REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia POWER
An Emera Company

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May 11, 2026

Confidential (Attachments only)

Crystal Henwood
Clerk of the Board
Nova Scotia Energy Board
1601 Lower Water Street, 3rd Floor
Halifax, NS B3J 3S3

Re: M12551 2026 Annually Adjusted Rates – Compliance Filing

Dear Ms. Henwood:

Nova Scotia Power (NS Power, Company) filed its 2026 Annually Adjusted Rates (AAR) Application on November 7, 2025. On March 9, 2026, the Nova Scotia Energy Board (NSEB, Board) issued its Decision approving Nova Scotia Power's (NS Power, Company) 2026 AAR Application "subject to retaining jurisdiction to make amendments if adjustments are required to them as a result of the GRA decision."[1] The Board's March 11, 2026 Order provided:

> NS Power is directed as follows:
>
> 1. If the updated Cost of Service Study is not approved as filed, currently before the Board in the NS Power GRA matter M12451, NS Power is directed to make any required adjustments to the 2026 AARs in a compliance filing two weeks after the GRA decision is issued.[2]

On March 25, 2026, the Board issued its Decision on the 2026-2027 General Rate Application (M12451), which included changes to NS Power's updated Cost of Service Study (COSS), and directed the Company to "file a compliance filing no later than two weeks after the date of this decision."[3]

[1] M12551 – Board Decision, 328272, page 7. March 9, 2026.
[2] M12551 – Board Order, 328162, page 1. March 11, 2026.
[3] M12451 – Board Decision, 328719, page 307, para. 737. March 25, 2026.

On March 30, 2026, the Board approved the Company's request to extend the due date for the 2026 AAR Compliance Filing to two weeks following the Board's Order in M12451. The Board issued its Order on the 2026-2027 GRA on April 30, 2026. In accordance with the Board's directive in this proceeding, the Company provides the following as its 2026 AAR Compliance Filing.

Revised AAR Tariffs and Rates

The Company has updated the applicable AAR Tariffs and rates to reflect the M12451 COSS changes. The following AAR Tariffs required revision:

- One-Part Transmission Real-Time Pricing Tariff (1P T-RTP);
- One-Part Distribution Voltage Real-Time Pricing Tariff (1P DV-RTP);
- Shore Power Tariff;
- Wholesale Market Back-up/Top-up (BUTU) Tariff;
- Renewable to Retail (RTR) Energy Balancing Service (EBS) Tariff;
- RTR Standby Service (SS) Tariff; and
- RTR Market Transition Tariff (RTT).

No changes were required to the Generation Replacement and Load Following (GRLF), the Wholesale Market Non-Dispatchable Supplier Spill (Spill), or the Extra Large Industrial Active Demand Control (ELIADC) tariffs.

Supporting data and calculations have been provided as referenced in Table 1. Justification for confidential information is consistent with that requested in the Company's 2026 AAR Application, as filed November 7, 2025.

Table 1 – References to Supporting Data and Calculations for Revised 2026 AARs

Tariff	Supporting Data & Calculations
GRLF	Not applicable; no changes required.
1P T-RTP	Appendix B2
1P DV-RTP	Appendix B2
Shore Power	Appendix C
BUTU	Appendix E3
Spill	Not applicable; no changes required.
EBS	Appendix F2
SS	Appendix F3
RTT	Appendix F4

Tariff	Supporting Data & Calculations
ELIADC	Not applicable; no changes required.

The following additional appendices are included in this compliance filing:

- Appendix A – clean versions of revised 2026 AAR Tariff sheets
- Appendix D – Cost of Service
- Appendix E4 – BCF Allocation
- Appendix G – an electronic copy of updated figures provided in the 2026 AAR Application
- Appendix H – redline versions of revised 2026 AAR Tariff sheets

As the Board's March 11, 2026 Order approved AARs effective April 1, 2026, subject to GRA Decision amendments, the Company has included the April 1, 2026 approved Tariffs with redline revisions to the applicable AARs to incorporate the compliance filing revisions.

Requested Relief

The Company respectfully requests Board approval of the revised 2026 AARs, provided as Appendix A, and as listed herein:

- One-Time Transmission Real-Time Pricing Tariff;
- One-Time Distribution Voltage Real-Time Pricing Tariff;
- Shore Power Tariff;
- Wholesale Market Back-up/Top-up Tariff;
- RTR Energy Balancing Service Tariff;
- RTR Standby Service Tariff; and
- RTR Market Transition Tariff.

The approved rates will be implemented in accordance with the Board's Decision per the Board approved effective date.

In accordance with the Board Order in this proceeding, the Company will file the 2027 AAR Application by November 6, 2026. An update on directives from 2026, and prior AAR proceedings, will be included in the 2027 AAR Application, subject to any Board directives establishing different reporting cycles.

Yours truly,

Karynne Munroe
Manager, Regulatory Affairs

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 ¢/kWh

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

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 ¢/kWh

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

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	7.062
Fixed Cost Adder	2.507	3.970
Total	**9.408**	**11.031**

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.

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.

<u>Penalty for Non-Compliance</u>

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 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
Demand-related Fixed Generation Cost	$5.601
Total	**$11.822**

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
Energy-related Fixed Generation Cost	2.155
Total	**9.129**

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.

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. 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.

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 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
Fixed Cost Adder	2.155
Total	**8.891**

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

ENERGY CREDIT

6.736 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 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; and

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

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:

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

This charge will be $414.63 per month.

DEMAND CHARGE

$5.601 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:

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

Where:

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

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

  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 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). 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	2.13	2.26	1.65
Small General	1.00	1.24	1.62	1.59	1.35
General	1.00	1.21	1.47	1.36	1.20
Large General	1.00	0.99	0.93	0.86	0.99
Small Industrial	1.00	1.25	1.23	1.27	1.16
Medium Industrial	1.00	1.11	1.04	1.03	0.96
Large Industrial Firm	1.00	1.04	0.92	0.89	0.92
Unmetered	1.00	1.19	1.99	1.98	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.

- "GCi" is the generator capacity dedicated to serving LRS load.

- "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, or the Renewable to Retail Market Transition Tariff.

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
Annually Adjusted Energy Savings Credit	0.000
Annual Energy Cost Adjustment	2.171
Total	**4.326**

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
Annually Adjusted Demand Savings Credit	$0.000
Total	**$5.601**

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.

Scenario A

					UNIT POWER PRODUCTION COSTS			RTP Avoided Costs								
	Monthly Hours in 2025	On	Off	Total	MC Ave	On	Off	RTP Ave Hourly KW Req On	Off	Total	RTPKWh Req On	Off	Total	Sales On	Off	Total
	Scenario A (2024)															
	Jan	368	376	744	[redacted]											
	Feb	320	352	672												
	Mar	336	408	744												
	Apr	352	368	720												
	May	352	392	744												
	Jun	336	384	720												
	Jul	368	376	744												
	Aug	336	408	744												
	Sep	352	368	720												
	Oct	368	376	744												
	Nov	320	400	720												
	Dec	368	376	744												
		4176	4584	8760												
	Scenario B: Monthly Hours in 2026															
		On	**Off**	**Total**												
	Jan	352	392	744	[redacted]											
1	Feb	320	352	672												
2	Mar	352	392	744												
3	Apr	352	368	720												
4	May	336	408	744												
5	Jun	352	368	720												
6	Jul	368	376	744												
7	Aug	336	408	744												
8	Sep	352	368	720												
9	Oct	352	392	744												
10	Nov	336	384	720												
11	Dec	368	376	744												
		4176	4,584	8760												
	Jan	-4.3%	4.3%	0.0%	[redacted]											
	Feb	0.0%	0.0%	0.0%												
	Mar	4.8%	-3.9%	0.0%												
	Apr	0.0%	0.0%	0.0%												
	May	-4.5%	4.1%	0.0%												
	Jun	4.8%	-4.2%	0.0%												
	Jul	0.0%	0.0%	0.0%												
	Aug	0.0%	0.0%	0.0%												
	Sep	0.0%	0.0%	0.0%												
	Oct	-4.3%	4.3%	0.0%												
	Nov	5.0%	-4.0%	0.0%												
	Dec	0.0%	0.0%	0.0%												
		0.0%	**0.0%**	**0.0%**												

	Monthly Hours in 2025 On	Off	Total	RTP Revenue: Revenue On MC	Adder	Total	Off MC	Adder	Total	Total MC	Adder	Revenue Total	Unit Revenue On	Off	All Hours	Adder as % of cost On	Off	Total
Scenario A (2024)																		
Jan	368	376	744	[redacted]														
Feb	320	352	672															
Mar	336	408	744															
Apr	352	368	720															
May	352	392	744															
Jun	336	384	720															
Jul	368	376	744															
Aug	336	408	744															
Sep	352	368	720															
Oct	368	376	744															
Nov	320	400	720															
Dec	368	376	744															
	4176	4584	8760															
Scenario B:	**Monthly Hours in 2026**																	
	On	**Off**	**Total**															
Jan	352	392	744	[redacted]														
Feb	320	352	672															
Mar	352	392	744															
Apr	352	368	720															
May	336	408	744															
Jun	352	368	720															
Jul	368	376	744															
Aug	336	408	744															
Sep	352	368	720															
Oct	352	392	744															
Nov	336	384	720															
Dec	368	376	744															
	4176	4,584	8760															
Jan	-4.3%	4.3%	0.0%	[redacted]														
Feb	0.0%	0.0%	0.0%															
Mar	4.8%	-3.9%	0.0%															
Apr	0.0%	0.0%	0.0%															
May	-4.5%	4.1%	0.0%															
Jun	4.8%	-4.2%	0.0%															
Jul	0.0%	0.0%	0.0%															
Aug	0.0%	0.0%	0.0%															
Sep	0.0%	0.0%	0.0%															
Oct	-4.3%	4.3%	0.0%															
Nov	5.0%	-4.0%	0.0%															
Dec	0.0%	0.0%	0.0%															
	0.0%	**0.0%**	**0.0%**															

EHV FUEL COST ADJUSTMENT

	Monthly Hours in 2025 On	Off	Total	KWh Requirement On	Off	Total	Line Loss Factors On	Off	Total	Average Hourly KW Requirement On	Off	Total	Sales On	Off	Total	MC Revenue On	Off	Total
Scenario A (2024)																		
Jan	368	376	744	8,983,384	10,071,824	19,055,208	1.030	1.030	1.030	24,411	26,787	25,612	8,721,732	9,778,470	18,500,202	[redacted]		
Feb	320	352	672	7,877,137	8,961,947	16,839,084	1.030	1.030	1.030	24,616	25,460	25,058	7,647,706	8,700,919	16,348,625			
Mar	336	408	744	8,621,681	9,375,993	17,997,674	1.030	1.030	1.030	25,660	22,980	24,190	8,370,564	9,102,906	17,473,470			
Apr	352	368	720	7,952,051	10,763,165	18,715,216	1.030	1.030	1.030	22,591	29,248	25,993	7,720,438	10,449,675	18,170,113			
May	352	392	744	9,182,422	10,519,019	19,701,441	1.030	1.030	1.030	26,086	26,834	26,480	8,914,973	10,212,640	19,127,613			
Jun	336	384	720	8,928,497	10,108,151	19,036,648	1.030	1.030	1.030	26,573	26,323	26,440	8,668,444	9,813,739	18,482,183			
Jul	368	376	744	9,222,025	10,697,383	19,919,408	1.030	1.030	1.030	25,060	28,450	26,773	8,953,423	10,385,808	19,339,231			
Aug	336	408	744	9,462,353	10,339,095	19,801,448	1.030	1.030	1.030	28,162	25,341	26,615	9,186,751	10,037,956	19,224,707			
Sep	352	368	720	8,935,693	10,173,085	19,108,778	1.030	1.030	1.030	25,385	27,644	26,540	8,675,430	9,876,782	18,552,212			
Oct	368	376	744	9,047,178	10,335,084	19,382,262	1.030	1.030	1.030	24,585	27,487	26,051	8,783,668	10,034,062	18,817,730			
Nov	320	400	720	8,659,558	10,707,724	19,367,282	1.030	1.030	1.030	27,061	26,769	26,899	8,407,338	10,395,848	18,803,186			
Dec	368	376	744	6,983,123	9,077,115	16,060,238	1.030	1.030	1.030	18,976	24,141	21,586	6,779,731	8,812,733	15,592,464			
	4176	4584	8760	**103,855,103**	**121,129,585**	**224,984,688**	**1.030**	**1.030**	**1.030**	**24,870**	**26,424**	**25,683**	**100,830,197**	**117,601,539**	**218,431,736**			
Scenario B:	**Monthly Hours in 2026**																	
	On	**Off**	**Total**															
Jan	352	392	744	18,743,940	19,288,323	38,032,262	1.035	1.035	1.035	53,250	49,205	51,119	18,107,019	18,639,373	36,746,391	[redacted]		
Feb	320	352	672	16,474,532	17,585,124	34,059,656	1.035	1.035	1.035	51,483	49,958	50,684	15,914,162	16,991,841	32,906,003			
Mar	352	392	744	15,086,706	18,759,554	33,846,260	1.035	1.035	1.035	42,860	47,856	45,492	14,577,683	18,133,888	32,711,571			
Apr	352	368	720	16,066,756	16,945,276	33,012,032	1.035	1.034	1.034	45,644	46,047	45,850	15,529,837	16,386,254	31,916,091			
May	336	408	744	18,211,397	18,153,433	36,364,830	1.035	1.034	1.035	54,201	44,494	48,877	17,598,749	17,550,342	35,149,091			
Jun	352	368	720	16,447,406	18,885,069	35,332,475	1.035	1.034	1.035	46,726	51,318	49,073	15,893,599	18,256,913	34,150,512			
Jul	368	376	744	18,563,631	18,697,161	37,260,792	1.035	1.034	1.035	50,445	49,726	50,082	17,940,188	18,075,252	36,015,440			
Aug	336	408	744	18,419,759	19,547,752	37,967,511	1.035	1.034	1.035	54,821	47,911	51,032	17,801,249	18,898,792	36,700,041			
Sep	352	368	720	16,555,833	18,561,560	35,117,393	1.035	1.035	1.035	47,034	50,439	48,774	15,998,506	17,942,161	33,940,667			
Oct	352	392	744	17,745,175	17,179,850	34,925,025	1.035	1.034	1.035	50,412	43,826	46,942	17,147,547	16,609,383	33,756,931			
Nov	336	384	720	16,505,809	18,021,750	34,527,559	1.035	1.035	1.035	49,124	46,932	47,955	15,948,264	17,419,947	33,368,211			
Dec	368	376	744	14,661,793	17,621,650	32,283,443	1.035	1.035	1.035	39,842	46,866	43,392	14,161,911	17,025,663	31,187,574			
	4176	4,584	8760	**203,482,737**	**219,246,501**	**422,729,239**	**1.035**	**1.035**	**1.035**	**48,727**	**47,829**	**48,257**	**196,618,713**	**211,929,809**	**408,548,522**			
Jan	-4.3%	4.3%	0.0%	108.7%	91.5%	99.6%	0.5%	0.5%	0.5%	118.1%	83.7%	99.6%	107.6%	90.6%	98.6%	[redacted]		
Feb	0.0%	0.0%	0.0%	109.1%	96.2%	102.3%	0.5%	0.5%	0.5%	109.1%	96.2%	102.3%	108.1%	95.3%	101.3%			
Mar	4.8%	-3.9%	0.0%	75.0%	100.1%	88.1%	0.5%	0.4%	0.5%	67.0%	108.2%	88.1%	74.2%	99.2%	87.2%			
Apr	0.0%	0.0%	0.0%	102.0%	57.4%	76.4%	0.4%	0.4%	0.4%	102.0%	57.4%	76.4%	101.2%	56.8%	75.7%			
May	-4.5%	4.1%	0.0%	98.3%	72.6%	84.6%	0.5%	0.4%	0.4%	107.8%	65.8%	84.6%	97.4%	71.8%	83.8%			
Jun	4.8%	-4.2%	0.0%	84.2%	86.8%	85.6%	0.5%	0.4%	0.4%	75.8%	95.0%	85.6%	83.4%	86.0%	84.8%			
Jul	0.0%	0.0%	0.0%	101.3%	74.8%	87.1%	0.5%	0.4%	0.4%	101.3%	74.8%	87.1%	100.4%	74.0%	86.2%			
Aug	0.0%	0.0%	0.0%	94.7%	89.1%	91.7%	0.5%	0.4%	0.4%	94.7%	89.1%	91.7%	93.8%	88.3%	90.9%			
Sep	0.0%	0.0%	0.0%	85.3%	82.5%	83.8%	0.5%	0.4%	0.5%	85.3%	82.5%	83.8%	84.4%	81.7%	82.9%			
Oct	-4.3%	4.3%	0.0%	96.1%	66.2%	80.2%	0.5%	0.4%	0.4%	105.1%	59.4%	80.2%	95.2%	65.5%	79.4%			
Nov	5.0%	-4.0%	0.0%	90.6%	68.3%	78.3%	0.5%	0.4%	0.5%	81.5%	75.3%	78.3%	89.7%	67.6%	77.5%			
Dec	0.0%	0.0%	0.0%	110.0%	94.1%	101.0%	0.5%	0.5%	0.5%	110.0%	94.1%	101.0%	108.9%	93.2%	100.0%			
	0.0%	**0.0%**	**0.0%**	**95.9%**	**81.0%**	**87.9%**	**0.5%**	**0.4%**	**0.5%**	**95.9%**	**81.0%**	**87.9%**	**95.0%**	**80.2%**	**87.0%**			

HV FUEL COST ADJUSTMENT

	Monthly Hours in 2025 On	Off	Total	KWh Requirement On	Off	Total	Line Loss Factors On	Off	Total	Average Hourly KW Requirement On	Off	Total	Sales On	Off	Total	MC Revenue On	Off	Total
Scenario A (2024)																		
Jan	368	376	744	9,272,519	9,257,446	18,529,965	1.040	1.040	1.040	25,197	24,621	24,906	8,915,883	8,901,391	17,817,274	[redacted]		
Feb	320	352	672	8,024,199	8,792,313	16,816,512	1.040	1.040	1.040	25,076	24,978	25,025	7,715,576	8,454,147	16,169,723			
Mar	336	408	744	7,993,133	7,471,503	15,464,637	1.040	1.040	1.040	23,789	18,313	20,786	7,685,705	7,184,138	14,869,843			
Apr	352	368	720	6,389,416	8,017,414	14,406,830	1.040	1.040	1.040	18,152	21,786	20,009	6,143,670	7,709,052	13,852,721			
May	352	392	744	8,497,344	8,271,207	16,768,551	1.040	1.040	1.040	24,140	21,100	22,538	8,170,523	7,953,083	16,123,607			
Jun	336	384	720	8,359,955	7,743,743	16,103,698	1.040	1.040	1.040	24,881	20,166	22,366	8,038,418	7,445,907	15,484,325			
Jul	368	376	744	8,286,056	8,596,423	16,882,480	1.040	1.040	1.040	22,516	22,863	22,692	7,967,362	8,265,792	16,233,154			
Aug	336	408	744	8,714,314	8,062,525	16,776,839	1.040	1.040	1.040	25,935	19,761	22,550	8,379,148	7,752,428	16,131,576			
Sep	352	368	720	7,831,324	8,157,898	15,989,222	1.040	1.040	1.040	22,248	22,168	22,207	7,530,120	7,844,133	15,374,252			
Oct	368	376	744	8,093,543	7,712,840	15,806,384	1.040	1.040	1.040	21,993	20,513	21,245	7,782,253	7,416,193	15,198,446			
Nov	320	400	720	8,310,264	8,245,074	16,555,339	1.040	1.040	1.040	25,970	20,613	22,994	7,990,639	7,927,956	15,918,595			
Dec	368	376	744	7,101,168	8,693,156	15,794,324	1.040	1.040	1.040	19,297	23,120	21,229	6,828,046	8,358,804	15,186,850			
	4176	4584	8760	**96,873,237**	**99,021,544**	**195,894,781**	**1.040**	**1.040**	**1.040**	**23,198**	**21,602**	**22,362**	**93,147,343**	**95,213,023**	**188,360,366**			
Scenario B: Monthly Hours in 2026																		
	On	Off	Total															
Jan	352	392	744	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-	[redacted]		
Feb	320	352	672	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Mar	352	392	744	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Apr	352	368	720	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
May	336	408	744	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Jun	352	368	720	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Jul	368	376	744	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Aug	336	408	744	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Sep	352	368	720	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Oct	352	392	744	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Nov	336	384	720	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
Dec	368	376	744	-	-	-	#DIV/0!	#DIV/0!	#DIV/0!	-	-	-	-	-	-			
	4176	4,584	8760	**-**	**-**	**-**	**#DIV/0!**	**#DIV/0!**	**#DIV/0!**	**-**	**-**	**-**	**-**	**-**	**-**			
Jan	-4.3%	4.3%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	[redacted]		
Feb	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Mar	4.8%	-3.9%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Apr	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
May	-4.5%	4.1%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Jun	4.8%	-4.2%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Jul	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Aug	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Sep	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Oct	-4.3%	4.3%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Nov	5.0%	-4.0%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
Dec	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	0.0%	0.0%	0.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%	-100.0%			
	0.0%	**0.0%**	**0.0%**	**-100.0%**	**-100.0%**	**-100.0%**	**0.0%**	**0.0%**	**0.0%**	**-100.0%**	**-100.0%**	**-100.0%**	**-100.0%**	**-100.0%**	**-100.0%**			

3PH FUEL COST ADJUSTMENT

	Monthly Hours in 2025			KWh Requirement			Line Loss Factors			Average Hourly KW Requirement			Sales			MC Revenue		
	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total	On	Off	Total
Scenario A (2024)																		
Jan	368	376	744	28,911,522	26,640,126	55,551,647	1.061	1.061	1.061	78,564	70,851	74,666	27,245,080	25,104,606	52,349,685	[redacted]		
Feb	320	352	672	26,042,876	26,268,743	52,311,619	1.061	1.061	1.061	81,384	74,627	77,845	24,541,781	24,754,629	49,296,410			
Mar	336	408	744	29,629,679	25,040,322	54,670,001	1.061	1.061	1.061	88,184	61,373	73,481	27,921,843	23,597,014	51,518,857			
Apr	352	368	720	24,834,670	27,620,655	52,455,326	1.061	1.061	1.061	70,553	75,056	72,855	23,403,216	26,028,618	49,431,833			
May	352	392	744	28,009,796	25,407,950	53,417,746	1.061	1.061	1.061	79,573	64,816	71,798	26,395,329	23,943,452	50,338,781			
Jun	336	384	720	30,239,093	25,315,858	55,554,951	1.061	1.061	1.061	89,997	65,927	77,160	28,496,131	23,856,667	52,352,798			
Jul	368	376	744	31,147,544	30,250,436	61,397,980	1.061	1.061	1.061	84,640	80,453	82,524	29,352,219	28,506,820	57,859,039			
Aug	336	408	744	35,651,361	30,355,763	66,007,124	1.061	1.061	1.061	106,105	74,401	88,719	33,596,439	28,606,076	62,202,515			
Sep	352	368	720	29,027,910	29,365,748	58,393,658	1.061	1.061	1.061	82,466	79,798	81,102	27,354,759	27,673,124	55,027,884			
Oct	368	376	744	29,909,621	27,588,172	57,497,793	1.061	1.061	1.061	81,276	73,373	77,282	28,185,649	25,998,007	54,183,656			
Nov	320	400	720	28,789,179	26,942,117	55,731,296	1.061	1.061	1.061	89,966	67,355	77,405	27,129,789	25,389,190	52,518,979			
Dec	368	376	744	23,325,156	27,540,094	50,865,250	1.061	1.061	1.061	63,384	73,245	68,367	21,980,709	25,952,700	47,933,409			
	4176	4584	8760	**345,518,408**	**328,335,984**	**673,854,392**	**1.061**	**1.061**	**1.061**	**82,739**	**71,627**	**76,924**	**325,602,942**	**309,410,903**	**635,013,845**			
Scenario B: Monthly Hours in 2026																		
	On	Off	Total															
Jan	352	392	744	29,156,817	26,610,879	55,767,696	1.052	1.052	1.052	82,832	67,885	74,957	27,719,805	25,299,346	53,019,151	[redacted]		
Feb	320	352	672	26,585,311	26,020,489	52,605,800	1.052	1.052	1.052	83,079	73,922	78,282	25,275,038	24,738,054	50,013,091			
Mar	352	392	744	26,519,356	28,347,838	54,867,193	1.052	1.052	1.052	75,339	72,316	73,746	25,212,333	26,950,698	52,163,031			
Apr	352	368	720	28,051,965	23,892,171	51,944,135	1.052	1.052	1.052	79,693	64,924	72,145	26,669,407	22,714,630	49,384,037			
May	336	408	744	27,521,832	22,574,938	50,096,769	1.052	1.052	1.052	81,910	55,331	67,334	26,165,401	21,462,318	47,627,720			
Jun	352	368	720	24,574,733	24,040,460	48,615,193	1.052	1.052	1.052	69,815	65,327	67,521	23,363,552	22,855,611	46,219,163			
Jul	368	376	744	28,477,718	25,413,628	53,891,346	1.052	1.052	1.052	77,385	67,589	72,435	27,074,176	24,161,102	51,235,278			
Aug	336	408	744	30,964,620	28,783,121	59,747,741	1.052	1.052	1.052	92,157	70,547	80,306	29,438,510	27,364,527	56,803,038			
Sep	352	368	720	27,741,370	28,342,518	56,083,888	1.052	1.052	1.052	78,811	77,018	77,894	26,374,120	26,945,640	53,319,760			
Oct	352	392	744	29,620,017	24,773,377	54,393,394	1.052	1.052	1.052	84,148	63,197	73,109	28,160,177	23,552,406	51,712,583			
Nov	336	384	720	27,306,815	25,845,587	53,152,401	1.052	1.052	1.052	81,270	67,306	73,823	25,960,982	24,571,771	50,532,753			
Dec	368	376	744	23,926,224	26,649,892	50,576,116	1.052	1.052	1.052	65,017	70,877	67,979	22,747,005	25,336,436	48,083,441			
	4176	4,584	8760	**330,446,776**	**311,294,898**	**641,741,674**	**1.052**	**1.052**	**1.052**	**79,130**	**67,909**	**73,258**	**314,160,506**	**295,952,540**	**610,113,046**			
Jan	-4.3%	4.3%	0.0%	0.8%	-0.1%	0.4%	-0.9%	-0.9%	-0.9%	5.4%	-4.2%	0.4%	1.7%	0.8%	1.3%	[redacted]		
Feb	0.0%	0.0%	0.0%	2.1%	-0.9%	0.6%	-0.9%	-0.9%	-0.9%	2.1%	-0.9%	0.6%	3.0%	-0.1%	1.5%			
Mar	4.8%	-3.9%	0.0%	-10.5%	13.2%	0.4%	-0.9%	-0.9%	-0.9%	-14.6%	17.8%	0.4%	-9.7%	14.2%	1.3%			
Apr	0.0%	0.0%	0.0%	13.0%	-13.5%	-1.0%	-0.9%	-0.9%	-0.9%	13.0%	-13.5%	-1.0%	14.0%	-12.7%	-0.1%			
May	-4.5%	4.1%	0.0%	-1.7%	-11.2%	-6.2%	-0.9%	-0.9%	-0.9%	2.9%	-14.6%	-6.2%	-0.9%	-10.4%	-5.4%			
Jun	4.8%	-4.2%	0.0%	-18.7%	-5.0%	-12.5%	-0.9%	-0.9%	-0.9%	-22.4%	-0.9%	-12.5%	-18.0%	-4.2%	-11.7%			
Jul	0.0%	0.0%	0.0%	-8.6%	-16.0%	-12.2%	-0.9%	-0.9%	-0.9%	-8.6%	-16.0%	-12.2%	-7.8%	-15.2%	-11.4%			
Aug	0.0%	0.0%	0.0%	-13.1%	-5.2%	-9.5%	-0.9%	-0.9%	-0.9%	-13.1%	-5.2%	-9.5%	-12.4%	-4.3%	-8.7%			
Sep	0.0%	0.0%	0.0%	-4.4%	-3.5%	-4.0%	-0.9%	-0.9%	-0.9%	-4.4%	-3.5%	-4.0%	-3.6%	-2.6%	-3.1%			
Oct	-4.3%	4.3%	0.0%	-1.0%	-10.2%	-5.4%	-0.9%	-0.9%	-0.9%	3.5%	-13.9%	-5.4%	-0.1%	-9.4%	-4.6%			
Nov	5.0%	-4.0%	0.0%	-5.1%	-4.1%	-4.6%	-0.9%	-0.9%	-0.9%	-9.7%	-0.1%	-4.6%	-4.3%	-3.2%	-3.8%			
Dec	0.0%	0.0%	0.0%	2.6%	-3.2%	-0.6%	-0.9%	-0.9%	-0.9%	2.6%	-3.2%	-0.6%	3.5%	-2.4%	0.3%			
	0.0%	**0.0%**	**0.0%**	**-4.4%**	**-5.2%**	**-4.8%**	**-0.9%**	**-0.9%**	**-0.9%**	**-4.4%**	**-5.2%**	**-4.8%**	**-3.5%**	**-4.3%**	**-3.9%**			

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Case	2025 TEMPLATE COL 1	2026 TEMPLATE COL 2	% Variance
Avoided Cost_EHV	[redacted]		
MC_Rev_EHV			
Avoided Cost_HV			
MC_Rev_HV			
Avoided Cost_Distr			
MC_Rev_Distr			
MC_on			
MC_off			
MC_ave			
GR_on			
GR_off			
GR_ave			
TC_on			
TC_off			
AC_ave			
AC_on			
AC_off			
LF_ave			
MC_Jan			
MC_Feb			
MC_Mar			
MC_Apr			
MC_May			
MC_Jun			
MC_Jul			
MC_Aug			
MC_Sep			
MC_Oct			
MC_Nov			
MC_Dec			
MC_on_Jan			
MC_on_Feb			
MC_on_Mar			
MC_on_Apr			
MC_on_May			
MC_on_Jun			
MC_on_Jul			
MC_on_Aug			
MC_on_Sep			
MC_on_Oct			
MC_on_Nov			
MC_on_Dec			
MC_off_Jan			
MC_off_Feb			
MC_off_Mar			
MC_off_Apr			
MC_off_May			
MC_off_Jun			
MC_off_Jul			
MC_off_Aug			
MC_off_Sep			
MC_off_Oct			
MC_off_Nov			
MC_off_Dec			

Case	2023 GRA COS	2026 GRA COS	
	TEMPLATE COL 1	TEMPLATE COL 2	% Variance
Fixed Generation Costs			
OM&G	$135,308,637	$141,523,198	4.6%
Capital	$231,659,690	$194,573,460	-16.0%
ROE	$101,798,828	$88,981,576	-12.6%
	$468,767,155	$425,078,233	-9.3%
Fixed Transmission Costs			
OM&G	$28,078,384	$35,933,112	28.0%
Capital	$72,142,278	$66,763,576	-7.5%
ROE	$36,679,937	$33,528,832	-8.6%
	$136,900,598	$136,225,520	-0.5%
EHV Portion	0.766	1.000	
Fixed Distribution Costs			
OM&G	$38,012,458	$67,684,345	78.1%
Capital	$144,921,581	$179,178,873	23.6%
ROE	$48,984,167	$65,810,275	34.4%
	$231,918,206	$312,673,494	34.8%
Total			
OM&G	$201,399,479	$245,140,655	21.7%
Capital	$448,723,549	$440,515,908	-1.8%
ROE	$187,462,932	$188,320,684	0.5%
	$837,585,960	$873,977,247	4.3%

Case	2025	2026 (EHV & HV Combined)	
	TEMPLATE COL 1	TEMPLATE COL 2	% Variance
3CP_GEN_EHV & HV	75.96	145.32	**91.3%**
3CP_GEN_HV	73.25		**-100.0%**
3CP_GEN_Distr	273.95	326.29	**19.1%**
3CP_GEN_NSR	6,815.27	6,888.54	**1.1%**
3CP_HV_HV	70.32		**-100.0%**
3CP_HV_Distr	262.99		**-100.0%**
3CP_HV_NSR	6,542.65		**-100.0%**
3CP_Distr_Distr	262.99	303.17	**15.3%**
3CP_HV_NSR	6,542.65	6,400.50	**-2.2%**
KWHs_EHV & HV_on	103,855,103	203,482,737	**95.9%**
KWHs_EHV & HV_off	121,129,585	219,246,501	**81.0%**
KWHs_HV_on	96,873,237		**-100.0%**
KWHs_HV_off	99,021,544		**-100.0%**
KWHs_Distr_on	345,518,408	330,446,776	**-4.4%**
KWHs_Distr_off	328,335,984	311,294,898	**-5.2%**
KWHs_Total_on			**0.0%**
KWHs_Total_off			**0.0%**
KWHs_Total			**0.0%**
Customers_EHV and HV	2	8	**300.0%**
Customers_HV	6		**-100.0%**
Customers_Distr	39	39	**0.0%**
Customers_All	558,998	566,431	**1.3%**
KWHs_Total_req	10,678,536,933	10,778,679,762	**0.9%**
RTP_req_off_Jan	[redacted]		
RTP_req_off_Feb	[redacted]		
RTP_req_off_Mar	[redacted]		
RTP_req_off_Apr	[redacted]		
RTP_req_off_May	[redacted]		
RTP_req_off_Jun	[redacted]		
RTP_req_off_Jul	[redacted]		
RTP_req_off_Aug	[redacted]		
RTP_req_off_Sep	[redacted]		
RTP_req_off_Oct	[redacted]		
RTP_req_off_Nov	[redacted]		
RTP_req_off_Dec	[redacted]		
RTP_req_on_Jan	[redacted]		
RTP_req_on_Feb	[redacted]		
RTP_req_on_Mar	[redacted]		
RTP_req_on_Apr	[redacted]		
RTP_req_on_May	[redacted]		
RTP_req_on_Jun	[redacted]		
RTP_req_on_Jul	[redacted]		
RTP_req_on_Aug	[redacted]		
RTP_req_on_Sep	[redacted]		
RTP_req_on_Oct	[redacted]		
RTP_req_on_Nov	[redacted]		
RTP_req_on_Dec	[redacted]		
RTP_sales_off_Jan	[redacted]		
RTP_sales_off_Feb	[redacted]		
RTP_sales_off_Mar	[redacted]		
RTP_sales_off_Apr	[redacted]		
RTP_sales_off_May	[redacted]		
RTP_sales_off_Jun	[redacted]		
RTP_sales_off_Jul	[redacted]		
RTP_sales_off_Aug	[redacted]		
RTP_sales_off_Sep	[redacted]		
RTP_sales_off_Oct	[redacted]		
RTP_sales_off_Nov	[redacted]		
RTP_sales_off_Dec	[redacted]		
RTP_sales_on_Jan	[redacted]		
RTP_sales_on_Feb	[redacted]		
RTP_sales_on_Mar	[redacted]		
RTP_sales_on_Apr	[redacted]		
RTP_sales_on_May	[redacted]		
RTP_sales_on_Jun	[redacted]		
RTP_sales_on_Jul	[redacted]		
RTP_sales_on_Aug	[redacted]		
RTP_sales_on_Sep	[redacted]		
RTP_sales_on_Oct	[redacted]		
RTP_sales_on_Nov	[redacted]		
RTP_sales_on_Dec	[redacted]		

3PH_Elig_req_off_Jan	26,640,126	26,610,879	-0.1%
3PH_Elig_req_off_Feb	26,268,743	26,020,489	-0.9%
3PH_Elig_req_off_Mar	25,040,322	28,347,838	13.2%
3PH_Elig_req_off_Apr	27,620,655	23,892,171	-13.5%
3PH_Elig_req_off_May	25,407,950	22,574,938	-11.2%
3PH_Elig_req_off_Jun	25,315,858	24,040,460	-5.0%
3PH_Elig_req_off_Jul	30,250,436	25,413,628	-16.0%
3PH_Elig_req_off_Aug	30,355,763	28,783,121	-5.2%
3PH_Elig_req_off_Sep	29,365,748	28,342,518	-3.5%
3PH_Elig_req_off_Oct	27,588,172	24,773,377	-10.2%
3PH_Elig_req_off_Nov	26,942,117	25,845,587	-4.1%
3PH_Elig_req_off_Dec	27,540,094	26,649,892	-3.2%
3PH_Elig_req_on_Jan	28,911,522	29,156,817	0.8%
3PH_Elig_req_on_Feb	26,042,876	26,585,311	2.1%
3PH_Elig_req_on_Mar	29,629,679	26,519,356	-10.5%
3PH_Elig_req_on_Apr	24,834,670	28,051,965	13.0%
3PH_Elig_req_on_May	28,009,796	27,521,832	-1.7%
3PH_Elig_req_on_Jun	30,239,093	24,574,733	-18.7%
3PH_Elig_req_on_Jul	31,147,544	28,477,718	-8.6%
3PH_Elig_req_on_Aug	35,651,361	30,964,620	-13.1%
3PH_Elig_req_on_Sep	29,027,910	27,741,370	-4.4%
3PH_Elig_req_on_Oct	29,909,621	29,620,017	-1.0%
3PH_Elig_req_on_Nov	28,789,179	27,306,815	-5.1%
3PH_Elig_req_on_Dec	23,325,156	23,926,224	2.6%
3PH_Elig_sales_off_Jan	25,104,606	25,299,346	0.8%
3PH_Elig_sales_off_Feb	24,754,629	24,738,054	-0.1%
3PH_Elig_sales_off_Mar	23,597,014	26,950,698	14.2%
3PH_Elig_sales_off_Apr	26,028,618	22,714,630	-12.7%
3PH_Elig_sales_off_May	23,943,452	21,462,318	-10.4%
3PH_Elig_sales_off_Jun	23,856,667	22,855,611	-4.2%
3PH_Elig_sales_off_Jul	28,506,820	24,161,102	-15.2%
3PH_Elig_sales_off_Aug	28,606,076	27,364,527	-4.3%
3PH_Elig_sales_off_Sep	27,673,124	26,945,640	-2.6%
3PH_Elig_sales_off_Oct	25,998,007	23,552,406	-9.4%
3PH_Elig_sales_off_Nov	25,389,190	24,571,771	-3.2%
3PH_Elig_sales_off_Dec	25,952,700	25,336,436	-2.4%
3PH_Elig_sales_on_Jan	27,245,080	27,719,805	1.7%
3PH_Elig_sales_on_Feb	24,541,781	25,275,038	3.0%
3PH_Elig_sales_on_Mar	27,921,843	25,212,333	-9.7%
3PH_Elig_sales_on_Apr	23,403,216	26,669,407	14.0%
3PH_Elig_sales_on_May	26,395,329	26,165,401	-0.9%
3PH_Elig_sales_on_Jun	28,496,131	23,363,552	-18.0%
3PH_Elig_sales_on_Jul	29,352,219	27,074,176	-7.8%
3PH_Elig_sales_on_Aug	33,596,439	29,438,510	-12.4%
3PH_Elig_sales_on_Sep	27,354,759	26,374,120	-3.6%
3PH_Elig_sales_on_Oct	28,185,649	28,160,177	-0.1%
3PH_Elig_sales_on_Nov	27,129,789	25,960,982	-4.3%
3PH_Elig_sales_on_Dec	21,980,709	22,747,005	3.5%
HV_Elig_req_off_Jan	9,257,446		-100.0%
HV_Elig_req_off_Feb	8,792,313		-100.0%
HV_Elig_req_off_Mar	7,471,503		-100.0%
HV_Elig_req_off_Apr	8,017,414		-100.0%
HV_Elig_req_off_May	8,271,207		-100.0%
HV_Elig_req_off_Jun	7,743,743		-100.0%
HV_Elig_req_off_Jul	8,596,423		-100.0%
HV_Elig_req_off_Aug	8,062,525		-100.0%
HV_Elig_req_off_Sep	8,157,898		-100.0%
HV_Elig_req_off_Oct	7,712,840		-100.0%
HV_Elig_req_off_Nov	8,245,074		-100.0%
HV_Elig_req_off_Dec	8,693,156		-100.0%
HV_Elig_req_on_Jan	9,272,519		-100.0%
HV_Elig_req_on_Feb	8,024,199		-100.0%
HV_Elig_req_on_Mar	7,993,133		-100.0%
HV_Elig_req_on_Apr	6,389,416		-100.0%
HV_Elig_req_on_May	8,497,344		-100.0%
HV_Elig_req_on_Jun	8,359,955		-100.0%
HV_Elig_req_on_Jul	8,286,056		-100.0%
HV_Elig_req_on_Aug	8,714,314		-100.0%
HV_Elig_req_on_Sep	7,831,324		-100.0%
HV_Elig_req_on_Oct	8,093,543		-100.0%
HV_Elig_req_on_Nov	8,310,264		-100.0%
HV_Elig_req_on_Dec	7,101,168		-100.0%

HV_Elig_sales_off_Jan	8,901,391		-100.0%
HV_Elig_sales_off_Feb	8,454,147		-100.0%
HV_Elig_sales_off_Mar	7,184,138		-100.0%
HV_Elig_sales_off_Apr	7,709,052		-100.0%
HV_Elig_sales_off_May	7,953,083		-100.0%
HV_Elig_sales_off_Jun	7,445,907		-100.0%
HV_Elig_sales_off_Jul	8,265,792		-100.0%
HV_Elig_sales_off_Aug	7,752,428		-100.0%
HV_Elig_sales_off_Sep	7,844,133		-100.0%
HV_Elig_sales_off_Oct	7,416,193		-100.0%
HV_Elig_sales_off_Nov	7,927,956		-100.0%
HV_Elig_sales_off_Dec	8,358,804		-100.0%
HV_Elig_sales_on_Jan	8,915,883		-100.0%
HV_Elig_sales_on_Feb	7,715,576		-100.0%
HV_Elig_sales_on_Mar	7,685,705		-100.0%
HV_Elig_sales_on_Apr	6,143,670		-100.0%
HV_Elig_sales_on_May	8,170,523		-100.0%
HV_Elig_sales_on_Jun	8,038,418		-100.0%
HV_Elig_sales_on_Jul	7,967,362		-100.0%
HV_Elig_sales_on_Aug	8,379,148		-100.0%
HV_Elig_sales_on_Sep	7,530,120		-100.0%
HV_Elig_sales_on_Oct	7,782,253		-100.0%
HV_Elig_sales_on_Nov	7,990,639		-100.0%
HV_Elig_sales_on_Dec	6,828,046		-100.0%
EHV & HV_Elig_req_off_Jan	10,071,824	19,288,323	91.51%
EHV & HV_Elig_req_off_Feb	8,961,947	17,585,124	96.22%
EHV & HV_Elig_req_off_Mar	9,375,993	18,759,554	100.08%
EHV & HV_Elig_req_off_Apr	10,763,165	16,945,276	57.44%
EHV & HV_Elig_req_off_May	10,519,019	18,153,433	72.58%
EHV & HV_Elig_req_off_Jun	10,108,151	18,885,069	86.83%
EHV & HV_Elig_req_off_Jul	10,697,383	18,697,161	74.78%
EHV & HV_Elig_req_off_Aug	10,339,095	19,547,752	89.07%
EHV & HV_Elig_req_off_Sep	10,173,085	18,561,560	82.46%
EHV & HV_Elig_req_off_Oct	10,335,084	17,179,850	66.23%
EHV & HV_Elig_req_off_Nov	10,707,724	18,021,750	68.31%
EHV & HV_Elig_req_off_Dec	9,077,115	17,621,650	94.1%
EHV & HV_Elig_req_on_Jan	8,983,384	18,743,940	108.7%
EHV & HV_Elig_req_on_Feb	7,877,137	16,474,532	109.1%
EHV & HV_Elig_req_on_Mar	8,621,681	15,086,706	75.0%
EHV & HV_Elig_req_on_Apr	7,952,051	16,066,756	102.0%
EHV & HV_Elig_req_on_May	9,182,422	18,211,397	98.3%
EHV & HV_Elig_req_on_Jun	8,928,497	16,447,406	84.2%
EHV & HV_Elig_req_on_Jul	9,222,025	18,563,631	101.3%
EHV & HV_Elig_req_on_Aug	9,462,353	18,419,759	94.7%
EHV & HV_Elig_req_on_Sep	8,935,693	16,555,833	85.3%
EHV & HV_Elig_req_on_Oct	9,047,178	17,745,175	96.1%
EHV & HV_Elig_req_on_Nov	8,659,558	16,505,809	90.6%
EHV & HV_Elig_req_on_Dec	6,983,123	14,661,793	110.0%
EHV & HV_Elig_sales_off_Jan	9,778,470	18,639,373	90.6%
EHV & HV_Elig_sales_off_Feb	8,700,919	16,991,841	95.3%
EHV & HV_Elig_sales_off_Mar	9,102,906	18,133,888	99.2%
EHV & HV_Elig_sales_off_Apr	10,449,675	16,386,254	56.8%
EHV & HV_Elig_sales_off_May	10,212,640	17,550,342	71.8%
EHV & HV_Elig_sales_off_Jun	9,813,739	18,256,913	86.0%
EHV & HV_Elig_sales_off_Jul	10,385,808	18,075,252	74.0%
EHV & HV_Elig_sales_off_Aug	10,037,956	18,898,792	88.3%
EHV & HV_Elig_sales_off_Sep	9,876,782	17,942,161	81.7%
EHV & HV_Elig_sales_off_Oct	10,034,062	16,609,383	65.5%
EHV & HV_Elig_sales_off_Nov	10,395,848	17,419,947	67.6%
EHV & HV_Elig_sales_off_Dec	8,812,733	17,025,663	93.2%
EHV & HV_Elig_sales_on_Jan	8,721,732	18,107,019	107.6%
EHV & HV_Elig_sales_on_Feb	7,647,706	15,914,162	108.1%
EHV & HV_Elig_sales_on_Mar	8,370,564	14,577,683	74.2%
EHV & HV_Elig_sales_on_Apr	7,720,438	15,529,837	101.2%
EHV & HV_Elig_sales_on_May	8,914,973	17,598,749	97.4%
EHV & HV_Elig_sales_on_Jun	8,668,444	15,893,599	83.4%
EHV & HV_Elig_sales_on_Jul	8,953,423	17,940,188	100.4%
EHV & HV_Elig_sales_on_Aug	9,186,751	17,801,249	93.8%
EHV & HV_Elig_sales_on_Sep	8,675,430	15,998,506	84.4%
EHV & HV_Elig_sales_on_Oct	8,783,668	17,147,547	95.2%
EHV & HV_Elig_sales_on_Nov	8,407,338	15,948,264	89.7%
EHV & HV_Elig_sales_on_Dec	6,779,731	14,161,911	108.9%

1P-RTP ADDER CALCULATION

Line No		Approved Year 2025				Proposed Year 2026				% VARIANCE		
1												
2		Approved Year 2025				Proposed Year 2026						
4		Exclude the GRLF, LRT and Shore Power rate classes.				Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.				% VARIANCE		
5		ON-PEAK	OFF-PEAK	TOTAL	% Share/ Factors	ON-PEAK	OFF-PEAK	TOTAL	% Share/Factors	ON-PEAK	OFF-PEAK	TOTAL
7	**RTP ADDER COMPONENTS BY THE COST FUNCTIONAL AREAS ADJUSTED FOR FUEL COST IMBALANCE IN CENTS PER KWH**											
8												
9	**Transmission-connected**											
10	**Generation Costs**	$0.07633	$0.00000			$0.04561	$0.00000			-40%		
11	**Transmission Costs**	$0.00788	$0.00788			$0.00703	$0.00703			-11%	-11%	
12	**Customer Cost**	$0.00004	$0.00004			$0.00009	$0.00009			114%	114%	
13	**Total**	**$0.08425**	**$0.00793**			**$0.05274**	**$0.00713**			**-37%**	**-10%**	
14												
15	**HV (Not Applicable starting in 2026)**											
16	**Generation Costs**	$0.07901	$0.00000							-100.0%		
17	**EHV Transmission Costs**	$0.00958	$0.00958							-100.0%	-100.0%	
18	**HV Transmission Costs**	$0.00183	$0.00183							-100.0%	-100.0%	
19	**Customer Cost**	$0.00015	$0.00015							-100.0%	-100.0%	
20	**Total**	**$0.09058**	**$0.01156**							**-100.0%**	**-100.0%**	
21												
22	**3PH Distribution**											
23	**Adjusted Generation Costs**	$0.06323	$0.00000			$0.06409	$0.00000			1.4%		
24	**Transmission Costs**	$0.00880	$0.00880			$0.01058	$0.01058			20.2%	20.2%	
25	**HV Transmission Costs**	$0.00203	$0.00203							-100.0%	-100.0%	
26	**Distribution Costs**	$0.01468	$0.01468			$0.02428	$0.02428			65.4%	65.4%	
27	**Customer Cost**	$0.00029	$0.00029			$0.00031	$0.00031			4.1%	4.1%	
28	**Total**	**$0.08903**	**$0.02580**			**$0.09925**	**$0.03516**			**11.5%**	**36.3%**	
30	**RTP ADDER COST COMPONENTS IN CENTS PER KWH**											
32	**Transmission-connected**											
33	**O&M**	$0.01496				$0.01518				1.5%		
34	**Capital**	$0.02561				$0.02088				-18.5%		
35	**ROE**	$0.01125				$0.00955				-15.2%		
36	**Generation Costs**	**$0.05182**				**$0.04561**				-12.0%		
38	**O&M**	$0.00110	$0.00110			$0.00186	$0.00186			69.1%	69.1%	
39	**Capital**	$0.00282	$0.00282			$0.00345	$0.00345			22.3%	22.3%	
40	**ROE**	$0.00143	$0.00143			$0.00173	$0.00173			20.8%	20.8%	
41	**Transmission Costs**	**$0.00535**	**$0.00535**			**$0.00703**	**$0.00703**			31.5%	31.5%	
43	**Fixed Costs**	**$0.05717**	**$0.00535**			**$0.05264**	**$0.00703**			-7.9%	31.5%	
45	**Avoided Costs**	$0.19937	$0.01866			$0.00000	$0.00000			-100.0%	-100.0%	
46	**less: MC Revenue**	$0.17233	$0.01613			$0.00000	$0.00000			-100.0%	-100.0%	
47	**Fuel Cost Adj**	**$0.02704**	**$0.00253**			**$0.00000**	**$0.00000**			-100.0%	-100.0%	
49	**Customer Cost**	**$0.00004**	**$0.00004**			**$0.00009**	**$0.00009**			113.9%	113.9%	
50	**EHV**	**$0.08425**	**$0.00793**			**$0.05274**	**$0.00713**			-37.4%	-10.1%	

Line		Approved Year 2025		Proposed Year 2026		% VARIANCE	
4		Exclude the GRLF, LRT and Shore Power rate classes.		Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.			
52	**HV (Not Applicable starting in 2026)**						
53	O&M	$0.01561				-100.0%	
54	Capital	$0.02673				-100.0%	
55	ROE	$0.01175				-100.0%	
56	Generation Costs	$0.05409				-100.0%	
57							
58	O&M	$0.00160	$0.00160			-100.0%	-100.0%
59	Capital	$0.00412	$0.00412			-100.0%	-100.0%
60	ROE	$0.00209	$0.00209			-100.0%	-100.0%
61	Transmission Costs	$0.00781	$0.00781			-100.0%	-100.0%
62							
63	Fixed Costs	$0.06190	$0.00781			-100.0%	-100.0%
64							
65	Avoided Costs	$0.18982	$0.02395			-100.0%	-100.0%
66	less: MC Revenue	$0.16130	$0.02036			-100.0%	-100.0%
67	Fuel Cost Adj	$0.02852	$0.00360			-100.0%	-100.0%
69	Customer Cost	$0.00015	$0.00015			-100.0%	-100.0%
70	HV	$0.09058	$0.01156			-100.0%	-100.0%
72	**DISTRIBUTION VOLTAGE**						
73	O&M	$0.01670		$0.02134		27.7%	
74	Capital	$0.02860		$0.02934		2.6%	
75	ROE	$0.01257		$0.01342		6.8%	
76	Generation Costs	$0.05787		$0.06409		10.8%	
77							
78	O&M	$0.00178	$0.00178	$0.00279	$0.00279	57.0%	57.0%
79	Capital	$0.00457	$0.00457	$0.00518	$0.00518	13.5%	13.5%
80	ROE	$0.00232	$0.00232	$0.00260	$0.00260	12.1%	12.1%
81	Transmission Costs	$0.00867	$0.00867	$0.010576	$0.01058	22.0%	22.0%
82							
83	O&M	$0.00241	$0.00241	$0.00525	$0.00525	118.4%	118.4%
84	Capital	$0.00917	$0.00917	$0.01391	$0.01391	51.6%	51.6%
85	ROE	$0.00310	$0.00310	$0.00511	$0.00511	64.8%	64.8%
86	Distribution Costs	$0.01468	$0.01468	$0.02428	$0.02428	65.4%	65.4%
87							
88	Fixed Costs	$0.08122	$0.02335	$0.09894	$0.03485	21.8%	49.3%
89							
90	Avoided Costs	$0.14419	$0.04145	$0.00000	$0.00000	-100.0%	-100.0%
91	less: MC Revenue	$0.13666	$0.03928	$0.00000	$0.00000	-100.0%	-100.0%
92	Fuel Cost Adj	$0.00752	$0.00216	$0.00000	$0.00000	-100.0%	-100.0%
93							
94	Customer Costs	$0.00029	$0.00029	$0.00031	$0.00031	4.1%	4.1%
95	Distribution	$0.08903	$0.02580	$0.09925	$0.03516	11.5%	36.3%
96							

2		Approved Year 2025			Proposed Year 2026					
4		Exclude the GRLF, LRT and Shore Power rate classes.			Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.			% VARIANCE		
97	Allocation of Fixed Costs of GENCO & WIRECO									
98	**Generation**									
100	**OM&G**									
101	**Transmission-connected**	$1,508,132		$1,508,132	$2,985,593		$2,985,593	98.0%		98.0%
102	**HV (Not Applicable starting in 2026)**	$1,454,265		$1,454,265	$0		$0	-100.0%		-100.0%
103	**Distr. Class**	$5,438,851		$5,438,851	$6,703,582		$6,703,582	23.3%		23.3%
104	**Eligible Total**	$8,401,247		$8,401,247	$9,689,175		$9,689,175	15.3%		15.3%
105	**None Eligible Total**	$126,907,390		$126,907,390	$131,834,022		$131,834,022	3.9%		3.9%
106	**NSPI Total**	**$135,308,637**		**$135,308,637**	**$141,523,198**		**$141,523,198**	4.6%		4.6%
108	**Capital**									
109	**Transmission-connected**	$2,582,047		$2,582,047	$4,104,749		$4,104,749	59.0%		59.0%
110	**HV (Not Applicable starting in 2026)**	$2,489,823		$2,489,823	$0		$0	-100.0%		-100.0%
111	**Distr. Class**	$9,311,767		$9,311,767	$9,216,434		$9,216,434	-1.0%		-1.0%
112	**Eligible Total**	$14,383,637		$14,383,637	$13,321,183		$13,321,183	-7.4%		-7.4%
113	**None Eligible Total**	$217,276,053		$217,276,053	$181,252,277		$181,252,277	-16.6%		-16.6%
114	**NSPI Total**	**$231,659,690**		**$231,659,690**	**$194,573,460**		**$194,573,460**	-16.0%		-16.0%
116	**ROE**									
117	**Transmission-connected**	$1,134,636		$1,134,636	$1,877,168		$1,877,168	65.4%		65.4%
118	**HV (Not Applicable starting in 2026)**	$1,094,109		$1,094,109	$0		$0	-100.0%		-100.0%
119	**Distr. Class**	$4,091,894		$4,091,894	$4,214,824		$4,214,824	3.0%		3.0%
120	**Eligible Total**	$6,320,639		$6,320,639	$6,091,991		$6,091,991	-3.6%		-3.6%
121	**None Eligible Total**	$95,478,188		$95,478,188	$82,889,585		$82,889,585	-13.2%		-13.2%
122	**NSPI Total**	**$101,798,828**		**$101,798,828**	**$88,981,576**		**$88,981,576**	-12.6%		-12.6%
123										
124	**Generation Total**									
125	**Transmission-connected**	$5,224,815		$5,224,815	$8,967,510		$8,967,510	71.6%		71.6%
126	**HV (Not Applicable starting in 2026)**	$5,038,196		$5,038,196	$0		$0	-100.0%		-100.0%
127	**Distr. Class**	$18,842,512		$18,842,512	$20,134,840		$20,134,840	6.9%		6.9%
128	**Eligible Total**	$29,105,523		$29,105,523	$29,102,349		$29,102,349	0.0%		0.0%
129	**None Eligible Total**	$439,661,632		$439,661,632	$395,975,884		$395,975,884	-9.9%		-9.9%
130	**NSPI Total**	**$468,767,155**		**$468,767,155**	**$425,078,233**		**$425,078,233**	-9.3%		-9.3%
131										
132	**Transmission**									
133	**OM&G**									
134	**Transmission-connected**	$110,660	$129,066	$239,726	$364,820	$393,230	$758,050	229.7%	204.7%	216.2%
135	**HV (Not Applicable starting in 2026)**	$149,235	$152,545	$301,780				-100.0%	-100.0%	-100.0%
136	**Distr. Class**	$578,707	$549,928	$1,128,636	$876,426	$825,631	$1,702,057	51.4%	50.1%	50.8%
137	**Eligible Total**	$838,602	$831,539	$1,670,141	$1,241,247	$1,218,860	$2,460,107	48.0%	46.6%	47.3%
138	**None Eligible Total**			$26,408,243			$33,473,004			26.8%
139	**NSPI Total**			**$28,078,384**			**$35,933,112**			28.0%
141	**Capital**									
142	**Transmission-connected**	$284,320	$331,612	$615,931	$677,835	$730,619	$1,408,454	138.4%	120.3%	128.7%
143	**HV (Not Applicable starting in 2026)**	$383,432	$391,936	$775,368				-100.0%	-100.0%	-100.0%
144	**Distr. Class**	$1,486,882	$1,412,941	$2,899,823	$1,628,397	$1,534,019	$3,162,415	9.5%	8.6%	9.1%
145	**Eligible Total**	$2,154,635	$2,136,488	$4,291,122	$2,306,231	$2,264,638	$4,570,869	7.0%	6.0%	6.5%
146	**None Eligible Total**			$67,851,156			$62,192,707			-8.3%
147	**NSPI Total**			**$72,142,278**			**$66,763,576**			-7.5%

Row		Approved Year 2025			Proposed Year 2026					
4		Exclude the GRLF, LRT and Shore Power rate classes.			Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.			% VARIANCE		
149	**ROE**									
150	**Transmission-connected**	$144,559	$168,604	$313,163	$340,410	$366,919	$707,329	135.5%	117.6%	125.9%
151	**HV (Not Applicable starting in 2026)**	$194,952	$199,275	$394,227				-100.0%	-100.0%	-100.0%
152	**Distr. Class**	$755,989	$718,394	$1,474,383	$817,785	$770,388	$1,588,173	8.2%	7.2%	7.7%
153	**Eligible Total**	$1,095,500	$1,086,273	$2,181,773	$1,158,195	$1,137,307	$2,295,502	5.7%	4.7%	5.2%
154	**None Eligible Total**			$34,498,163			$31,233,331			-9.5%
155	**NSPI Total**			**$36,679,937**			**$33,528,832**			-8.6%
157	**Transmission Total**									
158	**Transmission-connected**	$539,539	$629,282	$1,168,820	$1,383,065	$1,490,767	$2,873,833	156.3%	136.9%	145.9%
159	**HV (Not Applicable starting in 2026)**	$727,619	$743,755	$1,471,375				-100.0%	-100.0%	-100.0%
160	**Distr. Class**	$2,821,578	$2,681,263	$5,502,841	$3,322,608	$3,130,038	$6,452,645	17.8%	16.7%	17.3%
161	**Eligible Total**	$4,088,736	$4,054,300	$8,143,036	$4,705,673	$4,620,805	$9,326,478	15.1%	14.0%	14.5%
162	**None Eligible Total**			$128,757,562			$126,899,042			-1.4%
163	**NSPI Total**			**$136,900,598**			**$136,225,520**			-0.5%
164										
165	**Distribution**									
166	**OM&G**									
167	**Eligible Total**	$783,453	$744,492	$1,527,945	$1,650,855	$1,555,175	$3,206,030	110.7%	108.9%	109.8%
168	**None Eligible Total**			$36,484,514			$64,478,316			76.7%
169	**NSPI Total**			$38,012,458			$67,684,345			78.1%
171	**Capital**									
172	**Eligible Total**	$2,986,894	$2,838,358	$5,825,252	$4,370,261	$4,116,972	$8,487,233	46.3%	45.0%	45.7%
173	**None Eligible Total**			$139,096,329			$170,691,640			22.7%
174	**NSPI Total**			$144,921,581			$179,178,873			23.6%
176	**ROE**									
177	**Eligible Total**	$1,009,584	$959,378	$1,968,962	$1,605,145	$1,512,115	$3,117,260	59.0%	57.6%	58.3%
178	**None Eligible Total**			$47,015,205			$62,693,015			33.3%
179	**NSPI Total**			$48,984,167			$65,810,275			34.4%
181	**Distribution Total**									
182	**Eligible Total**	$4,779,931	$4,542,228	$9,322,158	$7,626,261	$7,184,262	$14,810,522	59.5%	58.2%	58.9%
183	**None Eligible Total**			$222,596,048			$297,862,971			33.8%
184	**NSPI Total**			**$231,918,206**			**$312,673,494**			34.8%
185										
186	**Total Cost Break-down by Category**									
187	**OM&G**			$201,399,479			$245,140,655			21.7%
188	**Capital**			$448,723,549			$440,515,908			-1.8%
189	**ROE**			$187,462,932			$188,320,684			0.5%
190	**Total**			**$837,585,960**			**$873,977,247**			**4.3%**
191										
192										

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

		Approved Year 2025	Proposed Year 2026	
2				
4		Exclude the GRLF, LRT and Shore Power rate classes.	Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.	% VARIANCE

193 Fuel Cost Adjustment

[redacted]

Row		Approved Year 2025				Proposed Year 2026				% VARIANCE		
2		**Approved Year 2025**				**Proposed Year 2026**						
4		**Exclude the GRLF, LRT and Shore Power rate classes.**				**Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.**				**% VARIANCE**		
237												
238	**Customer Admin Costs by Voltage Classes**											
239												
240	**EHV**											
241	Customers			2				8				300.0%
242	Average Cost per month			$400				$400				0.0%
243	Total	$4,431	$5,169	$9,600		$18,480	$19,920	$38,400		317.0%	285.4%	300.0%
244												
245	**HV (Not Applicable starting in 2026)**											
246	Customers			6								-100.0%
247	Average Cost per month			$400								-100.0%
248	Total	$14,242	$14,558	$28,800						-100.0%	-100.0%	-100.0%
249												
250	**3PH**											
251	Customers			39				39				0.0%
252	Average Cost per month			$400				$400				0.0%
253	Total	$95,765	$91,002	$186,767		$96,170	$90,597	$186,767		0.4%	-0.4%	0.0%
254												
255	**COST DETERMINANTS OF ELIGIBLE VOLTAGE CLASSES**											
256												
257	**Sum of 3 Coincident Peak Contributions by eligible Voltage Classes**											
258												
259												
260	**Generation and EHV Transmission Systems**											
261	EHV			76.0	1.11%			145.3	2.11%			91.3%
262	HV (Not Applicable starting in 2026)			73.2	1.07%							-100.0%
263	3PH			273.9	4.02%			326.3	4.74%			19.1%
264	None Eligible			6392.1	93.79%			6416.9	93.15%			0.4%
265	Total			6,815.3	100.00%			6,888.5	100.00%			1.1%
266												
267	**HV Transmission System**											
268	HV (Not Applicable starting in 2026)			70.3	1.07%							-100.0%
269	3PH			263.0	4.02%							-100.0%
270	None Eligible			6,209.3	94.91%							-100.0%
271	Total			6,542.7	100.00%							-100.0%
272												
273	**Distribution System**											
274	3PH			263.0	4.02%			303.2	4.74%			15.3%
275	None Eligible			6,279.7	95.98%			6,097.3	95.26%			-2.9%
276	Total			6,542.7	100.00%			6,400.5	100.00%			-2.2%
277												

		Approved Year 2025				Proposed Year 2026						
2												
4		Exclude the GRLF, LRT and Shore Power rate classes.				Exclude the following rate classes: the GRLF, OATT, LRT and Shore Power.				% VARIANCE		
278	**KWh Load by eligible voltage Classes**											
279												
280	**Average Hourly KW Requirement**											
281	EHV	24,870	26,424	25,683		48,727	47,829	48,257		95.9%	81.0%	87.9%
282	HV (Not Applicable starting in 2026)	23,198	21,602	22,362						-100.0%	-100.0%	-100.0%
283	3PH	82,739	71,627	76,924		79,130	67,909	73,258		-4.4%	-5.2%	-4.8%
284												
285	**MWh Sales per One MW of 3CP**											
286	EHV	1,327	1,548	2,876		1,353	1,458	2,811		1.9%	-5.8%	-2.2%
287	HV (Not Applicable starting in 2026)	1,272	1,300	2,572						-100.0%	-100.0%	-100.0%
288	3PH	1,189	1,129	2,318		963	907	1,870		-19.0%	-19.7%	-19.3%
289												
290	**KWh Requirement**											
291	EHV	103,855,103	121,129,585	224,984,688	20.6%	203,482,737	219,246,501	422,729,239	39.7%	95.9%	81.0%	87.9%
292	HV (Not Applicable starting in 2026)	96,873,237	99,021,544	195,894,781	17.9%					-100.0%	-100.0%	-100.0%
293	3PH	345,518,408	328,335,984	673,854,392	61.6%	330,446,776	311,294,898	641,741,674	60.3%	-4.4%	-5.2%	-4.8%
	Total	546,246,748	548,487,113	1,094,733,861	100.0%	533,929,514	530,541,399	1,064,470,913	100.0%			
294												
295	**KWh Sales**											
296	EHV	100,830,197	117,601,539	218,431,736	21.0%	196,618,713	211,929,809	408,548,522	40.1%	95.0%	80.2%	87.0%
297	HV	93,147,343	95,213,023	188,360,366	18.1%					-100.0%	-100.0%	-100.0%
298	3PH	325,602,942	309,410,903	635,013,845	61.0%	314,160,506	295,952,540	610,113,046	59.9%	-3.5%	-4.3%	-3.9%
	Total	519,580,483	522,225,464	1,041,805,947	100.0%	510,779,220	507,882,348	1,018,661,568	100.0%			
299												
300	**% Line Losses**											
301	EHV	3.0%	3.0%	3.0%		3.5%	3.5%	3.5%				
302	HV (Not Applicable starting in 2026)	4.0%	4.0%	4.0%		#DIV/0!	#DIV/0!	#DIV/0!				
303	3PH	6.1%	6.1%	6.1%		5.2%	5.2%	5.2%				
304												
305	**% Sales Split by TOU**											
306	EHV	46.16%	53.84%	100.00%		48.13%	51.87%	100.00%		4.3%	-3.7%	0.0%
307	HV (Not Applicable starting in 2026)	49.45%	50.55%	100.00%						-100.0%	-100.0%	-100.0%
308	3PH	51.27%	48.73%	100.00%		51.49%	48.51%	100.00%		0.4%	-0.4%	0.0%
309												
311	**Customer Count**											
312	Transmission-connected			2				8				300.0%
313	HV (Not Applicable starting in 2026)			6								-100.0%
314	3PH Class			39				39				0.0%
315	None Eligible			558,951				566,384				1.3%
316	Total			558,998				566,431				1.3%

2026 AAR Compliance Filing Appendix C has been filed electronically.

COST BREADOWN BY FUNCTIONAL AREA

Source: 2026 COSS with GRA application Filing

EXHIBIT 6.1
PAGE 11 OF 11

`

RATE CLASS DISAGGREGATION ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2023

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)	$1,528,710	$740,938	$74,223	$109,815	$53,749	$237,787	$978,725	10,548,590	---	9.278	---
(2)	Reliability (Demand)	$1,002,060	$168,963	$67,300	$84,759	$35,232	$187,291	356,254	22,327,201	$15.956	---	---
(3)	**Total Generation**	$2,530,770	$909,901	$141,523	$194,573	$88,982	$425,078	$1,334,979		$15.956	9.278	$0.000
(4)	MWh Sales		10,548,590	10,548,590	10,548,590	10,548,590	10,548,590	10,548,590				
(5)	MWh Energy Requirement		11,303,785									
(6)	kW 3 CP		9,225,751									
(7)	kW 12 NCP		22,327,201									
(8)	Unit Cost (cents/kW.h)		8.626	1.342	1.845	0.844	4.030	12.656				
	Transmission/Distribution											
(9)	Delivery--Trans.(Eng) - HV	0	0	$0	$0	$0	0	$0	10,548,590	---	0.000	---
(10)	Delivery--Trans.(Eng) - EHV	0	0	0	0	0	0	0	10,548,590		0.000	
(11)	Delivery--Trans.(Dmd) - HV	0	0	0	0	0	0	0	22,327,201	$0.000	---	---
(12)	Delivery--Trans.(Dmd) - EHV	953,610	0	35,933	66,764	33,529	136,226	136,226	22,327,201	$6.101	---	---
(13)	**Total Transmission**	$953,610	$0	$35,933	$66,764	$33,529	$136,226	$136,226		$6.101	-	$0.000
(14)	Delivery -- Dist. (Demand)	1,091,895	0	19,536	107,674	38,391	165,601	165,601	22,327,201	$7.417	---	---
(15)	Delivery -- Dist. (Customer)	779,848	0	48,149	71,505	27,419	147,073	147,073	6,478,208	---	---	$22.703
(16)	**Total Distribution**	1,871,743	0	67,684	179,179	65,810	312,673	312,673		$7.417	-	$22.703
(17)	**Total Transmission/Distribution**	$2,825,354	$0	$103,617	$245,942	$99,339	$448,899	$448,899		$13.518	-	$22.703
(18)	kW.h Sold		---	10,548,590	10,548,590	10,548,590	10,548,590	10,548,590				
(19)	Unit Cost (cents/kW.h)		---	0.982	2.332	0.942	4.256	4.256				
	Retail											
(20)	Customer -- Field		0	$6,321	0	0	$6,321	$6,321	6,478,208	0.000	0.000	$0.976
(21)	Customer -- Head Office	206,880	0	3,144	11,432	7,274	21,850	21,850	6,478,208	0.000	0.000	$3.373
(22)	**Total Customer**	$206,880	0	9,465	11,432	7,274	28,172	28,172	6,478,208	$0.000	-	$4.349
(23)	Marketing		0	13,257	0	0	13,257	13,257	6,478,208	0.000	0.000	$2.046
(24)	**Total Retail**	$206,880	$0	$22,722	$11,432	$7,274	$41,428	41,428	6,478,208	0	-	$6.395
(25)	Total Customers x 12 months		---	6,478,208			6,054,372	6,054,372				
(26)	Unit Cost ($/month)		---	$3.508			$3.508	$3.508				
(27)	**TOTAL**	**$5,563,003**	**$909,901**	**$267,863**	**$451,948**	**$195,595**	**$915,406**	**$1,825,306**		$29.474	9.278	$29.098
(28)	**Unit Cost (cents/kW.h)**		**8.626**	**2.539**	**4.284**	**1.854**	**8.678**	**17.304**				
			$8.626	$2.539	$4.284	$1.854	$8.678	$17.304				
	Check		(0.00)	0.00	0.00	0.00	(0.00)	(0.00)				

ENVIRONMENTAL COST CALCULATIONS

Summarized Rate base from Schedule 2a in 2026 COSS

	TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT [4]	CUSTOMER RELATED PLANT	Relative Share of Energy	Blended
		INITIAL CLASSIFICATION AS PER 2026 GRA Application Filing				
Steam	383,306	383,306	-	-	0%	
Hydro	699,665	699,665	-	-	0%	
Wind	163,771	163,771	-	-	0%	0.0%
LM6000	93,737	93,737	-	-	0%	
Other	68,141	68,141	-	-	0%	
GENERATION BATTERIES	160,767	160,767	-	-		
RADIAL TO GENERATION TRANS	58,575	58,575	-	-		
Total Generation	**1,627,962**	**1,627,962**	**-**	**-**	**0%**	
GENERAL PROPERTY PLANT	144,056	144,056	-	-	0%	
Total Plant in Service	**1,772,019**	**1,772,019**	**-**	**-**	**0%**	
Total Generation	2,530,770	2,179,642	351,128	-	14%	
Transmission	953,610	953,610	-	-	0%	
Distribution	1,871,743	1,091,895	-	779,848	0%	
Retail	206,880	-	-	206,880	0%	
Total Rate Base	**5,563,003**	**4,225,148**	**351,128**	**986,728**	**6%**	

Summarized Costs from Schedule 5 in 2026 COSS					Relative Share (1) (based on rate base)	Environmental Portion (based on rate base)
Generation Function (excluding Fuel)						
OM&G - Steam	111,342	50,384	60,957		0%	-
OM&G - Hydro/Wind/Biomass	32,020	14,490	17,530			-
OM&G - LM6000	1,214	549	665		0%	-
OM&G - Other CTs	2,999	2,999	-		0%	-
DSM Amortization	-	-	-		0%	-
FCR Deferral	-	-	-		0%	-
Reg. Affairs -Advocay Expenses	1,364	617	747			
Grants in Lieu	22,178	10,036	12,142		0%	-
Deprecation	-	-	-			
Steam	46,717	21,140	25,577		0%	-
Hydro	16,146	7,306	8,839		0%	-
Wind	12,949	5,860	7,089		0%	-
LM6000	6,832	3,092	3,741		0%	-
Gas - Other	2,805	1,269	1,536		0%	-
GENERATION BATTERIES		3,779	4,572			
RADIAL TO GENERATION TRANS.		1,276	1,544			
General Property	17,217	7,791	9,426		0%	-
		-	-			
Interest Net of AFUDC	62,759	24,753	38,007		0%	-
Preferred Dividends	-	-	-		0%	-
Corporate Taxes	(4,353)	(1,717)	(2,636)		0%	-
Exports	-	-	-		Variable (2)	-
Steam and Ash Sales	(1,295)	(1,295)	-			
Other Revenue	(4,589)	(866)	(3,723)		0%	-
Return	32,647	35,138	(2,490)		0%	-
Total Generation	**358,952**	**186,601**	**183,522**	**-**		**-**
Transmission	21,154	$10,577	$10,577	$0	0%	-
Distribution	55,486	27,743	27,743	0	0%	-
Retail	-	0	0	0	0%	-
Total Net Expenses	**435,592**	**224,921**	**221,842**	**-**		**-**

SHORE POWER	Distr	HV	EHV
Total Fixed Costs	426,288	279,215	279,215
Assumed Environmental portion	-	-	-
Relative Share	**0%**	**0%**	**0%**

1P - RTP ADDERS	Distr	HV	EHV &HV	Non-Eligible	Total
Class Costs by Functional Area					
Generation	$20,134.84	$0	$8,968	$395,976	$425,078
Transmission	$6,453	$0	$2,874	$126,899	$136,226
Distribution	$14,811	$0	$0	$297,863	$312,673
Retail	$0	$0	$0	NA	
Total	$41,398	$0	$11,841	NA	
Relative Share of functional area in class costs					
Generation	4.7%	0.0%	2.1%	93.2%	100.0%
Transmission	4.7%	0.0%	2.1%	93.2%	100.0%
Distribution	4.7%	0.0%	0.0%	95.3%	100.0%
Apportionment of Environmental costs					
Generation	$0	$0	$0	$0	-
Transmission	$0	$0	$0	$0	-
Total	$0	$0	$0	$0	$0
Relative Share of Environmental costs in Fixed Cost Adders before fuel cost adjustment					
Total Fixed Costs assigned to the clas	41,398	0	11,841		
Assumed Environmental portion	-	-	-		
Relative Share	**0.0%**	**0.0%**	**0.0%**		

(1) Assumed ratios would be the same as apportioned in schedule 2a of the COSS

(2) Removed Exports as this is a variable cost

(3) This investment, deemed as made for environmental reasons, was identified as energy-related under the previous COS methodology.

EXHIBIT 9A

NOVA SCOTIA POWER INC.

SALES, GENERATION AND DEMAND ANALYSIS

FOR THE YEAR ENDING DECEMBER 31, 2026

	(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	5,286,337,241	8.2%	5,721,931,430	1,461,049	90.4%	1,321,016	13.9%	1,504,675	43.41%	4,365	66.4%
(2) SMALL GENERAL	376,992,742	8.2%	407,868,448	82,774	84.9%	70,275	12.2%	78,842	59.06%	229	3.5%
(3) GENERAL	2,308,034,614	**7.9%**	2,490,138,545	431,533	**94.1%**	406,073	**11.0%**	450,556	**63.09%**	1,236	18.8%
(4) GENERAL LARGE	363,766,784	5.1%	382,282,513	60,859	73.6%	44,792	6.7%	47,805	91.29%	140	2.1%
(5) SMALL INDUSTRIAL	257,949,167	7.7%	277,837,047	42,190	84.8%	35,777	13.7%	40,691	77.94%	116	1.8%
(6) MEDIUM INDUSTRIAL	491,456,958	**6.8%**	524,679,448	93,066	74.2%	69,055	10.7%	76,438	78.36%	192	**2.9%**
(7) LARGE INDUSTRIAL	643,319,737	**3.6%**	666,286,252	93,891	79.8%	74,925	5.6%	79,112	96.14%	232	3.5%
(8) ELI 2P-RTP											
(9) MUNICIPAL	55,845,030	**2.4%**	57,204,049	8,789	99.9%	8,780	4.2%	9,151	71.36%	28	
(10) UNMETERED	78,143,044	8.2%	84,574,217	41,597	25.0%	10,399	13.9%	11,845	81.51%	31	0.5%
(11) SUB-TOTAL	**9,861,845,316**	**7.6%**	**10,612,801,948**	**2,315,749**	**88.1%**	**2,041,094**	**12.64%**	**2,299,116**	**52.69%**	**6,570**	**100.0%**
	18,021,173.940	0.075	18,486,231	0.06736	1,245,233						
(12) BOWATER MERSEY	0	N/A	0	0	N/A	0	N/A	0	N/A	-	
(13) GEN.REPL./LOAD FOLL.	[redacted]										
(8) BUTU											
(14) REAL TIME PRICING											
(15) ELIADC											
(16) Shore Power											
EBS/RTR											
Below The Line											
(16) TOTAL	**10,796,412,017**	**7.2%**	**11,571,680,069**	**2,573,664**	**83.2%**	**2,141,546**	**N/A**	**2,404,875**	**54.93%**	**6,889**	**6,690**
GL, LI and Municipal Classes Combined	**1,062,931,551**	**4.0%**	**1,105,772,813**	**163,540**	**78.6%**	**128,498**	**5.6%**	**136,068**	92.77%	**400**	**6.1%**
			11,406,661,987								

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

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
EHV											
LIR	**217,317,521**	**2.4%**	**222,606,059**	**33,243**	**56.0%**	**18,609**	**4.2%**	**19,391**	**131.1%**	**61.4**	**15.4%**
HV											
LIR HV	149,380,856	2.4%	153,016,119	24,113	83.9%	20,237	4.2%	21,087	82.8%	55.0	**13.8%**
Municipal class HV	45,987,920	2.4%	47,107,060	11,063	92.7%	10,260	4.2%	10,691	50.3%	27.0	**6.8%**
Total	**195,368,776**	**2.4%**	**200,123,180**	**35,175**	**86.7%**	**30,497**	**4.2%**	**31,778**	**71.9%**	**81.9**	**20.6%**
3 Phase Distribution (> 2 MVA)											
LIR (other than EHV and HV)	236,489,152	**5.4%**	249,190,023	41,773	72.7%	30,350	7.5%	32,613	**87.2%**	115.5	**29.0%**
Munis (other than HV)	9,857,110	**0.0%**	10,269,137	3,129	N/A	3,129	-6.5%	2,926	**40.1%**	**0.0**	**0.0%**
Large General (whole)	363,766,784	**5.1%**	382,282,513	61,258	73.1%	44,792	6.7%	47,805	**91.3%**	**139.8**	**35.1%**
Total	**610,113,046**	**5.2%**	**641,741,674**	**106,159**	**73.7%**	**78,271**	**6.5%**	**83,344**	**87.9%**	**255.3**	**64.0%**
EHV, HV and 3 Phase Distribution Total	**1,022,799,343**	**4.1%**	**1,064,470,913**	**174,578**	**73.0%**	**127,377**	**5.6%**	**134,513**	**90.34%**	**398.7**	**100.0%**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)
			INITIAL CLASSIFICATION		
		TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
(1)	**GENERATION FUNCTION**				
(2)					
(3)	STEAM PLANT	$847,049	$847,049	$0	$0
(4)	HYDRO PLANT	699,665	699,665	0	0
(5)	WIND PLANT	163,771	163,771	0	0
(6)	LM6000 PLANT	93,737	93,737	0	0
(7)	GAS TURBINE PLANT - OTHER	68,141	68,141	0	0
(8)	GENERATION BATTERIES	160,767	160,767	0	0
(9)	RADIAL TO GENERATION TRANS.	58,575	58,575	0	0
(8)	**TOTAL GENERATION PLANT**	**2,091,705**	**2,091,705**	**0**	**0**
(9)					
(10)	GENERAL PROPERTY PLANT	144,056	144,056	0	0
(11)	**TOTAL PLANT IN SERVICE**	**2,235,761**	**2,235,761**	**0**	**0**
(12)					
(13)	Working Capital & Deferred Charges/Credits:				
(14)	CASH - FUEL	0	0	0	0
(15)	CASH - OTHER	0	0	0	0
(16)	MAT. & SUPPLIES - FUEL	222,761	0	222,761	0
(17)	MAT. & SUPPLIES - OTHER	34,225	34,225	0	0
(18)	DEF. CHG. - Financing	10,075	10,075	0	0
(19)	DEF. CHG. - Tax	11,485	11,485	0	0
(20)	DEF. CHG. - Pension	75,433	34,974	40,459	0
(21)	DEF. CHG. - Steam Assets	0	0	0	0
(22)	DEF. CHG. - Fuel Deferral	-5,403	0	-5,403	0
(23)	DEF. CHG. - Other	13,725	13,725	0	0
(24)	DEF. CHG. - FCR	4,084	4,084	0	0
(25)	DEF. CR. - ARO Steam	-81,338	-81,338	0	0
(26)	DEF. CR. - ARO Hydro	-40,430	-40,430	0	0
(27)	DEF. CR. - ARO Wind	-16,505	-16,505	0	0
(28)	DEF. CR. - ARO LM6000	-1,393	-1,393	0	0
(28)	DEF. CR. - ARO CT	-6,244	-6,244	0	0
(29)	DEF. CR. - Other	-29,365	-29,365	0	0
(30)	DEF. CR. - COST OF REMOVAL LIABILITY (COR)	10,587	10,587	0	0
(31)	CONTRACT RECEIVABLE	93,310	0	93,310	0
(32)	SUB-TOTAL	295,009	-56,119	351,128	0
(33)					
(34)	**TOTAL GENERATION FUNCTION**	**2,530,770**	**2,179,642**	**351,128**	**0**
(35)					
(36)	**TRANSMISSION FUNCTION**				
(37)					
(38)	**Transmission - HV**	0	0	0	0
(39)					
(40)	GENERAL PROPERTY PLANT	0	0	0	0
(41)	TOTAL PLANT IN SERVICE	0	0	0	0
(42)					
(43)	Working Capital & Deferred Charges/Credits:				
(44)	CASH - FUEL	0	0	0	0
(45)	CASH - OTHER	0	0	0	0
(46)	MAT. & SUPPLIES - FUEL	0	0	0	0
(47)	MAT. & SUPPLIES - OTHER	0	0	0	0
(48)	DEF. CHG. - Financing	0	0	0	0
(49)	DEF. CHG. - Tax	0	0	0	0
(50)	DEF. CHG. - Pension	0	0	0	0
(51)	DEF. CHG. - Other	0	0	0	0
(52)	DEF. CHG. - ARO Transformers	-0	-0	0	0
(53)	SUB-TOTAL	0	0	0	0
(55)	Transmission - HV	0	0	0	0

EXHIBIT 2A
Page 2 of 3

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)		
			INITIAL CLASSIFICATION				
		TOTAL COMPANY	DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT		
(1)	**Transmission - EHV**	820,016	820,016	0	0		
(2)							
(3)	GENERAL PROPERTY PLANT	85,899	85,899	0	0		
(4)	TOTAL PLANT IN SERVICE	905,915	905,915	0	0		
(5)							
(6)	Working Capital & Deferred Charges/Credits:						
(7)	CASH - FUEL	0	0	0	0		
(8)	CASH - OTHER	0	0	0	0		
(9)	MAT. & SUPPLIES - FUEL	0	0	0	0		
(10)	MAT. & SUPPLIES - OTHER	13,868	13,868	0	0		
(11)	DEF. CHG. - Financing	4,082	4,082	0	0		
(12)	DEF. CHG. - Tax	4,654	4,654	0	0		
(13)	DEF. CHG. - Pension	18,220	18,220	0	0		
(14)	DEF. CHG. - Other	5,268	5,268	0	0		
(15)	DEF. CHG. - FCR	1,655	1,655	0	0		
(16)	DEF. CHG. - ARO Transformers	-52	-52	0	0		
(17)	SUB-TOTAL	47,695	47,695	0	0		
(18)							
(19)	Transmission - EHV	953,610	953,610	0	0		
(20)							
(21)	**TOTAL TRANSMISSION FUNCTION**	**$953,610**	**$953,610**	**$0**	**$0**	$0	$953,610
(22)							
(23)	**DISTRIBUTION FUNCTION**						
(24)							
(25)	DISTRIBUTION PLANT:						
(26)	LAND	5,052	2,664	0	2,388		
(27)	EASEMENTS & SURVEY	177,554	93,631	0	83,922		
(28)	OTHER	17,970	9,476	0	8,493		
(29)	SUBSTATIONS	183,948	183,948	0	0		
(30)	POLES & FIXTURES	399,387	114,551	0	284,836		
(31)	O.H. LINES	173,434	100,577	0	72,857		
(32)	U.G. LINES	61,773	15,504	0	46,269		
(33)	LINE TRANSFORMERS	369,256	369,256	0	0		
(34)	SERVICES	56,181	0	0	56,181		
(35)	METERS	70,426	0	0	70,426		
(36)	STREET LIGHTING	35,211	35,211	0	0		
(37)	TOTAL DISTRIBUTION PLANT	1,550,189	924,817	0	625,372		
(38)							
(39)	GENERAL PROPERTY PLANT	204,348	121,911	0	82,437		
(40)	TOTAL PLANT IN SERVICE	1,754,537	1,046,728	0	707,809		
(41)							
(42)	Working Capital & Deferred Charges/Credits:						
(43)	CASH - FUEL	0	0	0	0		
(44)	CASH - OTHER	0	0	0	0		
(45)	MAT. & SUPPLIES - FUEL	0	0	0	0		
(46)	MAT. & SUPPLIES - OTHER	26,859	16,023	0	10,835		
(47)	DEF. CHG. - Financing	7,906	4,717	0	3,190		
(48)	DEF. CHG. - Tax	9,013	5,377	0	3,636		
(49)	DEF. CHG. - Pension	63,282	13,020	0	50,262		
(50)	DEF. CHG. - Other	10,203	6,087	0	4,116		
(51)	DEF. CR. - ARO Substations	-1	-1	0	0		
(52)	DEF. CR. - ARO Transformers	-55	-55	0	0		
(51)	SUB-TOTAL	117,206	45,167	0	72,039		
(52)							
(53)	**TOTAL DISTRIBUTION FUNCTION**	**1,871,743**	**1,091,895**	**0**	**779,848**		

NOVA SCOTIA POWER INC.

CLASSIFICATION OF RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1)		(2)	(3)	(4)
				INITIAL CLASSIFICATION		
		TOTAL COMPANY		DEMAND RELATED PLANT	ENERGY RELATED PLANT	CUSTOMER RELATED PLANT
(1)	**RETAIL FUNCTION**					
(2)						
(3)	DISTRIBUTION PLANT:					
(4)	SERVICES	0		0	0	0
(5)	METERS	0		0	0	0
(6)	TOTAL RETAIL PLANT	0		0	0	0
(7)				0	0	0
(8)	GENERAL PROPERTY PLANT	42,983		0	0	42,983
(9)	TOTAL PLANT IN SERVICE	42,983		0	0	42,983
(10)						
(11)	Working Capital & Deferred Charges/Credits:					
(12)	CASH - FUEL	0		0	0	0
(13)	CASH - OTHER	162,574		0	0	162,574
(14)	MAT. & SUPPLIES - FUEL	0		0	0	0
(15)	MAT. & SUPPLIES - OTHER	658		0	0	658
(16)	DEF. CHG. - Financing	194		0	0	194
(17)	DEF. CHG. - Tax	221		0	0	221
(18)	DEF. CHG. - Pension	0		0	0	0
(19)	DEF. CHG. - Other	250		0	0	250
(20)	SUB-TOTAL	163,897		0	0	163,897
(21)						
(22)	**TOTAL RETAIL FUNCTION**	**206,880**		**0**	**0**	**206,880**
(23)						
(24)	**TOTAL AVE. RATE BASE**	**$5,563,003**		**$4,225,148**	**$351,128**	**$986,728**
		$5,563,003		**$4,225,148**	**$351,128**	**$986,728**
	Check	$0	$0	$0	$0	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**GENERATION FUNCTION**									
(2)										
(3)	STEAM PLANT	$847,049	$0	$0	($463,743)	$463,743	$0	$383,306	$463,743	$0
(4)	HYDRO PLANT	699,665	0	0	-383,053	383,053	0	316,612	383,053	0
(5)	WIND PLANT	163,771	0	0	-89,661	89,661	0	74,110	89,661	0
(6)	LM6000 PLANT	93,737	0	0	-51,319	51,319	0	42,418	51,319	0
(7)	GAS TURBINE PLANT - OTHER	68,141	0	0	-37,306	37,306	0	30,835	37,306	0
(8)	GENERATION BATTERIES	160,767	0	0	-88,017	88,017	0	72,750	88,017	0
(9)	RADIAL TO GENERATION TRANS.	58,575	0	0	-32,068	32,068	0	26,506	32,068	0
(10)	TOTAL GENERATION PLANT	2,091,705	0	0	-1,145,168	1,145,168	0	946,537	1,145,168	0
(11)										
(12)	GENERAL PROPERTY PLANT	144,056	0	0	-78,868	78,868	0	65,188	78,868	0
(13)	TOTAL PLANT IN SERVICE	2,235,761	0	0	-1,224,036	1,224,036	0	1,011,726	1,224,036	0
(14)										
(15)	Rate Base Factors Applicable to Base Cost of Fuel Classification							**45.252%**	**54.748%**	
(16)										
(17)	Working Capital & Deferred Charges/Credits:									
(18)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(19)	CASH - OTHER	0	0	0	0	0	0	0	0	0
(20)	MAT. & SUPPLIES - FUEL	0	222,761	0	0	0	0	0	222,761	0
(21)	MAT. & SUPPLIES - OTHER	34,225	0	0	-18,738	18,738	0	15,488	18,738	0
(22)	DEF. CHG. - Financing	10,075	0	0	-5,516	5,516	0	4,559	5,516	0
(23)	DEF. CHG. - Tax	11,485	0	0	-6,288	6,288	0	5,197	6,288	0
(24)	DEF. CHG. - Pension	34,974	40,459	0	0	0	0	34,974	40,459	0
(25)	DEF. CHG. - Steam Assets	0	0	0	0	0	0	0	0	0
(26)	DEF. CHG. - Fuel Deferral	0	-5,403	0	0	0	0	0	-5,403	0
(27)	DEF. CHG. - Other	13,725	0	0	-7,514	7,514	0	6,211	7,514	0
(28)	DEF. CHG. - FCR	4,084	0	0	-2,236	2,236	0	1,848	2,236	0
(29)	DEF. CR. - ARO Steam	-81,338	0	0	44,531	-44,531	0	-36,807	-44,531	0
(30)	DEF. CR. - ARO Hydro	-40,430	0	0	22,134	-22,134	0	-18,295	-22,134	0
(31)	DEF. CR. - ARO Wind	-16,505	0	0	9,036	-9,036	0	-7,469	-9,036	0
(32)	DEF. CR. - ARO LM6000	-1,393	0	0	763	-763	0	-631	-763	0
(32)	DEF. CR. - ARO CT	-6,244	0	0	0	0	0	-6,244	0	0
(33)	DEF. CR. - Other	-29,365	0	0	16,077	-16,077	0	-13,288	-16,077	0
(34)	DEF. CR. - COST OF REMOVAL LIABILITY (COR)	10,587	0	0	-5,796	5,796	0	4,791	5,796	0
(35)	CONTRACT RECEIVABLE	0	93,310	0	0	0	0	0	93,310	0
(36)	SUB-TOTAL	-56,119	351,128	0	46,453	-46,453	0	-9,666	304,674	0
(37)										
(38)	**TOTAL GENERATION FUNCTION**	2,179,642	351,128	0	-1,177,582	1,177,582	0	1,002,060	1,528,710	0
(39)										
(40)	**TRANSMISSION FUNCTION**									
(41)										
(42)	**Transmission - HV (not aplicable as a separate item)**	0	0	0	0	0	0	0	0	0
(43)										
(44)	GENERAL PROPERTY PLANT	0	0	0	0	0	0	0	0	0
(45)	TOTAL PLANT IN SERVICE	0	0	0	0	0	0	0	0	0
(46)										
(47)	Working Capital & Deferred Charges/Credits:									
(48)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(49)	CASH - OTHER	0	0	0	0	0	0	0	0	0
(50)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(51)	MAT. & SUPPLIES - OTHER	0	0	0	0	0	0	0	0	0
(52)	DEF. CHG. - Financing	0	0	0	0	0	0	0	0	0
(53)	DEF. CHG. - Tax	0	0	0	0	0	0	0	0	0
(54)	DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(55)	DEF. CHG. - Other	0	0	0	0	0	0	0	0	0
(56)	DEF. CHG. - ARO Trans.	-0	0	0	0	0	0	-0	0	0
(57)	SUB-TOTAL	0	0	0	0	0	0	0	0	0
(58)										
(59)	Transmission - HV	0	0	0	0	0	0	0	0	0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**Transmission - EHV and HV combined**	820,016	0	0	0	0	0	820,016	0	0
(2)										
(3)	GENERAL PROPERTY PLANT	85,899	0	0	0	0	0	85,899	0	0
(4)	TOTAL PLANT IN SERVICE	905,915	0	0	0	0	0	905,915	0	0
(5)										
(6)	Working Capital & Deferred Charges/Credits:									
(7)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(8)	CASH - OTHER	0	0	0	0	0	0	0	0	0
(9)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(10)	MAT. & SUPPLIES - OTHER	13,868	0	0	0	0	0	13,868	0	0
(11)	DEF. CHG. - Financing	4,082	0	0	0	0	0	4,082	0	0
(12)	DEF. CHG. - Tax	4,654	0	0	0	0	0	4,654	0	0
(13)	DEF. CHG. - Pension	18,220	0	0	0	0	0	18,220	0	0
(14)	DEF. CHG. - Other	5,268	0	0	0	0	0	5,268	0	0
(15)	DEF. CHG. - FCR	1,655	0	0	0	0	0	1,655	0	0
(16)	DEF. CR. - ARO Trans	-52	0	0	0	0	0	-52	0	0
(17)	SUB-TOTAL	47,695	0	0	0	0	0	47,695	0	0
(18)										
(19)	Transmission - EHV	953,610	0	0	0	0	0	953,610	0	0
(20)										
(21)	**TOTAL TRANSMISSION FUNCTION**	$953,610	$0	$0	$0	$0	$0	$953,610	$0	$0

NOVA SCOTIA POWER INC.

CLASSIFICATION OF AVERAGE RATE BASE

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		INITIAL R/B CLASSIFICATION			FURTHER CLASSIFICATION			FULLY CLASSIFIED RATE BASE		
		DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT	DEMAND PLANT	ENERGY PLANT	CUSTOMER PLANT
(1)	**DISTRIBUTION FUNCTION**									
(2)										
(3)	DISTRIBUTION PLANT:									
(4)	LAND	$2,664	$0	$2,388	$0	$0	$0	$2,664	$0	$2,388
(5)	EASEMENTS & SURVEY	93,631	0	83,922	0	0	0	93,631	0	83,922
(6)	OTHER	9,476	0	8,493	0	0	0	9,476	0	8,493
(7)	SUBSTATIONS	183,948	0	0	0	0	0	183,948	0	0
(8)	POLES & FIXTURES	114,551	0	284,836	0	0	0	114,551	0	284,836
(9)	O.H. LINES	100,577	0	72,857	0	0	0	100,577	0	72,857
(10)	U.G. LINES	15,504	0	46,269	0	0	0	15,504	0	46,269
(11)	LINE TRANSFORMERS	369,256	0	0	0	0	0	369,256	0	0
(12)	SERVICES	0	0	56,181	0	0	0	0	0	56,181
(13)	METERS	0	0	70,426	0	0	0	0	0	70,426
(14)	STREET LIGHTING	35,211	0	0	0	0	0	35,211	0	0
(15)	TOTAL DISTRIBUTION PLANT	924,817	0	625,372	0	0	0	924,817	0	625,372
(16)										
(17)	GENERAL PROPERTY PLANT	121,911	0	82,437	0	0	0	121,911	0	82,437
(18)	TOTAL PLANT IN SERVICE	1,046,728	0	707,809	0	0	0	1,046,728	0	707,809
(19)										
(20)	Working Capital & Deferred Charges/Credits:									
(21)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(22)	CASH - OTHER	0	0	0	0	0	0	0	0	0
(23)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(24)	MAT. & SUPPLIES - OTHER	16,023	0	10,835	0	0	0	16,023	0	10,835
(25)	DEF. CHG. - Financing	4,717	0	3,190	0	0	0	4,717	0	3,190
(26)	DEF. CHG. - Tax	5,377	0	3,636	0	0	0	5,377	0	3,636
(27)	DEF. CHG. - Pension	13,020	0	50,262	0	0	0	13,020	0	50,262
(28)	DEF. CHG. - Other	6,087	0	4,116	0	0	0	6,087	0	4,116
(29)	DEF. CR. - ARO Substations	-1	0	0	0	0	0	-1	0	0
(30)	DEF. CR. - ARO Transformers	-55	0	0	0	0	0	-55	0	0
(31)	SUB-TOTAL	45,167	0	72,039	0	0	0	45,167	0	72,039
(32)										
(33)	**(24) TOTAL DISTRIBUTION FUNCTION**	$1,091,895	$0	$779,848	$0	$0	$0	$1,091,895	$0	$779,848
(34)										
(35)	**RETAIL FUNCTION**									
(36)										
(37)	DISTRIBUTION PLANT:									
(38)	SERVICES	$0	$0	$0	$0	$0	$0	$0	$0	$0
(39)	METERS	0	0	0	0	0	0	0	0	0
(40)	TOTAL RETAIL PLANT	0	0	0	0	0	0	0	0	0
(41)										
(42)	GENERAL PROPERTY PLANT	0	0	42,983	0	0	0	0	0	42,983
(43)	TOTAL PLANT IN SERVICE	0	0	42,983	0	0	0	0	0	42,983
(44)										
(45)	Working Capital & Deferred Charges/Credits:									
(46)	CASH - FUEL	0	0	0	0	0	0	0	0	0
(47)	CASH - OTHER	0	0	162,574	0	0	0	0	0	162,574
(48)	MAT. & SUPPLIES - FUEL	0	0	0	0	0	0	0	0	0
(49)	MAT. & SUPPLIES - OTHER	0	0	658	0	0	0	0	0	658
(50)	DEF. CHG. - Financing	0	0	194	0	0	0	0	0	194
(51)	DEF. CHG. - Tax	0	0	221	0	0	0	0	0	221
(52)	DEF. CHG. - Pension	0	0	0	0	0	0	0	0	0
(53)	DEF. CHG. - Other	0	0	250	0	0	0	0	0	250
(54)	SUB-TOTAL	0	0	163,897	0	0	0	0	0	163,897
(55)										
(56)	**TOTAL RETAIL FUNCTION**	0	0	206,880	0	0	0	0	0	206,880
(57)										
(58)	**TOTAL AVE. RATE BASE**	**$4,225,148**	**$351,128**	**$986,728**	**($1,177,582)**	**$1,177,582**	**$0**	**$3,047,566**	**$1,528,710**	**$986,728**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	GENERATION FUNCTION				
(1)	FUEL	434,033	$0	$434,033	-
(2)	PURCHASES - OTHER THAN BIOMASS AND WIND	18,420	$8,334	$10,086	-
(3)	PURCHASES - BIOMASS	20,238	$5,365	$14,874	-
(4)	MARITIME LINK	198,036	$89,600	$108,436	
(5)	PURCHASES - WIND ERIS	33,315	15,071.9	18,242.9	-
(6)	PURCHASES - WIND NRIS	111,167	50,291.6	60,875.8	
(7)	IMPORTS	94,391	0	94,390.8	-
(8)	BUTU CAPACITY CREDIT	300	300	0	
(8)	OPER. & MAINT. - STEAM	110,090	49,818	60,272	-
(9)	OPER. & MAINT. - HYDRO	3,504	1,586	1,918	-
(10)	OPER. & MAINT. - WIND	15,596	7,057	8,538	-
(11)	OPER. & MAINT. - BIOMASS	12,560	5,684	6,877	-
(12)	OPER. & MAINT. - LM6000	1,200	543	657	-
(13)	OPER. & MAINT. - OTHER CT's	2,966	2,966	0	-
(14)	OPER. & MAINT. - GENERATION BATTERIES	0	0	0	-
(15)	OPER. & MAINT. - RADIAL TO GENERATION TRANS.	2,627	1,189	1,438	-
(16)	DSM				
(17)	FCR DEFERRAL	0	0	0	-
(18)	REG. AFFAIRS - ADVOCACY EXPENSE	1,367.0	619	748	-
(18)	GRANTS IN LIEU OF TAXES	22,260	10,073	12,187	-
(19)	**Depreciation:**				
(20)	STEAM	46,715	21,139	25,575	-
(21)	HYDRO	16,145	7,306	8,839	-
(22)	WIND	12,948	5,859	7,089	-
(23)	LM6000	6,832	3,092	3,740	-
(24)	GAS TURBINE - OTHER	2,805	1,269	1,536	-
(25)	GENERATION BATTERIES	8,351	3,779	4,572	-
(26)	RADIAL TO GENERATION TRANS.	3,086	1,397	1,690	-
(27)	GENERAL PROPERTY	17,283	7,821	9,462	-
(28)					
(29)	INTEREST NET OF AFUDC	62,852	24,886	37,966	-
(30)	PREFERRED DIVIDENDS	0	0	0	-
(31)	CORPORATE TAXES	-4,703	-1,862	-2,841	-
(32)	NON-OPERATING REVENUE:				
(33)	EXPORT SALES	0	0	0	-
(34)	STEAM AND ASH SALES	-5,018	-1,293	-3,725	-
(35)	OTHER REVENUE	-3,370	-868	-2,501	-
(36)	RETURN (PROFIT/LOSS)	88,982	35,232	53,749	-
(37)					
(38)	**TOTAL GENERATION**	**$1,334,978.846**	**$356,253.788**	**$978,725.059**	**-**

EXHIBIT 5
Page 2 of 5

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	TRANSMISSION FUNCTION				
(1)	**Transmission - HV (not aplicable as a separate item)**				
(2)	O&M - HV Before Storm Expense	0	0	0	-
(3)	O&M - HV Storm Expense	0	0	0	-
(4)	REG. AFFAIRS - ADVOCACY EXPENSE	0	0	0	-
(5)	GRANTS IN LIEU OF TAXES	0	0	0	-
(6)	**Depreciation:**				
(7)	TRANSMISSION	0	0	0	-
(8)	GENERAL PROPERTY	0	0	0	-
(9)					
(10)	INTEREST NET OF AFUDC	0	0	0	-
(11)	PREFERRED DIVIDENDS	0	0	0	-
(12)	CORPORATE TAXES	-0	-0	0	-
(13)	**Non-Operating Revenue:**				
(14)	OTHER REVENUE	-0	-0	0	-
(15)	RETURN (PROFIT/LOSS)	0	0	0	-
(16)					
(17)	**TOTAL - HV**	**0.0**	**0**	**0**	**-**
(18)					
(19)	**Transmission - EHV and HV combined**				
(20)					
(21)	O&M - EHV Before Storm Expense	35,820	35,820	0	-
(22)	O&M - EHV Storm Expense	258	258	0	-
(23)	REG. AFFAIRS - ADVOCACY EXPENSE	132	132	0	-
(24)	GRANTS IN LIEU OF TAXES	9,019	9,019	0	-
(25)	**Depreciation:**				
(26)	TRANSMISSION	25,397	25,397	0	-
(27)	GENERAL PROPERTY	10,436	10,436	0	-
(28)					
(29)	INTEREST NET OF AFUDC	23,683	23,683	0	-
(30)	PREFERRED DIVIDENDS	0	0	0	-
(31)	CORPORATE TAXES	-1,772	-1,772	0	-
(32)	**Non-Operating Revenue:**				
(33)	OTHER REVENUE	-277	-277	0	-
(34)	FCR DEFERRAL	0	0	0	-
(35)	RETURN (PROFIT/LOSS)	33,529	33,529	0	-
(36)					
(37)	**TOTAL - EHV and HV Combined**	**136,226**	**136,226**	**0**	**-**
(38)					
(39)	**TOTAL TRANSMISSION**	**$136,225.520**	**$136,225.52**	**$0**	**-**

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	DISTRIBUTION FUNCTION				
(1)	**Before Streetlights:**				
(2)	SUBSTATIONS	$2,078	$2,078	$0	-
(3)	OVERHEAD LINES Before Storm Expense	$54,323	$13,607	$0	40,716.2
(4)	OVERHEAD LINES Storm Expense	24,747	9,071	0	15,675.3
(5)	UNDERGROUND LINES	814	234	0	580.8
(6)	LINE TRANSFORMERS	0	0	0	-
(7)	METERS	1,672	0	0	1,672.2
(8)	COMMUNICATIONS	0	0	0	-
(9)	REG. AFFAIRS - ADVOCACY EXPENSE	309	89	0	220.2
(9)	GRANTS IN LIEU OF TAXES	17,140	9,862	0	7,278.1
(10)	**Depreciation:**				
(11)	DISTRIBUTION - Land	0	-	0	-
(12)	DISTRIBUTION - Easements	2,995	1,580	0	1,415.8
(13)	DISTRIBUTION - Other	1,328	700	0	627.6
(14)	DISTRIBUTION - Substations	8,860	8,860	0	-
(15)	DISTRIBUTION - Poles and Fixtures	20,475	5,873	0	14,602.3
(16)	DISTRIBUTION - OH Lines	11,917	6,911	0	5,006.1
(17)	DISTRIBUTION -UG Lines	2,886	724	0	2,161.3
(18)	DISTRIBUTION -Line Transformers	27,737	27,737	0	-
(19)	DISTRIBUTION -Services	4,053	-	0	4,052.9
(20)	DISTRIBUTION -Meters	7,940	-	0	7,939.6
(21)	GENERAL PROPERTY	26,034	15,531	0	10,502.6
(22)					
(23)	INTEREST NET OF AFUDC	45,610	26,243	0	19,367.5
(24)	PREFERRED DIVIDENDS	0	0	0	-
(25)	CORPORATE TAXES	-3,413	-1,964	0	(1,449.1)
(26)	RETURN (PROFIT/LOSS)	64,572	37,153	0	27,419.4
(27)					
(28)	**Streetlights:**				
(29)	MAINTENACE	814	814	0	-
(30)	GRANTS IN LIEU OF TAXES	329	329	0	-
(31)	DEPRECIATION	4,480	4,480	0	-
(32)	INTEREST NET OF AFUDC	874	874	0	-
(33)	PREFERRED DIVIDENDS	0	0	0	-
(34)	CORPORATE TAXES	-65	-65	0	-
(35)	RETURN (PROFIT/LOSS)	1,238	1,238	0	-
(36)	**Subtotal**	7,670	7,670	0	-
(37)					
(38)	POLE SERVICES	-16,364	-5,999	0	(10,365.7)
(39)	OTHER REVENUE	-709	-359	0	(350.2)
(41)	**TOTAL DISTRIBUTION**	**$312,673.494**	**$165,600.74**	**$0**	**147,072.8**

NOVA SCOTIA POWER INC.

CLASSIFICATION OF OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

		(1) TOTAL COMPANY	(2) DEMAND EXPENSES	(3) ENERGY EXPENSES	(4) CUSTOMER EXPENSES
	RETAIL FUNCTION				
(1)	CUSTOMER EXPERIENCE AND SOLUTIONS	8,486	0	0	8,485.8
(2)	CALL CENTRE	13,257	0	0	13,256.7
(3)	BILLING SERVICES & PAYMENTS	3,733	0	0	3,732.9
(4)	METER SERVICES - INSPECTORS	0	0	0	-
(5)	METER DATA SERVICES	717	0	0	716.8
(6)	METER SERVICES - FIELD	2,323	0	0	2,323.5
(7)	ELECT. WIRING INSPECT. - FIELD	7,492	0	0	7,492.2
(8)	REVENUE OPS ADMIN	0	0	0	-
(9)	CREDIT SERVICES	0	0	0	-
(10)	BAD DEBT EXPENSE	4,966	0	0	4,965.9
(11)	MARKETING & SALES	0	0	0	-
(12)	REG. AFFAIRS - ADVOCACY EXPENSE	29	0	0	29.2
(12)	COGS	0	0	0	-
(13)	GRANTS IN LIEU OF TAXES	428	0	0	427.9
(14)	**Depreciation:**				
(15)	DISTRIBUTION	0	0	0	-
(16)	GENERAL PROPERTY	6,251	0	0	6,250.7
(17)	INTEREST NET OF AFUDC	5,138	0	0	5,137.9
(18)					
(19)	PREFERRED DIVIDENDS	0	0	0	-
(20)	CORPORATE TAXES	-384	0	0	(384.4)
(21)	**Non-Operating Revenue:**				
(22)	LATE PAYMENT CHARGE	(5,743.1)	0	0	(5,743.1)
(23)	CONNECTION CHARGES AND METER REMOVAL	(3,494.1)	0	0	(3,494.1)
(24)	NSF	(158.5)	0	0	(158.5)
(25)	RETAIL SALES	(1,490.5)	0	0	(1,490.5)
(26)	WIRING INSPECTIONS	(7,253.5)	0	0	(7,253.5)
(27)	AMI OPT OUT CHARGE	(0.0)	0	0	(0.0)
(28)	OTHER REVENUE	(140.9)	0	0	(140.9)
(29)	RETURN (PROFIT/LOSS)	7,274.1	0	0	7,274.1
(31)	**TOTAL RETAIL**	**$41,428.7**	**$0.0**	**$0.0**	**$41,428.7**
(33)					
(34)	**TOTAL NET EXPENSES**	**$1,825,306.6**	**$658,080.0**	**$978,725.1**	**$188,501.5**

NOVA SCOTIA POWER INC.
CLASSIFICATION OF OPERATING EXPENSES
FOR THE YEAR ENDING DECEMBER 31, 2026
(IN THOUSANDS OF DOLLARS)

(1)	***INTERMEDIATE CLASSIFICATION***			
(2)				
(3)	THERMAL O&M	$110,090		
(4)	HYDRO O&M	$3,504		
(5)	WIND O&M	$15,596		
(6)	BIOMASS O&M	$12,560		
(7)	LM6000 O&M	$1,200		
(8)	OTHER CT's O&M	$2,966		
(9)	GENERATION BATTERIES	$0		
(10)	RADIAL TO GENERATION TRANS.	$2,627		
(11)				
(12)	NET THERMAL O&M	$148,543		
(13)				
(14)	THERMAL O&M	$0	Intermediate Classification Factor	
(15)	HYDRO O&M	0	Was:	16%
(16)	WIND O&M	0	Now:	0%
(17)				
(18)	BIOMASS O&M	0		
(19)				
(20)	LM6000 O&M	0		
(21)				
(22)				
(23)	OTHER CT's O&M	0		
(24)				
(25)	THERMAL VARIABLE O&M	$0		
(26)				
(27)	THERMAL O&M	$110,090		
(28)				
(29)	HYDRO O&M	3,504		
(30)	WIND O&M	15,596		
(31)	BIOMASS O&M	12,560		
(32)	LM6000 O&M	1,200		
(33)	OTHER CT's O&M	2,966		
	GENERATION BATTERIES	0		
	RADIAL TO GENERATION TRANS.	2,627		
(34)				
(35)	NET THERMAL O&M D&E SPLIT	$148,543		
(36)				
(37)	THERMAL O&M DMD. ALLOC. %	45.25%		
(38)	THERMAL O&M ENG. ALLOC. %	54.75%		
(39)				
(40)	BIOMASS DEMAND ALLOC %	45.25%		
(41)				
(42)	BIOMASS ENERGY ALLOC %	54.75%		
(43)				
(44)		NRIS	ERIS	
(45)	WIND O&M DMD. ALLOC. %	45.25%	45.25%	
(46)	WIND O&M ENG. ALLOC. %	54.75%	54.75%	
(47)				
(48)				
(49)	OTHER CT's O&M DMD. ALLOC. %	100.00%		
(50)				
(51)	POLE & WIRE DMD/CUST SPLIT	28.68%		
(52)				
(53)		**DEMAND**	**ENERGY**	**CUSTOMER**
(54)				
(55)	GEN. PROP. ALLOC. - GEN.	7,821	9,462	0
(56)	GEN. PROP. ALLOC. - TRANS. < 138 kV	0	0	0
(57)	GEN. PROP. ALLOC. - TRANS. > 69 kV	10,436	0	0
(58)	GEN. PROP. ALLOC. - DIST.	15,531	0	10,503
(59)	GEN. PROP. ALLOC. - RETAIL	0	0	6,251
(60)				
(61)	TOTAL	33,788	9,462	16,753

2026 AAR Compliance Filing Appendix E3 has been filed electronically.

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

FOR THE YEAR ENDING DECEMBER 31, 2026

Cost Allocation Factors

Line #	COLUMN / Rate Class	A: R/C Ratios	B: 3 CP Demands – KW Demand	C: 3 CP Demands – Relative Shares of Embedded Cost Classes	D: Energy Requirement – KWh Energy	E: Energy Requirement – Relative Shares of Embedded Cost Classes	F: kWhs Sales	G: Fuel Costs before Purchased Power	H: Imports (allocated on monthly energy requirements)
15	**FAM Rate Classes (ATL)**								
16	Residential	97.159%	4,353,838	64.027806%	5,644,778,858	49.7998%	5,213,776,964	$220,605,297	$44,140,315
17	Small General	103.60%	222,264	3.26862%	382,310,202	3.37%	353,433,715	$14,745,827	$3,171,069
18	General Demand	104.38%	1,206,116	17.73722%	2,393,510,995	21.12%	2,219,406,397	$91,296,733	$20,577,967
19	Large General	104.38%	137,482	2.02182%	376,587,283	3.32%	358,568,276	$14,102,288	$3,451,531
20	Small Industrial	104.38%	123,550	1.81693%	274,651,533	2.42%	255,141,808	$10,377,461	$2,422,479
21	Medium Industrial	104.38%	158,818	2.33558%	467,931,323	4.13%	438,584,616	$17,476,489	$4,259,468
22	Large Industrial	104.38%	246,525	3.62541%	722,193,823	6.37%	697,602,851	$26,846,935	$6,707,581
23	PHP	104.38%	203,227	2.98867%	829,996,205	7.32%	810,547,200	$30,393,954	$7,924,664
24	Municipal	104.38%	93,931	1.38135%	128,549,631	1.13%	124,528,392	$5,082,900	$975,982
25	Unmetered	100.00%	31,520	0.46353%	83,275,289	0.73%	77,000,000	$3,105,001	$759,730
26	Total	100.00%	6,777,270	99.66695%	11,303,785,142	99.73%	10,548,590,219	$434,032,883	$94,390,785
27									
28	Purchased Power Allocation Factors.								
30	**Non-FAM Rate Classes**								
31	BUTU	100.00%	[redacted]						
32	GRLF	100.00%							
33	1P - RTP	100.00%							
34	ELIADC	100.00%							
35	Shore Power								
	EBS /RSS								
37	**Total Below-the-line**		178,670	0.3%	159,281,443	0.3%	155,071,055	$11,424,198	$306,483
38									
39	**In Province Total**		6,955,940	100.0%	11,463,066,585	100.0%	10,703,661,274	$445,457,081	$94,697,267
40									
41	Exports	100.00%	-		-		-		
42									
43	Grand Total		6,955,940		11,463,066,585		10,703,661,274	$445,457,081	$94,697,267

Fuel-related Costs from COS

Line #	Rate Class	I: Purchased Power- Biomass – (allocated on monthly energy	J: Purchased Power- Biomass – (allocated on annual energy	K: Purchased Power- Biomass – Demand-related	L: Purchased Power- Biomass – Total	M: Maritime Link – Basic and Supplemental Blocks – Fixed Energy-related	N: Maritime Link – Basic and Supplemental Blocks – Fixed Demand-related	O: Maritime Link – Total	P: Purchased Power other than Biomass and Wind – Fixed Energy-related	Q: Purchased Power other than Biomass and Wind – Fixed Demand-related	R: Purchased Power other than Biomass and Wind – Total
15	**FAM Rate Classes (ATL)**										
16	Residential	$4,108,568	$3,130,679	$3,446,385	$10,685,632	$52,586,405	$57,560,707	$110,147,112	$4,875,653	$5,353,756	$10,229,409
17	Small General	$285,586	$219,195	$175,938	$680,719	$3,648,587	$2,938,477	$6,587,064	$339,058	$273,310	$612,367
18	General Demand	$1,801,772	$1,401,750	$954,731	$4,158,253	$23,309,898	$15,945,683	$39,255,581	$2,164,515	$1,483,118	$3,647,633
19	Large General	$289,502	$230,084	$108,827	$628,413	$3,771,759	$1,817,607	$5,589,367	$352,503	$169,057	$521,560
20	Small Industrial	$209,886	$162,174	$97,799	$469,859	$2,766,916	$1,633,415	$4,400,331	$253,321	$151,925	$405,246
21	Medium Industrial	$356,316	$279,641	$125,716	$761,673	$4,722,043	$2,099,678	$6,821,721	$437,755	$195,292	$633,048
22	Large Industrial	$551,396	$437,072	$195,143	$1,183,611	$7,260,618	$3,259,230	$10,519,848	$679,330	$303,143	$982,473
23	PHP	$623,117	$510,890	$160,869	$1,294,877	$8,379,303	$2,686,802	$11,066,106	$798,245	$249,901	$1,048,146
24	Municipal	$92,645	$70,502	$74,353	$237,501	$1,157,673	$1,241,827	$2,399,500	$107,946	$115,503	$223,449
25	Unmetered	$63,255	$49,732	$24,950	$137,937	$832,602	$416,711	$1,249,313	$77,744	$38,759	$116,502
26	Total	$8,382,044	$6,491,719	$5,364,712	$20,238,476	$108,435,804	$89,600,137	$198,035,941	$10,086,071	$8,333,763	$18,419,834
27											
28	Purchased Power Allocation Factors.	41.4%	32.1%	26.5%	100.0%	54.7%	45.3%	100.0%	54.7%	45.3%	100.0%
30	**Non-FAM Rate Classes**										
31	BUTU	[redacted]									
32	GRLF										
33	1P - RTP										
34	ELIADC										
35	Shore Power										
	EBS /RSS										
37	**Total Below-the-line**	$25,689	$20,461	$17,927	$64,077	$329,092	$299,409	$628,501	$30,217	$27,848	$58,066
38											
39	**In Province Total**	$8,407,734	$6,512,181	$5,382,638	$20,302,553	$108,764,896	$89,899,546	$198,664,442	$10,116,289	$8,361,611	$18,477,900
40											
41	Exports										
42											
43	Grand Total	$8,407,734	$6,512,181	$5,382,638	$20,302,553	$108,764,896	$89,899,546	$198,664,442	$10,116,289	$8,361,611	$18,477,900

Line #	Rate Class	S: Purchased Power - Wind – ERIS – Energy-related	T: Purchased Power - Wind – ERIS – Demand-related	U: Purchased Power - Wind – ERIS – Total	V: Purchased Power - Wind – NRIS – Energy-related	W: Purchased Power - Wind – NRIS – Demand-related	X: Purchased Power - Wind – NRIS – Total	Y: Purchased Power - Wind – Total
15	**FAM Rate Classes (ATL)**							
16	Residential	$8,948,653	$9,682,485	$18,631,138	$30,002,574	$32,308,240	$62,310,814	$80,941,952
17	Small General	$614,098	$494,291	$1,108,389	$2,047,064	$1,649,337	$3,696,401	$4,804,790
18	General Demand	$3,887,660	$2,682,278	$6,569,939	$12,928,207	$8,950,150	$21,878,357	$28,448,296
19	Large General	$624,955	$305,746	$930,701	$2,066,722	$1,020,205	$3,086,927	$4,017,627
20	Small Industrial	$452,497	$274,762	$727,259	$1,503,324	$916,819	$2,420,143	$3,147,402
21	Medium Industrial	$776,260	$353,194	$1,129,454	$2,578,183	$1,178,528	$3,756,711	$4,886,165
22	Large Industrial	$1,198,054	$548,246	$1,746,300	$3,976,649	$1,829,373	$5,806,022	$7,552,322
23	PHP	$1,403,954	$451,956	$1,855,910	$4,647,455	$1,508,075	$6,155,530	$8,011,440
24	Municipal	$198,971	$208,892	$407,863	$667,341	$697,025	$1,364,366	$1,772,229
25	Unmetered	$137,842	$70,096	$207,938	$458,327	$233,895	$692,223	$900,161
26	Total	$18,242,943	$15,071,948	$33,418,031	$60,875,845	$50,291,647	$111,508,333	$144,482,383
27								
28	Purchased Power Allocation Factors.	54.7%	45.3%	100.0%	54.7%	45.3%	100.0%	
30	**Non-FAM Rate Classes**							
31	BUTU	[redacted]						
32	GRLF							
33	1P - RTP							
34	ELIADC							
35	Shore Power							
	EBS /RSS							
37	**Total Below-the-line**	$52,775	$50,365	$103,140	$172,786	$168,055	$340,841	$443,981
38								
39	**In Province Total**	$18,295,718	$15,122,313	$33,521,171	$61,048,631	$50,459,702	$111,849,174	$144,926,364
40								
41	Exports							
42								
43	Grand Total	$18,295,718	$15,122,313	$33,418,031	$61,048,631	$50,459,702	$111,508,333	$144,926,364

Line #	COLUMN	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI
11								Fuel Costs used for FAM purposes			
12–14	Rate Class	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)	Export Revenues	OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh
15	**FAM Rate Classes (ATL)**										
16	Residential	$476,749,716	$192,925	$0	$0	$0	$476,942,641	$463,391,785	50.7%	$460,918,915	8.8404
17	Small General	$30,601,836	$9,849	$0	$0	$0	$30,611,685	$31,714,756	3.5%	$31,545,511	8.925
18	General Demand	$187,384,462	$53,445	$0	$0	$0	$187,437,907	$195,638,857	21.4%	$194,594,839	8.768
19	Large General	$28,310,786	$6,092	$0	$0	$0	$28,316,878	$29,555,823	3.2%	$29,398,100	8.199
20	Small Industrial	$21,222,779	$5,475	$0	$0	$0	$21,228,254	$22,157,051	2.4%	$22,038,811	8.638
21	Medium Industrial	$34,838,563	$7,037	$0	$0	$0	$34,845,601	$36,370,196	4.0%	$36,176,108	8.248
22	Large Industrial	$53,792,769	$10,924	$0	$0	$0	$53,803,693	$56,157,760	6.1%	$55,858,077	8.007
23	PHP	$59,739,185	$9,005	$0	$0	$0	$59,748,191	$62,362,347	6.8%	$62,029,553	7.653
24	Municipal	$10,691,561	$4,162	$0	$0	$0	$10,695,723	$11,163,692	1.2%	$11,104,118	8.917
25	Unmetered	$6,268,644	$1,397	$0	$0	$0	$6,270,041	$6,270,041	0.7%	$6,236,581	8.099
26	Total	$909,600,302	$300,311	$0	$0	$0	$909,900,613	$914,782,308	100.0%	$909,900,613	8.626
27											
28	Purchased Power Allocation Factors.										
30	**Non-FAM Rate Classes**										
31	BUTU	[redacted]									
32	GRLF										
33	1P - RTP										
34	ELIADC										
35	Shore Power										
	EBS /RSS										
37	**Total Below-the-line**	$12,925,305	-$300,311	$0	$0	$0	$12,624,994			$12,624,994	8.141
38											
39	**In Province Total**	$922,525,607	$0	$0	$0	$0	$922,525,607			$922,525,607	8.619
40											
41	Exports										
42											
43	Grand Total	$922,525,607	$0	$0	$0	$0	$922,525,607		100.0%	$922,525,607	

Line #	COLUMN	AJ	AK	AL	AM	AN	AO	AP	AQ	AR
11		FAM Cost Classification						V A R I A N C E FROM CA IR-001		
12		Cost Amount			Unit Cost (cents per kWh)					
13–14	Rate Class	Demand-related	Energy-related	Total	Demand-related	Energy-related	Total	Total Fuel-related costs (CA IR-001)	Variance	% Var
15	**FAM Rate Classes (ATL)**									
16	Residential	$108,544,498	$368,398,143	$476,942,641	2.08	7.066	9.148	$477,624,733	-$682,092	-0.1%
17	Small General	$5,541,202	$25,070,483	$30,611,685	1.57	7.093	8.661	$30,675,353	-$63,668	-0.2%
18	General Demand	$30,069,405	$157,368,503	$187,437,907	1.35	7.091	8.445	$187,835,033	-$397,125	-0.2%
19	Large General	$3,427,534	$24,889,344	$28,316,878	0.96	6.941	7.897	$28,409,065	-$92,188	-0.3%
20	Small Industrial	$3,080,196	$18,148,058	$21,228,254	1.21	7.113	8.320	$21,216,769	$11,484	0.1%
21	Medium Industrial	$3,959,445	$30,886,156	$34,845,601	0.90	7.042	7.945	$34,890,616	-$45,015	-0.1%
22	Large Industrial	$6,146,059	$47,657,634	$53,803,693	0.88	6.832	7.713	$53,969,549	-$165,856	-0.3%
23	PHP	$5,066,609	$54,681,581	$59,748,191	0.63	6.746	7.371	$60,069,944	-$321,753	-0.5%
24	Municipal	$2,341,762	$8,353,961	$10,695,723	1.88	6.708	8.589	$10,727,436	-$31,713	-0.3%
25	Unmetered	$785,808	$5,484,233	$6,270,041	1.02	7.122	8.143	$6,286,580	-$16,539	-0.3%
26	Total	$168,962,518	$740,938,095	$909,900,613	1.60	7.024	8.626	$911,705,078	-$1,804,465	-0.2%
27		18.6%	81.4%							
28	Purchased Power Allocation Factors.									
30	**Non-FAM Rate Classes**									
31	BUTU	[redacted]								
32	GRLF									
33	1P - RTP									
34	ELIADC									
35	Shore Power									
	EBS /RSS									
37	**Total Below-the-line**	$263,292	$12,361,702	$12,624,994	0.170	7.972	8.141	$12,629,301	-$4,307	0.0%
38										
39	**In Province Total**	$169,225,810	$753,299,797	$922,525,607	1.581	7.038	8.619	$924,334,379	-$1,808,772	-0.2%
40										
41	Exports									
42										
43	Grand Total	$169,225,810	$753,299,797	$922,525,607	1.581	7.038	8.619	$924,334,379	-$1,808,772	-0.2%

Monthly Fuel Cost Allocation

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Purchased Power													
Imports	$4,757,627	$4,589,694	$3,462,924	$11,463,432	$11,169,883	$11,583,281	$8,099,729	$7,009,590	$10,846,749	$12,840,536	$6,018,108	$2,855,712	**$94,697,267**
Biomass													
IPP	$1,933,751	$1,501,824	$1,568,024	$71,916	$1,476,419	$1,440,568	$1,932,636	$1,975,140	$1,562,773	$85,309	$1,604,921	$1,699,971	**$16,853,252**
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	**$2,209,053**	**$1,774,468**	**$1,910,905**	**$338,372**	**$1,760,529**	**$1,747,854**	**$2,221,955**	**$2,265,821**	**$1,832,245**	**$345,941**	**$1,921,853**	**$1,973,556**	**$20,302,553**
Maritime Link													
ML - NS Block (GWh)	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$198,664,442
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$13,250,000**	**$13,250,000**	**$13,250,000**	**$13,250,000**	**$33,082,221**	**$13,250,000**	**$13,250,000**	**$13,250,000**	**$13,250,000**	**$13,250,000**	**$33,082,221**	**$13,250,000**	**$198,664,442**
	7,254,116												
Regular other than biomass and wind													
IPP	$1,089,522	$1,308,985	$1,789,401	$1,774,269	$1,644,728	$1,527,824	$1,253,560	$1,142,692	$1,514,565	$1,430,960	$1,813,629	$2,167,026	**$18,457,161**
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	**$1,092,392**	**$1,310,424**	**$1,791,130**	**$1,775,899**	**$1,646,171**	**$1,529,120**	**$1,254,941**	**$1,144,436**	**$1,516,133**	**$1,432,478**	**$1,815,907**	**$2,168,869**	**$18,477,900**
Wind NRIS													
IPP	$3,389,237	$3,589,681	$4,112,442	$3,528,178	$3,229,511	$2,482,409	$2,309,965	$2,149,334	$3,273,229	$4,362,000	$6,574,920	$8,509,661	**$47,510,568**
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	**$9,003,590**	**$9,435,246**	**$11,296,633**	**$9,631,189**	**$8,715,152**	**$7,017,296**	**$6,234,525**	**$5,674,290**	**$7,868,746**	**$8,140,557**	**$13,197,455**	**$15,293,654**	**$111,508,333**
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	**$32,922,323**	**$33,618,292**	**$35,338,682**	**$38,980,308**	**$59,224,446**	**$37,661,631**	**$33,253,106**	**$31,260,232**	**$37,564,692**	**$38,167,443**	**$59,747,461**	**$39,329,909**	**$477,068,526**
Plant Fuel Costs													
Plant Fuel Costs	$67,441,935	$54,358,722	$49,574,650	$30,087,598	$22,231,785	$23,382,648	$35,228,716	$35,916,700	$23,184,621	$25,673,066	$33,591,286	$44,785,354	**$445,457,081**
BTL Class Fuel-related costs													
GRLF	[redacted]												
1P - RTP													
PHP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Shore Power	[redacted]												
Total	$666,442	$572,516	$334,043	$672,296	$765,054	$981,238	$1,157,980	$1,506,607	$1,175,360	$872,849	$741,340	$827,467	**$10,273,192**

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
ATL-related Fuel costs (net of BTL without BUTU)	$66,775,493	$53,786,205	$49,240,607	$29,415,302	$21,466,732	$22,401,410	$34,070,736	$34,410,093	$22,009,261	$24,800,217	$32,849,946	$43,957,887	**$435,183,889**
Fuel costs before PP													
Domestic	$38,228,651	$31,179,517	$26,920,887	$15,230,729	$10,102,130	$9,371,790	$14,259,027	$14,576,495	$8,810,958	$10,712,877	$16,063,256	$25,148,979	$220,605,297
Small General	$2,328,777	$1,884,233	$1,684,765	$957,025	$718,176	$759,918	$1,179,382	$1,181,806	$734,372	$796,603	$1,074,465	$1,446,305	$14,745,827
General	$13,213,118	$10,476,936	$9,942,469	$5,814,496	$4,433,710	$5,202,359	$7,949,988	$8,023,624	$5,110,445	$5,595,799	$7,027,357	$8,506,432	$91,296,733
Large General	$1,696,610	$1,406,484	$1,328,990	$921,409	$757,067	$900,952	$1,495,678	$1,476,239	$977,867	$957,757	$1,034,918	$1,148,316	$14,102,288
Small Industrial	$1,423,129	$1,111,387	$1,030,696	$669,777	$567,747	$718,259	$995,536	$910,709	$586,032	$595,351	$776,133	$992,704	$10,377,461
Medium Industrial	$2,187,197	$1,732,967	$1,713,093	$1,158,826	$1,014,272	$1,215,616	$1,690,455	$1,604,876	$1,111,130	$1,151,069	$1,410,496	$1,486,492	$17,476,489
Large Industrial	$3,259,098	$2,560,613	$2,417,917	$1,782,721	$1,594,382	$1,809,538	$2,544,362	$2,832,908	$1,852,198	$1,927,664	$2,172,371	$2,093,161	$26,846,935
PHP	$2,973,113	$2,276,438	$3,223,246	$2,268,484	$1,863,211	$1,956,097	$3,210,697	$3,031,656	$2,286,771	$2,522,785	$2,556,281	$2,225,176	$30,393,954
Municipal	$961,984	$736,135	$630,118	$326,255	$163,163	$173,355	$313,775	$304,865	$219,045	$271,679	$418,555	$563,973	$5,082,900
Unmetered	[redacted]												
BUTU													
Total	**$66,775,493**	**$53,786,205**	**$49,240,607**	**$29,415,302**	**$21,466,732**	**$22,401,410**	**$34,070,736**	**$34,410,093**	**$22,009,261**	**$24,800,217**	**$32,849,946**	**$43,957,887**	**$435,183,889**
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	$2,723,719	$2,660,616	$1,893,254	$5,935,564	$5,256,488	$4,845,949	$3,389,837	$2,969,340	$4,342,274	$5,546,689	$2,942,788	$1,633,796	$44,140,315
Small General	$165,921	$160,786	$118,484	$372,962	$373,692	$392,937	$280,378	$240,743	$361,918	$412,448	$196,842	$93,959	$3,171,069
General	$941,410	$894,020	$699,220	$2,265,966	$2,307,013	$2,690,027	$1,889,972	$1,634,471	$2,518,563	$2,897,275	$1,287,411	$552,618	$20,577,967
Large General	$120,880	$120,018	$93,463	$359,082	$393,928	$465,863	$355,572	$300,721	$481,919	$495,887	$189,597	$74,600	$3,451,531
Small Industrial	$101,395	$94,837	$72,485	$261,018	$295,419	$371,396	$236,671	$185,518	$288,812	$308,248	$142,188	$64,491	$2,422,479
Medium Industrial	$155,834	$147,878	$120,476	$451,606	$527,761	$628,569	$401,876	$326,925	$547,594	$595,976	$258,403	$96,570	$4,259,468
Large Industrial	$232,205	$218,503	$170,044	$694,744	$829,612	$935,673	$604,878	$577,084	$912,813	$998,065	$397,978	$135,982	$6,707,581
PHP	$211,829	$194,253	$226,680	$884,050	$969,493	$1,011,455	$763,288	$617,571	$1,126,982	$1,306,195	$468,311	$144,558	$7,924,664
Municipal	$68,540	$62,816	$44,314	$127,145	$84,899	$89,638	$74,595	$62,103	$107,951	$140,664	$76,679	$36,638	$975,982
Unmetered	[redacted]												
BUTU													
Total	$4,757,627	$4,589,694	$3,462,924	$11,463,432	$11,169,883	$11,583,281	$8,099,729	$7,009,590	$10,846,749	$12,840,536	$6,018,108	$2,855,712	$94,697,267
Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	12,236,372	11,899,369	16,036,280	16,447,820	13,090,652	418,181	13,292,610	14,132,701	139,470,614
Relative Share	11.5%	8.9%	9.3%	0.3%	8.8%	8.5%	11.5%	11.8%	9.4%	0.3%	9.5%	10.1%	100.0%
Bio-fuel Apportioned	$970,018	$751,630	$783,969	$21,251	$737,648	$717,332	$966,718	$991,527	$789,146	$25,209	$801,321	$851,964	$8,407,734
Domestic	$555,331	$435,715	$428,612	$11,004	$347,133	$300,101	$404,584	$420,022	$315,919	$10,890	$391,837	$487,422	$4,108,568
Small General	$33,829	$26,331	$26,823	$691	$24,678	$24,334	$33,464	$34,054	$26,331	$810	$26,210	$28,031	$285,586
General	$191,941	$146,409	$158,296	$4,201	$152,353	$166,589	$225,572	$231,201	$183,236	$5,688	$171,421	$164,866	$1,801,772
Large General	$24,646	$19,655	$21,159	$666	$26,015	$28,850	$42,438	$42,538	$35,062	$974	$25,245	$22,256	$289,502
Small Industrial	$20,673	$15,531	$16,410	$484	$19,509	$23,000	$28,247	$26,242	$21,012	$605	$18,933	$19,240	$209,886
Medium Industrial	$31,772	$24,217	$27,274	$837	$34,853	$38,926	$47,965	$46,245	$39,840	$1,170	$34,407	$28,810	$356,316
Large Industrial	$47,343	$35,783	$38,496	$1,288	$54,787	$57,945	$72,193	$81,630	$66,411	$1,959	$52,991	$40,568	$551,396
PHP	$43,189	$31,812	$51,318	$1,639	$64,024	$62,638	$91,100	$87,357	$81,993	$2,564	$62,356	$43,127	$623,117
Municipal	$13,974	$10,287	$10,032	$236	$5,607	$5,551	$8,903	$8,785	$7,854	$276	$10,210	$10,931	$92,645
Unmetered	[redacted]												
BUTU													
Total	**$970,018**	**$751,630**	**$783,969**	**$21,251**	**$737,648**	**$717,332**	**$966,718**	**$991,527**	**$789,146**	**$25,209**	**$801,321**	**$851,964**	**$8,407,734**

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Domestic	$41,507,701	$34,275,849	$29,242,754	$21,177,297	$15,705,751	$14,517,840	$18,053,448	$17,965,856	$13,469,151	$16,270,455	$19,397,881	$27,270,197	$268,854,180
Small General	$2,528,527	$2,071,349	$1,830,072	$1,330,678	$1,116,546	$1,177,189	$1,493,224	$1,456,603	$1,122,621	$1,209,861	$1,297,517	$1,568,295	$18,202,482
General	$14,346,469	$11,517,365	$10,799,985	$8,084,663	$6,893,076	$8,058,974	$10,065,532	$9,889,296	$7,812,244	$8,498,762	$8,486,189	$9,223,916	$113,676,472
Large General	$1,842,136	$1,546,157	$1,443,613	$1,281,157	$1,177,010	$1,395,665	$1,893,688	$1,819,498	$1,494,848	$1,454,618	$1,249,760	$1,245,171	$17,843,321
Small Industrial	$1,545,197	$1,221,756	$1,119,592	$931,279	$882,675	$1,112,655	$1,260,454	$1,122,469	$895,857	$904,205	$937,254	$1,076,435	$13,009,826
Medium Industrial	$2,374,803	$1,905,061	$1,860,843	$1,611,269	$1,576,886	$1,883,111	$2,140,296	$1,978,046	$1,698,564	$1,748,215	$1,703,306	$1,611,872	$22,092,273
Large Industrial	$3,538,646	$2,814,899	$2,626,457	$2,478,753	$2,478,781	$2,803,156	$3,221,434	$3,491,623	$2,831,422	$2,927,689	$2,623,340	$2,269,711	$34,105,911
PHP	$3,228,131	$2,502,503	$3,501,244	$3,154,173	$2,896,728	$3,030,190	$4,065,084	$3,736,584	$3,495,745	$3,831,544	$3,086,948	$2,412,860	$38,941,734
Municipal	$1,044,498	$809,238	$684,464	$453,635	$253,669	$268,544	$397,273	$375,753	$334,850	$412,619	$505,444	$611,542	$6,151,528
Unmetered	[redacted]												
BUTU													
Total	**$72,503,138**	**$59,127,530**	**$53,487,499**	**$40,899,985**	**$33,374,262**	**$34,702,023**	**$43,137,184**	**$42,411,210**	**$33,645,156**	**$37,665,963**	**$39,669,375**	**$47,665,563**	**$538,288,890**
Domestic	6.38	5.62	5.08	4.76	4.35	4.96	5.65	5.59	4.88	4.97	4.49	4.52	5.16
Small General	6.38	5.62	5.08	4.76	4.35	4.96	5.64	5.58	4.88	4.97	4.49	4.52	5.15
General	6.36	5.60	5.06	4.75	4.34	4.94	5.63	5.57	4.86	4.95	4.48	4.51	5.12
Large General	6.19	5.45	4.93	4.62	4.23	4.82	5.49	5.44	4.74	4.83	4.36	4.39	4.98
Small Industrial	6.35	5.59	5.06	4.74	4.33	4.94	5.62	5.56	4.86	4.94	4.47	4.50	5.10
Medium Industrial	6.29	5.54	5.01	4.70	4.29	4.90	5.57	5.52	4.82	4.90	4.43	4.46	5.04
Large Industrial	6.09	5.37	4.85	4.56	4.17	4.75	5.42	5.37	4.68	4.76	4.29	4.33	4.89
PHP	6.02	5.30	4.79	4.51	4.12	4.70	5.36	5.32	4.63	4.71	4.24	4.28	4.80
Municipal	6.07	5.35	4.83	4.54	4.15	4.73	5.40	5.35	4.66	4.74	4.28	4.31	4.94
Unmetered	[redacted]												
BUTU													
Total	**6.34**	**5.59**	**5.04**	**4.73**	**4.32**	**4.92**	**5.61**	**5.56**	**4.84**	**4.92**	**4.45**	**4.50**	**5.10**
Maritime Link	$7,254,116	$7,254,116	$7,254,116	$7,254,116	$18,111,869	$7,254,116	$7,254,116	$7,254,116	$7,254,116	$7,254,116	$18,111,869	$7,254,116	$108,764,896
Energy													
Domestic	$4,205,164	$3,965,979	$3,756,054	$3,413,749	$7,577,230	$3,035,938	$3,072,923	$2,904,037	$3,133,539	$3,547,182	$10,362,077	$3,612,532	$52,586,405
Small General	$254,125	$248,199	$236,012	$242,689	$614,405	$251,106	$249,141	$242,044	$233,008	$237,270	$595,918	$244,670	$3,648,587
General	$1,413,019	$1,464,722	$1,433,914	$1,498,255	$4,206,184	$1,692,659	$1,691,489	$1,684,371	$1,636,783	$1,551,822	$3,504,886	$1,531,794	$23,309,898
Large General	$189,692	$195,787	$227,229	$255,831	$728,433	$318,450	$311,211	$322,299	$280,146	$228,537	$473,138	$241,007	$3,771,759
Small Industrial	$149,892	$151,842	$165,174	$191,855	$580,723	$211,963	$191,990	$193,153	$174,141	$171,390	$409,022	$175,771	$2,766,916
Medium Industrial	$233,724	$252,373	$285,778	$342,747	$982,844	$359,920	$338,330	$366,221	$336,690	$311,474	$612,476	$299,466	$4,722,043
Large Industrial	$345,348	$356,207	$439,637	$538,779	$1,463,038	$541,729	$597,216	$610,473	$563,846	$479,716	$862,440	$462,188	$7,260,618
PHP	$307,022	$474,848	$559,431	$629,623	$1,581,533	$683,600	$639,114	$753,706	$737,920	$564,493	$916,834	$531,179	$8,379,303
Municipal	$99,282	$92,829	$80,458	$55,137	$140,160	$66,807	$64,270	$72,196	$79,467	$92,428	$232,372	$82,269	$1,157,673
Unmetered	$43,733	$43,804	$52,847	$62,470	$165,859	$61,030	$58,789	$70,649	$58,355	$57,160	$104,612	$53,294	$832,602
BUTU	$13,114	$7,526	$17,580	$22,982	$71,460	$30,913	$39,643	$34,967	$20,221	$12,646	$38,094	$19,946	$329,092
Total	**$7,254,116**	**$7,254,116**	**$7,254,116**	**$7,254,116**	**$18,111,869**	**$7,254,116**	**$7,254,116**	**$7,254,116**	**$7,254,116**	**$7,254,116**	**$18,111,869**	**$7,254,116**	**$108,764,896**
BIOMASS	$678,347.67	$559,983.80	$616,975.41	$173,617.30	$560,007.72	$564,190.92	$687,217.42	$697,650.99	$571,076.32	$175,594.26	$613,469.50	$614,049.62	$6,512,181
Energy													
Domestic	$393,234	$306,155	$319,459	$81,703	$234,283	$236,121	$291,113	$279,290	$246,686	$85,864	$350,975	$305,795	$3,130,679
Small General	$23,764	$19,160	$20,073	$5,808	$18,997	$19,530	$23,602	$23,278	$18,343	$5,743	$20,184	$20,711	$219,195
General	$132,134	$113,070	$121,957	$35,859	$130,053	$131,647	$160,243	$161,991	$128,855	$37,564	$118,714	$129,664	$1,401,750
Large General	$17,738	$15,114	$19,326	$6,123	$22,523	$24,768	$29,483	$30,996	$22,054	$5,532	$16,026	$20,401	$230,084
Small Industrial	$14,017	$11,721	$14,048	$4,592	$17,956	$16,485	$18,188	$18,576	$13,709	$4,149	$13,854	$14,879	$162,174
Medium Industrial	$21,856	$19,482	$24,306	$8,203	$30,389	$27,993	$32,052	$35,221	$26,506	$7,540	$20,745	$25,349	$279,641
Large Industrial	$32,294	$27,498	$37,392	$12,895	$45,236	$42,133	$56,577	$58,711	$44,388	$11,612	$29,212	$39,123	$437,072
PHP	$28,710	$36,656	$47,581	$15,069	$48,900	$53,167	$60,546	$72,486	$58,092	$13,664	$31,054	$44,963	$510,890
Municipal	$9,284	$7,166	$6,843	$1,320	$4,334	$5,196	$6,089	$6,943	$6,256	$2,237	$7,871	$6,964	$70,502
Unmetered	$4,090	$3,381	$4,495	$1,495	$5,128	$4,747	$5,569	$6,795	$4,594	$1,384	$3,543	$4,511	$49,732
BUTU	$1,226	$581	$1,495	$550	$2,209	$2,404	$3,756	$3,363	$1,592	$306	$1,290	$1,688	$20,461
Total	**$678,348**	**$559,984**	**$616,975**	**$173,617**	**$560,008**	**$564,191**	**$687,217**	**$697,651**	**$571,076**	**$175,594**	**$613,469**	**$614,050**	**$6,512,181**
Regular other than biomass and wind	$598,063.06	$717,431.71	$980,608.79	$972,269.89	$901,246.56	$837,163.11	$687,055.89	$626,556.24	$830,052.89	$784,253.60	$994,173.59	$1,187,413.32	$10,116,289
Energy													
Domestic	$346,693	$392,235	$507,742	$457,545	$377,043	$350,363	$291,044	$250,829	$358,556	$383,491	$568,782	$591,329	$4,875,653
Small General	$20,951	$24,547	$31,904	$32,528	$30,573	$28,979	$23,597	$20,906	$26,662	$25,652	$32,710	$40,050	$339,058
General	$116,496	$144,861	$193,836	$200,811	$209,300	$195,342	$160,205	$145,483	$187,289	$167,770	$192,386	$250,737	$2,164,515
Large General	$15,639	$19,363	$30,717	$34,289	$36,247	$36,751	$29,476	$27,838	$32,056	$24,707	$25,971	$39,450	$352,503
Small Industrial	$12,358	$15,017	$22,328	$25,714	$28,897	$24,462	$18,184	$16,683	$19,926	$18,529	$22,452	$28,772	$253,321
Medium Industrial	$19,269	$24,960	$38,631	$45,938	$48,906	$41,537	$32,044	$31,631	$38,526	$33,674	$33,619	$49,019	$437,755
Large Industrial	$28,472	$35,229	$59,430	$72,213	$72,801	$62,518	$56,564	$52,728	$64,518	$51,863	$47,340	$75,655	$679,330
PHP	$25,312	$46,962	$75,624	$84,388	$78,697	$78,891	$60,532	$65,099	$84,437	$61,028	$50,326	$86,948	$798,245
Municipal	$8,185	$9,181	$10,876	$7,390	$6,974	$7,710	$6,087	$6,236	$9,093	$9,993	$12,755	$13,466	$107,946
Unmetered	$3,606	$4,332	$7,144	$8,373	$8,253	$7,043	$5,568	$6,102	$6,677	$6,180	$5,742	$8,724	$77,744
BUTU	$1,081	$744	$2,376	$3,080	$3,556	$3,568	$3,755	$3,020	$2,314	$1,367	$2,091	$3,265	$30,217
Total	**$598,063**	**$717,432**	**$980,609**	**$972,270**	**$901,247**	**$837,163**	**$687,056**	**$626,556**	**$830,053**	**$784,254**	**$994,174**	**$1,187,413**	**$10,116,289**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Wind NRIS	$4,929,289.59	$5,165,612.74	$6,184,685.79	$5,272,887.31	$4,771,375.04	$3,841,832.14	$3,413,280.33	$3,106,562.51	$4,307,984.78	$4,456,795.59	$7,225,348.69	$8,372,976.41	$61,048,631
Energy													
Domestic	$2,857,477	$2,824,150	$3,202,322	$2,481,393	$1,996,139	$1,607,855	$1,445,903	$1,243,649	$1,860,908	$2,179,323	$4,133,732	$4,169,722	$30,002,574
Small General	$172,682	$176,741	$201,218	$176,406	$161,858	$132,988	$117,228	$103,655	$138,376	$145,774	$237,729	$282,407	$2,047,064
General	$960,169	$1,043,020	$1,222,521	$1,089,055	$1,108,073	$896,444	$795,897	$721,329	$972,032	$953,411	$1,398,200	$1,768,054	$12,928,207
Large General	$128,899	$139,418	$193,730	$185,959	$191,898	$168,653	$146,434	$138,024	$166,370	$140,409	$188,748	$278,180	$2,066,722
Small Industrial	$101,854	$108,126	$140,823	$139,456	$152,985	$112,257	$90,337	$82,717	$103,417	$105,299	$163,171	$202,881	$1,503,324
Medium Industrial	$158,819	$179,713	$243,648	$249,136	$258,919	$190,616	$159,194	$156,834	$199,949	$191,364	$244,334	$345,655	$2,578,183
Large Industrial	$234,670	$253,653	$374,824	$391,629	$385,422	$286,903	$281,008	$261,434	$334,850	$294,728	$344,052	$533,475	$3,976,649
PHP	$208,626	$338,136	$476,958	$457,662	$416,638	$362,040	$300,723	$322,773	$438,227	$346,814	$365,752	$613,107	$4,647,455
Municipal	$67,464	$66,103	$68,596	$40,078	$36,924	$35,381	$30,241	$30,918	$47,193	$56,786	$92,700	$94,958	$667,341
Unmetered	$29,717	$31,193	$45,056	$45,408	$43,694	$32,322	$27,662	$30,255	$34,655	$35,118	$41,733	$61,514	$458,327
BUTU	$8,911	$5,359	$14,989	$16,705	$18,825	$16,372	$18,653	$14,975	$12,008	$7,769	$15,197	$23,022	$172,786
Total	**$4,929,290**	**$5,165,613**	**$6,184,686**	**$5,272,887**	**$4,771,375**	**$3,841,832**	**$3,413,280**	**$3,106,563**	**$4,307,985**	**$4,456,796**	**$7,225,349**	**$8,372,976**	**$61,048,631**

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Wind ERIS	$1,428,737.80	$1,783,942.56	$1,985,760.83	$1,380,426.49	$1,560,587.52	$1,387,359.23	$1,200,053.03	$1,049,025.08	$1,232,278.83	$1,181,425.01	$2,032,201.40	$2,073,920.51	$18,295,718
Energy													
Domestic	$828,230	$975,319	$1,028,192	$649,621	$652,883	$580,627	$508,356	$419,956	$532,304	$577,704	$1,162,653	$1,032,807	$8,948,653
Small General	$50,051	$61,037	$64,607	$46,183	$52,939	$48,024	$41,216	$35,002	$39,582	$38,642	$66,864	$69,950	$614,098
General	$278,302	$360,207	$392,524	$285,111	$362,421	$323,723	$279,824	$243,579	$278,045	$252,734	$393,258	$437,933	$3,887,660
Large General	$37,361	$48,148	$62,202	$48,683	$62,765	$60,904	$51,484	$46,608	$47,589	$37,220	$53,087	$68,903	$624,955
Small Industrial	$29,522	$37,341	$45,215	$36,509	$50,037	$40,538	$31,761	$27,932	$29,582	$27,913	$45,893	$50,252	$452,497
Medium Industrial	$46,033	$62,064	$78,230	$65,223	$84,686	$68,835	$55,970	$52,960	$57,195	$50,727	$68,722	$85,616	$776,260
Large Industrial	$68,018	$87,599	$120,348	$102,527	$126,061	$103,606	$98,798	$88,281	$95,782	$78,128	$96,768	$132,138	$1,198,054
PHP	$60,470	$116,775	$153,140	$119,814	$136,271	$130,739	$105,729	$108,994	$125,353	$91,935	$102,871	$151,862	$1,403,954
Municipal	$19,554	$22,829	$22,025	$10,492	$12,077	$12,777	$10,632	$10,440	$13,499	$15,053	$26,073	$23,520	$198,971
Unmetered	$8,613	$10,772	$14,466	$11,888	$14,291	$11,672	$9,725	$10,217	$9,913	$9,309	$11,738	$15,237	$137,842
BUTU	$2,583	$1,851	$4,812	$4,373	$6,157	$5,912	$6,558	$5,057	$3,435	$2,059	$4,274	$5,702	$52,775
Total	**$1,428,738**	**$1,783,943**	**$1,985,761**	**$1,380,426**	**$1,560,588**	**$1,387,359**	**$1,200,053**	**$1,049,025**	**$1,232,279**	**$1,181,425**	**$2,032,201**	**$2,073,921**	**$18,295,718**

Monthly Energy Allocators

Rate Class	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
kWh requirements													
ATL													
Domestic Total	707,116,004	662,646,274	625,765,329	481,109,226	389,926,477	315,832,492	344,330,438	345,113,243	297,672,902	353,637,738	468,685,690	652,943,045	5,644,778,858
Small General	43,075,431	40,044,871	39,161,684	30,230,565	27,720,465	25,609,499	28,480,010	27,980,457	24,810,312	26,296,289	31,350,205	37,550,416	382,310,202
General	244,403,273	222,662,284	231,108,747	183,668,663	171,134,295	175,321,259	191,978,244	189,967,402	172,653,292	184,720,285	205,040,721	220,852,532	2,393,510,995
Large General	31,382,222	29,891,458	30,891,848	29,105,540	29,221,607	30,362,399	36,118,000	34,951,453	33,036,649	31,616,065	30,196,319	29,813,722	376,587,283
Small Industrial	26,323,632	23,619,890	23,958,128	21,156,943	21,914,164	24,205,562	24,040,437	21,561,950	19,798,742	19,652,860	22,645,635	25,773,589	274,651,533
Medium Industrial	40,456,616	36,830,070	39,820,167	36,605,073	39,149,327	40,966,679	40,821,513	37,997,064	37,538,851	37,997,398	41,154,755	38,593,810	467,931,323
Large Industrial	60,283,593	54,419,718	56,203,514	56,312,715	61,540,663	60,982,054	61,441,880	67,071,964	62,575,410	63,633,209	63,384,353	54,344,751	722,193,823
PHP	54,993,729	48,380,250	74,923,076	71,657,003	71,917,020	65,921,139	77,532,680	71,777,511	77,257,186	83,278,469	74,585,898	57,772,243	829,996,205
Municipal	17,793,843	15,644,788	14,646,832	10,305,750	6,297,827	5,842,110	7,577,118	7,217,995	7,400,291	8,968,255	12,212,395	14,642,427	128,549,631
Unmetered	[redacted]												
BUTU													
Total	1,235,147,403	1,143,097,507	1,144,578,344	929,172,442	828,582,358	754,935,070	822,748,406	814,693,714	743,569,610	818,668,306	958,479,362	1,141,278,810	11,334,951,333

	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Total
Fuel Cost Allocators													
ATL													
Domestic	57.24952%	57.97%	54.67%	51.78%	47.06%	41.84%	41.85%	42.36%	40.03%	43.20%	48.90%	57.21%	49.80%
Small General	3.48747%	3.50%	3.42%	3.25%	3.35%	3.39%	3.46%	3.43%	3.34%	3.21%	3.27%	3.29%	3.37%
General	19.78738%	19.48%	20.19%	19.77%	20.65%	23.22%	23.33%	23.32%	23.22%	22.56%	21.39%	19.35%	21.12%
Large General	2.54077%	2.61%	2.70%	3.13%	3.53%	4.02%	4.39%	4.29%	4.44%	3.86%	3.15%	2.61%	3.32%
Small Industrial	2.13121%	2.07%	2.09%	2.28%	2.64%	3.21%	2.92%	2.65%	2.66%	2.40%	2.36%	2.26%	2.42%
Medium Industrial	3.27545%	3.22%	3.48%	3.94%	4.72%	5.43%	4.96%	4.66%	5.05%	4.64%	4.29%	3.38%	4.13%
Large Industrial	4.88068%	4.76%	4.91%	6.06%	7.43%	8.08%	7.47%	8.23%	8.42%	7.77%	6.61%	4.76%	6.37%
PHP	4.45%	4.23%	6.55%	7.71%	8.68%	8.73%	9.42%	8.81%	10.39%	10.17%	7.78%	5.06%	7.32%
Municipal	1.44063%	1.37%	1.28%	1.11%	0.76%	0.77%	0.92%	0.89%	1.00%	1.10%	1.27%	1.28%	1.13%
Unmetered	[redacted]												
BUTU													
Total	100.00000%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%

	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	20.5%	7,549	$6.222	[redacted]	[redacted]	[redacted]
Imports	[redacted]	0%	[redacted]	$6.222	[redacted]	[redacted]	[redacted]
Total	[redacted]		[redacted]		[redacted]	[redacted]	-$300,311

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Biomass Calculations

($ in millions)	2026		
Capital	[redacted]		[redacted]
Fuel			
Operating			
Total	54.0	100.0%	

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

Annual Peak of ATL	2,356,954
Annual Energy Requirement of ATL	11,303,785,142

System Coincident Load Factor **54.748044%**

Rate Base	**Average**	**2025**	**2026**
Steam Plant	$ 481,584	$ 543,265	$ 419,903
Steam Plant - CWIP	$ 4,559	$ 4,744	$ 4,374
Steam Environmental & Fuel Conversion	$ 360,906	$ 369,394	$ 352,418
Steam Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Hydro Plant	$ 644,461	$ 603,548	$ 685,374
Hydro Plant - CWIP	$ 44,561	$ 55,299	$ 33,823
Hydro Environmental & Fuel Conversion	$ 10,643	$ 10,402	$ 10,884
Hydro Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Wind Plant	$ 163,575	$ 168,639	$ 158,510
Wind Plant - CWIP	$ 196	$ 196	$ 196
Gas Turbine Plant	$ 67,260	$ 58,451	$ 76,069
Gas Turbine Plant - CWIP	$ 881	$ 1,070	$ 692
Gas Environmental & Fuel Conversion	$ -	$ -	$ -
Gas Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
LM6000 Plant	$ 93,707	$ 94,612	$ 92,802
LM6000 Plant - CWIP	$ 30	$ 0	$ 60
LM6000 Environmental & Fuel Conversion	$ -	$ -	$ -
LM6000 Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
ECEI Batteries Plant	$ 145,582	$ 119,318	$ 171,846
ECEI Batteries CWIP	$ 15,185	$ 30,370	$ (0)
Generation-related Trans Assets Plant	$ 58,575	$ 58,575	$ 58,575
Generation-related Trans Assets CWIP	$ -	$ -	$ -
Total Generation Exclusing Solar	**$ 2,091,705**	**$ 2,117,884**	**$ 2,065,526**
DISTRIBUTION	$ 40,929	$ 44,376	$ 37,483
TRANSMISSION	$ 2,906	$ 3,104	$ 2,708
DISTRIBUTION/ TRANSMISSION COMMUNICATION	$ 34,964	$ 32,676	$ 37,252
DISTRIBUTION/ TRANSMISSION NON-COMMUNICATION	$ 48,211	$ 41,591	$ 54,831
RETAIL	$ 42,983	$ 46,109	$ 39,858
NON-FUNCTIONALIZED	$ 292,481	$ 287,072	$ 297,891
General Property Plant	$ 462,475	$ 454,929	$ 470,022
General Property Plant - CWIP	$ 14,812	$ 10,022	$ 19,601
Total General Plant	**$ 477,287**	**$ 464,951**	**$ 489,623**

Total System Plant in Service	$ 4,463,196
Direct Plant in Service (Solar)	$ 1,285

Generation Rate Base		**Initial Classification**			**Further Classification**			**Fully Classified**		
	Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$ 847,049	$ 847,049	$ -	$ -	$ (463,743)	$ 463,743	$ -	$ 383,306	$ 463,743	$ -
Hydro Plant	$ 699,665	$ 699,665	$ -	$ -	$ (383,053)	$ 383,053	$ -	$ 316,612	$ 383,053	$ -
Wind Plant	$ 163,771	$ 163,771	$ -	$ -	$ (89,661)	$ 89,661	$ -	$ 74,110	$ 89,661	$ -
LM6000 Plant	$ 93,737	$ 93,737	$ -	$ -	$ (51,319)	$ 51,319	$ -	$ 42,418	$ 51,319	$ -
Gas Turbine Plant - Other	$ 68,141	$ 68,141	$ -	$ -	$ (37,306)	$ 37,306	$ -	$ 30,835	$ 37,306	$ -
Batteries	$ 160,767	$ 160,767	$ -	$ -	$ (88,017)	$ 88,017	$ -	$ 72,750	$ 88,017	$ -
Radial to Generation Transmission	$ 58,575	$ 58,575	$ -	$ -	$ (32,068)	$ 32,068	$ -	$ 26,506	$ 32,068	$ -
Total Generation Plant	$ 2,091,705	$ 2,091,705	$ -	$ -	$ (1,145,168)	$ 1,145,168	$ -	$ 946,537	$ 1,145,168	$ -
General Property Plant -generation-related	$ 144,056.3	$ 144,056	$ -	$ -	$ (78,868)	$ 78,868	$ -	$ 65,188	$ 78,868	$ -
Total Generation Plant in Service	$ 2,235,761	$ 2,235,761	$ -	$ -	$ (1,224,036)	$ 1,224,036	$ -	$ 1,011,726	$ 1,224,036	$ -
Rate Base Factors Applicable to Base Cost of Fuel Classification								**45.252%**	**54.748%**	

Data Inputs

Category	Jan-26	Feb-26	Mar-26	Apr-26	May-26	Jun-26	Jul-26	Aug-26	Sep-26	Oct-26	Nov-26	Dec-26	Annual
Plant Fuel Costs	$67,441,935	$54,358,722	$49,574,650	$30,087,598	$22,231,785	$23,382,648	$35,228,716	$35,916,700	$23,184,621	$25,673,066	$33,591,286	$44,785,354	$445,457,081
Maritime Link													
ML - NS Block	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$198,664,442
ML - Supp Block													
ML - Surplus													
Total	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$198,664,442
Non-Wind Purchases													
Purchased Power Regular bfr Biomass	$1,089,522	$1,308,985	$1,789,401	$1,774,269	$1,644,728	$1,527,824	$1,253,560	$1,142,692	$1,514,565	$1,430,960	$1,813,629	$2,167,026	$18,457,161
Purchased Power - Biomass	$1,933,751	$1,501,824	$1,568,024	$71,916	$1,476,419	$1,440,568	$1,932,636	$1,975,140	$1,562,773	$85,309	$1,604,921	$1,699,971	$16,853,252
Non-Wind Purchases	$3,023,273	$2,810,809	$3,357,425	$1,846,185	$3,121,147	$2,968,392	$3,186,196	$3,117,832	$3,077,338	$1,516,269	$3,418,550	$3,866,997	$35,310,413
Wind Purchases													
Purchased Power Wind - NRIS	$3,389,237	$3,589,681	$4,112,442	$3,528,178	$3,229,511	$2,482,409	$2,309,965	$2,149,334	$3,273,229	$4,362,000	$6,574,920	$8,509,661	$47,510,568
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	$ 5,998,896.96	$ 6,848,140.25	$ 7,739,532.09	$ 6,049,595.00	$ 6,080,000.73	$ 5,016,489.41	$ 4,501,921.10	$ 4,065,430.31	$ 5,524,047.11	$ 6,519,930.62	$ 10,286,835.84	$ 12,297,779.11	$80,928,599
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	$ 4,757,627.35	$ 4,589,694.32	$ 3,462,923.76	$ 11,463,431.84	$ 11,169,882.87	$ 11,583,281.24	$ 8,099,729.47	$ 7,009,590.04	$ 10,846,749.33	$ 12,840,536.41	$ 6,018,108.42	$ 2,855,712.04	$94,697,267
Export Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0
OM&G (Solid Fuel Handling) recovered in fuels													$0
Foreign Exchange (Fuel-related)													$0
ML - NS Block per Appliation	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$16,706,101	$200,473,214
ML - NS Block per NSEB Decision	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$13,250,000	$33,082,221	$13,250,000	$198,664,442
Adjustment	($3,456,101)	($3,456,101)	($3,456,101)	($3,456,101)	$16,376,120	($3,456,101)	($3,456,101)	($3,456,101)	($3,456,101)	($3,456,101)	$16,376,120	($3,456,101)	($1,808,772)
Total FAM related costs	**$ 99,292,393**	**$ 87,034,418**	**$ 84,132,033**	**$ 68,695,346**	**$ 81,292,765**	**$ 60,902,254**	**$ 68,218,774**	**$ 66,938,388**	**$ 60,541,283**	**$ 63,571,483**	**$ 92,782,383**	**$ 83,402,401**	**$ 916,803,922**
Total FAM related costs	**$ 100,364,257**	**$ 87,977,014**	**$ 84,913,332**	**$ 69,067,906**	**$ 81,456,232**	**$ 61,044,279**	**$ 68,481,823**	**$ 67,176,932**	**$ 60,749,312**	**$ 63,840,509**	**$ 93,338,748**	**$ 84,115,263**	**$ 922,525,607**
Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	12,236,372	11,899,369	16,036,280	16,447,820	13,090,652	418,181	13,292,610	14,132,701	139,470,614
BLT Fuel Costs bfr BUTU													
GRLF	[redacted]												
1P - RTP													
ELIADC													
Shore Power													
EBS													
Export													
Total													
NRIS	**$3,389,237**	**$3,589,681**	**$4,112,442**	**$3,528,178**	**$3,229,511**	**$2,482,409**	**$2,309,965**	**$2,149,334**	**$3,273,229**	**$4,362,000**	**$6,574,920**	**$8,509,661**	**$47,510,568**
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	**$5,998,897**	**$6,848,140**	**$7,739,532**	**$6,049,595**	**$6,080,001**	**$5,016,489**	**$4,501,921**	**$4,065,430**	**$5,524,047**	**$6,519,931**	**$10,286,836**	**$12,297,779**	**$80,928,599**
Usage Data													
kWh Requirements													
ATL Classes													
Domestic Total	707,116,004	662,646,274	625,765,329	481,109,226	389,926,477	315,832,492	344,330,438	345,113,243	297,672,902	353,637,738	468,685,690	652,943,045	5,644,778,858
Small General	43,075,431	40,044,871	39,161,684	30,230,565	27,720,465	25,609,499	28,480,010	27,980,457	24,810,312	26,296,289	31,350,205	37,550,416	382,310,202
General	244,403,273	222,662,284	231,108,747	183,668,663	171,134,295	175,321,259	191,978,244	189,967,402	172,653,292	184,720,285	205,040,721	220,852,532	2,393,510,995
Large General	31,382,222	29,891,458	30,891,848	29,105,540	29,221,607	30,362,399	36,118,000	34,951,453	33,036,649	31,616,065	30,196,319	29,813,722	376,587,283
Small Industrial	26,323,632	23,619,890	23,958,128	21,156,943	21,914,164	24,205,562	24,040,437	21,561,950	19,798,742	19,652,860	22,645,635	25,773,589	274,651,533
Medium Industrial	40,456,616	36,830,070	39,820,167	36,605,073	39,149,327	40,966,679	40,821,513	37,997,064	37,538,851	37,997,398	41,154,755	38,593,810	467,931,323
Large Industrial- FIRM	9,201,024	8,512,978	9,418,815	8,624,471	8,141,245	8,072,742	7,821,638	8,459,964	7,772,251	8,496,042	7,967,496	9,298,442	101,787,108
Large Industrial- INT	51,082,569	45,906,740	46,784,699	47,688,244	53,399,418	52,909,312	53,620,241	58,611,999	54,803,159	55,137,167	55,416,856	45,046,310	620,406,715
Large Industrial	60,283,593	54,419,718	56,203,514	56,312,715	61,540,663	60,982,054	61,441,880	67,071,964	62,575,410	63,633,209	63,384,353	54,344,751	722,193,823
PHP	54,993,729	48,380,250	74,923,076	71,657,003	71,917,020	65,921,139	77,532,680	71,777,511	77,257,186	83,278,469	74,585,898	57,772,243	829,996,205
Municipal	17,793,843	15,644,788	14,646,832	10,305,750	6,297,827	5,842,110	7,577,118	7,217,995	7,400,291	8,968,255	12,212,395	14,642,427	128,549,631
Unmetered	7,158,277	6,891,341	6,911,547	6,769,126	7,135,422	6,913,303	6,921,957	6,602,437	7,241,751	6,585,723	7,552,541	6,591,865	83,275,289
BTL													
BUTU	[redacted]												
GRLF													
1P - RTP													
ELIADC													
Shore Power													
EBS													
In-Province Total	**1,242,959,225**	**1,150,008,709**	**1,148,612,081**	**937,180,833**	**838,342,464**	**767,376,879**	**837,090,197**	**833,404,968**	**759,112,853**	**830,121,301**	**967,691,718**	**1,151,165,358**	**11,463,066,585**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

kWh Sales													
ATL Classes													
Domestic Total	650,516,346	609,861,973	575,443,919	444,691,089	361,130,872	292,676,815	319,746,011	321,629,685	276,087,911	327,490,330	431,585,156	602,916,858	5,213,776,964
Small General	39,646,802	36,872,846	36,030,048	27,955,066	25,684,851	23,742,468	26,458,063	26,087,271	23,021,385	24,362,914	28,882,437	34,689,563	353,433,715
General	225,607,551	205,621,429	213,252,365	170,313,244	158,994,964	162,974,879	178,813,708	177,554,075	160,628,518	171,601,292	189,446,952	204,597,422	2,219,406,397
Large General	29,781,581	28,374,439	29,308,647	27,704,040	27,849,857	28,947,670	34,480,364	33,443,094	31,514,673	30,130,059	28,673,711	28,360,142	358,568,276
Small Industrial	24,341,933	21,850,356	22,146,064	19,651,121	20,392,694	22,537,179	22,426,996	20,183,083	18,449,134	18,286,726	20,959,754	23,916,770	255,141,808
Medium Industrial	37,761,228	34,388,307	37,154,644	34,300,556	36,745,594	38,469,740	38,399,377	35,849,667	35,276,258	35,661,523	38,443,583	36,134,139	438,584,616
Large Industrial- FIRM	23,791,612	21,471,689	20,513,154	16,238,756	12,721,887	12,078,786	13,785,587	13,174,415	13,899,341	14,801,813	18,773,938	20,277,413	201,528,392
Large Industrial- INT	34,302,075	30,981,126	33,638,706	38,144,371	46,763,762	46,882,227	45,675,545	51,840,880	46,625,934	46,703,815	42,334,500	32,181,517	496,074,459
Large Industrial	58,093,687	52,452,815	54,151,860	54,383,127	59,485,649	58,961,013	59,461,132	65,015,295	60,525,276	61,505,628	61,108,439	52,458,931	697,602,851
PHP	53,616,000	47,174,400	73,036,800	69,964,800	70,262,400	64,416,000	75,811,200	70,262,400	75,513,600	81,360,000	72,739,200	56,390,400	810,547,200
Municipal	17,205,665	15,128,677	14,156,784	9,981,453	6,112,815	5,671,771	7,357,285	7,020,739	7,182,116	8,702,481	11,818,578	14,190,027	124,528,392
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	**1,143,156,740**	**1,058,068,253**	**1,061,037,502**	**865,201,801**	**773,268,766**	**704,804,549**	**769,382,437**	**763,198,984**	**694,916,095**	**765,200,285**	**890,613,170**	**1,059,741,637**	**10,548,590,219**
BTL Classes													
BUTU	[redacted]												
GRLF													
1P - RTP													
ELIADC													
Shore Power													
EBS													
Export kWh Sales													
Export kWh Losses	-	-	-	-	-	-	-	-	-	-	-	-	-
Export kWh Req.	-	-	-	-	-	-	-	-	-	-	-	-	-
In Province Losses	90,116,924	83,221,868	82,505,364	61,997,742	53,015,109	47,550,956	50,312,801	47,601,079	45,567,154	51,551,247	66,494,873	79,470,194	759,405,311
NSR	**1,242,959,225**	**1,150,008,709**	**1,148,612,081**	**937,180,833**	**838,342,464**	**767,376,879**	**837,090,197**	**833,404,968**	**759,112,853**	**830,121,301**	**967,691,718**	**1,151,165,358**	**11,463,066,585**

Winter kW Peaks	January	February	March	April	May	June	July	August	September	October	November	December	3CP	Annual Peak
ATL Classes														
Domestic Total	1,501,844	1,443,879	1,189,517	978,550	750,399	609,577	636,042	708,174	584,352	730,459	1,028,601	1,408,115	4,353,838	1,501,844
Small General	76,999	80,029	67,740	52,200	44,962	46,333	49,596	43,072	46,874	51,670	57,766	65,236	222,264	76,999
General	432,607	426,373	367,087	294,769	265,519	281,558	305,354	277,951	305,996	315,700	356,039	347,137	1,206,116	432,607
Large General	47,132	48,958	47,042	45,757	42,874	55,389	53,856	51,187	54,331	48,611	43,924	41,392	137,482	47,132
Small Industrial	41,444	43,926	36,098	29,890	35,010	31,938	36,525	29,897	30,903	36,276	35,031	38,180	123,550	41,444
Medium Industrial	62,638	53,212	48,588	46,920	53,118	49,047	56,555	43,151	54,132	54,184	56,426	42,967	158,818	62,638
Large Industrial	82,192	88,515	77,199	81,559	90,140	89,041	90,197	85,665	100,800	81,958	97,338	75,818	246,525	82,192
PHP	67,790	67,612	139,489	138,942	138,566	138,028	138,421	138,512	138,449	138,804	139,826	67,825	203,227	67,790
Municipal	31,866	33,064	30,557	21,902	15,612	15,918	16,401	15,238	15,861	22,306	24,619	29,001	93,931	31,866
Unmetered	12,443	4,547	1,745	2,144	2,555	2,322	2,544	2,125	2,203	1,625	19,149	14,529	31,520	12,443
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	**2,364,503**	**2,297,664**	**2,012,612**	**1,700,181**	**1,446,305**	**1,326,700**	**1,393,041**	**1,402,521**	**1,341,452**	**1,489,142**	**1,866,268**	**2,137,749**	**6,799,917**	**2,364,503**
Total bfr BUTU	39,415													
BTL Classes														
GRLF	[redacted]													
1P - RTP														
ELIADC														
Shore Power														
EBS														
Total	**48,967**	**56,214**	**55,044**	**43,191**	**38,004**	**49,486**	**40,310**	**41,744**	**41,957**	**46,470**	**46,776**	**50,842**	**156,023**	**48,967**
NSR Peak:	**2,413,470**	**2,353,879**	**2,067,656**	**1,743,372**	**1,484,308**	**1,376,186**	**1,433,351**	**1,444,266**	**1,383,409**	**1,535,612**	**1,913,044**	**2,188,591**	**6,955,940**	**2,413,470**
Marginal Cost	$85.35	$86.54	$77.98	$55.52	$47.54	$44.50	$56.70	$55.39	$45.24	$45.99	$65.74	$69.88	$61.37	
Incremental Cost	$1,071,864	$942,596	$781,300	$372,560	$163,466	$142,025	$263,048	$238,545	$208,029	$269,026	$556,364	$712,862	$5,721,685	
OATT LOAD														
Energy Requirement	12,558,155	10,891,419	10,019,435	6,710,678	3,438,711	3,191,215	4,639,419	4,306,371	4,597,928	5,849,807	8,462,771	10,201,188	84,867,098	

2026 AAR Compliance Filing Appendix F2 has been filed electronically.

2026 AAR Compliance Filing Appendix F3 has been filed electronically.

2026 AAR Compliance Filing Appendix F4 has been filed electronically.

2026 AAR Compliance Filing Appendix G has been filed electronically.

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): ~~5.308~~5.274 ¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): ~~0.728~~0.713 ¢/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.

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): ~~10.008~~9.925 ¢/kWh

Off-peak (11:00 pm – 7:00am, non-holiday weekdays): ~~3.573~~3.516 ¢/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.

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	7.062
Fixed Cost Adder	~~2.516~~2.507	~~4.064~~3.970
Total	**~~9.417~~9.408**	**~~11.126~~11.031**

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.

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 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	$~~6.252~~6.222
Demand-related Fixed Generation Cost	$~~5.616~~5.601
Total	**$~~11.868~~11.822**

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	~~6.984~~6.974
Energy-related Fixed Generation Cost	~~2.166~~2.155
Total	**~~9.150~~9.129**

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.

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. 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.

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 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
Fixed Cost Adder	~~2.166~~2.155
Total	**~~8.902~~8.891**

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

ENERGY CREDIT

6.736 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 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; and

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

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 per month.

DEMAND CHARGE

$~~5.616~~5.601 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:

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

Where:

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

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

  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 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). 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	2.13	2.26	1.65
Small General	1.00	1.24	1.62	1.59	1.35
General	1.00	1.21	1.47	1.36	1.20
Large General	1.00	0.99	0.93	0.86	0.99
Small Industrial	1.00	1.25	1.23	1.27	1.16
Medium Industrial	1.00	1.11	1.04	1.03	0.96
Large Industrial Firm	1.00	1.04	0.92	0.89	0.92
Unmetered	1.00	1.19	1.99	1.98	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.

- "GCi" is the generator capacity dedicated to serving LRS load.

- "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, or the Renewable to Retail Market Transition Tariff.

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	~~2.166~~2.155
Annually Adjusted Energy Savings Credit	0.000
Annual Energy Cost Adjustment	~~2.198~~2.171
Total	**~~4.363~~4.326**

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	$~~5.452~~5.601
Annually Adjusted Demand Savings Credit	$0.000
Total	**$~~5.452~~5.601**

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.