345		10,345	0	0	49,681		11,271	0	0	38,410

Barbados Light & Power Company

Allocated Class COS Study — Test Year Ended December 31, 2020

Table 6: Classification Factor Values

Factor Name	Demand	Demand-Primary	Demand-Secondary	Energy	Customer
External Factors					
Demand	100.0%	0.0%	0.0%	0.0%	0.0%
Energy	0.0%	0.0%	0.0%	100.0%	0.0%
Customer	0.0%	0.0%	0.0%	0.0%	100.0%
Internal Factors					
Production Plant	100%	0%	0%	0%	0%
T&D Plant	49%	0%	0%	0%	51%
364 - Poles, towers and fixtures	32%				68%
365 - Overhead conductors and devices	60%				40%
367 - Underground conductors and devices	60%				40%
368 - Line transformers	14%				86%
369 - Services	40%				60%
370 - Meters	50%				50%

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 7: Functionalization Results by FERC Account

Dollars in Thousands FERC Account Description	Account Code	Total	Functionalization	Generation	Transmission	Distribution
I. ELECTRIC PLANT IN SERVICE						
A. STEAM PRODUCTION PLANT						
Structures and improvements	311	53,008	Generation	53,008	0	0
Boiler plant equipment	312	543,885	Generation	543,885	0	0
Miscellaneous power plant equipment	316	33,378	Generation	33,378	0	0
Subtotal - Steam Production Plant	304-316	630,271		630,271	0	0
B. RENEWABLE PRODUCTION PLANT						
Generators	344	38,921	Generation	38,921	0	0
Energy Storage Equipment - Production	348	16,448	Generation	16,448	0	0
Subtotal - Renewable Production Plant	344-348	55,369		55,369	0	0
C. TRANSMISSION AND DISTRIBUTION PLANT						
Structures and improvements	361	22,099	361_FUNC	0	11,049	11,049
Station equipment	362	94,693	362_FUNC	0	52,081	42,612
Poles, towers and fixtures	364	109,183	364_FUNC	0	10,918	98,265
Overhead conductors and devices	365	43,472	365_FUNC	0	4,347	39,125
Underground conductors and devices	367	209,608	367_FUNC	0	62,882	146,726
Line transformers	368	56,531	368_FUNC	0	11,306	45,225
Services	369	43,094	Distribution	0	0	43,094
Meters	370.1	5,763	Distribution	0	0	5,763
AMI Meters	370.2	44,400	Distribution	0	0	44,400
Street lighting and signal systems	373	21,193	Distribution	0	0	21,193
Subtotal - Transmission and Distribution Plant	361-387	650,035		0	152,585	497,450
D. GENERAL PLANT						
Land and land rights	389	17,362	Plant x.General	8,913	1,983	6,466
Structures and improvements	390	27,239	Plant x.General	13,983	3,112	10,145
Office furniture and equipment	391	17,438	Plant x.General	8,952	1,992	6,495
Transportation equipment	392	13,238	Plant x.General	6,795	1,512	4,930
Communication equipment	397	2,498	Plant x.General	1,282	285	930
Miscellaneous equipment	398	48,650	Plant x.General	24,973	5,558	18,119
Subtotal - General Plant	389-399	126,425		64,898	14,443	47,085
TOTAL UTILITY PLANT IN SERVICE		1,462,100		750,537	167,027	544,535
II. CONSTRUCTION WORK IN PROGRESS						
Construction work in progress - Generation	107.1	138,592	Generation	138,592	0	0
Construction work in progress - Transmission	107.2	1,074	Transmission	0	1,074	0
Construction work in progress - Distribution	107.3	2,851	Distribution	0	0	2,851
Construction work in progress - General	107.4	488	Plant x.General	250	56	182
Total Construction Work in Progress		143,005		138,842	1,130	3,033
TOTAL UTILITY PLANT		1,605,105		889,379	168,157	547,568

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 7: Functionalization Results by FERC Account

Dollars in Thousands

FERC Account Description	Account Code	Total	Functionalization	Generation	Transmission	Distribution
III. CURRENT ASSET AND LIABILITY ADJUSTMENT						
Cash working capital	131	13,580	Plant x.General	6,971	1,551	5,058
Materials, supplies, and prepayments	165	29,323	Plant x.General	15,052	3,350	10,921
Customer advances for construction	252	(3,171)	Plant x.General	(1,628)	(362)	(1,181)
Accumulated deferred income taxes	190	(3,356)	Plant x.General	(1,723)	(383)	(1,250)
Total Current Asset and Liability Adjustment	0	36,376		18,673	4,156	13,548
GROSS RATE BASE (UTILITY PLANT + WORKING CAPITAL)		1,641,481		908,052	172,312	561,116
IV. ACCUMULATED DEPRECIATION						
Accumulated Depreciation - Generation	108.1	421,503	DEP_ACCUM_PROD	421,503	0	0
Accumulated Depreciation - Transmission	108.2	0	Transmission	0	0	0
Accumulated Depreciation - Transmission and Distribution	108.3	320,055	DEP_ACCUM_TRANS_	0	74,887	245,168
Accumulated Depreciation - General	108.4	74,031	DEP_ACCUM_GRAL	38,002	8,457	27,572
Total Accumulated Depreciation	108	815,590		459,506	83,344	272,740
NET RATE BASE (GROSS RATE BASE NET OF DEPRECIATION)		825,891		448,547	88,968	288,376
I. OPERATION & MAINTENANCE EXPENSE						
A. PRODUCTION EXPENSES						
1. Power Generation - Steam						
Operation supervision and engineering	500	14,864	Generation	14,864	0	0
Fuel	501	202,979	Generation	202,979	0	0
Water, Lubricants, and Ash Handling	502	7,866	Generation	7,866	0	0
Miscellaneous steam power expenses (Major only)	506	279	Generation	279	0	0
Production Supplies	508	23	Generation	23	0	0
Maintenance of structures (Major only)	511	824	Generation	824	0	0
Maintenance of boiler plant (Major only)	512	507	Generation	507	0	0
Maintenance of electric plant (Major only)	513	13,016	Generation	13,016	0	0
Maintenance of miscellaneous steam plant (Major only)	514	1,447	Generation	1,447	0	0
Maintenance of steam production plant (Nonmajor only)	515	2,879	Generation	2,879	0	0
Subtotal - Power Production - Steam	500-515	244,685		244,685	0	0
Subtotal - Power Production and Purchased Power Expens	500-557	244,685		244,685	0	0

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 7: Functionalization Results by FERC Account

Dollars in Thousands

FERC Account Description	Account Code	Total	Functionalization	Generation	Transmission	Distribution
B. TRANSMISSION AND DISTRIBUTION EXPENSES						
Operation supervision and engineering	580	3,057	580_FUNC	0	245	2,813
Load dispatching (Major only)	581	1,903	581_FUNC	0	190	1,713
Miscellaneous distribution expenses	588	460	580_FUNC	0	37	424
Maintenance of structures (Major only)	591	361	591_FUNC	0	180	180
Maintenance of station equipment (Major only)	592	911	592_FUNC	0	273	638
Maintenance of overhead lines (Major only)	593	3,056	593_FUNC	0	153	2,903
Maintenance of underground lines (Major only)	594	217	594_FUNC	0	65	152
Maintenance of line transformers	595	194	595_FUNC	0	39	155
Maintenance of street lighting and signal systems	596	91	Distribution	0	0	91
Maintenance of meters	597	949	Distribution	0	0	949
Maintenance of miscellaneous distribution plant	598	69	580_FUNC	0	6	64
Subtotal - Transmission and Distribution Expenses	580-598	11,268		0	1,188	10,080
TOTAL OPERATION & MAINTENANCE EXPENSES		255,952		244,685	1,188	10,080
II. CUSTOMER ACCOUNTS, SERVICE, AND INFORMATIONAL EXPENSES						
Supervision (Major only)	901	1,008	Distribution	0	0	1,008
Meter reading expenses	902	419	Distribution	0	0	419
Customer records and collection expenses	903	2,958	Distribution	0	0	2,958
Uncollectible accounts	904	363	Distribution	0	0	363
Miscellaneous customer accounts expenses (Major only)	905	845	Distribution	0	0	845
Customer service and informational expenses (Nonmajor (	906	(6)	Distribution	0	0	(6)
Supervision (Major only)	907	1,716	Distribution	0	0	1,716
Customer assistance expenses (Major only)	908	2,932	Distribution	0	0	2,932
Informational and instructional advertising expenses (Maj	909	1,150	Distribution	0	0	1,150
Subtotal - Customer Accounts, Service, and Informational Expenses		11,384		0	0	11,384
TOTAL CUSTOMER ACCOUNTS, SERVICE & INFORMATIONAL EXPENSES		11,384		0	0	11,384
III. ADMINISTRATIVE & GENERAL EXPENSES						
A. LABOR RELATED						
Administrative and general salaries	920	10,421	Distribution	0	0	10,421
Office supplies and expenses	921	8,108	Distribution	0	0	8,108
Outside services employed	923	1,088	Distribution	0	0	1,088
Property insurance	924	12,349	Distribution	0	0	12,349
Employee pensions and benefits	926	2,703	Distribution	0	0	2,703
Subtotal - Labor Related A&G		34,668		0	0	34,668
B. OTHER A&G						
Regulatory commission expenses	928	2,217	Distribution	0	0	2,217
General advertising expenses	930.1	1,031	Distribution	0	0	1,031
Miscellaneous general expenses	930.2	228	Distribution	0	0	228
Subtotal - Other A&G		3,476		0	0	3,476
TOTAL ADMINISTRATIVE & GENERAL EXPENSES		38,144		0	0	38,144
TOTAL OPERATING EXPENSES (Excluding Dep, Tax)		305,481		244,685	1,188	59,609

Barbados Light & Power Company
Allocated Class COS Study — Test Year Ended December 31, 2020
Table 7: Functionalization Results by FERC Account

Dollars in Thousands						
FERC Account Description	Account Code	Total	Functionalization	Generation	Transmission	Distribution
IV. DEPRECIATION EXPENSE						
Production Depreciation Expense	403-GEN	32,827	Generation	32,827	0	0
Transmission Depreciation Expense	403-TRANS	0	Transmission	0	0	0
Distribution Depreciation Expense	403-DIST	20,279	Distribution	0	0	20,279
General Depreciation Expense	403-GRAL	4,524	Plant x.General	2,322	517	1,685
Subtotal - Depreciation Expense		57,629		35,149	517	21,963
V. TAXES AND CREDITS						
Taxes other than income taxes, utility operating income	408.1	6,135	PT_TOTAL	3,149	701	2,285
Corporation tax expense	409.2	0	PT_TOTAL	0	0	0
Deferred taxes	410.2	(467)	PT_TOTAL	(240)	(53)	(174)
Deferred investment tax credit and manufacturers tax cre	411.4	(2,313)	PT_TOTAL	(1,187)	(264)	(862)
Subtotal - Taxes and Credits		3,354		1,722	383	1,249
TOTAL EXPENSES		366,465		281,556	2,088	82,821
I. REVENUES FROM SALES						
Revenue - Service	440.1	15,306	Distribution	0	0	15,306
Revenue - Demand	440.2	40,334	Distribution	0	0	40,334
Revenue - Volumetric	440.3	135,257	Generation	135,257	0	0
Revenue - Fuel	440.4	202,979	Generation	202,979	0	0
Adjustment-Unbilled	440.5	(805)	Generation	(805)	0	0
Revenue - Early Payment Credit	440.6	(3,457)	Generation	(3,457)	0	0
Revenue - Interruptible Credit	440.7	(597)	Generation	(597)	0	0
Revenue - Renewable Credit	440.8	0	Generation	0	0	0
Subtotal - Electric Revenues		389,017		333,377	0	55,640
II. OTHER REVENUES						
Miscellaneous Service Revenues	451	4,421	Distribution	0	0	4,421
Interest and dividend income	419	327	PT_TOTAL	168	37	122
Subtotal Non-Operating Income		4,748		168	37	4,543
TOTAL REVENUE AT CURRENT RATES		393,765		333,545	37	60,183
Required Return	999	72,610	PT_TOTAL	37,273	8,295	27,043
Additional income taxes resulting from rate increase	409.3	271	PT_TOTAL	139	31	101
Provisions for deferred income taxes	410.3	894	PT_TOTAL	459	102	333
Additional revenue required as a result of rate increase	0	1,165		598	133	434
Tariff Revenue Requirement		435,492		319,259,267	10,478,156	105,754,888
NET INCOME AT CURRENT RATES		27,300		51,989	(2,050)	(22,638)
Required Increase (Decrease)		45,310,164		-14,715,714	10,345,053	49,680,825

Barbados Light & Power Company

Allocated Class COS Study — Test Year Ended December 31, 2020

Table 8: Functionalization Factor Values

Functionalization Factor	Generation	Transmission	Distribution
External Factors			
Generation	100.0%	0.0%	0.0%
Transmission	0.0%	100.0%	0.0%
Distribution	0.0%	0.0%	100.0%
None	0.0%	0.0%	0.0%
361 - Substation Structures		50.00%	50.00%
362 - Substation Equipment		55.00%	45.00%
364 - Poles		10.00%	90.00%
365 - Overhead Conductors		10.00%	90.00%
367 - Underground Conductors		30.00%	70.00%
368 - Transformers		20.00%	80.00%
580 - Distribution Superintendence		8.00%	92.00%
581 - SCADA Expenses		10.00%	90.00%
591 - Maintenance of Substation Buildings		50.00%	50.00%
592 - Maintenance of Substation Equipment		30.00%	70.00%
593 - Maintenance of Overhead Lines		5.00%	95.00%
594 - Maintenance of Underground Systems		30.00%	70.00%
595 - Maintenance of Transformers		20.00%	80.00%
Total Plant in Service	51.33%	11.42%	37.24%
DEP_ACCUM_PROD	100.00%	0.00%	0.00%
DEP_ACCUM_TRANS_DIST	0.00%	23.40%	76.60%
DEP_ACCUM_GRAL	51.33%	11.42%	37.24%
Plant x.General	51.33%	11.42%	37.24%

Barbados Light & Power Company
Allocated Class COS Study
Table 9: Factors Used by FERC Account

				Classification				Allocation						
Account Code	FERC Account Description	Amount	Functionalizati	C_GEN	C_TRANS	C_DIST	C_CUST	Generation_Demand	Generation_Energy	Transmission_Demand	Distribution_Demand	Distribution_Demand-Prima	Distribution_Demand-Secon	Distribution_Customer
	I. ELECTRIC PLANT IN SERVICE													
	A. STEAM PRODUCTION PLANT													
311	Structures and improvements	53,007,620	Generation	Demand	None	None	None	12 CP						
312	Boiler plant equipment	543,885,473	Generation	Demand	None	None	None	12 CP						
316	Miscellaneous power plant equipment	33,378,230	Generation	Demand	None	None	None	12 CP						
304-316	Subtotal - Steam Production Plant	630,271,323												
	B. RENEWABLE PRODUCTION PLANT													
344	Generators	38,920,953	Generation	Demand	None	None	None	12 CP						
348	Energy Storage Equipment - Production	16,447,572	Generation	Demand	None	None	None	12 CP						
344-348	Subtotal - Renewable Production Plant	55,368,525												
	C. TRANSMISSION AND DISTRIBUTION PLANT													
361	Structures and improvements	22,098,517	361_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
362	Station equipment	94,693,378	362_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
364	Poles, towers and fixtures	109,183,319	364_FUNC	None	Demand	364_CLASS	None			12 CP	1 NCP			Customers
365	Overhead conductors and devices	43,471,718	365_FUNC	None	Demand	365_CLASS	None			12 CP	1 NCP			Customers
367	Underground conductors and devices	209,608,144	367_FUNC	None	Demand	367_CLASS	None			12 CP	1 NCP			Customers
368	Line transformers	56,531,197	368_FUNC	None	Demand	368_CLASS	None			12 CP - Excl. Primary	1 NCP - Excl. Primary			Customers - Excl. Primary
369	Services	43,093,637	Distribution	None	None	369_CLASS	None				1 NCP			Customers
370.1	Meters	5,762,859	Distribution	None	None	370_CLASS	None				Meter Cost			Meter Cost
370.2	AMI Meters	44,399,839	Distribution	None	None	370_CLASS	None				Meter Cost			Meter Cost
373	Street lighting and signal systems	21,192,588	Distribution	None	None	Customer	None							Street Lighting
361-387	Subtotal - Transmission and Distribution Plant	650,035,195												
	D. GENERAL PLANT													
389	Land and land rights	17,362,459	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
390	Structures and improvements	27,238,950	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
391	Office furniture and equipment	17,438,195	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
392	Transportation equipment	13,237,546	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
397	Communication equipment	2,497,743	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
398	Miscellaneous equipment	48,650,061	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
389-399	Subtotal - General Plant	126,424,955												
300-399	TOTAL UTILITY PLANT IN SERVICE	1,462,099,998												
	II. CONSTRUCTION WORK IN PROGRESS													
107.1	Construction work in progress - Generation	138,591,637	Generation	Demand	None	None	None	12 CP						
107.2	Construction work in progress - Transmission	1,073,857	Transmission	None	Demand	None	None			12 CP				
107.3	Construction work in progress - Distribution	2,851,384	Distribution	None	None	DIST_PT	None				1 NCP			Customers
107.4	Construction work in progress - General	487,914	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
107	Total Construction Work in Progress	143,004,791												
	TOTAL UTILITY PLANT	1,605,104,789												
	III. CURRENT ASSET AND LIABILITY ADJUSTMENT													
131.00	Cash working capital	13,579,651	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
165.00	Materials, supplies, and prepayments	29,323,147	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
252.00	Customer advances for construction	-3,171,092	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
190.00	Accumulated deferred income taxes	-3,355,763	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
	Total Current Asset and Liability Adjustment	36,375,943												
	GROSS RATE BASE (UTILITY PLANT + WORKING CAPITAL)	1,641,480,732												
	IV. ACCUMULATED DEPRECIATION													
108.100	Accumulated Depreciation - Generation	421,503,186	DEP_ACCUM_PROI	Demand	None	None	None	12 CP						
108.200	Accumulated Depreciation - Transmission	0	Transmission	None	Demand	None	None							
108.300	Accumulated Depreciation - Transmission and Distribution	320,055,048	DEP_ACCUM_TRAN	None	Demand	DIST_PT	None			12 CP	1 NCP			Customers
108.400	Accumulated Depreciation - General	74,031,364	DEP_ACCUM_GRAI	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
108	Total Accumulated Depreciation	815,589,598												
	NET RATE BASE (GROSS RATE BASE NET OF DEPRECIATION)	825,891,134												

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Table 9: Factors Used by FERC Account

				Classification				Allocation						
Account Code	FERC Account Description	Amount	Functionalizati	C_GEN	C_TRANS	C_DIST	C_CUST	Generation_Demand	Generation_Energy	Transmission_Demand	Distribution_Demand	Distribution_Demand-Prima	Distribution_Demand-Secon	Distribution_Customer
	I. OPERATION & MAINTENANCE EXPENSE													
	A. PRODUCTION EXPENSES													
	1. Power Generation - Steam													
500	Operation supervision and engineering	14,863,916	Generation	Demand	None	None	None	12 CP						
501	Fuel	202,978,824	Generation	Energy	None	None	None		Revenue - Fuel					
502	Water, Lubricants, and Ash Handling	7,866,077	Generation	Energy	None	None	None		Energy Sales - Total					
506	Miscellaneous steam power expenses (Major only)	279,233	Generation	Demand	None	None	None	12 CP						
508	Production Supplies	23,097	Generation	Energy	None	None	None		Energy Sales - Total					
511	Maintenance of structures (Major only)	824,095	Generation	Demand	None	None	None	12 CP						
512	Maintenance of boiler plant (Major only)	507,245	Generation	Demand	None	None	None	12 CP						
513	Maintenance of electric plant (Major only)	13,015,829	Generation	Demand	None	None	None	12 CP						
514	Maintenance of miscellaneous steam plant (Major only)	1,447,148	Generation	Demand	None	None	None	12 CP						
515	Maintenance of steam production plant (Nonmajor only)	2,879,357	Generation	Demand	None	None	None	12 CP						
500-515	Subtotal - Power Production - Steam	244,684,821												
500-557	Subtotal - Power Production and Purchased Power Expenses	244,684,821												
	B. TRANSMISSION AND DISTRIBUTION EXPENSES													
580	Operation supervision and engineering	3,057,091	580_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
581	Load dispatching (Major only)	1,902,827	581_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
588	Miscellaneous distribution expenses	460,476	580_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
591	Maintenance of structures (Major only)	360,592	591_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
592	Maintenance of station equipment (Major only)	911,222	592_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
593	Maintenance of overhead lines (Major only)	3,055,929	593_FUNC	None	Demand	365_CLASS	None			12 CP	1 NCP			Customers
594	Maintenance of underground lines (Major only)	216,943	594_FUNC	None	Demand	367_CLASS	None			12 CP	1 NCP			Customers
595	Maintenance of line transformers	193,987	595_FUNC	None	Demand	368_CLASS	None			12 CP - Excl. Primary	1 NCP - Excl. Primary			Customers - Excl. Primary
596	Maintenance of street lighting and signal systems	90,510	Distribution	None	None	Customer	None			12 CP				Street Lighting
597	Maintenance of meters	948,772	Distribution	None	None	369_CLASS	None			12 CP	Meter Cost			Meter Cost
598	Maintenance of miscellaneous distribution plant	69,199	580_FUNC	None	Demand	Demand	None			12 CP	1 NCP			
580-598	Subtotal - Transmission and Distribution Expenses	11,267,549												
	TOTAL OPERATION & MAINTENANCE EXPENSES	255,952,370												
	II. CUSTOMER ACCOUNTS, SERVICE, AND INFORMATIONAL EXPENSES													
901	Supervision (Major only)	1,008,196	Distribution	None	None	Customer	None							Customer Service
902	Meter reading expenses	419,128	Distribution	None	None	Customer	None							Meter Reading
903	Customer records and collection expenses	2,957,839	Distribution	None	None	Customer	None							Customer Service
904	Uncollectible accounts	362,520	Distribution	None	None	Customer	None							Uncollectibles
905	Miscellaneous customer accounts expenses (Major only)	844,578	Distribution	None	None	Customer	None							Customer Service
906	Customer service and informational expenses (Nonmajor only)	-5,975	Distribution	None	None	Customer	None							Customer Service
907	Supervision (Major only)	1,715,985	Distribution	None	None	Customer	None							Customer Service
908	Customer assistance expenses (Major only)	2,932,064	Distribution	None	None	Customer	None							Customer Service
909	Informational and instructional advertising expenses (Major only)	1,150,111	Distribution	None	None	Customer	None							Customer Service
901-910	Subtotal - Customer Accounts, Service, and Informational Expenses	11,384,447												
	TOTAL CUSTOMER ACCOUNTS, SERVICE & INFORMATIONAL EXPENSES	11,384,447												
	III. ADMINISTRATIVE & GENERAL EXPENSES													
	A. LABOR RELATED													
920	Administrative and general salaries	10,421,248	Distribution	None	None	DIST_PT	None				Salaries and Wages	Salaries and Wages	Salaries and Wages	Salaries and Wages
921	Office supplies and expenses	8,107,631	Distribution	None	None	DIST_PT	None				Salaries and Wages	Salaries and Wages	Salaries and Wages	Salaries and Wages
923	Outside services employed	1,087,598	Distribution	None	None	DIST_PT	None				Salaries and Wages	Salaries and Wages	Salaries and Wages	Salaries and Wages
924	Property insurance	12,348,641	Distribution	None	None	DIST_PT	None				Rate Base	Rate Base	Rate Base	Rate Base
926	Employee pensions and benefits	2,702,655	Distribution	None	None	DIST_PT	None				Salaries and Wages	Salaries and Wages	Salaries and Wages	Salaries and Wages
920-926	Subtotal - Labor Related A&G	34,667,773												
	B. OTHER A&G													
928	Regulatory commission expenses	2,217,037	Distribution	None	None	DIST_PT	None				Rate Base	Rate Base	Rate Base	Rate Base
930.1	General advertising expenses	1,030,992	Distribution	None	None	DIST_PT	None				Rate Base	Rate Base	Rate Base	Rate Base
930.2	Miscellaneous general expenses	228,442	Distribution	None	None	DIST_PT	None				Rate Base	Rate Base	Rate Base	Rate Base
927-932	Subtotal - Other A&G	3,476,471												
	TOTAL ADMINISTRATIVE & GENERAL EXPENSES	38,144,244												
OP_EX	TOTAL OPERATING EXPENSES (Excluding Dep, Tax)	305,481,061												

Barbados Light & Power Company
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				Classification				Allocation						
Account Code	FERC Account Description	Amount	Functionalizati	C_GEN	C_TRANS	C_DIST	C_CUST	Generation_Demand	Generation_Energy	Transmission_Demand	Distribution_Demand	Distribution_Demand-Prima	Distribution_Demand-Secon	Distribution_Customer
	IV. DEPRECIATION EXPENSE													
403-GEN	Production Depreciation Expense	32,827,164	Generation	Demand	None	None	None	12 CP						
403-TRANS	Transmission Depreciation Expense	0	Transmission	None	Demand	None	None			12 CP				
403-DIST	Distribution Depreciation Expense	20,278,544	Distribution	None	None	DIST_PT	None				1 NCP			Customers
403-GRAL	General Depreciation Expense	4,523,665	Plant x.General	Demand	Demand	DIST_PT	None	12 CP		12 CP	1 NCP			Customers
403	Subtotal - Depreciation Expense	57,629,372												
	V. TAXES AND CREDITS													
408.1	Taxes other than income taxes, utility operating income	6,134,971	PT_TOTAL	PROD_PT	Demand	DIST_PT	None	Rate Base		Rate Base	Rate Base			Rate Base
409.2	Corporation tax expense	0	PT_TOTAL	PROD_PT	Demand	DIST_PT	None	Rate Base		Rate Base	Rate Base			Rate Base
410.2	Deferred taxes	-467,495	PT_TOTAL	PROD_PT	Demand	DIST_PT	None	Rate Base		Rate Base	Rate Base			Rate Base
411.4	Deferred investment tax credit and manufacturers tax credit	-2,313,178	PT_TOTAL	PROD_PT	Demand	DIST_PT	None	Rate Base		Rate Base	Rate Base			Rate Base
	Subtotal - Taxes and Credits	3,354,299												
	TOTAL EXPENSES	366,464,731												
	I. REVENUES FROM SALES													
440.1	Revenue - Service	15,305,796	Distribution	None	None	Customer	None							Revenue - Service
440.2	Revenue - Demand	40,334,328	Distribution	None	None	Demand	None				Revenue - Demand			
440.3	Revenue - Volumetric	135,256,812	Generation	Energy	None	None	None		Revenue - Volumetric					
440.4	Revenue - Fuel	202,978,824	Generation	Energy	None	None	None		Revenue - Fuel					
440.5	Adjustment-Unbilled	-805,041	Generation	Energy	None	None	None		Revenue - Unbilled					
440.6	Revenue - Early Payment Credit	-3,457,057	Generation	Energy	None	None	None		Energy Sales - Total					
440.7	Revenue - Interruptible Credit	-596,661	Generation	Energy	None	None	None		Energy Sales - Total					
440.8	Revenue - Renewable Credit	0	Generation	Energy	None	None	None		Revenue - Volumetric					
	Subtotal - Electric Revenues	389,017,002												
	II. OTHER REVENUES													
451	Miscellaneous Service Revenues	4,421,121	Distribution	None	None	Customer	None							Customers
419	Interest and dividend income	326,939	PT_TOTAL	PROD_PT	Demand	DIST_PT	None	Rate Base		Rate Base	Rate Base			Rate Base
Non-Op-Inc	Subtotal Non-Operating Income	4,748,061												
	TOTAL REVENUE AT CURRENT RATES	393,765,063												
999	Required Return	72,610,495	PT_TOTAL	PROD PT	Demand	DIST PT	None	Rate Base	Rate Base	Rate Base	Rate Base	Rate Base	Rate Base	Rate Base
409.3	Additional income taxes resulting from rate increase	271,370	PT_TOTAL	PROD_PT	Demand	DIST_PT	None	Rate Base		Rate Base	Rate Base			Rate Base
410.3	Provisions for deferred income taxes	893,776	PT_TOTAL	PROD_PT	Demand	DIST_PT	None	Rate Base		Rate Base	Rate Base			Rate Base
	Additional revenue required as a result of rate increase	1,165,146												
	Tariff Revenue Requirement	435,492,311												
	NET INCOME AT CURRENT RATES	27,300,331												
	Required Increase (Decrease)	45,310,164												

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