REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Energy Board

IN THE MATTER OF *The Public Utilities Act,* R.S.N.S. 1989, c.380, as amended

2027 Annually Adjusted Rates (AARs)

NS Power
Application

November 6, 2026

REDACTED

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1.0 INTRODUCTION

Nova Scotia Power Incorporated (NS Power, Company) requests approval from the Nova Scotia Energy Board (NSEB, Board) of the annually adjusted rates (AARs) provided herein for 2027 (2027 AARs).

(1) Generation Replacement and Load Following (GRLF)Tariff
(2) One-Part Real Transmission Time Pricing (1P-RTP) Tariff
(3) One-Part Real Time Distribution Voltage Pricing (1P-DV-RTP) Tariff
(4) Shore Power (SP)Tariff
(5) Wholesale Market Back-up/Top-Up Service (BUTU)Tariff
(6) Wholesale Market Non-Dispatchable Supplier Spill (Spill)Tariff
(7) Renewable to Retail (RtR) Energy Balancing Service (EBS)Tariff
(8) RtR Standby Service (SS) Tariff
(9) RtR Market Transition (RTT) Tariff
(10) RtR Distribution-connected Aggregation Service (DAS) Tariff

In this Application, NS Power provides updates on prior AAR proceeding directives (Sections 1.1 and 1.2), outlines the marginal cost assumptions (Section 2.0), and presents the proposed AARs determined by the Company using the approved rate setting methodologies for each Tariff (Sections 4.0 to 7.0). As the term of the Extra Large Industrial Active Demand Control (ELIADC) Tariff expires at the end of 2026, the Company has not included this Tariff in its Application (as discussed in Section 8.0).

As discussed in the Financing Order Application (M13133) proceeding, NS Power has amended its AAR tariff schedules, where applicable. For clarity, AAR tariff revisions in relation to M13133 are limited to amendments to incorporate language reflecting SECRR applicability, consistent with the revisions proposed for the above-the-line tariffs in M13133 and no additional BTL tariff changes related to M13133 are included in this Application. Given the timing of the respective proceedings, to the extent additional revisions to the AAR tariffs are required following the

Board's determination in M13133, the Company proposes to incorporate AAR tariff revisions through a compliance filing as part of this process, unless otherwise directed by the Board.

NS Power has also amended the AAR tariff schedules, where applicable, to incorporate the Storm Cost Recovery Rider provisions, thereby aligning their treatment with that of the above-the-line Tariffs and the Storm Cost Recovery Rider itself.

The non-fuel cost components of the energy charges of all the AAR tariffs, other than the GRLF, are derived from the 2027 Cost of Service Study (COSS) approved as part of the 2026-2027 General Rate Application (GRA) (M12451).

1.1 Prior AAR Proceeding Directives

The Board issued several directives in the 2024 AAR (M11422) and 2026 AAR (M12551) proceedings. The following are the in-progress directives from these proceedings with reference to the sections where related updates are provided.

(1) "The Board directs NS Power to work with stakeholders to provide a recommended TVP structure for the AARs in the 2027 application."[1] – this is addressed in section 1.2

(2) "The Board directs NS Power to provide an update in the 2027 AAR application explaining when the new wind resources came online. If there was a delay in any of the resources going into service by the time the 2027 AAR application is filed, NS Power is directed to provide scenarios for the total amount of energy not realized for periods ranging between one month and 10 months in 2027."[2] – this is addressed in section 2.2.

(3) "The Board directs that NS Power revise the sensitivity analysis for the Maritime Link energy to one that models an outcome in which NS Power receives only half of expected

[1] M12551, NS Power 2026 Annually Adjusted Rates, NSEB Decision, March 9, 2026, p. 7.
[2] M12551, NSEB Decision, March 9, 2026, p. 7.

deliveries during peak periods. The Board will reconsider the need for this sensitivity analysis in the 2027 AAR application."[3] – this is addressed in section 2.2.

(4) "The Board directs NS Power to provide a comparison of the monthly forecasted New Brunswick imports to actual New Brunswick imports for the years 2021 to 2026 inclusive, in the 2027 AAR application."[4] – this is addressed in section 2.3.

(5) "The Board directs NS Power to provide data justifying any proposed administration charge inflation adjustment/escalator in future AAR applications when the increase exceeds the Statistics Canada CPI 12-month change or the Bank of Canada's most recent monetary policy forecast."[5] – this is addressed in section 6.1.1.

(6) "NS Power and Roswall are directed to explore ways in which interruptible customers may take service under the RTR Tariff and provide their recommendations in the 2025 AAR application"[6] – this is addressed in Section 7.6.

1.2 Board Directive regarding Time-varying Pricing Structure for AARs

In the 2026 AARs (M12551) proceeding, the NSEB issued the following directive:

> The Board directs NS Power to work with stakeholders to provide a recommended TVP structure for the AARs in the 2027 application.[7]

Since the issuance of that direction, the Company has continued to assess the suitability of introducing time-variable pricing (TVP) structures within the AAR framework. This assessment has considered both AARs associated with the emerging RtR market (specifically the EBS Tariff) and certain other AARs that could potentially lend themselves to time- or seasonally-differentiated

[3] M12551, NSEB Decision, March 9, 2026, p. 7.
[4] M12551, NSEB Decision, March 9, 2026, p. 7.
[5] M12551, NSEB Decision, March 9, 2026, p. 7.
[6] M11422, NS Power 2024 Annually Adjusted Rates, NSEB Decision, March 5, 2024, page 4..
[7] M12551, NSEB Decision, March 9, 2026, p. 7.

pricing approaches, including Shore Power, Wholesale Spill, and the load-following portion of the GRLF. Based on the latest information provided by Renewall Energy Inc. (REI), customer participation in the RtR market is anticipated to commence in December 2026. With forecast usage of approximately 113 GWh in 2027, the EBS Tariff is expected to account for the majority of AAR-related volumes and, therefore, represents the most significant potential application of a TVP structure. Please refer to Figure 1 for details.

Figure 1: Usage and Revenues of AAR Classes in 2026 Test Year of the 2026 GRA.

Rate	Usage		Revenue (millions of $s)			Fuel as % of Total Cost	AAR Revenue as % of Total System Costs
	Sales (GWh)	System Coincident Peak (MWs)	Fuel	Non-Fuel	Total		
GRLF	15.0	0.1	$1.2	$0.1	$1.2	95	0.1
1P-RTP	13.1	0.0	$1.0	$0.2	$1.3	80	0.1
Shore Power	1.3	0.0	$0.1	$0.0	$0.2	73	0.0
BUTU	29.9	7.5	$2.4	$0.9	$3.3	72	0.2
Spill	0.0	n/a	$0.0	$0.0	$0.0	0	0.0
EBS	95.7	48.9	$8.0	$2.9	$10.9	73	0.6
SS/RTT	0.0	n/a	$0.0	$19.8	$19.8	0	1.1
Total	**155.1**	**56.5**	**$12.6**	**$24.0**	**$36.7**	**34**	**2.0**

In the course of the Company's discussions with REI on other RtR initiatives, including the RtR Market Elements Application (M13008), monthly pricing structures, true-up mechanisms, and the enablement of interruptible service in the market, the Company considered the potential application of TVP structures to the EBS Tariff. Through these discussions, neither the Company nor REI identified an immediate need to modify the current EBS pricing structure. The existing EBS framework continues to support implementation of the RtR market while broader market-design and operational matters are being developed, implemented, and evaluated.

Those discussions also highlighted that customer participation under the RtR framework is not expected to commence until late 2026 and meaningful information regarding participation levels, usage patterns, cost causation, and service delivery outcomes will not be available until sufficient

market experience has accumulated. As a result, any assessment of the suitability, benefits, or design of a TVP structure for the EBS Tariff would be based primarily on assumptions rather than actual operating experience.

More broadly, many of the considerations that would inform the development of a TVP structure continue to evolve. These include the continued development of the RtR market, the review of RtR Market Elements in M13008, the enablement of interruptible service in the RtR market, and evolving roles and responsibilities involving the Nova Scotia Independent Electricity System Operator (IESO NS). The Company notes that M13008 contemplates a broader review of RtR market design following a period of market operation, including a review after 2028. The Company submits that any consideration of TVP structures applicable to RtR-related AARs would be more appropriately informed through that future review and the operational experience accumulated in the intervening period.

In light of the foregoing, the Company is not proposing changes to the current AAR pricing structures at this time and submits that stakeholder consultation on a TVP structure applicable to the RtR market would be premature and would be unlikely to produce a meaningful or durable outcome. Consistent with the Company's August 31, 2026 update to the Board and stakeholders, the Company considers any future evaluation of TVP structures applicable to RtR-related AARs to be more appropriately undertaken following the accumulation of market experience and the broader review of RtR market design contemplated after 2028. The Company will provide a future update through a subsequent AAR application, as appropriate.

2.0 MARGINAL COST ANALYSIS

The average annual marginal cost (MC) forecast for 2027 used in determination of the GRLF, SP, Spill, EBS, and RTT is $62.54/MWh. This represents approximately a 7 percent decrease from the forecast marginal cost of $67.36/MW approved for use in the 2026 AARs.

The forecast MC was determined using the most recent forecast of the system load, which in contrast to the MC forecasted for use in the 2026 AAR, was not adjusted for the exclusion of Port Hawkesbury Paper (PHP) load, as the ELIADC Tariff expires at the end of 2026. Further details are provided in Section 8.0.

The average annual marginal generation cost calculation is included in **Partially Confidential Appendix A2**.

2.1 Assumptions

In its Decision on the 2017 Annually Adjusted Rates, the Board directed as follows:

> As noted earlier, NSPI's future AAR applications are to include the main modelling assumptions used in determining the LF rate, and any potential beneficial impact of the Maritime Link. The application is also to include a high level analysis of year-over-year changes that support the reasonableness of the average annual marginal costs derived by PLEXOS, as well as evidence to justify splitting the annual administration cost of the BUTU/Spill tariffs on a 50/50 basis.[8]

The decrease in modeling output prices in 2027 as compared to 2026, is driven by more wind generation on the system, increasing the frequency of low-price and $0 hours resulting from energy oversupply. This offsets increased thermal and import costs, relative to 2026. The modeled marginal cost is inclusive of PHP's load as they will no longer be on the ELIADC tariff.

[8] M08383, 2017 Annually Adjusted Rates, NSEB Decision, February 15, 2018, page 6.

The components of the energy production cost changes are outlined in the table below.

Figure 2: Cost of Energy Generation (Partially Confidential)

$/MWh by Gen. Source	2027 AAR	2026 AAR	Percentage Change (%)
Solid Fuel	[redacted]		
Oil & Gas			
NB Imports			
ML Surplus			

In addition, in the 2019 AARs proceeding NS Power committed to providing a comparison of values associated with each assumption from the current and previous year's application and PLEXOS output reports.[9] The PLEXOS model used for the 2027 AAR forecast is the 2026 Q3 Fuel and Purchased Power Model.[10]

The modeling assumptions used in the PLEXOS model for the 2027 AARs are summarized in **Partially Confidential Appendix A3, Confidential Appendices A4,** and **A5**.

2.2 Board Directed Sensitivity Analyses

In accordance with the Board's prior AAR directives, NS Power has considered the following sensitivities on the marginal cost:

(1) Forward commodity market returns volatility of plus 1.5 standard deviations (**+1.5 σ**) for the following fuel prices: AECO, AGT, HFO, API2, Mass Hub Off-Peak, and Mass Hub On-Peak.

[9] M08966, 2019 Annually Adjusted Rates, NS Power Reply Evidence, January 28, 2019, page 10, lines 8-12.
[10] 2027 PLEXOS AAR F&PP model is based on the 2026 Q3 forecast F&PP model, with updated system assumptions, including commodity pricing update as of 2026-09-17.

(2) Forward commodity market returns volatility of negative 1.5 standard deviations (**-1.5 σ**) for the following fuel prices: AECO, AGT, HFO, API2, Mass Hub Off-Peak, and Mass Hub On-Peak.

(3) Revise the sensitivity analysis for the Maritime Link energy to one that models an outcome in which NS Power receives only half of expected deliveries during peak periods.

Since becoming commercially available in April 2023, NS Power has experienced significant improvement in the reliability of energy flows across the Labrador Island Link (LIL) and Maritime Link (ML). NS Power has received the energy owed since signing the Acceleration Agreement in August 2021, and has experienced steady-state operations since Q4 2024, with only minor outages and planned maintenance impacting deliveries of energy. Given the history NS Power now has with Maritime Link Surplus energy, forecasts have been further refined on this basis, incorporating expected commercial and scheduling behaviour.

In addition, in its October 2026 decision regarding NSPML's application to end the Maritime Link holdback mechanism (M12696), the Board found that the conditions for termination had been satisfied and that concerns associated with historical under-deliveries had been addressed. The Board further concluded that the instances of under-delivery relied upon in that proceeding resulted from good utility practice or exceptional circumstances. In light of the demonstrated operating performance of the LIL and ML, and the Board's findings in that proceeding, NS Power submits that this sensitivity scenario is not representative of a reasonably foreseeable outcome and requests that the Board discontinue this sensitivity analysis requirement in future AAR applications, as it had suggested it would consider as part of its 2026 AAR Decision.[11]

[11] M12551, NSEB Decision, March 9, 2026, p. 7.

(4) Update explaining when new wind resources came online, and if delayed by the time of the 2027 AAR Application, provide scenarios for the total amount of energy not realized for periods ranging between one month and 10 months in 2027.

Wind resources previously expected to come online in 2026 came online as expected. These resources include Benjamins Mill (January 1, 2026), Higgins Mountain (May 1, 2026) and Goose Harbour Lake (producing but not fully commissioned as of October 5, 2026). NS Power, at the time of the forecast used for the 2027 AAR Application, is not expecting a material delay in remaining wind generation. However, NS Power has received notice that there could be potential delays on two sites which were expected online in January after the forecast was completed. Scenarios for a one and 10 month delay have been included to cover the bookends of what a potential delay could mean for marginal costs.

The results of the sensitivity analysis for items 1 to 4 are provided in **Partially Confidential Appendix A6.**

2.3 Board Directive regarding Comparison of Monthly Forecast-to-Actual New Brunswick Imports

In accordance with the Board's directive in the 2026 AARs, a review comparing the monthly forecast NB imports to actual NB imports for the years 2021 to 2026, inclusive, is provided in **Confidential Appendix A7**. As a result of the cyber incident, NS Power is unable to provide the monthly import values for the forecast associated with 2021 AAR application.

3.0 LOAD FOLLOWING PORTION OF THE GRLF TARIFF

The GRLF Tariff is available to customers who have their own generation of continuous capability, normally used to support the customer's own load, where the customer has signed an operating agreement with NS Power. The GRLF service has three separate components: Generation Replacement (GR), Optional Load Following (LF), and Spill. There are currently two customers taking service under the GRLF Tariff. One customer takes only the GR service while the other customer takes all three services.

The GR service is a back-up service provided on a best-efforts basis where the customer's generation is shut down for scheduled maintenance, forced outage or loss of fuel supply. The service is priced at NS Power's incremental cost of generation at the hour the energy is required by the customer, plus the 0.5 cent per kWh fixed cost adder for additional Operating and Maintenance costs, service charges and Administration & General compensation costs.

Optional LF service applies where the customer's process limitations affect the ongoing loading of the customer's own generator. The LF rate is an energy-only charge composed of the forecast average annual incremental cost of generation plus 0.5 cent per kWh for additional Operating and Maintenance costs.

Spill Service consists of reception of surplus generation from the customer's generator by NS Power when the customer's hourly generation is in excess of the customer's load.

The proposed LF rates for 2027, compared to the 2026 rates, are shown in **Figure 3**.

Figure 3: **LF Tariff Charges in Cents per kWh**

	2026	2027	Variance
Fuel Cost	6.736	6.254	(0.482)
Additional O&M costs	0.500	0.500	0.000
Total	7.236	6.754	(0.482)

The proposed GRLF Tariff is provided in **Appendix A1** and the redline version is provided in **Appendix G**.

4.0 ONE-PART REAL-TIME PRICING TARIFFS

There are two 1P-RTP Tariffs: One Part Transmission RTP Tariff and One Part Distribution Voltage RTP Tariff. Each of these tariffs include energy charges with two components: hourly marginal costs forecast 20 minutes ahead, and fixed costs adders, updated annually. The hourly marginal costs are determined in real time and are not subject to Board approval. The adders are designed to recover the non-fuel-related costs that would be incurred by NS Power in serving the eligible customers under each of the 1P-RTP tariffs.

The proposed fixed cost adders for 2027, compared to the 2026 adders, are shown in **Figure 4.**

Figure 4: 1P-RTP Tariff Fixed Cost Adders by Voltage in Cents per kWh

	2026		2027		Variance	
	On-Peak	Off-Peak	On-Peak	Off-Peak	On-Peak	Off-Peak
Transmission	5.274	0.713	6.156	0.918	0.882	0.205
Distribution	9.925	3.516	8.513	3.091	(1.412)	(0.425)

The calculations for the 2026 Fixed Cost adder are provided in **Partially Confidential Appendix B2**. Please also refer to **Partially Confidential Appendix D** for usage determinants used in rate calculations in **Partially Confidential Appendix B2**. The proposed 1P-RTP Tariffs are provided in **Appendix B1**.

Since August 2014, the Company has provided service under the 1P-RTP Tariff to one transmission-connected customer who migrated a portion of its interruptible load from the Large Industrial Interruptible Rider (LIIR). Consistent with the requirement under Special Condition (6) of the Transmission RTP Tariff, the transitioned load remains interruptible.

5.0 SHORE POWER TARIFF

Service under the SP Tariff is a seasonal priority interruptible service, differentiated by two voltage levels: transmission and primary distribution. It is available to seaports in Nova Scotia from April 1 to November 30. There is currently one customer subscribed to the SP Tariff, taking service at the distribution voltage level.

The voltage-based SP rates are flat energy charges, each with the following two cost components:

(1) The line-loss adjusted Fuel Cost component represents the average annual marginal fuel cost.

(2) The Fixed Cost Adder component, drawn from the Cost-of-Service Study, reflects the non-demand related fixed costs.

The proposed SP rates represent a decrease relative to the current rates. This decrease is driven by a reduction in the marginal fuel cost, which more than offsets an increase in the embedded non-fuel cost. The decrease in marginal fuel cost is discussed in Section 2.0. The proposed energy charge components underlying the 2027 rates, compared to the current 2026 rates, are presented in **Figure 5**.

Figure 5: Shore Power Tariff Charges by Voltage and Cost Components in Cents per kWh

	2026	2027	Variance
Transmission			
Fuel Cost	6.900	6.406	(0.494)
Fixed Cost Adder	2.507	2.576	0.069
Total	9.408	8.983	(0.425)
Distribution			
Fuel Cost	7.062	6.556	(0.505)
Fixed Cost Adder	3.970	4.226	0.257
Total	**11.031**	**10.783**	**(0.249)**

The calculations for the SP rates are provided in **Appendix C2**. The proposed SP Tariff is provided as **Appendix C1**. A redline version is provided in **Appendix G**. Please also refer to **Partially Confidential Appendix D** for energy requirement figures used in rate calculations in **Appendix C2**.

6.0 WHOLESALE MARKET TARIFFS

Two tariffs applicable to Wholesale Market participants are adjusted on an annual basis: the Back-up/Top-up Tariff and the Wholesale Market Spill Tariff.

The BUTU Tariff provides optional backup/top-up service to customers taking energy under the Open Access Transmission Tariff (OATT). The Spill Tariff is available for use by independent non-dispatchable electric generators serving customers taking service under the BUTU Tariff. Both tariffs are subscribed to on a minimum 12 month, annually renewable basis.

Four wholesale customers, which are Municipal Electric Utilities (MEUs), have expressed an intention to take service under the BUTU Tariff in 2027 in conjunction with that portion of their energy requirement which will continue to be supplied by the Ellershouse Wind Farm. The remaining portion of their energy requirements will continue to be served under bundled service billed under the Municipal Tariff.[12]

One non-dispatchable supplier, Alternate Resource Energy Authority, was approved for service under the Spill Tariff.

6.1 Back-up/Top-up (BUTU) Tariff

The BUTU Tariff has three base cost rate components subject to approval in this Application: a Customer Charge, a Demand Charge, and an Energy Charge.

[12] Starting June 1, 2026, the four OATT MEUs have taken BUTU service under a non-reciprocal billing arrangement contingent upon the application of a 22.4 MW Contract Demand (CD). This has resulted in a shift from the balanced annual top-up/spilled energy mix to one in which spilled energy represents only a small fraction of total wind generation.

6.1.1 BUTU Customer Charge

The Customer Charge is set in advance of the rate year, based on the anticipated administration costs and the forecast number of customers' accounts to which the Company issues separate BUTU bills. Consistent with the Board's 2019 AAR Decision,[13] NS Power has calculated this charge on the basis of six accounts, three of which belong to one municipal customer.

As approved by the Board in the original proceeding to set these rates,[14] the BUTU Tariff and the Spill Tariff were each assigned 50 percent of the associated administration cost. In its 2019 AAR Decision, the Board issued the following directive:

> For 2019, NS Power is directed to use the 2018 amount of $47,761.86 adjusted by the proposed annual inflation rate of 2.8%.[15]

In its Decision on the 2021 AARs, the Board stated:

> KDC observed that the relevant rate of inflation to be used for the purposes of the administration charge used in the AARs should be periodically reviewed, and NS Power agreed. The Board notes that the previous Board directive regarding the rate to be used to increase the administration charge was a directive that only applied to that year's application. The Board expects that NS Power will reassess this rate annually and choose a more appropriate rate, if applicable.[16]

Further, in its 2026 AAR Decision the NSEB provided as follows.

> The Board directs NS Power to provide data justifying any proposed administration charge inflation adjustment/escalator in future AAR applications when the increase exceeds the Statistics Canada CPI 12-month change or the Bank of Canada's most recent monetary policy forecast.

[13] M08966, NS Power 2019 Annual Adjusted Rates, NSEB Decision, March 1, 2019.
[14] M00543 – Wholesale Market Backup/Top-up Service Tariff and Wholesale Market Non-Dispatchable Supplier Spill Tariff proceeding, MEUNSC/SRENA IR-1 and Multeese IR-6, October 24, 2008.
[15] M08966, NSEB Decision, March 1, 2019, page 4.
[16] M09898, NS Power 2021 Annually Adjusted Rates, NSEB Decision, page 7.

As of August 2026, the Canadian Consumer Price Index (CPI) increased 3.0 percent year over year. The Bank of Canada's July 2026 Monetary Policy Report projects inflation to average 2.0 percent in 2027, in line with its long-term inflation target.

While CPI and the Bank of Canada's inflation forecast provide useful measures of general economic conditions, compensation costs are also influenced by labour market dynamics, including talent availability, competitive pay practices, and employee retention. As a result, salary increase budgets do not always move in step with inflation.

Current compensation planning surveys indicate that employers across Canada continue to budget salary increases above both current inflation and the Bank of Canada's medium-term outlook. Market forecasts from Mercer, Willis Towers Watson, PayScale, and WorldatWork suggest salary increase budgets have largely stabilized and are expected to remain consistent with recent years. Most organizations are planning annual salary increases of 3.3 to 3.5 percent to maintain competitive compensation and support attraction and retention in a still-competitive labour market.

Accordingly, the Company proposes to increase the current administration charge of $414.63 per customer per month by 3.0 percent, resulting in a 2027 administration charge of $427.07 per customer per month.

6.1.2 BUTU Energy Charge

The proposed Energy Charge of 8.683 cents per kWh reflects the sum of two components:

(1) the FAM-based component of 6.430 cents per kWh, determined in the 2027 Base Cost of Fuel calculations in **Partially Confidential Appendix E4** (tab "BCF Allocation," cell AS31); and

(2) the non-FAM-based component of 2.253 per kWh, as provided in **Appendix F2**.

6.1.3 BUTU Demand Charge

The proposed Demand Charge of $14.341 per kilowatt (kW) of billing demand reflects a sum of two components:

(1) the 2027 FAM-based component of $8.142 per kW, determined in the 2027 Base Cost of Fuel calculations in **Partially Confidential Appendix E4** (tab "BUTU Capacity Credit Calc," cell E6 and E7); and

(2) the non-FAM-based component of $6.20 per kW, determined in **Appendix F3**.

6.1.4 Proposed BUTU Rates

The proposed BUTU Tariff charges for 2027 are set out in **Figure 6**.

Figure 6: BUTU Tariff Charges

	2026	2027	Variance
Customer Charge ($/customer/month)	414.63	427.07	12.44
Energy Charge (cents per kWh)	9.129	8.683	(0.446)
Demand Charge ($/kW)	11.822	14.341	2.519

The proposed 2027 BUTU Tariff is provided in **Appendix E1**. A redline version is provided in **Appendix G**.

6.2 Spill Tariff

The Spill Tariff has two components: an Administration Charge and an Energy Credit.

The Administration Charge is proposed to increase from the currently approved $2,487.77 to $2,562.40 per supplier, per month in 2027. NS Power has determined this Charge by applying a 3 percent escalator to the Administration Charge currently in effect. Please refer to **Appendix E2**

for the supporting calculations. The Energy Credit is the Company's forecast average marginal energy cost as approved for use with the GRLF rate.

The proposed rates for 2027 and their comparison with 2026 charges are set out in **Figure** 7. The proposed Spill Tariff is provided in **Appendix E1**. A redline version is provided in **Appendix H**.

Figure 7: Spill Tariff Charges

	2026	2027	Variance
Administration Charge ($/supplier/month)	$2,487.77	$2,562.40	$74.63
Energy Credit (cents per kWh)	6.736	6.254	(0.482)

7.0 RENEWABLE TO RETAIL MARKET TARIFFS

This AAR Application includes four RtR tariffs: the EBS, SS, RTT, and the DAS tariffs. The versions of these four tariffs in this application are the same as proposed in the Company's Updates to RtR Market Elements Application, which remains an open Matter before the Board under M13008. Subject to the Board's Decision in M13008 and pending the timing of such decision, the outcome of M13008 will be reflected in the compliance filing applicable to this proceeding.

The RtR Tariff changes proposed under M13008 support distribution-connected generation to be supplied to the RTR market.

7.1 RtR Tariff Administration Charges

In its October 19, 2026 correspondence (M12551), the Board provided:

> Specifically referring to the Annually Adjusted Rates (AARs) process, NS Power is not seeking tariff amendments to process the Board's implementation cost decisions arising from Matters M12588 and M06214. The Board understands these costs will be addressed under existing tariff provisions in the 2027 AAR application.

Consistent with the Board's understanding, the Company has revised the Administration Charges applicable to the EBS and SS tariffs and has proposed an Administration Charge under the new DAS Tariff. The purpose of these charges is to recover forecast administration, settlement, billing, implementation, and ongoing resource and support costs associated with the RtR market, including a portion of previously deferred development costs. As with other annually adjusted rates, these charges are based on forecast information and constitute the Company's best estimate of costs expected to be incurred in 2027.

7.1.1 EBS and SS Tariff Administration Charge

The proposed EBS and SS tariff administration charges include the recovery of retail costs forecast to be incurred in 2027 and mark the commencement of a long-term recovery of deferred costs associated with the development of the RtR market and implementation of RtR billing systems.[17] Specifically, the proposed EBS and SS Administration Charges recover costs associated with the implementation and operation of the RtR market, including:

(1) recovery of approximately $5.7 million in RtR implementation capital investments over a ten-year period with the inclusion of the cost of financing at the Company's Weighted Average Cost of Capital (WACC);

(2) recovery of approximately $1.5 million in deferred regulatory costs of the M06214 proceeding over a ten-year period with the inclusion of the cost of financing at the Company's WACC;

(3) ongoing settlement, billing, administration, and market support costs associated with RtR operations;

(4) software licensing and maintenance costs; and

(5) dedicated operational and customer support resources required to administer the market.

Further details on the EBS and SS tariff administration charges is provided in Sections 7.2 and 7.3, respectively.

[17] M11874, Renewable to Retail Market Implementation Costs, Exhibit N-4, NSPI (NSUARB) IR-1, October 18, 2024..

7.1.2 DAS Tariff Administration Charge

Consistent with the Company's proposed approach outlined in M13008, the administration charge for the services provided under the DAS Tariff is proposed as part of this Application. The proposed DAS Administration Charge is set to recover incremental administrative costs associated with the aggregation of Distribution-Connected Generation and Net Billing services and does not include costs recovered through the EBS and SS tariff administration charges.

The Company notes that the proposed DAS Administration Fee establishes the charge that would apply if and when a Licensed Retail Supplier elects to take service under the DAS Tariff. The proposal does not result in immediate cost recovery from REI or any other market participant. Charges will only become payable where customers are enrolled, and service is provided under the tariff. Consistent with the position advanced by REI in M13008, the Company will continue to monitor actual costs and operational experience and bring forward refinements through future AAR proceedings as necessary to ensure costs are appropriately recovered without duplication. Further details, including the Company's assumptions used in developing this forecasted incremental cost, are provided in Section 7.4.

7.2 Energy Balancing Service Tariff

The Energy Balancing Service (EBS) Tariff is a mandatory tariff applicable to the LRS. The EBS consists of the delivery of top-up energy to RtR customers and the receipt of surplus generation from qualifying generators. The service must be taken in conjunction with standby service under the SS Tariff to ensure that the reliability of service provided to RtR customers is equivalent to that provided to NS Power's Bundled Service customers. The EBS Tariff has three rate components: the Administration Charge, the Energy Charge, and the Energy Credit.

The Administration Charge applies to each LRS account and is set annually in advance of the rate year based on forecast administration costs and the projected number of LRSs. As described in Section 7.1, in light of the commencement of the RtR market, the Company has updated the EBS

and SS tariff administration charges. For 2027, the EBS and SS Tariff Administration Charges are proposed to increase from $414.63 to $67,734. This significant increase is largely due to the cost recovery for both the Capital Project Costs, and prior outstanding market establishment amounts which to date have been deferred. REI has requested all cost recovery amounts be amortized over a 10-year payback timeframe, and NS Power has agreed to that amortization period. While the parties are aligned on the amortization period, NS Power understands that REI has concerns regarding the proposal to recover the full Year 1 amount through a flat monthly customer charge.

This increase also includes ongoing cost recovery related to increased resource requirements identified to facilitate operational support of the Renewable to Retail line of business and ongoing software licensing and support costs. The additional resource requirements were identified by evaluating the extent of technology needs, associated tasks, complexity of the transactions with the LRS, and were based on the forecasted generation levels and customer volumes anticipated and provided by the LRS. This analysis identified the need for three designated full-time employees to perform the roles of (1) RtR Customer Transaction Analyst, (2) RtR Coordination Specialist, and (3) RtR SMOC Processing Specialist. Further, NS Power estimates exceptional time billing from a number of internal resources working to support the RtR market in an amount equivalent to an additional full-time employee.

Based on information provided by REI, it is expected that RtR market activity in Nova Scotia will begin in December 2026. As referenced in the Capital Item C0053699, this has required the development of technology solutions. Associated with this, tariff administration charges have been updated to provide for recovery of the costs.

Please refer to Appendix F5 for the forecast deferred costs and the retail costs forecast to be incurred in 2027.

The Energy Charge is applicable to top-up energy and is made up of the following two components:

(1) Annually adjusted average annual marginal fuel cost.

(2) Fixed Cost Adder reflective of fixed energy-related generation costs updated concurrent with changes in base cost rates brought through GRAs.

The Energy Credit applies to spilled energy and is the same as the Fuel Cost component used under the Energy Charge above. The proposed EBS rate charges and credit for 2027 as compared to 2026 are set out in **Figure 8**.

Figure 8: Energy Balancing Service Tariff Charges

	2026	2027	Variance
Administration Charge ($/LRS/month)	$414.63	$67,734.00	67,319.37
Energy Charge (cents per kWh)			
Fuel Cost (cents per kWh)	6.736	6.254	(0.482)
Fixed Cost Adder (cents per kWh)	2.155	2.253	0.098
Total Energy Charge (cents per kWh)	8.891	8.507	(0.384)
Energy Credit (cents per kWh)	6.736	6.254	(0.482)

The calculations for the proposed Energy Charge under the EBS Tariff are provided in **Appendix F2** RtR Energy Balancing Charge. The proposed EBS Tariff is provided in **Appendix F1**. A redline version is provided in **Appendix G**.

7.3 Standby Service Tariff

The Standby Service (SS) Tariff is a mandatory tariff applicable to LRSs for supplemental standby generation capacity service provided in combination with EBS under the EBS Tariff. The SS Tariff has two rate components: the Administration Charge and the Demand Charge.

The Administration Charge is applicable to each LRS' account and is set annually in advance of the rate year, based on the anticipated administration costs and the forecast number of LRS

accounts. The charge is set at par with the Administration Charge under the EBS Tariff discussed above. The proposed Administration Charge for 2027 is therefore $67,734 per month.

The Demand Charge is determined by the demand-related costs of generation from the COSS conducted for the purpose of GRAs. The most recent COSS comes from the 2027 COSS,[18] which gave rise to the Demand Charge under this rate. As such, the Company proposes that it be set for 2027 at $6.200 per month per kilowatt of monthly standby contract demand.

The proposed SS rate charges for 2027 as compared to 2026 are set out in **Figure 9**.

Figure 9: Standby Service Tariff Charges

	2026	2027	Variance
Administration Charge ($/customer/month)	414.63	$67,734.00	67,319.37
Demand Charge ($/kW)	5.601	6.200	0.599

The calculations for the proposed Demand Charge under the SS Tariff are provided in **Appendix F3** RtR Standby Demand Charge. The proposed SS Tariff is provided in **Appendix F1**. A redline version is provided in **Appendix G**.

7.4 Distribution-connected Aggregation Service Tariff

The DAS Tariff Administration Charge is intended to recover the incremental administrative costs associated with the aggregation of Distribution-Connected Generation and Net Billing Surplus under the Distributed-generation Aggregation Service (DAS) Tariff. These resources will be treated as additional sources of generation for the Licensed Retail Supplier in the RtR market and will require ongoing administration, monitoring, troubleshooting, and settlement support.

[18] M12451, NS Power 2027 Cost of Service Study: 2026 General Rate Application.

As discussed in Section 7.1, the RtR market remains in the early stages of implementation and operational experience with the DAS framework does not yet exist. Accordingly, the proposed Administration Charge has been developed using forecast information and represents the Company's best estimate of the incremental administrative effort required to support the service beginning in 2027. Given the absence of operating experience, there remains uncertainty regarding future participation levels, administrative effort, and system impacts associated with the DAS Tariff.

The Company has therefore developed a modest, forecast-based Administration Charge intended to recover only the incremental costs associated with administering the service. For the purpose of establishing this charge, it was assumed that up to 100 Distribution-Connected Generation and Net Billing Surplus metering points could be enrolled in the service. Based on this assumption, an estimated three hours of additional staff time per month would be required to support the administration, settlement, troubleshooting, and related activities associated with the tariff. This is summarized in Figure 10.

Figure 10: Assumptions Underlying the 2027 Forecast DAS Tariff Administration Charge

Item	Value
Number of metering points requiring administration/review	100
Estimated monthly administration effort	3 hours
Resource cost	$53.57/hour
Administrative overhead (AO)	$39.00/hour
2027 DAS Tariff Administration Charge	**$277.71/month**

Consistent with the approach discussed in M13008 and the broader review of RtR market elements contemplated following a period of operational experience, the Company will continue to monitor actual costs and participation levels and, where appropriate, propose refinements through future AAR proceedings. The Company further notes that approval of the proposed Administration Charge does not result in immediate cost recovery from REI or any other market participant. The

charge will only become payable where a Licensed Retail Supplier elects to take service under the DAS Tariff and customers are enrolled in the service.

The proposed DAS Tariff is provided in **Appendix F1**. A redline version is provided in **Appendix G**.

7.5 Renewable to Retail Transition Tariff

The RtR Transition Tariff (RTT) is designed to recover from the LRSs NS Power's embedded fixed costs and deferred costs (ordinarily recovered through bundled service rates) which are not otherwise recovered through other RtR tariffs. RTT has two rate components: the Energy Charge and the Demand Charge.

7.5.1 RTT Energy Charge

The RTT Energy Charge has three components: Fixed Cost Adder, Annually Adjusted Energy Savings Credit and Annual Energy Cost Adjustment.

The charge is designed to only apply to the LRS' monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the EBS Tariff. For the purposes of this 2027 AAR Application, the Company assumed, as in previous years, that 50 percent of RtR Market energy will represent displaced energy on NS Power's system as a result of direct deliveries from third party suppliers (that is, deliveries which are consumed in real time as opposed to spilled to NS Power's system).

7.5.1.1 Fixed Cost Adder

The Fixed Cost Adder component of the EBS Tariff is designed to recover the fixed energy-related generation costs of NS Power and is to be updated concurrently with changes in base cost rates

brought through a GRA. It is the same rate component as used in the Energy Charge of the EBS Tariff. However, it is applicable to the LRS' displaced energy on NS Power's generation system by bundled service customers who transitioned their load to the RtR market, as opposed to the top-up energy billed under the EBS Tariff.

7.5.1.2 Annually Adjusted Energy Savings Credit

The Annually Adjusted Energy Savings Credit is designed to credit the LRS with any non-fuel energy-related cost savings arising from freed-up capacity on NS Power's system as a result of a departure of its bundled service load to the RtR market. The Company's ability to mitigate this cost is limited by its ongoing requirement to maintain generation capacity in the event the RtR customer returns to NS Power's bundled service. The Company does not project savings in this cost category and proposes that the current value of zero remains in effect in 2027.

7.5.1.3 Annual Energy Cost Adjustment

The Annual Energy Cost Adjustment is designed to ensure that FAM customers are not affected by changes in system fuel costs as a result of a reduction in NS Power's generation due to the departure of the bundled service customers to the RtR market. If the average avoided cost of departing load exceeds the average system fuel cost paid by the FAM customers, this adjustment will be a credit and thus a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost paid by the FAM customers, this adjustment will be a debit and thus an increase in the Energy Charge.

The 2026 component was a debit of 2.171 cents/kWh because the forecast 2026 marginal fuel cost of 6.736 cents/kWh was less than the 2026 average system unit fuel cost of 7.882 cents/kWh before the fixed cost credit already accounted for under earnings adjustments above. The 2027 marginal fuel cost forecast, at 6.254 cents/kWh, is lower than the 2027 test year average system unit fuel cost charge of 8.160 cents/kWh, as proposed for recovery through the base fuel cost rates under the 2026-2027 GRA, so the 2027 Energy cost adjustment is a debit of 3.812 cents/kWh.

Please refer to **Appendix F4** for calculations related to this rate component.

7.5.2 RTT Demand Charge

The Demand Charge is made up of two components: the Demand Charge from the SS Tariff and the Annually Adjusted Demand Savings Credit.

As discussed in Section 7.3, the proposed 2027 SS Tariff Demand Charge is $6.200 per month per kilowatt of monthly standby contract demand.

The Annually Adjusted Demand Savings Credit is designed to pass to the LRS any non-fuel demand-related cost savings arising from freed up capacity on NS Power's system because of the departure of its bundled service load to the RtR market. As is the case with the Annually Adjusted Energy Savings Credit, the Company's ability to mitigate this cost is limited by its ongoing requirement to maintain generation capacity in the event the RtR customer returns to NS Power's service. The Company does not project savings in this cost category and proposes that the current value of zero remain in effect in 2027.

7.5.3 Proposed RTT Rates

The proposed RTT rate charges by components for 2027, as compared to 2026, are set out in **Figure 11**. The proposed RTT is provided in **Appendix F1**. A redline version is provided in **Appendix G**.

Figure 11: Renewable to Retail Transition Tariff Charges by Cost Components

Energy Charge by Components (cents per kWh)	2026	2027	Variance
Fixed Cost Adder from EBS Tariff	2.155	2.253	0.098
Annually Adjusted Energy Savings Credit	0.000	0.000	0.000
Annual Energy Cost Adjustment	2.171	3.812	1.641
Total	**4.326**	**6.065**	**1.739**

Demand Charge by Components ($/kW)	2026	2027	Variance
Demand Charge from Standby Service Tariff	5.601	6.200	0.599
Annually Adjusted Demand Savings Credit	0.000	0.000	0.000
Total	**5.601**	**6.200**	**0.599**

7.6 Board Directive regarding Interruptible Service in the RTR Market

The Board provided the following directive in its Order, dated March 20, 2024, approving the 2024 AARs:

> NS Power and Roswall are directed to explore ways in which interruptible customers may take service under the RtR Tariff and provide their recommendations in the 2025 AAR application.[19]

Since the Company's update through the 2026 AAR proceedings (M12551), NS Power and REI have continued to work collaboratively on matters related to the participation of interruptible customers within the RtR framework. This work has progressed alongside broader RtR market development initiatives, including the Company's RtR Market Elements Application (M13008), where the parties have continued to evaluate tariff, settlement, operational, and implementation considerations relevant to future participation of interruptible resources. As provided in the Company's Reply Submission under M13008, NS Power and REI continue to work collaboratively toward a resolution of the tariff and process revisions required to enable interruptible service.

[19] M11422, NSEB Order, March 20, 2024, p. 2.

8.0 EXTRA LARGE INDUSTRIAL ACTIVE DEMAND CONTROL TARIFF

Given the current term of the ELIADC Tariff will expire at the end of this year, the Company is not proposing any ELIADC-related rate adjustments as part of this AAR Application and, accordingly, has not included an updated Tariff. On December 29, 2025, NS Power filed an application seeking approval of a successor tariff, the Extra Large Industrial Dispatchable (ELID) Tariff, which remains an open matter before the Board in M12661.

9.0 RELIEF SOUGHT

NS Power respectfully requests the following relief:

(1) Approval to discontinue the 'No Muskrat Falls surplus (market-priced) energy' sensitivity analysis as a requirement for future AAR applications.

(2) Approval of the following Tariffs for use in 2027:

1. Generation Replacement and Load Following Tariff
2. One-Part Real Transmission Time Pricing Tariff
3. One-Part Real Time Distribution Voltage Pricing Tariff
4. Shore Power Tariff
5. Wholesale Market Back-up/Top-Up Service Tariff
6. Wholesale Market Non-Dispatchable Supplier Spill Tariff
7. RtR Energy Balancing Service Tariff
8. RtR Standby Service Tariff
9. RtR Market Transition Tariff
10. RtR Distribution-connected Aggregation Service Tariff

Clean versions of the proposed tariffs are provided in **Appendices A1, B1, C1, E1,** and **F1.**

A redline version of each tariff showing the changes from the tariffs approved by the Board for 2026 is provided in **Appendix G**.

SERVICE DEFINITION

Service under this tariff consists in delivery of supplemental power to partial requirement customers who operate their own dispatchable generation equipment, as approved to be connected to the grid by the Company. The Service has three components.

Generation Replacement Service – backup supply of power on a best efforts basis where the customer's generation equipment is removed from service due to scheduled maintenance, forced outage, or loss of fuel supply.

Optional Load Following Service – energy delivery in respect of imbalance between load and generation where customer's generation falls in any given hour below the lower of the established net operating capability or customer's load. Energy delivery under this service is defined as top-up energy.

Spill Service – hourly generation in excess of the customer's load absorbed by the Company. This excess energy is defined as spilled energy.

Power supplied by the Company to the customer in any given hour above the customer generation, if not below the established net operating capability, is defined as supplementary power and will be billed under applicable full requirement tariff. Customers taking this service will be referred to as "customer-generators."

Rate

Backup Service

The actual or estimated average time coincident incremental cost of generation including transmission losses for the period service is provided plus 0.500 cents per kWh for additional Operating and Maintenance costs, service charges and Administration & General compensation.

Optional Generation Load Following

Average incremental cost of generation expressed in cents per kWh as determined by the generation forecast for the rate year plus add on charges as defined for back-up service. This price will be 6.754 cents per kWh.

ENERGY CREDIT

The Energy Credit is equal to the average incremental cost of generation as defined under Optional Generation Load Following.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY

This tariff is available to:

(a) Customers who have their own qualifying generating facility of not less than 2,000 kW of aggregate capacity, as defined under Special Condition 8, normally used to support their own load;

(b) Energy supplied to Non-Utility Owned Generation sites for purposes of startup and replacement of energy normally supplied from their own generation, where the customer has signed an operating agreement under this tariff schedule.

The following general terms and conditions will apply to the applications.

(1) Energy under the Generation Replacement Service provision will be supplied upon request by the customer. In cases where advance written notification can be given by the customer, such as planned maintenance, the Company will advise the customer in writing of the quoted price which will be based on estimated costs during the period. In an emergency situation where time does not permit advance notification the price will be based upon actual costs until the customer provides written notification of the duration of the taking following which the Company will advise the customer in writing of the quoted price for the remainder of the period.

Energy under the load following section will be supplied either through on-going communication provision such as telemetering (when load fluctuations are involved) or written requests (where application is to a specific level of load).

(2) In the event there is an interruption required by NS Power in order to avoid shortfalls in electric supply, customers taking energy under the Generation Replacement Service or Load Following Service will be the first to be called upon to interrupt energy usage from NS Power.

(3) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by the Company, the Company may hold this load as Operating Reserve as required by system conditions. When interruptions are required, the Company will exercise the automated control of the customer's load to interrupt the customer load.

(4) Following interruption, service may only be restored by the customer with approval of the Company.

(5) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(6) Customers must install metering equipment to monitor the output of the customer's generation. The equipment and installation must be approved by the Company and the costs will be the responsibility of the customer.

SPECIAL CONDITIONS

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Any service requirements beyond those provided by a single step-down transformation from transmission voltage must be borne by the customer. The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(5) The Company reserves the right to determine the metering location.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) Qualifying generating facility must meet the following requirements:

(i.) Utilize dispatchable sources of generation.

(ii.) May have more than one generating unit so long as the aggregate manufacturer's nameplate rating is of not less than 2,000 kilowatts and which NSPI has the right to verify through inspection or testing.

(iii.) At the discretion of the customer, the generator may be connected to the grid either at any of the existing points of delivery of purchased power from NS Power or at a separate point if approved by NSPI. If a separate point of delivery is used, all additional costs will be the responsibility of the customer-generator.

(iv.) Generating facility shall meet all applicable safety and performance standards established by Measurement Canada, the Canadian Electrical Code, and NSPI's interconnection guidelines.

GENERATION LOAD FOLLOWING CRITERIA

(1) Two months preceding each tariff year the customer-generator, in conjunction with the Company, shall establish the aggregate net operating capability of its generation equipment for the billing purposes of calculating hourly top-up energy from NS Power during the next tariff year. The net operating capability will be set based upon tests of customer's generation equipment and/or operating records. During a period during which the customer-generator encounters conditions that will result in a temporary significant reduction in generation below the established net operating capability, bill payments under the Load Following service and the other full requirement rate, if applicable, will be set based on adjusted net operating capability reflecting the average generation level during such period. For each billing month of the tariff year the Company will load follow to the equivalent of one hundred (100) percent load factor of the adjusted net operating capability in each hour that the customer generation does not exceed its adjusted net operating capability.

(2) On or before November 7th preceding each tariff year the Company shall apply to the Nova Scotia Energy Board for approval of its forecasted incremental cost of generation for the following tariff year. Such average forecasted incremental cost shall be included in determining the load following rate for the next tariff year and each affected customer shall be notified.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Marginal Cost ($/MWh)			
2027	**Peak**	**Off-peak**	**All periods**
Jan			
Feb			
Mar			
Apr			
May			
Jun			
Jul			
Aug			
Sep			
Oct			
Nov			
Dec			
Year			62.54

2027 Annually Adjusted Rates

Modelling Assumptions used in PLEXOS

The PLEXOS model used for the 2027 Annually Adjusted Rates forecast is based on the 2026 Q3 fuel and purchased power forecast model.

A high-level list of updates for the 2026 Q3 fuel and purchased power model include:

Update number	Update Description
1.	Generation maintenance scheduled (GMS).
2.	Fuel and power prices.
3.	Coal blends, restrictions, emissions parameters, and volumes.
4.	Emission limits for SO2 updated.
5.	2027 Port Hawkesbury Paper (PHP CBL) load.
6.	ML surplus energy schedule.
7.	ML re-delivery energy schedule.
8.	NB market energy schedule.
9.	NB Power RFP energy removed.

Maritime Link Impacts

Approximately [redacted] of the total 2027 forecasted energy requirement is supplied by ML energy.

2027 AAR Appendix A4
has been filed electronically.

2027 AAR Confidential Appendix A5 has been removed due to confidentiality.

Sensitivity 1: Prices Adjusted Upwards (+1.5 σ)

System Marginal Cost ($/MWh)			
2027	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb			
Mar			
Apr			
May			
Jun			
Jul			
Aug			
Sep			
Oct			
Nov			
Dec			
Year			73.67

Sensitivity 2: Prices Adjusted Downwards (-1.5 σ)

System Marginal Cost ($/MWh)			
2027	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb	[redacted]	[redacted]	[redacted]
Mar	[redacted]	[redacted]	[redacted]
Apr	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]
Oct	[redacted]	[redacted]	[redacted]
Nov	[redacted]	[redacted]	[redacted]
Dec	[redacted]	[redacted]	[redacted]
Year	[redacted]	[redacted]	54.38

Sensitivity 3: Prices Half Surplus On Peak

System Marginal Cost ($/MWh)			
2027	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb	[redacted]	[redacted]	[redacted]
Mar	[redacted]	[redacted]	[redacted]
Apr	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]
Oct	[redacted]	[redacted]	[redacted]
Nov	[redacted]	[redacted]	[redacted]
Dec	[redacted]	[redacted]	[redacted]
Year	[redacted]	[redacted]	64.86

Sensitivity 4: Wind Delay 1 month

System Marginal Cost ($/MWh)			
2027	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb			
Mar			
Apr			
May			
Jun			
Jul			
Aug			
Sep			
Oct			
Nov			
Dec			
Year			71.29

Sensitivity 4: Wind Delay 1 month

System Marginal Cost ($/MWh)			
2027	Peak	Off-peak	All periods
Jan	[redacted]	[redacted]	[redacted]
Feb	[redacted]	[redacted]	[redacted]
Mar	[redacted]	[redacted]	[redacted]
Apr	[redacted]	[redacted]	[redacted]
May	[redacted]	[redacted]	[redacted]
Jun	[redacted]	[redacted]	[redacted]
Jul	[redacted]	[redacted]	[redacted]
Aug	[redacted]	[redacted]	[redacted]
Sep	[redacted]	[redacted]	[redacted]
Oct	[redacted]	[redacted]	[redacted]
Nov	[redacted]	[redacted]	[redacted]
Dec	[redacted]	[redacted]	[redacted]
Year	[redacted]	[redacted]	64.21

2027 AAR Confidential Appendix A7 has been removed due to confidentiality.

DEMAND CHARGE

Nil.

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00 am – 11:00 pm, non-holiday weekdays): 6.156¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): 0.918¢/kWh

Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Energy Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at transmission voltage of 69 kV or higher and have loads of 2,000 KVA or 1,800 kW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days' notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause 1, but agrees to remain interruptible for up to five years as provided for under Availability Clause 5 of the Large Industrial Tariff Interruptible Rider. Within the five-year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

DEMAND CHARGE

Nil.

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00 am – 11:00 pm, non-holiday weekdays): 8.513¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): 3.091¢/kWh

Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Energy Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at voltage less than 69 kV and have loads of 2,000 KVA or 1,800 kW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days' notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause 1, but agrees to remain interruptible for up to five years as provided for under Availability Clause 5 of the Large Industrial Tariff Interruptible Rider. Within the five-year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

2027 AAR Partially Appendix B2 has been filed electronically.

AVAILABILITY

(1) This tariff is available to port authorities of Nova Scotia for the sole purpose of providing port electricity to cruise ships docked in ports to meet their own consumption needs in displacement of the on-board self-generation. The tariff is applicable to electric energy where the regular demand is 2,000 kVA or 1,800 kW, and over.

(2) Customers served under this tariff must accept supply interruption. In the event there is an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

(i.) Generation Replacement and Load Following (GR&LF) Rate;
(ii.) Extra Large Industrial Active Demand Control Tariff and PHP Tariff;
(iii.) Shore Power Tariff; and
(iv.) Interruptible Rider to the Large Industrial Rate.

unless there are technical reasons to alter this sequence specific to the instance.

(3) This is a seasonal tariff available from April 1 to November 30.

ENERGY CHARGE

Energy charges will vary by voltage level of the point of delivery and will be made up of two components.

(1) Annually adjusted fuel cost component which shall be the Company's forecast average annual marginal energy cost as approved for use with the GR&LF tariff and adjusted for line losses at the voltage level of the point of delivery.

(2) A fixed cost adder adjusted concurrent with changes in base cost rates coming into effect as a result of a General Rate Case application.

Base Energy Charge Components	**Transmission Voltage of 69 kV or Higher (cents per kWh)**	**Distribution Voltage (cents per kWh)**
Fuel Cost	6.406	6.556
Fixed Cost Adder	2.576	4.226
Total	**8.983**	**10.783**

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer and the customer is served at a transmission voltage level.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

SUPPLY INTERRUPTIONS

This is an interruptible service. Before connecting the ship to the shore supply the port authority will request permission from NSPI indicating the expected load and duration for which the power is needed.

The customer will make available suitable contact telephone numbers of a person or persons who are able to disconnect the load within ten minutes. Supply Interruption calls will be made to all customers taking energy under this tariff on an equitable and transparent basis.

This Tariff will be available provided that:

(1) The customer has provided written notice of its desire to take interruptible service.

(2) The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order and must have a designated staff person to answer the dedicated telephone at all times when cruise ships are connected to the utility grid. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rate.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty will apply based on the usage of the vessel being served via the Port Authority's equipment following the request to interrupt on the day on which the non- compliance took place.

Penalty for Non-Compliance

All energy served after the 10-minute deadline has expired will be billed at $5.00 per kWh. In addition a fixed charge of $2,000.00 will be applied.

The penalty charge is applicable above and beyond the Port Authority's monthly bill.

SPECIAL CONDITIONS

(1) The Port Authority owns and is responsible for the maintenance and operation of all electrical equipment required for the supply of port electricity to docked ships other than the meters and metering transformers supplied by NSPI. NSPI owns and is responsible for the maintenance of meters and metering transformers installed on the Port Authority premises for the purposes of billing.

(2) The Port Authority will ensure that trained staff is available to operate on-shore interconnection equipment to facilitate the connection, synchronization, disconnection, and interruption if needed at all times. Such operators must be available to be contacted by NSPI from a minimum of one hour before connection is required to the time that the ship returns to on board power supply.

(3) The Port Authority will file a two-year schedule of expected vessels showing their peak electrical demand before October 31 in a calendar year preceding the cruise ship season.

(4) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(5) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

2027 AAR Appendix C2
has been filed electronically.

COST BREADOWN BY FUNCTIONAL AREA

Source: 2027 COSS with GRA application Filing

EXHIBIT 6.1
PAGE 11 OF 11

RATE CLASS DISAGGREGATION ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2027

CLASS : TOTAL COMPANY

		RATE BASE	COSTS (Source Exh 6)									
			Variable	Fixed						Unit Cost		
			Fuel	Operating	Capital	Return	Total	Total Cost	Units Sold	Demand	Energy	Customer
	Generation											
(1)	Usage (Energy)	$1,467,999	$646,117	$72,066	$111,286	$51,027	$234,378	$880,495	9,923,466	---	8.873	---
(2)	Reliability (Demand)	$1,071,311	$220,494	$72,829	$95,602	$37,238	$205,668	426,163	22,698,943	$18.775	---	---
(3)	**Total Generation**	$2,539,311	$866,611	$144,894	$206,888	$88,265	$440,047	$1,306,658		$18.775	8.873	$0.000
(4)	MWh Sales		9,923,466	9,923,466	9,923,466	9,923,466	9,923,466	9,923,466				
(5)	MWh Energy Requirement		10,656,169									
(6)	kW 3 CP		9,190,588									
(7)	kW 12 NCP		22,698,943									
(8)	Unit Cost (cents/kW.h)		8.733	1.460	2.085	0.889	4.434	13.167				
	Transmission/Distribution											
(9)	Delivery--Trans.(Eng) - HV	0	0	$0	$0	$0	0	$0	9,923,466	---	0.000	---
(10)	Delivery--Trans.(Eng) - EHV	0	0	0	0	0	0	0	9,923,466		0.000	
(11)	Delivery--Trans.(Dmd) - HV	0	0	0	0	0	0	0	22,698,943	$0.000	---	---
(12)	Delivery--Trans.(Dmd) - EHV	1,158,946	0	34,441	83,108	40,284	157,833	157,833	22,698,943	$6.953	---	---
(13)	**Total Transmission**	$1,158,946	$0	$34,441	$83,108	$40,284	$157,833	$157,833		$6.953	-	$0.000
(14)	Delivery -- Dist. (Demand)	1,178,642	0	20,610	118,776	40,969	180,355	180,355	22,698,943	$7.946	---	---
(15)	Delivery -- Dist. (Customer)	845,343	0	46,293	78,169	29,384	153,845	153,845	6,448,289	---	---	$23.858
(16)	**Total Distribution**	2,023,985	0	66,903	196,944	70,352	334,200	334,200		$7.946	-	$23.858
(17)	**Total Transmission/Distribution**	$3,182,931	$0	$101,344	$280,052	$110,637	$492,033	$492,033		$14.899	-	$23.858
(18)	kW.h Sold		---	9,923,466	9,923,466	9,923,466	9,923,466	9,923,466				
(19)	Unit Cost (cents/kW.h)		---	1.021	2.822	1.115	4.958	4.958				
	Retail											
(20)	Customer -- Field		0	$6,334	0	0	$6,334	$6,334	6,448,289	0.000	0.000	$0.982
(21)	Customer -- Head Office	163,816	0	2,673	10,993	5,694	19,361	19,361	6,448,289	0.000	0.000	$3.002
(22)	**Total Customer**	$163,816	0	9,008	10,993	5,694	25,695	25,695	6,448,289	$0.000	-	$3.984
(23)	Marketing		0	13,410	0	0	13,410	13,410	6,448,289	0.000	0.000	$2.080
(24)	**Total Retail**	$163,816	$0	$22,418	$10,993	$5,694	$39,106	39,106	6,448,289	0	-	$6.064
(25)	Total Customers x 12 months		---	6,448,289			6,054,372	6,054,372				
(26)	Unit Cost ($/month)		---	$3.477			$3.477	$3.477				
(27)	**TOTAL**	**$5,886,058**	**$866,611**	**$268,657**	**$497,933**	**$204,596**	**$971,185**	**$1,837,796**		$33.674	8.873	$29.922
(28)	**Unit Cost (cents/kW.h)**		**8.733**	**2.707**	**5.018**	**2.062**	**9.787**	**18.520**				

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2027

	(1) MWH SALES	(2) ENERGY LINE LOSSES	(3) ENERGY REQUIREMENT	(4) CLASS NON-COINCIDENT DMD. (KW)	(5) SYSTEM COINCIDENT FACTOR	(6) SYSTEM COINCIDENT DMD. (KW)	(7) DEMAND LINE LOSSES	(8) SYSTEM COIN. PEAK DMD. (KW)	(9) SYSTEM COINCIDENT L/D FACTOR	(10) 3CP MW	(11) 3CP Contribution
(1) DOMESTIC	5,326,614,029	8.5%	5,780,026,508	1,497,921	90.8%	1,360,109	13.9%	1,549,203	42.59%	4,416	64.2%
(2) SMALL GENERAL	436,037,580	8.2%	471,845,606	95,987	84.9%	81,493	12.2%	91,427	58.91%	271	3.9%
(3) GENERAL	2,248,906,543	8.0%	2,428,877,765	424,789	94.1%	399,726	11.0%	443,515	62.52%	1,236	18.0%
(4) GENERAL LARGE	356,917,033	5.1%	375,084,109	61,863	73.6%	45,531	6.7%	48,593	88.12%	138	2.0%
(5) SMALL INDUSTRIAL	252,148,727	7.7%	271,619,062	42,138	84.8%	35,733	13.7%	40,641	76.29%	123	1.8%
(6) MEDIUM INDUSTRIAL	448,132,056	6.8%	478,501,542	87,271	74.2%	64,755	10.7%	71,678	76.21%	183	2.7%
(7) LARGE INDUSTRIAL	595,226,798	3.6%	616,476,395	84,721	79.8%	67,607	5.6%	71,385	98.58%	212	3.1%
(8) PHP (ELID)	321,899,980	2.4%	329,733,588	199,370	32.6%	65,000	4.2%	67,745	56%	203	3.0%
(9) MUNICIPAL	46,528,201	2.5%	47,707,797	19,571	99.9%	19,551	5.7%	20,661	26.36%	67	1.0%
(10) UNMETERED	67,519,456	8.2%	73,076,308	36,533	25.0%	9,133	13.9%	10,403	80.19%	27	0.4%
(11) SUB-TOTAL	**10,099,930,402**	**7.7%**	**10,872,948,681**	**2,550,162**	**84.3%**	**2,148,639**	**12.41%**	**2,415,251**	**51.39%**	**6,875**	**100.0%**
(12) BOWATER MERSEY											
(13) GEN.REPL./LOAD FOLL.											
(14) BUTU											
(15) REAL TIME PRICING											
(16) PHP											
(17) Shore Power											
(18) EBS/RTR											
(19) SUB-TOTAL	**731,158,223**	**2.6%**	**750,367,117**	**111,626**	**68.5%**	**76,417**	**5.6%**	**80,690**	**106%**	**252**	
(20) TOTAL	**10,831,088,625**	**7.3%**	**11,623,315,798**	**2,661,788**	**83.6%**	**2,225,056**	**18.0%**	**2,495,941**	**53.16%**	**6,950**	**6,747**
GL, LI, ELID and Municipal Combined	**1,320,572,012**	**3.7%**	**1,369,001,890**	**365,524**	**54.1%**	**197,689**	**5.1%**	**208,384**	75.00%	**620**	**9.0%**

Large Customer Rate Class Load Disaggregation by Voltage-based Service Levels

Transmission											
LIR	343,915,797	2.4%	352,285,172	61,127	58.2%	35,550	4.2%	37,043	108.6%	109	1.6%
ELID	321,899,980	2.4%	329,733,588	199,370	32.6%	65,000	4.2%	67,745	55.6%	203	3.0%
Municipal class	43,819,389	2.4%	44,885,758	15,135	88.5%	13,391	4.2%	13,953	36.7%	44	0.6%
Total	**709,635,166**	**2.4%**	**726,904,518**	**275,632**	**41.3%**	**113,940**	**4.2%**	**118,741**	**69.9%**	**356**	**5.2%**
Distribution (> 2 MVA)											
LIR (other than EHV and HV)	251,311,001	5.1%	264,191,223	48,007	66.8%	32,057	7.1%	34,342	87.8%	103	1.5%
Munis (other than HV)	2,708,811	4.2%	2,822,040	8,314	N/A	6,160	8.9%	6,708	4.8%	26	0.4%
Large General (whole)	356,917,033	5.1%	375,084,109	65,946	69.0%	45,531	6.7%	48,593	88.1%	138	2.0%
Total	**610,936,845**	**5.1%**	**642,097,372**	**122,267**	**68.5%**	**83,749**	**7.0%**	**89,643**	**81.8%**	**266**	**3.9%**
Tranmission and Distribution (> 2MVA) Total	**1,320,572,012**	**3.7%**	**1,369,001,890**	**397,900**	**49.7%**	**197,689**	**5.4%**	**208,385**	**75.00%**	**622**	**9.1%**

CUSTOMER CHARGE

The monthly customer charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of customers subscribed} * 12}$$

This charge will be $427.07 per month.

DEMAND CHARGE

The demand charge for this service is made up of the following two components:

(1) Annually adjusted demand-related purchased power cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism, or General Rate Application.

(2) Demand-related fixed generation cost, coming into effect as a result of a General Rate Application.

Demand Charge Components	**$ per kW of billing demand**
Demand-related Purchased Power Cost	$8.142
Demand-related Fixed Generation Cost	$6.200
Total	**$14.341**

Contract Demand requirement is defined as the firm demand (kW) requested by the wholesale customer (or aggregate customer group) and agreed to be supplied by NSPI. This may constitute all, or a portion of the demand contracted to be served on a primary basis by a third-party supplier.

Billing demand is determined based upon the following formula:

$$\text{Billing demand} = (PR/(1+PR) * \min(CD, CCF * GC)) + (CD - \min(CD, CCF*GC))$$

Where:

PR is Planning Reserve (based on NPCC planning criteria, i.e. 20% or as updated)

GC is the third-party supplier's generating capacity

(a) For non-dispatchable generation, GC = MSC, the Maximum Spill Capacity as defined in Wholesale Market Non-Dispatchable Supplier Spill Tariff.

(b) For dispatchable generation, GC = the supplier's maximum capacity contracted to provide its wholesale customers' demand.

CD is the customer's Contract Demand

CCF is the capacity contribution factor of the third party supplier's generation to the NSPI system, as determined at the beginning of a billing year by NSPI using information provided in accordance with Special Condition 7 of this tariff and in a manner consistent with NSPI's generation planning studies as amended from time to time.

ENERGY CHARGE

The energy charge is made up of the following two components:

(1) Annually adjusted energy-related purchased power and fuel cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism or General Rate Application.

(2) Energy-related fixed generation cost, coming into effect as a result of a General Rate Application.

Energy Charge Components	**cents per kWh**
Energy-related Purchased Power and Fuel Cost	6.430
Energy-related Fixed Generation Cost	2.253
Total	**8.683**

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the customer charge plus the demand charge.

AVAILABILITY

The tariff is available to wholesale customers as defined in section 2(d) of the *Electricity Act*, Chapter 25 of the Acts of 2004.

(d) "wholesale customer" means Nova Scotia Power Incorporated or a municipal utility.

The tariff is applicable to the *scheduled* backup/top-up load of participating customers under the following terms and conditions:

(1) The wholesale customer has provided written notice of its intent to take service under this tariff, clearly identifying the following:

(a) The Municipal utility or utilities for which service is being requested.

(b) The year for which service is being requested.

(c) The contract demand (kW) required for backup and top-up service.

(d) The portion of the customer's annual load contracted to be supplied by third-party suppliers or through self-supply.

(e) The names, addresses, contact details and supply arrangements associated with contracted third-party suppliers.

(2) Backup/top-up service will be subscribed on a minimum 12 month, annual-renewable basis, provided that, if a wholesale customer satisfies the requirement of Special Condition 7(d), the backup/top-up service required with respect to the wholesale customer's procured capacity which satisfies the requirement of Special Condition 7(d) shall be subscribed by the customer on a minimum three-year forward basis.

Applications for service with a CCF value greater than zero in the billing demand calculation of the demand charge must be provided annually to NSPI by January 31st of each year, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision by March 31st of each year following an application.

Applications for service with a CCF value of zero in the billing demand calculation of the demand charge must be provided to NSPI by no later than September 1st, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision within two months of receipt of such an application.

(3) Adequate metering equipment, as dictated by the Generation Interconnection Agreement, must be installed to monitor the generation of any third-party generators selected for use by the wholesale customer. The equipment and installation must be approved by the Company and the costs will be the responsibility of the generator.

SPECIAL CONDITIONS

(1) This tariff is designed for customers supplied and metered at the high side of the transformer at transmission voltage of 69 kV or higher. For customers metered at the low side of the transformer, or at a distribution voltage level, meter readings shall be increased by 1.1% for each transformation between the meter and the transmission voltage.

(2) The charges under this rate do not reflect transmission service costs. Customers taking service under this tariff must also take service under the Open Access Transmission Tariff (OATT).

(3) For system reasons, NSPI may, at its discretion, deny an application for service from a customer who has not taken service from NSPI in the year prior to the year requested.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(7) Unless the following can be demonstrated by the wholesale customer to the satisfaction of NSPI, the CCF shall be attributed a value of zero in the billing demand calculation of the demand charge:

(a) For a third-party generation resource within Nova Scotia (Internal Resource):

(i.) If the Internal Resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the wholesale customer to NSPI, if directed to do so by the Nova Scotia Power System Operator (NSPSO), in the event of a resource adequacy need;

(ii.) If the Internal Resource is non-dispatchable, that it make its full output contracted to, but unused by, the wholesale customer available to deliver energy to NSPI, in the event of a resource adequacy need;

(iii.) The Internal Resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO; and

(iv.) Any export transactions utilizing energy from the Internal Resource will be recallable by the NSPSO, up to the amount contracted to the wholesale customer, for delivery to the NSPI system in the event of a resource adequacy need.

(b) For a third-party generation resource outside of Nova Scotia (External Resource):

(i.) The energy from the External Resource that is contracted to the wholesale customer will be scheduled and delivered to NSPI in the event of a resource adequacy need;

(ii.) The capacity from the External Resource that is contracted to the wholesale customer must be associated with one or more specific external resource assets, or be system-backed import capacity supported by the external control area where the capacity will be afforded the same curtailment priority as the external control area's native load, and be available to the NSPSO in the event of a resource adequacy need;

(iii.) If the capacity from the External Resource that is contracted to the wholesale customer is associated with one or more specific external resource assets, the wholesale customer must provide:

1. The name and location of each external resource asset;
2. For each asset, generator data including documentation of dependable maximum net capacity and NERC Generating Availability Data System data;
3. Documentation demonstrating proof of contractual control of the capacity all the way to each external resource asset providing the capacity; and
4. Letter of attestation or other documentation from the External Resource owner establishing that the capacity from the External Resource is not being used as capacity in any other balancing area.

(iv.) If the capacity from the External Resource will be supported by the external control area, the wholesale customer must provide:

1. Documentation demonstrating that the import capacity will be supported by the external control area and afforded the same curtailment priority as the external control area's native load.
2. Documentation demonstrating that the External Resource has firm transmission from the specific external resource asset or external control area to the NSPI system.

(c) The Internal Resource or External Resource, as applicable, will perform as needed to meet NSPI's reliability requirements.

(d) The capacity derived based on the CCF is procured and available to the wholesale customer on a minimum three-year forward basis, unless this requirement is waived by NSPI.

(8) In the event of a failure by the Internal Resource or External Resource, as applicable, to deliver scheduled energy or capacity following a direction to do so by the NSPSO in accordance with Special Condition 7, above, then the wholesale customer will be required to make payment to NSPI of an amount equal to the costs incurred by NSPI to procure or to self-supply the undelivered energy and/or capacity, as applicable, less the energy charge paid by the wholesale customer to NSPI under this tariff with respect to any such undelivered energy and/or capacity, as applicable. If delivery of an Internal Resource or External Resource, as applicable, is affected by circumstances that are inconsistent with the information and/or documentation provided to NSPI pursuant to Special Condition 7, above, then NSPI and the wholesale customer shall attempt to negotiate an adjustment to the CCF for the Internal Resource or External Resource, as applicable. If NSPI and the wholesale customer are unable to agree on an adjustment to the CCF, the matter may be submitted to the Board by either party on an expedited basis for adjudication.

ADMINISTRATION CHARGE

The monthly administration charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of suppliers supplying wholesale customers} * 12}$$

This charge will be $2,562.40 per month.

ENERGY CREDIT

Compensation for spill energy delivered to NSPI will be at the Company's forecast average annual marginal energy costs of 6.254 cents per kilowatt hour as approved for use with the GRLF rate.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the administration charge.

AVAILABILITY

This tariff is available for use by, independent non-dispatchable electric generators serving the Wholesale Market. The tariff is applicable to scheduled "spill energy," under the following terms and conditions:

(1) "Spill energy" is defined as the scheduled hourly energy forecast to be produced by the supplier above the scheduled hourly energy requirement of their wholesale customer(s). Unscheduled energy produced will be compensated according to the Open Access Transmission Tariff (OATT) imbalance guidelines. Spill compensation under this tariff is limited to the supplier's Maximum Spill Capacity (kW). Maximum Spill Capacity must be approved by NSPI prior to commencement of service. Spill capacity will be reviewed periodically and adjusted as required.

(2) Suppliers must install metering equipment to monitor the output of their generation. Consistent with the Generation Interconnection Agreement, the equipment and installation must be approved by the Company and the costs will be the responsibility of the supplier.

SPECIAL CONDITIONS

(1) Suppliers must meet all conditions set forth in the Generation Interconnection Procedures and Generation Interconnection Agreement.

(2) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(3) The supplier will make all necessary arrangements to ensure that its generation output does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated in the Generation Interconnection Agreement.

In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

2027 AAR Appendix E2
has been filed electronically.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Base Cost of Fuel Cost of Service Allocation of Fuel Expenses among Rate Classes

FOR THE YEAR ENDING DECEMBER 31, 2027

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO	AP	AQ	AR
10		Cost Allocation Factors						Fuel-related Costs from COS																									Fuel Costs used for FAM purposes				FAM Cost Classification								VARIANCE FROM CA IR-001		
11			3 CP Demands		Energy Requirement						Purchased Power- Biomass			Maritime Link			Purchased Power other than Biomass and Wind			Purchased Power - Wind																	Cost Amount			Unit Cost (cents per kWh)					
12														Basic and Supplemental Blocks						ERIS			NRIS																						
13				Relative Shares of Embedded Cost Classes		Relative Shares of Embedded Cost Classes														Demand-						Total Fuel-related costs before BUTU Capacity Credit, Export Revenues, OM&G, and Foreign Exchange	BUTU Capacity Credit (Allocated demand-related Costs less BUTU payments)		OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs																
14	Rate Class	A/C Ratios	KW Demand		kWh Energy		kWhs Sales	Fuel Costs before Purchased Power	Imports (allocated on monthly energy requirements)	(allocated on monthly energy	(allocated on annual energy	Demand-related	Total	Fixed Energy-related	Fixed Demand-related	Total	Fixed Energy-related	Fixed Demand-related	Total	Energy-related	Demand-related	Total	Energy-related	Demand-related	Total	Total	Export Revenues					Adjusted for A/C ratio and coincidence	Relative Share	Adjusted for A/C ratio and Allocated	cents per kWh	Demand-related	Energy-related	Total	Demand-related	Energy-related	Total	Total Fuel-related costs	Variance	% Var
15	**FAM Rate Classes (ATL)**																																												
16	Residential	97.20%	4,351,189		64.167%		52.41%	5,174,285,808	$167,599,722	$45,268,087	$4,583,138	$3,168,969	$11,492,495	$53,295,370	$62,511,340	$115,806,710	$7,248,850	$8,577,202	$15,826,052	$8,915,528	$10,333,885	$19,249,413	$48,783,748	$56,543,384	$105,327,132	$124,574,545	$480,569,611	$253,020	$0	$0	$0	$480,822,631	$407,356,822	53.7%	$465,012,048	8.9870	$141,959,220	$338,863,411	$480,822,631	2.744	6.549	9.293	$481,505,910	-$683,279	-0.1%
17	Small General	104.52%	230,332		3.397%		3.61%	356,341,152	$11,289,468	$3,229,880	$323,909	$225,552	$747,460	$3,760,204	$3,309,065	$7,069,269	$516,425	$454,038	$970,463	$621,827	$547,029	$1,168,856	$3,402,667	$2,993,148	$6,395,815	$7,564,672	$30,871,211	$13,394	$0	$0	$0	$30,884,605	$32,279,658	3.7%	$32,117,707	9.013	$7,514,672	$23,369,933	$30,884,605	2.109	6.558	8.667	$30,948,722	-$64,117	-0.2%
18	General Demand	104.71%	1,595,401		17.629%		21.85%	2,165,415,899	$67,108,968	$20,067,255	$1,978,517	$1,395,915	$4,602,028	$23,247,475	$17,173,719	$40,421,193	$3,194,637	$2,356,412	$5,551,049	$3,809,465	$2,810,025	$6,648,490	$20,826,750	$15,334,144	$36,160,895	$43,009,184	$180,789,878	$69,512	$0	$0	$0	$180,859,390	$189,384,258	21.7%	$188,434,099	8.702	$59,000,407	$141,858,983	$180,859,390	1.801	6.551	8.352	$181,242,317	-$383,927	-0.2%
19	Large General	104.71%	136,936		2.019%		3.51%	357,052,888	$10,499,765	$3,367,995	$324,721	$234,685	$774,526	$3,843,601	$1,967,292	$5,810,893	$535,089	$269,933	$805,022	$625,393	$325,217	$950,611	$5,420,084	$1,779,475	$5,199,559	$6,150,170	$27,310,363	$7,963	$0	$0	$0	$27,318,326	$28,605,985	3.3%	$28,462,466	7.971	$8,467,594	$22,850,733	$27,318,326	1.251	6.400	7.651	$27,407,990	-$89,664	-0.3%
20	Small Industrial	104.71%	125,244		1.847%		2.56%	254,467,664	$7,795,729	$2,384,829	$235,632	$165,103	$507,663	$508,787	$258,198	$766,985	$70,845	$34,686	$105,531	$83,449	$297,450	$380,899	$2,483,013	$1,627,542	$4,107,555	$4,858,494	$20,797,614	$7,283	$0	$0	$0	$20,804,897	$21,785,543	2.5%	$21,676,243	8.518	$4,686,148	$16,718,749	$20,804,897	1.606	6.570	8.176	$20,793,526	$11,371	0.1%
21	Medium Industrial	104.71%	144,442		2.130%		4.14%	414,535,689	$12,371,041	$3,922,199	$379,165	$269,398	$874,200	$124,166	$773,270	$897,436	$4,565,584	$2,075,130	$6,640,714	$629,122	$284,729	$913,852	$737,445	$343,044	$1,080,485	$4,042,235	$1,877,018	$5,910,253	$6,999,738	$31,620,814	$8,999	$0	$0	$0	$31,629,213	$33,120,066	3.8%	$32,953,900	7.950	$4,712,487	$26,916,726	$31,629,213	1.137	6.493	7.630	$31,668,715	-$40,502	-0.1%
22	Large Industrial	104.71%	245,492		3.630%		6.73%	694,581,928	$19,975,853	$6,468,241	$618,421	$444,646	$1,415,031	$1,274,097	$7,899,948	$13,536,856	$10,926,801	$1,090,289	$483,921	$1,514,210	$1,199,091	$583,032	$1,782,113	$6,581,289	$3,390,147	$9,771,437	$11,553,550	$51,752,791	$14,275	$0	$0	$0	$51,727,066	$54,345,239	6.2%	$53,893,486	7.759	$8,609,263	$43,717,803	$51,727,066	1.153	6.294	7.447	$51,838,379	-$161,313	-0.3%
23	PHP	104.71%	203,269		2.998%		2.91%	304,282,817	$7,737,367	$3,192,401	$281,342	$218,137	$674,213	$3,416,930	$2,920,260	$6,337,191	$505,491	$400,690	$906,181	$558,187	$482,755	$1,040,941	$3,047,646	$2,641,463	$5,689,109	$6,730,050	$25,577,403	$13,820	$0	$0	$0	$25,589,223	$26,795,380	3.1%	$26,660,945	8.762	$6,631,723	$18,957,500	$25,589,223	2.179	6.230	8.410	$25,855,947	-$266,724	-1.0%
24	Municipal	104.71%	93,358		1.382%		1.21%	129,551,972	$3,598,155	$1,038,264	$105,018	$72,580	$250,598	$401,543	$1,346,159	$1,539,353	$162,329	$184,707	$347,036	$140,432	$122,536	$262,968	$1,058,436	$1,217,641	$2,330,079	$2,740,046	$10,860,648	$5,449	$0	$0	$0	$10,866,098	$11,378,694	1.3%	$11,321,606	9.021	$3,057,040	$7,809,458	$10,866,098	2.436	6.223	8.658	$10,898,229	-$31,731	-0.3%
25	Unmetered	100.00%	32,917		0.487%		0.78%	77,000,000	$2,323,730	$727,868	$73,215	$50,800	$177,815	$249,830	$1,346,159	$1,595,989	$101,075	$184,707	$285,782	$87,415	$122,536	$209,951	$438,320	$1,217,641	$1,655,961	$1,981,468	$5,181,468	$1,396,868	$6,107,259	$1,882	$0	$0	$6,109,141	$6,109,141	0.7%	$6,078,491	7.894	$1,053,692	$5,055,449	$6,109,141	1.371	6.563	7.934	$6,125,418	-$16,277	-0.3%
26	Total	100.00%	6,758,364		99.660%		100.00%	10,656,168,727	$310,869,795	$99,476,994	$8,901,118	$6,245,744	$25,809,653	$90,966,533	$104,395,094	$197,094,059	$28,201,489	$24,143,779	$13,222,302	$27,046,080	$17,240,394	$16,010,821	$15,418,031	$49,444,856	$47,824,445	$102,851,708	$215,579,516	$644,217,993	$382,997	$0	$0	$0	$644,610,990	$670,980,786	100.0%	$666,610,990	8.733	$220,494,227	$446,116,764	$666,610,990	2.222	6.511	8.733	$668,338,152	-$1,727,162	-0.2%
27																																					25.4%	74.6%							
28	Purchased Power Allocation Factors.										42.5%	29.8%	27.7236%	100.0%	51.8%	48.2%	100.0%	51.8%	48.2%	100.0%	51.8%	48.2%	100.0%	51.8%	48.2%	100.0%																			
29																																												
30	**Non-FAM Rate Classes**																																											
31	BUTU	100.00%																																										
32	GRLF	100.00%																																										
33	LF - RTP	100.00%																																										
34	PHP	100.00%																																										
35	Shore Power																																											
36	EBS																																											
37	**Total below-the-line**		240,665		0.3%		0.3%	700,773,677	$55,224,498	$295,503	$28,981	$20,914	$69,363	$336,616	$325,358	$661,974	$46,494	$44,642	$91,136	$53,030	$53,786	$106,816	$285,111	$294,296	$581,407	$690,223	$57,032,697	-$382,997	$0	$0	$0	$56,639,700			$56,639,700	8.082	$344,553	$56,295,147	$56,639,700	0.049	8.033	8.082	$56,643,830	-$4,130	0.0%
38																																												
39	**In Province Total**		6,999,029		100.0%		100.0%	11,376,442,170	$366,094,293	$99,772,498	$8,930,099	$6,266,657	$25,879,121	$91,303,149	$104,720,452	$197,756,033	$28,247,983	$24,188,421	$13,313,438	$27,099,110	$17,293,524	$16,117,607	$15,703,342	$49,738,763	$48,118,742	$103,432,915	$216,269,739	$701,250,690	$382,997	$0	$0	$0	$701,633,687			$723,250,690	8.690	$220,838,780	$502,411,910	$723,250,690	2.079	6.611	8.690	$724,979,982	-$1,729,291	-0.2%
40																																												
41	Exports	100.00%	-		-		-	-																																					
42																																												
43	Grand Total		6,999,029				11,376,442,170	10,624,339,872	$366,094,293	$99,772,498	$8,930,099	$6,266,657	$25,879,121	$91,303,149	$104,720,452	$197,756,033	$28,247,983	$24,188,421	$13,313,438	$27,099,110	$17,293,524	$16,117,607	$15,703,342	$49,738,763	$48,118,742	$103,432,915	$216,269,739	$701,250,690	$382,997	$0	$0	$0	$701,633,687		100.0%	$723,250,690	8.690	$220,838,780	$502,411,910	$723,250,690	2.079	6.611	8.690	$724,979,982	-$1,729,291	-0.2%

Monthly Fuel Cost Allocation

	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Purchased Power													
Imports	$4,745,529	$6,120,982	$4,325,089	$9,790,100	$6,316,986	$7,064,377	$9,857,844	$8,238,549	$7,755,359	$10,275,341	$7,707,758	$7,774,583	**$89,972,498**
Biomass													
IPP	$2,017,708	$1,566,665	$1,635,557	$71,916	$1,488,347	$1,501,997	$2,015,967	$2,112,601	$1,631,723	$85,309	$1,675,174	$1,773,613	**$17,576,577**
Comfit	$275,302	$272,644	$342,881	$266,456	$284,110	$307,286	$289,319	$290,681	$269,472	$260,632	$316,932	$273,585	**$3,449,301**
Total	**$2,293,010**	**$1,839,309**	**$1,978,438**	**$338,372**	**$1,772,457**	**$1,809,283**	**$2,305,286**	**$2,403,282**	**$1,901,195**	**$345,941**	**$1,992,106**	**$2,047,198**	**$21,025,878**
Maritime Link													
ML - NS Block (GWh)	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$202,151,066
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$13,608,333**	**$13,608,333**	**$13,608,333**	**$13,608,333**	**$33,033,866**	**$13,608,333**	**$13,608,333**	**$13,608,333**	**$13,608,333**	**$13,608,333**	**$33,033,866**	**$13,608,333**	**$202,151,066**
Regular other than biomass and wind													
IPP	$1,912,288	$2,286,050	$2,869,763	$2,877,723	$2,707,206	$2,536,520	$2,107,445	$1,929,300	$2,181,948	$1,876,929	$2,048,752	$2,382,554	**$27,716,478**
Comfit	$2,870	$1,439	$1,729	$1,630	$1,443	$1,296	$1,381	$1,744	$1,568	$1,518	$2,278	$1,843	**$20,739**
Total	**$1,915,158**	**$2,287,489**	**$2,871,492**	**$2,879,353**	**$2,708,649**	**$2,537,816**	**$2,108,826**	**$1,931,044**	**$2,183,516**	**$1,878,447**	**$2,051,030**	**$2,384,397**	**$27,737,217**
Wind NRIS													
IPP	$10,554,584	$11,025,307	$12,646,368	$11,336,003	$9,731,713	$8,062,396	$7,371,600	$7,047,619	$8,572,620	$8,632,744	$11,831,470	$12,041,520	**$118,853,943**
Comfit	$5,614,353	$5,845,565	$7,184,191	$6,103,011	$5,485,641	$4,534,886	$3,924,560	$3,524,955	$4,595,517	$3,778,557	$6,622,536	$6,783,993	**$63,997,765**
Total	**$16,168,937**	**$16,870,872**	**$19,830,559**	**$17,439,014**	**$15,217,354**	**$12,597,282**	**$11,296,159**	**$10,572,574**	**$13,168,138**	**$12,411,302**	**$18,454,006**	**$18,825,513**	**$182,851,708**
Wind ERIS													
IPP	$2,609,660	$3,258,459	$3,627,090	$2,521,417	$2,850,490	$2,534,080	$2,191,956	$1,916,096	$2,250,818	$2,157,931	$3,711,916	$3,788,118	**$33,418,031**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$2,609,660**	**$3,258,459**	**$3,627,090**	**$2,521,417**	**$2,850,490**	**$2,534,080**	**$2,191,956**	**$1,916,096**	**$2,250,818**	**$2,157,931**	**$3,711,916**	**$3,788,118**	**$33,418,031**
Grand Total	**$41,340,627**	**$43,985,444**	**$46,241,001**	**$46,576,589**	**$61,899,803**	**$40,151,171**	**$41,368,405**	**$38,669,878**	**$40,867,359**	**$40,677,295**	**$66,950,683**	**$48,428,142**	**$557,156,397**
Plant Fuel Costs													
Plant Fuel Costs	$57,665,346	$47,414,297	$37,738,955	$19,947,552	$17,809,534	$19,048,134	$26,258,615	$29,457,627	$17,973,072	$21,352,621	$29,524,181	$41,904,360	**$366,094,293**
BTL Class Fuel-related costs													
GRLF	[redacted]												
1P - RTP													
PHP	$3,979,629	$3,736,003	$4,015,761	$3,736,955	$3,359,461	$2,879,821	$2,514,570	$2,399,998	$2,907,972	$3,424,494	$3,880,102	$3,979,638	**$40,814,403**
Shore Power	[redacted]												
Total	$4,872,867	$4,525,474	$4,474,415	$4,646,192	$4,401,021	$4,174,893	$4,042,371	$4,377,111	$4,461,152	$4,537,700	$4,796,904	$5,059,546	**$54,369,645**
ATL-related Fuel costs (net of BTL without BUTU)	$52,792,479	$42,888,823	$33,264,540	$15,301,360	$13,408,513	$14,873,241	$22,216,244	$25,080,517	$13,511,920	$16,814,922	$24,727,276	$36,844,814	**$311,724,648**
Fuel costs before PP													
Domestic	$31,648,650	$26,072,293	$19,116,568	$8,383,302	$6,677,255	$6,560,766	$9,702,698	$11,071,519	$5,710,044	$7,700,970	$12,805,373	$22,150,285	$167,599,722
Small General	$1,956,200	$1,598,492	$1,214,453	$535,097	$482,893	$541,954	$816,882	$913,454	$484,688	$582,601	$870,153	$1,292,601	$11,289,468
General	$10,755,943	$8,611,485	$6,940,191	$3,144,350	$2,881,263	$3,586,577	$5,326,867	$5,999,809	$3,261,443	$3,958,183	$5,508,865	$7,363,994	$67,338,968
Large General	$1,405,698	$1,177,447	$945,452	$509,020	$503,334	$635,650	$1,025,073	$1,128,722	$637,918	$691,696	$827,123	$1,012,632	$10,499,765
Small Industrial	$1,181,052	$931,836	$734,438	$370,568	$378,059	$507,604	$683,603	$697,508	$382,883	$430,563	$621,104	$876,512	$7,795,729
Medium Industrial	$1,719,954	$1,377,309	$1,156,752	$607,763	$640,046	$813,963	$1,099,816	$1,164,950	$688,088	$789,012	$1,069,513	$1,243,875	$12,371,041
Large Industrial	$2,699,038	$2,142,451	$1,719,153	$984,230	$1,059,433	$1,276,156	$1,743,948	$2,166,735	$1,208,695	$1,392,715	$1,736,803	$1,846,494	$19,975,851
PHP	$200,714	$0	$735,152	$426,171	$507,389	$618,533	$1,302,081	$1,342,978	$783,448	$875,705	$696,319	$248,876	$7,737,367
Municipal	$806,016	$623,171	$453,451	$182,432	$110,008	$124,058	$217,968	$236,279	$144,788	$198,675	$338,381	$502,927	$3,938,155
Unmetered	[redacted]												
BUTU													
Total	**$52,792,479**	**$42,888,823**	**$33,264,540**	**$15,301,360**	**$13,408,513**	**$14,873,241**	**$22,216,244**	**$25,080,517**	**$13,511,920**	**$16,814,922**	**$24,727,276**	**$36,844,814**	**$311,724,648**
Exports													
Domestic	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Small General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Small Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Medium Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PHP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unmetered	[redacted]												
BUTU													
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Imports													
Domestic	$2,844,905	$3,720,970	$2,485,555	$5,363,795	$3,145,772	$3,116,182	$4,305,304	$3,636,817	$3,277,361	$4,705,945	$3,991,573	$4,673,907	$45,268,087
Small General	$175,843	$228,133	$157,904	$342,365	$227,499	$257,413	$362,469	$300,055	$278,194	$356,019	$271,236	$272,750	$3,229,880
General	$966,854	$1,229,009	$902,371	$2,011,815	$1,357,414	$1,703,524	$2,363,650	$1,970,841	$1,871,952	$2,418,785	$1,717,173	$1,553,868	$20,067,255
Large General	$126,359	$168,042	$122,929	$325,680	$237,129	$301,916	$454,848	$370,767	$366,142	$422,685	$257,823	$213,674	$3,367,995
Small Industrial	$106,165	$132,989	$95,492	$237,097	$178,110	$241,098	$303,330	$229,120	$219,761	$263,110	$193,605	$184,952	$2,384,829
Medium Industrial	$154,607	$196,566	$150,402	$388,858	$301,537	$386,610	$488,013	$382,668	$394,938	$482,153	$333,379	$262,469	$3,922,199
Large Industrial	$242,617	$305,765	$223,526	$629,729	$499,118	$606,139	$773,829	$711,738	$693,748	$851,067	$541,380	$389,627	$6,468,281
PHP	$18,042	$0	$95,585	$272,672	$239,040	$293,786	$577,763	$441,147	$449,671	$535,130	$217,050	$52,515	$3,192,401
Municipal	$72,453	$88,937	$58,958	$116,724	$51,827	$58,924	$96,717	$77,614	$83,103	$121,407	$105,477	$106,122	$1,038,264
Unmetered	[redacted]												
BUTU													
Total	$4,745,529	$6,120,982	$4,325,089	$9,790,100	$6,316,986	$7,064,377	$9,857,844	$8,238,549	$7,755,359	$10,275,341	$7,707,758	$7,774,583	$89,972,498
Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	11,818,708	11,899,369	16,036,280	16,865,484	13,090,652	418,181	13,303,650	14,132,701	139,481,654
Relative Share	11.5%	8.9%	9.3%	0.3%	8.5%	8.5%	11.5%	12.1%	9.4%	0.3%	9.5%	10.1%	100.0%
Bio-fuel Apportioned	$1,030,203	$798,265	$832,610	$22,570	$756,675	$761,839	$1,026,698	$1,079,787	$838,109	$26,773	$851,746	$904,825	$8,930,099
Domestic	$617,598	$485,269	$478,487	$12,366	$376,814	$336,056	$448,399	$476,660	$354,179	$12,262	$441,089	$543,960	$4,583,138
Small General	$38,174	$29,752	$30,398	$789	$27,251	$27,760	$37,751	$39,327	$30,064	$928	$29,973	$31,743	$323,909
General	$209,894	$160,281	$173,713	$4,638	$162,597	$183,712	$246,175	$258,309	$202,299	$6,302	$189,756	$180,843	$1,978,517
Large General	$27,431	$21,915	$23,665	$751	$28,404	$32,559	$47,373	$48,595	$39,568	$1,101	$28,491	$24,868	$324,721
Small Industrial	$23,047	$17,344	$18,383	$547	$21,335	$26,001	$31,592	$30,030	$23,749	$686	$21,394	$21,525	$235,632
Medium Industrial	$33,564	$25,635	$28,953	$896	$36,119	$41,693	$50,827	$50,154	$42,680	$1,256	$36,840	$30,547	$379,165
Large Industrial	$52,670	$39,876	$43,030	$1,452	$59,786	$65,367	$80,595	$93,284	$74,972	$2,218	$59,825	$45,346	$618,421
PHP	$3,917	$0	$18,401	$629	$28,633	$31,683	$60,174	$57,819	$48,595	$1,394	$23,985	$6,112	$281,342
Municipal	$15,729	$11,599	$11,350	$269	$6,208	$6,354	$10,073	$10,172	$8,981	$316	$11,656	$12,351	$105,058
Unmetered	[redacted]												
BUTU													
Total	**$1,030,203**	**$798,265**	**$832,610**	**$22,570**	**$756,675**	**$761,839**	**$1,026,698**	**$1,079,787**	**$838,109**	**$26,773**	**$851,746**	**$904,825**	**$8,930,099**
Domestic	$35,111,152	$30,278,531	$22,080,610	$13,759,463	$10,199,841	$10,013,004	$14,456,401	$15,184,996	$9,341,584	$12,419,177	$17,238,035	$27,368,153	$217,450,947
Small General	$2,170,217	$1,856,377	$1,402,755	$878,251	$737,643	$827,127	$1,217,102	$1,252,836	$792,946	$939,547	$1,171,362	$1,597,095	$14,843,258
General	$11,932,691	$10,000,775	$8,016,274	$5,160,803	$4,401,273	$5,473,813	$7,936,692	$8,228,958	$5,335,694	$6,383,270	$7,415,794	$9,098,704	$89,384,740
Large General	$1,559,488	$1,367,404	$1,092,045	$835,451	$768,867	$970,126	$1,527,294	$1,548,084	$1,043,628	$1,115,481	$1,113,437	$1,251,174	$14,192,480
Small Industrial	$1,310,265	$1,082,168	$848,314	$608,212	$577,503	$774,702	$1,018,524	$956,658	$626,394	$694,358	$836,103	$1,082,989	$10,416,189
Medium Industrial	$1,908,125	$1,599,511	$1,336,107	$997,517	$977,702	$1,242,265	$1,638,656	$1,597,772	$1,125,706	$1,272,421	$1,439,732	$1,536,891	$16,672,405
Large Industrial	$2,994,325	$2,488,092	$1,985,709	$1,615,410	$1,618,337	$1,947,662	$2,598,372	$2,971,757	$1,977,415	$2,245,999	$2,338,009	$2,281,466	$27,062,553
PHP	$222,673	$0	$849,138	$699,472	$775,062	$944,001	$1,940,018	$1,841,944	$1,281,714	$1,412,229	$937,354	$307,503	$11,211,110
Municipal	$894,198	$723,707	$523,759	$299,425	$168,043	$189,336	$324,759	$324,065	$236,872	$320,399	$455,513	$621,400	$5,081,477
Unmetered	[redacted]												
BUTU													
Total	**$58,568,211**	**$49,808,070**	**$38,422,240**	**$25,114,030**	**$20,482,174**	**$22,699,456**	**$33,100,786**	**$34,398,853**	**$22,105,387**	**$27,117,036**	**$33,286,781**	**$45,524,222**	**$410,627,245**
Domestic	5.42	4.99	3.86	3.12	2.85	3.46	4.57	4.77	3.42	3.83	4.02	4.56	4.20
Small General	5.42	4.99	3.86	3.12	2.85	3.46	4.57	4.77	3.42	3.82	4.02	4.56	4.17
General	5.41	4.97	3.85	3.11	2.84	3.45	4.56	4.76	3.41	3.81	4.01	4.55	4.13
Large General	5.26	4.84	3.74	3.03	2.77	3.37	4.45	4.65	3.33	3.72	3.90	4.43	3.97
Small Industrial	5.40	4.97	3.84	3.10	2.84	3.45	4.55	4.75	3.40	3.81	4.00	4.54	4.09
Medium Industrial	5.35	4.92	3.80	3.08	2.82	3.42	4.52	4.72	3.38	3.77	3.96	4.50	4.02
Large Industrial	5.18	4.77	3.68	2.98	2.73	3.32	4.39	4.59	3.28	3.67	3.84	4.37	3.90
PHP	5.12	#DIV/0!	3.64	2.95	2.70	3.28	4.34	4.54	3.24	3.63	3.80	4.32	3.68
Municipal	5.16	4.75	3.67	2.98	2.72	3.31	4.37	4.57	3.27	3.65	3.83	4.35	4.05
Unmetered	[redacted]												
BUTU													
Total	**5.40**	**4.97**	**3.84**	**3.10**	**2.84**	**3.45**	**4.55**	**4.76**	**3.40**	**3.80**	**3.99**	**4.55**	**4.14**
Maritime Link	$7,050,291	$7,050,291	$7,050,291	$7,050,291	$17,114,394	$7,050,291	$7,050,291	$7,050,291	$7,050,291	$7,050,291	$17,114,394	$7,050,291	$104,731,700
Energy													
Domestic	$4,285,901	$4,051,683	$3,862,710	$3,510,948	$7,549,365	$3,079,136	$3,112,274	$2,979,404	$3,228,923	$3,651,094	$10,288,794	$3,695,137	$53,295,370
Small General	$262,769	$257,399	$246,552	$253,909	$623,617	$259,236	$256,778	$252,902	$244,277	$248,100	$600,412	$254,252	$3,760,204
General	$1,415,601	$1,470,947	$1,448,798	$1,514,988	$4,127,015	$1,690,473	$1,686,584	$1,701,766	$1,659,618	$1,570,699	$3,420,571	$1,540,415	$23,247,475
Large General	$193,555	$200,385	$234,537	$264,656	$731,432	$325,305	$317,291	$332,855	$290,019	$235,831	$470,367	$247,367	$3,843,601
Small Industrial	$153,180	$155,661	$170,744	$198,786	$584,091	$216,940	$196,074	$199,782	$180,530	$177,090	$407,139	$180,689	$2,820,707
Medium Industrial	$226,409	$245,169	$280,034	$336,541	$936,613	$349,025	$327,475	$359,032	$330,823	$304,942	$577,779	$291,741	$4,565,584
Large Industrial	$352,187	$364,368	$453,496	$557,057	$1,468,452	$553,439	$609,083	$630,677	$583,948	$495,201	$857,695	$474,341	$7,399,944
PHP	$0	$155,813	$196,364	$266,789	$711,736	$413,214	$377,520	$408,790	$367,172	$198,536	$115,603	$205,396	$3,416,930
Municipal	$102,440	$96,107	$84,058	$57,843	$142,751	$69,172	$66,420	$75,548	$83,302	$96,480	$233,609	$85,464	$1,193,194
Unmetered	$44,809	$45,024	$54,775	$64,899	$167,262	$62,628	$60,199	$73,271	$60,659	$59,218	$104,401	$54,931	$852,075
BUTU	$13,439	$7,736	$18,222	$23,876	$72,060	$31,721	$40,595	$36,264	$21,019	$13,102	$38,023	$20,559	$336,616
Total	**$7,050,291**	**$7,050,291**	**$7,050,291**	**$7,050,291**	**$17,114,394**	**$7,050,291**	**$7,050,291**	**$7,050,291**	**$7,050,291**	**$7,050,291**	**$17,114,394**	**$7,050,291**	**$104,731,700**
BIOMASS	$654,243.31	$539,350.66	$593,637.56	$163,612.69	$526,263.03	$542,666.69	$662,418.59	$685,684.74	$550,770.49	$165,356.29	$590,805.11	$591,848.15	$6,266,657
Energy													
Domestic	$397,717	$309,956	$325,242	$81,477	$232,141	$237,004	$292,417	$289,766	$252,244	$85,632	$355,179	$310,194	$3,168,969
Small General	$24,384	$19,691	$20,760	$5,892	$19,176	$19,954	$24,126	$24,596	$19,083	$5,819	$20,727	$21,344	$225,552
General	$131,363	$112,528	$121,989	$35,158	$126,905	$130,117	$158,465	$165,507	$129,650	$36,839	$118,081	$129,313	$1,395,915
Large General	$17,961	$15,330	$19,748	$6,142	$22,491	$25,039	$29,811	$32,372	$22,656	$5,531	$16,238	$20,766	$234,085
Small Industrial	$14,215	$11,908	$14,377	$4,613	$17,961	$16,698	$18,422	$19,430	$14,103	$4,153	$14,055	$15,168	$165,103
Medium Industrial	$21,010	$18,756	$23,579	$7,810	$28,801	$26,865	$30,768	$34,918	$25,844	$7,152	$19,945	$24,491	$269,938
Large Industrial	$32,682	$27,874	$38,185	$12,927	$45,154	$42,599	$57,227	$61,337	$45,618	$11,614	$29,608	$39,819	$444,646
PHP	$0	$11,920	$16,534	$6,191	$21,886	$31,805	$35,470	$39,757	$28,684	$4,656	$3,991	$17,242	$218,137
Municipal	$9,506	$7,352	$7,078	$1,342	$4,390	$5,324	$6,241	$7,348	$6,508	$2,263	$8,064	$7,174	$72,589
Unmetered	$4,158	$3,444	$4,612	$1,506	$5,143	$4,821	$5,656	$7,126	$4,739	$1,389	$3,604	$4,611	$50,809
BUTU	$1,247	$592	$1,534	$554	$2,216	$2,442	$3,814	$3,527	$1,642	$307	$1,313	$1,726	$20,914
Total	**$654,243**	**$539,351**	**$593,638**	**$163,613**	**$526,263**	**$542,667**	**$662,419**	**$685,685**	**$550,770**	**$165,356**	**$590,805**	**$591,848**	**$6,266,657**
Regular other than biomass and win	$992,216.96	$1,185,116.93	$1,487,680.83	$1,491,753.30	$1,403,314.09	$1,314,807.56	$1,092,554.10	$1,000,447.38	$1,131,249.49	$973,197.59	$1,062,610.60	$1,235,323.41	$14,370,272
Energy													
Domestic	$603,173	$681,067	$815,070	$742,873	$619,019	$574,228	$482,296	$422,782	$518,095	$503,984	$638,818	$647,447	$7,248,850
Small General	$36,981	$43,267	$52,025	$53,724	$51,134	$48,345	$39,792	$35,887	$39,195	$34,247	$37,279	$44,549	$516,425
General	$199,224	$247,258	$305,711	$320,553	$338,399	$315,256	$261,363	$241,483	$266,293	$216,814	$212,379	$269,905	$3,194,637
Large General	$27,240	$33,684	$49,490	$55,998	$59,975	$60,666	$49,169	$47,233	$46,535	$32,553	$29,204	$43,343	$535,089
Small Industrial	$21,558	$26,166	$36,029	$42,061	$47,893	$40,457	$30,385	$28,349	$28,967	$24,445	$25,279	$31,660	$383,247
Medium Industrial	$31,864	$41,212	$59,090	$71,208	$76,799	$65,090	$50,747	$50,947	$53,082	$42,093	$35,874	$51,118	$629,122
Large Industrial	$49,565	$61,248	$95,692	$117,866	$120,407	$103,211	$94,387	$89,494	$93,697	$68,356	$53,253	$83,112	$1,030,289
PHP	$0	$26,191	$41,435	$56,449	$58,360	$77,060	$58,503	$58,008	$58,914	$27,405	$7,178	$35,989	$505,491
Municipal	$14,417	$16,155	$17,737	$12,239	$11,705	$12,900	$10,293	$10,720	$13,366	$13,318	$14,505	$14,975	$162,329
Unmetered	$6,306	$7,568	$11,558	$13,732	$13,715	$11,680	$9,329	$10,397	$9,733	$8,174	$6,482	$9,625	$118,299
BUTU	$1,891	$1,300	$3,845	$5,052	$5,909	$5,916	$6,291	$5,146	$3,373	$1,808	$2,361	$3,602	$46,494
Total	**$992,217**	**$1,185,117**	**$1,487,681**	**$1,491,753**	**$1,403,314**	**$1,314,808**	**$1,092,554**	**$1,000,447**	**$1,131,249**	**$973,198**	**$1,062,611**	**$1,235,323**	**$14,370,272**
Wind NRIS	$8,376,904.94	$8,740,567.67	$10,273,941.07	$9,034,914.30	$7,883,902.74	$6,526,479.48	$5,852,385.49	$5,477,505.78	$6,822,231.80	$6,430,125.40	$9,560,767.84	$9,753,240.37	$94,732,967
Energy													
Domestic	$5,092,355	$5,023,056	$5,628,882	$4,499,263	$3,477,685	$2,850,367	$2,583,471	$2,314,756	$3,124,475	$3,329,932	$5,747,722	$5,111,783	$48,783,748
Small General	$312,212	$319,109	$359,285	$325,383	$287,275	$239,976	$213,149	$196,484	$236,376	$226,276	$335,414	$351,728	$3,402,667
General	$1,681,967	$1,823,600	$2,111,242	$1,941,450	$1,901,147	$1,564,877	$1,400,019	$1,322,134	$1,605,933	$1,432,535	$1,910,864	$2,130,982	$20,826,750
Large General	$229,975	$248,426	$341,776	$339,156	$336,941	$301,136	$263,380	$258,601	$280,638	$215,086	$262,765	$342,202	$3,420,084
Small Industrial	$182,003	$192,981	$248,814	$254,743	$269,067	$200,822	$162,759	$155,214	$174,690	$161,513	$227,444	$249,962	$2,480,013
Medium Industrial	$269,012	$303,947	$408,076	$431,275	$431,460	$323,094	$271,834	$278,939	$320,122	$278,118	$322,770	$403,589	$4,042,235
Large Industrial	$418,457	$451,723	$660,851	$713,866	$676,456	$512,321	$505,594	$489,985	$565,059	$451,641	$479,142	$656,194	$6,581,289
PHP	$0	$193,168	$286,148	$341,888	$327,868	$382,513	$313,376	$317,597	$355,295	$181,072	$64,580	$284,140	$3,047,646
Municipal	$121,716	$119,149	$122,492	$74,126	$65,760	$64,033	$55,134	$58,695	$80,608	$87,993	$130,503	$118,229	$1,098,436
Unmetered	$53,241	$55,818	$79,820	$83,167	$77,051	$57,975	$49,971	$56,925	$58,697	$54,009	$58,322	$75,990	$760,986
BUTU	$15,968	$9,591	$26,554	$30,596	$33,195	$29,365	$33,697	$28,175	$20,339	$11,949	$21,241	$28,441	$289,111
Total	**$8,376,905**	**$8,740,568**	**$10,273,941**	**$9,034,914**	**$7,883,903**	**$6,526,479**	**$5,852,385**	**$5,477,506**	**$6,822,232**	**$6,430,125**	**$9,560,768**	**$9,753,240**	**$94,732,967**
Wind ERIS	$1,352,029.12	$1,688,163.00	$1,879,145.67	$1,306,311.63	$1,476,799.85	$1,312,872.16	$1,135,622.40	$992,703.11	$1,166,117.99	$1,117,994.51	$1,923,092.86	$1,962,572.08	$17,313,424
Energy													
Domestic	$821,904	$970,159	$1,029,545	$650,525	$651,434	$573,382	$501,308	$419,509	$534,064	$578,969	$1,156,121	$1,028,606	$8,915,528
Small General	$50,391	$61,633	$65,715	$47,045	$53,812	$48,274	$41,360	$35,609	$40,403	$39,342	$67,467	$70,776	$621,827
General	$271,469	$352,212	$386,155	$280,704	$356,120	$314,792	$271,666	$239,614	$274,501	$249,072	$384,359	$428,802	$3,809,465
Large General	$37,118	$47,981	$62,512	$49,037	$63,115	$60,577	$51,107	$46,867	$47,969	$37,397	$52,854	$68,859	$625,393
Small Industrial	$29,375	$37,272	$45,509	$36,832	$50,401	$40,398	$31,583	$28,130	$29,860	$28,082	$45,749	$50,298	$453,489
Medium Industrial	$43,418	$58,705	$74,639	$62,356	$80,820	$64,994	$52,748	$50,553	$54,718	$48,356	$64,923	$81,211	$737,441
Large Industrial	$67,539	$87,246	$120,872	$103,214	$126,713	$103,059	$98,108	$88,801	$96,585	$78,526	$96,377	$132,041	$1,199,081
PHP	$0	$37,309	$52,338	$49,432	$61,416	$76,947	$60,809	$57,559	$60,730	$31,483	$12,990	$57,175	$558,187
Municipal	$19,645	$23,012	$22,404	$10,717	$12,318	$12,881	$10,698	$10,637	$13,778	$15,299	$26,250	$23,790	$201,432
Unmetered	$8,593	$10,781	$14,599	$12,025	$14,433	$11,662	$9,697	$10,317	$10,033	$9,390	$11,731	$15,291	$138,552
BUTU	$2,577	$1,852	$4,857	$4,424	$6,218	$5,907	$6,539	$5,106	$3,477	$2,078	$4,272	$5,723	$53,030
Total	**$1,352,029**	**$1,688,163**	**$1,879,146**	**$1,306,312**	**$1,476,800**	**$1,312,872**	**$1,135,622**	**$992,703**	**$1,166,118**	**$1,117,995**	**$1,923,093**	**$1,962,572**	**$17,313,424**

Monthly Energy Allocators

Rate Class	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
kWh requirements													
ATL													
Domestic Total	703,364,192	658,966,637	621,859,856	477,310,981	386,030,904	312,074,064	340,348,944	341,337,631	294,471,755	350,550,933	465,593,287	649,442,487	5,601,351,669
Small General	43,474,868	40,401,246	39,506,010	30,466,221	27,917,411	25,778,958	28,654,396	28,162,017	24,995,770	26,520,209	31,638,087	37,898,840	385,414,032
General	239,041,633	217,651,798	225,763,643	179,026,472	166,573,907	170,601,654	186,854,579	184,975,557	168,195,353	180,177,917	200,297,987	215,911,001	2,335,071,503
Large General	31,240,447	29,759,497	30,755,445	28,981,505	29,099,129	30,235,793	35,957,274	34,798,787	32,897,964	31,486,231	30,073,533	29,690,186	374,975,792
Small Industrial	26,247,876	23,551,766	23,891,198	21,098,646	21,856,626	24,145,035	23,979,255	21,504,341	19,745,607	19,599,367	22,582,840	25,699,179	273,901,737
Medium Industrial	38,224,517	34,810,937	37,629,007	34,603,519	37,002,859	38,717,523	38,579,100	35,915,695	35,485,255	35,916,108	38,886,660	36,470,208	442,241,388
Large Industrial	59,983,811	54,149,586	55,923,847	56,038,010	61,248,809	60,702,539	61,173,808	66,800,979	62,333,417	63,396,889	63,148,792	54,138,885	719,039,371
PHP	4,460,705	0	23,914,417	24,264,437	29,333,583	29,421,577	45,674,101	41,404,350	40,403,072	39,862,407	25,317,601	7,297,002	311,353,251
Municipal	17,913,015	15,750,383	14,750,720	10,386,959	6,359,874	5,901,015	7,645,845	7,284,541	7,466,849	9,043,776	12,303,250	14,745,745	129,551,972
Unmetered													
BUTU													
Total	1,173,267,727	1,083,997,632	1,082,091,857	871,196,951	775,183,877	707,471,169	779,296,159	773,238,437	696,821,031	765,421,294	899,064,291	1,080,283,496	10,687,333,921
Fuel Cost Allocators													
ATL													
Domestic	59.95%	60.79%	57.47%	54.79%	49.80%	44.11%	43.67%	44.14%	42.26%	45.80%	51.79%	60.12%	52.41%
Small General	3.71%	3.73%	3.65%	3.50%	3.60%	3.64%	3.68%	3.64%	3.59%	3.46%	3.52%	3.51%	3.61%
General	20.37%	20.08%	20.86%	20.55%	21.49%	24.11%	23.98%	23.92%	24.14%	23.54%	22.28%	19.99%	21.85%
Large General	2.66%	2.75%	2.84%	3.33%	3.75%	4.27%	4.61%	4.50%	4.72%	4.11%	3.34%	2.75%	3.51%
Small Industrial	2.24%	2.17%	2.21%	2.42%	2.82%	3.41%	3.08%	2.78%	2.83%	2.56%	2.51%	2.38%	2.56%
Medium Industrial	3.26%	3.21%	3.48%	3.97%	4.77%	5.47%	4.95%	4.64%	5.09%	4.69%	4.33%	3.38%	4.14%
Large Industrial	5.11%	5.00%	5.17%	6.43%	7.90%	8.58%	7.85%	8.64%	8.95%	8.28%	7.02%	5.01%	6.73%
PHP	0.38%	0.00%	2.21%	2.79%	3.78%	4.16%	5.86%	5.35%	5.80%	5.21%	2.82%	0.68%	2.91%
Municipal	1.53%	1.45%	1.36%	1.19%	0.82%	0.83%	0.98%	0.94%	1.07%	1.18%	1.37%	1.36%	1.21%
Unmetered													
BUTU													
Total	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

BUTU Capacity Credit Calc.

	Installed Capacity	Capacity Credit	Approved Contract Demands (kWs)	FAM-related Demand Charge	Gross Demand Payment	Net Demand payment bfr Credits	Capacity Credit
Ellershouse	23,500	20.54%	7,549	$8.142	[redacted]		
Imports	[redacted]	0%	[redacted]	$8.142			
Total							-$392,997

Biomass Calculations

($ in millions)	2027	
Capital	[redacted]	[redacted]
Fuel		
Operating		
Total	54.6	100.0%

Data from M05473 Exhibit N-3 CA IR-065P Confidential from the COSS Proceeding

Annual Peak of ATL	2,347,983
Annual Energy Requirement of ATL	10,656,168,727

System Coincident Load Factor **51.81%**

Rate Base	**Average**	**2026**	**2027**
Steam Plant	$ 458,622	$ 419,903	$ 497,342
Steam Plant - CWIP	$ 4,174	$ 4,374	$ 3,974
Steam Environmental & Fuel Conversion	$ 343,930	$ 352,418	$ 335,442
Steam Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Hydro Plant	$ 703,062	$ 685,374	$ 720,751
Hydro Plant - CWIP	$ 38,477	$ 33,823	$ 43,131
Hydro Environmental & Fuel Conversion	$ 10,863	$ 10,884	$ 10,842
Hydro Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Wind Plant	$ 153,668	$ 158,510	$ 148,826
Wind Plant - CWIP	$ 196	$ 196	$ 196
Gas Turbine Plant	$ 77,087	$ 76,069	$ 78,105
Gas Turbine Plant - CWIP	$ 2,431	$ 692	$ 4,171
Gas Environmental & Fuel Conversion	$ -	$ -	$ -
Gas Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
LM6000 Plant	$ 96,186	$ 92,802	$ 99,569
LM6000 Plant - CWIP	$ 186	$ 60	$ 312
LM6000 Environmental & Fuel Conversion	$ -	$ -	$ -
LM6000 Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
ECEI Batteries Plant	$ 166,178	$ 171,846	$ 160,511
ECEI Batteries CWIP	$ (0)	$ (0)	$ (0)
Generation-related Trans Assets Plant	$ 60,407	$ 58,575	$ 62,240
Generation-related Trans Assets CWIP	$ -	$ -	$ -
Total Generation	**$ 1,888,883**	**$ 2,065,526**	**$ 2,165,412**
DISTRIBUTION	$ 34,037	$ 37,483	$ 30,590
TRANSMISSION	$ 2,509	$ 2,708	$ 2,311
DISTRIBUTION/ TRANSMISSION COMMUNICATION	$ 39,282	$ 37,252	$ 41,312
DISTRIBUTION/ TRANSMISSION NON-COMMUNICATION	$ 59,565	$ 54,831	$ 64,298
RETAIL	$ 36,737	$ 39,858	$ 33,616
NON-FUNCTIONALIZED	$ 297,058	$ 297,891	$ 296,226
General Property Plant	$ 469,187	$ 470,022	$ 468,353
General Property Plant - CWIP	$ 29,234	$ 19,601	$ 38,868
Total General Plant	**$ 498,422**	**$ 489,623**	**$ 507,221**

Total System Plant in Service	$ 4,802,854
Direct Plant in Service (Solar)	$ 1,224

Generation Rate Base		**Initial Classification**			**Further Classification**			**Fully Classified**		
	Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$ 806,726	$ 806,726	$ -	$ -	$ (417,954)	$ 417,954	$ -	$ 388,772	$ 417,954	$ -
Hydro Plant	$ 752,403	$ 752,403	$ -	$ -	$ (389,810)	$ 389,810	$ -	$ 362,593	$ 389,810	$ -
Wind Plant	$ 153,864	$ 153,864	$ -	$ -	$ (79,715)	$ 79,715	$ -	$ 74,149	$ 79,715	$ -
LM6000 Plant	$ 96,372	$ 96,372	$ -	$ -	$ (49,929)	$ 49,929	$ -	$ 46,443	$ 49,929	$ -
Gas Turbine Plant - Other	$ 79,518	$ 79,518	$ -	$ -	$ (41,197)	$ 41,197	$ -	$ 38,321	$ 41,197	$ -
Generation Batteries	$ 166,178	$ 166,178	$ -	$ -	$ (86,095)	$ 86,095	$ -	$ 80,084	$ 86,095	$ -
Radial to Generation Transmission	$ 60,407	$ 60,407	$ -	$ -	$ (31,296)	$ 31,296	$ -	$ 29,111	$ 31,296	$ -
Total Generation Plant	$ 2,115,469	$ 2,115,469	$ -	$ -	$ (1,095,995)	$ 1,095,995	$ -	$ 1,019,473	$ 1,095,995	$ -
General Property Plant -generation-related	$ 143,756	$ 143,756	$ -	$ -	$ (74,478)	$ 74,478	$ -	$ 69,278	$ 74,478	$ -
Total Generation Plant in Service	$ 2,259,225	$ 2,259,225	$ -	$ -	$ (1,170,473)	$ 1,170,473	$ -	$ 1,088,751	$ 1,170,473	$ -
Rate Base Factors Applicable to Base Cost of Fuel Classification								**48.191%**	**51.809%**	

Data Inputs

Category	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Annual
Plant Fuel Costs	$57,665,346	$47,414,297	$37,738,955	$19,947,552	$17,809,534	$19,048,134	$26,258,615	$29,457,627	$17,973,072	$21,352,621	$29,524,181	$41,904,360	$366,094,293
Maritime Link													
ML - NS Block	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$202,151,066
ML - Supp Block													
ML - Surplus													
Total	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$202,151,066
Non-Wind Purchases													
Purchased Power Regular bfr Biomass	$1,912,288	$2,286,050	$2,869,763	$2,877,723	$2,707,206	$2,536,520	$2,107,445	$1,929,300	$2,181,948	$1,876,929	$2,048,752	$2,382,554	$27,716,478
Purchased Power - Biomass	$2,017,708	$1,566,665	$1,635,557	$71,916	$1,488,347	$1,501,997	$2,015,967	$2,112,601	$1,631,723	$85,309	$1,675,174	$1,773,613	$17,576,577
Non-Wind Purchases	$3,929,996	$3,852,715	$4,505,320	$2,949,639	$4,195,553	$4,038,517	$4,123,412	$4,041,901	$3,813,671	$1,962,238	$3,723,926	$4,156,167	$45,293,055
Wind Purchases													
Purchased Power Wind - NRIS	$10,554,584	$11,025,307	$12,646,368	$11,336,003	$9,731,713	$8,062,396	$7,371,600	$7,047,619	$8,572,620	$8,632,744	$11,831,470	$12,041,520	$118,853,943
Purchased Power Wind - ERIS	$2,609,660	$3,258,459	$3,627,090	$2,521,417	$2,850,490	$2,534,080	$2,191,956	$1,916,096	$2,250,818	$2,157,931	$3,711,916	$3,788,118	$33,418,031
Purchased Power Wind	$ 13,164,243.69	$ 14,283,765.76	$ 16,273,457.62	$ 13,857,420.27	$ 12,582,203.02	$ 10,596,475.95	$ 9,563,555.70	$ 8,963,714.67	$ 10,823,438.19	$ 10,790,675.36	$ 15,543,386.36	$ 15,829,637.73	$152,271,974
COMFIT													
Wind Generation (NRIS)	$5,614,353	$5,845,565	$7,184,191	$6,103,011	$5,485,641	$4,534,886	$3,924,560	$3,524,955	$4,595,517	$3,778,557	$6,622,536	$6,783,993	$63,997,765
Wind Generation (ERIS)													
Biomass/ Biogas	$ 275,302.28	$272,644	$342,881	$266,456	$284,110	$307,286	$289,319	$290,681	$269,472	$260,632	$316,932	$273,585	$3,449,301
Other	$ 2,869.65	$1,439	$1,729	$1,630	$1,443	$1,296	$1,381	$1,744	$1,568	$1,518	$2,278	$1,843	$20,739
Total Comfit	$ 5,892,525	$ 6,119,648	$ 7,528,801	$ 6,371,096	$ 5,771,194	$ 4,843,468	$ 4,215,260	$ 3,817,380	$ 4,866,557	$ 4,040,707	$ 6,941,746	$ 7,059,421	$67,467,805
Imports	$ 4,745,528.60	$ 6,120,981.79	$ 4,325,089.22	$ 9,790,099.71	$ 6,316,986.14	$ 7,064,376.62	$ 9,857,844.46	$ 8,238,549.38	$ 7,755,358.96	$ 10,275,340.99	$ 7,707,758.44	$ 7,774,583.31	$89,972,498
Export Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0
OM&G (Solid Fuel Handling) recovered in fuels													$0
Foreign Exchange (Fuel-related)													$0
ML - NS Block per Appliation	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$203,880,357
ML - NS Block per NSEB Decision	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$13,608,333	$33,033,866	$13,608,333	$202,151,066
Adjustment	($3,381,696)	($3,381,696)	($3,381,696)	($3,381,696)	$16,043,836	($3,381,696)	($3,381,696)	($3,381,696)	($3,381,696)	($3,381,696)	$16,043,836	($3,381,696)	($1,729,291)
Total FAM related costs	$ 97,778,753	$ 90,259,018	$ 83,192,641	$ 66,106,514	$ 79,556,536	$ 59,027,569	$ 67,293,631	$ 67,837,999	$ 58,597,434	$ 61,642,822	$ 95,870,071	$ 89,460,033	$ 916,623,022
Total FAM related costs with OATT customers	$ 99,005,973	$ 91,399,741	$ 83,979,957	$ 66,524,141	$ 79,709,337	$ 59,199,305	$ 67,627,020	$ 68,127,506	$ 58,840,430	$ 62,029,916	$ 96,474,864	$ 90,332,503	$ 923,250,690
Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	11,818,708	11,899,369	16,036,280	16,865,484	13,090,652	418,181	13,303,650	14,132,701	139,481,654
BLT Fuel Costs bfr BUTU													
GRLF	[redacted]												
1P - RTP													
PHP	$3,979,629	$3,736,003	$4,015,761	$3,736,955	$3,359,461	$2,879,821	$2,514,570	$2,399,998	$2,907,972	$3,424,494	$3,880,102	$3,979,638	$40,814,403
Shore Power	[redacted]												
EBS													
Export													
Total	$4,872,867	$4,525,474	$4,474,415	$4,646,192	$4,401,021	$4,174,893	$4,042,371	$4,377,111	$4,461,152	$4,537,700	$4,796,904	$5,059,546	$54,369,645
NRIS	**$10,554,584**	**$11,025,307**	**$12,646,368**	**$11,336,003**	**$9,731,713**	**$8,062,396**	**$7,371,600**	**$7,047,619**	**$8,572,620**	**$8,632,744**	**$11,831,470**	**$12,041,520**	**$118,853,943**
ERIS	**$2,609,660**	**$3,258,459**	**$3,627,090**	**$2,521,417**	**$2,850,490**	**$2,534,080**	**$2,191,956**	**$1,916,096**	**$2,250,818**	**$2,157,931**	**$3,711,916**	**$3,788,118**	**$33,418,031**
Total	**$13,164,244**	**$14,283,766**	**$16,273,458**	**$13,857,420**	**$12,582,203**	**$10,596,476**	**$9,563,556**	**$8,963,715**	**$10,823,438**	**$10,790,675**	**$15,543,386**	**$15,829,638**	**$152,271,974**

Usage Data

kWh Requirements													
ATL Classes													
Domestic Total	703,364,192	658,966,637	621,859,856	477,310,981	386,030,904	312,074,064	340,348,944	341,337,631	294,471,755	350,550,933	465,593,287	649,442,487	5,601,351,669
Small General	43,474,868	40,401,246	39,506,010	30,466,221	27,917,411	25,778,958	28,654,396	28,162,017	24,995,770	26,520,209	31,638,087	37,898,840	385,414,032
General	239,041,633	217,651,798	225,763,643	179,026,472	166,573,907	170,601,654	186,854,579	184,975,557	168,195,353	180,177,917	200,297,987	215,911,001	2,335,071,503
Large General	31,240,447	29,759,497	30,755,445	28,981,505	29,099,129	30,235,793	35,957,274	34,798,787	32,897,964	31,486,231	30,073,533	29,690,186	374,975,792
Small Industrial	26,247,876	23,551,766	23,891,198	21,098,646	21,856,626	24,145,035	23,979,255	21,504,341	19,745,607	19,599,367	22,582,840	25,699,179	273,901,737
Medium Industrial	38,224,517	34,810,937	37,629,007	34,603,519	37,002,859	38,717,523	38,579,100	35,915,695	35,485,255	35,916,108	38,886,660	36,470,208	442,241,388
Large Industrial- FIRM	24,806,200	22,381,224	21,393,458	16,895,757	13,223,566	12,552,222	14,313,874	13,657,679	14,436,723	15,389,261	19,563,430	21,108,372	209,721,768
Large Industrial- INT	35,177,611	31,768,361	34,530,388	39,142,252	48,025,243	48,150,317	46,859,934	53,143,300	47,896,694	48,007,628	43,585,362	33,030,513	509,317,603
Large Industrial	59,983,811	54,149,586	55,923,847	56,038,010	61,248,809	60,702,539	61,173,808	66,800,979	62,333,417	63,396,889	63,148,792	54,138,885	719,039,371
PHP	4,460,705	-	23,914,417	24,264,437	29,333,583	29,421,577	45,674,101	41,404,350	40,403,072	39,862,407	25,317,601	7,297,002	311,353,251
Municipal	17,913,015	15,750,383	14,750,720	10,386,959	6,359,874	5,901,015	7,645,845	7,284,541	7,466,849	9,043,776	12,303,250	14,745,745	129,551,972
Unmetered	7,156,209	6,889,510	6,910,350	6,768,476	7,135,640	6,914,229	6,922,567	6,602,334	7,241,762	6,585,485	7,551,522	6,589,927	83,268,011
BTL													
BUTU	[redacted]												
GRLF													
1P - RTP													
PHP													
Shore Power													
EBS													
In-Province Total	**1,234,401,922**	**1,141,957,896**	**1,138,665,916**	**929,511,465**	**830,929,069**	**760,275,228**	**830,043,987**	**828,098,063**	**753,863,279**	**823,245,563**	**959,703,243**	**1,143,746,540**	**11,374,442,170**

kWh Sales													
ATL Classes													
Domestic Total	647,252,015	606,636,812	571,951,663	441,222,760	357,512,052	289,155,165	316,020,939	318,115,915	273,118,476	324,643,480	428,795,442	599,861,090	5,174,285,808
Small General	40,025,956	37,210,835	36,353,106	28,175,677	25,866,548	23,896,385	26,617,737	26,256,951	23,193,436	24,571,253	29,151,573	35,021,694	356,341,152
General	220,719,571	201,045,788	208,354,951	166,023,936	154,753,521	158,567,212	174,026,660	172,890,991	156,480,835	167,387,332	185,088,925	200,076,177	2,165,415,899
Large General	29,652,502	28,253,964	29,182,459	27,587,664	27,732,589	28,824,506	34,325,004	33,297,344	31,382,347	30,007,016	28,559,573	28,247,921	357,052,888
Small Industrial	24,278,483	21,792,788	22,087,798	19,598,744	20,338,567	22,477,989	22,368,066	20,129,451	18,399,595	18,237,571	20,904,288	23,854,324	254,467,664
Medium Industrial	35,686,431	32,510,237	35,115,226	32,427,604	34,730,033	36,353,618	36,287,359	33,886,362	33,346,398	33,709,192	36,328,987	34,154,242	414,535,689
Large Industrial- FIRM	23,908,210	21,574,899	20,614,133	16,317,524	12,781,818	12,135,486	13,851,876	13,238,978	13,963,728	14,874,963	18,862,130	20,378,606	202,502,351
Large Industrial- INT	33,904,172	30,623,847	33,272,509	37,802,665	46,420,904	46,551,718	45,347,471	51,514,094	46,327,442	46,403,247	42,022,935	31,888,570	492,079,576
Large Industrial	57,812,382	52,198,746	53,886,642	54,120,189	59,202,722	58,687,204	59,199,347	64,753,072	60,291,170	61,278,210	60,885,065	52,267,177	694,581,928
PHP	4,350,384	-	23,319,217	23,698,010	28,666,097	28,756,648	44,670,450	40,541,133	39,502,420	38,955,260	24,698,470	7,124,729	304,282,817
Municipal	17,322,263	15,231,887	14,257,764	10,060,221	6,172,746	5,728,472	7,423,574	7,085,302	7,246,503	8,775,631	11,906,769	14,291,220	125,502,351
Unmetered	6,585,947	6,343,012	6,356,370	6,257,304	6,609,072	6,407,015	6,428,302	6,153,676	6,717,225	6,099,332	6,955,360	6,087,386	77,000,000
ATL Classes	**1,083,685,933**	**1,001,224,068**	**1,000,865,195**	**809,172,110**	**721,583,947**	**658,854,214**	**727,367,437**	**723,110,196**	**649,678,406**	**713,664,278**	**833,274,452**	**1,000,985,959**	**9,923,466,195**
BTL Classes													
BUTU	[redacted]												
GRLF													
1P - RTP													
PHP	49,265,616	47,174,400	49,717,583	46,266,790	41,596,303	35,659,352	31,140,750	29,721,267	36,011,180	42,404,740	48,040,730	49,265,671	506,264,383
Shore Power	[redacted]												
EBS													
Export kWh Sales													-
Export kWh Losses	-	-	-	-	-	-	-	-	-	-	-	-	-
Export kWh Req.	-	-	-	-	-	-	-	-	-	-	-	-	-
In Province Losses	89,039,553	82,233,842	81,516,562	61,244,106	52,367,636	46,969,148	49,696,938	47,007,936	45,004,073	50,918,565	65,695,981	78,507,958	750,202,298
NSR	**1,234,401,922**	**1,141,957,896**	**1,138,665,916**	**929,511,465**	**830,929,069**	**760,275,228**	**830,043,987**	**828,098,063**	**753,863,279**	**823,245,563**	**959,703,243**	**1,143,746,540**	**11,374,442,170**

Winter kW Peaks	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**3CP**	**Annual Peak**
ATL Classes														
Domestic Total	1,495,207	1,437,837	1,191,699	977,652	750,419	600,757	627,956	703,573	572,585	730,872	1,033,180	1,418,145	4,351,189	1,495,207
Small General	80,028	82,985	70,240	54,238	46,163	47,944	51,444	44,693	48,692	53,480	60,221	67,320	230,332	80,028
General	431,772	422,524	362,219	291,476	257,470	272,629	295,626	268,909	295,996	309,387	354,020	341,104	1,195,401	431,772
Large General	46,933	48,773	46,873	45,631	42,793	55,357	53,815	51,138	54,324	48,535	43,787	41,229	136,936	46,933
Small Industrial	42,168	44,548	36,567	30,414	35,281	32,400	37,221	30,453	31,480	36,756	35,759	38,528	125,244	42,168
Medium Industrial	57,598	48,202	43,515	42,620	47,820	43,956	51,551	39,236	49,363	48,813	51,826	38,642	144,442	57,598
Large Industrial	81,796	88,132	76,845	81,262	89,922	88,865	90,054	85,535	100,746	81,802	97,127	75,564	245,492	81,796
PHP	67,801	67,622	139,488	138,935	138,592	138,065	138,484	138,564	138,526	138,819	139,835	67,846	203,269	67,801
Municipal	31,866	33,064	30,557	21,902	15,612	15,918	16,401	15,238	15,861	22,306	24,619	28,772	93,701	31,866
Unmetered	12,814	4,674	1,794	2,212	2,607	2,389	2,623	2,193	2,272	1,669	19,790	14,870	32,357	12,814
BUTU	7,549	7,549	7,549	7,549	7,549	7,549	7,549	7,549	7,549	7,549	7,549	7,549	22,647	7,549
Total	**2,355,532**	**2,285,911**	**2,007,348**	**1,693,891**	**1,434,228**	**1,305,827**	**1,372,725**	**1,387,080**	**1,317,395**	**1,479,988**	**1,867,714**	**2,139,568**	**6,781,011**	**2,355,532**
Total bfr BUTU														
BTL Classes														
GRLF	[redacted]													
1P - RTP														
PHP														
Shore Power														
EBS														
Total	**68,697**	**78,835**	**77,204**	**60,627**	**53,036**	**66,581**	**56,252**	**57,015**	**57,570**	**63,740**	**64,166**	**70,486**	**218,018**	**68,697**
NSR Peak:	**2,424,228**	**2,364,746**	**2,084,552**	**1,754,518**	**1,487,264**	**1,372,408**	**1,428,977**	**1,444,095**	**1,374,965**	**1,543,728**	**1,931,880**	**2,210,055**	**6,999,029**	**2,424,228**
Marginal Cost	$97.01	$103.96	$77.95	$61.66	$43.83	$53.06	$71.04	$66.43	$52.26	$65.51	$70.86	$84.85	$70.55	
Incremental Cost	$1,227,220	$1,140,723	$787,315	$417,627	$152,801	$171,735	$333,389	$289,507	$242,996	$387,093	$604,793	$872,469	$6,627,669	

OATT LOAD													
Energy Requirement	12,650,834	10,972,924	10,099,740	6,773,483	3,486,028	3,236,378	4,692,951	4,357,960	4,650,067	5,909,317	8,534,484	10,282,055	85,646,221

		$ 80.80											Total
Wind Demand		0%											
PHP wind forecast													
Goose Harbour Lake GWh													
	27-Jan	**27-Feb**	**27-Mar**	**27-Apr**	**27-May**	**27-Jun**	**27-Jul**	**27-Aug**	**27-Sep**	**27-Oct**	**27-Nov**	**27-Dec**	
PHP Energy (GWh)													
Energy Requirement	54.989	48.376	74.919	71.655	71.918	65.924	77.535	71.777	77.257	83.278	74.583	57.767	829.98
Sales	53.616	47.174	73.037	69.965	70.262	64.416	75.811	70.262	75.514	81.360	72.739	56.390	810.55
Goose Harbour Lake Production (GWh)													
Energy Requirement (at generator)	50.5280	49.3252	51.0046	47.3904	42.5841	36.5023	31.8607	30.3728	36.8542	43.4151	49.2651	50.4699	519.57
Line Losses	2.536%	2.524%	2.552%	2.390%	2.328%	2.312%	2.247%	2.129%	2.280%	2.329%	2.507%	2.418%	
Wind Production Net of Losses	49.278	48.111	49.735	46.284	41.615	35.677	31.161	29.740	36.033	42.427	48.060	49.278	507.40
PHP ATL Rate													
Energy Requirement	4.461	-	23.914	24.264	29.334	29.422	45.674	41.404	40.403	39.862	25.318	7.297	311.35
Sales	4.350	-	23.319	23.698	28.666	28.757	44.670	40.541	39.502	38.955	24.698	7.125	304.28
PHP BTL Rate													
Energy Requirement	50.528	48.376	51.005	47.390	42.584	36.502	31.861	30.373	36.854	43.415	49.265	50.470	518.62
Sales	49.27	47.17	49.72	46.27	41.60	35.66	31.14	29.72	36.01	42.40	48.04	49.27	506.26
Spill (at the meter)	0.013	0.937	0.018	0.017	0.019	0.018	0.020	0.018	0.021	0.022	0.020	0.013	1.14
Net Sales	49.28	48.11	49.74	46.28	41.62	35.68	31.16	29.74	36.03	42.43	48.06	49.28	507.40
Fuel Cost													
$ per MWh	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	$ 80.80	
Sales	$3,980.66	$3,811.69	$4,017.18	$3,738.36	$3,360.98	$2,881.28	$2,516.17	$2,401.48	$2,909.70	$3,426.30	$3,881.69	$3,980.67	$40,906.16
Spill (at the meter)	($1.03)	($75.69)	($1.42)	($1.40)	($1.52)	($1.46)	($1.60)	($1.48)	($1.73)	($1.81)	($1.59)	($1.03)	($91.76)
Net Sales	$3,979.63	$3,736.00	$4,015.76	$3,736.95	$3,359.46	$2,879.82	$2,514.57	$2,400.00	$2,907.97	$3,424.49	$3,880.10	$3,979.64	$40,814.40

Check

Energy Requirement	-	-	-	-	-	-	-	-	-	-	-	-	-
Sales	-	-	-	-	-	-	-	-	-	-	-	-	-
Spill													
3CP before the WIND	67,800.70	67,622.24	139,487.90	138,935.34	138,592.23	138,065.28	138,484.28	138,563.93	138,526.19	138,818.96	139,835.19	67,845.87	203,268.80
3 CPS BTL	-	-	-	-	-	-	-	-	-	-	-	-	

ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's Renewable to Retail (RtR) Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities and is independent of the LRS' forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. Where the LRS purchases electricity from customers with Distribution-connected Generation, the LRS' aggregate customer load will include customer imports only (i.e. exclude customer exports to the system) and the aggregate renewable low-impact electricity supplied by the LRS, will include customer exports only. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS' aggregate customer load adjusted by the addition of distribution

losses over the aggregate renewable low-impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low-impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission locational losses, as applicable to the geographic zone in which the generating facility is interconnected, over its aggregate customer load adjusted by the addition of distribution losses. The locational loss values will be published by the NS Power System Operator. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low-impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS' generation portfolio.

(6) Under the Distribution-connected Aggregation Service, the LRS will aggregate its customers' Distribution-connected Generation and use this to serve other RtR Customers. To facilitate this, NS Power will separately track hourly customer imports of electricity and hourly LRS customer exports to the grid. Customer imports will be used to determine NS Power's charges to retail customers under the Distribution Tariff and will serve as an input to the demand and energy amounts applicable to the LRS under the OATT, Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs. Customer exports will be tracked and reported to the LRS to support the LRS' commercial arrangement with the LRS' customer and will serve as an input to the generation amount applicable to the LRS under the Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $67,734 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

(1) Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS' forecasted incremental top-up load.

(2) Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	cents per kWh
Fuel Cost	6.254
Fixed Cost Adder	2.253
Total	**8.507**

The charge is applicable to top-up energy consumed in each hour.

ENERGY CREDIT

6.254 cents per kilowatt-hour.

The Energy Credit for spill service is set annually and is applicable to spilled energy in each hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff, the Standby Service Tariff, the Distribution-connected Aggregation Service Tariff, or the Renewable to Retail Market Transition Tariff.

STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licensed Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

Capacity adequacy service – fulfillment of the LRS' obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.

Top-up capacity service – provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Standby Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by Renewable to Retail (RtR) Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power;

(2) The LRS must be providing service to RtR Customers; and

(3) Under the Distribution-connected Aggregation Service Tariff, the LRS will aggregate its customers' Distribution-connected Generation and use this to serve other RtR Customers. To facilitate this, NS Power will separately track hourly customer imports of electricity and hourly LRS customer exports to the grid. Customer imports will be used to determine NS Power's charges to retail customers under the Distribution Tariff and will serve as an input to demand and energy amounts applicable to the LRS under the OATT, Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs. Customer exports will be tracked and reported to the LRS to support the LRS' commercial arrangement with the LRS' customer and will serve as an input to the generation amounts applicable to the LRS under the Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs.

APPLICABILITY

(1) An LRS taking service under this Standby Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

(4) This service is applicable to firm load only.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $67,734 per month.

DEMAND CHARGE

$6.200 per month, per kilowatt (kW) of monthly standby contract demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$\text{MSCD} = \text{LWPFD} - \textit{min}\ (\textit{LWPFD}, (\Sigma_{ii=1}^{nn}\ \textit{CCi} * \textit{GCi})/(1+\textit{PR}))$$

Where:

- "LWPFD" is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

$$LWPFD = \Sigma_{i=1}^{k}(CMPFDi * CMDAFi)$$

Where:

- "k" is the number of otherwise applicable bundled service rate classes to RtR customers of an LRS.

- "CMPFDi" is hourly kW Class Monthly Peak Firm Demand (CMPFD) of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). Where the LRS purchases electricity from customers with Behind-the-Meter Generation, demand will include customer imports only (i.e. exclude customer exports to the system). The CMPFD for the unmetered customer class shall be determined by use of research-based class load profile data.

- "CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

Classes	**Jan, Feb, Dec**	**Mar, Apr**	**May, Jun**	**Jul, Aug, Sep**	**Oct, Nov**
Domestic	1.00	1.34	2.15	2.29	1.64
Small General	1.00	1.23	1.63	1.59	1.35
General	1.00	1.22	1.50	1.39	1.20
Large General	1.00	0.99	0.93	0.86	0.99
Small Industrial	1.00	1.25	1.23	1.26	1.15
Medium Industrial	1.00	1.12	1.05	1.03	0.96
Large Industrial Firm	1.00	1.04	0.92	0.89	0.91
Unmetered	1.00	1.19	1.98	1.97	1.33

- "PR" is Planning Reserve (%) based on Northeast Power Coordinating Council planning criteria (i.e. 20% or as updated).

- "CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power. For non-dispatchable resources, the capacity contribution factor shall be determined using the Effective Load Carrying Capability (ELCC) methodology as set out in the most recently approved Integrated Resource Plan, or as otherwise updated by the Nova

Scotia Power System Operator (NSPSO) or IESO Nova Scotia. NS Power shall provide the LRS with the applicable ELCC value and the basis for its determination upon request.

- "GCi" is the generator capacity dedicated to serving LRS load. Where the LRS purchases surplus electricity from customers with Distribution-connected Generation, GCi, if applicable to this generation, will include exports only.

- "n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff, Distribution-connected Aggregation Service Tariff, or the Renewable to Retail Market Transition Tariff.

(5) Unless the following can be demonstrated by the LRS to the satisfaction of NS Power, the capacity contribution factor shall be attributed a value of zero in the billing demand calculation of the demand charge:

(i) If the LRS' resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the LRS to NS Power, if directed to do so by the NSPSO, in the event of a resource adequacy need;

(ii) If the LRS' resource is non-dispatchable, that it makes its full output for which it is provided an ELCC value contracted to, but unused by, the LRS available to deliver energy to NS Power, in the event of a resource adequacy need;

(iii) The LRS' resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO;

(iv) Any export transactions utilizing energy from the LRS' resource will be recallable by the NSPSO, up to the amount contracted to the LRS, for delivery to the NS Power system in the event of a resource adequacy need;

(v) The LRS' resource, as applicable, will perform as needed to meet NS Power's reliability requirements; and

(vi) The capacity derived based on the capacity contribution factor is procured and available to the LRS on a minimum three-year forward basis, unless this requirement is waived by NS Power.

(6) In the event of a failure by the LRS' resource, as applicable, to deliver scheduled energy or capacity following a direction to do so by the NSPSO, in accordance with Special Condition (5), then the LRS will be required to make payment to NS Power of an amount equal to the costs incurred by NS Power to procure or to self-supply the undelivered capacity, as applicable, less the charge paid by the LRS to NS Power under this Tariff with respect to any such undelivered capacity, as applicable. If delivery of an LRS' resource, as applicable, is affected by circumstances that are inconsistent with the information and/or documentation provided to NS Power pursuant to Special Condition (5), then NS Power and the LRS shall attempt to negotiate an adjustment to the capacity contribution factor for the LRS' resource as applicable. If NS Power and the LRS are unable to agree on an adjustment to the capacity contribution factor, the matter may be submitted to the Board by either party on an expedited basis for adjudication.

PURPOSE

Pursuant to Section 3G(2) of the *Electricity Act* (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its Renewable to Retail (RtR) Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax, and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Energy Board (NSEB, Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

APPLICABILITY

(1) The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, or the Energy Balancing Service Tariff. A charge under the RTT will only apply to the extent the cumulative amount calculated under the RTT for the calendar year is equal to greater than zero.

(2) The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

(3) Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

(4) The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS' supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

(5) An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

ENERGY CHARGE

The Energy Charge is made up of the following components:

Energy Charge Components	**cents per kWh**
Fixed Cost Adder from Energy Balancing Service Tariff	2.253
Annually Adjusted Energy Savings Credit	0.000
Annual Energy Cost Adjustment	3.812
Total	**6.065**

The Energy Charge is applicable to the LRS' monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

The Demand Charge is made up of two components:

Demand Charge Components	**dollars per kW**
Demand Charge from Standby Service Tariff	$6.200
Annually Adjusted Demand Savings Credit	$0.000
Total	**$6.200**

The Demand Charge is applicable to the LRS' monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff, or the Energy Balancing Service Tariff.

DISTRIBUTION-CONNECTED AGGREGATION SERVICE

The Distribution-connected Aggregation Service (DAS) is provided by NS Power to Licenced Retail Suppliers (LRS) to facilitate the purchase by the LRS of LRS Customer Distribution-connected Generation surplus to LRS' Customer's requirements. The service will support the transport of this electricity between LRS customers across the NS Power grid and will enable identification and accumulation of hourly customer surplus generation (i.e. exports) and LRS Distribution-connected Generation for incorporation of this information within the Standby Service (SS) Tariff, Energy Balancing Service (EBS) Tariff, and Renewable to Retail Market Transition Tariff (RTT).

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This DAS Tariff is applicable to the LRS in order to facilitate the purchase of RtR Customer Distribution-connected Generation by the LRS and the delivery and sale of this generation and LRS Distribution-connected Generation to LRS Customers.

This DAS Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power;

(2) The LRS must be providing service to RtR Customers; and

(3) The purchaser of the LRS' DAS Tariff energy is an NS Power customer under the Distribution Tariff.

APPLICABILITY

(1) An LRS taking service under this DAS Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, the Energy Balancing Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) Under the DAS, the LRS will aggregate its customers' surplus generation and Distribution-connected Generation and use this to serve other LRS customers. To facilitate this, NS Power will separately track hourly customer imports of electricity and hourly LRS customer exports to the grid. Customer imports will be used to determine NS Power's charges to retail customers under the Distribution Tariff and will serve as an input to the demand and energy amounts applicable to the LRS under the OATT, Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs. Customer exports will be tracked and reported to the LRS to support the LRS' commercial arrangement with the RtR Customer and will serve as

an input to the generation amount applicable to the LRS under the Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs.

ADMINISTRATION CHARGE

As a new service offering, the cost of providing this service is uncertain and the applicable regulatory practice remains to be determined. Until reviewed and, if necessary, revised at some point in the future, it is assumed the cost of distribution service associated with DAS is recovered from the LRS' Customer under the applicable Distribution Tariff charges. As result, at least initially, the DAS Tariff charge is limited to an Administration Charge based on the forecast incremental cost for NS Power to provide this service. The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $277.71 per month.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the Administration Charge.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels, and other related conditions.

(4) Nothing contained in this DAS Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and

conditions contained in this DAS Tariff, the Standby Service Tariff, the Energy Balancing Service Tariff, or the Renewable to Retail Market Transition Tariff.

DAS TARIFF REVIEW

In light of the early stages of RtR market development in general and, in particular, Distribution-connected Generation market development following 2028, a review of the operation of this tariff and the broader RtR construct will be undertaken by NS Power and submitted to the Board for its review. If this review identifies the requirement for revision to the DAS Tariff or any other RtR-related tariff, revisions will be proposed for the Board's approval.

If, at any time, NS Power or an LRS determines that the DAS Tariff or related RtR tariffs are not working effectively, the parties shall work together to try to resolve any such concerns. If the parties cannot resolve such concerns, either party may apply to the Board to adjust the DAS Tariff or the related RtR tariffs. If necessary, and to protect customers, the Board may grant such approval on an expedited basis.

2027 AAR Appendix F2
has been filed electronically.

2027 AAR Appendix F3
has been filed electronically.

2027 AAR Appendix F4
has been filed electronically.

2027 AAR Appendix F5
has been filed electronically.

SERVICE DEFINITION

Service under this tariff consists in delivery of supplemental power to partial requirement customers who operate their own dispatchable generation equipment, as approved to be connected to the grid by the Company. The Service has three components.

Generation Replacement Service – backup supply of power on a best efforts basis where the customer's generation equipment is removed from service due to scheduled maintenance, forced outage, or loss of fuel supply.

Optional Load Following Service – energy delivery in respect of imbalance between load and generation where customer's generation falls in any given hour below the lower of the established net operating capability or customer's load. Energy delivery under this service is defined as top-up energy.

Spill Service – hourly generation in excess of the customer's load absorbed by the Company. This excess energy is defined as spilled energy.

Power supplied by the Company to the customer in any given hour above the customer generation, if not below the established net operating capability, is defined as supplementary power and will be billed under applicable full requirement tariff. Customers taking this service will be referred to as "customer-generators."

Rate

Backup Service

The actual or estimated average time coincident incremental cost of generation including transmission losses for the period service is provided plus 0.500 cents per kWh for additional Operating and Maintenance costs, service charges and Administration & General compensation.

Optional Generation Load Following

Average incremental cost of generation expressed in cents per kWh as determined by the generation forecast for the rate year plus add on charges as defined for back-up service. This price will be ~~7.236~~6.754 cents per kWh.

ENERGY CREDIT

The Energy Credit is equal to the average incremental cost of generation as defined under Optional Generation Load Following.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY

This tariff is available to:

(a) Customers who have their own qualifying generating facility of not less than 2,000 kW of aggregate capacity, as defined under Special Condition 8, normally used to support their own load;

(b) Energy supplied to Non-Utility Owned Generation sites for purposes of startup and replacement of energy normally supplied from their own generation, where the customer has signed an operating agreement under this tariff schedule.

The following general terms and conditions will apply to the applications.

(1) Energy under the Generation Replacement Service provision will be supplied upon request by the customer. In cases where advance written notification can be given by the customer, such as planned maintenance, the Company will advise the customer in writing of the quoted price which will be based on estimated costs during the period. In an emergency situation where time does not permit advance notification the price will be based upon actual costs until the customer provides written notification of the duration of the taking following which the Company will advise the customer in writing of the quoted price for the remainder of the period.

Energy under the load following section will be supplied either through on-going communication provision such as telemetering (when load fluctuations are involved) or written requests (where application is to a specific level of load).

(2) In the event there is an interruption required by NS Power in order to avoid shortfalls in electric supply, customers taking energy under the Generation Replacement Service or Load Following Service will be the first to be called upon to interrupt energy usage from NS Power.

(3) The customers will reduce their available interruptible system load by the amount required by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order at all times and must have a designated staff person to answer the dedicated telephone at all times. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rider.

Where the customer has provided NS Power with the ability to monitor and interrupt its load under terms and conditions determined by the Company, the Company may hold this load as Operating Reserve as required by system conditions. When interruptions are required, the Company will exercise the automated control of the customer's load to interrupt the customer load.

(4) Following interruption, service may only be restored by the customer with approval of the Company.

(5) Failure to comply in whole or in part with a requirement to interrupt load will result in penalty charges. The penalty will be comprised of two parts, a Threshold Penalty and a Performance Penalty.

The Threshold Penalty charge shall be the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

The Performance Penalty which is based on the customer's performance during the interruption event is calculated as per the formula below:

Performance Penalty = ($15/kVA x A) + ($30/kVA x B)

Where:

"A" is any residual customer demand (above that required by the interruption notice) remaining in the third interval directly following two complete 5-minute intervals after the interruption call is initiated and sent by NSPI.

"B" is the customer's average demand based on 5-minute interval data during the entire interruption event excluding the interval used to determine "A."

The total penalty will not exceed two times the cost of the appropriate firm billing effective at that time for the consumption used in that billing period.

(6) Customers must install metering equipment to monitor the output of the customer's generation. The equipment and installation must be approved by the Company and the costs will be the responsibility of the customer.

SPECIAL CONDITIONS

(1) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(2) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. Specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Any service requirements beyond those provided by a single step-down transformation from transmission voltage must be borne by the customer. The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(5) The Company reserves the right to determine the metering location.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR-h, as recorded, of not less than 90% lagging for the total customer load (under all rates) shall be maintained, or the following adjustment factors (Constant) will be applied to the Energy Charge in effect:

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) Qualifying generating facility must meet the following requirements:

(i.) Utilize dispatchable sources of generation.

(ii.) May have more than one generating unit so long as the aggregate manufacturer's nameplate rating is of not less than 2,000 kilowatts and which NSPI has the right to verify through inspection or testing.

(iii.) At the discretion of the customer, the generator may be connected to the grid either at any of the existing points of delivery of purchased power from NS Power or at a separate point if approved by NSPI. If a separate point of delivery is used, all additional costs will be the responsibility of the customer-generator.

(iv.) Generating facility shall meet all applicable safety and performance standards established by Measurement Canada, the Canadian Electrical Code, and NSPI's interconnection guidelines.

GENERATION LOAD FOLLOWING CRITERIA

(1) Two months preceding each tariff year the customer-generator, in conjunction with the Company, shall establish the aggregate net operating capability of its generation equipment for the billing purposes of calculating hourly top-up energy from NS Power during the next tariff year. The net operating capability will be set based upon tests of customer's generation equipment and/or operating records. During a period during which the customer-generator encounters conditions that will result in a temporary significant reduction in generation below the established net operating capability, bill payments under the Load Following service and the other full requirement rate, if applicable, will be set based on adjusted net operating capability reflecting the average generation level during such period. For each billing month of the tariff year the Company will load follow to the equivalent of one hundred (100) percent load factor of the adjusted net operating capability in each hour that the customer generation does not exceed its adjusted net operating capability.

(2) On or before November 7th preceding each tariff year the Company shall apply to the Nova Scotia Energy Board for approval of its forecasted incremental cost of generation for the following tariff year. Such average forecasted incremental cost shall be included in determining the load following rate for the next tariff year and each affected customer shall be notified.

DEMAND CHARGE

Nil.

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00 am – 11:00 pm, non-holiday weekdays): ~~5.274~~ 6.156¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): ~~0.713~~ 0.918¢/kWh

Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Energy Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at transmission voltage of 69 kV or higher and have loads of 2,000 KVA or 1,800 kW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days' notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause 1, but agrees to remain interruptible for up to five years as provided for under Availability Clause 5 of the Large Industrial Tariff Interruptible Rider. Within the five-year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

DEMAND CHARGE

Nil.

ENERGY CHARGE

NSPI's actual hourly marginal energy costs, plus the following fixed cost adders for on-peak and off-peak usage:

On-peak (7:00 am – 11:00 pm, non-holiday weekdays): ~~9.925~~ 8.513¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): ~~3.516~~ 3.091¢/kWh

Weekend and holiday fixed cost adders are set at the off-peak price during all hours of the day.

These adders shall be developed annually based on budgeted costs and submitted to the Nova Scotia Energy Board for approval.

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

AVAILABILITY

(1) Customers must make a written request to take service under this tariff.

(2) This tariff is available to customers who are served at voltage less than 69 kV and have loads of 2,000 KVA or 1,800 kW, and over.

SPECIAL CONDITIONS

(1) Projections of the anticipated hourly energy price (week ahead and day ahead) will be provided to the customer according to the following schedule:

- By midnight each business day, hourly price forecasts for each hour of the next five days shall be provided to the customer.

- Major changes to the hourly price forecasts will be provided to the customer as soon as they occur.

The actual price charged for each hour will be final twenty minutes prior to the commencement of that hour.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(4) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(5) Customers shall take service under this tariff for a minimum of twelve months from the commencement date of taking service under this tariff. The customer may terminate service under this tariff by giving 30 days' notice before the end of the contract term. Service shall automatically renew for successive terms if no notice is given.

(6) This is a firm service tariff. However, existing customers served under the Interruptible Rider of the Large Industrial Tariff will be eligible to take service under this tariff provided that the customer applies for firm service in their written request as required by Availability Clause 1, but agrees to remain interruptible for up to five years as provided for under Availability Clause 5 of the Large Industrial Tariff Interruptible Rider. Within the five-year window, a customer who has applied for firm service will be permitted to return to the Interruptible Rider without penalty, only if NSPI has not made irrevocable commitments to adding new capacity to meet the customer's request for firm service. Where such commitment has been made, the customer must reimburse NSPI or accept firm service for a period of at least two years.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

AVAILABILITY

(1) This tariff is available to port authorities of Nova Scotia for the sole purpose of providing port electricity to cruise ships docked in ports to meet their own consumption needs in displacement of the on-board self-generation. The tariff is applicable to electric energy where the regular demand is 2,000 kVA or 1,800 kW, and over.

(2) Customers served under this tariff must accept supply interruption. In the event there is an interruption required in order to avoid shortfalls in electricity supply, rate classes will be called upon to provide capacity to NSPI in the following order:

(i.) Generation Replacement and Load Following (GR&LF) Rate;
(ii.) Extra Large Industrial Active Demand Control Tariff and PHP Tariff;
(iii.) Shore Power Tariff; and
(iv.) Interruptible Rider to the Large Industrial Rate.

unless there are technical reasons to alter this sequence specific to the instance.

(3) This is a seasonal tariff available from April 1 to November 30.

ENERGY CHARGE

Energy charges will vary by voltage level of the point of delivery and will be made up of two components.

(1) Annually adjusted fuel cost component which shall be the Company's forecast average annual marginal energy cost as approved for use with the GR&LF tariff and adjusted for line losses at the voltage level of the point of delivery.

(2) A fixed cost adder adjusted concurrent with changes in base cost rates coming into effect as a result of a General Rate Case application.

Base Energy Charge Components	**Transmission Voltage of 69 kV or Higher (cents per kWh)**	**Distribution Voltage (cents per kWh)**
Fuel Cost	~~6.900~~6.406	~~7.062~~6.556
Fixed Cost Adder	~~2.507~~2.576	~~3.970~~4.226
Total	**~~9.408~~8.983**	**~~11.031~~10.783**

A credit equal to 32 cents per peak kilovolt-ampere of monthly peak demand will be applied where the transformer is owned by the customer and the customer is served at a transmission voltage level.

STORM COST RECOVERY RIDER

Storm Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Storm Cost Recovery Rider, shall apply, in addition to the energy charge.

SECURITIZATION COST RECOVERY RIDER

Securitization Cost Recovery charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Securitization Cost Recovery Rider, shall apply, in addition to the energy charge.

SUPPLY INTERRUPTIONS

This is an interruptible service. Before connecting the ship to the shore supply the port authority will request permission from NSPI indicating the expected load and duration for which the power is needed.

The customer will make available suitable contact telephone numbers of a person or persons who are able to disconnect the load within ten minutes. Supply Interruption calls will be made to all customers taking energy under this tariff on an equitable and transparent basis.

This Tariff will be available provided that:

(1) The customer has provided written notice of its desire to take interruptible service.

(2) The customer will reduce its available interruptible system load by the amount requested by NSPI within ten (10) minutes of NSPI initiating and sending notice to the customer's dedicated telephone number (as confirmed by the automated dialing system) requiring such reduction. The customer must maintain a dedicated telephone number and dedicated telephone system in working order and must have a designated staff person to answer the dedicated telephone at all times when cruise ships are connected to the utility grid. The failure of the customer to answer the telephone, shall not excuse the customer from its responsibilities under this rate.

(3) Following interruption, service may only be restored by the customer with approval of the Company.

(4) Failure to comply in whole or in part with a request to interrupt load will result in penalty charges. The penalty will apply based on the usage of the vessel being served via the Port Authority's equipment following the request to interrupt on the day on which the non- compliance took place.

Penalty for Non-Compliance

All energy served after the 10-minute deadline has expired will be billed at $5.00 per kWh. In addition a fixed charge of $2,000.00 will be applied.

The penalty charge is applicable above and beyond the Port Authority's monthly bill.

SPECIAL CONDITIONS

(1) The Port Authority owns and is responsible for the maintenance and operation of all electrical equipment required for the supply of port electricity to docked ships other than the meters and metering transformers supplied by NSPI. NSPI owns and is responsible for the maintenance of meters and metering transformers installed on the Port Authority premises for the purposes of billing.

(2) The Port Authority will ensure that trained staff is available to operate on-shore interconnection equipment to facilitate the connection, synchronization, disconnection, and interruption if needed at all times. Such operators must be available to be contacted by NSPI from a minimum of one hour before connection is required to the time that the ship returns to on board power supply.

(3) The Port Authority will file a two-year schedule of expected vessels showing their peak electrical demand before October 31 in a calendar year preceding the cruise ship season.

(4) Metering will normally be at the low voltage side of the transformer. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(5) The cost of any special metering or communication systems required by the customer to take service under this tariff shall be paid for by the customer as a capital contribution.

(6) Energy is supplied at the low side of the transformer. Meter readings shall be decreased by 1.1% to adjust for transformer losses if primary metering is used.

(7) Under normal operating conditions, an average power factor over the entire billing period, calculated for kWh consumed and lagging kVAR.h, as recorded, of not less than 90% lagging at each metering point shall be maintained, or the following adjustment factors (constant) will be applied to the billed consumption.

Power Factor	Constant	Power Factor	Constant
90-100%	1.0000	65-70%	1.1255
80-90%	1.0230	60-65%	1.1785
75-80%	1.0500	55-60%	1.2455
70-75%	1.0835	50-55%	1.3335

(8) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(9) The customer will make all necessary arrangements and bear all costs of ensuring that its load does not unduly deteriorate the integrity of the power supply system, by reason of its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(10) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

CUSTOMER CHARGE

The monthly customer charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of customers subscribed} * 12}$$

This charge will be $~~414.63~~427.07 per month.

DEMAND CHARGE

The demand charge for this service is made up of the following two components:

(1) Annually adjusted demand-related purchased power cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism, or General Rate Application.

(2) Demand-related fixed generation cost, coming into effect as a result of a General Rate Application.

Demand Charge Components	**$ per kW of billing demand**
Demand-related Purchased Power Cost	$~~6.222~~8.142
Demand-related Fixed Generation Cost	$~~5.601~~6.200
Total	**$~~11.822~~14.341**

Contract Demand requirement is defined as the firm demand (kW) requested by the wholesale customer (or aggregate customer group) and agreed to be supplied by NSPI. This may constitute all, or a portion of the demand contracted to be served on a primary basis by a third-party supplier.

Billing demand is determined based upon the following formula:

$$\text{Billing demand} = (PR/(1+PR) * \min(CD, CCF * GC)) + (CD - \min(CD, CCF*GC))$$

Where:

PR is Planning Reserve (based on NPCC planning criteria, i.e. 20% or as updated)

GC is the third-party supplier's generating capacity

(a) For non-dispatchable generation, GC = MSC, the Maximum Spill Capacity as defined in Wholesale Market Non-Dispatchable Supplier Spill Tariff.

(b) For dispatchable generation, GC = the supplier's maximum capacity contracted to provide its wholesale customers' demand.

CD is the customer's Contract Demand

CCF is the capacity contribution factor of the third party supplier's generation to the NSPI system, as determined at the beginning of a billing year by NSPI using information provided in accordance with Special Condition 7 of this tariff and in a manner consistent with NSPI's generation planning studies as amended from time to time.

ENERGY CHARGE

The energy charge is made up of the following two components:

(1) Annually adjusted energy-related purchased power and fuel cost, coming into effect as a result of a Base Cost of Fuel, Fuel Adjustment Mechanism or General Rate Application.

(2) Energy-related fixed generation cost, coming into effect as a result of a General Rate Application.

Energy Charge Components	**cents per kWh**
Energy-related Purchased Power and Fuel Cost	~~6.974~~6.430
Energy-related Fixed Generation Cost	~~2.155~~2.253
Total	**~~9.129~~8.683**

FUEL ADJUSTMENT MECHANISM (FAM)

The FAM Actual Adjustment (AA) and Balance Adjustment (BA) charges or credits (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the FAM Tariff, shall apply, in addition to the energy charge.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the customer charge plus the demand charge.

AVAILABILITY

The tariff is available to wholesale customers as defined in section 2(d) of the *Electricity Act*, Chapter 25 of the Acts of 2004.

(d) "wholesale customer" means Nova Scotia Power Incorporated or a municipal utility.

The tariff is applicable to the *scheduled* backup/top-up load of participating customers under the following terms and conditions:

(1) The wholesale customer has provided written notice of its intent to take service under this tariff, clearly identifying the following:

(a) The Municipal utility or utilities for which service is being requested.

(b) The year for which service is being requested.

(c) The contract demand (kW) required for backup and top-up service.

(d) The portion of the customer's annual load contracted to be supplied by third-party suppliers or through self-supply.

(e) The names, addresses, contact details and supply arrangements associated with contracted third-party suppliers.

(2) Backup/top-up service will be subscribed on a minimum 12 month, annual-renewable basis, provided that, if a wholesale customer satisfies the requirement of Special Condition 7(d), the backup/top-up service required with respect to the wholesale customer's procured capacity which satisfies the requirement of Special Condition 7(d) shall be subscribed by the customer on a minimum three-year forward basis.

Applications for service with a CCF value greater than zero in the billing demand calculation of the demand charge must be provided annually to NSPI by January 31st of each year, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision by March 31st of each year following an application.

Applications for service with a CCF value of zero in the billing demand calculation of the demand charge must be provided to NSPI by no later than September 1st, for service applicable to the subsequent year, which would commence January 1st of that subsequent year. Absent extraordinary circumstances, NSPI shall notify the wholesale customer of its decision within two months of receipt of such an application.

(3) Adequate metering equipment, as dictated by the Generation Interconnection Agreement, must be installed to monitor the generation of any third-party generators selected for use by the wholesale customer. The equipment and installation must be approved by the Company and the costs will be the responsibility of the generator.

SPECIAL CONDITIONS

(1) This tariff is designed for customers supplied and metered at the high side of the transformer at transmission voltage of 69 kV or higher. For customers metered at the low side of the transformer, or at a distribution voltage level, meter readings shall be increased by 1.1% for each transformation between the meter and the transmission voltage.

(2) The charges under this rate do not reflect transmission service costs. Customers taking service under this tariff must also take service under the Open Access Transmission Tariff (OATT).

(3) For system reasons, NSPI may, at its discretion, deny an application for service from a customer who has not taken service from NSPI in the year prior to the year requested.

(4) The Company reserves the right to have a separate service agreement, if in the opinion of the Company, issues not specifically set out herein must be addressed for the ongoing benefit of the Company and its customers.

(5) The customer will make all necessary arrangements to ensure that its load does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(6) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(7) Unless the following can be demonstrated by the wholesale customer to the satisfaction of NSPI, the CCF shall be attributed a value of zero in the billing demand calculation of the demand charge:

(a) For a third-party generation resource within Nova Scotia (Internal Resource):

(i.) If the Internal Resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the wholesale customer to NSPI, if directed to do so by the Nova Scotia Power System Operator (NSPSO), in the event of a resource adequacy need;

(ii.) If the Internal Resource is non-dispatchable, that it make its full output contracted to, but unused by, the wholesale customer available to deliver energy to NSPI, in the event of a resource adequacy need;

(iii.) The Internal Resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO; and

(iv.) Any export transactions utilizing energy from the Internal Resource will be recallable by the NSPSO, up to the amount contracted to the wholesale customer, for delivery to the NSPI system in the event of a resource adequacy need.

(b) For a third-party generation resource outside of Nova Scotia (External Resource):

(i.) The energy from the External Resource that is contracted to the wholesale customer will be scheduled and delivered to NSPI in the event of a resource adequacy need;

(ii.) The capacity from the External Resource that is contracted to the wholesale customer must be associated with one or more specific external resource assets, or be system-backed import capacity supported by the external control area where the capacity will be afforded the same curtailment priority as the external control area's native load, and be available to the NSPSO in the event of a resource adequacy need;

(iii.) If the capacity from the External Resource that is contracted to the wholesale customer is associated with one or more specific external resource assets, the wholesale customer must provide:

1. The name and location of each external resource asset;
2. For each asset, generator data including documentation of dependable maximum net capacity and NERC Generating Availability Data System data;
3. Documentation demonstrating proof of contractual control of the capacity all the way to each external resource asset providing the capacity; and
4. Letter of attestation or other documentation from the External Resource owner establishing that the capacity from the External Resource is not being used as capacity in any other balancing area.

(iv.) If the capacity from the External Resource will be supported by the external control area, the wholesale customer must provide:

1. Documentation demonstrating that the import capacity will be supported by the external control area and afforded the same curtailment priority as the external control area's native load.
2. Documentation demonstrating that the External Resource has firm transmission from the specific external resource asset or external control area to the NSPI system.

(c) The Internal Resource or External Resource, as applicable, will perform as needed to meet NSPI's reliability requirements.

(d) The capacity derived based on the CCF is procured and available to the wholesale customer on a minimum three-year forward basis, unless this requirement is waived by NSPI.

(8) In the event of a failure by the Internal Resource or External Resource, as applicable, to deliver scheduled energy or capacity following a direction to do so by the NSPSO in accordance with Special Condition 7, above, then the wholesale customer will be required to make payment to NSPI of an amount equal to the costs incurred by NSPI to procure or to self-supply the undelivered energy and/or capacity, as applicable, less the energy charge paid by the wholesale customer to NSPI under this tariff with respect to any such undelivered energy and/or capacity, as applicable. If delivery of an Internal Resource or External Resource, as applicable, is affected by circumstances that are inconsistent with the information and/or documentation provided to NSPI pursuant to Special Condition 7, above, then NSPI and the wholesale customer shall attempt to negotiate an adjustment to the CCF for the Internal Resource or External Resource, as applicable. If NSPI and the wholesale customer are unable to agree on an adjustment to the CCF, the matter may be submitted to the Board by either party on an expedited basis for adjudication.

ADMINISTRATION CHARGE

The monthly administration charge under this tariff is calculated according to the following formula:

$$\text{Monthly customer charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of suppliers supplying wholesale customers} * 12}$$

This charge will be $~~2,487.77~~2,562.40 per month.

ENERGY CREDIT

Compensation for spill energy delivered to NSPI will be at the Company's forecast average annual marginal energy costs of ~~6.7366~~6.254 cents per kilowatt hour as approved for use with the GRLF rate.

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the administration charge.

AVAILABILITY

This tariff is available for use by, independent non-dispatchable electric generators serving the Wholesale Market. The tariff is applicable to scheduled "spill energy," under the following terms and conditions:

(1) "Spill energy" is defined as the scheduled hourly energy forecast to be produced by the supplier above the scheduled hourly energy requirement of their wholesale customer(s). Unscheduled energy produced will be compensated according to the Open Access Transmission Tariff (OATT) imbalance guidelines. Spill compensation under this tariff is limited to the supplier's Maximum Spill Capacity (kW). Maximum Spill Capacity must be approved by NSPI prior to commencement of service. Spill capacity will be reviewed periodically and adjusted as required.

(2) Suppliers must install metering equipment to monitor the output of their generation. Consistent with the Generation Interconnection Agreement, the equipment and installation must be approved by the Company and the costs will be the responsibility of the supplier.

SPECIAL CONDITIONS

(1) Suppliers must meet all conditions set forth in the Generation Interconnection Procedures and Generation Interconnection Agreement.

(2) The Company reserves the right to have a separate service agreement, if in the opinion of the Company issues not specifically set out herein, must be addressed for the ongoing benefit of the Company and its customers.

(3) The supplier will make all necessary arrangements to ensure that its generation output does not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated in the Generation Interconnection Agreement.

In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

ENERGY BALANCING SERVICE

The Energy Balancing Service is a supplemental generation service provided to Licenced Retail Suppliers (LRS) in respect of the Licenced Retail Supplier's Renewable to Retail (RtR) Customers utilizing the production from renewable low-impact generators. The service consists of delivery of complementary energy to RtR Customers and reception of surplus generation from qualifying generators. The service is required to be taken in conjunction with Standby Service under the Standby Service Tariff so that the reliability of service to RtR Customers is equivalent to that provided under Bundled Service. For the purposes of this Energy Balancing Service Tariff, hourly LRS load in excess of generation is defined as top-up energy and hourly generation in excess of LRS load is defined as spill energy.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Energy Balancing Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by RtR Customers.

This Energy Balancing Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power; and

(2) The LRS must be providing service to RtR Customers.

APPLICABILITY

(1) An LRS taking service under this Energy Balancing Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Energy Balancing Service Tariff is based on metered energy quantities and is independent of the LRS' forecasts. OATT Schedule 4 is not applicable, but the Generation Forecasting Service under Schedule 4A of the OATT is applicable.

(3) The hourly top-up and spill quantities are determined at the delivery point from the transmission system. Where the LRS purchases electricity from customers with Distribution-connected Generation, the LRS' aggregate customer load will include customer imports only (i.e. exclude customer exports to the system) and the aggregate renewable low-impact electricity supplied by the LRS, will include customer exports only. The hourly top-up quantity equals the excess in each hour, if positive, of the LRS' aggregate customer load adjusted by the addition of distribution

losses over the aggregate renewable low-impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission losses. The hourly spill quantity equals the excess in each hour, if positive, of the aggregate renewable low-impact electricity supplied by the LRS or its contracted generation adjusted by the deduction of transmission locational losses, as applicable to the geographic zone in which the generating facility is interconnected, over its aggregate customer load adjusted by the addition of distribution losses. The locational loss values will be published by the NS Power System Operator. The aggregate hourly load quantities are determined in accordance with the applicable provisions in the LRS Terms and Conditions.

(4) To qualify for this service, the LRS must ensure that the imbalance between low-impact renewable generation and energy consumption over the established compliance period conforms to Section 10 of the Board Electricity Retailers Regulations (Nova Scotia) enacted under the Act.

(5) Maximum Spill Capacity must be approved by NS Power prior to commencement of service and will be limited to a level agreed as being required to provide the contracted annual amount of participating LRS energy. Spill capacity will be reviewed annually and will include the LRS' proposal to mitigate it on a going forward basis. If NS Power is not satisfied with the LRS' proposal, it may impose a limit on hourly production of the LRS' generation portfolio.

(6) Under the Distribution-connected Aggregation Service, the LRS will aggregate its customers' Distribution-connected Generation and use this to serve other RtR Customers. To facilitate this, NS Power will separately track hourly customer imports of electricity and hourly LRS customer exports to the grid. Customer imports will be used to determine NS Power's charges to retail customers under the Distribution Tariff and will serve as an input to the demand and energy amounts applicable to the LRS under the OATT, Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs. Customer exports will be tracked and reported to the LRS to support the LRS' commercial arrangement with the LRS' customer and will serve as an input to the generation amount applicable to the LRS under the Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $~~414.63~~67,734 per month.

ENERGY CHARGE

Energy charge for top-up service is made up of the following two components:

(1) Annually adjusted fuel cost component based on NS Power's incremental cost of serving the LRS' forecasted incremental top-up load.

(2) Fixed cost adder reflective of fixed cost energy-related generation costs.

Energy Charge Components	cents per kWh
Fuel Cost	~~6.736~~6.254
Fixed Cost Adder	~~2.155~~2.253
Total	~~**8.891**~~**8.507**

The charge is applicable to top-up energy consumed in each hour.

ENERGY CREDIT

~~6.736~~6.254 cents per kilowatt-hour.

The Energy Credit for spill service is set annually and is applicable to spilled energy in each hour.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Energy Balancing Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Energy Balancing Service Tariff, the Standby Service Tariff, the Distribution-connected Aggregation Service Tariff, or the Renewable to Retail Market Transition Tariff.

STANDBY SERVICE

Standby Service is a supplemental generation capacity service provided to Licensed Retail Suppliers (LRS). The service is provided in combination with Energy Balancing Service under the Energy Balancing Service Tariff. The service has two components:

Capacity adequacy service – fulfillment of the LRS' obligation to provide or pay for its share of firm capacity required to meet adequacy standards of the Nova Scotia electricity system arising from forced and unforced generation outages. Energy delivered during generation outages will be billed under the Energy Balancing Service Tariff.

Top-up capacity service – provision of capacity to support energy delivery through the Energy Balancing Service in respect of imbalance between load and generation.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This Standby Service Tariff is applicable to the LRS in order to facilitate the purchase of renewable low-impact electricity by Renewable to Retail (RtR) Customers.

This Standby Service Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power;

(2) The LRS must be providing service to RtR Customers; and

(3) Under the Distribution-connected Aggregation Service Tariff, the LRS will aggregate its customers' Distribution-connected Generation and use this to serve other RtR Customers. To facilitate this, NS Power will separately track hourly customer imports of electricity and hourly LRS customer exports to the grid. Customer imports will be used to determine NS Power's charges to retail customers under the Distribution Tariff and will serve as an input to demand and energy amounts applicable to the LRS under the OATT, Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs. Customer exports will be tracked and reported to the LRS to support the LRS' commercial arrangement with the LRS' customer and will serve as an input to the generation amounts applicable to the LRS under the Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs.

APPLICABILITY

(1) An LRS taking service under this Standby Service Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Energy Balancing Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) The service under this Standby Service Tariff is complementary to the generation ancillary services to the Renewable to Retail market under OATT.

(3) The aggregate hourly load quantities are determined at the delivery point from the transmission system, inclusive of distribution system losses, in accordance with the provisions of the LRS Terms and Conditions.

(4) This service is applicable to firm load only.

ADMINISTRATION CHARGE

The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

This charge will be $~~414.63~~67,734 per month.

DEMAND CHARGE

$~~5.601~~6.200 per month, per kilowatt (kW) of monthly standby contract demand.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the administration charge.

DETERMINATION OF MONTHLY STANDBY CONTRACT DEMAND

Monthly Standby Contract Demand (MSCD) in kW is determined using the following formula:

$$MSCD = LWPFD - min\ (LWPFD, (\Sigma_{ii=1}^{nn}\ CCi * GCi)/(1+PR))$$

Where:

- "LWPFD" is LRS Winter Peak Firm Demand in respect of each billing month calculated as follows:

$$LWPFD = \Sigma_{i=1}^{k}(CMPFDi * CMDAFi)$$

Where:

- "k" is the number of otherwise applicable bundled service rate classes to RtR customers of an LRS.

- "CMPFDi" is hourly kW Class Monthly Peak Firm Demand (CMPFD) of the LRS firm load in each tariff class at the time of system coincident firm load peak in each month at transmission delivery points (i.e. inclusive of distribution system losses). Where the LRS purchases electricity from customers with Behind-the-Meter Generation, demand will include customer imports only (i.e. exclude customer exports to the system). The CMPFD for the unmetered customer class shall be determined by use of research-based class load profile data.

- "CMDAFi" is the Class Monthly Demand Adjustment Factor applicable to each class as set out below:

Classes	Jan, Feb, Dec	Mar, Apr	May, Jun	Jul, Aug, Sep	Oct, Nov
Domestic	1.00	1.34	2.153	2.296	1.645
Small General	1.00	1.24 23	1.632	1.59	1.35
General	1.00	1.21 22	1.5047	1.396	1.20
Large General	1.00	0.99	0.93	0.86	0.99
Small Industrial	1.00	1.25	1.23	1.267	1.156
Medium Industrial	1.00	1.121	1.054	1.03	0.96
Large Industrial Firm	1.00	1.04	0.92	0.89	0.912
Unmetered	1.00	1.19	1.989	1.978	1.33

- "PR" is Planning Reserve (%) based on Northeast Power Coordinating Council planning criteria (i.e. 20% or as updated).

- "CCi" is a capacity contribution factor of LRS' generator to NS Power's system peak as determined by NS Power. The capacity contribution factor may be the subject of periodic adjustment if operating conditions of the generator, such as a prolonged deration, depart from those assumed by NS Power. For non-dispatchable resources, the capacity contribution factor shall be determined using the Effective Load Carrying Capability (ELCC) methodology as set out in the most recently approved Integrated Resource Plan, or as otherwise updated by the Nova

Scotia Power System Operator (NSPSO) or IESO Nova Scotia. NS Power shall provide the LRS with the applicable ELCC value and the basis for its determination upon request.

- "GCi" is the generator capacity dedicated to serving LRS load. Where the LRS purchases surplus electricity from customers with Distribution-connected Generation, GCi, if applicable to this generation, will include exports only.

- "n" is the total number of LRS' generators including those under contract.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' RtR Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels and other related conditions.

(4) Nothing contained in this Standby Service Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this Standby Service Tariff, the Energy Balancing Service Tariff, Distribution-connected Aggregation Service Tariff, or the Renewable to Retail Market Transition Tariff.

(5) Unless the following can be demonstrated by the LRS to the satisfaction of NS Power, the capacity contribution factor shall be attributed a value of zero in the billing demand calculation of the demand charge:

(i) If the LRS' resource is dispatchable, that it can start up and deliver energy contracted to, but unused by, the LRS to NS Power, if directed to do so by the NSPSO, in the event of a resource adequacy need;

(ii) If the LRS' resource is non-dispatchable, that it makes its full output for which it is provided an ELCC value contracted to, but unused by, the LRS available to deliver energy to NS Power, in the event of a resource adequacy need;

(iii) The LRS' resource will remain available for dispatch, if called upon by the NSPSO, by coordinating with the NSPSO and refraining from taking planned outages during certain critical times of the year, as determined by the NSPSO;

(iv) Any export transactions utilizing energy from the LRS' resource will be recallable by the NSPSO, up to the amount contracted to the LRS, for delivery to the NS Power system in the event of a resource adequacy need;

(v) The LRS' resource, as applicable, will perform as needed to meet NS Power's reliability requirements; and

(vi) The capacity derived based on the capacity contribution factor is procured and available to the LRS on a minimum three-year forward basis, unless this requirement is waived by NS Power.

(6) In the event of a failure by the LRS' resource, as applicable, to deliver scheduled energy or capacity following a direction to do so by the NSPSO, in accordance with Special Condition (5), then the LRS will be required to make payment to NS Power of an amount equal to the costs incurred by NS Power to procure or to self-supply the undelivered capacity, as applicable, less the charge paid by the LRS to NS Power under this Tariff with respect to any such undelivered capacity, as applicable. If delivery of an LRS' resource, as applicable, is affected by circumstances that are inconsistent with the information and/or documentation provided to NS Power pursuant to Special Condition (5), then NS Power and the LRS shall attempt to negotiate an adjustment to the capacity contribution factor for the LRS' resource as applicable. If NS Power and the LRS are unable to agree on an adjustment to the capacity contribution factor, the matter may be submitted to the Board by either party on an expedited basis for adjudication.

PURPOSE

Pursuant to Section 3G(2) of the *Electricity Act* (Nova Scotia), this Renewable to Retail Market Transition Tariff (RTT) is designed to recover from Licenced Retail Suppliers (LRS) NS Power's embedded fixed costs and deferred costs, recovered through Bundled Service, which are not otherwise recovered through other tariffs applicable to the LRS or its Renewable to Retail (RtR) Customers. For certainty, for the purposes of this RTT, NS Power's embedded fixed costs include, but are not limited to, generation related fixed costs (e.g. depreciation, cost of financing including return on common equity, income tax, and OM&G). Deferred costs of NS Power are those costs approved by the Nova Scotia Energy Board (NSEB, Board) for recovery by NS Power from customers at a future date.

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

APPLICABILITY

(1) The RTT is applicable to the LRS, and is in addition to (and not in substitution of) any charges owing by the LRS to NS Power under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, or the Energy Balancing Service Tariff. A charge under the RTT will only apply to the extent the cumulative amount calculated under the RTT for the calendar year is equal to greater than zero.

(2) The RTT employs certain usage determinants and rate components applicable under both the Standby Service Tariff and the Energy Balancing Service Tariff.

(3) Energy Charges and Demand Charges (both as set out below) under this RTT include provision for mitigation in respect of forecasted NS Power savings enabled by the LRS's supply of electricity to its RtR Customers. The savings credits will be determined annually on the basis of experience and will be applied on a prospective basis.

(4) The Energy Charge under this RTT includes provision for annual adjustment on a prospective basis to account for the forecasted difference between NS Power's average avoided cost by the LRS' supply of electricity and its average system fuel cost. If the average avoided cost exceeds the average system fuel cost, this adjustment will be a reduction in the Energy Charge; if the average avoided cost is less than the average system fuel cost, this adjustment will be an addition to the Energy Charge.

(5) An LRS taking service under this RTT shall also take service under the OATT, the Standby Service Tariff, and the Energy Balancing Service Tariff.

ENERGY CHARGE

The Energy Charge is made up of the following components:

Energy Charge Components	**cents per kWh**
Fixed Cost Adder from Energy Balancing Service Tariff	~~2.155~~2.253
Annually Adjusted Energy Savings Credit	0.000
Annual Energy Cost Adjustment	~~2.171~~3.812
Total	**~~4.3266~~6.065**

The Energy Charge is applicable to the LRS' monthly displaced energy on NS Power's generation system, defined as the total monthly LRS load, including distribution losses, minus the total monthly LRS top-up quantity as determined under the Energy Balancing Service Tariff for that LRS.

DEMAND CHARGE

The Demand Charge is made up of two components:

Demand Charge Components	**dollars per kW**
Demand Charge from Standby Service Tariff	$~~5.601~~6.200
Annually Adjusted Demand Savings Credit	$0.000
Total	**$~~5.601~~6.200**

The Demand Charge is applicable to the LRS' monthly displaced demand on NS Power's system determined as the difference between Winter Peak Firm Demand, in respect of the monthly bill of the LRS, and Monthly Standby Contract Demand, both as determined under the Standby Service Tariff for that LRS. For greater certainty, Winter Peak Firm Demand and Monthly Standby Contract Demand are as set out in the Standby Service Tariff.

SPECIAL CONDITIONS

(1) Nothing contained in this RTT or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this RTT, the Standby Service Tariff, or the Energy Balancing Service Tariff.

DISTRIBUTION-CONNECTED AGGREGATION SERVICE

The Distribution-connected Aggregation Service (DAS) is provided by NS Power to Licenced Retail Suppliers (LRS) to facilitate the purchase by the LRS of LRS Customer Distribution-connected Generation surplus to LRS' Customer's requirements. The service will support the transport of this electricity between LRS customers across the NS Power grid and will enable identification and accumulation of hourly customer surplus generation (i.e. exports) and LRS Distribution-connected Generation for incorporation of this information within the Standby Service (SS) Tariff, Energy Balancing Service (EBS) Tariff, and Renewable to Retail Market Transition Tariff (RTT).

All capitalized terms herein shall, unless otherwise defined herein, have the meanings ascribed thereto in the LRS Terms and Conditions.

AVAILABILITY

This DAS Tariff is applicable to the LRS in order to facilitate the purchase of RtR Customer Distribution-connected Generation by the LRS and the delivery and sale of this generation and LRS Distribution-connected Generation to LRS Customers.

This DAS Tariff is provided under the following terms and conditions:

(1) The LRS must have a valid LRS Participation Agreement executed with NS Power;

(2) The LRS must be providing service to RtR Customers; and

(3) The purchaser of the LRS' DAS Tariff energy is an NS Power customer under the Distribution Tariff.

APPLICABILITY

(1) An LRS taking service under this DAS Tariff shall also take service under the Open Access Transmission Tariff (OATT), the Standby Service Tariff, the Energy Balancing Service Tariff, and the Renewable to Retail Market Transition Tariff.

(2) Under the DAS, the LRS will aggregate its customers' surplus generation and Distribution-connected Generation and use this to serve other LRS customers. To facilitate this, NS Power will separately track hourly customer imports of electricity and hourly LRS customer exports to the grid. Customer imports will be used to determine NS Power's charges to retail customers under the Distribution Tariff and will serve as an input to the demand and energy amounts applicable to the LRS under the OATT, Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs. Customer exports will be tracked and reported to the LRS to support the LRS' commercial arrangement with the RtR Customer and will serve as

an input to the generation amount applicable to the LRS under the Standby Service, Energy Balancing Service, and Renewable to Retail Market Transition tariffs.

ADMINISTRATION CHARGE

As a new service offering, the cost of providing this service is uncertain and the applicable regulatory practice remains to be determined. Until reviewed and, if necessary, revised at some point in the future, it is assumed the cost of distribution service associated with DAS is recovered from the LRS' Customer under the applicable Distribution Tariff charges. As result, at least initially, the DAS Tariff charge is limited to an Administration Charge based on the forecast incremental cost for NS Power to provide this service. The monthly administration charge is applicable to each LRS and is set annually according to the following formula:

$$\text{Monthly charge} = \frac{\text{forecast annual administration costs}}{\text{forecast number of LRS' subscribed} * 12}$$

~~Information on the monthly administration charge will be provided to the Nova Scotia Energy Board (Board) for the Board's review and approval as part of the 2027 Annually Adjusted Rates Application~~This charge will be $277.71 per month.

MINIMUM MONTHLY CHARGE

The minimum monthly charge will be the Administration Charge.

SPECIAL CONDITIONS

(1) NS Power reserves the right to have a separate service agreement, if in the opinion of NS Power issues not specifically set out herein, must be addressed for the ongoing benefit of NS Power and its customers.

(2) The LRS' Customers and generators will make all necessary arrangements to ensure that their generation and load do not unduly deteriorate the integrity of the power supply system, either by its design and/or operation. These specific requirements shall be stipulated by way of a written operating agreement.

(3) In assessing issues which might unduly affect the integrity of the power supply system the following would be considered: reliability, harmonic voltage and current levels, voltage flicker, unbalance, rate of change in load levels, stability, fault levels, and other related conditions.

(4) Nothing contained in this DAS Tariff or any service agreement shall be construed as affecting or in any way limiting the right of NS Power to make application to the Nova Scotia Energy Board

for a change in any rates, terms and conditions, charges, classification of service, service agreement, rule or regulation, including, without limitation, the rates, charge or terms and conditions contained in this DAS Tariff, the Standby Service Tariff, the Energy Balancing Service Tariff, or the Renewable to Retail Market Transition Tariff.

DAS TARIFF REVIEW

In light of the early stages of RtR market development in general and, in particular, Distribution-connected Generation market development following 2028, a review of the operation of this tariff and the broader RtR construct will be undertaken by NS Power and submitted to the Board for its review. If this review identifies the requirement for revision to the DAS Tariff or any other RtR-related tariff, revisions will be proposed for the Board's approval.

If, at any time, NS Power or an LRS determines that the DAS Tariff or related RtR tariffs are not working effectively, the parties shall work together to try to resolve any such concerns. If the parties cannot resolve such concerns, either party may apply to the Board to adjust the DAS Tariff or the related RtR tariffs. If necessary, and to protect customers, the Board may grant such approval on an expedited basis.

2027 AAR Appendix H
has been filed electronically.