Requirement:

Cost of Service Study

Submission:

The Cost of Service Study and other calculations affecting tariffed rates are provided as follows:

SR-01 Attachment	1	a. Cost of Service Procedures b. Determination of Revenue Responsibilities by Rate Classes c. Fuel and Purchased Power Related Cost of Service Methodology d. Unmetered Services Pricing e. Open Access Transmission Tariff (OATT) Updates
SR-01 Attachment	2	2026 Cost of Service Study Partially Confidential
SR-01 Attachment	3	2027 Cost of Service Study Partially Confidential
SR-01 Attachment	4	Interruptible Credit Calculations
SR-01 Attachment	5	2026 BCF Allocation Partially Confidential
SR-01 Attachment	6	2027 BCF Allocation Partially Confidential
SR-01 Attachment	7	Revenue to Cost (R/C) Ratios
SR-01 Attachment	8	Rates by Component Tables
SR-01 Attachment	9	2026 Unmetered Calculations
SR-01 Attachment	10	2027 Unmetered Calculations

SR-01 Attachment	11	2026 OATT Rate Development
SR-01 Attachment	12	2026 OATT Ancillary Service Costs
SR-01 Attachment	13	2027 OATT Rate Development
SR-01 Attachment	14	2027 OATT Ancillary Service Costs
SR-01 Attachment	15	2026-2027 Distribution Tariff and Proof of Revenue Calculations

Nova Scotia Power

Cost of Service Study Methodology

2025

1. Overview

This report summarizes the methodology for development of the Cost of Service Studies (COSS) models, in the 2026-2027 General Rate Application (GRA), included in **SR-01 Attachments 2, 3, 5,** and **6.**

From a cost of service (COS) methodology perspective, NS Power's rate classes fall into two broad categories, below-the-line (BTL) and above-the-line (ATL). The COS methodology subject to discussion in this section is concerned with the cost allocation of the ATL classes and allocation of a fuel portion of the Backup/Top-up (BUTU) class costs. The BUTU class is a BTL class. NS Power's 2026-2027 COSS includes PHP as an ATL customer.

Before costs are allocated to the ATL and BUTU classes, the total cost responsibility of this group must be determined by subtracting costs associated with serving BTL classes, other than the BUTU, from the total revenue requirement of the Company. By the Board's 2022 Decision on the Amendment to the BUTU Tariff (M09940), the costing process for determination of the BUTU class demand and energy charges has changed from marginal- to embedded-cost based with a four-year phase-in starting in 2023. 2026 marks the full transition of the BUTU class to the embedded cost methodology. The BUTU rate is subject to the Fuel Adjustment Mechanism (FAM), but it remains a BTL class and is an annually adjusted rate for the reasons of:

- the treatment of its Customer Charge, which changes annually; and
- the determination of its non-fuel energy and demand rate components which are set at system average costs as opposed to class specific apportioned costs.

These non-fuel embedded costs are apportioned to the BUTU class through the use of a recursive cost allocation process in the COSS spreadsheet.

The overall objective of a COSS is to determine the costs associated with serving each customer class, and in the case of the ATL classes, also to identify any inter-class inequities that may be present with regard to over- or under-contribution to the total allocated costs. This determination is based on a comparison of revenue-to-cost (R/C) ratios.

The first step in preparing the COSS, once the test period is established, is to collect the detailed financial and operating information pertaining to that period. The data accumulated includes estimates for: plant-in-service, construction work in progress (CWIP), reserve for depreciation, working capital allowances, deferred charges, deferred credits, contract receivables, revenues, operating expenses, energy sales and demand statistics, and customer counts.

The COSS allocates the costs (therefore the revenue requirement) of providing electric service by the Company to the ATL and BUTU classes. This includes the appropriate assignment of operating and maintenance expenses, grants in lieu of taxes, depreciation and responsibility for interest and corporate taxes incurred on those elements of the electric utility plant in service that are necessary in whole, or in part, to provide electric service to the various classifications of utility customers, as well as an approved return on investment.

Where possible, as is the case with the capital- and maintenance-related costs of streetlight fixtures, costs are assigned directly to classes of service based upon information acquired from the financial books and records of the Company or through additional analyses or studies.

Costs not directly assigned are analyzed by functional responsibility in groupings of accounts, such as production, transmission, distribution, and retail. These groupings are then allocated to the various classes of service on the basis of their demands, energy use, number of customers, and/or revenue associated with the functional responsibility appropriate for each class of service. In general, the demand-related cost component comprises those cost items that are incurred in order to produce and deliver electric energy to customers in real time as it is being used. Sufficient infrastructure must be installed to supply peak demand as required, while maintaining a required reserve margin.

Plant investment increases as units and facilities grow to meet demand. Consequently, demand-related generation and transmission costs are allocated to rate classes based on their contributions to system coincident peaks. NS Power is using a three-winter peak (3CP) methodology for allocation of these costs. Distribution facilities are allocated based on class annual, non-coincident

demands to recognize the disaggregated nature of the distribution network, whose individual substation and feeder capacities must be sized to meet localized customer demands. Class non-coincident demands are the demands that are imposed on the distribution system and, in general, are substantially larger than their coincident peak demands. Consequently, the COS elements that increase with plant size and capacity are classified as demand costs.

Energy related costs are those costs that vary with the annual volume of energy supplied to the various classes of service provided by the Company. Prime examples of energy costs are plant fuel, non-firm imports, and most of the non-dispatchable generation purchase costs. These costs increase as the quantity of fuel required to produce energy from generating units is increased or the amount of purchased energy from external sources is increased.

The customer related costs are those costs that vary with the number of customers served. Examples of these costs include retail operating and maintenance (O&M) costs of customer care representatives in the Company's contact and billing centres or the capital-related costs of certain elements of distribution infrastructure such as customer meters, service drops or that portion of the feeder investment which is driven by the need to bring electric service to geographically dispersed customer locations.

Costs associated with services related to Non-Operating Revenues, also referred to as Miscellaneous Revenues, such as charges for connections, disconnections, late payments, wiring inspections, etc., are determined outside of the COSS. Revenues from these services are functionalized to service areas and deducted from the operating costs applicable to the ATL rate classes.

NS Power's COSS process consists of application of the four sequential computational steps reflective of the generic COSS methodology used by North American utilities.

Functionalization

The first step in the cost analysis is the **functionalization** of plant and expenses into the functional

groups of production, transmission, distribution, and retail. From the financial books and records of the Company, most of the net plant investments are readily identifiable as production, transmission, and distribution functions. Likewise, most of the expenses for operation and maintenance of production, transmission, distribution, and retail are also readily identifiable. However, there are several components of plant depreciation and O&M expenses, such as those associated with general property or combined transmission and distribution (T&D) services, that are not readily available or identified on a production, transmission, or distribution basis. These cost items must be functionalized through a separate manual process prior to classification and allocation. Examples of these processes include re-functionalization of the capital costs of the bulk power transformer substations from transmission to distribution or separation of many T&D-combined O&M expenses, such as storm costs, load control centre, vegetation management, right of way, etc. into transmission and distribution service areas.

Classification

Following the functionalization step, production, transmission, distribution and retail plant and operating expenses are **classified**. Classification is the process by which plant and operating costs are determined to be grouped by demand-, energy-, or customer-related services.

Determination of Allocation Factors

The third step in conducting the cost study consists of the determination of those demand, energy or customer allocation factors that are necessary to allocate plant or operating expenses to the ATL rate classes.

Allocation

The fourth and final step is the **allocation** procedure. This step involves applying the above allocation factors to the classified plant and operating expenses from step 2, to determine the overall cost assigned to each class of service based upon the total plant and expenses for the test period.

The COSS is organized into 10 Exhibits (corresponding to tabs in the Excel model) , as follows:

	EXHIBIT
COMPARISON OF REVENUE TO EXPENSE RATIOS	1
FUNCTIONALIZATION OF AVERAGE RATE BASE	2
INITIAL CLASSIFICATION OF AVERAGE RATE BASE	2A
FINAL CLASSIFICATION OF AVERAGE RATE BASE	2B
ALLOCATION OF AVERAGE RATE BASE	3
ALLOCATION OF AVERAGE DISTRIBUTION RATE BASE	3A
ANALYSIS OF AVERAGE DISTRIBUTION SUBSTATION RATE BASE	3B
ANALYSIS OF AVERAGE POLE INVESTMENT	3C
ALLOCATION OF AVERAGE POLE INVESTMENT	3D
ANALYSIS OF AVERAGE OVERHEAD WIRE INVESTMENT	3E
ALLOCATION OF AVERAGE OVERHEAD WIRE INVESTMENT	3F
ANALYSIS OF AVERAGE UNDERGROUND WIRE INVESTMENT	3G
ALLOCATION OF AVERAGE UNDERGROUND WIRE INVESTMENT	3H
ANALYSIS OF AVERAGE METER INVESTMENT	3I
FUNCTIONALIZATION OF OPERATING EXPENSES	4 & 4 Detail
TRANSMISSION OPERATING EXPENSES	4.1
CLASSIFICATION OF OPERATING EXPENSES	5
ALLOCATION OF OPERATING EXPENSES	6
RATE CLASS DISAGGREGATION ANALYSIS BY FUNCTIONAL AREAS	6.1
ALLOCATION OF DISTRIBUTION OPERATING EXPENSES	6A
ALLOCATION OF CUSTOMER SERVICE FIELD EXPENSES	6B
ALLOCATION OF CREDIT SERVICES EXPENSES	6C
ALLOCATION OF DEPRECIATION EXPENSES	6D
STORM EXPENSES AND REVENUE	6E
REVENUE ANALYSIS	7
DEVELOPMENT OF ALLOCATION FACTORS	8A & 8B & 8C
SALES, GENERATION AND DEMAND ANALYSIS	9A
DETERMINATION OF CLASS NON-COIN. KW DEMAND BY VOLTAGE LEVEL	9B
DETAIL OF MONTHLY CLASS COINCIDENT kW DEMAND	9C
SUMMARY OF SYSTEM LINE LOSSES	9D
SUMMARY OF REVENUE AND EXPENSE COMPONENTS - PROPOSED RATES	10

Exhibit 1 summarizes the results of the COSS under the proposed rates for the test period. The full analysis is provided in the remaining exhibits.

- **Exhibits** in the **2 to 3** series detail the rate base analyses.
- **Exhibits** in the **4 to 6** series show the analyses of operating costs and depreciation expense.
- **Exhibit 7** contains the revenue analysis.
- **Exhibits** in the **8** series detail the development of allocation factors.
- **Exhibits** in the **9** series show the analysis of sales and demand data.
- **Exhibit 10** details the demand, energy, and customer costs along with the revenue by class and the resulting Revenue/Cost Ratios for the test period under proposed rates.

2. Methodology

The major component of the approved cost methodology at NS Power is classification of generation costs to energy and demand based on the system load factor and allocation of the demand-related cost of generation and transmission based on the 3 Coincident Peaks (SLF/3CP). This methodology was originally approved by the Nova Scotia Energy Board (NSEB, Board) in its September 29, 1995 Order NSPI-864 and is now proposed to be amended in the 2026-2027 GRA.

The method of utilized distribution cost assignment is the Minimum System Method introduced in the 2023-2024 GRA proceeding (M10431) which classifies costs to demand and customer.

As far as sub-functionalization of distribution and retail costs goes, most of this predates the 1995 Order, however, it was subject to scrutiny and minor adjustments in the two subsequent generic COSS proceedings: 2014 (M05473) and the on-going 2024 (M11475), as well as the 2023-2024 GRA (M10431).

A percentage of generation costs, equal to the system peak load factor percentage, is considered energy related and allocated to rate classes on the kWh basis. The remaining generation costs are considered demand-related and are allocated to rate classes based on each class' share in the three

system coincident peaks for December, January, and February. All of the transmission costs are classified 100% to demand and allocated to rate classes on the basis of their relative contribution to the 3CP metric. Distribution demand-related costs are apportioned to rate classes based on their relative share in the total sum of their annual non-coincident demands whereas the customer-related costs are apportioned based on various customer count metrics. All of the retail costs are classified as customer-related and are apportioned to rate classes based on their customer counts and revenues.

2.1. Rate Base Analysis: Functionalization, Classification and Allocation

Rate Base Exhibits 2, 2A and 2B

Exhibit 2 contains the net plant investment in the various asset categories, with allowance for working capital and allowance for materials and supplies.

In keeping with the Board's Decision[1] from the 2005 Rate Application, changes were made in this exhibit and subsequent rate base exhibits (**2A, 2B and 3**) to include construction work in progress (CWIP), deferred charges, and deferred credits.

The net plant investment, allowance for working capital, allowance for materials and supplies, deferred charges, deferred credits, and contract receivables, that are directly assigned, are identified as the "Direct Capital" column in **Exhibit 2**. Direct capital is subtracted from the total company rate base to arrive at the amounts to be allocated among COSS-based rate classes.
For the purposes of this GRA/COSS proceeding there were changes made around functionalization of battery storage and radial to generation transmission lines which were re-functionalized from transmission to generation. The Extra High Voltage (EHV) and High Voltage (HV) components of transmission assets have been combined as the Company has proposed that this distinction be eliminated.

[1] M05675, Decision 2005 NSUARB 27, March 31, 2005

The functionalization of General Property investment, which until now has been prorated in its entirety to the service areas of generation, transmission and distribution based on the relative shares of these areas in in their total rate base, is proposed to be changed. The Company broke out the General Property assets into three categories for the purpose of their functionalization in this proceeding as follows.

- Assets identified as directly attributable to each service area of generation, distribution, and transmission.
- Assets identified as attributable to the combined Transmission and Distribution areas, which are split between these two areas based on the shares of these areas in their combined labour-related O&M expenses. This is primarily communication equipment listed under the General Property.
- Assets which are functionalized to generation, transmission and distribution based on the shares of these areas in their total rate base combined.

Rate Base Exhibits 3 series, Allocator Exhibit 8A, Usage Exhibits 9 series

Rate Base Exhibits **3, 3A, 3B, 3C, 3D, 3E, 3F, 3G, 3H, 3I** detail the allocation of rate base to the ATL rate classes.

The first allocation factors to be developed are those related to demand, energy sales and the number of customers. **Exhibit 9A series** show the projected energy sales for the test period and the quantity generated and purchased before line losses. For the purposes of this proceeding the Company has updated line losses by rate class in **Exhibit 9A series**. Given these figures by class and the forecasted coincident peak demands by sector, load factors are applied to arrive at each class's demand contribution. **Exhibit 9B** makes use of the class non-coincident demands and the load levels of those customers known to take power at various voltage levels, in order to arrive at the individual class responsibilities for non-coincident demand at the secondary, primary and substation levels with losses included. For the purposes of this proceeding the Company has updated line losses by rate class in **Exhibit 9B**. The above exhibits provide the data necessary to calculate the demand and energy allocation factors in **Exhibits 8A**. The calculation of these factors is the class usage amount divided by the total ATL usage. The remaining allocation factors are

developed throughout as needed.

Generation Rate Base Treatment

With the demand, energy and customer factors developed, the allocation phase proceeds. Starting with this proceeding there is no longer initial classification of base-load generation units to energy for the environmental and fuel conversion reasons as initiated by Board's 1995 Order (NSPI-864). Instead, all generation units see a portion of their investments and costs reclassified from demand to energy only once through the uniform application of the System Load Factor (SLF). The demand portion of the system rate base and costs is allocated to rate classes based on their shares in the 3CP metric. The energy portion of the system rate base and the energy portion of the non-fuel costs are apportioned to rate classes based on their shares in the annual system energy requirements whereas all the FAM-related energy costs are apportioned to rate classes based on their shares in the system monthly energy requirements.

Transmission Rate Base Treatment

Transmission plant is no longer segregated between 69 kV and 138 kV voltage levels. All of transmission rate base and costs are classified 100% to demand and allocated to rate classes based on their shares in the 3CP metric.

Distribution Rate Base Treatment

Distribution plant is more complex in its cost causalities than is the plant in other service areas. Many of the individual distribution plant categories are sub-functionalized, classified and allocated to rate classes in separate Exhibits before they are reflected in **Exhibit 3A** providing detailed summary of allocation of distribution plant by rate classes.

Substations are allocated in accordance with **Exhibit 3B**. The totals for each class are carried forward as class allocations of substation investment, as shown in **Exhibit 3A**.

Pole and wire investment also requires a more detailed analysis since the total is made up of both demand and customer components. **Exhibit 3C** provides the breakdown of investments in distribution poles and **Exhibits 3E and 3G** of overhead and underground wire investment by voltage levels and class of service. The factors used in sub-functionalization and classification of pole and wire rate base values were developed using the **Minimum System Method** for the purposes of the 2023-2024 GRA. The total pole and wire investment, broken down into primary demand and customer and secondary demand and customer, are allocated to rate classes in **Exhibits 3D, 3F and 3H** for poles, overhead lines, and underground lines, respectively by the appropriate allocation factors.

Meter Investment is allocated in **Exhibit 3I**. The average unit investment cost of an installed meter for each class was determined. These costs when multiplied by the number of customers in each class provide the cost causation relationships required for developing the allocation.

The allocation of the following plant categories to rate classes is done directly in **Exhibit 3A**.

- Line transformers that are used in the secondary system were allocated on secondary class non-coincident demands.
- Services were distributed on a weighted customer count basis.
- The "Land," "Easement & Survey" and "Other" assets, were allocated on the basis of total substation, pole, and wire investments.

Rate Base Categories apportioned to Generation, Transmission and Distribution Service Areas

- The "**General Property Plant**" investment; functionalized to the service areas of generation, transmission and distribution in a manner discussed above; is then classified in **Exhibits 2A** and **2B** to the services of demand, energy, and customer by using the proportions in which the underlying service areas are already classified to these services. Thus, for example, the general property functionalized to generation is classified to energy and demand based on the system load factor whereas that functionalized to transmission is classified 100% to demand. The classified investments are then allocated to rate classes

in the same proportion those of the underlying plant investments of each service area in **Exhibit 3**.

- The "**Working Capital and Deferred Charges and Credits**" comprised of allowance for working capital, allowance for materials and supplies, deferred charges, deferred credits, and contract receivables are allocated in accordance with their cost causalities as determined by the allocation factors used.

To provide more transparency in the allocation of streetlight fixture-related costs, the distribution-related rate base information in **Exhibit 3** has been separated between the streetlight-related versus non-streetlight related categories.

At this point, all Rate Base items have been assigned to the various classes recognizing the cost causation and cost utilization relationships as defined above.

2.2. Cost Analysis: Sub-functionalization, Classification, and Allocation

The analysis of operating costs begins in **Exhibit 4 Detail** with functionalization. In this step total operating costs are grouped according to production, transmission, distribution, retail, and direct assignment. The "Direct Expenses" column contains those costs that are not to be assigned to ATL customer classes as they represent costs incurred by the BTL rate classes. The "Corporate Groups" operating expenses are assigned to each function based on their overall responsibility to each primary business operation within the Company using allocation factors from **Exhibit 8C**. "Grants in Lieu of Taxes", "Depreciation" (by function), "Interest" (net of AFUDC), "Preferred Dividends" and "Corporate Taxes" are functionalized to service areas in proportion to their relative shares in the total rate base from Exhibit 2A. The Non-operating Revenues, also referred to as Miscellaneous Revenues, are subtracted from the costs applicable to the ATL rate classes using the treatment proposed by the Company in the 2013 COSS proceeding (M05473). **Exhibit 4.1** provides the breakdown of transmission expenses by the ATL and BTL rate class categories and is used to calculate the transmission rates under the OATT.

In **Exhibit 5**, the functionalized expenses from **Exhibit 4** are listed and sub-grouped, where necessary, in order to classify them as demand, energy and customer. To provide more clarity in the treatment of streetlight fixture-related costs, they have been separated from all the other distribution-related costs to form a separate sub-group of the "Distribution Function."

Exhibit 6 summarizes the next stage of the study, which is the allocation of operating costs. Some of the cost categories are allocated to rate classes in separate exhibits before they are reflected in **Exhibit 6**.

Costs classified as "Demand" (generation, transmission, and distribution) are allocated on the basis of the 3CP demand allocators.

Costs classified as "Energy" such as fuel, imports, and purchased power are allocated to rate classes on the basis of their monthly energy allocators. The non-fuel costs classified to energy, such as capital-related, operating and maintenance, are allocated to rate classes on the basis of their annual energy allocators.

Costs classified as "Customer" (distribution and retail) are allocated on the basis of various customer count and revenue metrics.

Consistent with the treatment of the streetlight fixture-related costs in **Exhibit 5**, these costs are shown separately in **Exhibit 6**.

Exhibit 6A contains the analysis of total distribution operating expenses broken down by demand, customer, and retail-related categories. The basic allocation premise used is that costs should be allocated in the same manner as their rate base counterparts. Overhead feeder and underground line expenses were assigned in relation to the pole and wire and underground investments. Line transformers are secondary demand related. Service expenses were allocated to secondary customers. Metering expenses were allocated according to the meter investment per class. The street lighting costs were assigned directly to the unmetered class.

Exhibit 6B details the analysis of customer service field expenses, for the distribution function, by class.

Once expenses have been functionalized and classified, they are allocated to rate classes. The allocation of distribution costs is determined in **Exhibit 6A**. In **Exhibit 6**, the "Call Centre" was assigned using total weighted customers. "Customer Service – H/O" and "Billing Services" were assigned using average customers, adjusted for seasonality. "Quality Assurance and Communication," "Electrical Wiring Inspection" (head office) and "Payment Services" costs were assigned using average customers. "Marketing and Sales" and "Meter Data Services" costs were allocated on the basis of defined responsibility commitments to each customer class.

Exhibit 6C details the allocation of credit services expenses. First, the "Bad Debt Expense" is split between domestic and all other classes based on gross write-off experience. The other portion of bad debt expense is assigned to each class based on secondary customer revenue. The other operating portion is distributed on the basis of average number of customers.

Depreciation is allocated by function as shown on **Exhibit 6D**. Consistent with the treatment of streetlight fixture related costs in **Exhibits 5 and 6**, they are shown as separate sub-components under the Distribution Function category. With the streetlight fixture depreciation cost information being available from the Company's accounting information system, it is applied directly for the direct cost assignment purposes.

Exhibit 6E details breakdown of storm expenses by rate classes within transmission and distribution service areas at four storm levels. This information is used for calculation of the Storm Cost Recovery Rider (SCRR).

In **Exhibit 6**, grants in lieu of taxes are allocated on the basis of total production, transmission, distribution, and retail net plant. Interest (net of AFUDC), preferred dividends and corporate taxes expense are allocated on the basis of total rate base assignment from **Exhibit 3**. The total costs for each class are then determined and adjusted by non-rate revenue and the return (profit/loss) to arrive at the net cost to each customer class..

2.3. Revenue Analysis

Exhibit 7 serves the purpose of verifying the accuracy of the cost allocation analysis. The ATL revenues are shown against revenues of other categories, determined outside of the COSS, and retained earnings from the financial tables.

Using the total allocated costs for each class, a comparison is made with the revenues for each class to determine the percentage revenue to cost relationships. The results are shown on **Exhibit 10**, under proposed rates for the test year.

Nova Scotia Power

Determination of Revenue Responsibilities by Rate Class

in Years 2026 and 2027

Apportionment of the revenue requirement, exclusive of the Fuel Adjustment Mechanism (FAM), Demand Side Management (DSM) Cost Recovery Rider, and Storm Cost Recovery Rider (SCRR), among rate classes is done through the Cost of Service Study (COSS).

From a cost of service (COS) methodology perspective, NS Power's customers fall into three broad categories:

- Electric service above-the-line (ATL) rate classes;
- Electric service below-the-line (BTL) rate classes; and
- Non-electric service Miscellaneous revenues.

The total cost responsibilities of the ATL classes are determined as the total system revenue requirement net of the revenues forecasted to be collected from the other two categories. Please, refer to Exhibit 10 of the 2026 COSS and 2027 COSS[1] for the breakdown of class cost responsibilities.

Some of the cost increases described in this Application, which drive the revenue requirement increases for ATL classes, also result in required increases to the BTL and Miscellaneous revenues. BTL rates, also referred to as Annually Adjusted Rates (AARs), are rates normally recalculated and set annually based on pre-approved formulae and methodology.

There are several steps required to calculate the ATL revenue increase.

- Determine the annual ATL revenue requirement by subtracting revenues projected to be collected from the BTL classes and Miscellaneous revenues from the total system revenue requirement.
- Determine the total revenue shortfall from the ATL rate classes in each of the test years in the 2026-2027 period absent any change in the rates.

Assign the above shortfall to the ATL classes by applying the following revenue allocation process.

[1] SR-01 Attachments 02, 03.

1. Set the revenue of the Unmetered Rate class at a level commensurate with the revenue-to-cost (R/C) Ratio of 1.0.[2] Also, set PHP rate class to R/C Ratio of 1.0 as this was previously a BTL class under the ELIADC. Apply an across-the-board increase to all the other ATL rate classes, to eliminate the shortfall in revenue requirement. This step corresponds to calculations in columns I and J of SR-01 Att. 07.
2. Classes whose revenue to cost ratios fall outside of the 0.95 – 1.05 range are set at the lower or upper bound of this range as appropriate generating an imbalance in recovery of revenue requirement which could either be a surplus or a shortfall. This step corresponds to calculations in columns K and L of SR-01 Att. 07.
3. Apply an across-the-board increase to all those ATL classes whose revenue to cost ratios are below the upper bound of 1.05 when step 2 produces a deficiency or a decrease to all those ATL classes whose revenue to cost ratio is above the lower bound of 0.95 when step 2 produces a surplus. This step corresponds to calculations in columns M and N of SR-01 Att. 07.
4. The R/C ration for PHP was set at 1.05 creating an over recovery of system costs.
5. The imbalance from step 4 is eliminated by lowering the R/C ratios of all those classes whose R/C ratios were at 1.05 or near 1.05 (Municipal in 2026) in step 3. The revenues of all other classes are left as determined in step 3.

[2] This is a long-standing practicing dating back to the 2006 GRA.

Nova Scotia Power

Fuel and Purchased Power Related Cost of Service Methodology

2025

Each test year's fuel costs are apportioned to the above-the-line (ATL) and below-the-line (BTL) classes using the following process.

1. The Company determines test year incremental fuel costs of serving the following non-FAM, or BTL, rate classes consistent with their rate design.

    - The bundled service classes of the Generation Replacement and Load Following (GRLF), 1P-RTP and Shore Power class.
    - The unbundled service classes of the Energy Balancing Service Tariff (EBS) and Renewable to Retail Market Transition Tariff (RTT).

2. The incremental fuel costs of the above BTL classes are subtracted from the total system fuel costs to determine costs attributable to the ATL and the Wholesale Market Backup/Top-up Service (BUTU) classes.

3. The fuel costs are allocated among the ATL and BUTU classes by applying the following procedural steps for the allocation of plant fuel costs, purchased power costs and export revenue benefits.
    a. In-province purchased power from biomass generation is broken out between fuel and non-fuel components in the same proportion as that of the Port Hawkesbury biomass plant.
    b. The following costs and credits:
        i. NS Power's plant fuel costs
        ii. costs of biofuels of purchased biomass generation
        iii. non-firm imports costs
        iv. export revenue credits

    are classified 100 percent to energy and allocated to each class based on its relative contribution to monthly energy requirement.

c. Costs of firm imports and non-fuel portion of in-province purchased power are classified to demand and energy based on the load factor of all the ATL rate classes combined.
    i. The demand-related portion of the above costs is allocated to each class based on its relative contribution to the three-monthly system peaks (3CP) occurring in December, January and February. The energy portion of the above costs is allocated to each class based on its relative contribution to the monthly energy requirements.
d. The revenue responsibilities for allocated fuel cost to the ATL classes are determined by applying the revenue-to-cost (R/C) ratios[1] applicable in the 2026-2027 GRA as described below.
    i. Allocated class costs are multiplied by class R/C ratios and then scaled across-the board by the ratio of the total costs and the total of the values calculated as described herein.

The class annual unit fuel cost revenue, calculated as the ratio of class annual fuel revenue responsibility and its annual kWh sales, represent the fuel cost component of the class energy charge.

[1] The Revenue to Cost ratios are provided in SR-01 Attachment 07.

Nova Scotia Power

Unmetered Services Pricing

2025

TABLE OF CONTENTS

1.0 INTRODUCTION 3
2.0 RATEMAKING METHODOLOGY FOR UNMETERED 4
2.1 Cost of Service Studies 4
2.2 Pricing of Unmetered Services 4
2.3 Determination of Electric Service Rates 5
3.0 UNMETERED SERVICE STUDY 6
3.1 Schedule 1 – Street and Crosswalk Lighting Inventory: Actual and Forecast 6
3.2 Schedule 2 – Determination of Maintenance Costs by Fixture 7
3.3 Schedule 3 – Determination of Average Installation Labour Costs Associated with Streetlighting Gross Assets 7
3.4 Schedule 4 – Determination of Depreciation and Capital-related Costs by Fixture Type 8
3.5 Schedule 5 and 5A – Tax-adjusted Weighted Average Cost of Capital 9
3.6 Schedule 6 and 7 – Summary and Detail of Streetlight Material Costs 10
3.7 Schedule 8 – Lamp Life Analysis 10
3.8 Schedule 9 – Capital Cost Allowance (CCA) Calculation 10
3.9 Schedule 10 and Schedule 10 Smoothed – Street and Crosswalk Lighting Rates by Cost Component 10

APPENDICES

2026-2027 GRA SR-01 Attachment 9 Unmetered services calculations for 2026
2026-2027 GRA SR-01 Attachment 10 Unmetered services calculations for 2027

1.0 INTRODUCTION

This report is filed in support of NS Power's General Rate Application (GRA). The report provides a description of unmetered services, an outline of the current ratemaking methodology and a detailed discussion of the calculations of streetlight rates.

The Unmetered Class includes three service categories in each of the bundled service and unbundled Renewable to Retail (RTR) markets.

The electric service in the unbundled market is comprised only of the distribution and retail service. NS Power forecasts commencement of service uptake in this market in 2026.

1. Electric service only, applicable to:
   - street and area lighting; and
   - miscellaneous loads with predetermined usage and where metering is considered impractical and for which no rates have been provided under the Street and Area Lighting rate.
2. Electric service combined with streetlight fixture maintenance.
3. Full charge rate – streetlight service, which includes electric service, maintenance, and capital.

These services are eligible for unmetered service, based on the impracticality of metering their loads. Costs of metering these loads, which include capital meter costs and operational costs, are prohibitively high relative to the value of energy consumed, and/or the loads are highly predictable. All service categories involve consumption of electricity.

The fixture maintenance costs have a significant direct cost component. The capital costs of fixtures are treated as a direct responsibility of the unmetered class and are not shared with other rate classes. Street and Area lighting customers have a choice of maintenance service providers

and fixture ownership. Consistent with the three types of streetlight services, there are six distinct types of streetlight charges: three in the bundled market and three in the unbundled market.

1. The streetlight rate, reflective of all three services combined, is referred to as a full charge rate.
2. Where the customer owns the fixture and NS Power performs the fixture maintenance, applicable rates include the electric service and maintenance charges.
3. Where the customer owns and maintains the fixture, only electric service charge is applied.

2.0 RATEMAKING METHODOLOGY FOR UNMETERED

The ratemaking methodology is comprised of two steps:

1. Determination of cost responsibilities of the Cost of Service Study (COSS)-based unmetered class, which is comprised of all costs of street and area lighting and miscellaneous loads.
2. Determination of revenue responsibilities of each service category by setting them at costs, as determined above, followed by individual service rate calculations.

2.1 Cost of Service Studies

From a broad cost treatment perspective, costs of unmetered services can be categorized as those shared with other COSS classes and those assigned directly to the unmetered class.

2.2 Pricing of Unmetered Services

The Street/crosswalk Lighting Study, contained in Section 3, focuses on determining capital and maintenance costs. Revenue responsibilities for electricity, fixture maintenance, and fixture capital are aligned with the costs of these services. Costs of unmetered services can be categorized as those shared with other COSS classes and those assigned directly to the Unmetered Class.

Most electric service costs are shared with metered classes and are assigned to the Unmetered Class using a three-step costing process consisting of functionalization, classification, and allocation. As is the case with other classes, the cost responsibilities of the Unmetered Class are determined based on its cost causation and utilization of the electric infrastructure.

The fixture maintenance-related costs are made up of costs assigned directly to this class and costs shared with other classes.

The streetlight fixture capital related costs such as depreciation, financing costs and taxes are considered a direct responsibility of the streetlight customers.

However, the cost information for the above categories, except for depreciation, is only available in aggregate. Consequently, customer responsibilities for these costs cannot be determined by direct assignment. The capital costs associated with the fixtures are determined using the COSS-based cost allocation methodology.

2.3 Determination of Electric Service Rates

The unmetered rates for electricity, determined separately for the bundled and unbundled markets, are determined by applying miscellaneous lighting and miscellaneous small load rates to the pre-determined patterns and levels of energy consumption. The rate structure includes one demand charge and two declining block energy charges, applicable to energy blocks whose sizes vary with metered demand. The rates are changed in GRA proceedings.

3.0 UNMETERED SERVICE STUDY

The following schedules have been updated to support the 2026-2027 study:

- Schedule 1 – Street and Crosswalk Lighting Inventory Levels: actual and forecast
- Schedule 2 – Determination of Maintenance Costs by Fixture Type
- Schedule 3 – Determination of Average Fixture Installation Labour Costs
- Schedule 4 – Determination of Depreciation and Capital-related costs by Fixture Type
- Schedule 5 – Tax-adjusted Weighted Average Cost of Capital (WACC)
- Schedule 5A – Capital Cost Expenses calculated with WACC
- Schedule 6 & 7 – Summary and Detail of Current Material Costs by Fixture Type
- Schedule 8 – Lamp Life Analysis
- Schedule 9 – CCA Benefit Schedule
- Schedule 10 – Updated Street and Crosswalk Lighting Rates by Cost Component and Total Revenue based on forecast Inventory levels
- Schedule 10 Smoothed – Updated Street and Crosswalk Lighting Rates by Cost Component and Total Revenue based on forecast Inventory levels

3.1 Schedule 1 – Street and Crosswalk Lighting Inventory: Actual and Forecast

The lighting units used for the 2026 and 2027 test years' rate calculations were forecasted using actual inventory levels as of February 2025. A factor was applied to 2025 inventories to determine the forecast units for 2026 and 2027, respectively. The forecast units are as follows:

TYPE OF FIXTURE	2026			2027		
	Non-LED	LED	Total	Non-LED	LED	Total
Full Charge	22,478	54,000	76,478	22,478	54,000	76,478
Maintenance and Energy	304	0	304	304	0	304
Energy only	1,455	78,025	80,388	1,455	78,025	80,388

TYPE OF FIXTURE	2026			2027		
	Non-LED	LED	Total	Non-LED	LED	Total
Total	24,237	132,025	157,326	24,237	132,025	157,170

3.2 Schedule 2 – Determination of Maintenance Costs by Fixture

The purpose of this schedule is to determine fixture maintenance costs, based on the service life of each lamp type and the associated maintenance weighting factors, as measured relative to the replacement of 100W High Pressure (Intensity) Sodium lights. These weighting factors and all maintenance-charged lights are used to determine the weighted eligible total number of lights maintained (column G). Current streetlight operating expenses are used to determine annual and monthly maintenance costs by fixture type.

The operating expenses used in this review are based on the forecast streetlight expenses for 2026 and 2027. The operating expenses of approximately $0.8 million in each test year is identified in Exhibits 6A of the 2026 COSS and 2027 COSS[1]. The forecast weighted number of streetlights and the forecast operating expenses for streetlights are used to determine the annual and monthly maintenance charge to be applied to each type of light.

3.3 Schedule 3 – Determination of Average Installation Labour Costs Associated with Streetlighting Gross Assets

The installation and retirement costs for the fixtures are determined using the current approved methodology for forecasting gross plant value, number of fixtures, and the most recent fixture market replacement value.

For streetlight installation labour cost, to arrive at the total installation labour cost, this schedule uses:

[1] SR-01 Attachment 2 and 3

- the average gross plant value of streetlight assets;
- the current material costs of each type of fixture; and
- the forecast average number of fixtures.

To determine the labour cost of streetlight the current material cost of each fixture is multiplied by the number of forecast fixtures to calculate the total material capital cost. The material cost amount is then subtracted from the forecast total street-light gross plant value to arrive at a total labour cost which, divided by the number of fixtures to produce the average labour cost per fixture. This results in non-LED labour per fixture of $756 in 2026 and $790 in 2027, and average labour cost per fixture for LED of $268 in 2026 and $294 in 2027.

Some of the material cost for non-LED was not available thus an escalation inflation factor[2] was applied to the unit costs from 2014. This schedule includes a sample material cost breakdown of a 100W High Pressure (Intensity) Sodium light, which is reproduced below.

Sample Material Cost 100-Watt High Intensity (Pressure) Sodium Inventory Prices as of Feb 2025	
Fixture, Ballast & Photocell	$201.73
Bracket Assembly (Davit)	$70.74
Wire	$0.00
Miscellaneous Hardware	$0.00
Lamp Replacement	$14.78
Total	**$287.25**

3.4 Schedule 4 – Determination of Depreciation and Capital-related Costs by Fixture Type

Schedule 4 illustrates the determination of capital costs and rates for non-LED and LED fixtures.

[2] NWT Bureau of Statistics - CPI - Historical Inflation Rate

The Company has maintained the distinction in capital cost calculation between the non-LED and LED capital asset groups in this Application, as was the case in the 2023-2024 GRA, because the newer LED fixture stock is less depreciated than non-LED one and as such has higher per fixture carrying costs.

The depreciation rate used is 5.33 percent for both LED and non-LED. The tax adjusted WACC for non-LED and LED is 8.66 percent in 2026 and 8.40 percent in 2027.

The capital carrying costs of non-LED and LED fixtures are determined using the following three-step process:

1. The tax-adjusted WACC is multiplied by the gross plant value of each fixture type to arrive at a gross carrying cost estimate per fixture.
2. Each fixture type carrying cost estimate is multiplied by its inventory count to arrive at a total carrying cost by fixture type. These fixture type costs are then aggregated by LED and non-LED fixture types.
3. The total carrying cost estimates by LED and non-LED fixture types are scaled down using the appropriate cost-based correction factors for each type determined as a ratio between carrying costs calculated for each type in Schedule 5A and simulated gross carrying costs above.

3.5 Schedule 5 and 5A – Tax-adjusted Weighted Average Cost of Capital

The tax-adjusted WACC rate calculations are shown in Schedule 5. It is broken down into four components: pre-tax WACC, additional income tax on Common Equity, and Grants-in-Lieu of Property Taxes. This results in a tax-adjusted WACC of 8.66 percent in 2026 and 8.40 percent in 2027.

Schedule 5A shows how preferred dividends, return, corporate taxes, and Grant in Lieu of taxes from the 2026 COSS and 2027 COSS were allocated to the LED and non-LED lights based on the net Plan value of LED and non-LED.

3.6 Schedule 6 and 7 – Summary and Detail of Streetlight Material Costs

An analysis of current material costs was conducted using information as of February 2025. This analysis involved the review of all components used in the installation of streetlight fixtures such as the lamp, photocell, davit, wire, connectors, and fasteners. In addition, NS Power has provided a detailed listing of all material costs obtained from the material inventory control system.

3.7 Schedule 8 – Lamp Life Analysis

Average Rated Life Spans of each lamp type were used in this study. Annual photocell cumulative operating time is based on 4,000 hours per year or 333 hours per month.

Using the average lamp life and burning hours per year results in the expected service life, in years, by lamp type. The lamp life and number of replacements, relative to those of a 100W High Pressure (Intensity) Sodium lamp, are then determined. The results of this analysis are used to determine the frequency of bulb replacements as it pertains to annual maintenance work in Schedule 2.

3.8 Schedule 9 – Capital Cost Allowance (CCA) Calculation

Capital cost allowance is not applicable to the current rates.

3.9 Schedule 10 and Schedule 10 Smoothed – Street and Crosswalk Lighting Rates by Cost Component

Consistent with bundled service smoothing of rates across 2026 and 2027 years, NS Power has also provided the smoothed unmetered service bundled tariffs.

Once the analysis of all cost components is complete, the results are summarized in Schedule 10 and Schedule 10 smoothed including the rate description, the rate code, the calculated monthly

kWh usage, the new power and energy rates in the Distribution Tariff and bundled markets, fixture maintenance, and fixture capital cost components.

Calculation of the demand and energy charges, for both the Distribution Tariff and bundled service rate, which are based on the Miscellaneous Lighting Rates proposed, is shown at the bottom of Schedule 10 and Schedule 10 smoothed tabs and are based on annual photocell and continuous burning energy usage to arrive at average cents per kWh that is applied to the standard energy usage.

Under the standard (unsmoothed) unmetered tariffs, the total Street and Crosswalk Lighting Revenue and miscellaneous load revenues are $22.1 million in 2026 and $23.0 million for 2027. The standard (unsmoothed) revenues are in the revenue summary tabs of the 2026-2027 Attachments.

Based on smoothed unmetered tariffs, the total Street and Crosswalk Lighting Revenue and miscellaneous load revenues are $21.7 million in 2026 and $23.4 million for 2027. The smoothed revenues are in the revenue summary tabs of the 2026-2027 Attachments.

The components for the unbundled RTR service results are included in Schedule 10 and Schedule 10 Smoothed.

Nova Scotia Power

Open Access Transmission Tariff Updates

2025

TABLE OF CONTENTS

1 Introduction 4
2 Services 6
2.1 Transmission Services 6
2.2 Exhibit 1: Ancillary Services Rates 15
2.3 Summary of Rates 21
2.4 Exhibit 2: Development of NS Power's Transmission Revenue Requirement 22
3 Rate Variance Analysis 27
4 Directives from the 2023-2024 General Rate Application 29
4.1 Alternative Treatment of Interruptible Loads 30
4.2 Costing and Treatment for the -16 MW Component of AGC 32
4.3 Wreck Cove Capacity in 10-Minute Reserve Costs Calculation 34
4.4 Inclusion of Less Expensive Combustion Turbines in the Capacity Based Ancillary Service Costing Calculations for 30-Minute Supplemental Reserve 41

List of Figures

Figure 2-1 – Overview of the Steps taken in the Update of Transmission Rates 6
Figure 2-2 – Transmission System Revenue Requirement 7
Figure 2-3 – Functional Allocation of Revenue Requirements 10
Figure 2-4 – Transmission System Usage 10
Figure 2-5 – Transmission Services Revenue Requirements 11
Figure 2-6 – Per Unit Transmission Services Revenue Requirements 11
Figure 2-7 – Determination of Nominal Rates by Service 12
Figure 2-8 – Summary of Transmission Service Rates 13
Figure 2-9 – Revenue Requirement of Capacity Based Ancillary Services 18
Figure 2-10 – Rates for Capacity Based Ancillary Services 19
Figure 2-11 – Reactive Supply and Voltage Control Service Rates 21
Figure 2-12 – Rates for Services in NS Power's Open Access Transmission Tariff 21
Figure 3-1 – Rate Variance Analysis 27
Figure 4-1 – Allocation of Generation Capacity to Spinning Reserve Since 2005 36
Figure 4-2 – Comparison of Spinning Reserve Rate: 2023 Rate Versus Rate with Wreck Cove Capped at the 32 MW Spinning Reserve Requirement 37

Attachments

As part of the General Rate Application:

SR-01 Attachment	11	2026 OATT Rate Development
SR-01 Attachment	12	2026 OATT Ancillary Service Costs
SR-01 Attachment	13	2027 OATT Rate Development
SR-01 Attachment	14	2027 OATT Ancillary Service Costs

1 INTRODUCTION

As part of its General Rate Application (GRA), Nova Scotia Power Incorporated (NS Power, the Company) has reviewed and updated the prices for the services offered under NS Power's Open Access Transmission Tariff (OATT).

The OATT includes terms, conditions and rates for Transmission Services and Ancillary Services, service and operating agreements under which service will be provided, and the Standards of Conduct which govern the treatment of transmission system and market information within NS Power. The OATT, as approved by the Nova Scotia Utility and Review Board, predecessor to the Nova Scotia Energy Board (NSEB, Board), in 2005 and as amended June 10, 2016, is available at: http://oasis.nspower.ca/en/home/oasis/default.aspx

NS Power proposes the following amendments to the OATT methodology arising from the stakeholder consultation process in the 2024 COSS proceeding[1]

- OATT Rates to be set based on forecasted test year usage as opposed to the historic usage.
- Transmission rates under schedules 7, 8 and 10 to be set based on transmission-related revenue requirement as determined in the Cost of Service Studies and reported in Exhibit 4.1 in lieu of the revenue requirement determined through formulaic calculations.

The proposed amendments will help eliminate differences in transmission revenue requirements as used for the OATT and bundled service rate purposes.

In addition, NS Power is proposing a modification to the determination of reactive power usage, applied in rate calculations under Schedule 2, from a single system peak hour to a multi-hour one based on 97 percentile usage of Reactive Power from generation. This matter is discussed in Section 2.2.5.1.

[1] Mini Stakeholder Session – Bundled/Unbundled Markets held on October 3, 2024.

The rates proposed have been updated to reflect the changes in revenue requirement, driven by changes in generation and transmission asset mix and costs, and changes in system usage since the last update as part of the 2023-2024 GRA.

The information provided in **Sections 2** and **3** describes the Board-approved methodology for the development of the revenue requirements and their allocation to the transmission services of the OATT. It also describes the calculations for ancillary services. All transmission charges shown are updated for costs and load determinants forecasted for 2026-2027 test years. The ancillary charges are based on 2023 and 2024 operational actual data. **Section 4** of this Report provides an update on OATT-specific directives from the 2023-2024 GRA.

This update provides for new rates in OATT Schedules as follows:

Schedule 1	Scheduling, System Control and Dispatch Service	Updated rates
Schedule 2	Reactive Supply and Voltage Control from Generation Sources Service	Updated rates
Schedule 3	Regulation and Frequency Response Service	Updated rates
Schedule 5	Operating Reserve - Spinning Reserve Service	Updated rates
Schedule 6	Operating Reserve - Supplemental Reserve Service	Updated rates
Schedule 7	Long-Term and Short-Term Firm Point-to-Point Transmission Service	Updated rates
Schedule 8	Non-Firm Point-to-Point Transmission Service	Updated rates
Schedule 9	Real Power Loss Factors	Revisions to Tariff Sheet language
Schedule 10	Network Integration Transmission Service Rate	Updated rates

The redline and clean proposed Schedules are provided in the General Rate Application **PR-01 Attachments 1 and 2**.

The remaining schedules are listed below, but are not discussed in this Update

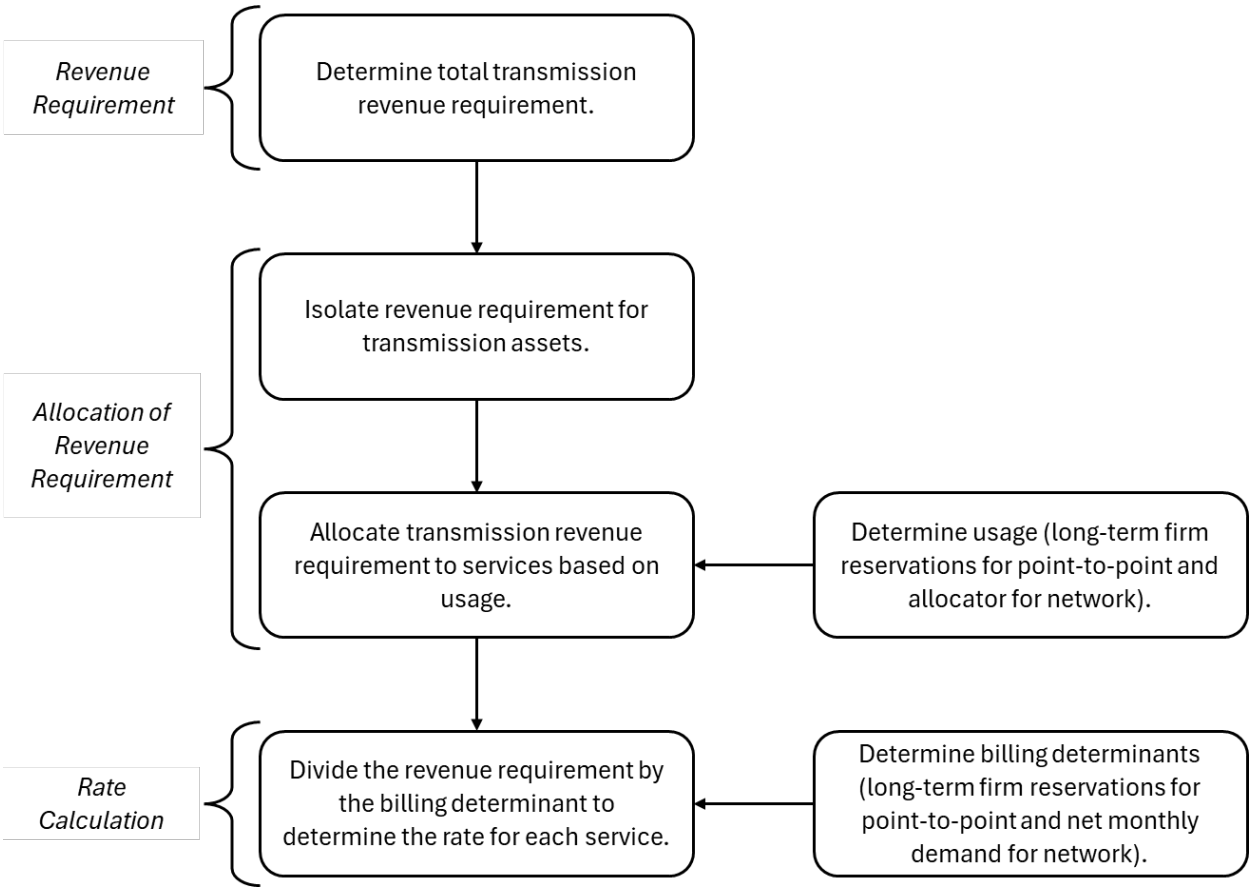
Schedule 4	Energy Imbalance Service	No change required
Schedule 4A	Generation Forecasting Service	No change required

2 SERVICES

2.1 Transmission Services

The methodology for developing transmission tariff rates is shown in **Figure 2-1**.

Figure 2-1 – Overview of the Steps taken in the Update of Transmission Rates



2.1.1 Transmission Revenue Requirement

The first step in calculating the transmission tariff is to determine the appropriate revenue requirement that must be recovered from the sale of Transmission Services. Refer to **Figure 2-2.**

Figure 2-2 – Transmission System Revenue Requirement

Revenue Requirement Component	2026	2027
	$ millions	
Depreciation	37.7	43.5
O&M including overhead costs	29.6	31.2
Interest, taxes and return on equity	67.5	85.3
Scheduling, System Control & Dispatch	8.8	6.1
Total	**143.7**	**166.2**

The revenue requirement shown in **Figure 2-2** includes the costs of all transmission lines at voltages of 69 kV or higher and the terminal stations associated with those transmission lines. It is set using costs functionalized to transmission as provided in Exhibit 4.1 of the Cost-of-Service Studies filed in this proceeding as SR-01 Attachment 02 and SR-01 Attachment 03.

The costs of Generation-related Transmission Assets (GRTA), comprised of step-up transformers, radial to generation lines, and general breakers, have been removed from transmission service area and placed in generation, instead. This treatment of these assets reflects the proposed changes to the functionalization of these costs in the COSS and is also consistent with their past cost treatment under the OATT.

2.1.2 Allocation of Revenue Requirement

The second step in the calculation of transmission rates is to allocate the revenue requirement (i.e. the costs associated with transmission) among the appropriate services. The following steps are required to do this:

1. Definition of the Transmission Services to be provided.
2. Definition of the basic functions of the Transmission System.
3. Allocation of transmission revenue requirements to the different functional uses of the system.
4. Determination of system usage by service.
5. Allocation of the functional costs to the Transmission Services.

2.1.3 Services Defined in the Tariff

There are two basic Transmission Services available under the OATT: Point-to-Point and Network Integration Service. In addition, the Scheduling, System Control, and Dispatch (Schedule 1) and Reactive Supply and Voltage Control (Schedule 2) are required ancillary services that can only be provided by the Transmission Provider and must be taken by the Transmission Customer. The rate design of Point-to-Point Service and Network Service, and the Scheduling, Control and Dispatch service is considered in Section 2.1, while the rates for the other Ancillary Services are detailed in Section 2.2.

Point-to-Point Service refers to the reservation of capacity (for a specified period of time and a specified amount of MW) to allow the transmission of energy from a Point of Receipt to a Point of Delivery; for example, a one-month reservation of 100 MW from a generator inside Nova Scotia (the Point of Receipt) to the New Brunswick interconnection (the Point of Delivery). This service is available on either a firm or a non-firm basis.

Network Service is a firm Transmission Service for the delivery of both capacity and energy to the high side of the substation transformer of the Transmission Customer. It is usually used for supply of load within the system.

Scheduling, System Control, and Dispatch Service is the process through which the system operator ensures that scheduled transactions are executed. It is required to schedule the movement of power into, out of, or within Nova Scotia. Only the NS Power System Operator can provide this service.

2.1.4 Transmission Functions

The services defined in the OATT and described in the previous section use different parts of the Transmission System. To ensure appropriate cost allocation, it is necessary to break the revenue requirement down into component pieces. Once such a breakdown is completed, costs can be allocated to specific services.

This section identifies which assets are used to provide which services. For the purposes of the NS Power System Operator OATT, the assets have been grouped into three main functional groups as follows:

1. Generation-related Transmission Assets (GRTA)

   Direct Assignment Facilities are generation-related transmission assets that serve the function of connecting generation units to the shared Transmission System. They consist of generator step up transformers, a portion of substation assets, and transmission lines whose primary purpose is to connect a generator to the Transmission System. These assets and the associated revenue requirements are to be recovered directly from the generation owners and not accounted for in the rate for the transmission tariff.

2. Bulk Network Assets (BNA)

   Bulk Network Assets make up the portion of the Transmission System that is highly interconnected and that serves multiple functions. The bulk network has two components: interconnections and in-province assets. Interconnections are transmission lines that interconnect Nova Scotia with neighboring provincial electrical systems. The in-province assets consist of all transmission lines that operate as part of the integrated system within Nova Scotia.

3. Radial-to-Load Assets (RLA)

   Radial-to-Load Assets are those parts of the Transmission System that are not a part of the integrated network and are used only to serve in-province loads. However, because the impact of including RLA as part of the bulk power network is not large, and because the status of these assets changes each time new generation is connected to such lines, the ratemaking methodology includes these assets with the bulk power network assets.

2.1.5 Functional Allocation of Costs

The allocation of the Transmission Services revenue requirement of $143.7 in 2026 and $166.2 million in 2027 to the functional uses of the system is summarized in **Figure 2-3**. Details of this allocation are found in Figure 2-5**.**

Figure 2-3 – Functional Allocation of Revenue Requirements

Functional Use	Revenue Requirement Share ($ millions)	
	2026	2027
Generator Related Transmission Assets[2] (GRTA)	0.0	0.0
Bulk Network In Province	134.9	160.1
Energy Control Centre	8.8	6.1
TOTAL	**143.7**	**166.2**

2.1.6 Determination of System Usage

The transmission revenue requirement is allocated between Point-to-Point and Network Integration Services based on the monthly coincident peak system load. There is a single long-term firm Point-to-Point transmission reservation in the amount of 330 MW used in this analysis. The resulting system usage is shown in **Figure 2-4**.

Figure 2-4 – Transmission System Usage

Usage	Quantity (MW)		Allocation Factors (%)	
	2026	2027	2026	2027
Average export usage over 5 years	330	330	15.65%	15.60%
Forecasted average Network Loads at the time of the 12 monthly system peaks in 2026 and 2027	1,778	1,785	84.35%	84.40%
Total	**2,108**	**2,115**	**100%**	**100%**

2.1.7 Allocation of Revenue Requirements to Services

The last step in the cost allocation analysis is to allocate total transmission costs to the services that will be offered under the Tariff. As noted above, these are Point-to-Point Service, Network Service, and Scheduling, System Control, and Dispatch Service.

[2] NS Power through Nova Scotia Power Cost of Service Study Process under M 11475 is proposing to Functionalize Generator Related Transmission Assets cost to Generation

The transmission revenue requirement for Point-to-Point and Network Services has been determined in Section 2.1.5. Applying percent share of usage for Point-to-Point reservations and percent for Network Service, the allocation of costs to these services shown in **Figure 2-5**.

Figure 2-5 – Transmission Services Revenue Requirements

Service	2026 Share (%)	2027 Share (%)	Revenue Requirement ($ millions)	
			2026	2027
Point-to-Point	15.7%	15.6%	21.1	25.0
Network	84.3%	84.4%	113.8	135.1
Total	**100%**	**100%**	**134.9**	**160.1**

The revenue requirement for each service can also be expressed on a per-unit of usage basis as shown in **Figure 2-6**. The $/MW-year figures represent the per-unit cost of providing each of the services based on the application of the transmission pricing principles.

Figure 2-6 – Per Unit Transmission Services Revenue Requirements

Service	Revenue Requirement	Usage (MW)	Per Unit Revenue Requirement ($/MW-Year)
2026			
Point-to-Point	21.1	330	63,996.09
Network	113.8	1,778	63,996.09
2026 Total	**134.9**	**2,108**	
2027			
Point-to-Point	25.0	330	75,699.93
Network	135.1	1,778	75,699.93
2027 Total	**160.1**	**2,108**	

2.1.8 Determination of Rates

The nominal rates for each service are determined by dividing their revenue requirements by their respective billing determinants. For Point-to-Point Transmission Service, the approved billing determinant is the transmission capacity reserved by the customer.

For Network Integration Transmission Service, the approved billing determinant is monthly non-coincident peak (NCP) demand. The NCP demand for all Eligible Customers (except NS Power) is available from existing metering at the customer-level. Given the lack of complete metering at the transmission-level for all of NS Power's interfaces with the Distribution System, NS Power uses a Cost of Service Study (COSS) coincidence factor to derive NS Power's NCP demand from the known coincident peak demand. NS Power estimates this coincidence factor to be 91.7 percent in 2026 and 89.7 percent in 2027.

Figure 2-7 illustrates the calculation of the annual nominal rate for each service.

Figure 2-7 – Determination of Nominal Rates by Service

Services	Revenue Requirement ($millions/yr.)	Billing Determinant (MW)	Nominal Rate ($/MW/yr.)
2026			
Point to Point Services			
Transmission Service	21.1	330	63,996.09
Scheduling, Control & Dispatch	1.4	330	4,177.65
Network Services			
Transmission Service	113.8	1,778	63,996.09
Scheduling, Control & Dispatch	7.4	1,635	4,177.65
2027			
Point to Point Services			
Transmission Service	25.0	330	75,699.93
Scheduling, Control & Dispatch	1.0	330	2,896.44
Network Services			
Transmission Service	135.1	1,635	75,699.93

Services	Revenue Requirement ($millions/yr.)	Billing Determinant (MW)	Nominal Rate ($/MW/yr.)
Scheduling, Control & Dispatch	5.2	1,635	2,896.44

For time differentiated Point-to-Point Service, NS Power is using Appalachian pricing. In Appalachian pricing the short-term services are priced higher for an equivalent time period. The Appalachian pricing approach defines various short-term rates as a fraction of the yearly rate as follows:

Yearly	Nominal rate
Monthly rate	Yearly rate / 12
Weekly rate	Yearly rate / 52
On-Peak Daily rate	Weekly rate / 5
Off-Peak Daily rate	Yearly rate / 365
On-Peak Hourly rate	On-Peak Daily rate / 16
Off-Peak Hourly rate	Yearly rate / 8760

NS Power has proposed rates based on the previously approved calculations shown above. This approach helps ensure adequate collection of revenues for services provided, while facilitating the use of the transmission capacity in the off-peak hours. Based on the overall revenue requirement defined, the application of the revenue requirement allocation analysis, and the design of the end use rates just described, the rates proposed are set out in **Figure 2-8.**

Figure 2-8 – Summary of Transmission Service Rates

Services	Units	Transmission Service	Scheduling, System Control & Dispatch
2026			
Point-to-Point			
Yearly	$/MW-yr	63,996.09	4,177.65
Monthly	$/MW-m	5,333.01	348.14
Weekly	$/MW-w	1,230.69	80.34
On-Peak Daily	$/MW-d	246.14	16.07

Services	Units	Transmission Service	Scheduling, System Control & Dispatch
Off-Peak Daily	$/MW-d	175.33	11.45
On-Peak Hourly	$/MW-h	15.38	1.00
Off-Peak Hourly	$/MW-h	7.31	0.48
Network	$/MW-m	4,888.13	319.10
2027			
Point-to-Point			
Yearly	$/MW-yr	75,699.93	2,896.44
Monthly	$/MW-m	6,308.33	241.37
Weekly	$/MW-w	1,455.77	55.70
On-Peak Daily	$/MW-d	291.15	11.14
Off-Peak Daily	$/MW-d	207.40	7.94
On-Peak Hourly	$/MW-h	18.20	0.70
Off-Peak Hourly	$/MW-h	8.64	0.33
Network	$/MW-m	5,658.78	216.52

Additional details with respect to the derivation of these rates are provided in **Figure 5-12** and **Figure 5-14** found in **SR-01 Attachments 11** and **13.**

2.1.9 Power Factor Penalty in the Transmission Tariff

NS Power's OATT includes a power factor penalty that will be applied for any month in which a Transmission Customer has a power factor of less than 0.90. As approved by the Board, the penalty paid shall be based on excess kVA, where excess kVA shall be defined as:

$$Excess\ kVA = \frac{Max.kVA\ - Max.kW}{0.9}$$

Where:

- Max. kVA is maximum kVA consumed during the month
- Max. kW is maximum kW consumed during the month

The charge per excess kVA is set equal to the demand charge of the NS Power Large Industrial Tariff in effect.

2.2 Exhibit 1: Ancillary Services Rates

Ancillary Services are the support services that are required to enable the Transmission System to transmit energy while maintaining reliable operation of the system in accordance with Good Utility Practice. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller to services that are necessary to maintain the integrity of the Transmission System and enable it to be operated reliably at designed voltages and frequency.

This section discusses calculations of rates for all the Ancillary Services that are provided by generators under the control of the System Operator at the Energy Control Centre. Scheduling, System Control, and Dispatch Service is an Ancillary Service supplied directly by the Transmission Provider as discussed in Section 2.1.

The Ancillary Services provided by generators and discussed in this Section can be grouped into two main categories:

1. Capacity based services provided from generation capacity that must be committed to the provision of the service and cannot be used at the same time for other purposes; and
2. Non-capacity-based services that do not require the commitment of generator capacity for provision of the service.

2.2.1 Capacity Based Ancillary Services

Capacity-based services include the following:

- Regulation and Frequency Response Service, comprising Regulation and Load Following (**Schedule 3**);
- Operating Reserve – Spinning Reserve Service (**Schedule 5**); and
- Operating Reserve – Supplemental Reserve Service, comprising Supplemental 10-minute and 30-minute Reserve (**Schedule 6**).

The costs of supplying these services are calculated from the embedded costs of existing generating units. The revenue requirement for these capacity-based services is determined by multiplying the per-unit embedded cost of capacity for each service by the amount of capacity required to deliver the service. Once the revenue requirement is determined, it is allocated to services, and rates are set in a manner similar to that used for Transmission Services in Section 2.1.

2.2.2 Requirements of Capacity Based Ancillary Services

NS Power System Operator as the Transmission Provider operates in accordance with NERC Reliability Standards and NPCC criteria, as approved by the NSEB. This includes the responsibility to determine the need for, and to sufficiently procure, ancillary resources to reliably operate the electrical power network.

Additionally, the OATT requires NS Power, as the Transmission Provider, to make all Ancillary Services available to all Transmission Customers. Therefore, NS Power must be able to procure adequate generation resources to do so.

Transmission Customers can purchase each of the Ancillary Services from the Transmission Provider (NS Power) whether they are taking Point-to-Point or Network Service. Therefore, the Ancillary Services are priced for both services. Transmission Customers can self-supply the capacity-based Ancillary Services or purchase them from either the Transmission Provider or a third party. The NS Power system requirements for “Regulation and Frequency Response” and “Operating Reserves” are outlined below.

2.2.2.1 Regulation and Frequency Response

Regulation and Frequency Response Ancillary Service is necessary to provide for the continuous balancing of resources (generation and scheduled interprovincial interchange) with load, which supports the grid operation at 60 Hz. Historical operating experience was used to determine the amount of capacity that is required to provide the Regulation and Frequency Response Ancillary Service. The NS Power grid has integrated a significant amount of variable generation, mostly in

the form of wind, which is dispatched ahead of other generating units other than as required to maintain system stability requirements; therefore, this Ancillary Service now includes the requirement to balance the net variations of load and variable generation with NS Power's conventional generation fleet. There are two characteristics of this Ancillary Service that dictate its requirements: (a) moment-to-moment load and variable generation fluctuations (Regulation), and (b) the change in load and variable generation from hour-to-hour (Load Following).

The moment-to-moment fluctuations require 32 MW of generation capacity for the Nova Scotia system, and the hour-to-hour change in load requires 122.6 MW of generation capacity calculated using the 2-standard deviation. The requirements for this Ancillary Service are expected to increase with the addition of more wind to the power system.

2.2.2.2 Operating Reserves

NPCC defines the requirement for Operating Reserves in the Maritimes Control Area. NS Power is obliged to provide its share of Operating Reserves as follows:

- Spinning Reserve 32 MW
- 10-minute (non-spinning) Reserve 136 MW[3]
- 30-minute Reserve 50 MW

This means that at all times, NS Power must have: 32 MW of spare capacity available from units already online, 136 MW of capacity (or load reduction) that can be made available within 10 minutes, and an additional 50 MW of capacity (or load reduction) that can be made available within 30-minutes.

2.2.3 Summary of Revenue Requirements for Capacity Based Ancillary Services

The total revenue requirement for each service is the product of the quantity required multiplied by the cost per unit of service supplied as shown in **Figure 2-9**.

[3] Please note that for the pricing purposes of the Supplemental (10 minute) service, the required installed generation capacity has been reduced by 35 MWs, or 50% of an average hourly load of the interruptible customers under the Large Industrial class, to 101 MWs. Please refer section 4.1 Alternative Treatment of Interruptible Loads.

Figure 2-9 – Revenue Requirement of Capacity Based Ancillary Services

Services	Revenue Requirement ($/kW-yr)		Services Required (MW)		Revenue Requirement ($1,000/yr)	
	2026	2027	2026	2027	2026	2027
Regulation	159.3	171.6	32.0	32.0	5,099.09	5,490.93
Load Following	172.6	181.3	122.6[4]	122.6	21,166.11	22,225.35
Spinning (10-minute)	131.4	137.9	32.0	32.0	4,206.37	4,413.46
Supplemental (10-minute)	122.1	133.0	101.0[5]	68.0	12,328.77	13,435.32
Supplemental (30-minute)	120.3	125.4	50.0	50.0	6,012.71	6,271.25

Additional detail with respect to the derivation of these revenue requirements is provided in Figure 6-8 found in **SR-01 Attachments 11** and **13.**

2.2.4 Capacity Based Ancillary Service Rates

The annual cost of providing each service as a function of the usage is determined by dividing the total cost of providing the service by the usage of the respective service. For monthly Point-to-Point and Network Services the annual cost of providing each service on a $/kW basis is divided by 12 to determine the monthly rate. Point-to-Point customers purchasing Ancillary Services on a yearly or monthly basis, as well as customers taking Network Service, are billed at the monthly rate at the end of each calendar month as noted in the terms and conditions of the OATT. The rate for weekly Point-to-Point Services is 1/52nd of the annual rate and the daily rate is 1/7th of the weekly rate. Hourly service is not available for the capacity-based Ancillary Services due to the additional administrative burden of tracking how various Point-to-Point customers are fulfilling their obligations on an hourly basis. The rates produced by this process are summarized in **Figure 2-10**.

[4] The Test year Load Following Services Required (MW) usage is predicated on the 2- Standard deviation.
[5] as part of developing this consensus GRA, it was agreed that for the 2026-2027 test periods the costing approach will utilize 50 percent of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis.

Figure 2-10 – Rates for Capacity Based Ancillary Services

Services	Rate ($/MW-month)	
	2026	2027
Regulation	219.03	229.94
Load Following	909.20	930.71
Operating Reserve – Spinning	180.69	184.82
Operating Reserve – Supplemental (10 minute)	529.59	562.62
Operating Reserve – Supplemental (30 minute)	258.28	262.62

2.2.5 Non-Capacity Based Ancillary Services

Non-capacity based Ancillary Services are:

- Scheduling, System Control and Dispatch (**Schedule 1**);
- Reactive Supply and Voltage Control Service (**Schedule 2**); and
- Energy Imbalance Service (**Schedule 4**).

The three-step methodology for developing rates (outlined in **Figure 2-1**) is also employed to determine rates for these services. Rates for Scheduling, System Control and Dispatch service are derived from the transmission revenue requirements in Section 2.1.1 of this report. The remaining two non-capacity based Ancillary Services are considered below.

2.2.5.1 Reactive Supply and Voltage Control Service

Reactive power must be appropriately distributed across the Transmission System since it cannot be transported efficiently. If there were no continuously variable reactive power available from generation, dynamic reactive devices would have to be strategically deployed across the grid to provide this Ancillary Service.

The total system requirement for this service from generators on the system is based on the historical reactive power output of in-province generators plus an additional MVAR capability

held in reserve to ensure dynamic system security. The total revenue requirement for this service is determined by applying estimated embedded unit cost to the total system requirement for reactive power. Details of this are provided in **SR-01 Attachments 12** and **14**.

Without this service, transmission of electrical power cannot occur, so the revenue requirement is allocated to both Point-to-Point and Network Service. This allocation is done on the same basis as the allocation of the revenue requirement associated with the Transmission System. This allocation to Point-to-Point and Network Services is explained in Section 3.1.7. The respective usages are based on long-term firm transmission reservations and an average of 12 monthly peak Network Loads coincident with the system peak.

Proposed Changes to Rate Calculation

In 2012, reactive power was provided by generation units in peak hour. In the years 2019-2020, most of the Reactive Power was provided by transmission system equipment, plus support from the Maritime Link acting as a STATCOM device. However, generation equipment plays an important role in real-time Voltage Control and providing reactive power at other times of the year, so Schedule 2 is based on a 97-percentile usage of Reactive Power from generation, rather than only the peak hour of the year. The revised methodology now captures the cost of delivering Reactive Power and Voltage Control from the combustion turbines at Victoria Junction, Burnside and Tusket while they are operating in synchronous condenser mode, not only while in generate mode as per previous OATT.

The rate calculations are done in the same manner as used in the determination of transmission service rates. The revenue requirement for this service for users of Point-to-Point Service is divided by the long-term firm transmission reservation quantity. The revenue requirement of this service for users of Network Service is divided by the average of the 12 monthly coincident peak net demands for Network Service, adjusted for system coincidence factor to provide billing based on non-coincident metering. The Appalachian pricing approach (explained in Section 3.1.8) is applied to this service in the same fashion as it is applied to the Point-to-Point Service. The rates for this service are summarized in **Figure 2-11**.

Figure 2-11 – Reactive Supply and Voltage Control Service Rates

Services	Units	Rate	
		2026	2027
Point-to-Point			
Yearly	$/MW-yr	$1,953.42	$2,123.23
Monthly	$/MW-m	$162.79	$176.94
Weekly	$/MW-w	$37.57	$40.83
On-Peak Daily	$/MW-d	$7.51	$8.17
Off-Peak Daily	$/MW-d	$5.35	$5.82
On-Peak Hourly	$/MW-h	$0.47	$0.51
Off-Peak Hourly	$/MW-h	$0.22	$0.24
Network Service	$/MW-m	149.20	158.72

2.2.5.2 Energy Imbalance

Energy imbalance is a service that has no predictable required quantity. The cost of providing the service fluctuates with the real time cost of producing energy. For these reasons, this service is priced using hourly marginal costs. NS Power does not propose any changes to this mechanism in this submission.

2.3 Summary of Rates

Rates proposed for all OATT services included in this Application are set out in **Figure 2-12**. For ease of comparison, the rates for all services are provided in the common units of $/MW-month.

Figure 2-12 – Rates for Services in NS Power's Open Access Transmission Tariff

Services	Schedule in OATT	2026	2027
		$/MW-month	$/MW-month
Scheduling, System Control, and Dispatch Service	Schedule 1	348.14	241.37
Point-to-Point Network		319.10	216.52
Reactive Supply and Voltage Control	Schedule 2	162.79	176.94

Services	Schedule in OATT	2026	2027
		$/MW-month	$/MW-month
Point-to-Point Network		149.20	158.72
Regulation	Schedule 3	219.03	229.94
Load Following		909.20	930.71
Energy Imbalance Service	Schedule 4	variable as described in OATT	
Operating Reserve – Spinning	Schedule 5	180.69	184.82
Operating Reserve – Supplemental (10-minute)	Schedule 6	529.59	562.62
Operating Reserve – Supplemental (30-minute)			
Point-to-Point Service	Schedule 7	258.28	262.62
Network Integration Service	Schedule 10	4,888.13	5,658.78

OATT Schedule 9 Real Power Loss Factors[6] references seasonally adjusted path-specific loss factors for Point-to-Point Service and System Average Loss Factor for Network Service. OATT Loss Factors[7] for customer transactions are updated periodically and posted to OASIS.

2.4 Exhibit 2: Development of NS Power's Transmission Revenue Requirement

2.4.1 Overview

The transmission revenue requirement used in the development of the OATT rates includes:

(a) Depreciation costs;
(b) Interest costs;
(c) Return on equity;
(d) All taxes (income, grants in lieu, etc.);
(e) Operating and maintenance costs;
(f) Appropriate portions of corporate overheads; and
(g) Fixed cost deferral.

[6] OATT Schedule 9 is posted on the NS Power OASIS at: https://www.nspower.ca/docs/default-source/monthly-reports/oatt-schedules(pdf).pdf?sfvrsn=a5db547_5
[7] OATT loss factors are posted on the NS Power OASIS at: https://www.nspower.ca/oasis/system-reports-messages

Each of these is discussed in more detail below. Items (a) through (d) are derived from the total transmission assets.

2.4.2 Total Transmission Assets

NS Power's average transmission assets have a gross plant value (i.e. before any depreciation and Distribution adjustment) as shown in the "Total Assets" tabs of the OATT Rate Development (**SR-01 Attachments 14** and **16**). To align with COSS study, The Gross Plant Value has been adjusted by the cost attributable to Distribution customers.

Transmission assets requirements included portion of General Property assets and a portion of other assets amounts such as deferred charges, materials inventory and net receivables) as shown in the "Total Assets" tabs of the OATT Rate Development (**SR-01 Attachments 11** and **13**), which are assigned to the transmission function in the COSS.

The figure below shows the adjustments made for the purpose of developing the OATT revenue requirement. These adjustments, and the total transmission assets for the purposes of OATT values, are found in the "Trans - Fig 5-9" tab of the OATT Rate Development (**SR-01 Attachments 14** and **16)**.

- Generator step-up transformers' revenue requirement have been excluded ($2.1 million in 2026 and $1.9 million in 2027).
- Transmission lines that are radial-to-generation have been excluded ($6.9 million in 2026 and $6.9 million in 2027); and
- Portions of substations (such as breakers) that are radial-to-generation have been excluded ($0.8 million in 2026 and $0.8 million in 2027).

NS Power's total transmission net assets for the purposes of OATT are $972,420 million in 2026 and $1,158,533 million in 2027.

2026-TRANSMISSION REVENUE REQUIREMENT						
Generation Related Transmission Assets:	**Net Plant**	**OM&G**	**Depreciation**	**Int., Taxes &**	**FCR**	**Total**
Step Up Transformers	$13,443	$309	$662	$1,093	$0	$2,064
Radial to Generation	45,235	1,040	2,228	3,679	0	6,947
Generator Breakers	5,667	130	279	461	0	870
	64,344	1,479	3,169	5,233	0	$9,881
Bulk Transmission: Total Equipment	**972,420**	**29,635**	**37,748**	**67,527**	**0**	**134,910**
Scheduling, System Control & Dispatch		8,807				8,807
Amount for the Purposes of Rate Development	**972,420**	**38,442**	**37,748**	**67,527**	**0**	**143,717**

2027-TRANSMISSION REVENUE REQUIREMENT						
Generation Related Transmission Assets:	**Net Plant**	**OM&G**	**Depreciation**	**Int., Taxes &**	**FCR**	**Total**
Step Up Transformers	$12,210	$296	$607	$982	$0	$1,885
Radial to Generation	44,602	1,082	2,218	3,588	0	6,888
Generator Breakers	5,147	125	256	414	0	795
	61,959	1,503	3,081	4,984	0	$9,568
Bulk Transmission: Total Equipment	**1,158,533**	**31,248**	**43,526**	**85,341**	**0**	**160,114**
Scheduling, System Control & Dispatch		6,126				6,126
Amount for the Purposes of Rate Development	**1,158,533**	**37,374**	**43,526**	**85,341**	**0**	**166,241**

2.4.2.1 Depreciation Costs, Interest Costs, Return on Equity, and All Taxes (income, grants in lieu, etc.) and

NS Power is proposing the calculation of the Depreciation, interest cost Return on Equity, and all Taxes applicable to OATT rates to align to the Transmission service amount calculated in the 2026 and 2027 Cost of Service studies. NS Power has developed OATT cost rate categories in exhibit 4.1 of the COSS Studies provided as Attachment 02 and Attachment 03 in the 2026-2027 GRA. The amounts for the OATT rate development exclusively of the auxiliary service rates are presented as follows forms an input to the Transmission Revenue Requirement described above:

EXHIBIT 4.1

NOVA SCOTIA POWER INC.

TRANSMISSION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2026

(IN THOUSANDS OF DOLLARS)

		ABOVE-THE-LINE RATE CLASSES	BELOW-THE-LINE RATE CLASSES	TOTAL
(1)	**OPERERATION & MAINTENANCE**			
(2)	DIRECT	22,956	744	23,700
(3)	NON-DIRECT	14,279	463	14,742
(4)	TOTAL OPER. & MAINT.	37,235	1,207	38,442
(6)	**DEPRECIATION**			
(7)	DIRECT	25,986	842	26,828
(8)	GENERAL PROPERTY	10,577	343	10,920
(9)	TOTAL DEPRECIATION	36,562	1,185	37,748
(11)	**TAX**			
(12)	CORPORATE TAX	(3,041)	(99)	(3,139)
(13)	REGULATORY AMORTIZATION	1,373	45	1,417
(14)	GRANTS IN LIEU OF TAXES	9,171	297	9,468
(15)	TOTAL TAX	7,503	243	7,747
(17)	**INTEREST**			
(18)	TOTAL BEFORE AFUDC	24,431	792	25,223
(19)	LESS: AFUDC INTEREST	(388)	(13)	(400)
(20)	INTEREST TOTAL	24,044	780	24,823
(22)	**RETAINED EARNINGS**	34,131	1,107	35,238
(24)	**MISCELLANEOUS REVENUE CREDIT**	(281)	-	(281)
(26)	**TOTAL**	139,195	4,522	143,717

EXHIBIT 4.1

NOVA SCOTIA POWER INC.

TRANSMISSION OPERATING EXPENSES

FOR THE YEAR ENDING DECEMBER 31, 2027

(IN THOUSANDS OF DOLLARS)

		ABOVE-THE-LINE RATE CLASSES	BELOW-THE-LINE RATE CLASSES	TOTAL
(1)	**OPERERATION & MAINTENANCE**			
(2)	DIRECT	21,094	988	22,081
(3)	NON-DIRECT	14,609	684	15,293
(4)	TOTAL OPER. & MAINT.	35,703	1,672	37,374
(6)	**DEPRECIATION**			
(7)	DIRECT	28,744	1,346	30,089
(8)	GENERAL PROPERTY	12,835	601	13,436
(9)	TOTAL DEPRECIATION	41,579	1,947	43,526
(11)	**TAX**			
(12)	CORPORATE TAX	517	24	541
(13)	REGULATORY AMORTIZATION	1,568	73	1,641
(14)	GRANTS IN LIEU OF TAXES	10,342	484	10,827
(15)	TOTAL TAX	12,427	582	13,009
(17)	**INTEREST**			
(18)	TOTAL BEFORE AFUDC	27,825	1,303	29,128
(19)	LESS: AFUDC INTEREST	1,355	63	1,419
(20)	INTEREST TOTAL	29,180	1,366	30,546
(22)	**RETAINED EARNINGS**	40,218	1,883	42,101
(24)	**MISCELLANEOUS REVENUE CREDIT**	(316)	-	(316)
(26)	**TOTAL**	158,791	7,449	166,241

2.4.2.2 Appropriate Portions of Corporate Overheads

As the NS Power System Operator operates on a shared services model, appropriate portions of shared corporate overheads are allocated to the OATT revenue requirement. These costs include corporate functions such as Finance, Information Technology, Regulatory Affairs, Legal, and Procurement. Based on estimates prepared by NS Power, the costs of each group are assigned to the Power Production, Customer Operations, and Marketing and Sales groups. The portion assigned to Customer Operations is split between Transmission and Distribution and the Transmission portion ($8.8 million in 2026 and $6.1 million in 2027) is included in the OATT.

3 RATE VARIANCE ANALYSIS

Figure 3-1 provides a comparison of the changes to the Transmission and Ancillary Services rates in the OATT for 2026 and 2027 and identifies the key drivers of the variances.

Figure 3-1 – Rate Variance Analysis

Rate Variance Analysis											
Rate	2005	2013	2014	2023-2025	2026	2027	Percentage Change				
	($/MW/month)						2013 /2005	2014/2 013	2023 /2014	2026 /2023	2027 /2026
Transmission											
Point to Point	$3,580.88	$4,670.50	$4,989.66	$5,079.47	$5,333.01	$6,308.33	30%	6.8%	1.8%	5.0%	18.3%
Network	$2,782.20	$3,969.93	$4,241.21	$4,317.55	$4,888.13	$5,658.78	43%	6.8%	1.8%	13.2%	15.8%
Scheduling, System Control and Dispatch											
Point to Point	$232.84	$403.24	$416.45	$404.41	$348.14	$241.37	73%	3.3%	-2.9%	-13.9%	-30.7%
Network	$181.18	$342.76	$353.98	$360.35	$319.10	$216.52	89%	3.3%	1.8%	-11.4%	-32.1%
Reactive Power											
Point to Point	$293.54	$214.72	$214.97	$187.82	$162.79	$176.94	-27%	0.12%	-12.63%	-13.33%	8.69%
Network	$227.99	$182.48	$182.76	$170.89	$149.20	$158.72	-20%	0.15%	-6.50%	-12.69%	6.38%
Capacity-based Ancillary Services											
Regulation	$78.60	$216.73	$217.06	$218.90	$219.03	$229.94	176%	0.2%	0.8%	0.1%	5.0%
Load Following	$449.80	$775.66	$776.85	$790.83	$909.20	$930.71	72%	0.2%	1.8%	15.0%	2.4%
Spinning (10 minute)	$91.91	$166.33	$166.58	$169.58	$180.69	$184.82	81%	0.2%	1.8%	6.6%	2.3%
Supplemental (10 minute)	$203.94	$331.32	$331.83	$337.80	$529.59	$562.62	62%	0.2%	1.8%	56.8%	6.2%
Supplement (30 minute)	$195.54	$280.80	$281.23	$286.29	$258.28	$262.62	44%	0.2%	1.8%	-9.8%	1.7%

Prices of OATT services are determined by dividing revenue requirement associated with the provision of OATT service by the amount of total system usage. Thus, changes in rates are an outcome of a combined effect of changes in total revenue requirement and changes in usage. For the 2026 and 2027 GRA test years, the following observations apply in relation to **Figure 3-1**:

1. The individual OATT services show diverse changes in their revenue requirements due to the diversity of their underlying cost drivers. Apart from upward unit cost pressures of employed capital and labour resources in delivery of OATT services, the amount and mix of these resources have also changed in response to changes in the operational characteristics of the NS Power system.

2. The unit costs of employed resources have increased and decreased for several reasons.

   - Average Investment in NS Power's transmission assets has increased gross plant value in 2026 over 2022-2024 GRA[8] by 32 percent. NS Power is also forecasting an increase to gross plant in 2027 of 8 percent over 2026.
   - The weighted depreciation rates in the 2026-2027 GRA calculation for transmission and general property assets were 3.23 percent and 6.70 percent, respectively. The weighted depreciation rates in 2026 and 2027 for transmission and general property assets are 3.23 percent and 6.70 percent, respectively.
   - NS Power's total operating costs increased 34.1 percent in 2026 from 2022-2024 GRA. Operating costs, in 2027, also decrease by 5.4 percent over 2026.
   - The WACC, adjusted to reflect taxes used in 2022-2024 GRA. was 6.56 percent compared to 5.74 percent in 2026 and 5.67 percent in 2027.

3. The system operational factors, which affect the amount of generation resources employed in the delivery of generation-based ancillary services, have changed.

   - The increase in the presence of wind generation from 600 MW in 2023/2024 to an expected quantity of 1,037 MW in 2027 is expected to cause an increase in the demand for Regulation and Load Following services. More conventional generation resources are now dedicated to the delivery of these services than in 2024.
   - The overall system usage measured in monthly coincident kW demand for combined Point-to-Point and Network Service[9] has increased by 9 percent in 2026 and 0.4 percent in 2027.

[8] The Current OATT rates approved in 2022-2024 GRA was based on 2023 projected cost.
[9] 2026 and 2027 Network usage is based on the average of the 12-month Test year coincident peaks

4 DIRECTIVES FROM THE 2023-2024 GENERAL RATE APPLICATION

In the 2023-2024 GRA[10], NS Power requested approval of the revenue requirement and updated prices for services offered under the OATT.

The OATT includes terms, conditions, and rates for Transmission Services and Ancillary Services, as well as service and operating agreements under which service will be provided, and the Standards of Conduct which govern the treatment of transmission system and market information within NS Power.

In its February 3, 2023 Decision, the Board approved capping NS Power's OATT rates at a maximum increase of 1.8% in 2023 and 0% in 2024 as described in the GRA Settlement Agreement[11], which states as follows:

> [...] the Rates for Services in NS Power's Open Access Transmission Tariff shall be capped at a maximum increase of 1.8% in 2023 and 0% in 2024. With respect to the CBAS recommendations proposed by WKM Energy Consultants, the parties agree that these issues will be left to the Board's determination in this proceeding. The MEUs will file a closing argument on these issues, following which NS Power and other parties as they see fit will have the opportunity to file a reply.[12]

Ancillary Services are the support services required to enable the Transmission System to transmit energy while maintaining reliable operation of the system. They range from the actions necessary to effect and balance a transfer of electricity between buyer and seller, to services that are necessary to maintain the integrity of the Transmission System and enable it to be operated reliably at design voltages and frequency.

The Capacity-Based Ancillary Services (CBAS) provided from generation capacity must be committed to the provision of the service and cannot be used at the same time for other purposes.

[10] M10431 – NS Power, 2023-2024 General Rate Application, Exhibit N-2. February 2, 2022.
[11] M10431 – NSUARB Decision, 2023-2024 General Rate Application, 300864, page 175, para. 458. February 3, 2023.
[12] M10431 – Exhibit N-155, Settlement Agreement, page 6. November 24, 2023.

The costs of supplying these services are calculated from the embedded costs of existing generating units and the revenue requirement is determined by multiplying the per-unit embedded cost of capacity for each service by the amount of capacity required to deliver the service.

NS Power was directed by the Board in its 2023-2024 GRA Decision to explore alternative treatments, demonstrate various items related to CBAS, and provide additional explanations on the issues raised by stakeholders. NS Power provides an update on each of these Board directives in the sections that follow.

4.1 Alternative Treatment of Interruptible Loads

In its Decision, the Board provided as follows:

> As stated earlier, the MEUs' Closing Submission noted their support for Board approval of the GRA Settlement Agreement, but also sought Board approval of the CBAS recommendations proposed by Mr. Marshall. In addition, they stated that the Board should accept these recommendations and they should be used the next time NS Power requests approval of CBAS rates. The MEUs also recommended that NS Power obtain information from NPCC about the terms under which interruptible load is counted toward reserves. In its response in Undertaking U-14, NS Power stated that interruptible load is counted toward 10-minute reserve when the required amount is not available from generation resources. It also stated that planning to interrupt interruptible loads is not a consideration in meeting day-ahead load and reserve requirements. The Board considers there may be some value in alternate treatment of interruptible loads and directs NS Power to explore options with NPCC. In the next GRA, NS Power is directed to file its analysis of cost implications associated with alternative treatment of interruptible loads.[13] [emphasis added]

The following provides NS Power's review of alternative treatment of interruptible loads. Interruptible loads, which can offer material load relief for the System Operator during capacity scarcity events, fall into two main categories: (1) customer load served under the Extra Large Industrial Active Demand Control (ELIADC) Tariff, and (2) customer loads served under the Large Industrial Interruptible Rider (LIIR).

[13] M10431 – NSUARB Decision, 300864, page 183, para. 478.

(1) ELIADC Interruptible Load

In its GRA Rebuttal Evidence, NS Power provided as follows:

> As stated in NS Power's IR response to MUNIS (NSPI) IR-42, it is not NS Power's operating practice to hold PHP load in operating reserve on a day-ahead basis. Rather PHP load is used in real-time operation to meet periods of capacity scarcity.
>
> The ELIADC load is optimized along with other supply resources in the development of the day-ahead dispatch plan, providing the least cost dispatch of energy and ancillary services for customers. Scheduling of ELIADC load for the sole purpose of ancillary services would not provide the intended benefits of the rate.
>
> In the development of the day-ahead plan, during hours when the margin between generation plus reserve and load is small, PHP load will be economically dispatched down and therefore be unavailable for Operating Reserve. NPCC Directory 5 Operating Reserve Requirement 7 indicates that "loads that are already counted in other demand response programs and would result in double counting the same capacity" shall not be counted as synchronized reserve, ten-minute reserve or thirty-minute reserve.[14]

For the preceding reasons, NS Power submits that alternative treatment of ELIADC load, focused only on the provision of reserve Ancillary Services, would not provide the intended benefits of the ELIADC Tariff. The Tariff was designed and vetted through a stakeholder process to maximize the benefit of the active demand control construct for NS Power customers.

(2) LIIR Interruptible Load

The use of LIIR interruptible load to meet operating reserve requirements on a day-ahead basis has challenges and has, therefore, not been used historically. From a day-ahead planning perspective, the LIIR interruptible load is difficult to forecast and may not materialize as expected. This load is made up of larger industrial customers whose daily load pattern may not repeat in a predictable fashion, making it difficult to forecast reliably. Basing a future operating reserve requirement on a product which may not materialize would be problematic for the System Operator and could lead to reliability issues.

[14] M10431 – NS Power Rebuttal Evidence, Exhibit N-102, page 139, lines 2-14. August 23, 2022.

The System Operator does not view alternative treatment of LIIR interruptible loads as a viable option for day-ahead reserve due to the limitation described above. LIIR interruptible load, while not suitable for day-ahead reserve planning, does provide value when used in real time to manage through capacity scarcity events. When the System Operator is managing through a period of reserve shortfall and capacity scarcity, access to the LIIR interruptible customers to provide some level of load relief helps to ensure reliable service for, and the continued ability to serve, firm load customers. However, as part of developing this consensus GRA, it was agreed that for the 2026-2027 test periods the costing approach will utilize 50 percent of the estimated average hourly demand of LIIR interruptible load as 10-minute operating reserve on a day ahead basis. With the average hourly interruptible load under the Large Industrial Rate class, estimated to be 70 MWs, the required 10 minute Supplemental capacity of 136 MWs is reduced by 35 MWs to 101 MWs for the pricing purposes of this service in tab "Anc Serv – Fig 6-8" of SR-01 attachments 11 and 13.

To this end, the System Operator has enhanced its operating practice for managing reserve by including LIIR interruptible load equipped with Telemetry and Control (LIIR T&C) toward its real-time 10-minute reserve requirement at all times and not just when it is not available from generation resources. LIIR T&C load differs from LIIR non-T&C load in that the System Operator has real-time visibility of LIIR T&C customer load to determine exactly how much load relief can be obtained whereas with non-T&C, the amount of potential load relief is unknown. In addition, LIIR T&C provides the System Operator with direct control such that if the LIIR T&C customer does not interrupt within 10 minutes when called upon to do so, then the System Operator can interrupt using its control capability, ensuring the load relief is realized.

4.2 Costing and Treatment for the -16 MW Component of AGC

In its Decision, the Board provided as follows:

> On the AGC issue and NS Power's treatment of the -16 MW requirement in its CBAS calculation, the Board views Mr. Marshall's concern worthy of further consideration. The Board notes Mr. Marshall's reference in Exhibit N-117 to FERC Order 890, paragraph 690, which was quoted as:

> "If the transmission provider elects to have separate demand charges assigned to customers for the purpose of recovering the cost of holding additional reserves for meeting imbalances, the transmission provider should file a rate schedule and demonstrate that these charges do not allow for double recovery of such costs."

Prior to the next GRA, NS Power is directed to explore alternative treatment of the -16 MW requirement and to demonstrate that it is not double charging transmission customers.[15]

NS Power has explored alternative costing treatment of the negative component of Regulation Service (-16 MW, Regulation Down) provided for in OATT Schedule 3 Regulation and Frequency Response Service. The Company maintains that the current costing methodology, which has been consistently applied to the total regulation requirement of 32 MW (and which has not varied since the inception of the OATT in 2005), adequately and fairly allocates capacity costs to the provision of Regulation Service.

Evidence in the Opening Statement of WKM Energy Consultants Inc. on behalf of the Municipal Electric Utilities provided as follows:

> 16. In Nova Scotia the generators that provide the -16 MW of AGC are also scheduled to deliver energy for NS Power customers, so this should not be included in the calculation of the AGC revenue requirement.
>
> 17. The current NS Power proposal for Schedule 3(a) (Regulation) is based on an AGC requirement of +/-16 MW for a total of 32 MW total done through a statistical analysis of NS Power net loads. Including the -16 MW component in the calculation is discriminatory and over charges wholesale market participants for AGC. The Revenue Requirement for Schedule 3(a) should be calculated using only the +16 MW component.[16]

Nova Scotia, as its own Balancing Authority, must balance load and generation within the province, measured by the Area Control Error (ACE) on the Nova Scotia-New Brunswick (NS-NB) tie-line. The NS-NB tie-line, which shares components with the New Brunswick-Prince Edward Island (NB-PE) tie-line, has no long-term firm transmission reservations, while the NB-PE tie-line has 300 MW of such reservations. To maintain transmission security limits, it is crucial

[15] M10431 – NSUARB Decision, 300864, page 184, para. 481-482.
[16] M10431 – WKM Opening Statement, Exhibit N-117, page 3. September 7, 2022.

to closely control ACE on the NB-NS tie-line. ACE changes can affect the stability of the transmission network, for instance: violations of transmission security limits may cause disruptions or outages. Relaxing AGC, and therefore increasing ACE, also risks imposing additional transfer margins that limit imports, beyond just NB, which may affect the availability and reliability of power supply. Adequate regulation capability is, therefore, needed to manage deviations in net load and variable generation, ensuring system stability. Based on its analysis of net load-variable generation deviations in the NS Balancing Area, NS Power has determined that it needs +/- 16 MW of regulation capability to adequately manage the system with the current level of variable generation and load behaviour.

NS Power submits that not allocating a separate quantity of capacity, separate from that used to serve the energy needs of load customers, does not adequately reflect the true cost of providing Regulation Down (Reg Down) service. For example, a dispatchable generator when operating at or near minimum generation limits, bottoms out on its ability to provide Reg Down service. That generator's capacity would still be supplying the energy needs of load customers; however, it cannot offer Reg Down service because its output cannot be lowered any further. Capacity for Reg Down service must be set aside separately from capacity used to serve the energy needs of load customers. This set-aside capacity is incremental to that allocated to serving energy, and so the cost of that set-aside capacity for Reg Down service must be recovered through the prescribed costing methodology, as has been the practice since the inception of the OATT.

The approach to costing Reg Down service is also consistent with operational practice. In day-ahead dispatch planning, generation capacity is allocated to serving the Reg Down service (in addition to Reg Up service) requirement, separate from capacity scheduled to serve load.

Considering this information, NS Power respectfully submits that there is no double-counting of capacity, and no change is required to the costing methodology, or the 32 MW regulation service requirement used in the calculation of the rate for OATT Schedule 3 Regulation and Frequency Response Service.

4.3 Wreck Cove Capacity in 10-Minute Reserve Costs Calculation

In its Decision the Board provided as follows:

> Regarding the suggestion that Wreck Cove capacity may be over-credited in the 10-minute spinning reserve costs calculation, the Board understands NS Power's evidence to be that the units are utilized for spinning reserve and for 10-minute supplementary reserve, so the CBAS charges reflect that actual use of those assets. However, considering Mr. Marshall's questioning of the calculation, NS Power is directed to clearly demonstrate, no later than in its next GRA, how the spinning reserve and 10-minute supplementary reserve utilization is represented in its calculations.[17] [emphasis added]

NS Power reviewed the Wreck Cove 1 and Wreck Cove 2 capacity utilization for Spinning Reserve and the associated calculations in Table E4-5 of the OATT cost allocation model submitted in the 2023-2024 GRA.[18]

The Spinning Reserve unit utilization and calculations presented in Table E4-5 are consistent with the methodology approved by the Board under the Consensus Proposal and NSPI's Supplementary Evidence of May 6, 2005.[19]

Since 2005, Wreck Cove facilities have continued to form part of the group of generating units that contribute to the Spinning Reserve service, and Wreck Cove capacity has been consistently allocated in the calculation of Spinning Reserve Service cost. As shown in the bold section of **Figure 4-1** (rows 16 and 17/columns I through M), Wreck Cove capacity has been allocated in similar amounts from period to period.

[17] M10431 – NSUARB Decision, 300864, page 185, para. 485.
[18] M10431, Exhibit N-1, SR-01 Att 19.
[19] The NSPI allocation is according to the Settlement Agreement reached between NSPI and its interveners from the OATT filing (M06341) with the NSUARB in 2005. All documents are available on the NSEB website under Matter no. M06341.

Figure 4-1 – Allocation of Generation Capacity to Spinning Reserve Since 2005

	A	B	C	D	E	F	G	H	I	J	K	L	M
	Unit				Name Plate				Generation in 10 Minutes				
	2005	2009	2013 and 2014	2023	2005	2009	2013 and 2014	2023	2005	2009	2013 and 2014	2014	2023
1	**Energy Requirement in MW**								**25**	**32**	**33**	**33**	**32**
2	Lingan 1	Lingan 1	Lingan 1	Lingan 1	150	150	150	150	10	10	10	10	10
3	Lingan 2	Lingan 2	Lingan 2	Lingan 2	150	150	150	150	10	10	10	10	10
4	Lingan 3	Lingan 3	Lingan 3	Lingan 3	150	150	150	150	10	10	10	10	10
5	Lingan 4	Lingan 4	Lingan 4	Lingan 4	150	150	150	150	10	7	10	10	10
6	Tufts Cove 1	Tufts Cove 1	Tufts Cove 1	Tufts Cove 1	100	100	100	100	0	0	0	0	0
7	Tufts Cove 2	Tufts Cove 2	Tufts Cove 2	Tufts Cove 2	100	100	100	100	15	15	15	15	15
8	Tufts Cove 3	Tufts Cove 3	Tufts Cove 3	Tufts Cove 3	150	150	150	150	15	15	15	15	15
9	Tufts Cove 4	Tufts Cove 4	Tufts Cove 4	Tufts Cove 4	54	47	54	54	0	0	13	13	19
10	Tufts Cove 5	Tufts Cove 5	Tufts Cove 5	Tufts Cove 5	54	47	54	54	0	0	16	16	17
11				Tufts Cove 6				46	0	0	0	0	10
12	Trenton 5	Trenton 5	Trenton 5	Trenton 5	150	150	150	150	10	10	0	0	10
13	Trenton 6	Trenton 6	Trenton 6	Trenton 6	160	160	160	160	12	13	18	18	20
14	Pt. Tupper 2	Pt. Tupper 2	Pt. Tupper 2	Pt. Tupper 2	150	150	150	150	10	10	10	10	10
15	Pt. Aconi 1	Pt. Aconi 1	Pt. Aconi 1	Pt. Aconi 1	185	165	185	185	0	0	0	0	0
16	**Wreck Cove 1**	**Wreck Cove 1**	**Wreck Cove 1**	**Wreck Cove 1**	**100**	**100**	**100**	**100**	**46**	**42**	**37**	**37**	**40**
17	**Wreck Cove 2**	**Wreck Cove 2**	**Wreck Cove 2**	**Wreck Cove 2**	**100**	**100**	**100**	**100**	**47**	**41**	**37**	**37**	**42**
18	Annapolis Tidal	Annapolis Tidal	Annapolis Tidal	Annapolis Tidal	17.2	17.2	17.2	0	0	0	0	0	0
19	Other Hydro	Other Hydro	Other Hydro	Other Hydro	163	163	163	163	0	0	0	0	0
20	Burnside 1	Burnside 1	Burnside 1	Burnside 1	30	30	30	30	11	11	17	17	23
21	Burnside 2	Burnside 2	Burnside 2	Burnside 2	30	30	30	30	10	12	15	15	23
22	Burnside 3	Burnside 3	Burnside 3	Burnside 3	30	30	30	30	12	13	17	17	23
23	Burnside 4	Burnside 4	Burnside 4	Burnside 4	30	30	30	30	10	30	30	30	24
24	Victoria Junction 1	Victoria Junction 1	Victoria Junction 1	Victoria Junction 1	30	30	30	30	10	14	25	25	29
25	Victoria Junction 2	Victoria Junction 2	Victoria Junction 2	Victoria Junction 2	30	30	30	30	10	16	30	30	29
26	Tusket 1	Tusket 1	Tusket 1	Tusket 1	24	24	24	30	12	23	16	16	24

NS Power has determined that the small variations in the capacity contribution of Wreck Cove used in the calculation of the Ancillary Services rate for Spinning Reserve result in an immaterial difference. Capping Wreck Cove at a 32 MW capacity contribution (the current requirement for Spinning Reserve) produces a 10-Minute Spinning Reserve weighted annual cost of $139.69/kW which is immaterially different by 0.2 percent as compared to the $139.98/kW rate used in the 2023-2024 GRA, presented in **Figure 4-2.** NS Power has capped the contribution of Wreck Cove to the 32 MW Spinning Reserve requirement in the calculation of the rate for Spinning Reserve service.

Figure 4-2 – Comparison of Spinning Reserve Rate: 2023 Rate Versus Rate with Wreck Cove Capped at the 32 MW Spinning Reserve Requirement

2023	2023 Rates	Wreck Cove Capped at 32MW usage	Variance	
			Amount	%
Service Required (MW)	32	32		
Usage MW	1,797	1,797		
Revenue Requirement	$4,479.46	$4,469.96	($9.50)	-0.2%
Rate for Network ($/MW-y	$2,492.74	$2,487.46	($5.29)	-0.2%
Lingan 1	$8.19	$8.48	$0.29	3.5%
Lingan 2	$5.99	$6.21	$0.21	3.5%
Lingan 3	$6.89	$7.14	$0.25	3.5%
Lingan 4	$8.13	$8.42	$0.29	3.5%
Tufts Cove 1	$0.00	$0.00	$0.00	0.0%
Tufts Cove 2	$1.58	$1.63	$0.06	3.5%
Tufts Cove 3	$2.61	$2.70	$0.09	3.5%
Tufts Cove 4	$15.04	$15.58	$0.54	3.5%
Tufts Cove 5	$11.09	$11.49	$0.40	3.5%
Tufts Cove 6	$1.77	$1.83	$0.06	3.5%
Trenton 5	$7.61	$7.88	$0.27	3.5%
Trenton 6	$29.41	$30.47	$1.06	3.5%
Pt. Tupper 2	$13.02	$13.48	$0.47	3.5%
Pt. Aconi 1	$0.00	$0.00	$0.00	0.0%
Wreck Cove 1	**$14.09**	**$11.56**	**($2.52)**	**-21.8%**
Wreck Cove 2	**$8.99**	**$7.02**	**($1.97)**	**-28.0%**
Annapolis Tidal	$0.00	$0.00	$0.00	0.0%
Other Hydro	$0.00	$0.00	$0.00	0.0%
Burnside 1	$0.37	$0.38	$0.01	3.5%
Burnside 2	$0.20	$0.21	$0.01	3.5%
Burnside 3	$0.26	$0.26	$0.01	3.5%
Burnside 4	$0.21	$0.22	$0.01	3.5%
Victoria Junction 1	$1.42	$1.47	$0.05	3.5%
Victoria Junction 2	$3.10	$3.21	$0.11	3.5%
Tusket 1	$0.03	$0.03	$0.00	3.5%
	$0.00	$0.00	$0.00	0.0%
the total weighted annual cost of the service	**$139.98**	**$139.69**	**($0.30)**	-0.2%

The cost calculations for Spinning Reserve and 10-Minute Supplemental Reserve, and their utilization of generating resources, including Wreck Cove, are represented in Tables E4-5 and E4-

6, respectively, of the 2026 and 2027 OATT Cost Allocation models[20] included with the GRA application and is further described in the sections that follow.

4.3.1 Spinning Reserve Service

Table E4-5 of the OATT allocation, **SR-01 Attachment 12** and **14** shows the calculations with implementation of the directives.

This section provides a step-by-step explanation of the methodology used to calculate the Ancillary Service rate.

Spinning Reserve is provided by online generating units that can adjust their contribution to NS Power's net generation in response to commands from the System Operator. These units must be running and synchronized to the power system. This is a service that must respond within 10-minutes of a contingency (such as the loss of a generator due to forced outage). The methodology evaluates the ability of each unit to respond to commands from the System Operator.

Rate Calculation Steps:

Referring to Table E4-5 in **SR-01 Attachment 12**, beginning at the leftmost column.

(1) Generation Units and Types

The first two columns (unnumbered) identify the generating unit and type which may contribute to the provision of Spinning Reserve.

(2) Generator Nameplate

Generator Nameplate (Column 1) is the maximum output (in MW) that a generator can produce.

(3) Net Book Value, Fixed Charge Rate, and the Product of These Two Representing the Potential Value

[20] 2026-2027 GRA SR -01 Att 12 and 2026-2027 GRA SR -01 Att 14.

Column 2 depicts the Net Book Value of the generator (in $/kW) while Column 3 provides the Fixed Charge Rate (in percent). Column 4 is the product of Net Book Value and Fixed Charge Rate (i.e. Column 2 * Column 3) providing the potential value (in $/kW) that may be allocated to the Ancillary Service cost.

(4) Annual Generation, Time Connected to Load, Average Generation, Equivalent Availability Factor, and Unit Response Rate

The Annual Generation (Column 5) is the output (in MWh) that each unit generated in the test year, as derived from operational data.

The Time Connected to Load (Column 6) is the number of hours in the year that the generator was connected to load, as derived from historical operational data.

Average Generation (Column 7) is calculated by dividing Annual Generation by the Time Connected to Load (i.e. Column 5 / Column 6) with the quotient expressed in MW. This value represents the average MW output for each generator across all hours it was online throughout the test year.

The Equivalent Availability Factor (Column 8) is a calculation of the percentage of time that each generator was available to operate throughout the test year, based on historical operational data.

The Unit Response Rate (Column 9), expressed in MW/minute, reflects the rate at which a generator can ramp its power output. This value is derived from operational data.

(5) Response 0 - 10 Min., Used (Yes/No), Actual Recallable Sales, Potential Reserve, Total Reserve, Unit/Inter. Contribution, and Weighted Annual Cost

The Response 0 - 10 Min. value (Column 10), expressed in MW, is calculated by taking the lesser of the generator's Unit Response Rate (Column 9) multiplied by 10 minutes or the Nameplate Capacity of the generator (Column 1). This value represents the amount of ramping (in MW) that the generator can contribute within 10 minutes.

Used (Yes/No) (Column 11) is a Boolean variable which indicates whether the generator contributes to the Ancillary Service and is included in the cost calculation. A value of "1" indicates a "Yes" the generator contributes and is included in the cost calculation, and vice versa for a value of "0" which indicates "No."

The Actual Recallable Sales (Column 12) is no longer applicable as per regulation change and is no longer used in the calculation.

The Potential Reserve (Column 13), expressed in MWh, is calculated by multiplying the ramping capability of the generator (Column 9), limited by available headroom from its average annual output (Column 7) to its nameplate capacity (Column 1), by its Time Connected to Load (Column 6). Applicable when Used (Column 11) is "Yes."

Total Reserve (Column 14) is equal to Potential Reserve (Column 13) since Actual Recallable Sales (Column 12) no longer applies as per regulation change.

Unit/Interruptible Load Contribution (Column 15) is calculated for each unit using Total Reserve (Column 14) for each unit divided by the sum of the Total Reserve (i.e., sum of Column 14) for all units; the quotient (Column 15) shows the percentage contribution of each unit to the Total Reserve for all units.

Weighted Annual Cost (Column 16) is then calculated for each generator by multiplying its Net Book Value (Column 2) by its Fixed Charge Rate (Column 3) by its Unit/Inter. Contribution (Column 15) to determine the cost contribution of each unit to the Ancillary Service rate (in $/kW).

The Weighted Annual Cost for each generator is then summed to determine the Spinning Reserve Ancillary Service rate (in $/kW).

4.3.2 Supplemental 10-Minute Reserve Service

Table E4-6 of the OATT allocation, **SR-01 Attachment 12** and **14** shows the calculations with implementation of the directives. The section that follows provides an explanation of the methodology used to calculate the Ancillary Services rate.

Supplemental 10-Minute Reserve is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather is available within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load.

Rate Calculation Steps:

The methodology and steps to calculate the rate for Supplemental 10-Minute Reserve Service are the same as those used above to calculate Spinning Reserve Service. Referring to Table E4-6 in **SR-01 Attachment 12** the only difference is at the step where the Used (Yes/No) (Column 11) is established. This step determines which generators contribute to the Supplemental 10-Minute Reserve Revenue Requirement and are thus included in the cost calculation for Supplemental 10-Minute Reserve Service.

4.4 Inclusion of Less Expensive Combustion Turbines in the Capacity Based Ancillary Service Costing Calculations for 30-Minute Supplemental Reserve

In its Decision, the Board provided as follows:

> Regarding inclusion of less expensive CTs in the CBAS costing calculations for 30-minute supplemental reserve, the Board understands NS Power's evidence to be that the CT contribution to that reserve capacity is negligible, so it is not factored into the calculation. Considering that there are currently seven units in service, the Board finds NS Power's explanation to be lacking and directs that a more fulsome explanation be provided, no later than in its next GRA, to justify its position in this matter.[21]

[21] M10431 – NSUARB Decision, 300864, page 185, para. 486.

Since the inception of the OATT in 2005, the costing methodology for the calculation of 30-Minute Supplemental Reserve Ancillary Service has remained largely unchanged. Since that time, the power system has begun a transformation from a system with large base-loaded, dispatchable generators to one with a large and growing penetration of variable renewable energy resources.

Considering this evolution of the power system to include a higher penetration of renewable generation which is variable and its impact on dispatch, NS Power conducted an analysis of historical day-ahead dispatch plans for the years 2021 to 2023. On average, the Combustion Turbines (CTs) were dispatched to fulfill approximately 35 percent of the 30-Minute Supplemental Reserve requirement each hour.

Given this change, NS Power has adjusted the cost allocation in this GRA application for 30-Minute Supplemental Reserve to account for the contribution that CTs make in the provision of 30-Minute reserve, as per this analysis. These changes have been implemented as part of this General Rate Application in **SR-01 Attachment 12** and **14**.

2026-2027 SR-01 Partially Confidential Attachment 2 has been removed due to confidentiality.

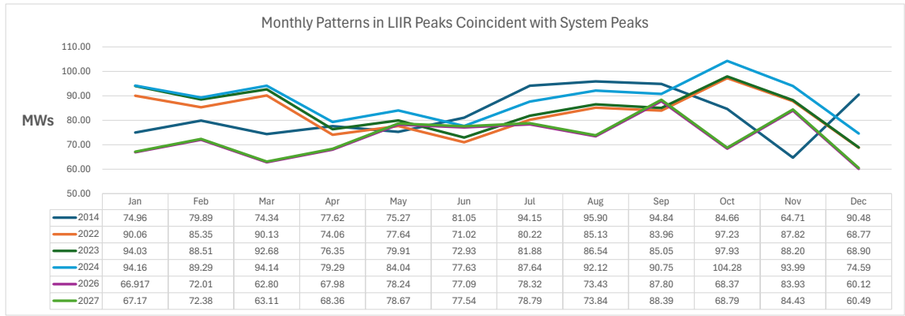
2026-2027 SR-01 Partially Confidential Attachment 3 has been removed due to confidentiality.

Preliminary Interruptible Credit Calculations for test years 2026 - 2027

	1996 GRA	2013 GRA	2022 GRA	2023 GRA	2024 GRA	2026 GRA	2027 GRA
Determination of Unit Avoided Marginal Generation Capacity Cost							
Annual Cost of Load Served ($/kW, in 1994 dollars)	($60.625)	($60.625)	NA	NA	NA	NA	NA
Annual Cost of Load Served ($/kW, in 1994 dollars) adjusted for annual inflation of 2%	($63.074)	($63.074)	NA	NA	NA	NA	NA
Annual Avoided Cost rounded to nearest dollar in 1996	($63.000)	($63.000)	($130.978)	($130.978)	($130.978)	($160.435)	($160.435)
% Change from 1996 Benchmark		0.0%	107.9%	107.9%	107.9%	22.5%	22.5%
Determination of Intrruptible Credit							
System Coincident Demand (kW)	202,000	79,894	90,060	94,030	94,160	66,917	67,170
Total Annual Avoided Cost	($12,726,000)	($5,033,294)	($11,795,850)	($12,315,831)	($12,332,858)	($10,735,827)	($10,776,394)
Annual total of monthly non-coincident kVA demands	3,700,000	1,595,907	1,592,284	1,645,190	1,698,121	1,405,560	1,405,560
Interruptible Credit ($/kVA/month)	**($3.430)**	**($3.430)**	**($7.408)**	**($7.486)**	**($7.263)**	**($7.638)**	**($7.667)**
		0.0%	116.0%	118.2%	-3.0%	2.0%	2.4%
Anticipated Revenue Credit	($12,691,000)	($5,473,962)	($11,795,850)	($12,315,831)	($12,332,858)	($10,735,827)	($10,776,394)
Variance between Allocated Costs and Anticipated Credit payout	$35,000	($440,668)	$0	$0	$0	$0	$0
Excess Credit Paid as a % of total avoided costs	-0.3%	8.8%	0.0%	0.0%	0.0%	0.0%	0.0%
	($3.44)						

Test Year Volatility in Large Industrial Interruptible Customers' Monthly Demands Coincident with System Peaks (MWs)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Demand coincident with System	Test Year Annual System Peak Month	Maximum Coincident Demand
2014	74.96	79.89	74.34	77.62	75.27	81.05	94.15	95.90	94.84	84.66	64.71	90.48	**79.89**	February	95.90
2022	90.06	85.35	90.13	74.06	77.64	71.02	80.22	85.13	83.96	97.23	87.82	68.77	**90.06**	January	97.23
2023	94.03	88.51	92.68	76.35	79.91	72.93	81.88	86.54	85.05	97.93	88.20	68.90	**94.03**	January	97.93
2024	94.16	89.29	94.14	79.29	84.04	77.63	87.64	92.12	90.75	104.28	93.99	74.59	**94.16**	January	104.28
2026	66.917	72.01	62.80	67.98	78.24	77.09	78.32	73.43	87.80	68.37	83.93	60.12	**66.92**	Sept	87.80
2027	67.17	72.38	63.11	68.36	78.67	77.54	78.79	73.84	88.39	68.79	84.43	60.49	**67.17**	Sept	88.39



Input Assumptions
1. Capital costs are for a 50MW combustion Turbine (Frame) from E3 Resource Option Study using 2024 nominal values;
2. Fixed Operating costs are derived from E3 Resource Option Study using 2024 nominal values
3. Screening level costing assumes AFUDC is incorporated into System Cost (capital cost)
4. No cost assumptions for Administrative Overhead
5. Pro Forma statement and associated accounting treatments are simplified for screening purposes - reflecting substantially NSPI's accounting treatments and costs of capital for new generation resources;
6. FO&M costs are ecalated annually at 2%

Peaker Deferral Method
Summary Outputs
Updated 6/26/2024

Year	Equivalent Escalating Series ($/kW-Yr)	Levelized ($/kW-Yr)
2024	$ 124.75	$ 160.44
2025	$ 127.25	$ 160.44
2026	$ 129.79	$ 160.44
2027	$ 132.39	$ 160.44
2028	$ 135.04	$ 160.44
2029	$ 137.74	$ 160.44
2030	$ 140.49	$ 160.44
2031	$ 143.30	$ 160.44
2032	$ 146.17	$ 160.44
2033	$ 149.09	$ 160.44
2034	$ 152.07	$ 160.44
2035	$ 155.11	$ 160.44
2036	$ 158.22	$ 160.44
2037	$ 161.38	$ 160.44
2038	$ 164.61	$ 160.44
2039	$ 167.90	$ 160.44
2040	$ 171.26	$ 160.44
2041	$ 174.68	$ 160.44
2042	$ 178.18	$ 160.44
2043	$ 181.74	$ 160.44
2044	$ 185.38	$ 160.44
2045	$ 189.08	$ 160.44
2046	$ 192.87	$ 160.44
2047	$ 196.72	$ 160.44
2048	$ 200.66	$ 160.44

Peaker Deferral Method (PDM) - Simplified Pro Forma Model

Resource Cost, Performance, & Financing

System Cost	
System Size (MW)	50
System Cost ($/kW)	$1,339
System Cost ($)	$66,971,299
Total System Cost ($)	$66,971,299

Performance Inputs	
System Depreciable Lifetime	35

Ongoing Costs	
Fixed O&M Costs ($/kW-yr)	$20.45
Fixed O&M Costs Escalator (%/yr)	2.00%

Income Tax Assumptions	
Income Tax - Statutory Tax Rate	29.0%
Capital Cost Allowance (CCA)	17 - 8%

Vintage	
Available Year	2024

Financing	
% Financed w/ equity	40.0%
% Financed w/ debt	60.0%
Debt Interest rate	5.21%
Cost of Equity	9.0%
Debt period in years	35
Pre-tax WACC	6.72%
Inflation Rate	2.00%
Equity Amount	$26,788,520
Debt Amount	$40,182,780

Outputs	Equiv. Escalating (2024) $/kW-yr	Levelized $/kW-yr
Capital	$100.74	$129.55
Current Tax Savings	($17.22)	($22.15)
Fixed O&M	$20.45	$26.29
Total	**$103.96**	**$133.70**
PRM Adjusted (20% adder)	**$124.75**	**$160.44**

IOU Pro Forma

Year	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Debt Term Flag		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Capital Cost		$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299
Starting Rate Base		$66,971,299	$65,057,834	$63,144,368	$61,230,902	$59,317,436	$57,403,971	$55,490,505	$53,577,039	$51,663,574	$49,750,108	$47,836,642	$45,923,177	$44,009,711	$42,096,245	$40,182,780	$38,269,314	$36,355,848
Accumulated Depreciation		($1,913,466)	($3,826,931)	($5,740,397)	($7,653,863)	($9,567,328)	($11,480,794)	($13,394,260)	($15,307,726)	($17,221,191)	($19,134,657)	($21,048,123)	($22,961,588)	($24,875,054)	($26,788,520)	($28,701,985)	($30,615,451)	($32,528,917)
Ending Balance Rate Base	$66,971,299	$65,057,834	$63,144,368	$61,230,902	$59,317,436	$57,403,971	$55,490,505	$53,577,039	$51,663,574	$49,750,108	$47,836,642	$45,923,177	$44,009,711	$42,096,245	$40,182,780	$38,269,314	$36,355,848	$34,442,382
Debt																		
Beginning Balance		$40,182,780	$39,034,700	$37,886,621	$36,738,541	$35,590,462	$34,442,382	$33,294,303	$32,146,224	$30,998,144	$29,850,065	$28,701,985	$27,553,906	$26,405,827	$25,257,747	$24,109,668	$22,961,588	$21,813,509
Interest		$2,091,570	$2,031,810	$1,972,051	$1,912,292	$1,852,533	$1,792,774	$1,733,015	$1,673,256	$1,613,497	$1,553,737	$1,493,978	$1,434,219	$1,374,460	$1,314,701	$1,254,942	$1,195,183	$1,135,423
Principal		$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079
Equity																		
Beginning Balance		$26,788,520	$26,023,133	$25,257,747	$24,492,361	$23,726,975	$22,961,588	$22,196,202	$21,430,816	$20,665,429	$19,900,043	$19,134,657	$18,369,271	$17,603,884	$16,838,498	$16,073,112	$15,307,726	$14,542,339
Equity Return		$2,410,967	$2,342,082	$2,273,197	$2,204,312	$2,135,428	$2,066,543	$1,997,658	$1,928,773	$1,859,889	$1,791,004	$1,722,119	$1,653,234	$1,584,350	$1,515,465	$1,446,580	$1,377,695	$1,308,811
Return of Invested Equity		$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386
Book Equity Return		$3,176,353	$3,107,468	$3,038,584	$2,969,699	$2,900,814	$2,831,929	$2,763,044	$2,694,160	$2,625,275	$2,556,390	$2,487,505	$2,418,621	$2,349,736	$2,280,851	$2,211,966	$2,143,082	$2,074,197
Taxes																		
Equity Return		$2,410,967	$2,342,082	$2,273,197	$2,204,312	$2,135,428	$2,066,543	$1,997,658	$1,928,773	$1,859,889	$1,791,004	$1,722,119	$1,653,234	$1,584,350	$1,515,465	$1,446,580	$1,377,695	$1,308,811
Tax on Equity Return		$699,180	$679,204	$659,227	$639,251	$619,274	$599,297	$579,321	$559,344	$539,368	$519,391	$499,415	$479,438	$459,461	$439,485	$419,508	$399,532	$379,555
Tax Grossup - Equity		$285,581	$277,421	$269,262	$261,102	$252,943	$244,783	$236,624	$228,465	$220,305	$212,146	$203,986	$195,827	$187,667	$179,508	$171,348	$163,189	$155,030
Revenue Requirement																		
Fixed O&M		$1,042,736	$1,063,591	$1,084,863	$1,106,560	$1,128,691	$1,151,265	$1,174,291	$1,197,776	$1,221,732	$1,246,167	$1,271,090	$1,296,512	$1,322,442	$1,348,891	$1,375,869	$1,403,386	$1,431,454
Interest		$2,091,570	$2,031,810	$1,972,051	$1,912,292	$1,852,533	$1,792,774	$1,733,015	$1,673,256	$1,613,497	$1,553,737	$1,493,978	$1,434,219	$1,374,460	$1,314,701	$1,254,942	$1,195,183	$1,135,423
Equity Return		$2,410,967	$2,342,082	$2,273,197	$2,204,312	$2,135,428	$2,066,543	$1,997,658	$1,928,773	$1,859,889	$1,791,004	$1,722,119	$1,653,234	$1,584,350	$1,515,465	$1,446,580	$1,377,695	$1,308,811
Depreciation		$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466
Tax grossup - Depreciation		$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556
Impact of CCA deduction		($2,188,358)	($2,013,289)	($1,852,226)	($1,704,048)	($1,567,724)	($1,442,306)	($1,326,922)	($1,220,768)	($1,123,107)	($1,033,258)	($950,597)	($874,550)	($804,586)	($740,219)	($681,001)	($626,521)	($576,400)
Tax on Equity Return - before grossup		$699,180	$679,204	$659,227	$639,251	$619,274	$599,297	$579,321	$559,344	$539,368	$519,391	$499,415	$479,438	$459,461	$439,485	$419,508	$399,532	$379,555
Tax Grossup - Equity		$285,581	$277,421	$269,262	$261,102	$252,943	$244,783	$236,624	$228,465	$220,305	$212,146	$203,986	$195,827	$187,667	$179,508	$171,348	$163,189	$155,030
Total Revenue Requirement		**$7,036,698**	**$7,075,841**	**$7,101,396**	**$7,114,492**	**$7,116,167**	**$7,107,379**	**$7,089,009**	**$7,061,868**	**$7,026,705**	**$6,984,209**	**$6,935,013**	**$6,879,702**	**$6,818,817**	**$6,752,852**	**$6,682,268**	**$6,607,485**	**$6,528,895**
Accumulated Deferred Income Tax																		
Book Depreciation		$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466
CCA Schedule		8.00%	7.36%	6.77%	6.23%	5.73%	5.27%	4.85%	4.46%	4.11%	3.78%	3.48%	3.20%	2.94%	2.71%	2.49%	2.29%	2.11%
CCA Depreciation		$5,357,704	$4,929,088	$4,534,761	$4,171,980	$3,838,221	$3,531,164	$3,248,671	$2,988,777	$2,749,675	$2,529,701	$2,327,325	$2,141,139	$1,969,848	$1,812,260	$1,667,279	$1,533,897	$1,411,185
CCA Tax Savings		($2,188,358)	($2,013,289)	($1,852,226)	($1,704,048)	($1,567,724)	($1,442,306)	($1,326,922)	($1,220,768)	($1,123,107)	($1,033,258)	($950,597)	($874,550)	($804,586)	($740,219)	($681,001)	($626,521)	($576,400)
Check of Book Taxes																		
Revenue		$7,036,698	$7,075,841	$7,101,396	$7,114,492	$7,116,167	$7,107,379	$7,089,009	$7,061,868	$7,026,705	$6,984,209	$6,935,013	$6,879,702	$6,818,817	$6,752,852	$6,682,268	$6,607,485	$6,528,895
Expenses		$1,042,736	$1,063,591	$1,084,863	$1,106,560	$1,128,691	$1,151,265	$1,174,291	$1,197,776	$1,221,732	$1,246,167	$1,271,090	$1,296,512	$1,322,442	$1,348,891	$1,375,869	$1,403,386	$1,431,454
Operating Profit		$5,993,962	$6,012,250	$6,016,534	$6,007,932	$5,987,476	$5,956,114	$5,914,718	$5,864,092	$5,804,974	$5,738,042	$5,663,923	$5,583,191	$5,496,375	$5,403,962	$5,306,399	$5,204,099	$5,097,441
Interest		$2,091,570	$2,031,810	$1,972,051	$1,912,292	$1,852,533	$1,792,774	$1,733,015	$1,673,256	$1,613,497	$1,553,737	$1,493,978	$1,434,219	$1,374,460	$1,314,701	$1,254,942	$1,195,183	$1,135,423
Book Depreciation		$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466
Income		$1,988,926	$2,066,974	$2,131,017	$2,182,174	$2,221,477	$2,249,874	$2,268,238	$2,277,371	$2,278,011	$2,270,839	$2,256,479	$2,235,506	$2,208,449	$2,175,795	$2,137,992	$2,095,451	$2,048,552
Taxes		($422,040)	($275,108)	($142,181)	($22,139)	$86,049	$183,331	$270,580	$348,597	$418,123	$479,835	$534,360	$582,272	$624,099	$660,330	$691,412	$717,756	$739,741
After-tax income		$2,410,967	$2,342,082	$2,273,197	$2,204,312	$2,135,428	$2,066,543	$1,997,658	$1,928,773	$1,859,889	$1,791,004	$1,722,119	$1,653,234	$1,584,350	$1,515,465	$1,446,580	$1,377,695	$1,308,811
Check of book equity return																		
Earnings		$2,410,967	$2,342,082	$2,273,197	$2,204,312	$2,135,428	$2,066,543	$1,997,658	$1,928,773	$1,859,889	$1,791,004	$1,722,119	$1,653,234	$1,584,350	$1,515,465	$1,446,580	$1,377,695	$1,308,811
Book Equity		$26,788,520	$26,023,133	$25,257,747	$24,492,361	$23,726,975	$22,961,588	$22,196,202	$21,430,816	$20,665,429	$19,900,043	$19,134,657	$18,369,271	$17,603,884	$16,838,498	$16,073,112	$15,307,726	$14,542,339
ROE		9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%
Rev Requirement by Functional Category																		
Capital Costs		$8,182,320	$8,025,540	$7,868,760	$7,711,980	$7,555,200	$7,398,420	$7,241,640	$7,084,860	$6,928,080	$6,771,300	$6,614,520	$6,457,740	$6,300,960	$6,144,180	$5,987,401	$5,830,621	$5,673,841
CCA Tax Savings		($2,188,358)	($2,013,289)	($1,852,226)	($1,704,048)	($1,567,724)	($1,442,306)	($1,326,922)	($1,220,768)	($1,123,107)	($1,033,258)	($950,597)	($874,550)	($804,586)	($740,219)	($681,001)	($626,521)	($576,400)
Fixed Operations & Maintenance		$1,042,736	$1,063,591	$1,084,863	$1,106,560	$1,128,691	$1,151,265	$1,174,291	$1,197,776	$1,221,732	$1,246,167	$1,271,090	$1,296,512	$1,322,442	$1,348,891	$1,375,869	$1,403,386	$1,431,454
Total		$7,036,698	$7,075,841	$7,101,396	$7,114,492	$7,116,167	$7,107,379	$7,089,009	$7,061,868	$7,026,705	$6,984,209	$6,935,013	$6,879,702	$6,818,817	$6,752,852	$6,682,268	$6,607,485	$6,528,895
CHECK		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Discount Rate	6.72%
Real Discount Rate	4.63%
NPV Capacity (Real) - Equiv. Escal. Series	858,337
NPV Capacity (Nominal) - Levelized	667,435

Canadian Capital Cost Allowance (CCA) Schedules

CCA Schedules (Class - DB %)	Term	Start Year	End Year	This Schedule?	1	2	3	4	5	6	7	8	9	10	11	12	13	14
	17 - 8%	2024	2027	Y	8%	7%	7%	6%	6%	5%	5%	4%	4%	4%	3%	3%	3%	3%

erral Method (PDM) - Simplified Pro Forma Model

Resource Cost, Performance, & Financing

System Cost
System Size (MW)
System Cost ($/kW)
System Cost ($)

Total System Cost ($)

Performance Inputs
System Depreciable Lifetime

Ongoing Costs
Fixed O&M Costs ($/kW-yr)
Fixed O&M Costs Escalator (%/yr)

IOU Pro Forma

Year	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37	38	39	40
Debt Term Flag	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0	0	0
Capital Cost	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$66,971,299	$0	$0	$0	$0	$0
Starting Rate Base	$34,442,382	$32,528,917	$30,615,451	$28,701,985	$26,788,520	$24,875,054	$22,961,588	$21,048,123	$19,134,657	$17,221,191	$15,307,726	$13,394,260	$11,480,794	$9,567,328	$7,653,863	$5,740,397	$3,826,931	$1,913,466	$0	$0	$0	$0	$0
Accumulated Depreciation	($34,442,382)	($36,355,848)	($38,269,314)	($40,182,780)	($42,096,245)	($44,009,711)	($45,923,177)	($47,836,642)	($49,750,108)	($51,663,574)	($53,577,039)	($55,490,505)	($57,403,971)	($59,317,436)	($61,230,902)	($63,144,368)	($65,057,834)	($66,971,299)	$0	$0	$0	$0	$0
Ending Balance Rate Base	$32,528,917	$30,615,451	$28,701,985	$26,788,520	$24,875,054	$22,961,588	$21,048,123	$19,134,657	$17,221,191	$15,307,726	$13,394,260	$11,480,794	$9,567,328	$7,653,863	$5,740,397	$3,826,931	$1,913,466	$0	$0	$0	$0	$0	$0
Debt																							
Beginning Balance	$20,665,429	$19,517,350	$18,369,271	$17,221,191	$16,073,112	$14,925,032	$13,776,953	$12,628,874	$11,480,794	$10,332,715	$9,184,635	$8,036,556	$6,888,476	$5,740,397	$4,592,318	$3,444,238	$2,296,159	$1,148,079	$0	$0	$0	$0	$0
Interest	$1,075,664	$1,015,905	$956,146	$896,387	$836,628	$776,869	$717,110	$657,350	$597,591	$537,832	$478,073	$418,314	$358,555	$298,796	$239,037	$179,277	$119,518	$59,759	$0	$0	$0	$0	$0
Principal	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$1,148,079	$0	$0	$0	$0	$0
Equity																							
Beginning Balance	$13,776,953	$13,011,567	$12,246,180	$11,480,794	$10,715,408	$9,950,022	$9,184,635	$8,419,249	$7,653,863	$6,888,476	$6,123,090	$5,357,704	$4,592,318	$3,826,931	$3,061,545	$2,296,159	$1,530,773	$765,386	$0	$0	$0	$0	$0
Equity Return	$1,239,926	$1,171,041	$1,102,156	$1,033,271	$964,387	$895,502	$826,617	$757,732	$688,848	$619,963	$551,078	$482,193	$413,309	$344,424	$275,539	$206,654	$137,770	$68,885	$0	$0	$0	$0	$0
Return of Invested Equity	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$765,386	$0	$0	$0	$0	$0
Book Equity Return	$2,005,312	$1,936,427	$1,867,543	$1,798,658	$1,729,773	$1,660,888	$1,592,003	$1,523,119	$1,454,234	$1,385,349	$1,316,464	$1,247,580	$1,178,695	$1,109,810	$1,040,925	$972,041	$903,156	$834,271	$0	$0	$0	$0	$0
Taxes																							
Equity Return	$1,239,926	$1,171,041	$1,102,156	$1,033,271	$964,387	$895,502	$826,617	$757,732	$688,848	$619,963	$551,078	$482,193	$413,309	$344,424	$275,539	$206,654	$137,770	$68,885	$0	$0	$0	$0	$0
Tax on Equity Return	$359,578	$339,602	$319,625	$299,649	$279,672	$259,696	$239,719	$219,742	$199,766	$179,789	$159,813	$139,836	$119,859	$99,883	$79,906	$59,930	$39,953	$19,977	$0	$0	$0	$0	$0
Tax Grossup - Equity	$146,870	$138,711	$130,551	$122,392	$114,232	$106,073	$97,913	$89,754	$81,594	$73,435	$65,276	$57,116	$48,957	$40,797	$32,638	$24,478	$16,319	$8,159	$0	$0	$0	$0	$0
Revenue Requirement																							
Fixed O&M	$1,460,083	$1,489,284	$1,519,070	$1,549,451	$1,580,440	$1,612,049	$1,644,290	$1,677,176	$1,710,720	$1,744,934	$1,779,833	$1,815,429	$1,851,738	$1,888,773	$1,926,548	$1,965,079	$2,004,381	$2,044,468	$0	$0	$0	$0	$0
Interest	$1,075,664	$1,015,905	$956,146	$896,387	$836,628	$776,869	$717,110	$657,350	$597,591	$537,832	$478,073	$418,314	$358,555	$298,796	$239,037	$179,277	$119,518	$59,759	$0	$0	$0	$0	$0
Equity Return	$1,239,926	$1,171,041	$1,102,156	$1,033,271	$964,387	$895,502	$826,617	$757,732	$688,848	$619,963	$551,078	$482,193	$413,309	$344,424	$275,539	$206,654	$137,770	$68,885	$0	$0	$0	$0	$0
Depreciation	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$0	$0	$0	$0	$0
Tax grossup - Depreciation	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$781,556	$0	$0	$0	$0	$0
Impact of CCA deduction	($530,288)	($487,865)	($448,835)	($412,929)	($379,894)	($349,503)	($321,543)	($295,819)	($272,154)	($250,381)	($230,351)	($211,923)	($194,969)	($179,371)	($165,022)	($151,820)	($139,674)	($128,500)	$0	$0	$0	$0	$0
Tax on Equity Return - before grossup	$359,578	$339,602	$319,625	$299,649	$279,672	$259,696	$239,719	$219,742	$199,766	$179,789	$159,813	$139,836	$119,859	$99,883	$79,906	$59,930	$39,953	$19,977	$0	$0	$0	$0	$0
Tax Grossup - Equity	$146,870	$138,711	$130,551	$122,392	$114,232	$106,073	$97,913	$89,754	$81,594	$73,435	$65,276	$57,116	$48,957	$40,797	$32,638	$24,478	$16,319	$8,159	$0	$0	$0	$0	$0
Total Revenue Requirement	**$6,446,856**	**$6,361,701**	**$6,273,736**	**$6,183,244**	**$6,090,487**	**$5,995,708**	**$5,899,129**	**$5,800,958**	**$5,701,387**	**$5,600,594**	**$5,498,743**	**$5,395,988**	**$5,292,471**	**$5,188,323**	**$5,083,668**	**$4,978,621**	**$4,873,288**	**$4,767,770**	**$0**	**$0**	**$0**	**$0**	**$0**
Accumulated Deferred Income Tax																							
Book Depreciation	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$0	$0	$0	$0	$0
CCA Schedule	1.94%	1.78%	1.64%	1.51%	1.39%	1.28%	1.18%	1.08%	0.99%	0.92%	0.84%	0.77%	0.71%	0.66%	0.60%	0.56%	0.51%	0.47%	0.00%	0.00%	0.00%	0.00%	0.00%
CCA Depreciation	$1,298,290	$1,194,427	$1,098,873	$1,010,963	$930,086	$855,679	$787,225	$724,247	$666,307	$613,002	$563,962	$518,845	$477,338	$439,151	$404,019	$371,697	$341,961	$314,604	$0	$0	$0	$0	$0
CCA Tax Savings	($530,288)	($487,865)	($448,835)	($412,929)	($379,894)	($349,503)	($321,543)	($295,819)	($272,154)	($250,381)	($230,351)	($211,923)	($194,969)	($179,371)	($165,022)	($151,820)	($139,674)	($128,500)	$0	$0	$0	$0	$0
Check of Book Taxes																							
Revenue	$6,446,856	$6,361,701	$6,273,736	$6,183,244	$6,090,487	$5,995,708	$5,899,129	$5,800,958	$5,701,387	$5,600,594	$5,498,743	$5,395,988	$5,292,471	$5,188,323	$5,083,668	$4,978,621	$4,873,288	$4,767,770	$0	$0	$0	$0	$0
Expenses	$1,460,083	$1,489,284	$1,519,070	$1,549,451	$1,580,440	$1,612,049	$1,644,290	$1,677,176	$1,710,720	$1,744,934	$1,779,833	$1,815,429	$1,851,738	$1,888,773	$1,926,548	$1,965,079	$2,004,381	$2,044,468	$0	$0	$0	$0	$0
Operating Profit	$4,986,773	$4,872,416	$4,754,666	$4,633,792	$4,510,047	$4,383,658	$4,254,839	$4,123,782	$3,990,668	$3,855,660	$3,718,911	$3,580,559	$3,440,733	$3,299,550	$3,157,120	$3,013,542	$2,868,908	$2,723,302	$0	$0	$0	$0	$0
Interest	$1,075,664	$1,015,905	$956,146	$896,387	$836,628	$776,869	$717,110	$657,350	$597,591	$537,832	$478,073	$418,314	$358,555	$298,796	$239,037	$179,277	$119,518	$59,759	$0	$0	$0	$0	$0
Book Depreciation	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$1,913,466	$0	$0	$0	$0	$0
Income	$1,997,643	$1,943,045	$1,885,054	$1,823,940	$1,759,953	$1,693,324	$1,624,263	$1,552,966	$1,479,611	$1,404,362	$1,327,372	$1,248,779	$1,168,712	$1,087,289	$1,004,618	$920,799	$835,924	$750,077	$0	$0	$0	$0	$0
Taxes	$757,717	$772,004	$782,898	$790,668	$795,567	$797,822	$797,646	$795,234	$790,763	$784,399	$776,294	$766,586	$755,404	$742,865	$729,079	$714,145	$698,154	$681,192	$0	$0	$0	$0	$0
After-tax income	$1,239,926	$1,171,041	$1,102,156	$1,033,271	$964,387	$895,502	$826,617	$757,732	$688,848	$619,963	$551,078	$482,193	$413,309	$344,424	$275,539	$206,654	$137,770	$68,885	$0	$0	$0	$0	$0
Check of book equity return																							
Earnings	$1,239,926	$1,171,041	$1,102,156	$1,033,271	$964,387	$895,502	$826,617	$757,732	$688,848	$619,963	$551,078	$482,193	$413,309	$344,424	$275,539	$206,654	$137,770	$68,885	$0	$0	$0	$0	$0
Book Equity	$13,776,953	$13,011,567	$12,246,180	$11,480,794	$10,715,408	$9,950,022	$9,184,635	$8,419,249	$7,653,863	$6,888,476	$6,123,090	$5,357,704	$4,592,318	$3,826,931	$3,061,545	$2,296,159	$1,530,773	$765,386	$0	$0	$0	$0	$0
ROE	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	9.000%	0.000%	0.000%	0.000%	0.000%	0.000%
Rev Requirement by Functional Category																							
Capital Costs	$5,517,061	$5,360,281	$5,203,501	$5,046,721	$4,889,941	$4,733,161	$4,576,381	$4,419,601	$4,262,821	$4,106,041	$3,949,262	$3,792,482	$3,635,702	$3,478,922	$3,322,142	$3,165,362	$3,008,582	$2,851,802	$0	$0	$0	$0	$0
CCA Tax Savings	($530,288)	($487,865)	($448,835)	($412,929)	($379,894)	($349,503)	($321,543)	($295,819)	($272,154)	($250,381)	($230,351)	($211,923)	($194,969)	($179,371)	($165,022)	($151,820)	($139,674)	($128,500)	$0	$0	$0	$0	$0
Fixed Operations & Maintenance	$1,460,083	$1,489,284	$1,519,070	$1,549,451	$1,580,440	$1,612,049	$1,644,290	$1,677,176	$1,710,720	$1,744,934	$1,779,833	$1,815,429	$1,851,738	$1,888,773	$1,926,548	$1,965,079	$2,004,381	$2,044,468	$0	$0	$0	$0	$0
Total	$6,446,856	$6,361,701	$6,273,736	$6,183,244	$6,090,487	$5,995,708	$5,899,129	$5,800,958	$5,701,387	$5,600,594	$5,498,743	$5,395,988	$5,292,471	$5,188,323	$5,083,668	$4,978,621	$4,873,288	$4,767,770	$0	$0	$0	$0	$0
	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Discount Rate
Real Discount Rate
NPV Capacity (Real) - Equiv. Escal. Series
NPV Capacity (Nominal) - Levelized

Canadian Capital Cost Allowance (CCA) Schedules

CCA Schedules (Class - DB %)	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33	34	35	36	37
	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	0%	0%	0%

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

FOR THE YEAR ENDING DECEMBER 31, 2026

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L
1			Cost Allocation Factors										
2			3 CP Demands		Energy Requirement					Purchased Power- Biomass			
3													
4	Rate Class	R/C Ratios	KW Demand	Relative Shares of Embedded Cost Classes	KWh Energy	Relative Shares of Embedded Cost Classes	kWhs Sales	Fuel Costs before Purchased Power	Imports (allocated on monthly energy requirements)	Bio-fuel Related (allocated on monthly energy requirements)	Energy-related (allocated on annual energy requirements)	Demand-related	Total
5	FAM Rate Classes (ATL)												
6	Residential	97.180%	4,353,838	64.027806%	5,644,778,858	49.7998%	5,213,776,964	$220,605,297	$44,140,315	$4,108,568	$3,130,679	$3,446,385	$10,685,632
7	Small General	103.50%	222,264	3.26862%	382,310,202	3.37%	353,433,715	$14,745,827	$3,171,069	$285,586	$219,195	$175,938	$680,719
8	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	$1,801,772	$1,401,750	$954,731	$4,158,253
9	Large General	104.38%	137,482	2.02182%	376,587,283	3.32%	358,568,276	$14,102,288	$3,451,531	$289,502	$230,084	$108,827	$628,413
10	Small Industrial	104.38%	123,550	1.81693%	274,651,533	2.42%	255,141,808	$10,377,461	$2,422,479	$209,886	$162,174	$97,799	$469,859
11	Medium Industrial	104.38%	158,818	2.33558%	467,931,323	4.13%	438,584,616	$17,476,489	$4,259,468	$356,316	$279,641	$125,716	$761,673
12	Large Industrial	104.38%	246,525	3.62541%	722,193,823	6.37%	697,602,851	$26,846,935	$6,707,581	$551,396	$437,072	$195,143	$1,183,611
13	PHP	104.38%	203,227	2.98867%	829,996,205	7.32%	810,547,200	$30,393,954	$7,924,664	$623,117	$510,890	$160,869	$1,294,877
14	Municipal	104.38%	93,931	1.38135%	128,549,631	1.13%	124,528,392	$5,082,900	$975,982	$92,645	$70,502	$74,353	$237,501
15	Unmetered	100.00%	31,520	0.46353%	83,275,289	0.73%	77,000,000	$3,105,001	$759,730	$63,255	$49,732	$24,950	$137,937
16	Total	100.00%	6,777,270	99.66695%	11,303,785,142	99.73%	10,548,590,219	$434,032,883	$94,390,785	$8,382,044	$6,491,719	$5,364,712	$20,238,476
17													
18	Purchased Power Allocation Factors.									41.4%	32.1%	26.5121%	100.0%
19													
20	Non-FAM Rate Classes												
21	BUTU	100.00%											
22	GRLF	100.00%											
23	1P - RTP	100.00%											
24	ELIADC	100.00%											
25	Shore Power												
26	EBS /RSS												
27	Total Below-the-line		178,670	0.3%	159,281,443	0.3%	155,071,055	$11,424,198	$306,483	$25,689	$20,461	$17,927	$64,077
28													
29	In Province Total		6,955,940	100.0%	11,463,066,585	100.0%	10,703,661,274	$445,457,081	$94,697,267	$8,407,734	$6,512,181	$5,382,638	$20,302,553
30													
31	Exports	100.00%	-		-		-						
32													
33	Grand Total		6,955,940		11,463,066,585		10,703,661,274	$445,457,081	$94,697,267	$8,407,734	$6,512,181	$5,382,638	$20,302,553
34													
35													

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

FOR THE YEAR ENDING DECEMBER 31, 2026

COLUMN	M	N	O	P	Q	R	S	T	U	V	W	X	Y
	Fuel-related Costs from COS												
	Maritime Link			Wind			Purchased Power - Wind						
	Basic and Supplemental Blocks						ERIS			NRIS			
Rate Class	Fixed Energy-related	Fixed Demand-related	Total	Fixed Energy-related	Fixed Demand-related	Total	Energy-related	Demand-related	Total	Energy-related	Demand-related	Total	Total
FAM Rate Classes (ATL)													
Residential	$52,743,493	$58,084,777	$110,828,271	$4,875,653	$5,353,756	$10,229,409	$8,948,653	$9,682,485	$18,631,138	$30,002,574	$32,308,240	$62,310,814	$80,941,952
Small General	$3,685,454	$2,965,231	$6,650,684	$339,058	$273,310	$612,367	$614,098	$494,291	$1,108,389	$2,047,064	$1,649,337	$3,696,401	$4,804,790
General Demand	$23,561,585	$16,090,863	$39,652,448	$2,164,515	$1,483,118	$3,647,633	$3,887,660	$2,682,278	$6,569,939	$12,928,207	$8,950,150	$21,878,357	$28,448,296
Large General	$3,847,369	$1,834,156	$5,681,525	$352,503	$169,057	$521,560	$624,955	$305,746	$930,701	$2,066,722	$1,020,205	$3,086,927	$4,017,627
Small Industrial	$2,740,533	$1,648,287	$4,388,820	$253,321	$151,925	$405,246	$452,497	$274,762	$727,259	$1,503,324	$916,819	$2,420,143	$3,147,402
Medium Industrial	$4,747,907	$2,118,795	$6,866,701	$437,755	$195,292	$633,048	$776,260	$353,194	$1,129,454	$2,578,183	$1,178,528	$3,756,711	$4,886,165
Large Industrial	$7,396,747	$3,288,904	$10,685,652	$679,330	$303,143	$982,473	$1,198,054	$548,246	$1,746,300	$3,976,649	$1,829,373	$5,806,022	$7,552,322
PHP	$8,676,550	$2,711,265	$11,387,815	$798,245	$249,901	$1,048,146	$1,403,954	$451,956	$1,855,910	$4,647,455	$1,508,075	$6,155,530	$8,011,440
Municipal	$1,178,059	$1,253,133	$2,431,193	$107,946	$115,503	$223,449	$198,971	$208,892	$407,863	$667,341	$697,025	$1,364,366	$1,772,229
Unmetered	$845,341	$420,505	$1,265,845	$77,744	$38,759	$116,502	$137,842	$70,096	$207,938	$458,327	$233,895	$692,223	$900,161
Total	$109,423,038	$90,415,916	$199,838,954	$10,086,071	$8,333,763	$18,419,834	$18,242,943	$15,071,948	$33,418,031	$60,875,845	$50,291,647	$111,508,333	$144,482,383
Purchased Power Allocation Factors.	54.7%	45.3%	100.0%	54.7%	45.3%	100.0%	54.7%	45.3%	100.0%	54.7%	45.3%	100.0%	
Non-FAM Rate Classes													
BUTU													
GRLF													
1P - RTP													
ELIADC													
Shore Power													
EBS /RSS													
Total Below-the-line	$332,126	$302,135	$634,260	$30,217	$27,848	$58,066	$52,775	$50,365	$103,140	$172,786	$168,055	$340,841	$443,981
In Province Total	$109,755,163	$90,718,051	$200,473,214	$10,116,289	$8,361,611	$18,477,900	$18,295,718	$15,122,313	$33,521,171	$61,048,631	$50,459,702	$111,849,174	$144,926,364
Exports													
Grand Total	$109,755,163	$90,718,051	$200,473,214	$10,116,289	$8,361,611	$18,477,900	$18,295,718	$15,122,313	$33,418,031	$61,048,631	$50,459,702	$111,508,333	$144,926,364

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

FOR THE YEAR ENDING DECEMBER 31, 2026

COLUMN	Z	AA	AB	AC	AD	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO
							Fuel Costs used for FAM purposes				FAM Cost Classification					
											Cost Amount			Unit Cost (cents per kWh)		
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	Demand-related	Energy-related	Total	Demand-related	Energy-related	Total
FAM Rate Classes (ATL)																
Residential	$477,430,875	$193,858	$0	$0	$0	$477,624,733	$464,154,224	50.6%	$461,625,864	8.8540	$109,069,502	$368,555,231	$477,624,733	2.09	7.069	9.161
Small General	$30,665,456	$9,896	$0	$0	$0	$30,675,353	$31,750,160	3.5%	$31,577,210	8.934	$5,568,003	$25,107,349	$30,675,353	1.58	7.104	8.679
General Demand	$187,781,329	$53,703	$0	$0	$0	$187,835,033	$196,060,028	21.4%	$194,992,042	8.786	$30,214,843	$157,620,190	$187,835,033	1.36	7.102	8.463
Large General	$28,402,944	$6,122	$0	$0	$0	$28,409,065	$29,653,053	3.2%	$29,491,525	8.225	$3,444,112	$24,964,953	$28,409,065	0.96	6.962	7.923
Small Industrial	$21,211,268	$5,501	$0	$0	$0	$21,216,769	$22,145,817	2.4%	$22,025,184	8.633	$3,095,094	$18,121,675	$21,216,769	1.21	7.103	8.316
Medium Industrial	$34,883,544	$7,071	$0	$0	$0	$34,890,616	$36,418,420	4.0%	$36,220,040	8.258	$3,978,596	$30,912,020	$34,890,616	0.91	7.048	7.955
Large Industrial	$53,958,573	$10,977	$0	$0	$0	$53,969,549	$56,332,789	6.1%	$56,025,931	8.031	$6,175,786	$47,793,763	$53,969,549	0.89	6.851	7.736
PHP	$60,060,895	$9,049	$0	$0	$0	$60,069,944	$62,700,310	6.8%	$62,358,767	7.693	$5,091,115	$54,978,828	$60,069,944	0.63	6.783	7.411
Municipal	$10,723,254	$4,182	$0	$0	$0	$10,727,436	$11,197,174	1.2%	$11,136,180	8.943	$2,353,089	$8,374,347	$10,727,436	1.89	6.725	8.614
Unmetered	$6,285,177	$1,403	$0	$0	$0	$6,286,580	$6,286,580	0.7%	$6,252,336	8.120	$789,608	$5,496,972	$6,286,580	1.03	7.139	8.164
Total	$911,403,314	$301,764	$0	$0	$0	$911,705,078	$916,698,556	100.0%	$911,705,078	8.643	$169,779,749	$741,925,329	$911,705,078	1.61	7.033	8.643
											18.6%	81.4%				
Purchased Power Allocation Factors.																
Non-FAM Rate Classes																
BUTU																
GRLF																
1P - RTP																
ELIADC																
Shore Power																
EBS /RSS																
Total Below-the-line	$12,931,065	-$301,764	$0	$0	$0	$12,629,301			$12,629,301	8.144	$264,566	$12,364,735	$12,629,301	0.171	7.974	8.144
In Province Total	$924,334,379	$0	$0	$0	$0	$924,334,379			$924,334,379	8.636	$170,044,315	$754,290,064	$924,334,379	1.589	7.047	8.636
Exports																
Grand Total	$924,334,379	$0	$0	$0	$0	$924,334,379		100.0%	$924,334,379	8.636	$170,044,315	$754,290,064	$924,334,379	1.589	7.047	8.636

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)	$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 - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$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**
	9,146,264												
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	**$36,378,424**	**$37,074,393**	**$38,794,783**	**$42,436,409**	**$42,848,326**	**$41,117,732**	**$36,709,207**	**$34,716,334**	**$41,020,793**	**$41,623,544**	**$43,371,341**	**$42,786,010**	**$478,877,298**
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**
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**

	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
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													
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													
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													
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**
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													
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**

	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	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													
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	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$9,146,264	$109,755,163
Energy													
Domestic	$5,302,030	$5,000,457	$4,735,775	$4,304,183	$3,826,405	$3,827,825	$3,874,458	$3,661,520	$3,950,885	$4,472,421	$5,232,717	$4,554,818	$52,743,493
Small General	$320,411	$312,939	$297,573	$305,991	$310,267	$316,604	$314,126	$305,179	$293,785	$299,158	$300,931	$308,489	$3,685,454
General	$1,781,587	$1,846,777	$1,807,934	$1,889,057	$2,124,069	$2,134,168	$2,132,693	$2,123,718	$2,063,718	$1,956,596	$1,769,923	$1,931,343	$23,561,585
Large General	$239,170	$246,855	$286,499	$322,561	$367,850	$401,514	$392,387	$406,367	$353,219	$288,148	$238,929	$303,871	$3,847,369
Small Industrial	$188,990	$191,448	$208,257	$241,898	$293,258	$267,251	$242,068	$243,534	$219,564	$216,095	$206,551	$221,619	$2,740,533
Medium Industrial	$294,688	$318,201	$360,320	$432,148	$496,324	$453,801	$426,579	$461,746	$424,512	$392,718	$309,293	$377,578	$4,747,907
Large Industrial	$435,428	$449,119	$554,311	$679,313	$738,816	$683,032	$752,992	$769,708	$710,918	$604,843	$435,521	$582,744	$7,396,747
PHP	$387,105	$598,706	$705,352	$793,852	$798,654	$861,909	$805,819	$950,301	$930,397	$711,734	$462,990	$669,731	$8,676,550
Municipal	$125,179	$117,042	$101,444	$69,518	$70,779	$84,233	$81,034	$91,027	$100,194	$116,536	$117,345	$103,728	$1,178,059
Unmetered	$55,140	$55,230	$66,632	$78,764	$83,757	$76,949	$74,123	$89,077	$73,577	$72,070	$52,828	$67,196	$845,341
BUTU	$16,535	$9,489	$22,166	$28,977	$36,086	$38,977	$49,984	$44,088	$25,495	$15,944	$19,237	$25,148	$332,126
Total	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$9,146,264**	**$109,755,163**

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**

	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**
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
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%

BUTU Capacity Credit Calc.

	Installed Capacity	Capacity Credit	Approved Contract Demands (kWs)	FAM-related Demand Charge	Gross Demand Payment	Net Demand payment bfr Credits	Capacity Credit
Ellershouse	23,500	20.5%	7,549	$6.252	[redacted]		
Imports	[redacted]	0%	[redacted]	$6.252			
Total							-$301,764

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**	**$ 2,117,885**	**$ 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	$ 4,480,567
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	$ -	$ -	$ (32,069)	$ 32,069	$ -	$ 26,506	$ 32,069	$ -
Total Generation Plant	$ 2,091,705	$ 2,091,705	$ -	$ -	$ (1,145,168)	$ 1,145,168	$ -	$ 946,538	$ 1,145,168	$ -
General Property Plant -generation-related	$ 143,497.6	$ 143,498	$ -	$ -	$ (78,562)	$ 78,562	$ -	$ 64,935	$ 78,562	$ -
Total Generation Plant in Service	$ 2,235,203	$ 2,235,203	$ -	$ -	$ (1,223,730)	$ 1,223,730	$ -	$ 1,011,473	$ 1,223,730	$ -
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	$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 - Supp Block													
ML - Surplus													
Total	$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
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)													$0
Total FAM related costs	**$ 102,748,495**	**$ 90,490,519**	**$ 87,588,134**	**$ 72,151,448**	**$ 64,916,645**	**$ 64,358,355**	**$ 71,674,875**	**$ 70,394,489**	**$ 63,997,384**	**$ 67,027,584**	**$ 76,406,263**	**$ 86,858,502**	**$ 918,612,694**
Total FAM related costs and Incremental Cost to OATT customers	**$ 103,820,358**	**$ 91,433,115**	**$ 88,369,434**	**$ 72,524,007**	**$ 65,080,112**	**$ 64,500,380**	**$ 71,937,924**	**$ 70,633,034**	**$ 64,205,413**	**$ 67,296,610**	**$ 76,962,628**	**$ 87,571,364**	**$ 924,334,379**
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	$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
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

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
BTL													
BUTU													
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**
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													
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														
BTL Classes														
GRLF														
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	

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

FOR THE YEAR ENDING DECEMBER 31, 2027

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
11		Cost Allocation Factors														
12			3 CP Demands		Energy Requirement					Purchased Power- Biomass				Maritime Link		
13														Basic and Supplemental Blocks		
14	Rate Class	R/C Ratios	KW Demand	Relative Shares of Embedded Cost Classes	KWh Energy	Relative Shares of Embedded Cost Classes	kWhs Sales	Fuel Costs before Purchased Power	Imports (allocated on monthly energy requirements)	Bio-fuel Related (allocated on monthly energy requirements)	Energy-related (allocated on annual energy requirements)	Demand-related	Total	Fixed Energy-related	Fixed Demand-related	Total
15	FAM Rate Classes (ATL)															
16	Residential	97.220%	4,351,189	64.167263%	5,601,351,669	52.4111%	5,174,285,808	$167,599,722	$45,268,087	$4,583,138	$3,168,969	$3,740,388	$11,492,495	$53,442,944	$63,046,091	$116,489,035
17	Small General	104.68%	230,332	3.39672%	385,414,032	3.61%	356,341,152	$11,289,468	$3,229,880	$323,909	$225,552	$197,999	$747,460	$3,795,963	$3,337,372	$7,133,335
18	General Demand	104.68%	1,195,401	17.62865%	2,335,071,503	21.85%	2,165,415,899	$67,338,968	$20,067,255	$1,978,517	$1,395,915	$1,027,595	$4,402,028	$23,483,228	$17,320,630	$40,803,858
19	Large General	104.68%	136,936	2.01941%	374,975,792	3.51%	357,052,888	$10,499,765	$3,367,995	$324,721	$234,085	$117,714	$676,520	$3,916,405	$1,984,121	$5,900,527
20	Small Industrial	104.68%	125,244	1.84699%	273,901,737	2.56%	254,467,664	$7,795,729	$2,384,829	$235,632	$165,103	$107,663	$508,398	$2,793,916	$1,814,716	$4,608,632
21	Medium Industrial	104.68%	144,442	2.13010%	442,241,388	4.14%	414,535,689	$12,371,041	$3,922,199	$379,165	$269,938	$124,166	$773,270	$4,588,303	$2,092,882	$6,681,185
22	Large Industrial	104.68%	245,492	3.62028%	719,039,371	6.73%	694,581,928	$19,975,851	$6,468,281	$618,421	$444,646	$211,031	$1,274,097	$7,531,033	$3,557,027	$11,088,060
23	PHP	104.68%	203,269	2.99762%	311,353,251	2.91%	304,282,817	$7,737,367	$3,192,401	$281,342	$218,137	$174,735	$674,213	$3,658,628	$2,945,242	$6,603,870
24	Municipal	104.68%	93,701	1.38182%	129,551,972	1.21%	125,502,351	$3,938,155	$1,038,264	$105,058	$72,589	$80,548	$258,196	$1,213,389	$1,357,675	$2,571,063
25	Unmetered	100.00%	32,357	0.47718%	83,268,011	0.78%	77,000,000	$2,323,730	$737,803	$71,215	$50,809	$27,815	$149,839	$864,368	$468,839	$1,333,206
26	Total	100.00%	6,758,364	99.66602%	10,656,168,727	99.71%	9,923,466,195	$310,869,795	$89,676,994	$8,901,118	$6,245,744	$5,809,653	$20,956,515	$105,288,176	$97,924,594	$203,212,770
27																
28	Purchased Power Allocation Factors.									42.5%	29.8%	27.7236%	100.0%	51.8%	48.2%	100.0%
29																
30	Non-FAM Rate Classes															
31	BUTU	100.00%														
32	GRLF	100.00%														
33	1P - RTP	100.00%														
34	ELIADC	100.00%														
35	Shore Power															
36	EBS															
37	Total Below-the-line		240,665	0.3%	718,273,443	0.3%	700,773,677	$55,224,498	$295,503	$28,981	$20,914	$19,468	$69,363	$339,445	$328,141	$667,587
38																
39	In Province Total		6,999,029	100.0%	11,374,442,170	100.0%	10,624,239,872	$366,094,293	$89,972,498	$8,930,099	$6,266,657	$5,829,121	$21,025,878	$105,627,622	$98,252,735	$203,880,357
40																
41	Exports	100.00%	-		-		-									
42																
43	Grand Total		6,999,029		11,374,442,170		10,624,239,872	$366,094,293	$89,972,498	$8,930,099	$6,266,657	$5,829,121	$21,025,878	$105,627,622	$98,252,735	$203,880,357
44																
45																

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

FOR THE YEAR ENDING DECEMBER 31, 2027

Line #	COLUMN	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD
11		Fuel-related Costs from COS														
12		Wind			Purchased Power - Wind											
13					ERIS			NRIS				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
14	Rate Class	Fixed Energy-related	Fixed Demand-related	Total	Energy-related	Demand-related	Total	Energy-related	Demand-related	Total	Total					
15	FAM Rate Classes (ATL)															
16	Residential	$7,248,850	$8,577,202	$15,826,052	$8,915,528	$10,333,885	$19,249,413	$48,783,748	$56,543,384	$105,327,132	$124,576,545	$481,251,935	$253,975	$0	$0	$0
17	Small General	$516,425	$454,038	$970,463	$621,827	$547,029	$1,168,856	$3,402,667	$2,993,148	$6,395,815	$7,564,672	$30,935,278	$13,444	$0	$0	$0
18	General Demand	$3,194,637	$2,356,412	$5,551,049	$3,809,465	$2,839,025	$6,648,490	$20,826,750	$15,534,144	$36,360,895	$43,009,384	$181,172,542	$69,775	$0	$0	$0
19	Large General	$535,089	$269,933	$805,022	$625,393	$325,217	$950,611	$3,420,084	$1,779,475	$5,199,559	$6,150,170	$27,399,997	$7,993	$0	$0	$0
20	Small Industrial	$383,247	$246,886	$630,133	$453,489	$297,450	$750,939	$2,480,013	$1,627,542	$4,107,555	$4,858,494	$20,786,215	$7,310	$0	$0	$0
21	Medium Industrial	$629,122	$284,729	$913,852	$737,441	$343,044	$1,080,485	$4,042,235	$1,877,018	$5,919,253	$6,999,738	$31,661,284	$8,431	$0	$0	$0
22	Large Industrial	$1,030,289	$483,921	$1,514,210	$1,199,081	$583,032	$1,782,113	$6,581,289	$3,190,147	$9,771,437	$11,553,550	$51,874,050	$14,329	$0	$0	$0
23	PHP	$505,491	$400,690	$906,181	$558,187	$482,755	$1,040,941	$3,047,646	$2,641,463	$5,689,109	$6,730,050	$25,844,082	$11,865	$0	$0	$0
24	Municipal	$162,329	$184,707	$347,036	$201,432	$222,536	$423,968	$1,098,436	$1,217,641	$2,316,078	$2,740,046	$10,892,759	$5,469	$0	$0	$0
25	Unmetered	$118,299	$63,784	$182,083	$138,552	$76,847	$215,400	$760,986	$420,482	$1,181,468	$1,396,868	$6,123,529	$1,889	$0	$0	$0
26	Total	$14,323,778	$13,322,302	$27,646,080	$17,260,394	$16,050,821	$33,418,031	$94,443,856	$87,824,445	$182,851,708	$215,579,516	$867,941,672	$394,480	$0	$0	$0
27																
28	Purchased Power Allocation Factors.	51.8%	48.2%	100.0%	51.8%	48.2%	100.0%	51.8%	48.2%	100.0%						
29																
30	Non-FAM Rate Classes															
31	BUTU															
32	GRLF															
33	1P - RTP															
34	ELIADC															
35	Shore Power															
36	EBS															
37	Total Below-the-line	$46,494	$44,642	$91,136	$53,030	$53,786	$106,816	$289,111	$294,296	$583,407	$690,223	$57,038,310	-$394,480	$0	$0	$0
38																
39	In Province Total	$14,370,272	$13,366,944	$27,737,217	$17,313,424	$16,104,607	$33,524,847	$94,732,967	$88,118,742	$183,435,116	$216,269,739	$924,979,982	$0	$0	$0	$0
40																
41	Exports															
42																
43	Grand Total	$14,370,272	$13,366,944	$27,737,217	$17,313,424	$16,104,607	$33,418,031	$94,732,967	$88,118,742	$182,851,708	$216,269,739	$924,979,982	$0	$0	$0	$0
44																
45																

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

FOR THE YEAR ENDING DECEMBER 31, 2027

Line #	COLUMN	AE	AF	AG	AH	AI	AJ	AK	AL	AM	AN	AO
1												
2												
3												
4			Fuel Costs used for FAM purposes				FAM Cost Classification					
5							Cost Amount			Unit Cost (cents per kWh)		
6											Energy-	
7							Demand-related	Energy-related	Total	Demand-related	related	Total
8												
9												
10												
11												
12												
13												
14	Rate Class	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	$481,505,910	$468,120,948	53.6%	$465,739,449	9.0010	$142,494,925	$339,010,985	$481,505,910	2.75	6.552	9.306
17	Small General	$30,948,722	$32,397,781	3.7%	$32,232,962	9.046	$7,543,030	$23,405,692	$30,948,722	2.12	6.568	8.685
18	General Demand	$181,242,317	$189,728,314	21.7%	$188,763,098	8.717	$39,147,581	$142,094,736	$181,242,317	1.81	6.562	8.370
19	Large General	$27,407,990	$28,691,267	3.3%	$28,545,305	7.995	$4,484,453	$22,923,537	$27,407,990	1.26	6.420	7.676
20	Small Industrial	$20,793,526	$21,767,105	2.5%	$21,656,368	8.510	$4,101,568	$16,691,958	$20,793,526	1.61	6.560	8.171
21	Medium Industrial	$31,669,715	$33,152,532	3.8%	$32,983,873	7.957	$4,730,270	$26,939,445	$31,669,715	1.14	6.499	7.640
22	Large Industrial	$51,888,379	$54,317,859	6.2%	$54,041,525	7.780	$8,039,487	$43,848,892	$51,888,379	1.16	6.313	7.470
23	PHP	$25,855,947	$27,066,556	3.1%	$26,928,858	8.850	$6,656,749	$19,199,198	$25,855,947	2.19	6.310	8.497
24	Municipal	$10,898,229	$11,408,498	1.3%	$11,350,459	9.044	$3,068,577	$7,829,652	$10,898,229	2.45	6.239	8.684
25	Unmetered	$6,125,418	$6,125,418	0.7%	$6,094,255	7.915	$1,059,656	$5,065,762	$6,125,418	1.38	6.579	7.955
26	Total	$868,336,152	$872,776,278	100.0%	$868,336,152	8.750	$221,326,296	$647,009,856	$868,336,152	2.23	6.520	8.750
27							25.5%	74.5%				
28	Purchased Power Allocation Factors.											
29												
30	Non-FAM Rate Classes											
31	BUTU	[redacted]										
32	GRLF											
33	1P - RTP											
34	ELIADC											
35	Shore Power											
36	EBS											
37	Total Below-the-line	$56,643,830			$56,643,830	8.083	$345,853	$56,297,976	$56,643,830	0.049	8.034	8.083
38												
39	In Province Total	$924,979,982			$924,979,982	8.706	$221,672,149	$703,307,833	$924,979,982	2.086	6.620	8.706
40												
41	Exports											
42												
43	Grand Total	$924,979,982		100.0%	$924,979,982	8.706	$221,672,149	$703,307,833	$924,979,982	2.086	6.620	8.706
44												
45												

Monthly Fuel Cost Allocation

	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Purchased Power													
Imports	$4,745,529	$6,120,982	$4,325,089	$9,790,100	$6,316,986	$7,064,377	$9,857,844	$8,238,549	$7,755,359	$10,275,341	$7,707,758	$7,774,583	**$89,972,498**
Biomass													
IPP	$2,017,708	$1,566,665	$1,635,557	$71,916	$1,488,347	$1,501,997	$2,015,967	$2,112,601	$1,631,723	$85,309	$1,675,174	$1,773,613	**$17,576,577**
Comfit	$275,302	$272,644	$342,881	$266,456	$284,110	$307,286	$289,319	$290,681	$269,472	$260,632	$316,932	$273,585	**$3,449,301**
Total	**$2,293,010**	**$1,839,309**	**$1,978,438**	**$338,372**	**$1,772,457**	**$1,809,283**	**$2,305,286**	**$2,403,282**	**$1,901,195**	**$345,941**	**$1,992,106**	**$2,047,198**	$21,025,878
Maritime Link													
ML - NS Block (GWh)	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$203,880,357
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$16,990,030**	**$203,880,357**
Regular other than biomass and wind													
IPP	$1,912,288	$2,286,050	$2,869,763	$2,877,723	$2,707,206	$2,536,520	$2,107,445	$1,929,300	$2,181,948	$1,876,929	$2,048,752	$2,382,554	**$27,716,478**
Comfit	$2,870	$1,439	$1,729	$1,630	$1,443	$1,296	$1,381	$1,744	$1,568	$1,518	$2,278	$1,843	**$20,739**
Total	**$1,915,158**	**$2,287,489**	**$2,871,492**	**$2,879,353**	**$2,708,649**	**$2,537,816**	**$2,108,826**	**$1,931,044**	**$2,183,516**	**$1,878,447**	**$2,051,030**	**$2,384,397**	$27,737,217
Wind NRIS													
IPP	$10,554,584	$11,025,307	$12,646,368	$11,336,003	$9,731,713	$8,062,396	$7,371,600	$7,047,619	$8,572,620	$8,632,744	$11,831,470	$12,041,520	**$118,853,943**
Comfit	$5,614,353	$5,845,565	$7,184,191	$6,103,011	$5,485,641	$4,534,886	$3,924,560	$3,524,955	$4,595,517	$3,778,557	$6,622,536	$6,783,993	**$63,997,765**
Total	**$16,168,937**	**$16,870,872**	**$19,830,559**	**$17,439,014**	**$15,217,354**	**$12,597,282**	**$11,296,159**	**$10,572,574**	**$13,168,138**	**$12,411,302**	**$18,454,006**	**$18,825,513**	$182,851,708
Wind ERIS													
IPP	$2,609,660	$3,258,459	$3,627,090	$2,521,417	$2,850,490	$2,534,080	$2,191,956	$1,916,096	$2,250,818	$2,157,931	$3,711,916	$3,788,118	**$33,418,031**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$2,609,660**	**$3,258,459**	**$3,627,090**	**$2,521,417**	**$2,850,490**	**$2,534,080**	**$2,191,956**	**$1,916,096**	**$2,250,818**	**$2,157,931**	**$3,711,916**	**$3,788,118**	$33,418,031
Grand Total	**$44,722,323**	**$47,367,141**	**$49,622,698**	**$49,958,285**	**$45,855,966**	**$43,532,868**	**$44,750,102**	**$42,051,575**	**$44,249,055**	**$44,058,991**	**$50,906,846**	**$51,809,839**	$558,885,689
Plant Fuel Costs													
Plant Fuel Costs	$57,665,346	$47,414,297	$37,738,955	$19,947,552	$17,809,534	$19,048,134	$26,258,615	$29,457,627	$17,973,072	$21,352,621	$29,524,181	$41,904,360	**$366,094,293**
BTL Class Fuel-related costs													
GRLF	[redacted]												
1P - RTP													
PHP	$3,979,629	$3,736,003	$4,015,761	$3,736,955	$3,359,461	$2,879,821	$2,514,570	$2,399,998	$2,907,972	$3,424,494	$3,880,102	$3,979,638	**$40,814,403**
Shore Power	[redacted]												
Total	$4,872,867	$4,525,474	$4,474,415	$4,646,192	$4,401,021	$4,174,893	$4,042,371	$4,377,111	$4,461,152	$4,537,700	$4,796,904	$5,059,546	**$54,369,645**
ATL-related Fuel costs (net of BTL without BUTU)	$52,792,479	$42,888,823	$33,264,540	$15,301,360	$13,408,513	$14,873,241	$22,216,244	$25,080,517	$13,511,920	$16,814,922	$24,727,276	$36,844,814	**$311,724,648**
Fuel costs before PP													
Domestic	$31,648,650	$26,072,293	$19,116,568	$8,383,302	$6,677,255	$6,560,766	$9,702,698	$11,071,519	$5,710,044	$7,700,970	$12,805,373	$22,150,285	$167,599,722
Small General	$1,956,200	$1,598,492	$1,214,453	$535,097	$482,893	$541,954	$816,882	$913,454	$484,688	$582,601	$870,153	$1,292,601	$11,289,468
General	$10,755,943	$8,611,485	$6,940,191	$3,144,350	$2,881,263	$3,586,577	$5,326,867	$5,999,809	$3,261,443	$3,958,183	$5,508,865	$7,363,994	$67,338,968
Large General	$1,405,698	$1,177,447	$945,452	$509,020	$503,334	$635,650	$1,025,073	$1,128,722	$637,918	$691,696	$827,123	$1,012,632	$10,499,765
Small Industrial	$1,181,052	$931,836	$734,438	$370,568	$378,059	$507,604	$683,603	$697,508	$382,883	$430,563	$621,104	$876,512	$7,795,729
Medium Industrial	$1,719,954	$1,377,309	$1,156,752	$607,763	$640,046	$813,963	$1,099,816	$1,164,950	$688,088	$789,012	$1,069,513	$1,243,875	$12,371,041
Large Industrial	$2,699,038	$2,142,451	$1,719,153	$984,230	$1,059,433	$1,276,156	$1,743,948	$2,166,735	$1,208,695	$1,392,715	$1,736,803	$1,846,494	$19,975,851
PHP	$200,714	$0	$735,152	$426,171	$507,389	$618,533	$1,302,081	$1,342,978	$783,448	$875,705	$696,319	$248,876	$7,737,367
Municipal	$806,016	$623,171	$453,451	$182,432	$110,008	$124,058	$217,968	$236,279	$144,788	$198,675	$338,381	$502,927	$3,938,155
Unmetered	[redacted]												
BUTU													
Total	**$52,792,479**	**$42,888,823**	**$33,264,540**	**$15,301,360**	**$13,408,513**	**$14,873,241**	**$22,216,244**	**$25,080,517**	**$13,511,920**	**$16,814,922**	**$24,727,276**	**$36,844,814**	**$311,724,648**

	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Exports													
Domestic	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Small General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Small Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Medium Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
PHP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unmetered	[redacted]												
BUTU													
Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Imports													
Domestic	$2,844,905	$3,720,970	$2,485,555	$5,363,795	$3,145,772	$3,116,182	$4,305,304	$3,636,817	$3,277,361	$4,705,945	$3,991,573	$4,673,907	$45,268,087
Small General	$175,843	$228,133	$157,904	$342,365	$227,499	$257,413	$362,469	$300,055	$278,194	$356,019	$271,236	$272,750	$3,229,880
General	$966,854	$1,229,009	$902,371	$2,011,815	$1,357,414	$1,703,524	$2,363,650	$1,970,841	$1,871,952	$2,418,785	$1,717,173	$1,553,868	$20,067,255
Large General	$126,359	$168,042	$122,929	$325,680	$237,129	$301,916	$454,848	$370,767	$366,142	$422,685	$257,823	$213,674	$3,367,995
Small Industrial	$106,165	$132,989	$95,492	$237,097	$178,110	$241,098	$303,330	$229,120	$219,761	$263,110	$193,605	$184,952	$2,384,829
Medium Industrial	$154,607	$196,566	$150,402	$388,858	$301,537	$386,610	$488,013	$382,668	$394,938	$482,153	$333,379	$262,469	$3,922,199
Large Industrial	$242,617	$305,765	$223,526	$629,729	$499,118	$606,139	$773,829	$711,738	$693,748	$851,067	$541,380	$389,627	$6,468,281
PHP	$18,042	$0	$95,585	$272,672	$239,040	$293,786	$577,763	$441,147	$449,671	$535,130	$217,050	$52,515	$3,192,401
Municipal	$72,453	$88,937	$58,958	$116,724	$51,827	$58,924	$96,717	$77,614	$83,103	$121,407	$105,477	$106,122	$1,038,264
Unmetered	[redacted]												
BUTU													
Total	$4,745,529	$6,120,982	$4,325,089	$9,790,100	$6,316,986	$7,064,377	$9,857,844	$8,238,549	$7,755,359	$10,275,341	$7,707,758	$7,774,583	$89,972,498
Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	11,818,708	11,899,369	16,036,280	16,865,484	13,090,652	418,181	13,303,650	14,132,701	139,481,654
Relative Share	11.5%	8.9%	9.3%	0.3%	8.5%	8.5%	11.5%	12.1%	9.4%	0.3%	9.5%	10.1%	100.0%
Bio-fuel Apportioned	$1,030,203	$798,265	$832,610	$22,570	$756,675	$761,839	$1,026,698	$1,079,787	$838,109	$26,773	$851,746	$904,825	$8,930,099
Domestic	$617,598	$485,269	$478,487	$12,366	$376,814	$336,056	$448,399	$476,660	$354,179	$12,262	$441,089	$543,960	$4,583,138
Small General	$38,174	$29,752	$30,398	$789	$27,251	$27,760	$37,751	$39,327	$30,064	$928	$29,973	$31,743	$323,909
General	$209,894	$160,281	$173,713	$4,638	$162,597	$183,712	$246,175	$258,309	$202,299	$6,302	$189,756	$180,843	$1,978,517
Large General	$27,431	$21,915	$23,665	$751	$28,404	$32,559	$47,373	$48,595	$39,568	$1,101	$28,491	$24,868	$324,721
Small Industrial	$23,047	$17,344	$18,383	$547	$21,335	$26,001	$31,592	$30,030	$23,749	$686	$21,394	$21,525	$235,632
Medium Industrial	$33,564	$25,635	$28,953	$896	$36,119	$41,693	$50,827	$50,154	$42,680	$1,256	$36,840	$30,547	$379,165
Large Industrial	$52,670	$39,876	$43,030	$1,452	$59,786	$65,367	$80,595	$93,284	$74,972	$2,218	$59,825	$45,346	$618,421
PHP	$3,917	$0	$18,401	$629	$28,633	$31,683	$60,174	$57,819	$48,595	$1,394	$23,985	$6,112	$281,342
Municipal	$15,729	$11,599	$11,350	$269	$6,208	$6,354	$10,073	$10,172	$8,981	$316	$11,656	$12,351	$105,058
Unmetered	[redacted]												
BUTU													
Total	**$1,030,203**	**$798,265**	**$832,610**	**$22,570**	**$756,675**	**$761,839**	**$1,026,698**	**$1,079,787**	**$838,109**	**$26,773**	**$851,746**	**$904,825**	**$8,930,099**
Domestic	$35,111,152	$30,278,531	$22,080,610	$13,759,463	$10,199,841	$10,013,004	$14,456,401	$15,184,996	$9,341,584	$12,419,177	$17,238,035	$27,368,153	$217,450,947
Small General	$2,170,217	$1,856,377	$1,402,755	$878,251	$737,643	$827,127	$1,217,102	$1,252,836	$792,946	$939,547	$1,171,362	$1,597,095	$14,843,258
General	$11,932,691	$10,000,775	$8,016,274	$5,160,803	$4,401,273	$5,473,813	$7,936,692	$8,228,958	$5,335,694	$6,383,270	$7,415,794	$9,098,704	$89,384,740
Large General	$1,559,488	$1,367,404	$1,092,045	$835,451	$768,867	$970,126	$1,527,294	$1,548,084	$1,043,628	$1,115,481	$1,113,437	$1,251,174	$14,192,480
Small Industrial	$1,310,265	$1,082,168	$848,314	$608,212	$577,503	$774,702	$1,018,524	$956,658	$626,394	$694,358	$836,103	$1,082,989	$10,416,189
Medium Industrial	$1,908,125	$1,599,511	$1,336,107	$997,517	$977,702	$1,242,265	$1,638,656	$1,597,772	$1,125,706	$1,272,421	$1,439,732	$1,536,891	$16,672,405
Large Industrial	$2,994,325	$2,488,092	$1,985,709	$1,615,410	$1,618,337	$1,947,662	$2,598,372	$2,971,757	$1,977,415	$2,245,999	$2,338,009	$2,281,466	$27,062,553
PHP	$222,673	$0	$849,138	$699,472	$775,062	$944,001	$1,940,018	$1,841,944	$1,281,714	$1,412,229	$937,354	$307,503	$11,211,110
Municipal	$894,198	$723,707	$523,759	$299,425	$168,043	$189,336	$324,759	$324,065	$236,872	$320,399	$455,513	$621,400	$5,081,477
Unmetered	[redacted]												
BUTU													
Total	**$58,568,211**	**$49,808,070**	**$38,422,240**	**$25,114,030**	**$20,482,174**	**$22,699,456**	**$33,100,786**	**$34,398,853**	**$22,105,387**	**$27,117,036**	**$33,286,781**	**$45,524,222**	**$410,627,245**

	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Domestic	5.42	4.99	3.86	3.12	2.85	3.46	4.57	4.77	3.42	3.83	4.02	4.56	4.20
Small General	5.42	4.99	3.86	3.12	2.85	3.46	4.57	4.77	3.42	3.82	4.02	4.56	4.17
General	5.41	4.97	3.85	3.11	2.84	3.45	4.56	4.76	3.41	3.81	4.01	4.55	4.13
Large General	5.26	4.84	3.74	3.03	2.77	3.37	4.45	4.65	3.33	3.72	3.90	4.43	3.97
Small Industrial	5.40	4.97	3.84	3.10	2.84	3.45	4.55	4.75	3.40	3.81	4.00	4.54	4.09
Medium Industrial	5.35	4.92	3.80	3.08	2.82	3.42	4.52	4.72	3.38	3.77	3.96	4.50	4.02
Large Industrial	5.18	4.77	3.68	2.98	2.73	3.32	4.39	4.59	3.28	3.67	3.84	4.37	3.90
PHP	5.12	#DIV/0!	3.64	2.95	2.70	3.28	4.34	4.54	3.24	3.63	3.80	4.32	3.68
Municipal	5.16	4.75	3.67	2.98	2.72	3.31	4.37	4.57	3.27	3.65	3.83	4.35	4.05
Unmetered													
BUTU													
Total	**5.40**	**4.97**	**3.84**	**3.10**	**2.84**	**3.45**	**4.55**	**4.76**	**3.40**	**3.80**	**3.99**	**4.55**	**4.14**
Maritime Link	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$8,802,302	$105,627,622
Energy													
Domestic	$5,350,956	$5,058,534	$4,822,601	$4,383,425	$3,882,801	$3,844,308	$3,885,680	$3,719,792	$4,031,316	$4,558,398	$5,291,749	$4,613,385	$53,442,944
Small General	$328,067	$321,363	$307,821	$317,005	$320,740	$323,657	$320,587	$315,749	$304,981	$309,753	$308,805	$317,435	$3,795,963
General	$1,767,381	$1,836,480	$1,808,828	$1,891,466	$2,122,613	$2,110,559	$2,105,703	$2,124,658	$2,072,036	$1,961,020	$1,759,273	$1,923,212	$23,483,228
Large General	$241,654	$250,181	$292,820	$330,424	$376,191	$406,144	$396,138	$415,570	$362,090	$294,435	$241,920	$308,838	$3,916,405
Small Industrial	$191,246	$194,344	$213,174	$248,184	$300,411	$270,850	$244,799	$249,428	$225,392	$221,098	$209,401	$225,591	$2,793,916
Medium Industrial	$282,673	$306,094	$349,623	$420,172	$481,720	$435,758	$408,853	$448,253	$413,033	$380,720	$297,164	$364,239	$4,588,303
Large Industrial	$439,707	$454,914	$566,191	$695,487	$755,256	$690,970	$760,441	$787,401	$729,061	$618,259	$441,131	$592,215	$7,531,033
PHP	$0	$194,532	$245,160	$333,086	$366,061	$515,898	$471,334	$510,375	$458,415	$247,872	$59,457	$256,437	$3,658,628
Municipal	$127,897	$119,990	$104,947	$72,217	$73,420	$86,361	$82,925	$94,322	$104,003	$120,455	$120,150	$106,702	$1,213,389
Unmetered	$55,944	$56,212	$68,387	$81,026	$86,026	$78,192	$75,159	$91,479	$75,733	$73,933	$53,696	$68,581	$864,368
BUTU	$16,779	$9,659	$22,751	$29,809	$37,062	$39,604	$50,682	$45,276	$26,243	$16,357	$19,556	$25,668	$339,445
Total	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$8,802,302**	**$105,627,622**
BIOMASS	$654,243.31	$539,350.66	$593,637.56	$163,612.69	$526,263.03	$542,666.69	$662,418.59	$685,684.74	$550,770.49	$165,356.29	$590,805.11	$591,848.15	$6,266,657
Energy													
Domestic	$397,717	$309,956	$325,242	$81,477	$232,141	$237,004	$292,417	$289,766	$252,244	$85,632	$355,179	$310,194	$3,168,969
Small General	$24,384	$19,691	$20,760	$5,892	$19,176	$19,954	$24,126	$24,596	$19,083	$5,819	$20,727	$21,344	$225,552
General	$131,363	$112,528	$121,989	$35,158	$126,905	$130,117	$158,465	$165,507	$129,650	$36,839	$118,081	$129,313	$1,395,915
Large General	$17,961	$15,330	$19,748	$6,142	$22,491	$25,039	$29,811	$32,372	$22,656	$5,531	$16,238	$20,766	$234,085
Small Industrial	$14,215	$11,908	$14,377	$4,613	$17,961	$16,698	$18,422	$19,430	$14,103	$4,153	$14,055	$15,168	$165,103
Medium Industrial	$21,010	$18,756	$23,579	$7,810	$28,801	$26,865	$30,768	$34,918	$25,844	$7,152	$19,945	$24,491	$269,938
Large Industrial	$32,682	$27,874	$38,185	$12,927	$45,154	$42,599	$57,227	$61,337	$45,618	$11,614	$29,608	$39,819	$444,646
PHP	$0	$11,920	$16,534	$6,191	$21,886	$31,805	$35,470	$39,757	$28,684	$4,656	$3,991	$17,242	$218,137
Municipal	$9,506	$7,352	$7,078	$1,342	$4,390	$5,324	$6,241	$7,348	$6,508	$2,263	$8,064	$7,174	$72,589
Unmetered	$4,158	$3,444	$4,612	$1,506	$5,143	$4,821	$5,656	$7,126	$4,739	$1,389	$3,604	$4,611	$50,809
BUTU	$1,247	$592	$1,534	$554	$2,216	$2,442	$3,814	$3,527	$1,642	$307	$1,313	$1,726	$20,914
Total	**$654,243**	**$539,351**	**$593,638**	**$163,613**	**$526,263**	**$542,667**	**$662,419**	**$685,685**	**$550,770**	**$165,356**	**$590,805**	**$591,848**	**$6,266,657**
Regular other than biomass and wind	$992,216.96	$1,185,116.93	$1,487,680.83	$1,491,753.30	$1,403,314.09	$1,314,807.56	$1,092,554.10	$1,000,447.38	$1,131,249.49	$973,197.59	$1,062,610.60	$1,235,323.41	$14,370,272
Energy													
Domestic	$603,173	$681,067	$815,070	$742,873	$619,019	$574,228	$482,296	$422,782	$518,095	$503,984	$638,818	$647,447	$7,248,850
Small General	$36,981	$43,267	$52,025	$53,724	$51,134	$48,345	$39,792	$35,887	$39,195	$34,247	$37,279	$44,549	$516,425
General	$199,224	$247,258	$305,711	$320,553	$338,399	$315,256	$261,363	$241,483	$266,293	$216,814	$212,379	$269,905	$3,194,637
Large General	$27,240	$33,684	$49,490	$55,998	$59,975	$60,666	$49,169	$47,233	$46,535	$32,553	$29,204	$43,343	$535,089
Small Industrial	$21,558	$26,166	$36,029	$42,061	$47,893	$40,457	$30,385	$28,349	$28,967	$24,445	$25,279	$31,660	$383,247
Medium Industrial	$31,864	$41,212	$59,090	$71,208	$76,799	$65,090	$50,747	$50,947	$53,082	$42,093	$35,874	$51,118	$629,122
Large Industrial	$49,565	$61,248	$95,692	$117,866	$120,407	$103,211	$94,387	$89,494	$93,697	$68,356	$53,253	$83,112	$1,030,289
PHP	$0	$26,191	$41,435	$56,449	$58,360	$77,060	$58,503	$58,008	$58,914	$27,405	$7,178	$35,989	$505,491
Municipal	$14,417	$16,155	$17,737	$12,239	$11,705	$12,900	$10,293	$10,720	$13,366	$13,318	$14,505	$14,975	$162,329
Unmetered	$6,306	$7,568	$11,558	$13,732	$13,715	$11,680	$9,329	$10,397	$9,733	$8,174	$6,482	$9,625	$118,299
BUTU	$1,891	$1,300	$3,845	$5,052	$5,909	$5,916	$6,291	$5,146	$3,373	$1,808	$2,361	$3,602	$46,494
Total	**$992,217**	**$1,185,117**	**$1,487,681**	**$1,491,753**	**$1,403,314**	**$1,314,808**	**$1,092,554**	**$1,000,447**	**$1,131,249**	**$973,198**	**$1,062,611**	**$1,235,323**	**$14,370,272**

	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Total
Wind NRIS	$8,376,904.94	$8,740,567.67	$10,273,941.07	$9,034,914.30	$7,883,902.74	$6,526,479.48	$5,852,385.49	$5,477,505.78	$6,822,231.80	$6,430,125.40	$9,560,767.84	$9,753,240.37	$94,732,967
Energy													
Domestic	$5,092,355	$5,023,056	$5,628,882	$4,499,263	$3,477,685	$2,850,367	$2,583,471	$2,314,756	$3,124,475	$3,329,932	$5,747,722	$5,111,783	$48,783,748
Small General	$312,212	$319,109	$359,285	$325,383	$287,275	$239,976	$213,149	$196,484	$236,376	$226,276	$335,414	$351,728	$3,402,667
General	$1,681,967	$1,823,600	$2,111,242	$1,941,450	$1,901,147	$1,564,877	$1,400,019	$1,322,134	$1,605,933	$1,432,535	$1,910,864	$2,130,982	$20,826,750
Large General	$229,975	$248,426	$341,776	$339,156	$336,941	$301,136	$263,380	$258,601	$280,638	$215,086	$262,765	$342,202	$3,420,084
Small Industrial	$182,003	$192,981	$248,814	$254,743	$269,067	$200,822	$162,759	$155,214	$174,690	$161,513	$227,444	$249,962	$2,480,013
Medium Industrial	$269,012	$303,947	$408,076	$431,275	$431,460	$323,094	$271,834	$278,939	$320,122	$278,118	$322,770	$403,589	$4,042,235
Large Industrial	$418,457	$451,723	$660,851	$713,866	$676,456	$512,321	$505,594	$489,985	$565,059	$451,641	$479,142	$656,194	$6,581,289
PHP	$0	$193,168	$286,148	$341,888	$327,868	$382,513	$313,376	$317,597	$355,295	$181,072	$64,580	$284,140	$3,047,646
Municipal	$121,716	$119,149	$122,492	$74,126	$65,760	$64,033	$55,134	$58,695	$80,608	$87,993	$130,503	$118,229	$1,098,436
Unmetered	$53,241	$55,818	$79,820	$83,167	$77,051	$57,975	$49,971	$56,925	$58,697	$54,009	$58,322	$75,990	$760,986
BUTU	$15,968	$9,591	$26,554	$30,596	$33,195	$29,365	$33,697	$28,175	$20,339	$11,949	$21,241	$28,441	$289,111
Total	**$8,376,905**	**$8,740,568**	**$10,273,941**	**$9,034,914**	**$7,883,903**	**$6,526,479**	**$5,852,385**	**$5,477,506**	**$6,822,232**	**$6,430,125**	**$9,560,768**	**$9,753,240**	**$94,732,967**
Wind ERIS	$1,352,029.12	$1,688,163.00	$1,879,145.67	$1,306,311.63	$1,476,799.85	$1,312,872.16	$1,135,622.40	$992,703.11	$1,166,117.99	$1,117,994.51	$1,923,092.86	$1,962,572.08	$17,313,424
Energy													
Domestic	$821,904	$970,159	$1,029,545	$650,525	$651,434	$573,382	$501,308	$419,509	$534,064	$578,969	$1,156,121	$1,028,606	$8,915,528
Small General	$50,391	$61,633	$65,715	$47,045	$53,812	$48,274	$41,360	$35,609	$40,403	$39,342	$67,467	$70,776	$621,827
General	$271,469	$352,212	$386,155	$280,704	$356,120	$314,792	$271,666	$239,614	$274,501	$249,072	$384,359	$428,802	$3,809,465
Large General	$37,118	$47,981	$62,512	$49,037	$63,115	$60,577	$51,107	$46,867	$47,969	$37,397	$52,854	$68,859	$625,393
Small Industrial	$29,375	$37,272	$45,509	$36,832	$50,401	$40,398	$31,583	$28,130	$29,860	$28,082	$45,749	$50,298	$453,489
Medium Industrial	$43,418	$58,705	$74,639	$62,356	$80,820	$64,994	$52,748	$50,553	$54,718	$48,356	$64,923	$81,211	$737,441
Large Industrial	$67,539	$87,246	$120,872	$103,214	$126,713	$103,059	$98,108	$88,801	$96,585	$78,526	$96,377	$132,041	$1,199,081
PHP	$0	$37,309	$52,338	$49,432	$61,416	$76,947	$60,809	$57,559	$60,730	$31,483	$12,990	$57,175	$558,187
Municipal	$19,645	$23,012	$22,404	$10,717	$12,318	$12,881	$10,698	$10,637	$13,778	$15,299	$26,250	$23,790	$201,432
Unmetered	$8,593	$10,781	$14,599	$12,025	$14,433	$11,662	$9,697	$10,317	$10,033	$9,390	$11,731	$15,291	$138,552
BUTU	$2,577	$1,852	$4,857	$4,424	$6,218	$5,907	$6,539	$5,106	$3,477	$2,078	$4,272	$5,723	$53,030
Total	**$1,352,029**	**$1,688,163**	**$1,879,146**	**$1,306,312**	**$1,476,800**	**$1,312,872**	**$1,135,622**	**$992,703**	**$1,166,118**	**$1,117,995**	**$1,923,093**	**$1,962,572**	**$17,313,424**

Monthly Energy Allocators

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

BUTU Capacity Credit Calc.

	Installed Capacity	Capacity Credit	Approved Contract Demands (kWs)	FAM-related Demand Charge	Gross Demand Payment	Net Demand payment bfr Credits	Capacity Credit
Ellershouse	23,500	20.54%	7,549	$8.173	[redacted]		
Imports	[redacted]	0%	[redacted]	$8.173			
Total							-$394,480

Biomass Calculations

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

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

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

System Coincident Load Factor **51.81%**

Rate Base	**Average**	**2026**	**2027**
Steam Plant	$ 458,622	$ 419,903	$ 497,342
Steam Plant - CWIP	$ 4,174	$ 4,374	$ 3,974
Steam Environmental & Fuel Conversion	$ 343,930	$ 352,418	$ 335,442
Steam Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Hydro Plant	$ 703,062	$ 685,374	$ 720,751
Hydro Plant - CWIP	$ 38,477	$ 33,823	$ 43,131
Hydro Environmental & Fuel Conversion	$ 10,863	$ 10,884	$ 10,842
Hydro Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
Wind Plant	$ 153,668	$ 158,510	$ 148,826
Wind Plant - CWIP	$ 196	$ 196	$ 196
Gas Turbine Plant	$ 77,087	$ 76,069	$ 78,105
Gas Turbine Plant - CWIP	$ 2,431	$ 692	$ 4,171
Gas Environmental & Fuel Conversion	$ -	$ -	$ -
Gas Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
LM6000 Plant	$ 96,186	$ 92,802	$ 99,569
LM6000 Plant - CWIP	$ 186	$ 60	$ 312
LM6000 Environmental & Fuel Conversion	$ -	$ -	$ -
LM6000 Environmental & Fuel Conversion - CWIP	$ -	$ -	$ -
ECEI Batteries Plant	$ 166,178	$ 171,846	$ 160,511
ECEI Batteries CWIP	$ (0)	$ (0)	$ (0)
Generation-related Trans Assets Plant	$ 60,402	$ 58,575	$ 62,230
Generation-related Trans Assets CWIP	$ -	$ -	$ -
Total Generation	**$ 1,888,883**	**$ 2,065,526**	**$ 2,165,402**
DISTRIBUTION	$ 34,037	$ 37,483	$ 30,590
TRANSMISSION	$ 2,509	$ 2,708	$ 2,311
DISTRIBUTION/ TRANSMISSION COMMUNICATION	$ 39,282	$ 37,252	$ 41,312
DISTRIBUTION/ TRANSMISSION NON-COMMUNICATION	$ 59,565	$ 54,831	$ 64,298
RETAIL	$ 36,737	$ 39,858	$ 33,616
NON-FUNCTIONALIZED	$ 297,058	$ 297,891	$ 296,226
General Property Plant	$ 469,187	$ 470,022	$ 468,353
General Property Plant - CWIP	$ 29,234	$ 19,601	$ 38,868
Total General Plant	**$ 498,422**	**$ 489,623**	**$ 507,221**
Total System Plant in Service	$ 4,802,854		
Direct Plant in Service (Solar)	$ 1,224		

Generation Rate Base		**Initial Classification**			**Further Classification**			**Fully Classified**		
	Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$ 806,726	$ 806,726	$ -	$ -	$ (417,954)	$ 417,954	$ -	$ 388,772	$ 417,954	$ -
Hydro Plant	$ 752,403	$ 752,403	$ -	$ -	$ (389,810)	$ 389,810	$ -	$ 362,593	$ 389,810	$ -
Wind Plant	$ 153,864	$ 153,864	$ -	$ -	$ (79,715)	$ 79,715	$ -	$ 74,149	$ 79,715	$ -
LM6000 Plant	$ 96,372	$ 96,372	$ -	$ -	$ (49,929)	$ 49,929	$ -	$ 46,443	$ 49,929	$ -
Gas Turbine Plant - Other	$ 79,518	$ 79,518	$ -	$ -	$ (41,197)	$ 41,197	$ -	$ 38,321	$ 41,197	$ -
Generation Batteries	$ 166,178	$ 166,178	$ -	$ -	$ (86,095)	$ 86,095	$ -	$ 80,084	$ 86,095	$ -
Radial to Generation Transmission	$ 60,402	$ 60,402	$ -	$ -	$ (31,294)	$ 31,294	$ -	$ 29,109	$ 31,294	$ -
Total Generation Plant	$ 2,115,464	$ 2,115,464	$ -	$ -	$ (1,095,993)	$ 1,095,993	$ -	$ 1,019,471	$ 1,095,993	$ -
General Property Plant -generation-related	$ 143,755	$ 143,755	$ -	$ -	$ (74,478)	$ 74,478	$ -	$ 69,278	$ 74,478	$ -
Total Generation Plant in Service	$ 2,259,219	$ 2,259,219	$ -	$ -	$ (1,170,470)	$ 1,170,470	$ -	$ 1,088,749	$ 1,170,470	$ -
Rate Base Factors Applicable to Base Cost of Fuel Classification								**48.191%**	**51.809%**	

Data Inputs

Category	Jan-27	Feb-27	Mar-27	Apr-27	May-27	Jun-27	Jul-27	Aug-27	Sep-27	Oct-27	Nov-27	Dec-27	Annual
Plant Fuel Costs	$57,665,346	$47,414,297	$37,738,955	$19,947,552	$17,809,534	$19,048,134	$26,258,615	$29,457,627	$17,973,072	$21,352,621	$29,524,181	$41,904,360	$366,094,293
Maritime Link													
ML - NS Block	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$203,880,357
ML - Supp Block													
ML - Surplus													
Total	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$16,990,030	$203,880,357
Non-Wind Purchases													
Purchased Power Regular bfr Biomass	$1,912,288	$2,286,050	$2,869,763	$2,877,723	$2,707,206	$2,536,520	$2,107,445	$1,929,300	$2,181,948	$1,876,929	$2,048,752	$2,382,554	$27,716,478
Purchased Power - Biomass	$2,017,708	$1,566,665	$1,635,557	$71,916	$1,488,347	$1,501,997	$2,015,967	$2,112,601	$1,631,723	$85,309	$1,675,174	$1,773,613	$17,576,577
Non-Wind Purchases	$3,929,996	$3,852,715	$4,505,320	$2,949,639	$4,195,553	$4,038,517	$4,123,412	$4,041,901	$3,813,671	$1,962,238	$3,723,926	$4,156,167	$45,293,055
Wind Purchases													
Purchased Power Wind - NRIS	$10,554,584	$11,025,307	$12,646,368	$11,336,003	$9,731,713	$8,062,396	$7,371,600	$7,047,619	$8,572,620	$8,632,744	$11,831,470	$12,041,520	$118,853,943
Purchased Power Wind - ERIS	$2,609,660	$3,258,459	$3,627,090	$2,521,417	$2,850,490	$2,534,080	$2,191,956	$1,916,096	$2,250,818	$2,157,931	$3,711,916	$3,788,118	$33,418,031
Purchased Power Wind	$ 13,164,243.69	$ 14,283,765.76	$ 16,273,457.62	$ 13,857,420.27	$ 12,582,203.02	$ 10,596,475.95	$ 9,563,555.70	$ 8,963,714.67	$ 10,823,438.19	$ 10,790,675.36	$ 15,543,386.36	$ 15,829,637.73	$152,271,974
COMFIT													
Wind Generation (NRIS)	$5,614,353	$5,845,565	$7,184,191	$6,103,011	$5,485,641	$4,534,886	$3,924,560	$3,524,955	$4,595,517	$3,778,557	$6,622,536	$6,783,993	$63,997,765
Wind Generation (ERIS)													
Biomass/ Biogas	$ 275,302.28	$272,644	$342,881	$266,456	$284,110	$307,286	$289,319	$290,681	$269,472	$260,632	$316,932	$273,585	$3,449,301
Other	$ 2,869.65	$1,439	$1,729	$1,630	$1,443	$1,296	$1,381	$1,744	$1,568	$1,518	$2,278	$1,843	$20,739
Total Comfit	$ 5,892,525	$ 6,119,648	$ 7,528,801	$ 6,371,096	$ 5,771,194	$ 4,843,468	$ 4,215,260	$ 3,817,380	$ 4,866,557	$ 4,040,707	$ 6,941,746	$ 7,059,421	$67,467,805
Imports	$ 4,745,528.60	$ 6,120,981.79	$ 4,325,089.22	$ 9,790,099.71	$ 6,316,986.14	$ 7,064,376.62	$ 9,857,844.46	$ 8,238,549.38	$ 7,755,358.96	$ 10,275,340.99	$ 7,707,758.44	$ 7,774,583.31	$89,972,498
Export Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$0
OM&G (Solid Fuel Handling) recovered in fuels													$0
Foreign Exchange (Fuel-related)													$0
Total FAM related costs	**$ 101,160,449**	**$ 93,640,714**	**$ 86,574,338**	**$ 69,488,210**	**$ 63,512,699**	**$ 62,409,266**	**$ 70,675,327**	**$ 71,219,695**	**$ 61,979,131**	**$ 65,024,519**	**$ 79,826,234**	**$ 92,841,730**	**$ 918,352,313**
Total FAM related costs and Incremental Cost to OATT customers	**$ 102,387,669**	**$ 94,781,437**	**$ 87,361,653**	**$ 69,905,837**	**$ 63,665,500**	**$ 62,581,001**	**$ 71,008,717**	**$ 71,509,202**	**$ 62,222,127**	**$ 65,411,612**	**$ 80,431,027**	**$ 93,714,199**	**$ 924,979,982**

Purchased Biomass Generation	16,091,017	12,468,320	13,004,765	352,527	11,818,708	11,899,369	16,036,280	16,865,484	13,090,652	418,181	13,303,650	14,132,701	139,481,654
BLT Fuel Costs bfr BUTU													
GRLF	[redacted]												
1P - RTP													
ELIADC													
Shore Power													
EBS													
Export													
Total	$4,872,867	$4,525,474	$4,474,415	$4,646,192	$4,401,021	$4,174,893	$4,042,371	$4,377,111	$4,461,152	$4,537,700	$4,796,904	$5,059,546	$54,369,645
NRIS	**$10,554,584**	**$11,025,307**	**$12,646,368**	**$11,336,003**	**$9,731,713**	**$8,062,396**	**$7,371,600**	**$7,047,619**	**$8,572,620**	**$8,632,744**	**$11,831,470**	**$12,041,520**	**$118,853,943**
ERIS	**$2,609,660**	**$3,258,459**	**$3,627,090**	**$2,521,417**	**$2,850,490**	**$2,534,080**	**$2,191,956**	**$1,916,096**	**$2,250,818**	**$2,157,931**	**$3,711,916**	**$3,788,118**	**$33,418,031**
Total	**$13,164,244**	**$14,283,766**	**$16,273,458**	**$13,857,420**	**$12,582,203**	**$10,596,476**	**$9,563,556**	**$8,963,715**	**$10,823,438**	**$10,790,675**	**$15,543,386**	**$15,829,638**	**$152,271,974**
Usage Data													
kWh Requirements													
ATL Classes													
Domestic Total	703,364,192	658,966,637	621,859,856	477,310,981	386,030,904	312,074,064	340,348,944	341,337,631	294,471,755	350,550,933	465,593,287	649,442,487	5,601,351,669
Small General	43,474,868	40,401,246	39,506,010	30,466,221	27,917,411	25,778,958	28,654,396	28,162,017	24,995,770	26,520,209	31,638,087	37,898,840	385,414,032
General	239,041,633	217,651,798	225,763,643	179,026,472	166,573,907	170,601,654	186,854,579	184,975,557	168,195,353	180,177,917	200,297,987	215,911,001	2,335,071,503
Large General	31,240,447	29,759,497	30,755,445	28,981,505	29,099,129	30,235,793	35,957,274	34,798,787	32,897,964	31,486,231	30,073,533	29,690,186	374,975,792
Small Industrial	26,247,876	23,551,766	23,891,198	21,098,646	21,856,626	24,145,035	23,979,255	21,504,341	19,745,607	19,599,367	22,582,840	25,699,179	273,901,737
Medium Industrial	38,224,517	34,810,937	37,629,007	34,603,519	37,002,859	38,717,523	38,579,100	35,915,695	35,485,255	35,916,108	38,886,660	36,470,208	442,241,388
Large Industrial- FIRM	24,806,200	22,381,224	21,393,458	16,895,757	13,223,566	12,552,222	14,313,874	13,657,679	14,436,723	15,389,261	19,563,430	21,108,372	209,721,768
Large Industrial- INT	35,177,611	31,768,361	34,530,388	39,142,252	48,025,243	48,150,317	46,859,934	53,143,300	47,896,694	48,007,628	43,585,362	33,030,513	509,317,603
Large Industrial	59,983,811	54,149,586	55,923,847	56,038,010	61,248,809	60,702,539	61,173,808	66,800,979	62,333,417	63,396,889	63,148,792	54,138,885	719,039,371
PHP	4,460,705	-	23,914,417	24,264,437	29,333,583	29,421,577	45,674,101	41,404,350	40,403,072	39,862,407	25,317,601	7,297,002	311,353,251
Municipal	17,913,015	15,750,383	14,750,720	10,386,959	6,359,874	5,901,015	7,645,845	7,284,541	7,466,849	9,043,776	12,303,250	14,745,745	129,551,972
Unmetered	7,156,209	6,889,510	6,910,350	6,768,476	7,135,640	6,914,229	6,922,567	6,602,334	7,241,762	6,585,485	7,551,522	6,589,927	83,268,011

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

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

Marginal Cost	$97.01	$103.96	$77.95	$61.66	$43.83	$53.06	$71.04	$66.43	$52.26	$65.51	$70.86	$84.85	$70.55	
Incremental Cost	$1,227,220	$1,140,723	$787,315	$417,627	$152,801	$171,735	$333,389	$289,507	$242,996	$387,093	$604,793	$872,469	$6,627,669	
OATT LOAD														
Energy Requirement	12,650,834	10,972,924	10,099,740	6,773,483	3,486,028	3,236,378	4,692,951	4,357,960	4,650,067	5,909,317	8,534,484	10,282,055	85,646,221	

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

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

2026 REVENUE TO COST RATIO DETERMINATION

Rate Classes	2026 Sales (GWh's)	COSS	2026 Sales at 2025 base cost rates (Millions of $'s)			Pre-set R/C Ratio	2026 Sales at 2026 base cost rates (Millions of $'s)										Revenue Variance	
							Steps in Assignment of Revenue Responsibilities								Revenue Responsibility	Revenue to Cost Ratio	cents per kWh	Amount	%
Steps			Revenues	Revenue to Cost Ratio (coloured cells designate ratios outside of 95/105)	cents per kWh		1		2		3		4		5						
Multiplier							1.050	R/C Ratio	NA	R/C Ratio	1.023	R/C Ratio	NA	R/C Ratio		1.0438					
FAM Classes																					
Residential	**5,213.8**	**$1,095.2**	**$985.0**	0.90	**18.9**	**NA**	**$1,034.6**	0.9446	**$1,040.5**	**0.950**	**$1,064.3**	**0.9718**	**$1,064.3**	**0.9718**	**$1,064.3**	**0.9718**	**$1,064.3**	**0.9718**	**20.4**	**$79.3**	**8.0%**
Small General	353.4	$66.4	$64.0	**0.96**	18.1	NA	$67.2	**1.01**	$67.2	**1.012**	$68.8	**1.0350**	$68.8	**1.035**	$68.8	**1.0350**	$68.8	**1.0350**	19.5	$4.8	7.4%
General Demand	2,219.4	$338.6	$348.0	**1.03**	15.7	NA	$365.5	1.08	$355.5	**1.050**	$355.5	**1.0500**	$355.5	**1.0500**	$353.4	**1.0438**	$353.4	**1.0438**	15.9	$5.4	1.6%
Large General	358.6	$45.7	$49.7	1.09	13.9	NA	$52.2	1.14	$48.0	**1.050**	$48.0	**1.0500**	$48.0	**1.0500**	$47.7	**1.0438**	$47.7	**1.0438**	13.3	($2.0)	-4.0%
Total Commercial	**2,931.4**	**$450.7**	**$461.7**		**15.7**		**$484.9**		**$470.7**		**$472.3**		**$472.3**		**$469.9**		**$469.9**	1.0425	**16.0**	**$8.2**	**1.8%**
Small Industrial	255.1	$38.1	$39.2	**1.03**	15.4	NA	$41.2	1.08	$40.0	**1.050**	$40.0	**1.0500**	$40.0	**1.0500**	$39.8	**1.0438**	$39.8	**1.0438**	15.6	$0.6	1.4%
Medium Industrial	438.6	$57.0	$63.3	1.11	14.4	NA	$66.5	1.17	$59.8	**1.050**	$59.8	**1.0500**	$59.8	**1.0500**	$59.5	**1.0438**	$59.5	**1.0438**	13.6	($3.8)	-6.0%
Large Industrial																					
Firm	98.3	NA	$12.7	NA	12.9	NA		NA		NA		NA		NA		NA	$0.0	NA	-	NA	NA
Interruptible	599.3	NA	$69.0	NA	11.5	NA		NA		NA		NA		NA		NA	$0.0	NA	-	NA	NA
Large Industrial Total	697.6	$73.0	$81.8	1.12	11.7	NA	$85.9	1.18	$76.6	**1.050**	$76.6	**1.0500**	$76.6	**1.0500**	$76.2	**1.0438**	$76.2	**1.0438**	10.9	($5.6)	-6.8%
PHP	810.5	$81.0	N/A	N/A	N/A		$81.0	**1.00**	$81.0	**1.000**	$81.0	**1.0000**	$85.1	**1.0500**	$84.579	**1.0438**	$84.6	**1.0438**	10.4	N/A	N/A
Total Industrial	2,201.9	$249.1	**$184.3**				$274.6		$257.5		$257.5		$261.6		$260.0		$260.0			($8.9)	
Municipal	124.5	$18.86	$18.9	**1.00**	15.2	NA	$19.9	1.05	$19.8	**1.050**	$19.8	**1.0500**	$19.8	**1.0500**	$19.7	**1.0438**	$19.7	**1.0438**	15.8	$0.8	4.1%
Unmetered	77.0	$22.112	$19.4	0.88	25.2	**1.00**	$22.1	**1.00**	$22.1	**1.000**	$22.1	**1.0000**	$22.1	**1.0000**	$22.1	**1.0000**	$22.1	**1.0000**	28.7	$2.7	13.8%
Total Other	**201.5**	**$41.0**	**$38.3**		**19.0**		**$42.0**		**$41.9**		**$41.9**		**$41.9**		**$41.8**		**$41.8**		**20.7**	**$3.5**	**9.0%**
Total FAM Classes	**10,548.6**	**$1,836.0**	**$1,669.4**		**15.8**		**$1,836.0**		**$1,810.6**		**$1,836.0**		**$1,840.1**		**$1,836.0**		**$1,836.0**		**17.4**	**$82.1**	**4.9%**
Revenue Shortfall/Surplus			**($166.7)**				**($0.0)**		**($25.4)**		**$0.0**		**$4.1**		**$0.0**		**$0.0**				

2027 REVENUE TO COST RATIO DETERMINATION

Rate Classes	2027 Sales (GWh's)	COSS	2027 Sales at 2026 base cost rates (Millions of $'s)			Pre-set R/C Ratio	2027 Sales at 2027 base cost rates (Millions of $'s)										Revenue Variance	
							Steps in Assignment of Revenue Responsibilities											
Steps			Revenues	Revenue to Cost Ratio (coloured cells designate ratios outside of 95/105)	cents per kWh		1		2		3		4		5		Revenue Responsibility	Revenue to Cost Ratio	cents per kWh	Amount	%
Multiplier							1.045	R/C Ratio	NA	R/C Ratio	1.008	R/C Ratio	NA	R/C Ratio		1.0468					
FAM Classes																					
Residential	**5,174.3**	**$1,144.8**	**$1,056.4**	0.92	**20.4**	**NA**	**$1,104.3**	**0.9646**	**$1,104.3**	**0.9646**	**$1,113.0**	**0.9722**	**$1,113.0**	**0.9722**	**$1,113.0**	**0.9722**	**$1,113.0**	**0.9722**	**21.5**	**$56.7**	**5.4%**
Small General	356.3	$69.9	$69.3	**0.99**	19.4	NA	$72.4	**1.0356**	$72.4	**1.0356**	$73.0	**1.0438**	$73.0	**1.0438**	$73.2	**1.0468**	$73.2	**1.0468**	20.5	$3.9	5.7%
General Demand	2,165.4	$341.0	$344.8	**1.01**	15.9	NA	$360.4	1.0569	$358.1	**1.0500**	$358.1	**1.0500**	$358.1	**1.0500**	$357.0	**1.0468**	$357.0	**1.0468**	16.5	$12.2	3.5%
Large General	357.1	$45.9	$47.5	**1.04**	13.3	NA	$49.7	1.0832	$48.2	**1.0500**	$48.2	**1.0500**	$48.2	**1.0500**	$48.0	**1.0468**	$48.0	**1.0468**	13.5	$0.5	1.0%
Total Commercial	**2,878.8**	**$456.9**	**$461.6**		**16.0**		**$482.6**		**$478.7**		**$479.3**		**$479.3**		**$478.3**		**$478.3**	1.0468	**16.6**	**$16.6**	**3.6%**
Small Industrial	254.5	$39.1	$39.7	**1.02**	15.6	NA	$41.5	1.0624	$41.0	**1.0500**	$41.0	**1.0500**	$41.0	**1.0500**	$40.9	**1.0468**	$40.9	**1.0468**	16.1	$1.2	3.0%
Medium Industrial	414.5	$53.6	$56.2	**1.05**	13.6	NA	$58.8	1.0968	$56.3	**1.0500**	$56.3	**1.0500**	$56.3	**1.0500**	$56.1	**1.0468**	$56.1	**1.0468**	13.5	($0.1)	-0.2%
Large Industrial																					
Firm	97.5	NA	$12.0	NA	12.3	NA		NA		NA		NA		NA		NA	$0.0	NA	-	NA	NA
Interruptible	597.1	NA	$63.7	NA	10.7	NA		NA		NA		NA		NA		NA	$0.0	NA	-	NA	NA
Large Industrial Total	694.6	$72.9	$75.7	**1.04**	10.9	NA	$79.1	1.0857	$76.5	**1.0500**	$76.5	**1.0500**	$76.5	**1.0500**	$76.3	**1.0468**	$76.3	**1.0468**	11.0	$0.6	0.8%
PHP	304.3	$37.6	N/A	N/A	N/A		$37.6	**1.0000**	$37.6	**1.0000**	$37.6	**1.0000**	$39.5	**1.0500**	$39.349	**1.0468**	$39.3	**1.0468**	12.9	N/A	N/A
Total Industrial	1,363.6	$203.1	**$171.6**		12.6		$217.0		$211.4		$211.4		$213.3		$212.6		$212.6		15.6	$1.7	1.0%
Municipal	125.5	$19.72	$19.8	**1.00**	15.8	NA	$20.7	**1.0496**	$20.7	**1.0496**	$20.9	1.0578	$20.7	**1.0500**	$20.6	**1.0468**	$20.641	**1.0468**	16.4	$0.8	4.3%
Unmetered	77.0	$22.962	$21.5	0.94	27.9	**1.00**	$23.0	**1.0000**	$23.0	**1.0000**	$23.0	**1.0000**	$23.0	**1.0000**	$23.0	**1.0000**	$22.962	**1.0000**	29.8	$1.4	6.7%
Total Other	**202.5**	**$42.7**	**$41.3**		**20.4**		**$43.7**		**$43.7**		**$43.8**		**$43.7**		**$43.6**		**$43.6**		**21.5**	**$2.3**	**5.5%**
Total FAM Classes	**9,923.5**	**$1,847.5**	**$1,730.9**		**17.4**		**$1,847.5**		**$1,838.0**		**$1,847.5**		**$1,849.2**		**$1,847.5**		**$1,847.514**		**18.6**	**$77.2**	**4.5%**
Revenue Shortfall/Surplus			**($116.6)**				**($0.0)**		**($9.5)**		**($0.0)**		**$1.7**		**($0.0)**		**($0.0)**				

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Domestic Service Tariff (Standard Offer)					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Energy Charges					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	8.695	9.495	0.800	9.2%
Subtotal		16.931	18.349	1.418	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	9.702	10.128	0.426	4.4%
Total		**18.561**	**19.138**	**0.577**	**3.1%**
Domestic Service Time-of-Day Tariff					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Energy Charges (December to February)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	14.329	15.647	1.318	9.2%
Subtotal		22.565	24.501	1.936	8.6%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	15.336	16.281	0.944	6.2%
Total		**24.195**	**25.291**	**1.095**	**4.5%**
Shoulder Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	9.751	10.648	0.897	9.2%
Subtotal		17.987	19.502	1.515	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	10.758	11.281	0.523	4.9%
Total		**19.617**	**20.291**	**0.674**	**3.4%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	2.474	2.702	0.228	9.2%
Subtotal		10.710	11.556	0.846	7.9%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	3.481	3.335	-0.146	-4.2%
Total		**12.340**	**12.345**	**0.005**	**0.0%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Energy Charges (March to November)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	9.751	10.648	0.897	9.2%
Subtotal		17.987	19.502	1.515	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	10.758	11.281	0.523	4.9%
Total	¢/kWh	**19.617**	**20.291**	**0.674**	**3.4%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	2.474	2.702	0.228	9.2%
Subtotal		10.710	11.556	0.846	7.9%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	3.481	3.335	-0.146	-4.2%
Total	¢/kWh	**12.340**	**12.345**	**0.005**	**0.0%**
Domestic Service Time-of-Use Tariff					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	25.626	27.844	2.218	8.7%
Subtotal		33.862	36.698	2.836	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	26.633	28.477	1.844	6.9%
Total	¢/kWh	**35.492**	**37.487**	**1.995**	**5.6%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	8.695	9.495	0.800	9.2%
Subtotal		16.931	18.349	1.418	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	9.702	10.128	0.426	4.4%
Total	¢/kWh	**18.561**	**19.138**	**0.577**	**3.1%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	3.190	3.537	0.347	10.9%
Subtotal		11.426	12.391	0.965	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	4.197	4.170	-0.027	-0.6%
Total	¢/kWh	**13.056**	**13.180**	**0.124**	**0.9%**
Domestic Service Critical Peak Pricing Tariff					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	161.074	174.634	13.560	8.4%
Subtotal	######	169.310	183.488	14.178	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	162.081	175.268	13.186	8.1%
Total	¢/kWh	**170.940**	**184.278**	**13.337**	**7.8%**
Non-Critical Peak Hours Charge					
Base cost of fuel	¢/kWh	8.236	8.854	0.618	7.5%
Non-fuel	¢/kWh	5.986	6.552	0.566	9.4%
Subtotal		14.222	15.406	1.184	8.3%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.010	0.151	1.7%
Non-fuel related in aggregate	¢/kWh	6.993	7.185	0.192	2.7%
Total	¢/kWh	**15.852**	**16.195**	**0.343**	**2.2%**
Small General Tariff (Standard Offer)					
Customer Charge	$/mo	**21.28**	**22.15643**	**0.88**	**4.12%**
Energy Charges					
First 200 kWh Block					
Base cost of fuel	¢/kWh	8.14700	8.934	0.787	9.7%
Non-fuel	¢/kWh	9.42000	9.984	0.564	6.0%
Subtotal		17.56700	18.918	1.351	7.7%
FAM AA	¢/kWh	0.39600	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.15600	0.156	0.000	0.0%
Subtotal		0.55200	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.69900	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	10.52800	10.737	0.209	2.0%
Total	¢/kWh	**19.227**	**19.827**	**0.600**	**3.1%**
All Additional KWhs					
Base cost of fuel	¢/kWh	8.147	8.934	0.787	9.7%
Non-fuel	¢/kWh	7.694	8.155	0.461	6.0%
Subtotal		15.841	17.089	1.248	7.9%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	8.802	8.908	0.106	1.2%
Total	¢/kWh	**17.501**	**17.998**	**0.497**	**2.8%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Small General Time-of-Use Tariff					
Customer Charge	$/mo	**21.28**	**22.16**	**0.88**	**4.1%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.147	8.934	0.787	9.7%
Non-fuel	¢/kWh	25.070	28.868	3.798	15.1%
Subtotal		33.217	37.802	4.585	13.8%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	26.178	29.621	3.443	13.2%
Total	¢/kWh	**34.877**	**38.711**	**3.834**	**11.0%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.1470	8.934	0.787	9.7%
Non-fuel	¢/kWh	9.4036	9.967	0.563	6.0%
Subtotal		17.5506	18.901	1.350	7.7%
FAM AA	¢/kWh	0.3960	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.1560	0.156	0.000	0.0%
Subtotal		0.5520	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.7780	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.0250	-0.025	0.000	0.0%
Subtotal		0.7530	0.753	0.000	0.0%
SCRR	¢/kWh	0.3550	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.6990	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	10.5116	10.720	0.208	2.0%
Total	¢/kWh	**19.2106**	**19.810**	**0.599**	**3.1%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.147	8.934	0.787	9.7%
Non-fuel	¢/kWh	3.584	3.399	-0.185	-5.2%
Subtotal		**11.731**	**12.334**	**0.603**	**5.1%**
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156		
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	4.692	4.152	-0.540	-11.5%
Total	¢/kWh	**13.391**	**13.243**	**0.248**	**-1.1%**
Small General Critical Peak Pricing Tariff					
Customer Charge	$/mo	**21.28**	**22.16**	**0.88**	**4.1%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.147	8.934	0.787	9.7%
Non-fuel	¢/kWh	136.457	144.626	8.169	6.0%
Subtotal		144.604	153.561	8.957	6.2%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	137.565	145.379	7.814	5.7%
Total	¢/kWh	**146.264**	**154.470**	**8.206**	**5.6%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	8.147	8.934	0.787	9.7%
Non-fuel	¢/kWh	7.338	7.777	0.439	6.0%
Subtotal		15.485	16.712	1.227	7.9%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	8.446	8.530	0.084	1.0%
Total	¢/kWh	**17.145**	**17.621**	**0.476**	**2.8%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	8.147	8.934	0.787	9.7%
Non-fuel	¢/kWh	5.993	6.352	0.359	6.0%
Subtotal		14.140	15.286	1.146	8.1%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.090	0.391	4.5%
Non-fuel related in aggregate	¢/kWh	7.101	7.105	0.004	0.1%
Total	¢/kWh	**15.800**	**16.195**	**0.395**	**2.5%**
General Tariff (Standard Offer)					
Demand Charge	$/kW	**10.554**	**9.838**	**-0.7162**	**-6.8%**
Transformer Ownership Credit	¢/kVA	**-32.0000**	**-32.0000**	**0.0000**	**0.0%**
Energy Charges					
First 200 kWhs per kW of Max Demand					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	6.265	5.840	-0.425	-6.8%
Subtotal		14.287	14.626	0.339	2.4%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	7.002	6.485	-0.516	-7.4%
Total	¢/kWh	**15.623**	**15.478**	**-0.144**	**-0.9%**
All Additional KWhs					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	2.968	2.767	-0.201	-6.8%
Subtotal		10.990	11.552	0.562	5.1%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	3.705	3.412	-0.292	-7.9%
Total	¢/kWh	**12.326**	**12.405**	**0.079**	**0.6%**
General Time-of-Use Tariff					
Demand Charge	$/kW	**10.554**	**9.838**	**-0.7162**	**-6.8%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	18.221	19.595	1.374	7.5%
Subtotal		26.243	28.381	2.138	8.1%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	18.958	20.240	1.283	6.8%
Total	¢/kWh	**27.579**	**29.233**	**1.655**	**6.0%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	5.798	5.405	-0.393	-6.8%
Subtotal		13.820	14.190	0.370	2.7%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	6.535	6.050	-0.484	-7.4%
Total	¢/kWh	**15.156**	**15.043**	**-0.113**	**-0.7%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	1.244	0.337	-0.907	-72.9%
Subtotal		9.266	9.123	-0.143	-1.5%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207		
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	1.981	0.982	-0.998	-50.4%
Total	¢/kWh	**10.602**	**9.975**	**-0.234**	**-5.9%**
Multi-Unit Residential Buildings Time-of-Use Tariff					
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	20.552	20.465	-0.087	-0.4%
Subtotal		28.574	29.251	0.677	2.4%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	21.289	21.111	-0.178	-0.8%
Total		**29.910**	**30.104**	**0.194**	**0.6%**
Mid-Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	6.265	5.840	-0.425	-6.8%
Subtotal		14.287	14.626	0.339	2.4%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	7.002	6.485	-0.516	-7.4%
Total		**15.623**	**15.478**	**-0.144**	**-0.9%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	4.122	3.646	-0.476	-11.5%
Subtotal		12.144	12.432	0.288	2.4%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	4.859	4.292	-0.567	-11.7%
Total		**13.480**	**13.284**	**-0.195**	**-1.4%**
Energy Charges (April to October)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	5.551	5.109	-0.442	-8.0%
Subtotal		13.573	13.894	0.322	2.4%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	6.287	5.754	-0.533	-8.5%
Total	¢/kWh	**14.908**	**14.747**	**-0.161**	**-1.1%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Off-Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	3.408	2.915	-0.493	-14.5%
Subtotal		11.430	11.700	0.271	2.4%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	4.144	3.560	-0.584	-14.1%
Total	¢/kWh	**12.765**	**12.553**	**-0.212**	**-1.7%**
General Critical Peak Pricing Tariff					
Demand Charge	$/kW	**10.554**	**9.838**	**-0.716**	**-6.8%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	144.187	134.402	-9.785	-6.8%
Subtotal		152.209	143.188	-9.021	-5.9%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	144.924	135.048	-9.876	-6.8%
Total	¢/kWh	**153.545**	**144.040**	**-9.504**	**-6.2%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	3.496	3.259	-0.237	-6.8%
Subtotal		11.518	12.045	0.527	4.6%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	4.233	3.904	-0.328	-7.8%
Total	¢/kWh	**12.854**	**12.897**	**0.044**	**0.3%**
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	8.022	8.786	0.764	9.5%
Non-fuel	¢/kWh	1.656	1.544	-0.112	-6.8%
Subtotal		9.678	10.329	0.651	6.7%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	8.993	0.372	4.3%
Non-fuel related in aggregate	¢/kWh	2.393	2.189	-0.203	-8.5%
Total	¢/kWh	**11.014**	**11.182**	**0.168**	**1.5%**
Large General Tariff					
Demand Charge (Ratcheted)	$/kVA	**13.845**	**11.201**	**-2.644**	**-19.1%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	7.574	8.225	0.651	8.6%
Non-fuel	¢/kWh	3.375	2.731	-0.644	-19.1%
Subtotal		10.949	10.955	0.006	0.1%
FAM AA	¢/kWh	0.359	0.000	-0.359	-100.0%
FAM BA	¢/kWh	0.158	0.158	0.000	0.0%
Subtotal		0.517	0.158	-0.359	-69.4%
DSM PCR	¢/kWh	0.768	0.768	0.000	0.0%
DSM BA	¢/kWh	0.022	0.022	0.000	0.0%
Subtotal		0.790	0.790	0.000	0.0%
SCRR	¢/kWh	0.041	0.000	-0.041	-100.0%
Fuel-related in aggregate	¢/kWh	8.091	8.383	0.292	3.6%
Non-fuel related in aggregate	¢/kWh	4.206	3.521	-0.685	-16.3%
Total	¢/kWh	**12.297**	**11.903**	**-0.394**	**-3.2%**
Small Industrial Tariff					
Demand Charge	$/kVA	**8.332**	**7.506**	**-0.825**	**-9.9%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
First 200 kWhs per kVA of Max Demand					
Base cost of fuel	¢/kWh	7.648	8.633	0.985	12.9%
Non-fuel	¢/kWh	5.589	5.035	-0.554	-9.9%
Subtotal		13.237	13.668	0.431	3.3%
FAM AA	¢/kWh	0.394	0.000	-0.394	-100.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.538	0.144	-0.394	-73.2%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.098	0.000	-0.098	-100.0%
Fuel-related in aggregate	¢/kWh	8.186	8.777	0.591	7.2%
Non-fuel related in aggregate	¢/kWh	6.440	5.788	-0.652	-10.1%
Total	¢/kWh	**14.626**	**14.565**	**-0.061**	**-0.4%**
All Additional KWhs					
Base cost of fuel	¢/kWh	7.648	8.633	0.985	12.9%
Non-fuel	¢/kWh	3.016	2.717	-0.299	-9.9%
Subtotal		10.663	11.349	0.686	6.4%
FAM AA	¢/kWh	0.394	0.000	-0.394	-100.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.538	0.144	-0.394	-73.2%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.098	0.000	-0.098	-100.0%
Fuel-related in aggregate	¢/kWh	8.186	8.777	0.591	7.2%
Non-fuel related in aggregate	¢/kWh	3.866	3.470	-0.397	-10.3%
Total	¢/kWh	**12.052**	**12.246**	**0.194**	**1.6%**
Medium Industrial Tariff					
Demand Charge	$/kVA	**13.796**	**10.728**	**-3.068**	**-22.2%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	7.614	8.258	0.644	8.5%
Non-fuel	¢/kWh	2.806	2.182	-0.624	-22.2%
Subtotal		10.421	10.441	0.020	0.2%
FAM AA	¢/kWh	0.358	0.000	-0.358	-100.0%
FAM BA	¢/kWh	0.206	0.206	0.000	0.0%
Subtotal		0.564	0.206	-0.358	-63.5%
DSM PCR	¢/kWh	0.306	0.306	0.000	0.0%
DSM BA	¢/kWh	0.008	0.008	0.000	0.0%
Subtotal		0.314	0.314	0.000	0.0%
SCRR	¢/kWh	0.059	0.000	-0.059	-100.0%
Fuel-related in aggregate	¢/kWh	8.178	8.464	0.286	3.5%
Non-fuel related in aggregate	¢/kWh	3.180	2.497	-0.683	-21.5%
Total		**11.358**	**10.961**	**-0.397**	**-3.5%**
Large Industrial Tariff					
Demand Charge (Ratcheted)	$/kVA	**12.601**	**9.280**	**-3.321**	**-26.4%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Interruptible Credit	$/kVA	**-7.486**	**-7.638**	**-0.152**	**2.0%**
Distribution Cost Adder		**1.632**	**2.332**	**0.701**	**42.9%**
Energy Charges					
Firm					
Base cost of fuel	¢/kWh	7.382	8.031	0.649	8.8%
Non-fuel	¢/kWh	2.802	2.0636	-0.738	-26.4%
Subtotal		10.184	10.095	-0.089	-0.9%
FAM AA	¢/kWh	0.366	0.000	-0.366	-100.0%
FAM BA	¢/kWh	0.247	0.247	0.000	0.0%
Subtotal		0.613	0.247	-0.366	-59.7%
DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
Subtotal		0.431	0.431	0.000	0.0%
SCRR (Transmission)	¢/kWh	0.002	0.000	-0.002	-100.0%
SCRR (Distribution)	¢/kWh	0.037	0.000	-0.037	-100.0%
Subtotal		0.039	0.000	-0.039	-100.0%
Fuel-related in aggregate	¢/kWh	7.995	8.278	0.283	3.5%
Non-fuel related in aggregate	¢/kWh	3.272	2.495	-0.777	-23.8%
Total		**11.267**	**10.773**	**-0.457**	**-4.4%**
Interruptible					
Base cost of fuel	¢/kWh	7.382	8.031	0.649	8.8%
Non-fuel	¢/kWh	2.802	2.064	-0.738	-26.4%
Subtotal		10.184	10.095	-0.089	-0.9%
FAM AA	¢/kWh	0.366	0.000	-0.366	-100.0%
FAM BA	¢/kWh	0.224	0.224	0.000	0.0%
Subtotal		0.590	0.224	-0.366	-62.0%
DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
Subtotal		0.431	0.431	0.000	0.0%
SCRR (Transmission)	¢/kWh	0.002	0.000	-0.002	-100.0%
SCRR (Distribution)	¢/kWh	0.037	0.000	-0.037	-100.0%
Subtotal		0.039	0.000	-0.039	-100.0%

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Fuel-related in aggregate	¢/kWh	7.972	8.255	0.283	3.6%
Non-fuel related in aggregate	¢/kWh	3.272	2.495	-0.777	-23.8%
Total	¢/kWh	**11.244**	**10.750**	**-0.457**	**-4.4%**
Municipal Tariff					
Demand Charge (Ratcheted)	$/kVA	**13.428**	**11.330**	**-2.098**	**-15.6%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	7.035	8.943	1.908	27.1%
Non-fuel	¢/kWh	3.098	2.614	-0.484	-15.6%
Subtotal		10.133	11.557	1.424	14.0%
FAM AA	¢/kWh	0.418	0.000	-0.418	-100.0%
FAM BA	¢/kWh	0.105	0.105	0.000	0.0%
Subtotal		0.523	0.105	-0.418	-79.9%
DSM PCR	¢/kWh	0.650	0.650	0.000	0.0%
DSM BA	¢/kWh	-0.023	-0.023	0.000	0.0%
Subtotal		0.627	0.627	0.000	0.0%
SCRR	¢/kWh	0.002	0.000	-0.002	-100.0%
Fuel-related in aggregate	¢/kWh	7.558	9.048	1.490	19.7%
Non-fuel related in aggregate	¢/kWh	3.727	3.241	-0.486	-13.0%
Total		**11.285**	**12.289**	**1.004**	**8.9%**
Outdoor Recreational Lighting Tariff					
Energy Charges					
Base cost of fuel	¢/kWh	7.430	8.120	0.690	9.3%
Non-fuel	¢/kWh	10.443	3.271	-7.172	-68.7%
Subtotal		17.873	11.391	-6.482	-36.3%
FAM AA	¢/kWh	0.413	0.000	-0.413	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.569	0.156	-0.413	-72.6%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.485	0.000	-0.485	-100.0%
Fuel-related in aggregate	¢/kWh	7.999	8.276	0.277	3.5%
Non-fuel related in aggregate	¢/kWh	11.285	3.628	-7.657	-67.8%
Total		**19.284**	**11.904**	**-7.380**	**-38.3%**
Unmetered Service Rates: Miscellaneous Lighting & Small Loads					
Demand Charge	$/kW	**12.314**	**13.843**	1.529	12.4%
Energy Charges					
First 200 kWhs per kW of Max Demand					
Base cost of fuel	¢/kWh	7.430	8.120	0.690	9.3%
Non-fuel	¢/kWh	8.379	9.652	1.273	15.2%
Subtotal		15.809	17.772	1.963	12.4%
FAM AA	¢/kWh	0.413	0.000	-0.413	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.569	0.156	-0.413	-72.6%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.485	0.000	-0.485	-100.0%
Fuel-related in aggregate	¢/kWh	7.999	8.276	0.277	3.5%
Non-fuel related in aggregate	¢/kWh	9.221	10.009	0.788	8.5%
Total		**17.220**	**18.285**	**1.065**	**6.2%**
All Additional KWhs					
Base cost of fuel	¢/kWh	7.430	8.120	0.690	9.3%
Non-fuel	¢/kWh	3.647	4.332	0.685	18.8%
Subtotal		11.077	12.452	1.375	12.4%
FAM AA	¢/kWh	0.413	0.000	-0.413	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.569	0.156	-0.413	-72.6%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.485	0.000	-0.485	-100.0%
Fuel-related in aggregate	¢/kWh	7.999	8.276	0.277	3.5%
Non-fuel related in aggregate	¢/kWh	4.489	4.689	0.200	4.5%
Total	¢/kWh	**12.488**	**12.965**	**0.477**	**3.8%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Domestic Service Tariff (Standard Offer)					
Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Energy Charges					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	9.495	10.334	0.839	8.8%
Subtotal		18.349	19.335	0.986	5.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	10.128	10.967	0.839	8.3%
Total		**19.138**	**20.124**	**0.986**	**5.2%**
Domestic Service Time-of-Day Tariff					
Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Energy Charges (December to February)					
Peak Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	15.647	17.030	1.383	8.8%
Subtotal		24.501	26.031	1.530	6.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	16.281	17.663	1.383	8.5%
Total		**25.291**	**26.820**	**1.530**	**6.0%**
Shoulder Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	10.648	11.589	0.941	8.8%
Subtotal		19.502	20.590	1.088	5.6%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	11.281	12.222	0.941	8.3%
Total		**20.291**	**21.379**	**1.088**	**5.4%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	2.702	2.940	0.239	8.8%
Subtotal		11.556	11.941	0.386	3.3%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	3.335	3.574	0.239	7.2%
Total		**12.345**	**12.731**	**0.386**	**3.1%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Energy Charges (March to November)					
Peak Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	10.648	11.589	0.941	8.8%
Subtotal		19.502	20.590	1.088	5.6%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	11.281	12.222	0.941	8.3%
Total	¢/kWh	**20.291**	**21.379**	**1.088**	**5.4%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	2.702	2.940	0.239	8.8%
Subtotal		11.556	11.941	0.386	3.3%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	3.335	3.574	0.239	7.2%
Total	¢/kWh	**12.345**	**12.731**	**0.386**	**3.1%**
Domestic Service Time-of-Use Tariff					
Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	27.844	29.669	1.825	6.6%
Subtotal		36.698	38.670	1.972	5.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	28.477	30.302	1.825	6.4%
Total	¢/kWh	**37.487**	**39.459**	**1.972**	**5.3%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	9.495	10.334	0.839	8.8%
Subtotal		18.349	19.335	0.986	5.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	10.128	10.967	0.839	8.3%
Total	¢/kWh	**19.138**	**20.124**	**0.986**	**5.2%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	3.537	4.092	0.555	15.7%
Subtotal		12.391	13.093	0.702	5.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	4.170	4.726	0.555	13.3%
Total	¢/kWh	**13.180**	**13.883**	**0.702**	**5.3%**
Domestic Service Critical Peak Pricing Tariff					
Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	174.634	184.349	9.714	5.6%
Subtotal		183.488	193.350	9.862	5.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	175.268	184.982	9.714	5.5%
Total	¢/kWh	**184.278**	**194.139**	**9.862**	**5.4%**
Non-Critical Peak Hours Charge					
Base cost of fuel	¢/kWh	8.854	9.001	0.147	1.7%
Non-fuel	¢/kWh	6.552	7.198	0.647	9.9%
Subtotal		15.406	16.199	0.794	5.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.010	9.157	0.147	1.6%
Non-fuel related in aggregate	¢/kWh	7.185	7.832	0.647	9.0%
Total	¢/kWh	**16.195**	**16.989**	**0.794**	**4.9%**
Small General Tariff (Standard Offer)					
Customer Charge	$/mo	**22.16**	**23.07**	**0.91**	**4.1%**
Energy Charges					
First 200 kWh Block					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	9.984	11.054	1.070	10.7%
Subtotal		18.918	20.100	1.182	6.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	10.737	11.807	1.070	10.0%
Total	¢/kWh	**19.827**	**21.009**	**1.182**	**6.0%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
All Additional KWhs					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	8.155	9.029	0.874	10.7%
Subtotal		17.089	18.074	0.985	5.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	8.908	9.782	0.874	9.8%
Total	¢/kWh	**17.998**	**18.983**	**0.985**	**5.5%**
Small General Time-of-Use Tariff					
Customer Charge	$/mo	**22.16**	**23.07**	**0.91**	**4.1%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	28.868	31.116	2.248	7.8%
Subtotal		37.802	40.161	2.360	6.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	29.621	31.869	2.248	7.6%
Total	¢/kWh	**38.711**	**41.070**	**2.360**	**6.1%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	9.967	11.035	1.069	10.7%
Subtotal		18.901	20.081	1.180	6.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	10.720	11.788	1.069	10.0%
Total	¢/kWh	**19.810**	**20.990**	**1.180**	**6.0%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	3.399	3.911	0.512	15.1%
Subtotal		**12.334**	**12.956**	**0.623**	**5.0%**
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156		
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	#REF!	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	4.152	#REF!	#REF!	0.0%
Total	¢/kWh	**13.243**	**#REF!**	**0.623**	**0.0%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Small General Critical Peak Pricing Tariff					
Customer Charge	$/mo	**22.16**	**23.07**	**0.91**	**4.1%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	144.626	160.133	15.507	10.7%
Subtotal		153.561	169.179	15.618	10.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	145.379	160.886	15.507	10.7%
Total	¢/kWh	**154.470**	**170.088**	**15.618**	**10.1%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	7.777	8.611	0.834	10.7%
Subtotal		16.712	17.657	0.945	5.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	8.530	9.364	0.834	9.8%
Total	¢/kWh	**17.621**	**18.566**	**0.945**	**5.4%**
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	8.934	9.046	0.111	1.2%
Non-fuel	¢/kWh	6.352	7.033	0.681	10.7%
Subtotal		15.286	16.078	0.792	5.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.090	9.202	0.111	1.2%
Non-fuel related in aggregate	¢/kWh	7.105	7.786	0.681	9.6%
Total	¢/kWh	**16.195**	**16.987**	**0.792**	**4.9%**
General Tariff (Standard Offer)					
Demand Charge	$/kW	**9.838**	**10.709**	**0.872**	**8.9%**
Transformer Ownership Credit	¢/kVA	**-32.0000**	**-32.0000**	**0.0000**	**0.0%**
Energy Charges					
First 200 kWhs per kW of Max Demand					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	5.840	6.357	0.518	8.9%
Subtotal		14.626	15.075	0.449	3.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	6.485	7.003	0.518	8.0%
Total	¢/kWh	**15.478**	**15.927**	**0.449**	**2.9%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
All Additional KWhs					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	2.767	3.012	0.245	8.9%
Subtotal		11.552	11.729	0.177	1.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	3.412	3.657	0.245	7.2%
Total	¢/kWh	**12.405**	**12.582**	**0.177**	**1.4%**
General Time-of-Use Tariff					
Demand Charge	$/kW	**9.838**	**10.709**	**0.872**	**8.9%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	19.595	20.484	0.889	4.5%
Subtotal		28.381	29.201	0.821	2.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	20.240	21.130	0.889	4.4%
Total	¢/kWh	**29.233**	**30.054**	**0.821**	**2.8%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	5.405	5.883	0.479	8.9%
Subtotal		14.190	14.601	0.410	2.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	6.050	6.529	0.479	7.9%
Total	¢/kWh	**15.043**	**15.453**	**0.410**	**2.7%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	0.337	0.634	0.297	88.1%
Subtotal		9.123	9.351	0.228	2.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207		
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	0.982	1.279	0.297	30.2%
Total	¢/kWh	**9.975**	**10.204**	**0.228**	**2.3%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Multi-Unit Residential Buildings Time-of-Use Tariff					
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	20.465	21.432	0.966	4.7%
Subtotal		29.251	30.149	0.898	3.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	21.111	22.078	0.966	4.6%
Total		**30.104**	**31.002**	**0.898**	**3.0%**
Mid-Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	5.840	6.357	0.518	8.9%
Subtotal		14.626	15.075	0.449	3.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	6.485	7.003	0.518	8.0%
Total		**15.478**	**15.927**	**0.449**	**2.9%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	3.646	4.096	0.450	12.3%
Subtotal		12.432	12.813	0.382	3.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	4.292	4.742	0.450	10.5%
Total		**13.284**	**13.666**	**0.382**	**2.9%**
Energy Charges (April to October)					
Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	5.109	5.604	0.495	9.7%
Subtotal		13.894	14.321	0.426	3.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	5.754	6.249	0.495	8.6%
Total	¢/kWh	**14.747**	**15.173**	**0.426**	**2.9%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Off-Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	2.915	3.342	0.428	14.7%
Subtotal		11.700	12.060	0.359	3.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	3.560	3.988	0.428	12.0%
Total	¢/kWh	**12.553**	**12.912**	**0.359**	**2.9%**
General Critical Peak Pricing Tariff					
Demand Charge	$/kW	**9.838**	**10.709**	**0.872**	**8.9%**
Transformer Ownership Credit	¢/kVA	**-32.0000**	**-32.0000**	**0.0000**	**0.0%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	134.402	146.313	11.911	8.9%
Subtotal		143.188	155.030	11.842	8.3%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	135.048	146.959	11.911	8.8%
Total	¢/kWh	**144.040**	**155.883**	**11.842**	**8.2%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	3.259	3.548	0.289	8.9%
Subtotal		12.045	12.265	0.220	1.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	3.904	4.193	0.289	7.4%
Total	¢/kWh	**12.897**	**13.117**	**0.220**	**1.7%**
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	8.786	8.717	-0.069	-0.8%
Non-fuel	¢/kWh	1.544	1.680	0.137	8.9%
Subtotal		10.329	10.398	0.068	0.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.993	8.924	-0.069	-0.8%
Non-fuel related in aggregate	¢/kWh	2.189	2.326	0.137	6.2%
Total	¢/kWh	**11.182**	**11.250**	**0.068**	**0.6%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Large General Tariff					
Demand Charge (Ratcheted)	$/kVA	**11.201**	**12.003**	**0.802**	**7.2%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	8.225	7.995	-0.230	-2.8%
Non-fuel	¢/kWh	2.731	2.926	0.195	7.2%
Subtotal		10.955	10.921	-0.035	-0.3%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.158	0.158	0.000	0.0%
Subtotal		0.158	0.158	0.000	0.0%
DSM PCR	¢/kWh	0.768	0.768	0.000	0.0%
DSM BA	¢/kWh	0.022	0.022	0.000	0.0%
Subtotal		0.790	0.790	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.383	8.153	-0.230	-2.7%
Non-fuel related in aggregate	¢/kWh	3.521	3.716	0.195	5.6%
Total	¢/kWh	**11.903**	**11.869**	**-0.035**	**-0.3%**
Small Industrial Tariff					
Demand Charge	$/kVA	**7.506**	**8.143**	**0.636**	**8.5%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
First 200 kWhs per kVA of Max Demand					
Base cost of fuel	¢/kWh	8.633	8.510	-0.122	-1.4%
Non-fuel	¢/kWh	5.035	5.462	0.427	8.5%
Subtotal		13.668	13.973	0.305	2.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.144	0.144	0.000	0.0%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.777	8.654	-0.122	-1.4%
Non-fuel related in aggregate	¢/kWh	5.788	6.215	0.427	7.4%
Total	¢/kWh	**14.565**	**14.870**	**0.305**	**2.1%**
All Additional KWhs					
Base cost of fuel	¢/kWh	8.633	8.510	-0.122	-1.4%
Non-fuel	¢/kWh	2.717	2.947	0.230	8.5%
Subtotal		11.349	11.458	0.108	1.0%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.144	0.144	0.000	0.0%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.777	8.654	-0.122	-1.4%
Non-fuel related in aggregate	¢/kWh	3.470	3.700	0.230	6.6%
Total	¢/kWh	**12.246**	**12.354**	**0.108**	**0.9%**
Medium Industrial Tariff					
Demand Charge	$/kVA	**10.728**	**11.277**	**0.549**	**5.1%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	8.258	7.957	-0.302	-3.7%
Non-fuel	¢/kWh	2.182	2.294	0.112	5.1%
Subtotal		10.441	10.251	-0.190	-1.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.206	0.206	0.000	0.0%
Subtotal		0.206	0.206	0.000	0.0%
DSM PCR	¢/kWh	0.306	0.306	0.000	0.0%
DSM BA	¢/kWh	0.008	0.008	0.000	0.0%
Subtotal		0.314	0.314	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.464	8.163	-0.302	-3.6%
Non-fuel related in aggregate	¢/kWh	2.497	2.608	0.112	4.5%
Total		**10.961**	**10.771**	**-0.190**	**-1.7%**

RATE SCHEDULES

		units	2026	2027	Variance	% Variance
1						
7	**Large Industrial Tariff**					
	Demand Charge (Ratcheted)	$/kVA	**9.280**	**10.000**	**0.719**	**7.8%**
	Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
	Interruptible Credit	$/kVA	**-7.638**	**-7.667**	**-0.029**	**0.4%**
	Distribution Cost Adder		**2.332**	**2.527**	**0.194**	**8.3%**
	Energy Charges					
	Firm					
	Base cost of fuel	¢/kWh	8.031	7.780	-0.251	-3.1%
	Non-fuel	¢/kWh	2.064	2.224	0.160	7.8%
	Subtotal		10.095	10.004	-0.091	-0.9%
	FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
	FAM BA	¢/kWh	0.247	0.247	0.000	0.0%
	Subtotal		0.247	0.247	0.000	0.0%
	DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
	DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
	Subtotal		0.431	0.431	0.000	0.0%
	SCRR (Transmission)	¢/kWh	0.000	0.000	0.000	
	SCRR (Distribution)	¢/kWh	0.000	0.000	0.000	
	Subtotal		0.000	0.000	0.000	
	Fuel-related in aggregate	¢/kWh	8.278	8.027	-0.251	-3.0%
	Non-fuel related in aggregate	¢/kWh	2.495	2.655	0.160	6.4%
	Total		**10.773**	**10.682**	**-0.091**	**-0.8%**
#	**Interruptible**					
	Base cost of fuel	¢/kWh	8.031	7.780	-0.251	-3.1%
	Non-fuel	¢/kWh	2.064	2.224	0.160	7.8%
	Subtotal		10.095	10.004	-0.091	-0.9%
	FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
	FAM BA	¢/kWh	0.224	0.224	0.000	0.0%
	Subtotal		0.224	0.224	0.000	0.0%
	DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
	DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
	Subtotal		0.431	0.431	0.000	0.0%
	SCRR (Transmission)	¢/kWh	0.000	0.000	0.000	0.0%
	SCRR (Distribution)	¢/kWh	0.000	0.000	0.000	0.0%
	Subtotal		0.000	0.000	0.000	0.0%
	Fuel-related in aggregate	¢/kWh	8.255	8.004	-0.251	-3.0%
	Non-fuel related in aggregate	¢/kWh	2.495	2.655	0.160	6.4%
	Total	¢/kWh	**10.750**	**10.659**	**-0.091**	**-0.8%**
#	**Municipal Tariff**					
	Demand Charge (Ratcheted)	$/kVA	**11.330**	**12.270**	**0.940**	**8.3%**
	Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
	Energy Charges					
	Base cost of fuel	¢/kWh	8.943	9.044	0.101	1.1%
	Non-fuel	¢/kWh	2.614	2.831	0.217	8.3%
	Subtotal		11.557	11.875	0.318	2.8%
	FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
	FAM BA	¢/kWh	0.105	0.105	0.000	0.0%
	Subtotal		0.105	0.105	0.000	0.0%
	DSM PCR	¢/kWh	0.650	0.650	0.000	0.0%
	DSM BA	¢/kWh	-0.023	-0.023	0.000	0.0%
	Subtotal		0.627	0.627	0.000	0.0%
	SCRR	¢/kWh	0.000	0.000	0.000	0.0%
	Fuel-related in aggregate	¢/kWh	9.048	9.149	0.101	1.1%
	Non-fuel related in aggregate	¢/kWh	3.241	3.458	0.217	6.7%
	Total		**12.289**	**12.607**	**0.318**	**2.6%**

RATE SCHEDULES

1		units	2026	2027	Variance	% Variance
#	**Outdoor Recreational Lighting Tariff**					
	Energy Charges					
	Base cost of fuel	¢/kWh	8.120	7.915	-0.205	-2.5%
	Non-fuel	¢/kWh	3.271	3.748	0.477	14.6%
	Subtotal		11.391	11.663	0.272	2.4%
	FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
	FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
	Subtotal		0.156	0.156	0.000	0.0%
	DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
	DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
	Subtotal		0.357	0.357	0.000	0.0%
	SCRR	¢/kWh	0.000	0.000	0.000	0.0%
	Fuel-related in aggregate	¢/kWh	8.276	8.071	-0.205	-2.5%
	Non-fuel related in aggregate	¢/kWh	3.628	4.105	0.477	13.2%
	Total		**11.904**	**12.176**	**0.272**	**2.3%**
#	**Unmetered Service Rates: Miscellaneous Lighting & Small Loads**					
	Demand Charge	$/kW	**13.843**	**14.173**	0.330	2.4%
	Energy Charges					
	First 200 kWhs per kW of Max Demand					
	Base cost of fuel	¢/kWh	8.120	7.915	-0.205	-2.5%
	Non-fuel	¢/kWh	9.652	10.281	0.629	6.5%
	Subtotal		17.772	18.196	0.424	2.4%
	FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
	FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
	Subtotal		0.156	0.156	0.000	0.0%
	DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
	DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
	Subtotal		0.357	0.357	0.000	0.0%
	SCRR	¢/kWh	0.000	0.000	0.000	0.0%
	Fuel-related in aggregate	¢/kWh	8.276	8.071	-0.205	-2.5%
	Non-fuel related in aggregate	¢/kWh	10.009	10.638	0.629	6.3%
	Total		**18.285**	**18.709**	**0.424**	**2.3%**
	All Additional KWhs					
	Base cost of fuel	¢/kWh	8.120	7.915	-0.205	-2.5%
	Non-fuel	¢/kWh	4.332	4.835	0.502	11.6%
	Subtotal		12.452	12.749	0.297	2.4%
	FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
	FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
	Subtotal		0.156	0.156	0.000	0.0%
	DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
	DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
	Subtotal		0.357	0.357	0.000	0.0%
	SCRR	¢/kWh	0.000	0.000	0.000	0.0%
	Fuel-related in aggregate	¢/kWh	8.276	8.071	-0.205	-2.5%
	Non-fuel related in aggregate	¢/kWh	4.689	5.192	0.502	10.7%
	Total	¢/kWh	**12.965**	**13.262**	**0.297**	**2.3%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Domestic Service Tariff (Standard Offer)					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Energy Charges					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	8.695	9.495	0.800	9.2%
Subtotal		16.931	18.454	1.523	9.0%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	9.702	10.128	0.426	4.4%
Total		**18.561**	**19.243**	**0.682**	**3.7%**
Domestic Service Time-of-Day Tariff					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Energy Charges (December to February)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	14.329	15.647	1.318	9.2%
Subtotal		22.565	24.606	2.041	9.0%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	15.336	16.281	0.944	6.2%
Total		**24.195**	**25.396**	**1.200**	**5.0%**
Shoulder Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	9.751	10.648	0.897	9.2%
Subtotal		17.987	19.607	1.620	9.0%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	10.758	11.281	0.523	4.9%
Total		**19.617**	**20.397**	**0.779**	**4.0%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	2.474	2.702	0.228	9.2%
Subtotal		10.710	11.661	0.951	8.9%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	3.481	3.335	-0.146	-4.2%
Total		**12.340**	**12.450**	**0.110**	**0.9%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Energy Charges (March to November)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	9.751	10.648	0.897	9.2%
Subtotal		17.987	19.607	1.620	9.0%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	10.758	11.281	0.523	4.9%
Total	¢/kWh	**19.617**	**20.397**	**0.779**	**4.0%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	2.474	2.702	0.228	9.2%
Subtotal		10.710	11.661	0.951	8.9%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	3.481	3.335	-0.146	-4.2%
Total	¢/kWh	**12.340**	**12.450**	**0.110**	**0.9%**
Domestic Service Time-of-Use Tariff					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	25.626	27.844	2.218	8.7%
Subtotal		33.862	36.803	2.941	8.7%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	26.633	28.477	1.844	6.9%
Total	¢/kWh	**35.492**	**37.592**	**2.100**	**5.9%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	8.695	9.495	0.800	9.2%
Subtotal		16.931	18.454	1.523	9.0%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	9.702	10.128	0.426	4.4%
Total	¢/kWh	**18.561**	**19.243**	**0.682**	**3.7%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	3.190	3.537	0.347	10.9%
Subtotal		11.426	12.496	1.070	9.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	4.197	4.170	-0.027	-0.6%
Total	¢/kWh	**13.056**	**13.285**	**0.229**	**1.8%**
Domestic Service Critical Peak Pricing Tariff					
Customer Charge	$/mo	**19.17**	**20.24**	**1.07**	**5.6%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	161.074	174.634	13.560	8.4%
Subtotal		169.310	183.593	14.283	8.4%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	162.081	175.268	13.186	8.1%
Total	¢/kWh	**170.940**	**184.383**	**13.442**	**7.9%**
Non-Critical Peak Hours Charge					
Base cost of fuel	¢/kWh	8.236	8.959	0.723	8.8%
Non-fuel	¢/kWh	5.986	6.552	0.566	9.4%
Subtotal		14.222	15.511	1.289	9.1%
FAM AA	¢/kWh	0.467	0.000	-0.467	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.623	0.156	-0.467	-75.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.374	0.000	-0.374	-100.0%
Fuel-related in aggregate	¢/kWh	8.859	9.115	0.256	2.9%
Non-fuel related in aggregate	¢/kWh	6.993	7.185	0.192	2.7%
Total	¢/kWh	**15.852**	**16.300**	**0.448**	**2.8%**
Small General Tariff (Standard Offer)					
Customer Charge	$/mo	**21.28**	**22.16**	**0.88**	**4.1%**
Energy Charges					
First 200 kWh Block				-0.0218902	
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	9.420	9.984	0.564	6.0%
Subtotal		17.567	19.053	1.486	8.5%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	10.528	10.737	0.209	2.0%
Total	¢/kWh	**19.227**	**19.962**	**0.735**	**3.8%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
All Additional KWhs					
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	7.694	8.155	0.461	6.0%
Subtotal		15.841	17.224	1.383	8.7%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	8.802	8.908	0.106	1.2%
Total	¢/kWh	**17.501**	**18.133**	**0.632**	**3.6%**
Small General Time-of-Use Tariff					
Customer Charge	$/mo	**21.28**	**22.16**	**0.88**	**4.1%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	25.070	28.868	3.798	15.1%
Subtotal		33.217	37.937	4.720	14.2%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	26.178	29.621	3.443	13.2%
Total	¢/kWh	**34.877**	**38.846**	**3.969**	**11.4%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	9.404	9.967	0.563	6.0%
Subtotal		17.551	19.036	1.485	8.5%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	10.512	10.720	0.208	2.0%
Total	¢/kWh	**19.211**	**19.945**	**0.734**	**3.8%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	3.584	3.399	-0.185	-5.2%
Subtotal		11.731	**12.468**	**0.737**	**6.3%**
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156		
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	4.692	4.152	-0.540	-11.5%
Total	¢/kWh	**13.391**	**13.377**	**0.382**	**-0.1%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Small General Critical Peak Pricing Tariff					
Customer Charge	$/mo	**21.28**	**22.16**	**0.88**	**4.1%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	136.457	144.626	8.169	6.0%
Subtotal		144.604	153.695	9.091	6.3%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	137.565	145.379	7.814	5.7%
Total	¢/kWh	**146.264**	**154.604**	**8.340**	**5.7%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	7.338	7.777	0.439	6.0%
Subtotal		15.485	16.846	1.361	8.8%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	8.446	8.530	0.084	1.0%
Total	¢/kWh	**17.145**	**17.755**	**0.610**	**3.6%**
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	8.147	9.069	0.922	11.3%
Non-fuel	¢/kWh	5.993	6.352	0.359	6.0%
Subtotal		14.140	15.421	1.281	9.1%
FAM AA	¢/kWh	0.396	0.000	-0.396	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.552	0.156	-0.396	-71.7%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.355	0.000	-0.355	-100.0%
Fuel-related in aggregate	¢/kWh	8.699	9.225	0.526	6.0%
Non-fuel related in aggregate	¢/kWh	7.101	7.105	0.004	0.1%
Total	¢/kWh	**15.800**	**16.330**	**0.530**	**3.4%**
General Tariff (Standard Offer)					
Demand Charge	$/kW	**10.554**	**9.838**	**-0.7162**	**-6.8%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
First 200 kWhs per kW of Max Demand					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	6.265	5.840	-0.425	-6.8%
Subtotal		14.287	14.846	0.559	3.9%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	7.002	6.485	-0.516	-7.4%
Total	¢/kWh	**15.623**	**15.698**	**0.076**	**0.5%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
All Additional KWhs					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	2.968	2.767	-0.201	-6.8%
Subtotal		10.990	11.773	0.783	7.1%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	3.705	3.412	-0.292	-7.9%
Total	¢/kWh	**12.326**	**12.625**	**0.300**	**2.4%**
General Time-of-Use Tariff					
Demand Charge	$/kW	**10.554**	**9.838**	**-0.716**	**-6.8%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	18.221	19.595	1.374	7.5%
Subtotal		26.243	28.601	2.358	9.0%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	18.958	20.240	1.283	6.8%
Total	¢/kWh	**27.579**	**29.453**	**1.875**	**6.8%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	5.798	5.405	-0.393	-6.8%
Subtotal		13.820	14.410	0.590	4.3%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	6.535	6.050	-0.484	-7.4%
Total	¢/kWh	**15.156**	**15.263**	**0.107**	**0.7%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	1.244	0.337	-0.907	-72.9%
Subtotal		9.266	9.343	0.077	0.8%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207		
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	1.981	0.982	-0.998	-50.4%
Total	¢/kWh	**10.602**	**10.195**	**-0.014**	**-3.8%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Multi-Unit Residential Buildings Time-of-Use Tariff					
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	20.552	20.686	0.134	0.7%
Subtotal		28.574	29.692	1.118	3.9%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	21.289	21.331	0.043	0.2%
Total		**29.910**	**30.544**	**0.635**	**2.1%**
Mid-Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	6.265	5.840	-0.425	-6.8%
Subtotal		14.287	14.846	0.559	3.9%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	7.002	6.485	-0.516	-7.4%
Total		**15.623**	**15.698**	**0.076**	**0.5%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	4.122	3.613	-0.509	-12.3%
Subtotal		12.144	12.619	0.475	3.9%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	4.859	4.259	-0.600	-12.3%
Total		**13.480**	**13.472**	**-0.008**	**-0.1%**
Energy Charges (April to October)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	5.551	5.098	-0.453	-8.2%
Subtotal		13.573	14.104	0.531	3.9%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	6.287	5.743	-0.544	-8.7%
Total	¢/kWh	**14.908**	**14.956**	**0.048**	**0.3%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Off-Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	3.408	2.871	-0.537	-15.8%
Subtotal		11.430	11.877	0.447	3.9%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	4.144	3.516	-0.628	-15.2%
Total	¢/kWh	**12.765**	**12.729**	**-0.036**	**-0.3%**
General Critical Peak Pricing Tariff					
Demand Charge	$/kW	**10.554**	**9.838**	**-0.716**	**-6.8%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	144.187	134.402	-9.785	-6.8%
Subtotal		152.209	143.408	-8.801	-5.8%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	144.924	135.048	-9.876	-6.8%
Total	¢/kWh	**153.545**	**144.261**	**-9.284**	**-6.0%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	3.496	3.259	-0.237	-6.8%
Subtotal		11.518	12.265	0.747	6.5%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	4.233	3.904	-0.328	-7.8%
Total	¢/kWh	**12.854**	**13.117**	**0.264**	**2.1%**
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	8.022	9.006	0.984	12.3%
Non-fuel	¢/kWh	1.656	1.544	-0.112	-6.8%
Subtotal		9.678	10.550	0.872	9.0%
FAM AA	¢/kWh	0.392	0.000	-0.392	-100.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.599	0.207	-0.392	-65.4%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.091	0.000	-0.091	-100.0%
Fuel-related in aggregate	¢/kWh	8.621	9.213	0.592	6.9%
Non-fuel related in aggregate	¢/kWh	2.393	2.189	-0.203	-8.5%
Total	¢/kWh	**11.014**	**11.402**	**0.389**	**3.5%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Large General Tariff					
Demand Charge (Ratcheted)	$/kVA	**13.845**	**11.201**	**-2.644**	**-19.1%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	7.574	8.508	0.934	12.3%
Non-fuel	¢/kWh	3.375	2.731	-0.644	-19.1%
Subtotal		10.949	11.239	0.290	2.6%
FAM AA	¢/kWh	0.359	0.000	-0.359	-100.0%
FAM BA	¢/kWh	0.158	0.158	0.000	0.0%
Subtotal		0.517	0.158	-0.359	-69.4%
DSM PCR	¢/kWh	0.768	0.768	0.000	0.0%
DSM BA	¢/kWh	0.022	0.022	0.000	0.0%
Subtotal		0.790	0.790	0.000	0.0%
SCRR	¢/kWh	0.041	0.000	-0.041	-100.0%
Fuel-related in aggregate	¢/kWh	8.091	8.666	0.575	7.1%
Non-fuel related in aggregate	¢/kWh	4.206	3.521	-0.685	-16.3%
Total	¢/kWh	**12.297**	**12.187**	**-0.110**	**-0.9%**
Small Industrial Tariff					
Demand Charge	$/kVA	**8.332**	**7.506**	**-0.825**	**-9.9%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
First 200 kWhs per kVA of Max Demand					
Base cost of fuel	¢/kWh	7.648	8.831	1.183	15.5%
Non-fuel	¢/kWh	5.589	5.035	-0.554	-9.9%
Subtotal		13.237	13.866	0.630	4.8%
FAM AA	¢/kWh	0.394	0.000	-0.394	-100.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.538	0.144	-0.394	-73.2%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.098	0.000	-0.098	-100.0%
Fuel-related in aggregate	¢/kWh	8.186	8.975	0.789	9.6%
Non-fuel related in aggregate	¢/kWh	6.440	5.788	-0.652	-10.1%
Total	¢/kWh	**14.626**	**14.763**	**0.138**	**0.9%**
All Additional KWhs					
Base cost of fuel	¢/kWh	7.648	8.831	1.183	15.5%
Non-fuel	¢/kWh	3.016	2.717	-0.299	-9.9%
Subtotal		10.663	11.548	0.884	8.3%
FAM AA	¢/kWh	0.394	0.000	-0.394	-100.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.538	0.144	-0.394	-73.2%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.098	0.000	-0.098	-100.0%
Fuel-related in aggregate	¢/kWh	8.186	8.975	0.789	9.6%
Non-fuel related in aggregate	¢/kWh	3.866	3.470	-0.397	-10.3%
Total	¢/kWh	**12.052**	**12.445**	**0.392**	**3.3%**
Medium Industrial Tariff					
Demand Charge	$/kVA	**13.796**	**10.728**	**-3.068**	**-22.2%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	7.614	8.564	0.949	12.5%
Non-fuel	¢/kWh	2.806	2.182	-0.624	-22.2%
Subtotal		10.421	10.746	0.325	3.1%
FAM AA	¢/kWh	0.358	0.000	-0.358	-100.0%
FAM BA	¢/kWh	0.206	0.206	0.000	0.0%
Subtotal		0.564	0.206	-0.358	-63.5%
DSM PCR	¢/kWh	0.306	0.306	0.000	0.0%
DSM BA	¢/kWh	0.008	0.008	0.000	0.0%
Subtotal		0.314	0.314	0.000	0.0%
SCRR	¢/kWh	0.059	0.000	-0.059	-100.0%
Fuel-related in aggregate	¢/kWh	8.178	8.770	0.591	7.2%
Non-fuel related in aggregate	¢/kWh	3.180	2.497	-0.683	-21.5%
Total		**11.358**	**11.266**	**-0.092**	**-0.8%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Large Industrial Tariff					
Demand Charge (Ratcheted)	$/kVA	**12.601**	**9.280**	**-3.321**	**-26.4%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Interruptible Credit	$/kVA	**-7.486**	**-7.638**	**-0.152**	**2.0%**
Distribution Cost Adder		**1.632**	**2.3321**	**0.701**	**42.9%**
Energy Charges					
Firm					
Base cost of fuel	¢/kWh	7.382	8.303	0.921	12.5%
Non-fuel	¢/kWh	2.802	2.0636	-0.738	-26.4%
Subtotal		10.184	10.367	0.183	1.8%
FAM AA	¢/kWh	0.366	0.000	-0.366	-100.0%
FAM BA	¢/kWh	0.247	0.247	0.000	0.0%
Subtotal		0.613	0.247	-0.366	-59.7%
DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
Subtotal		0.431	0.431	0.000	0.0%
SCRR (Transmission)	¢/kWh	0.002	0.000	-0.002	-100.0%
SCRR (Distribution)	¢/kWh	0.037	0.000	-0.037	-100.0%
Subtotal		0.039	0.000	-0.039	-100.0%
Fuel-related in aggregate	¢/kWh	7.995	8.550	0.555	6.9%
Non-fuel related in aggregate	¢/kWh	3.235	2.495	-0.740	-22.9%
Total		**11.230**	**11.045**	**-0.185**	**-1.6%**
Interruptible					
Base cost of fuel	¢/kWh	7.382	8.342	0.960	13.0%
Non-fuel	¢/kWh	2.802	2.064	-0.738	-26.4%
Subtotal		10.184	10.406	0.222	2.2%
FAM AA	¢/kWh	0.366	0.000	-0.366	-100.0%
FAM BA	¢/kWh	0.224	0.224	0.000	0.0%
Subtotal		0.590	0.224	-0.366	-62.0%
DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
Subtotal		0.431	0.431	0.000	0.0%
SCRR (Transmission)	¢/kWh	0.002	0.000	-0.002	-100.0%
SCRR (Distribution)	¢/kWh	0.037	0.000	-0.037	-100.0%
Subtotal		0.039	0.000	-0.039	-100.0%
Fuel-related in aggregate	¢/kWh	7.972	8.566	0.594	7.5%
Non-fuel related in aggregate	¢/kWh	3.235	2.495	-0.740	-22.9%
Total	¢/kWh	**11.207**	**11.061**	**-0.146**	**-1.3%**
Municipal Tariff					
Demand Charge (Ratcheted)	$/kVA	**13.428**	**11.330**	**-2.098**	**-15.6%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	7.035	9.022	1.987	28.2%
Non-fuel	¢/kWh	3.098	2.614	-0.484	-15.6%
Subtotal		10.133	11.636	1.503	14.8%
FAM AA	¢/kWh	0.418	0.000	-0.418	-100.0%
FAM BA	¢/kWh	0.105	0.105	0.000	0.0%
Subtotal		0.523	0.105	-0.418	-79.9%
DSM PCR	¢/kWh	0.650	0.650	0.000	0.0%
DSM BA	¢/kWh	-0.023	-0.023	0.000	0.0%
Subtotal		0.627	0.627	0.000	0.0%
SCRR	¢/kWh	0.002	0.000	-0.002	-100.0%
Fuel-related in aggregate	¢/kWh	7.558	9.127	1.569	20.8%
Non-fuel related in aggregate	¢/kWh	3.727	3.241	-0.486	-13.0%
Total		**11.285**	**12.368**	**1.083**	**9.6%**
Outdoor Recreational Lighting Tariff					
Energy Charges					
Base cost of fuel	¢/kWh	7.430	7.650	0.220	3.0%
Non-fuel	¢/kWh	10.443	3.615	-6.828	-65.4%
Subtotal		17.873	11.265	-6.608	-37.0%
FAM AA	¢/kWh	0.413	0.000	-0.413	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.569	0.156	-0.413	-72.6%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.485	0.000	-0.485	-100.0%
Fuel-related in aggregate	¢/kWh	7.999	7.806	-0.193	-2.4%
Non-fuel related in aggregate	¢/kWh	11.285	3.972	-7.313	-64.8%
Total		**19.284**	**11.778**	**-7.506**	**-38.9%**

RATE SCHEDULES

	units	2025	2026	Variance	% Variance
Unmetered Service Rates: Miscellaneous Lighting & Small Loads					
Demand Charge	$/kW	**12.314**	**13.690**	1.376	11.2%
Energy Charges					
First 200 kWhs per kW of Max Demand					
Base cost of fuel	¢/kWh	7.430	7.650	0.220	3.0%
Non-fuel	¢/kWh	8.379	9.681	1.302	15.5%
Subtotal		15.809	17.331	1.522	9.6%
FAM AA	¢/kWh	0.413	0.000	-0.413	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.569	0.156	-0.413	-72.6%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.485	0.000	-0.485	-100.0%
Fuel-related in aggregate	¢/kWh	7.999	7.806	-0.193	-2.4%
Non-fuel related in aggregate	¢/kWh	9.221	10.038	0.817	8.9%
Total		**17.220**	**17.844**	**0.624**	**3.6%**
All Additional KWhs					
Base cost of fuel	¢/kWh	7.430	7.650	0.220	3.0%
Non-fuel	¢/kWh	3.647	4.493	0.846	23.2%
Subtotal		11.077	12.143	1.066	9.6%
FAM AA	¢/kWh	0.413	0.000	-0.413	-100.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.569	0.156	-0.413	-72.6%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.485	0.000	-0.485	-100.0%
Fuel-related in aggregate	¢/kWh	7.999	7.806	-0.193	-2.4%
Non-fuel related in aggregate	¢/kWh	4.489	4.850	0.361	8.1%
Total	¢/kWh	**12.488**	**12.656**	**0.168**	**1.3%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Domestic Service Tariff (Standard Offer)					
Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Energy Charges					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	9.495	10.334	0.839	8.8%
Subtotal		18.454	19.216	0.762	4.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	10.128	10.967	0.839	8.3%
Total		**19.243**	**20.006**	**0.762**	**4.0%**
Domestic Service Time-of-Day Tariff				6.3%	4.4%
Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Energy Charges (December to February)					
Peak Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	15.647	17.030	1.383	8.8%
Subtotal		24.606	25.912	1.306	5.3%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	16.281	17.663	1.383	8.5%
Total		**25.396**	**26.702**	**1.306**	**5.1%**
Shoulder Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	10.648	11.589	0.941	8.8%
Subtotal		19.607	20.471	0.864	4.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	11.281	12.222	0.941	8.3%
Total		**20.397**	**21.261**	**0.864**	**4.2%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	2.702	2.940	0.239	8.8%
Subtotal		11.661	11.823	0.162	1.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	3.335	3.574	0.239	7.2%
Total		**12.450**	**12.612**	**0.162**	**1.3%**
Energy Charges (March to November)					
Peak Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	10.648	11.589	0.941	8.8%
Subtotal		19.607	20.471	0.864	4.4%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	11.281	12.222	0.941	8.3%
Total	¢/kWh	**20.397**	**21.261**	**0.864**	**4.2%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	2.702	2.940	0.239	8.8%
Subtotal		11.661	11.823	0.162	1.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	3.335	3.574	0.239	7.2%
Total	¢/kWh	**12.450**	**12.612**	**0.162**	**1.3%**

Domestic Service Time-of-Use Tariff

Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	27.844	29.669	1.825	6.6%
Subtotal		36.803	38.551	1.749	4.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	28.477	30.302	1.825	6.4%
Total	¢/kWh	**37.592**	**39.341**	**1.749**	**4.7%**
Off-Peak Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	9.495	10.334	0.839	8.8%
Subtotal		18.454	19.216	0.762	4.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	10.128	10.967	0.839	8.3%
Total	¢/kWh	**19.243**	**20.006**	**0.762**	**4.0%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	3.537	4.092	0.555	15.7%
Subtotal		12.496	12.975	0.479	3.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	4.170	4.726	0.555	13.3%
Total	¢/kWh	**13.285**	**13.764**	**0.479**	**3.6%**

Domestic Service Critical Peak Pricing Tariff

Customer Charge	$/mo	**20.24**	**21.38**	**1.13**	**5.6%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	174.634	184.349	9.714	5.6%
Subtotal		183.593	193.231	9.638	5.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	175.268	184.982	9.714	5.5%
Total	¢/kWh	**184.383**	**194.021**	**9.638**	**5.2%**
Non-Critical Peak Hours Charge					
Base cost of fuel	¢/kWh	8.959	8.883	-0.077	-0.9%
Non-fuel	¢/kWh	6.552	7.198	0.647	9.9%
Subtotal		15.511	16.081	0.570	3.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.657	0.657	0.000	0.0%
DSM BA	¢/kWh	-0.024	-0.024	0.000	0.0%
Subtotal		0.633	0.633	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.115	9.039	-0.077	-0.8%
Non-fuel related in aggregate	¢/kWh	7.185	7.832	0.647	9.0%
Total	¢/kWh	**16.300**	**16.870**	**0.570**	**3.5%**

Small General Tariff (Standard Offer)

Customer Charge	$/mo	**22.16**	**23.07**	**0.91**	**4.1%**
Energy Charges					
First 200 kWh Block					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%
Non-fuel	¢/kWh	9.984	11.054	1.070	10.7%
Subtotal		19.053	19.951	0.898	4.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	10.737	11.807	1.070	10.0%
Total	¢/kWh	**19.962**	**20.860**	**0.898**	**4.5%**
All Additional KWhs					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%
Non-fuel	¢/kWh	8.155	9.029	0.874	10.7%
Subtotal		17.224	17.925	0.701	4.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	8.908	9.782	0.874	9.8%
Total	¢/kWh	**18.133**	**18.834**	**0.701**	**3.9%**
Small General Time-of-Use Tariff					
Customer Charge	$/mo	**22.16**	**23.07**	**0.91**	**4.1%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%
Non-fuel	¢/kWh	28.868	31.116	2.248	7.8%
Subtotal		37.937	40.012	2.075	5.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	29.621	31.869	2.248	7.6%
Total	¢/kWh	**38.846**	**40.921**	**2.075**	**5.3%**
Off-Peak Period					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%
Non-fuel	¢/kWh	9.967	11.035	1.069	10.7%
Subtotal		19.036	19.931	0.896	4.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	10.720	11.788	1.069	10.0%
Total	¢/kWh	**19.945**	**20.840**	**0.896**	**4.5%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%
Non-fuel	¢/kWh	3.399	3.911	0.512	15.1%
Subtotal		**12.468**	**12.807**	**0.339**	**2.7%**
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156		
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	4.152	4.664	0.512	12.3%
Total	¢/kWh	**13.377**	**13.716**	**0.339**	**2.5%**
Small General Critical Peak Pricing Tariff					
Customer Charge	$/mo	**22.16**	**23.07**	**0.91**	**4.1%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%
Non-fuel	¢/kWh	144.626	160.133	15.507	10.7%
Subtotal		153.695	169.029	15.334	10.0%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	145.379	160.886	15.507	10.7%
Total	¢/kWh	**154.604**	**169.938**	**15.334**	**9.9%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Non-fuel	¢/kWh	7.777	8.611	0.834	10.7%
Subtotal		16.846	17.507	0.661	3.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	8.530	9.364	0.834	9.8%
Total	¢/kWh	**17.755**	**18.416**	**0.661**	**3.7%**
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	9.069	8.896	-0.173	-1.9%
Non-fuel	¢/kWh	6.352	7.033	0.681	10.7%
Subtotal		15.421	15.929	0.508	3.3%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.778	0.778	0.000	0.0%
DSM BA	¢/kWh	-0.025	-0.025	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.225	9.052	-0.173	-1.9%
Non-fuel related in aggregate	¢/kWh	7.105	7.786	0.681	9.6%
Total	¢/kWh	**16.330**	**16.838**	**0.508**	**3.1%**
General Tariff (Standard Offer)					
Demand Charge	$/kW	**9.838**	**10.709**	**0.872**	**8.9%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
First 200 kWhs per kW of Max Demand					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	5.840	6.357	0.518	8.9%
Subtotal		14.846	14.822	-0.024	-0.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	6.485	7.003	0.518	8.0%
Total	¢/kWh	**15.698**	**15.675**	**-0.024**	**-0.2%**
All Additional KWhs					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	2.767	3.012	0.245	8.9%
Subtotal		11.773	11.476	-0.296	-2.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	3.412	3.657	0.245	7.2%
Total	¢/kWh	**12.625**	**12.329**	**-0.296**	**-2.3%**
General Time-of-Use Tariff					
Demand Charge	$/kW	**9.838**	**10.709**	**0.872**	**8.9%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	19.595	20.484	0.889	4.5%
Subtotal		28.601	28.949	0.348	1.2%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	20.240	21.130	0.889	4.4%
Total	¢/kWh	**29.453**	**29.801**	**0.348**	**1.2%**
Off-Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	5.405	5.883	0.479	8.9%
Subtotal		14.410	14.348	-0.062	-0.4%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	6.050	6.529	0.479	7.9%
Total	¢/kWh	**15.263**	**15.201**	**-0.062**	**-0.4%**
Energy Charges (April to October)					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	0.337	0.634	0.297	88.1%
Subtotal		9.343	9.098	-0.244	-2.6%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207		
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	0.982	1.279	0.297	30.2%
Total	¢/kWh	**10.195**	**9.951**	**-0.244**	**-2.4%**

Multi-Unit Residential Buildings Time-of-Use Tariff

Energy Charges (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	20.686	21.179	0.494	2.4%
Subtotal		29.692	29.644	-0.048	-0.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	21.331	21.825	0.494	2.3%
Total		**30.544**	**30.497**	**-0.048**	**-0.2%**
Mid-Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	5.840	6.357	0.518	8.9%
Subtotal		14.846	14.822	-0.024	-0.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	6.485	7.003	0.518	8.0%
Total		**15.698**	**15.675**	**-0.024**	**-0.2%**
Off-Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	3.613	4.134	0.521	14.4%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Subtotal		12.619	12.599	-0.020	-0.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	4.259	4.780	0.521	12.2%
Total		**13.472**	**13.451**	**-0.020**	**-0.2%**
Energy Charges (April to October)					
Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	5.098	5.616	0.519	10.2%
Subtotal		14.104	14.081	-0.023	-0.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	5.743	6.262	0.519	9.0%
Total	¢/kWh	**14.956**	**14.934**	**-0.023**	**-0.2%**
Off-Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	2.871	3.393	0.522	18.2%
Subtotal		11.877	11.858	-0.019	-0.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	3.516	4.039	0.522	14.9%
Total	¢/kWh	**12.729**	**12.710**	**-0.019**	**-0.1%**

General Critical Peak Pricing Tariff

Demand Charge	$/kW	**9.838**	**10.709**	**0.872**	**8.9%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Critical Peak Hours Charge (November to March)					
Peak Period					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	134.402	146.313	11.911	8.9%
Subtotal		143.408	154.778	11.370	7.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	135.048	146.959	11.911	8.8%
Total	¢/kWh	**144.261**	**155.630**	**11.370**	**7.9%**
Non-Critical Peak Hours First 200 kWh Block Charge					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	3.259	3.548	0.289	8.9%
Subtotal		12.265	12.012	-0.253	-2.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Non-fuel related in aggregate	¢/kWh	3.904	4.193	0.289	7.4%
Total	¢/kWh	**13.117**	**12.865**	**-0.253**	**-1.9%**
Non-Critical Peak Hours All Additional kWh Block Charge					
Base cost of fuel	¢/kWh	9.006	8.465	-0.541	-6.0%
Non-fuel	¢/kWh	1.544	1.680	0.137	8.9%
Subtotal		10.550	10.145	-0.405	-3.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.207	0.207	0.000	0.0%
Subtotal		0.207	0.207	0.000	0.0%
DSM PCR	¢/kWh	0.635	0.635	0.000	0.0%
DSM BA	¢/kWh	0.010	0.010	0.000	0.0%
Subtotal		0.646	0.646	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.213	8.672	-0.541	-5.9%
Non-fuel related in aggregate	¢/kWh	2.189	2.326	0.137	6.2%
Total	¢/kWh	**11.402**	**10.998**	**-0.405**	**-3.5%**
Large General Tariff					
Demand Charge (Ratcheted)	$/kVA	**11.201**	**12.003**	**0.802**	**7.2%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	8.508	7.676	-0.832	-9.8%
Non-fuel	¢/kWh	2.731	2.926	0.195	7.2%
Subtotal		11.239	10.602	-0.636	-5.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.158	0.158	0.000	0.0%
Subtotal		0.158	0.158	0.000	0.0%
DSM PCR	¢/kWh	0.768	0.768	0.000	0.0%
DSM BA	¢/kWh	0.022	0.022	0.000	0.0%
Subtotal		0.790	0.790	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.666	7.834	-0.832	-9.6%
Non-fuel related in aggregate	¢/kWh	3.521	3.716	0.195	5.6%
Total	¢/kWh	**12.187**	**11.550**	**-0.636**	**-5.2%**
Small Industrial Tariff					
Demand Charge	$/kVA	**7.506**	**8.143**	**0.636**	**8.5%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
First 200 kWhs per kVA of Max Demand					
Base cost of fuel	¢/kWh	8.831	8.288	-0.543	-6.1%
Non-fuel	¢/kWh	5.035	5.462	0.427	8.5%
Subtotal		13.866	13.750	-0.116	-0.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.144	0.144	0.000	0.0%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.975	8.432	-0.543	-6.0%
Non-fuel related in aggregate	¢/kWh	5.788	6.215	0.427	7.4%
Total	¢/kWh	**14.763**	**14.647**	**-0.116**	**-0.8%**
All Additional KWhs					
Base cost of fuel	¢/kWh	8.831	8.288	-0.543	-6.1%
Non-fuel	¢/kWh	2.717	2.947	0.230	8.5%
Subtotal		11.548	11.235	-0.313	-2.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.144	0.144	0.000	0.0%
Subtotal		0.144	0.144	0.000	0.0%
DSM PCR	¢/kWh	0.720	0.720	0.000	0.0%
DSM BA	¢/kWh	0.033	0.033	0.000	0.0%
Subtotal		0.753	0.753	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.975	8.432	-0.543	-6.0%
Non-fuel related in aggregate	¢/kWh	3.470	3.700	0.230	6.6%
Total	¢/kWh	**12.445**	**12.132**	**-0.313**	**-2.5%**

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
Medium Industrial Tariff					
Demand Charge	$/kVA	**10.728**	**11.277**	**0.549**	**5.1%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	8.564	7.595	-0.968	-11.3%
Non-fuel	¢/kWh	2.182	2.294	0.112	5.1%
Subtotal		10.746	9.889	-0.857	-8.0%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.206	0.206	0.000	0.0%
Subtotal		0.206	0.206	0.000	0.0%
DSM PCR	¢/kWh	0.306	0.306	0.000	0.0%
DSM BA	¢/kWh	0.008	0.008	0.000	0.0%
Subtotal		0.314	0.314	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.770	7.801	-0.968	-11.0%
Non-fuel related in aggregate	¢/kWh	2.497	2.608	0.112	4.5%
Total		**11.266**	**10.410**	**-0.857**	**-7.6%**
Large Industrial Tariff					
Demand Charge (Ratcheted)	$/kVA	**9.280**	**10.000**	**0.719**	**7.8%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Interruptible Credit	$/kVA	**-7.638**	**-7.667**	**-0.029**	**0.4%**
Distribution Cost Adder		**2.332**	**2.527**	**0.194**	**8.3%**
Energy Charges					
Firm					
Base cost of fuel	¢/kWh	8.303	7.455	-0.848	-10.2%
Non-fuel	¢/kWh	2.064	2.224	0.160	7.8%
Subtotal		10.367	9.678	-0.688	-6.6%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.247	0.247	0.000	0.0%
Subtotal		0.247	0.247	0.000	0.0%
DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
Subtotal		0.431	0.431	0.000	0.0%
SCRR (Transmission)	¢/kWh	0.000	0.000	0.000	0.0%
SCRR (Distribution)	¢/kWh	0.000	0.000	0.000	0.0%
Subtotal		0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.550	7.702	-0.848	-9.9%
Non-fuel related in aggregate	¢/kWh	2.495	2.655	0.160	6.4%
Total		**11.045**	**10.356**	**-0.688**	**-6.2%**
Interruptible					
Base cost of fuel	¢/kWh	8.342	7.434	-0.908	-10.9%
Non-fuel	¢/kWh	2.064	2.224	0.160	7.8%
Subtotal		10.406	9.658	-0.748	-7.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.224	0.224	0.000	0.0%
Subtotal		0.224	0.224	0.000	0.0%
DSM PCR	¢/kWh	0.404	0.404	0.000	0.0%
DSM BA	¢/kWh	0.027	0.027	0.000	0.0%
Subtotal		0.431	0.431	0.000	0.0%
SCRR (Transmission)	¢/kWh	0.000	0.000	0.000	0.0%
SCRR (Distribution)	¢/kWh	0.000	0.000	0.000	0.0%
Subtotal		0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	8.566	7.658	-0.908	-10.6%
Non-fuel related in aggregate	¢/kWh	2.495	2.655	0.160	6.4%
Total	¢/kWh	**11.061**	**10.313**	**-0.748**	**-6.8%**
Municipal Tariff					
Demand Charge (Ratcheted)	$/kVA	**11.330**	**12.270**	**0.940**	**8.3%**
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	**0.000**	**0.0%**
Energy Charges					
Base cost of fuel	¢/kWh	9.022	8.956	-0.066	-0.7%
Non-fuel	¢/kWh	2.614	2.831	0.217	8.3%
Subtotal		11.636	11.787	0.151	1.3%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.105	0.105	0.000	0.0%
Subtotal		0.105	0.105	0.000	0.0%
DSM PCR	¢/kWh	0.650	0.650	0.000	0.0%

RATE SCHEDULES

	units	2026	2027	Variance	% Variance
DSM BA	¢/kWh	-0.023	-0.023	0.000	0.0%
Subtotal		0.627	0.627	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	9.127	9.061	-0.066	-0.7%
Non-fuel related in aggregate	¢/kWh	3.241	3.458	0.217	6.7%
Total		**12.368**	**12.519**	**0.151**	**1.2%**

Outdoor Recreational Lighting Tariff

Energy Charges					
Base cost of fuel	¢/kWh	7.650	8.441	0.791	10.3%
Non-fuel	¢/kWh	3.615	3.492	-0.124	-3.4%
Subtotal		11.265	11.932	0.667	5.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	7.806	8.597	0.791	10.1%
Non-fuel related in aggregate	¢/kWh	3.972	3.849	-0.124	-3.1%
Total		**11.778**	**12.446**	**0.667**	**5.7%**

Unmetered Service Rates: Miscellaneous Lighting & Small Loads

Demand Charge	$/kW	**13.690**	**14.341**	0.651	4.8%
Energy Charges					
First 200 kWhs per kW of Max Demand					
Base cost of fuel	¢/kWh	7.650	8.441	0.791	10.3%
Non-fuel	¢/kWh	9.681	10.261	0.581	6.0%
Subtotal		17.331	18.702	1.371	7.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	7.806	8.597	0.791	10.1%
Non-fuel related in aggregate	¢/kWh	10.038	10.619	0.581	5.8%
Total		**17.844**	**19.215**	**1.371**	**7.7%**
All Additional KWhs					
Base cost of fuel	¢/kWh	7.650	8.441	0.791	10.3%
Non-fuel	¢/kWh	4.493	4.663	0.170	3.8%
Subtotal		12.143	13.104	0.961	7.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0.0%
FAM BA	¢/kWh	0.156	0.156	0.000	0.0%
Subtotal		0.156	0.156	0.000	0.0%
DSM PCR	¢/kWh	0.353	0.353	0.000	0.0%
DSM BA	¢/kWh	0.004	0.004	0.000	0.0%
Subtotal		0.357	0.357	0.000	0.0%
SCRR	¢/kWh	0.000	0.000	0.000	0.0%
Fuel-related in aggregate	¢/kWh	7.806	8.597	0.791	10.1%
Non-fuel related in aggregate	¢/kWh	4.850	5.021	0.170	3.5%
Total	¢/kWh	**12.656**	**13.617**	**0.961**	**7.6%**

2026-2027 GRA SR-01 Attachment 9 has been filed electronically.

2026-2027 GRA SR-01 Attachment 10 has been filed electronically.

2026-2027 GRA SR-01 Attachment 11 has been filed electronically.

2026 Embedded Cost of Ancillary Services

TABLE E4-2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
VOLTAGE CONTROL and REACTIVE SUPPORT SERVICES REVENUE REQUIREMENT

Unit	Generator Nameplate Rating					Generator Net Book Value	Fixed Charge Rate	MVAR Production 97 percentile	Allocation to Reactive Power	Allocated Generator Cost	Exciter Cost Ratio	Exciter Cost	Total Gen/Exciter Allocation	Unit Exciter Rating		Ratio of Exciter to Unit Ratings	Exciter Capacity **(Note 4)**	Unit Reactive Capacity Factor	Exciter Energy Consumption Cost
	MVA	MW	MVAR	Peak MW	PRACTICAL MVAR	$				$		$	$	kVA	kW		$		$
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Formula			**(Note 2)**	**(Note 3)**	= sqrt((1*1) - (4*4))				= (5*5)/(1*1)	= 6*9		= 6*11	= 7*(10+12)			= 15/2/1000	= 6*7*16		= 15/1000*8760*18*T46
Lingan 1	177.0	150.0	94.0	161.8	71.8	$1,176,072	39.73%	15.50	16.44%	$193,319	8%	$94,086	$114,173	1430	858	0.57%	$2,672	29.41%	$218,463
Lingan 2	177.0	150.0	94.0	156.0	83.6	$1,176,072	39.73%	13.20	22.32%	$262,513	8%	$94,086	$141,660	1430	858	0.57%	$2,672	8.25%	$61,277
Lingan 3	177.0	150.0	94.0	162.0	71.3	$4,590,514	39.73%	14.50	16.2%	$745,085	8%	$367,241	$441,876	1430	858	0.57%	$10,431	30.05%	$223,231
Lingan 4	177.0	150.0	94.0	162.0	71.3	$4,590,514	39.73%	13.50	16.2%	$745,085	8%	$367,241	$441,876	1430	858	0.57%	$10,431	24.80%	$184,226
Tufts Cove 1	117.0	100.0	60.7	83.0	60.7	$559,306	70.16%	8.70	26.9%	$150,725	10%	$55,931	$144,988	639	383	0.38%	$1,505	36.13%	$119,906
Tufts Cove 2	117.0	100.0	60.7	97.0	60.7	$782,917	70.16%	9.70	26.9%	$210,986	8%	$62,633	$191,969	424	255	0.25%	$1,399	36.11%	$79,597
Tufts Cove 3	177.0	150.0	94.0	153.0	89.0	$1,201,614	70.16%	22.00	25.3%	$303,769	8%	$96,129	$280,565	1968	1181	0.79%	$6,636	35.88%	$366,752
Tufts Cove 4	60.0	54.0	26.2	49.0	26.2	$10,748,902	15.93%	5.30	19.0%	$2,042,291	8%	$859,912	$462,387	413	248	0.46%	$7,865	45.24%	$97,123
Tufts Cove 5	60.0	54.0	26.2	49.0	26.2	$7,745,937	15.94%	4.60	19.0%	$1,471,728	8%	$619,675	$333,392	413	248	0.46%	$5,671	46.95%	$100,799
Tufts Cove 6	59.8	46.0	38.1	46.0	38.1	$12,693,585	18.38%	4.80	40.7%	$5,172,530	8%	$1,015,487	$1,137,478	413	250	0.0	$12,681	30.04%	$65,010
Trenton 5	177.0	150.0	94.0	159.0	77.8	$5,022,218	121.71%	16.40	19.3%	$969,529	8%	$401,777	$1,668,956	1402	841	0.56%	$34,278	13.46%	$98,001
Trenton 6	188.0	160.0	98.7	160.0	98.7	($3,117,780)	121.71%	19.30	27.6%	($859,542)	8%	($249,422)	($1,349,671)	1700	1020	0.64%	($24,190)	35.38%	$312,380
Pt. Tupper 2	177.0	150.0	94.0	155.0	85.5	$6,315,829	33.20%	19.50	23.3%	$1,472,464	8%	$505,266	$656,627	1186	711	0.47%	$9,945	31.77%	$195,688
Pt. Aconi 1	218.0	185.0	115.3	184.0	115.3	$11,668,114	19.13%	14.50	28.0%	$3,265,176	8%	$933,449	$803,314	1800	1080	0.58%	$13,033	36.21%	$338,589
Wreck Cove 1	112.0	100.0	50.4	106.0	36.2	$3,458,135	13.51%	7.10	10.4%	$360,590	8%	$276,651	$86,115	575	345	0.35%	$1,612	0.40%	$1,205
Wreck Cove 2	112.0	100.0	50.4	106.0	36.2	$3,458,135	13.51%	8.10	10.4%	$360,590	8%	$276,651	$86,115	575	345	0.35%	$1,612	17.89%	$53,435
Annapolis Tidal (Note 5)	0.0	0.0	0.0	0.0	0.0	$1,301,939	25.29%	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wind (Note 1)	0.0	0.0	0.0	0.0	0.0	$0		0.0											$0
Other Hydro	181.0	163.0	78.7	163.0	78.7	$26,516,427	16.49%	18.0	18.9%	$0	8%	$2,121,314	$349,851	1358	815	0.50%	$21,852	23.00%	$162,152
Burnside 1	35.0	30.0	18.0	30.0	18.0	$1,952,307	19.87%	2.90	26.5%	$517,959	8%	$156,185	$133,925	169	102	0.34%	$1,313	0.53%	$462
Burnside 2	35.0	30.0	18.0	30.0	18.0	$1,952,307	19.87%	0.00	26.53%	$517,959	8%	$156,185	$133,925	169	102	0.34%	$1,313	0.34%	$299
Burnside 3	35.0	30.0	18.0	30.0	18.0	$1,952,307	19.87%	1.00	26.53%	$517,959	8%	$156,185	$133,925	169	102	0.34%	$1,313	0.44%	$388
Burnside 4	35.0	30.0	18.0	30.0	18.0	$1,952,307	19.87%	0.00	26.53%	$517,959	8%	$156,185	$133,925	169	102	0.34%	$1,313	0.36%	$320
Victoria Junction 1	35.0	30.0	18.0	30.0	18.0	$1,849,238	17.54%	4.90	26.53%	$490,614	8%	$147,939	$112,021	169	102	0.34%	$1,098	2.66%	$2,343
Victoria Junction 2	35.0	30.0	18.0	30.0	18.0	$1,849,238	17.54%	4.80	26.53%	$490,614	8%	$147,939	$112,021	169	102	0.34%	$1,098	4.06%	$3,568
Tusket 1 (Note 6)	35.0	30.0	18.0	30.3	17.5	$2,363,869	26.91%	0.00	25.05%	$592,241	8%	$189,110	$210,260	169	102	0.34%	$2,154	2.37%	$2,088
TOTALS	2,708.8	2,322.0	1,389.5	2,362.1	1,252.9	$113,760,021		228.3		$20,512,143		$9,007,833	$6,961,677				$129,709		$2,687,299

NOTES:

1. Current wind generation does not provide continuous voltage control. IPP embedded in PPA
2. Nameplate based on MVA and rated Power Factor.
3. Gross generator peak capacity.
4. Value of increased generator capacity required to operate exciter.
5. Unit not currently available for generation.
6. Tusket CT rebuilt 2019 2020, returned to service Dec 2020

Total VAR Requirements Mvar (Col. 8 doubled)	456.6
Total Reactive Support Costs - (Col.13+Col.17+Col.19)	$9,778,686
Ratio of VAR Requirements to Sum of Generator VAR Ratings	36.4%
Support services to Maritime Link STATCOM benefit	$554,307
Total Reactive Support Costs	**$4,117,997**

Average Cost of System Losses ($/MWh)	$98.82
Confidential	

2026 Embedded Cost of Ancillary Services

TABLE E4-3

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
REGULATION REVENUE REQUIREMENT

Unit	Generator Nameplate Capacity MW	Regulating Capacity MW	Regulating Ramp Rate MW/min	Time on AGC Hours	Regulating Capacity MWh	Ramp Rate Weighting Factor	Weighted Capacity to Regulate MWh	Participation Percentage	Net Book Value $/kW	Fixed Charge Rate	$/kW-yr	Weighted Annual Cost $/kW
Column	1	2	3	4	5	6	7	8	9	10	11	12
Formula		**(Note 1)**	**(Note 2)**	**(Note 3)**	= 2*4	= 3/(Sum of 3)	= 5*6	= 7/(Sum of 7)			= 9*10	= 8*11
Lingan 1	150	25	1.0	3,058.8	76,469	1%	503	1%	$320.37	39.73%	$127.27	$ 1.07
Lingan 2	150	25	1.0	0.0	-	1%	0	0%	$320.37	39.73%	$127.27	$ -
Lingan 3	150	25	1.0	3,195.0	79,875	1%	525	1%	$320.37	39.73%	$127.27	$ 1.11
Lingan 4	150	25	1.0	3,790.3	94,756	1%	623	1%	$320.37	39.73%	$127.27	$ 1.32
Tufts Cove 1	100	10	1.0	0.0	-	1%	0	0%	$179.94	70.16%	$126.24	$ -
Tufts Cove 2	100	11	1.5	3,376.0	37,136	1%	366	1%	$179.94	70.16%	$126.24	$ 0.77
Tufts Cove 3	150	52	1.5	6,379.0	331,708	1%	3,273	5%	$179.94	70.16%	$126.24	$ 6.87
Tufts Cove 4	54	30	10.0	6,268.3	188,048	7%	12,372	21%	$995.27	15.93%	$158.57	$ 32.64
Tufts Cove 5	54	30	10.0	6,419.8	192,593	7%	12,671	21%	$717.22	15.94%	$114.33	$ 24.10
Tufts Cove 6	46	0	0.0	0.0	-	0%	0	0%	$181.34	11.24%	$20.38	$ -
Trenton 5	150	30	1.0	0.0	-	1%	0	0%	$102.39	121.71%	$124.61	$ -
Trenton 6	160	25	2.0	3,926.5	98,163	1%	1,292	2%	$102.39	121.71%	$124.61	$ 2.68
Pt. Tupper 2	150	70	1.0	3,633.8	254,363	1%	1,673	3%	$701.76	33.20%	$232.99	$ 6.49
Pt. Aconi 1	185	0	0.0	0.0	-	0%	0	0%	$1,802.03	19.13%	$344.78	$ -
Wreck Cove 1	100	60	15.0	2,792.3	167,535	10%	16,533	28%	$1,383.25	13.51%	$186.93	$ 51.41
Wreck Cove 2	100	60	15.0	1,647.5	98,850	10%	9,755	16%	$1,383.25	13.51%	$186.93	$ 30.34
Annapolis Tidal	0	0	0.0	0.0	-	0%	0	0%	$1,513.88	25.29%	$382.88	$ -
Other Hydro	163	40	20.0	0.0	-	13%	0	0%	$2,323.96	16.49%	$383.27	$ -
Burnside 1	30	25	10.0	87.5	2,188	7%	144	0%	$325.38	19.87%	$64.64	$ 0.15
Burnside 2	30	25	10.0	56.0	1,400	7%	92	0%	$325.38	19.87%	$64.64	$ 0.10
Burnside 3	30	25	10.0	55.0	1,375	7%	90	0%	$325.38	19.87%	$64.64	$ 0.10
Burnside 4	30	25	10.0	45.5	1,138	7%	75	0%	$325.38	19.87%	$64.64	$ 0.08
Victoria Junction 1	30	25	10.0	45.5	1,138	7%	75	0%	$308.21	17.54%	$54.07	$ 0.07
Victoria Junction 2	30	25	10.0	22.0	550	7%	36	0%	$308.21	17.54%	$54.07	$ 0.03
Tusket 4	30	10	10.0	17.5	175	7%	12	0%	$492.47	26.91%	$132.52	$ 0.03
TOTALS	2322	678	152.0	44816	1,627,457	100%	60,111	100%				$ 159.35

NOTES:

1. Capacity assigned to Automatic Generation Control.
2. Unit tested capability for ramping control
3. Two year average (SCADA records)

2026 Embedded Cost of Ancillary Services

TABLE E4-4

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
LOAD FOLLOWING REVENUE REQUIREMENT

Unit	Type	Net Book Value $/kW	Fixed Charge Rate		Contribution to Load Following Winter morning MW-h	Unit Contribution	Weighted Annual Cost $/kW
Column		1	2	3	4	5	6
Formula				= 1*2		= 4/(Sum of 4)	= 3*5
Lingan 1	Thermal	$320.37	39.73%	$127.27	1,244	9%	$ 11.25
Lingan 2	Thermal	$320.37	39.73%	$127.27	1,743	12%	$ 15.76
Lingan 3	Thermal	$320.37	39.73%	$127.27	672	5%	$ 6.07
Lingan 4	Thermal	$320.37	39.73%	$127.27	933	7%	$ 8.43
Tufts Cove 1	Thermal	$179.94	70.16%	$126.24	42	0%	$ 0.38
Tufts Cove 2	Thermal	$179.94	70.16%	$126.24	510	4%	$ 4.57
Tufts Cove 3	Thermal	$179.94	70.16%	$126.24	1,357	10%	$ 12.17
Tufts Cove 4	Thermal	$995.27	15.93%	$158.57	-	0%	$ -
Tufts Cove 5	Thermal	$717.22	15.94%	$114.33	127	1%	$ 1.03
Tufts Cove 6	Thermal	$181.34	18.38%	$33.33	-	0%	$ -
Trenton 5	Thermal	$102.39	121.71%	$124.61	773	5%	$ 6.84
Trenton 6	Thermal	$102.39	121.71%	$124.61	338	2%	$ 2.99
Pt. Tupper 2	Thermal	$701.76	33.20%	$232.99	830	6%	$ 13.74
Pt. Aconi 1	Thermal	$1,802.03	19.13%	$344.78	705	5%	$ 17.27
Wreck Cove 1	Hydro	$1,383.25	13.51%	$186.93	2,782	20%	$ 36.94
Wreck Cove 2	Hydro	$1,383.25	13.51%	$186.93	1,280	9%	$ 17.00
Annapolis Tidal	Hydro	$1,513.88	25.29%	$382.88	-	0%	$ -
Other Hydro	Hydro	$2,323.96	16.49%	$383.27	654	5%	$ 17.81
Burnside 1	LFO	$325.38	19.87%	$64.64	35	0%	$ 0.16
Burnside 2	LFO	$325.38	19.87%	$64.64	5	0%	$ 0.02
Burnside 3	LFO	$325.38	19.87%	$64.64	24	0%	$ 0.11
Burnside 4	LFO	$325.38	19.87%	$64.64	24	0%	$ 0.11
TOTALS					14,078	100%	$ 172.64

NOTES:

1. Average one-hour load pickup morning peak November 2023 - March 2024 (SCADA records)

2026 Embedded Cost of Ancillary Services

TABLE E4-5

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SPINNING 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Spinning Reserve (10 Minutes)						
											Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
Column		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Formula					= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**		= Min (1,9*10)		**(Note 4)**	= Max (0,Min(1-7,10))*6*11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	$320.37	39.73%	$127.27	484,073	5440	89.0	0.593	1.0	10.0	1	-	54,405	54,405	6%	$ 7.05
Lingan 2	Thermal	150	$320.37	39.73%	$127.27	144,577	1663	86.9	0.580	1.0	10.0	1	-	16,630	16,630	2%	$ 2.15
Lingan 3	Thermal	150	$320.37	39.73%	$127.27	508,205	5757	88.3	0.589	1.0	10.0	1	-	57,567	57,567	6%	$ 7.46
Lingan 4	Thermal	150	$320.37	39.73%	$127.27	416,791	4870	85.6	0.571	1.0	10.0	1	-	48,697	48,697	5%	$ 6.31
Tufts Cove 1	Thermal	100	$179.94	70.16%	$126.24	376,185	5676	66.3	0.663	1.0	10.0	0	-	-	-	0%	$ -
Tufts Cove 2	Thermal	100	$179.94	70.16%	$126.24	390,992	5616	69.6	0.696	1.5	15.0	1	-	84,242	84,242	9%	$ 10.83
Tufts Cove 3	Thermal	150	$179.94	70.16%	$126.24	723,364	6881	105.1	0.701	1.5	15.0	1	-	103,220	103,220	11%	$ 13.27
Tufts Cove 4	Gas	54	$995.27	15.93%	$158.57	267,466	7673	34.9	0.646	10.0	32.0	1	-	146,852	146,852	15%	$ 23.71
Tufts Cove 5	Gas	54	$717.22	15.94%	$114.33	277,536	7788	35.6	0.660	10.0	32.0	1	-	143,006	143,006	15%	$ 16.64
Tufts Cove 6	Thermal	46	$181.34	18.38%	$33.33	163,524	6523	25.1	0.545	1.0	10.0	1	-	65,225	65,225	7%	$ 2.21
Trenton 5	Thermal	150	$102.39	121.71%	$124.61	229,447	2568	89.4	0.596	1.0	10.0	1	-	25,679	25,679	3%	$ 3.26
Trenton 6	Thermal	160	$102.39	121.71%	$124.61	635,172	6121	103.8	0.649	2.0	20.0	1	-	122,429	122,429	12%	$ 15.53
Pt. Tupper 2	Thermal	150	$701.76	33.20%	$232.99	522,857	5310	98.5	0.656	1.0	10.0	1	-	53,100	53,100	5%	$ 12.59
Pt. Aconi 1	Thermal	185	$1,802.03	19.13%	$344.78	783,261	6839	114.5	0.619	0.0	0.0	0	-	-	-	0%	$ -
Wreck Cove 1	Hydro	100	$1,383.25	13.51%	$186.93	2,945	1594	1.8	0.018	15.0	32.0	1.00	-	51,008	51,008	5%	$ 9.71
Wreck Cove 2	Hydro	100	$1,383.25	13.51%	$186.93	381,457	2706	141.0	1.410	15.0	32.0	1.00	-	-	-	0%	$ -
Annapolis Tidal	Hydro	0	$1,513.88	25.29%	$382.88	0	0	0.0	0.000	0.0	0.0	0	-	-	-	0%	$ -
Other Hydro	Hydro	163	$2,323.96	16.49%	$383.27	0	0	0.0	0.000	20.0	32.0	0	-	-	-	0%	$ -
Burnside 1	Diesel	30	$325.38	19.87%	$64.64	3,614	197	18.4	0.613	10.0	30.0	1	-	2,283	2,283	0%	$ 0.15
Burnside 2	Diesel	30	$325.38	19.87%	$64.64	3,355	174	19.3	0.643	10.0	30.0	1	-	1,864	1,864	0%	$ 0.12
Burnside 3	Diesel	30	$325.38	19.87%	$64.64	2,896	180	16.1	0.536	10.0	30.0	1	-	2,510	2,510	0%	$ 0.17
Burnside 4	Diesel	30	$325.38	19.87%	$64.64	1,490	93	16.0	0.533	10.0	30.0	1	-	1,306	1,306	0%	$ 0.09
Victoria Junction 1	Diesel	30	$308.21	17.54%	$54.07	839	42	20.1	0.671	10.0	30.0	1	-	411	411	0%	$ 0.02
Victoria Junction 2	Diesel	30	$308.21	17.54%	$54.07	1,063	63	16.8	0.561	10.0	30.0	1	-	832	832	0%	$ 0.05
Tusket 1	Diesel	30	$492.47	26.91%	$132.52	40	37	1.1	0.036	10.0	30.0	1	-	1,057	1,057	0%	$ 0.14
													-				
TOTALS		2322	$15,438.43			6,321,149		1,343.1		153.0			0	982,322	982,322	100%	$ 131.45

NOTES:

1. Average 2023- 2024
2. Average 2023 - 2024 (SCADA records)
3. Time available to operate, two year average
4. Non-firm exports assigned to units - this no longer applies because as per regulation can no longer include recallable sales/exports.

TABLE E4-6
TABLE E4-6

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Supplemental 10 Minute Reserve						
											Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
	Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**	**(Note 4)**	= Min (1,9*10)		**(Note 5)**	Thermal = Max (0,Min(1-7,10))*6 *11 Hyd & Diesel = 1*8*8760 - 5 *11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	$320.37	39.73%	$127.27	484,073	5,440.5	89.0	0.593	1.0	10.0	0	-	-	-	0%	$ -
Lingan 2	Thermal	150	$320.37	39.73%	$127.27	144,577	1,663.0	86.9	0.580	1.0	10.0	0	-	-	-	0%	$ -
Lingan 3	Thermal	150	$320.37	39.73%	$127.27	508,205	5,756.7	88.3	0.589	1.0	10.0	0	-	-	-	0%	$ -
Lingan 4	Thermal	150	$320.37	39.73%	$127.27	416,791	4,869.7	85.6	0.571	1.0	10.0	0	-	-	-	0%	$ -
Tufts Cove 1	Thermal	100	$179.94	70.16%	$126.24	376,185	5,676.1	66.3	0.663	1.0	10.0	0	-	-	-	0%	$ -
Tufts Cove 2	Thermal	100	$179.94	70.16%	$126.24	390,992	5,616.1	69.6	0.696	1.5	15.0	0	-	-	-	0%	$ -
Tufts Cove 3	Thermal	150	$179.94	70.16%	$126.24	723,364	6,881.3	105.1	0.701	1.5	15.0	0	-	-	-	0%	$ -
Tufts Cove 4	Gas	54	$995.27	15.93%	$158.57	267,466	7,672.6	34.9	0.646	10.0	54.0	0	-	-	-	0%	$ -
Tufts Cove 5	Gas	54	$717.22	15.94%	$114.33	277,536	7,787.8	35.6	0.660	10.0	54.0	0	-	-	-	0%	$ -
Tufts Cove 6	Thermal	46	$181.34	18.38%	$33.33	163,524	6,522.5	25.1	0.545	1.0	10.0	0	-	-	-	0%	$ -
Trenton 5	Thermal	150	$102.39	121.71%	$124.61	229,447	2,567.9	89.4	0.596	1.0	10.0	0	-	-	-	0%	$ -
Trenton 6	Thermal	160	$102.39	121.71%	$124.61	635,172	6,121.4	103.8	0.649	2.0	20.0	0	-	-	-	0%	$ -
Pt. Tupper 2	Thermal	150	$701.76	33.20%	$232.99	522,857	5,310.0	98.5	0.656	1.0	10.0	0	-	-	-	0%	$ -
Pt. Aconi 1	Thermal	185	$1,802.03	19.13%	$344.78	783,261	6,839.4	114.5	0.619	0.0	0.0	0	-	-	-	0%	$ -
Wreck Cove 1	Hydro	100	$1,383.25	13.51%	$186.93	2,945	1,594.0	1.8	0.018	15.0	32.0	1.000	-	13,240	13,240	1%	$ 1.38
Wreck Cove 2	Hydro	100	$1,383.25	13.51%	$186.93	381,457	2,706.0	141.0	1.410	15.0	32.0	1.000	-	853,414	853,414	47%	$ 88.75
Annapolis Tidal	Hydro	0	$1,513.88	25.29%	$382.88	0	0.0	0.0	0.000	0.0	0.0	0	-	-	-	0%	$ -
Other Hydro	Hydro	163	$2,323.96	16.49%	$383.27	0	0.0	0.0	0.000	20.0	163.0	0.0	-	-	-	0%	$ -
Burnside 1	Diesel	30	$325.38	19.87%	$64.64	3,614	196.5	18.4	0.613	10.0	30.0	1.0	-	157,452	157,452	9%	$ 5.66
Burnside 2	Diesel	30	$325.38	19.87%	$64.64	3,355	174.0	19.3	0.643	10.0	30.0	1.0	-	165,589	165,589	9%	$ 5.95
Burnside 3	Diesel	30	$325.38	19.87%	$64.64	2,896	180.2	16.1	0.536	10.0	30.0	1.0	-	137,903	137,903	8%	$ 4.96
Burnside 4	Diesel	30	$325.38	19.87%	$64.64	1,490	93.2	16.0	0.533	10.0	30.0	1.0	-	138,537	138,537	8%	$ 4.98
Victoria Junction 1	Diesel	30	$308.21	17.54%	$54.07	839	41.7	20.1	0.671	10.0	30.0	1.0	-	175,510	175,510	10%	$ 5.28
Victoria Junction 2	Diesel	30	$308.21	17.54%	$54.07	1,063	63.1	16.8	0.561	10.0	30.0	1.0	-	146,366	146,366	8%	$ 4.40
Tusket 1	Diesel	30	$492.47	26.91%	$132.52	40	36.6	1.1	0.036	10.0	30.0	1.0	-	9,522	9,522	1%	$ 0.70
TOTALS		2322	$15,438.43			6,321,149		1,343.1		153.0			0	1,797,534	1,797,534	100%	$ 122.07

NOTES:

1. Average 2023- 2024
2. Average 2023 - 2024 (SCADA records)
3. Time available to operate, two year average
4. Unit tested capability for ramping control
5. Non-firm exports assigned to units
6. Wreck Cove Change of Response does not affect the weighted Annual Cost

2026 Embedded Cost of Ancillary Services

TABLE E4-7

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 30 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Installed Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Supplemental 30 Minute Reserve						
											Response 10 - 30 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
Column		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Formula					= 2*3	(Note 1)	(Note 2)	= 5/6	(Note 3)	(Note 4)	= Min (1,9*20)		(Note 5)	Thermal = Max (0,Min(1-7,10))*6*11 Hyd & Diesel = ((1*8*8760)- 5)*11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	$320.37	39.73%	$127.27	484,073	5,440.5	89.0	0.593	1.0	20.0	1	-	108,810	108,810	6.21%	$ 7.91
Lingan 2	Thermal	150	$320.37	39.73%	$127.27	144,577	1,663.0	86.9	0.580	1.0	20.0	1	-	33,259	33,259	1.90%	$ 2.42
Lingan 3	Thermal	150	$320.37	39.73%	$127.27	508,205	5,756.7	88.3	0.589	1.0	20.0	1	-	115,133	115,133	6.57%	$ 8.37
Lingan 4	Thermal	150	$320.37	39.73%	$127.27	416,791	4,869.7	85.6	0.571	1.0	20.0	1	-	97,395	97,395	5.56%	$ 7.08
Tufts Cove 1	Thermal	100	$179.94	70.16%	$126.24	376,185	5,676.1	66.3	0.663	1.0	20.0	0	-	-	-	0.00%	$ -
Tufts Cove 2	Thermal	100	$179.94	70.16%	$126.24	390,992	5,616.1	69.6	0.696	1.5	30.0	1	-	168,484	168,484	9.62%	$ 12.14
Tufts Cove 3	Thermal	150	$179.94	70.16%	$126.24	723,364	6,881.3	105.1	0.701	1.5	30.0	1	-	206,440	206,440	11.79%	$ 14.88
Tufts Cove 4	Gas	54	$995.27	15.93%	$158.57	267,466	7,672.6	34.9	0.646	10.0	54.0	1	-	146,852	146,852	8.39%	$ 13.30
Tufts Cove 5	Gas	54	$717.22	15.94%	$114.33	277,536	7,787.8	35.6	0.660	10.0	54.0	1	-	143,006	143,006	8.17%	$ 9.34
Tufts Cove 6	Thermal	46	$181.34	18.38%	$33.33	163,524	6,522.5	25.1	0.545	1.0	20.0	1		130,450	130,450	0	2
Trenton 5	Thermal	150	$102.39	121.71%	$124.61	229,447	2,567.9	89.4	0.596	1.0	20.0	1	-	51,358	51,358	2.93%	$ 3.65
Trenton 6	Thermal	160	$102.39	121.71%	$124.61	635,172	6,121.4	103.8	0.649	2.0	40.0	1	-	244,858	244,858	13.98%	$ 17.42
Pt. Tupper 2	Thermal	150	$701.76	33.20%	$232.99	522,857	5,310.0	98.5	0.656	1.0	20.0	1	-	106,201	106,201	6.06%	$ 14.13
Pt. Aconi 1	Thermal	185	$1,802.03	19.13%	$344.78	783,261	6,839.4	114.5	0.619	0.0	0.0	0	-	-	-	0.00%	$ -
Wreck Cove 1	Hydro	100	$1,383.25	13.51%	$186.93	2,945	1,594.0	1.8	0.018	15.0	32.0	0	-	-	-	0.00%	$ -
Wreck Cove 2	Hydro	100	$1,383.25	13.51%	$186.93	381,457	2,706.0	141.0	1.410	15.0	32.0	0	-	-	-	0.00%	$ -
Annapolis Tidal	Hydro	0	$1,513.88	25.29%	$382.88	0	0.0		0.000	0.0	0.0	0	-	-	-	0.00%	$ -
Other Hydro	Hydro	163	$2,323.96	16.49%	$383.27	0	0.0	0.0	0.000	20.0	163.0	0	-	-	-	0.00%	$ -
Burnside 1	Diesel	30	$325.38	19.87%	$64.64	3,614	196.5	18.4	0.613	10.0	30.0	0.25	-	38,982	38,982	2.23%	$ 1.44
Burnside 2	Diesel	30	$325.38	19.87%	$64.64	3,355	174.0	19.3	0.643	10.0	30.0	0.24	-	40,536	40,536	2.31%	$ 1.50
Burnside 3	Diesel	30	$325.38	19.87%	$64.64	2,896	180.2	16.1	0.536	10.0	30.0	0.25	-	34,736	34,736	1.98%	$ 1.28
Burnside 4	Diesel	30	$325.38	19.87%	$64.64	1,490	93.2	16.0	0.533	10.0	30.0	0.27	-	37,185	37,185	2.12%	$ 1.37
Victoria Junction 1	Diesel	30	$308.21	17.54%	$54.07	839	41.7	20.1	0.671	10.0	30.0	0.18	-	32,020	32,020	1.83%	$ 0.99
Victoria Junction 2	Diesel	30	$308.21	17.54%	$54.07	1,063	63.1	16.8	0.561	10.0	30.0	0.09	-	13,855	13,855	0.79%	$ 0.43
Tusket 1	Diesel	30	$492.47	26.91%	$132.52	40	36.6	1.1	0.036	10.0	30.0	0.19	-	1,792	1,792	0.10%	$ 0.14
TOTALS		2322	$15,438.43			6,321,149		1,343.1		153.0			0	1,751,352	1,751,352	100.00%	$ 120.25

NOTES:

1. Average 2023- 2024
2. Average 2023 - 2024 (SCADA records)
3. Time available to operate, two year average
4. Unit tested capability for ramping control
5. Non-firm exports assigned to units

Power Production Average Load Report (MWh) - Net Generation by Unit
2024

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	82,534	53,609	52,807	34,659	47,385	19,273	21,415	67,068	48,082	25,895	-	49,020	501,747.05
Lingan 2	21,820	30,394	(0)	-	-	10,799	-	42,292	14,414	10,045	13,059	19,969	162,792.44
Lingan 3	84,213	65,735	23,153	-	15,868	41,003	48,201	43,698	27,473	43,106	57,044	69,499	518,993.04
Lingan 4	60,341	48,883	23,997	46,422	6,496	-	12,211	39,015	23,999	35,067	19,134	60,405	375,970.88
Tufts Cove 1	17,191	14,005	24,113	52,158	50,081	17,009	24,163	30,054	51,003	41,034	43,882	47,728	412,421.50
Tufts Cove 2	24,957	43,321	54,311	58,439	42,556	49,984	51,827	55,933	20,489	-	(0)	-	401,817.32
Tufts Cove 3	71,334	59,661	61,655	(251)	78,498	84,159	82,698	89,080	77,955	80,042	48,033	67,286	800,150.38
Tufts Cove 4	24,915	24,279	26,513	27,019	10,653	15,929	22,793	27,133	23,490	25,660	25,451	21,161	274,996.05
Tufts Cove 5	26,458	25,116	25,219	28,191	25,038	2,221	21,371	26,545	25,681	27,936	27,108	29,466	290,350.51
Tufts Cove 6	16,054	16,039	16,877	22,597	9,540	1,998	13,058	21,972	15,021	19,707	18,429	18,265	189,557.03
Trenton 5	52,319	59,648	13,102	(1,105)	(276)	-	(0)	(381)	31,038	41,638	43,813	36,491	276,287.60
Trenton 6	89,172	45,270	46,783	61,328	27,543	11,226	55,492	15,446	38,937	70,639	54,934	65,185	581,956.07
Pt. Tupper 2	92,599	57,178	32,756	49,744	22,853	-	28,935	71,636	63,017	49,237	24,380	70,701	563,036.29
Pt. Aconi 1	108,894	86,554	87,904	83,755	75,281	34,920	73,087	55,612	(1,805)	325	87,643	90,268	782,438.05
Wreck Cove 1	00.0	00.0	00.0	00.0	00.0	00.0	1857.0	8412.0	27.0	00.0	-113.1	1597.5	11,780.43
Wreck Cove 2	39916.8	22890.3	28988.7	42337.1	41501.6	23390.0	4688.0	5093.3	481.5	-107.1	00.0	00.0	209,180.12
Annapolis Tidal	-	-	-	-	-	-	-	-	-	-	-	-	0.00
Wind	19,824	20,485	26,193	20,190	14,960	19,147	16,969	12,980	14,693	22,467	32,935	23,291	244,135.27
Other Hydro	67,408	55,552	73,259	82,889	43,118	17,435	23,651	13,332	17,333	15,824	19,482	35,320	464,603.15
Burnside 1	622.7	660.3	87.2	-21.4	-8.5	-6.2	-9.6	589.4	150.9	717.3	582.4	693.5	4,057.85
Burnside 2	578.9	519.6	323.9	12.0	-11.3	64.3	7.8	398.4	200.7	624.1	437.9	677.9	3,834.23
Burnside 3	456.3	421.1	363.7	183.6	-14.9	87.0	9.8	283.6	214.3	256.3	386.0	564.7	3,211.48
Burnside 4	54.9	340.2	232.4	132.3	10.6	69.3	-1.6	242.6	53.0	231.3	161.0	539.1	2,065.07
Victoria Junction 1	39	188	61	117	(3)	11	23	68	(9)	190	20	48	753.61
Victoria Junction 2	146	170	91	122	20	13	13	97	14	252	69	134	1,142.32
Tusket 1	(44)	7	26	56	(14)	39	14	(24)	(3)	(9)	(17)	16	46.41

Power Production Average Load Report (Hours) - Operating Hours
2024

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	718.39	511.36	573.66	460.48	684.85	277.53	345.33	744.00	669.10	349.38	0.00	477.20	5,811.28
Lingan 2	198.22	340.52	0.00	0.00	0.00	177.60	0.00	712.07	262.38	111.48	167.00	185.42	2,154.69
Lingan 3	742.63	646.55	220.25	0.00	218.13	660.30	722.63	588.66	450.30	579.94	688.76	670.46	6,188.61
Lingan 4	540.52	478.60	294.41	627.87	80.07	0.00	186.93	573.61	393.82	513.88	250.94	659.67	4,600.32
Tufts Cove 1	306.91	230.10	373.38	720.00	715.68	271.33	376.31	439.03	720.00	574.45	633.61	744.00	6,104.80
Tufts Cove 2	381.23	642.14	712.59	720.00	549.54	687.72	744.00	744.00	309.71	0.00	0.00	0.00	5,490.93
Tufts Cove 3	744.00	600.50	516.71	0.00	628.89	720.00	744.00	744.00	720.00	720.06	429.39	650.80	7,218.35
Tufts Cove 4	683.72	668.97	736.99	698.75	282.60	497.60	704.96	725.36	685.48	715.81	710.34	596.06	7,706.64
Tufts Cove 5	715.95	680.58	715.93	709.49	687.31	87.85	642.84	743.99	701.42	719.39	700.38	743.98	7,849.11
Tufts Cove 6	672.00	686.00	684.00	661.00	404.00	162.00	527.00	729.00	540.00	566.00	634.00	675.00	6,940.00
Trenton 5	492.74	661.11	132.12	0.00	0.00	0.00	0.00	0.00	442.74	438.64	480.32	430.50	3,078.17
Trenton 6	632.52	584.72	499.18	623.99	331.80	193.98	673.88	216.15	470.83	637.93	530.98	656.84	6,052.80
Pt. Tupper 2	744.00	531.13	331.51	568.84	281.37	0.00	383.47	743.94	720.00	555.81	268.20	700.97	5,829.24
Pt. Aconi 1	744.00	616.46	744.00	720.00	744.00	480.20	653.86	493.38	0.00	44.32	695.31	694.39	6,629.92
Wreck Cove 1	368.00	269.00	253.00	409.00	345.00	324.00	336.00	64.00	95.00	196.00	100.00	429.00	3,188.00
Wreck Cove 2	85.00	102.00	86.00	130.00	167.00	121.00	172.00	68.00	0.00	3.00	57.00	0.00	991.00
Annapolis Tidal	0	0	0	0	0	0	0	0	0	0	0	0.00	
Wind	0	0	0	0	0	0	0	0	0	0	0	0	
Other Hydro	0	0	0	0	0	0	0	0	0	0	0	0	
Burnside 1	34	30	5	0	0	0	0	34	8	37	29	40	217.05
Burnside 2	29	22	17	1	0	4	1	24	11	32	17	35	192.07
Burnside 3	22	18	15	10	0	5	1	17	7	13	14	29	151.93
Burnside 4	5	16	12	8	2	4	1	13	3	12	6	30	112.19
Victoria Junction 1	2.02	8.36	4.51	6.07	0.53	0.91	1.1	3.26	0	10.82	1.71	2.89	42.18
Victoria Junction 2	5.95	7.59	5.01	5.71	1.42	1.04	0.91	5.15	1.08	13.69	3.73	7.6	58.88
Tusket 1	0	2.79	4.09	3.4	1.28	3.7	1.7	0.09	0.2	0	0.73	3.28	21.26

Power Production Average Load Report (MW) - Average Load
2024

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	114.89	104.84	92.05	75.27	69.19	69.44	62.01	90.15	71.86	74.12	N/A	102.72	86.34
Lingan 2	110.08	89.26	N/A	N/A	N/A	60.81	N/A	59.39	54.94	90.10	78.20	107.70	75.55
Lingan 3	113.40	101.67	105.12	N/A	72.75	62.10	66.70	74.23	61.01	74.33	82.82	103.66	83.86
Lingan 4	111.64	102.14	81.51	73.94	81.13	N/A	65.32	68.02	60.94	68.24	76.25	91.57	81.73
Tufts Cove 1	56.01	60.87	64.58	72.44	69.98	62.69	64.21	68.46	70.84	71.43	69.26	64.15	67.56
Tufts Cove 2	65.46	67.46	76.22	81.17	77.44	72.68	69.66	75.18	66.16	N/A	N/A	N/A	73.18
Tufts Cove 3	95.88	99.35	119.32	N/A	124.82	116.89	111.15	119.73	108.27	111.16	111.86	103.39	110.85
Tufts Cove 4	36.44	36.29	35.98	38.67	37.70	32.01	32.33	37.41	34.27	35.85	35.83	35.50	35.68
Tufts Cove 5	36.96	36.90	35.23	39.73	36.43	25.28	33.25	35.68	36.61	38.83	38.71	39.61	36.99
Tufts Cove 6	23.89	23.38	24.67	34.19	23.61	12.33	24.78	30.14	27.82	34.82	29.07	27.06	27.31
Trenton 5	106.18	90.22	99.17	N/A	N/A	N/A	N/A	N/A	70.10	94.93	91.22	84.76	89.76
Trenton 6	140.98	77.42	93.72	98.28	83.01	57.87	82.35	71.46	82.70	110.73	103.46	99.24	96.15
Pt. Tupper 2	124.46	107.65	98.81	87.45	81.22	N/A	75.46	96.29	87.52	88.59	90.90	100.86	96.59
Pt. Aconi 1	146.36	140.41	118.15	116.33	101.18	72.72	111.78	112.72	N/A	7.34	126.05	130.00	118.02
Wreck Cove 1	N/A	N/A	N/A	N/A	N/A	N/A	5.53	131.44	0.28	N/A	N/A	3.72	3.70
Wreck Cove 2	469.61	224.41	337.08	325.67	248.51	193.31	27.26	74.90	#DIV/0!	N/A	N/A	N/A	211.08
Annapolis Tidal	0	0	0	0	0	0	0	0	0	0	0	0	
Wind													
Other Hydro													
Burnside 1	18.1	22.1	19.0	0.0	0.0	0.0	-120.3	17.2	18.8	19.5	20.4	17.2	18.70
Burnside 2	20.2	23.9	19.2	19.6	-43.4	16.6	7.1	16.7	18.4	19.6	25.5	19.2	19.96
Burnside 3	20.6	23.5	23.6	19.0	0.0	16.5	8.0	16.8	29.1	19.5	27.5	19.5	21.14
Burnside 4	12.0	21.8	18.8	15.8	5.6	15.5	-3.2	18.5	17.7	18.6	25.4	18.2	18.41
Victoria Junction 1	19.2	22.5	13.6	19.3	-6.1	12.6	20.7	21.0	0.0	17.6	11.8	16.6	17.87
Victoria Junction 2	24.6	22.5	18.2	21.4	13.8	12.9	14.2	18.8	13.2	18.4	18.4	17.7	19.40
Tusket CT	0.0	2.7	6.3	16.5	-11.2	10.5	8.1	-264.2	-13.9	0.0	-23.5	5.0	2.18

Generation Statistics(MWh) - Hydro

2024

Hydro													
Little Brook Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Grand Etang Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Dickie Brook Hydro	1,585	887	1,263	1,583	771	192	571	651	336	438	420	870	9,567
Tusket Hydro	1,211	804	871	1,070	76	(13)	(8)	(7)	9	383	163	1,044	5,604
Bear River Hydro System	3,806	3,864	3,411	5,457	2,496	401	562	217	217	767	4,498	4,386	30,082
Sissiboo/Wevmouth System	8,487	6,939	12,719	12,873	6,496	4,882	2,957	3,448	1,869	1,125	2,579	4,471	68,846
Avon Hydro System	2,939	1,338	4,373	3,236	266	30	781	263	676	266	466	1,260	15,894
Lequille Hydro System	3,698	1,816	6,833	4,944	367	14	(26)	(20)	(15)	1,135	358	(7)	19,096
Nictaux/Paradise System	5,998	5,129	4,917	6,170	1,986	760	3,654	2,093	1,248	1,946	2,127	3,606	39,634
Paradise System	(8)	(19)	(7)	(10)	(5)	72	3,075	3,560	1,528	2,057	1,375	2,087	13,706
Annapolis Tidal Power	-	-	-	-	-	-	-	-	-	-	-	-	-
St.Marqaret's Hydro Syste	4,676	2,282	3,467	6,218	1,807	33	(33)	22	110	108	120	495	19,306
Sheet Harbour Hydro Syste	4,347	1,947	4,349	5,042	842	588	2,075	1,018	103	64	435	1,781	22,591
Black River Hydro System	15,420	11,158	13,479	13,463	5,464	2,191	5,487	625	4,816	3,901	3,854	7,096	86,954
Mersey Hydro System	14,890	19,202	17,264	22,504	22,519	8,278	4,537	1,461	6,416	3,565	3,062	8,036	131,736
Roseway & Harmony Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
Harmony Hydro System	-	-	-	-	-	-	-	-	-	-	-	-	-
Wreck Cove Hydro System	39,917	22,890	28,989	42,337	41,502	23,390	6,545	13,505	509	(107)	(113)	1,598	220,961
Fall River Hydro	359	204	321	340	34	6	17	1	19	69	25	194	1,589
TOTAL	107,325	78,442	102,248	125,226	84,620	40,825	30,196	26,837	17,842	15,717	19,369	36,917	685,564

Power Production Average Load Report (MWh) - Net Generation by Unit
2023

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	47,798	73,499	43,337	0	0	0	46,622	59,505	58,166	45,755	52,562	37,200	464,444
Lingan 2	46,965	48,494	4,632	0	0	0	0	0	0	0	11,593	3,480	115,164
Lingan 3	45,796	56,957	73,988	70,842	23,379	59,549	22,451	28,605	17,543	21,060	27,925	45,505	493,600
Lingan 4	70,734	42,550	53,431	69,500	41,719	12,627	54,327	13,128	39,902	20,237	0	41,538	459,692
Tufts Cove 1	17,433	40,991	7,361	46,521	20,590	47,785	28,067	0	15,998	50,992	43,708	21,602	341,048
Tufts Cove 2	38,700	33,986	38,803	48,163	45,856	20,912	34,263	44,824	42,079	13,649	0	18,040	379,275
Tufts Cove 3	63,072	43,392	66,005	-196	49,949	59,518	67,843	78,470	73,573	26,002	64,128	58,684	650,440
Tufts Cove 4	25,121	21,311	25,620	13,002	8,794	20,332	22,747	23,888	24,480	24,774	22,919	27,003	259,991
Tufts Cove 5	27,185	23,626	26,171	23,888	18,750	9,681	20,964	19,123	23,172	22,692	23,336	26,302	264,888
Tufts Cove 6	17,389	12,171	14,478	10,438	4,116	3,911	10,174	10,237	13,380	11,560	13,858	17,652	139,363
Trenton 5	24,897	57,586	38,633	12,010	-587	-843	-966	-705	-285	-790	37,573	16,496	183,020
Trenton 6	92,476	64,569	101,725	86,763	60,804	34,919	30,768	-51	53,080	16,056	71,836	76,487	689,434
Pt. Tupper 2	64,475	79,193	80,414	6,552	8,367	18,556	34,932	24,482	45,673	5,334	63,349	49,399	480,727
Pt. Aconi 1	99,154	58,126	83,596	30,120	45,001	78,623	81,932	56,906	7,758	70,036	72,693	98,676	782,620
Wreck Cove 1	0	0	0	0	0	0	0	0	0	0	0	0	0
Wreck Cove 2	60,481	43,779	27,214	9,804	19,088	20,727	11,746	-175	1,776	41,648	23,384	53,773	313,246
Annapolis Tidal	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	16,591	20,112	18,864	15,774	22,957	13,573	11,206	13,404	12,635	16,394	20,432	21,552	203,493
Other Hydro	94,581	71,590	64,987	42,432	32,107	38,543	46,417	47,515	53,186	39,408	41,234	57,954	629,953
Burnside 1	853.8	1033.1	61.8	251.6	228.5	161.5	135.1	17.9	46.7	19.0	40.4	332.9	3,182
Burnside 2	720.4	882.5	52.6	195.1	94.8	261.9	35.3	93.9	7.7	28.9	53.1	473.8	2,900
Burnside 3	460.2	1095.0	77.1	70.1	84.8	123.1	39.9	15.4	1.9	44.6	20.6	262.1	2,295
Burnside 4	-62.9	409.2	-4.4	151.2	-18.0	165.7	13.0	48.7	-0.9	64.0	1.3	239.4	1,006
Victoria Junction 1	382.1	314.3	14.7	94.8	62.8	-18.1	7.0	-4.9	-12.3	-11.2	-19.6	112.3	922
Victoria Junction 2	236.4	316.3	16.9	128.2	11.0	60.4	102.5	16.4	8.6	0.0	-1.5	66.1	961
Tusket 1	-39.6	582.8	-46.6	-35.8	40.0	81.8	43.9	-13.9	-24.4	-31.0	43.6	56.4	657

Power Production Average Load Report (Hours) - Operating Hours
2023

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	497.81	669.89	414.23	0.00	0.00	0.00	539.16	744.00	656.85	570.79	591.52	385.42	5,069.67
Lingan 2	481.17	447.74	48.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	157.91	36.33	1,171.23
Lingan 3	449.82	501.10	741.34	720.00	261.90	718.74	288.65	384.21	238.31	246.48	296.64	477.54	5,324.73
Lingan 4	744.00	400.63	556.08	684.58	528.31	159.22	652.66	174.98	457.54	289.47	0.00	491.69	5,139.16
Tufts Cove 1	278.06	672.00	131.50	705.04	331.97	720.00	430.71	0.00	251.44	744.00	646.67	335.94	5,247.33
Tufts Cove 2	622.94	477.20	632.77	685.96	647.75	305.38	516.58	700.60	632.34	203.16	0.00	316.67	5,741.35
Tufts Cove 3	595.82	496.28	743.56	0.00	478.18	536.20	657.55	744.00	694.71	254.47	699.53	644.02	6,544.32
Tufts Cove 4	702.84	614.99	723.83	382.13	305.35	667.13	700.10	724.77	712.27	704.58	656.47	744.00	7,638.46
Tufts Cove 5	734.12	662.62	734.16	643.07	545.05	309.31	661.06	623.61	708.88	689.98	685.48	729.21	7,726.55
Tufts Cove 6	674.00	569.00	646.00	531.00	269.00	150.00	400.00	502.00	570.00	524.00	606.00	664.00	6,105.00
Trenton 5	286.30	620.03	364.86	141.08	0.00	0.00	0.00	0.00	0.00	0.00	470.69	174.66	2,057.62
Trenton 6	744.00	563.20	744.00	720.00	596.40	397.76	336.40	0.00	527.15	199.18	720.00	642.00	6,190.09
Pt. Tupper 2	617.32	672.00	744.00	70.55	105.30	200.65	406.85	286.58	478.63	50.03	640.61	518.29	4,790.81
Pt. Aconi 1	744.00	477.82	733.97	311.37	441.35	720.00	744.00	598.97	97.94	744.00	720.00	715.43	7,048.85
Wreck Cove 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wreck Cove 2	733.00	631.00	435.00	131.00	305.00	340.00	160.00	0.00	77.00	522.00	372.00	715.00	4,421.00
Annapolis Tidal													
Wind													
Other Hydro													
Burnside 1	44.96	52.06	5.14	13.42	11.36	9.57	6.31	1.71	2.93	2.22	5.67	20.68	176.03
Burnside 2	35.78	45.41	3.60	10.66	4.64	14.30	1.84	5.57	0.54	2.83	5.42	25.24	155.83
Burnside 3	47.51	88.41	5.26	27.39	9.47	7.51	2.33	1.60	0.70	2.60	1.21	14.48	208.47
Burnside 4	0.38	34.33	2.17	5.98	0.55	8.80	1.65	3.49	0.98	1.29	0.98	13.60	74.20
Victoria Junction 1	5.92	16.53	0.94	4.27	3.68	0.00	1.14	0.63	0.31	0.79	0.00	6.95	41.16
Victoria Junction 2	12.89	30.36	1.46	6.58	1.48	3.91	5.58	0.38	0.66	0.00	0.28	3.83	67.41
Tusket 1	0.07	28.14	0.00	0.00	3.62	6.25	4.96	1.26	0.25	0.01	1.64	5.66	51.86

Power Production Average Load Report (MW) - Average Load
2023

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	92.00	85.02	178.62	N/A	N/A	N/A	41.64	38.45	26.71	36.90	47.21	118.07	91.61
Lingan 2	147.00	95.03	1,111.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	1,143.36	98.33
Lingan 3	38.75	81.80	9.93	64.61	78.62	66.49	97.23	0.00	67.13	206.88	147.34	45.24	92.70
Lingan 4	52.02	84.83	69.78	70.35	86.80	131.34	52.50	256.16	91.97	47.15	N/A	36.69	89.45
Tufts Cove 1	226.83	64.57	501.94	-0.28	150.46	82.66	157.51	N/A	292.60	34.95	99.17	174.69	64.99
Tufts Cove 2	40.33	44.66	40.49	18.95	13.58	66.58	44.03	34.10	38.71	121.94	N/A	85.27	66.06
Tufts Cove 3	45.63	47.61	35.20	N/A	39.21	18.05	31.88	25.70	33.35	89.17	33.36	40.84	99.39
Tufts Cove 4	24.74	19.79	20.00	27.32	13.48	5.86	14.53	14.12	18.78	16.41	21.11	23.73	34.04
Tufts Cove 5	33.91	86.91	52.62	18.68	-1.08	-2.72	-1.46	-1.13	-0.40	-1.14	54.81	22.62	34.28
Tufts Cove 6	137.21	113.48	157.47	163.40	226.04	232.79	76.92	-0.10	93.12	30.64	118.54	115.19	22.83
Trenton 5	225.20	127.73	220.40	46.44	N/A	N/A	N/A	N/A	N/A	N/A	134.59	282.83	88.95
Trenton 6	133.27	103.21	112.36	41.83	75.45	197.66	243.55	N/A	14.72	351.62	100.96	153.70	111.38
Pt. Tupper 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.34
Pt. Aconi 1	81.29	91.62	37.08	31.49	43.25	28.79	15.79	-0.29	18.14	55.98	32.48	75.16	111.03
Wreck Cove 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wreck Cove 2	82.51	69.38	62.56	74.84	62.58	60.96	73.41	0.00	23.07	79.79	62.86	75.21	70.85
Annapolis Tidal													
Wind													
Other Hydro													
Burnside 1	18.99	19.84	12.03	18.75	20.11	16.87	21.41	10.47	15.92	8.56	7.12	16.10	18.08
Burnside 2	20.13	19.43	14.62	18.30	20.42	18.32	19.18	16.86	14.20	10.20	9.79	18.77	18.61
Burnside 3	9.69	12.39	14.67	2.56	8.95	16.39	17.14	9.63	2.69	17.17	17.01	18.10	11.01
Burnside 4	-165.43	11.92	-2.05	25.28	-32.76	18.83	7.90	13.94	-0.88	49.60	1.34	17.60	13.56
Victoria Junction 1	64.55	19.01	15.68	22.20	17.07	0.00	6.16	-7.85	-39.81	-14.23	0.00	16.16	22.40
Victoria Junction 2	18.34	10.42	11.59	19.48	7.41	15.45	18.37	43.07	13.04	0.00	-5.36	17.25	14.26

Generation Statistics(MWh) - Hydro
2023

Hydro													
Little Brook Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Grand Etang Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Dickie Brook Hydro	874	724	752	(57)	1,395	717	856	559	562	659	583	1,539	9,164
Tusket Hydro	1,146	1,090	1,087	785	90	241	1,130	800	1,070	1,008	709	1,108	10,264
Bear River Hydro System	4,964	4,919	5,370	2,583	475	3,733	3,531	3,272	4,492	4,604	2,608	4,078	44,631
Sissiboo/Weymouth System	12,144	8,638	9,593	6,642	3,295	7,222	8,325	7,456	6,903	2,502	6,792	5,563	85,076
Avon Hydro System	3,641	1,676	764	812	727	1,489	2,278	3,615	3,229	980	1,495	2,726	23,433
Lequille Hydro System	7,449	2,909	1,847	2,284	154	1,969	3,093	1,459	2,959	1,801	1,369	3,645	30,936
Nictaux/Paradise System	6,116	4,575	6,196	4,385	2,667	3,004	4,295	3,401	4,895	4,482	3,647	5,738	53,400
Paradise System	3,455	2,403	3,260	2,279	965	1,390	1,540	(6)	(138)	(77)	182	(9)	15,243
Annapolis Tidal Power	-	-	-	-	-	-	-	-	-	-	-	-	-
St.Margaret's Hydro Syste	3,959	3,593	2,532	499	765	385	1,920	3,039	4,442	662	1,860	4,017	27,673
Sheet Harbour Hydro Syste	6,244	4,362	3,110	2,554	2,247	2,953	4,259	3,346	3,602	3,206	2,615	3,537	42,034
Black River Hydro System	15,437	13,736	10,261	5,202	4,421	3,729	3,457	2,170	3,948	3,005	4,758	12,789	82,912
Mersey Hydro System	28,807	22,743	20,091	14,361	14,828	11,594	11,401	18,074	16,918	16,380	14,452	12,935	202,584
Roseway & Harmony Hydro	(13)	(4)	(28)	(12)	(5)	(1)	(1)	-	-	-	-	-	(64)
Harmony Hydro System	-	-	-	-	-	-	-	-	-	-	-	-	-
Wreck Cove Hydro System	60,481	43,779	27,214	9,804	19,088	20,727	11,746	(175)	1,776	41,648	23,384	53,773	313,246
Fall River Hydro	357	227	152	114	84	120	332	329	303	195	165	289	2,667
TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	943,199

Nameplate	Maximum Poss ble Output	2023 Capacity Factor	2024 Capacity Factor	2023-2024 Average Capacity Factor	Average Reactive (MVAR)	Unit Average reactive factor	Unit Ramp Rate (MW/Min)
150.00	1,314,000.00	35.3%	38.2%	36.8%	0.80	29.41%	1.0
150.00	1,314,000.00	8.8%	12.4%	10.6%	0.78	8.25%	1.0
150.00	1,314,000.00	37.6%	39.5%	38.5%	0.78	30.05%	1.0
150.00	1,314,000.00	35.0%	28.6%	31.8%	0.78	24.80%	1.0
100.00	876,000.00	38.9%	47.1%	43.0%	0.84	36.13%	1.0
100.00	876,000.00	43.3%	45.9%	44.6%	0.81	36.11%	1.5
150.00	1,314,000.00	49.5%	60.9%	55.2%	0.65	35.88%	1.5
54.00	473,040.00	55.0%	58.1%	56.5%	0.80	45.24%	10.0
54.00	473,040.00	56.0%	61.4%	58.7%	0.80	46.95%	10.0
50.00	438,000.00	31.8%	43.3%	37.5%	0.80	30.04%	
150.00	1,314,000.00	13.9%	21.0%	17.5%	0.77	13.46%	1.0
160.00	1,401,600.00	49.2%	41.5%	45.4%	0.78	35.38%	2.0
150.00	1,314,000.00	36.6%	42.8%	39.7%	0.80	31.77%	1.0
185.00	1,620,600.00	48.3%	48.3%	48.3%	0.75	36.21%	0.0
100.00	876,000.00	0.0%	1.3%	0.7%	0.60	0.40%	15.0
100.00	876,000.00	35.8%	23.9%	29.8%	0.60	17.89%	15.0
-	-	0%	0%	0%	0.60	0.00%	0.0
-	-	0%	0%	0%	0.00	0.00%	0.0
163.00	1,427,880.00	44.1%	32.5%	38.3%	0.60	23.00%	20.0
30.00	262,800.00	1.2%	1.5%	1.4%	0.80	0.53%	10.0
30.00	262,800.00	1.1%	1.5%	1.3%	0.80	0.34%	10.0
30.00	262,800.00	0.9%	1.2%	1.0%	0.80	0.44%	10.0
30.00	262,800.00	0.4%	0.8%	0.6%	0.80	0.36%	10.0
30.00	262,800.00	0.4%	0.3%	0.3%	0.80	2.66%	10.0
30.00	262,800.00	0.4%	0.4%	0.4%	0.80	4.06%	10.0
30.00	262,800.00	0.3%	0.0%	0.1%	0.80	2.37%	10.0

COMBUSTION TURBINES IN SYNCHRONOUS CONDENSER MODE.

														2023	2024	2023-2024	MVAr		
	Mvar																		
2023	Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	TOTAL	Average	RATED	MAX MVh	Mvar CF
	BS1	143.2	145.4	34.7	70.8	54.7	38.3	282.2	224.3	40.2	11.5	19.0	62.2	1126.6	533.5	830.1	18.03	157923.1	0.526%
	BS2	64.1	114.9	12.9	20.6	10.3	53.7	183.1	168.8	17.5	11.8	18.3	41.1	717.0	357.0	537.0	18.03	157923.1	0.340%
	BS3	104.4	221.1	28.3	21.6	20.8	67.7	232.4	87.4	51.5	14.3	6.9	58.7	915.2	477.4	696.3	18.03	157923.1	0.441%
	BS4	7.6	0.0	14.3	13.0	1.4	52.5	437.0	175.3	54.4	4.5	2.3	48.1	810.5	337.9	574.2	18.03	157923.1	0.364%
	Hours																		
	BS1	69	73	12	22	22	26	255	210	29	17	13	32						
	BS2	54	57	11	16	9	57	207	222	25	17	17	40						
	BS3	41	74	10	11	8	48	296	124	26	6	3	23						
	BS4	5	37	6	9	2	38	357	186	24	4	2	26						
	BS1	2.1	2.0	2.9	3.2	2.5	1.5	1.1	1.1	1.4	0.7	1.5	1.9						
	BS2	1.2	2.0	1.2	1.3	1.1	0.9	0.9	0.8	0.7	0.7	1.1	1.0						
	BS3	2.5	3.0	2.8	2.0	2.6	1.4	0.8	0.7	2.0	2.4	2.3	2.6						
	BS4	1.5	0.0	2.4	1.4	0.7	1.4	1.2	0.9	2.3	1.1	1.2	1.8						

	Mvar													
2024	Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	BS1	148.4	70.0	10.4	0.0	0.0	0.0	2.7	89.9	10.0	51.2	72.5	78.4	533.5
	BS2	79.3	33.7	39.5	4.8	2.4	10.0	5.9	30.0	20.7	35.8	39.5	55.3	357.0
	BS3	91.9	112.7	48.8	23.1	0.0	17.9	7.5	37.9	16.8	29.0	46.9	44.8	477.4
	BS4	65.5	0.0	55.1	19.4	5.5	16.0	3.5	30.9	9.4	41.8	24.5	66.4	337.9
	Hours													
	BS1	51	41	11	0	0	0	2	49	15	53	46	61	
	BS2	43	34	27	5	2	5	3	34	18	44	28	49	
	BS3	38	35	26	16	0	6	4	23	11	20	22	37	
	BS4	12	26	22	15	3	6	3	20	6	20	10	41	
	BS1	2.9	1.7	0.9	0.0	0.0	0.0	1.3	1.8	0.7	1.0	1.6	1.3	
	BS2	1.8	1.0	1.5	1.0	1.2	2.0	2.0	0.9	1.2	0.8	1.4	1.1	
	BS3	2.4	3.2	1.9	1.4	0.0	3.0	1.9	1.6	1.5	1.5	2.1	1.2	
	BS4	5.5	0.0	2.5	1.3	1.8	2.7	1.2	1.5	1.6	2.1	2.5	1.6	

Year		Month												2023	2024	2023-2024	MVAr		
	Mvar																		
2023	Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	TOTAL	Average	RATED	MAX MVh	Mvar CF
	VJ1	582.1	554.9	29.1	341.6	597.1	891.7	790.7	589.9	852.1	731.9	637.4	427.3	7026.1	1389.1	4207.6	18.03	157923.1	2.664%
	VJ2	497.5	757.2	848.6	721.1	602.1	976.3	1133.7	796.3	591.2	0.0	728.6	730.7	8383.4	4432.5	6408.0	18.03	157923.1	4.058%
	TK4	3.5	478.6	0.0	0.0	144.9	1348.9	969.4	1121.9	323.8	139.6	3.8	7.2	4541.6	2745.0	3643.3	17.52	153465.1	2.374%
	Hours																		
	VJ1	413	394	23	194	531	713	740	742	720	739	715	387						
	VJ2	349	327	721	651	421	627	743	742	441	0	682	510						
	TK4	0	0	0	0	56	630	429	727	218	87	9	12						
	VJ1	1.4	1.4	1.3	1.8	1.1	1.3	1.1	0.8	1.2	1.0	0.9	1.1						
	VJ2	1.4	2.3	1.2	1.1	1.4	1.6	1.5	1.1	1.3	0.0	1.1	1.4						
	TK4	0.0	0.0	0.0	0.0	2.6	2.1	2.3	1.5	1.5	1.6	0.4	0.6						

Year		Month												
	Mvar													
2024	Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	VJ1	58.5	5.9	230.5	63.0	292.0	7.6	295.6	38.9	0.0	66.8	275.9	54.2	1389.1
	VJ2	1268.2	75.3	323.4	494.0	300.9	469.9	396.9	115.1	227.7	524.2	200.2	37.0	4432.5
	TK4	0.0	10.1	326.3	8.1	1163.1	567.3	661.2	2.6	0.3	0.0	2.3	3.7	2745.0
	Hours													
	VJ1	5	12	117	91	249	9	202	44	0	59	299	35	
	VJ2	728	43	228	352	314	449	167	51	59	223	181	32	
	TK4	0	0	117	8	617	318	280	4	1	0	9	10	
	VJ1	11.7	0.5	2.0	0.7	1.2	0.8	1.5	0.9	0.0	1.1	0.9	1.5	
	VJ2	1.7	1.8	1.4	1.4	1.0	1.0	2.4	2.3	3.9	2.4	1.1	1.2	
	TK4	0.0	0.0	2.8	1.0	1.9	1.8	2.4	0.6	0.3	0.0	0.3	0.4	

Performance Factors

Unit	2024 Operating Hours	2024 Average Production	2024 factor	2023 Operating Hours	2023 Average Production	2023 factor	2023 - 2024 2-year Average Hours	2023 - 2024 2-year Average factor	2023 - 2024 2-year Average Avg Prod	2023 - 2024 2-year Average Annual Prod	Time on AGC - 2 year average 2019	Time on AGC - 2 year average 2020	Time on AGC - 2 year average Average	Equivalent Availability Factor
Lingan 1	5,811.28	86.34	0.575601297	5,069.67	91.61	0.610749	150	5440	0.593	89.0	484,073	2382	3735.5	3059	59.3%
Lingan 2	2,154.69	75.55	0.503684032	1,171.23	98.33	0.655513	150	1663	0.580	86.9	144,577	0	0	0	58.0%
Lingan 3	6,188.61	83.86	0.559084123	5,324.73	92.70	0.617997	150	5757	0.589	88.3	508,205	3349	3041	3195	58.9%
Lingan 4	4,600.32	81.73	0.544847427	5,139.16	89.45	0.596326	150	4870	0.571	85.6	416,791	3768.5	3812	3790	57.1%
Tufts Cove 1	6,104.80	67.56	0.675569223	5,247.33	64.99	0.649945	100	5676	0.663	66.3	376,185	0	0	0	66.3%
Tufts Cove 2	5,490.93	73.18	0.731783714	5,741.35	66.06	0.660603	100	5616	0.696	69.6	390,992	2235	4517	3376	69.6%
Tufts Cove 3	7,218.35	110.85	0.738996564	6,544.32	99.39	0.6626	150	6881	0.701	105.1	723,364	5409	7349	6379	70.1%
Tufts Cove 4	7,706.64	35.68	0.660796337	7,638.46	34.04	0.630317	54	7673	0.646	34.9	267,466	5538.5	6998	6268	64.6%
Tufts Cove 5	7,849.11	36.99	0.685028149	7,726.55	34.28	0.634868	54	7788	0.660	35.6	277,536	5899	6940.5	6420	66.0%
Tufts Cove 6	6,940.00	27.31	0.593775937	6,105.00	22.83	0.496255	46	6523	0.545	25.1	163,524	0	0	0	54.5%
Trenton 5	3,078.17	89.76	0.598380631	2,057.62	88.95	0.592984	150	2568	0.596	89.4	229,447				59.6%
Trenton 6	6,052.80	96.15	0.600916172	6,190.09	111.38	0.696107	160	6121	0.649	103.8	635,172	2760.5	5092.5	3927	64.9%
Pt. Tupper 2	5,829.24	96.59	0.643921899	4,790.81	100.34	0.668958	150	5310	0.656	98.5	522,857	3794	3473.5	3634	65.6%
Pt. Aconi 1	6,629.92	118.02	0.637925477	7,048.85	111.03	0.600151	185	6839	0.619	114.5	783,261				61.9%
Wreck Cove 1	3,188.00	3.70	0.036952428	0.00	0.00	0	100	1594	0.018	1.8	2,945	2639.5	2945	2792	1.8%
Wreck Cove 2	991.00	211.08	2.110798375	4,421.00	70.85	0.708541	100	2706	1.410	141.0	381,457	2458	837	1648	141.0%
Annapolis Tidal															
Wind															
Other Hydro															
Burnside 1	217.05	18.70	0.623182063	176.03	18.08	0.602585	30	197	0.613	18.4	3,614	98	77	88	61.3%
Burnside 2	192.07	19.96	0.665422676	155.83	18.61	0.620301	30	174	0.643	19.3	3,355	43.5	68.5	56	64.3%
Burnside 3	151.93	21.14	0.704596196	208.47	11.01	0.366937	30	180	0.536	16.1	2,896	52.5	57.5	55	53.6%
Burnside 4	112.19	18.41	6.136E-01	74.20	13.56	0.452085	30	93	0.533	16.0	1,490	33.5	57.5	46	53.3%
Victoria Junction 1	42.18	17.87	0.595551604	41.16	22.40	0.746527	30	42	0.671	20.1	839	28	16	22	67.1%
Victoria Junction 2	58.88	19.40	0.646694407	67.41	14.26	0.475292	30	63	0.561	16.8	1,063				56.1%
Tusket 1	21.26	2.18	0.072770461	51.86	0.00	0	30	37	0.036	1.1	40				3.6%

18

Victoria Junction	450	725
Burnside	4063	6800

Monthly Power Production Average Load Report
SCADA Data

2026 Embedded Cost of Ancillary Services

TABLE E4-1

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
GENERATING STATION UNIT SPECIFIC FIXED CHARGE RATE SUMMARY

	Lingan	Tufts Cove	Tufts Cove 6	Trenton	Pt. Tupper	Pt. Aconi	Sub-Total Thermal Gen.	Wreck Cove	Annapolis Tidal Power	Other Hydro	Total Hydro	Wind Generation	Tufts Cove 4	Tufts Cove 5	Other Combustion Turbines	Total Combustion Turbines	Total Generation
Generator Nameplate Capacity kW's	600,000	350,000	350,000	310,000	150,000	185,000	1,945,000	200,000	17,200	163,000	380,200	1,300	54,000	54,000	204,000	312,000	2,637,200
Gross Plant Cost	$612,976,826	$104,689,524	$103,522,759	$242,816,902	$211,530,922	$310,573,805	$1,586,110,739	$337,800,330	$45,641,253	$489,320,955	$872,762,538	$0	$60,754,030	$43,850,628	$98,703,926	$203,308,585	$2,662,181,862
Gross Plant Cost/kW	$1,021.63	$299.11	$295.78	$783.28	$1,410.21	$1,678.78	$815.48	$1,689.00	$2,653.56	$3,001.97	$7,344.53	$0.00	$1,125.07	$812.05	$483.84	$651.63	$1,009.47
Net Plant Value	$192,219,522	$62,977,511	$63,467,926	$31,740,626	$105,263,813	$333,374,676	$789,044,074	$276,650,831	$26,038,789	$378,806,094	$681,495,714	$0	$53,744,509	$38,729,686	$68,240,358	$160,714,553	$1,631,254,341
Net Plant Value/kW	$320.37	$179.94	$181.34	$102.39	$701.76	$1,802.03	$405.68	$1,383.25	$1,513.88	$2,323.96	$5,221.10	$0.00	$995.27	$717.22	$334.51	$515.11	$618.56
- share of General Property Plant	$20,640,354	$6,762,467	$6,815,127	$3,408,279	$11,303,131	$35,797,464	$84,726,822	$29,706,510	$2,796,021	$40,675,848	$73,178,379	$0	$5,771,036	$4,158,758	$7,327,586	$17,257,380	$175,162,581
- share of Deferred Chgs & W/C	$27,696	$9,074	$9,145	$4,573	$15,167	$48,034	$113,688	$39,861	$3,752	$54,580	$98,192	$0	$7,744	$5,580	$9,832	$23,156	$235,037
Total NPV incl. GP & Deferred Chgs.	$212,887,572	$69,749,052	$70,292,198	$35,153,479	$116,582,110	$369,220,174	$873,884,585	$306,397,202	$28,838,562	$419,536,521	$754,772,285	$0	$59,523,288	$42,894,025	$75,577,776	$177,995,089	$1,806,651,959
OM&G (Direct)	$25,064,042	$22,626,363	$0	$17,903,669	$11,333,823	$12,197,072	$89,124,969	$1,452,888	$1,835,268	$7,190,376	$10,478,532	$0	$0	$0	$2,089,963	$2,089,963	$101,693,464
OM&G (Overhead)	$11,308,246	$10,208,428	$0	$8,077,671	$5,113,527	$5,503,002	$40,210,875	$655,505	$828,025	$3,244,111	$4,727,642	$0	$0	$0	$942,937	$942,937	$45,881,454
Grants in Lieu	$2,613,352	$856,221	$862,889	$431,535	$1,431,131	$4,532,450	$10,727,578	$3,761,252	$354,015	$5,150,120	$9,265,386	$0	$730,692	$526,556	$927,773	$2,185,021	$22,177,985
Depreciation (Direct)	$13,608,086	$3,266,313	$3,447,308	$6,361,803	$5,140,201	$7,764,345	$39,588,056	$4,425,184	$826,107	$8,601,244	$13,852,535	$0	$2,023,109	$1,460,226	$4,138,051	$7,621,386	$61,061,977
Depr. (General Property)	$6,385,997	$1,532,814	$1,617,751	$2,985,464	$2,412,192	$3,643,649	$18,577,868	$2,076,649	$387,675	$4,036,388	$6,500,712	$0	$949,404	$685,254	$1,941,903	$3,576,561	$28,655,141
Interest	$7,395,254	$2,422,931	$2,441,799	$1,221,156	$4,049,810	$12,825,910	$30,356,860	$10,643,576	$1,001,789	$14,573,791	$26,219,156	$0	$2,067,710	$1,490,046	$2,625,408	$6,183,164	$62,759,180
Preferred Dividends	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Corporate Taxes	($512,917)	($168,049)	($169,357)	($84,696)	($280,885)	($889,573)	($2,105,477)	($738,212)	($69,482)	($1,010,802)	($1,818,496)	$0	($143,411)	($103,346)	($182,092)	($428,849)	($4,352,822)
Return	$10,497,930	$3,439,471	$3,466,255	$1,733,491	$5,748,907	$18,207,017	$43,093,071	$15,109,085	$1,422,090	$20,688,221	$37,219,395	$0	$2,935,217	$2,115,194	$3,726,898	$8,777,309	$89,089,776
TOTAL	$76,359,990	$44,184,494	$11,666,644	$38,630,093	$34,948,707	$63,783,871	$269,573,800	$37,385,927	$6,585,487	$62,473,449	$106,444,863	$0	$8,562,722	$6,173,930	$16,210,842	$30,947,493	$406,966,155
OM&G	18.92%	52.14%	0.00%	81.86%	15.62%	5.31%	16.39%	0.76%	10.23%	2.75%	2.23%	0.00%	0.00%	0.00%	4.44%	1.89%	9.05%
Depreciation	10.40%	7.62%	7.98%	29.45%	7.17%	3.42%	7.37%	2.35%	4.66%	3.34%	2.99%	0.00%	5.53%	5.54%	8.91%	6.97%	5.50%
Sub-Total	29.32%	59.76%	7.98%	111.30%	22.80%	8.73%	23.76%	3.11%	14.89%	6.09%	5.22%	0.00%	5.53%	5.54%	13.35%	8.85%	14.55%
Grants in Lieu	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	1.36%	0.00%	1.36%	1.36%	1.36%	1.36%	1.36%
Interest	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	3.85%	0.00%	3.85%	3.85%	3.85%	3.85%	3.85%
Preferred Dividends	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Corporate Taxes	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%	0.00%	-0.27%	-0.27%	-0.27%	-0.27%	-0.27%
Return	5.46%	5.46%	5.46%	5.46%	5.46%	5.46%	5.46%	5.46%	5.46%	5.46%	5.46%	0.00%	5.46%	5.46%	5.46%	5.46%	5.46%
Cost of Capital	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	10.40%	0.00%	10.40%	10.40%	10.40%	10.40%	10.40%
FIXED CHARGE RATE	**39.73%**	**70.16%**	**18.38%**	**121.71%**	**33.20%**	**19.13%**	**34.16%**	**13.51%**	**25.29%**	**16.49%**	**15.62%**	**0.00%**	**15.93%**	**15.94%**	**23.76%**	**19.26%**	**24.95%**

Exh 5 of COSS: 2026 ALLOCATION OF OPERATING EXPENSES

(AMOUNT IN THOUSANDS OF DOLLARS)

(8) OPER. & MAINT. - STEAM	$111,341.8
(9) OPER. & MAINT. - HYDRO	$3,543.7
(10) OPER. & MAINT. - WIND	$15,773.1
(11) OPER. & MAINT. - BIOMASS	$12,703.2
(12) OPER. & MAINT. - LM6000	$1,213.9
(13) OPER. & MAINT. - OTHER CT's	$2,999.3
(14) DSM	$0.0
(15) FCR DEFERRAL	$0.0
(16) REG. AFFAIRS - ADVOCACY EXPE	$1,363.8
(16) GRANTS IN LIEU OF TAXES	$22,178.0
(17) DEPRECIATION:	
(18) STEAM	$46,717.0
(19) HYDRO	$16,145.7
(20) WIND	$12,948.7
(21) LM6000	$6,832.4
(22) GAS TURBINE - OTHER	$2,804.9
(23) GENERAL PROPERTY	$17,217.1
(24) INTEREST NET OF AFUDC	$62,759.2
(25) PREFERRED DIVIDENDS	$0.0
(26) CORPORATE TAXES	-$4,352.8
(27) NON-OPERATING REVENUE:	$0.0
(28) EXPORT SALES	$0.0
(29) STEAM AND ASH SALES	-$5,017.7
(30) OTHER REVENUE	-$3,356.8
(31) RETURN (PROFIT/LOSS)	$89,089.8

NOTES:

1. The Gross and Net Asset Values have been averaged based on actual year-end balances for 2025 and 2026.
2. OM&G and Capital Related Expenses have been based on the 2026 to 2027 GRA .
3. The percentages are calculated on "Total NPV incl. GP and Deferred Charges" since the capital-related expenses such as interest, taxes and return reflect NSPI's total capitalization.

DETAIL OF HYDRO FACILITIES

	Wreck Cove & Gisbourne	Avon	Black River	Lequille & Nict & Para	Mersey	Bear River & Sissiboo	Tusket	Roseway & Harmony	St. Margarets	Sheet Harbour	Dickie Brook	Fall River	Annapolis Tidal	Total Hydro
Installed Capacity kW's	204000	7000	22000	22000	42000	37000	2000	1000	10000	11000	4000	1000	17200	380200
Gross Plant Cost	$337,800,330	$25,938,406	$68,930,017	$49,235,761	$66,905,744	$68,700,079	$24,874,327	$56,919,422	$56,428,068	$51,356,923	$16,444,702	$3,587,507	$45,641,253	$872,762,538
Gross Plant Cost/kW	$1,655.88	$3,705.49	$3,133.18	$2,237.99	$1,592.99	$1,856.76	$12,437.16	$56,919.42	$5,642.81	$4,668.81	$4,111.18	$3,587.51	$2,653.56	$2,295.54
Net Book Value	$276,650,831	$18,543,963	$56,066,210	$41,862,328	$48,623,956	$54,868,102	$18,656,814	$41,417,735	$40,639,441	$40,694,942	$13,294,757	$4,137,845	$26,038,789	$681,495,714
Net Book Value/kW	$1,356.13	$2,649.14	$2,548.46	$1,902.83	$1,157.71	$1,482.92	$9,328.41	$41,417.74	$4,063.94	$3,699.54	$3,323.69	$4,137.84	$1,513.88	$1,792.47
- share of General Property Plant	$29,706,510	$1,991,234	$6,020,338	$4,495,138	$5,221,195	$5,891,686	$2,003,351	$4,447,398	$4,363,826	$4,369,785	$1,427,579	$444,318	$2,796,021	$73,178,379
- share of Deferred Chgs & W/C	$398,608	$26,719	$80,782	$60,317	$70,059	$79,056	$26,881	$59,676	$58,555	$58,635	$19,156	$5,962	$37,518	$981,923
Total NPV incl. GP & Deferred Chgs.	$306,755,950	$20,561,915	$62,167,330	$46,417,783	$53,915,211	$60,838,844	$20,687,046	$45,924,809	$45,061,822	$45,123,362	$14,741,491	$4,588,125	$28,872,328	$755,656,016
OM&G (Direct)	$1,452,888	$0	$1,333,515	$0	$2,808,067	$1,400,811	$0	$0	$735,567	$912,416	$0	$0	$1,835,268	$10,478,532
OM&G (Overhead)	$655,505	$0	$601,647	$0	$1,266,927	$632,010	$0	$0	$331,869	$411,658	$0	$0	$828,025	$4,727,642
Grants in Lieu	$1,993,340	$153,061	$406,752	$290,537	$394,807	$405,395	$146,782	$335,878	$332,979	$303,054	$97,039	$21,170	$269,326	$5,150,120
Depreciation (Direct)	$4,425,184	$490,236	$971,913	$861,626	$1,251,686	$927,451	$435,301	$1,041,625	$1,128,561	$1,093,902	$343,694	$55,248	$826,107	$13,852,535
Depr. (General Property)	$1,289,422	$142,846	$283,199	$251,063	$364,720	$270,243	$126,839	$303,512	$328,843	$318,744	$100,147	$16,098	$240,713	$4,036,388
Interest	$5,640,746	$433,131	$1,151,025	$822,161	$1,117,223	$1,147,186	$415,363	$950,467	$942,262	$857,582	$274,601	$59,906	$762,139	$14,573,791
Preferred Dividends	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Corporate Taxes	($391,228)	($30,041)	($79,832)	($57,023)	($77,488)	($79,566)	($28,809)	($65,922)	($65,353)	($59,480)	($19,046)	($4,155)	($52,860)	($1,010,802)
Return	$8,007,319	$614,852	$1,633,937	$1,167,099	$1,585,954	$1,628,487	$589,628	$1,349,235	$1,337,588	$1,217,380	$389,810	$85,039	$1,081,894	$20,688,221
TOTAL	$23,073,176	$1,804,085	$6,302,156	$3,335,463	$8,711,895	$6,332,016	$1,685,105	$3,914,795	$5,072,316	$5,055,257	$1,186,246	$233,306	$5,790,612	$72,496,427
OM&G	0.76%	0.00%	3.45%	0.00%	8.38%	3.70%	0.00%	0.00%	2.63%	3.25%	0.00%	0.00%	10.23%	2.23%
Depreciation	2.07%	3.41%	2.24%	2.66%	3.32%	2.18%	3.01%	3.25%	3.59%	3.47%	3.34%	1.72%	4.10%	2.62%
Sub-Total	2.83%	3.41%	5.69%	2.66%	11.70%	5.89%	3.01%	3.25%	6.21%	6.72%	3.34%	1.72%	14.33%	4.86%
Grants in Lieu	0.72%	0.83%	0.73%	0.69%	0.81%	0.74%	0.79%	0.81%	0.82%	0.74%	0.73%	0.51%	1.03%	0.76%
Interest	2.04%	2.34%	2.05%	1.96%	2.30%	2.09%	2.23%	2.29%	2.32%	2.11%	2.07%	1.45%	2.93%	2.14%
Preferred Dividends	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Corporate Taxes	-0.14%	-0.16%	-0.14%	-0.14%	-0.16%	-0.15%	-0.15%	-0.16%	-0.16%	-0.15%	-0.14%	-0.10%	-0.20%	-0.15%
Return	2.89%	3.32%	2.91%	2.79%	3.26%	2.97%	3.16%	3.26%	3.29%	2.99%	2.93%	2.06%	4.15%	3.04%
FIXED CHARGE RATE	**8.34%**	**9.73%**	**11.24%**	**7.97%**	**17.92%**	**11.54%**	**9.03%**	**9.45%**	**12.48%**	**12.42%**	**8.92%**	**5.64%**	**22.24%**	**10.64%**

SUMMARY OF HYDRO FACILITIES

	Wreck Cove	Annapolis Tidal	Wind Generation	Other Hydro	Total Hydro
Installed Capacity kW's	200000	17200	1300	163000	381500
Gross Plant Cost	$337,800,330	$45,641,253	$0	$489,320,955	$872,762,538
Gross Plant Cost/kW	$1,655.88	$2,653.56	$0.00	$3,001.97	$2,287.71
Net Book Value	$276,650,831	$26,038,789	$0	$378,806,094	$681,495,714
Net Book Value/kW	$1,356.13	$1,513.88	$0.00	$2,323.96	$1,786.36
- share of General Property Plant	$29,706,510	$2,796,021		$40,675,848	$73,178,379
- share of Deferred Chgs & W/C	$398,608	$37,518		$545,797	$981,923
Total NPV incl. GP & Deferred Chgs.	$306,755,950	$28,872,328	$0	$420,027,739	$755,656,016
OM&G (Direct)	$1,452,888	$1,835,268	$0	$7,190,376	$10,478,532
OM&G (Overhead)	$655,505	$828,025	$0	$3,244,111	$4,727,642
Grants in Lieu	$1,993,340	$269,326	$0	$2,887,454	$5,150,120
Depreciation (Direct)	$4,425,184	$826,107	$0	$8,601,244	$13,852,535
Depr. (General Property)	$1,289,422	$240,713	$0	$2,506,253	$4,036,388
Interest	$5,640,746	$762,139	$0	$8,170,907	$14,573,791
Preferred Dividends	$0	$0	$0	$0	$0
Corporate Taxes	($391,228)	($52,860)	$0	($566,714)	($1,010,802)
Return	$8,007,319	$1,081,894	$0	$11,599,008	$20,688,221
TOTAL	$23,073,176	$5,790,612	$0	$43,632,639	$72,496,427
OM&G	0.76%	10.23%	0.00%	2.75%	2.23%
Depreciation	2.07%	4.10%	0.00%	2.93%	2.62%
Sub-Total	2.83%	14.33%	0.00%	5.69%	4.86%
Grants in Lieu	0.72%	1.03%	0.00%	0.76%	0.76%
Interest	2.04%	2.93%	0.00%	2.16%	2.14%
Preferred Dividends	0.00%	0.00%	0.00%	0.00%	0.00%
Corporate Taxes	-0.14%	-0.20%	0.00%	-0.15%	-0.15%
Return	2.89%	4.15%	0.00%	3.06%	3.04%
FIXED CHARGE RATE	**8.34%**	**22.24%**	**0.00%**	**11.52%**	**10.64%**

NSPI **Embedded Cost of Ancillary Services**

TABLE E4-1
Page 2 of 2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES

DETAIL OF COMBUSTION TURBINES

	Burnside	Victoria Junction	Tusket	Tufts Cove 4	Tufts Cove 5	Total Combustion Turbines
Installed Capacity kW's	120000	60000	24000	54000	54000	312000
Gross Plant Cost	$53,110,081	$25,679,087	$20,321,534	$60,754,030	$43,850,628	$203,715,361
Gross Plant Cost/kW	$442.58	$427.98	$846.73	$1,125.07	$812.05	$3,654.42
Net Book Value	$39,046,137	$18,492,377	$11,819,346	$53,744,509	$38,729,686	$161,832,055
Net Book Value/kW	$325.38	$308.21	$492.47	$995.27	$717.22	$2,838.55
- share of General Property Plant	4,192,738	1,985,694	1,269,150	5,771,036	4,158,758	$17,377,376
- share of Deferred Chgs & W/C	5,626	2,664	1,703	7,744	5,580	$23,317
Total NPV incl. GP & Deferred Chgs.	$43,244,500	$20,480,736	$13,090,199	$59,523,288	$42,894,025	$179,232,749
OM&G (Direct)	$1,557,170	$319,864	$212,929	$0	$0	$2,089,963
OM&G (Overhead)	$702,555	$144,314	$96,068	$0	$0	$942,937
Grants in Lieu	$530,858	$251,416	$160,692	$730,692	$526,556	$2,200,214
Depreciation (Direct)	$977,225	$582,915	$1,117,684	$2,023,109	$1,460,226	$6,161,160
Depr. (General Property)	$458,592	$273,550	$524,507	$949,404	$685,254	$2,891,307
Interest	$1,502,220	$711,456	$454,725	$2,067,710	$1,490,046	$6,226,158
Preferred Dividends	$0	$0	$0	$0	$0	$0
Corporate Taxes	($104,190)	($49,345)	($31,539)	($143,411)	($103,346)	($431,831)
Return	$2,132,476	$1,009,948	$645,505	$2,935,217	$2,115,194	$8,838,341
TOTAL	$7,756,908	$3,244,119	$3,180,571	$8,562,722	$6,173,930	$28,918,249
OM&G	5.8%	2.5%	2.6%	0.0%	0.0%	1.9%
Depreciation	3.7%	4.6%	13.9%	5.5%	5.5%	5.6%
Sub-Total	9.5%	7.1%	16.5%	5.5%	5.5%	7.5%
Grants in Lieu	1.4%	1.4%	1.4%	1.4%	1.4%	1.4%
Interest	3.8%	3.8%	3.8%	3.8%	3.8%	3.8%
Preferred Dividends	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Corporate Taxes	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%	-0.3%
Return	5.5%	5.5%	5.5%	5.5%	5.5%	5.5%
Cost of Capital	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%
FIXED CHARGE RATE	**19.87%**	**17.54%**	**26.91%**	**15.93%**	**15.94%**	**17.87%**

2026 OATT DEVELOPMENT
DETERMINATION OF AVERAGE FIXED ASSETS, DEFERRED CHARGES & WORKING CAPITAL

ANALYSIS OF FIXED ASSETS as of December 31, 2026

	Gross Plant Value Dec. 2025	Net Plant Value Dec. 2025	Gross Plant Value Dec. 2026	Net Plant Value Dec. 2026	Gross Plant Value Average	Net Plant Value Average
Steam Production						
Lingan	$676,824,498	$238,184,517	$549,129,155	$146,254,527	$612,976,826	$192,219,522
Tufts Cove	104,189,612	63,897,672	105,189,436	62,057,351	104,689,524	62,977,511
Tufts Cove # 6	$103,522,759	$63,467,926	$103,522,759	$63,467,926	103,522,759	63,467,926
Trenton	$283,372,384	$70,482,075	$202,261,421	($7,000,823)	242,816,902	31,740,626
Pt. Tupper	$209,709,321	$105,678,929	$213,352,524	$104,848,696	211,530,922	105,263,813
Point Aconi	$355,232,137	$333,374,676	$265,915,473	$333,374,676	310,573,805	333,374,676
Total In-Service Generation	1,732,850,710	875,085,794	1,439,370,768	703,002,354	1,586,110,739	789,044,074
Strait Marine Terminal	$26,878,399	$6,230,607	$22,768,421	$2,319,538	24,823,410	4,275,073
Non-operational & General	$449,939,115	$31,342,472	$617,447,535	$62,081,965	533,693,325	46,712,218
Steam Generation Plant - S	$2,209,668,224	$912,658,874	$2,079,586,725	$767,403,857	2,144,627,474	840,031,365
Hydro Production						
Wreck Cove	$325,351,804	$266,218,194	$350,248,856	$287,083,468	337,800,330	276,650,831
Wind					0	0
Tidal (Annapolis)	$45,641,253	$26,491,047	$45,641,253	$25,586,531	45,641,253	26,038,789
Other Hydro:						
Dickie Brook	$16,129,969	$13,153,888	$16,759,435	$13,435,625	16,444,702	13,294,757
Tusket	$24,836,336	$18,672,555	$24,912,318	$18,641,073	24,874,327	18,656,814
Bear River/Sissiboo	$65,690,905	$50,943,463	$71,709,254	$58,792,742	68,700,079	54,868,102
Avon	$25,344,269	$17,845,779	$26,532,542	$19,242,147	25,938,406	18,543,963
Lequille	$48,880,635	$42,128,893	$49,590,886	$41,595,764	49,235,761	41,862,328
St. Margaret's	$56,333,997	$40,868,908	$56,522,139	$40,409,975	56,428,068	40,639,441
Sheet Harbour	$41,847,532	$31,474,144	$60,866,314	$49,915,740	51,356,923	40,694,942
Black River	$58,339,092	$43,535,939	$79,520,941	$68,596,480	68,930,017	56,066,210
Mersey	$64,368,543	$45,472,833	$69,442,945	$51,775,080	66,905,744	48,623,956
Roseway	$56,333,997	$40,868,908	$56,522,139	$40,409,975	56,428,068	40,639,441
Harmony	$491,353	$776,466	$491,353	$780,122	491,353	778,294
Fall River	$2,284,223	$2,209,023	$4,890,791	$6,066,667	3,587,507	4,137,845
Total In-Service Generation	**831,873,909**	**640,660,040**	**913,651,167**	**722,331,388**	**872,762,538**	**681,495,714**
Non-operational & General	-$39,947,549	-$26,709,614	-$39,708,707	-$31,516,041	(39,828,128)	(29,112,828)
Total Hydro Production	791,926,359	613,950,426	873,942,461	690,815,347	832,934,410	652,382,886
Wind Tubine						
Wind Turbine	$325,044,395	$168,638,932	$325,868,816	$158,353,757	325,456,606	163,496,344
Total Wind	325,044,395	168,638,932	325,868,816	158,353,757	325,456,606	163,496,344
Gas Turbine						
Tufts Cove #4	$60,089,448	$56,210,620	$60,754,030	$53,744,509	60,754,030	53,744,509
Tufts Cove #5	$42,624,931	$38,401,812	$45,076,326	$39,057,561	43,850,628	38,729,686
Burnside	$45,763,027	$30,286,020	$60,457,136	$47,806,253	53,110,081	39,046,137
Victoria Junction	$25,586,740	$18,758,101	$25,771,435	$18,226,654	25,679,087	18,492,377
Tusket	$19,854,691	$11,504,806	$20,788,377	$12,133,886	20,321,534	11,819,346
Total In-Service Generation	193,918,837	155,161,360	212,847,304	170,968,862	203,383,070	163,065,111
Other GTs	-$74,486	-$2,098,341	-$74,486	-$2,602,775	(74,486)	(2,350,558)
Total Gas Turbine	$193,844,352	$153,063,018	$212,772,818	$168,366,087	203,308,585	160,714,553
Total Generation Assets	**3,520,483,330**	**1,848,311,249**	**3,492,170,819**	**1,784,939,048**	**3,506,327,075**	**1,816,625,148**
Transmission	$1,532,255,029	$1,040,472,780	$1,712,156,022	$1,195,466,218	1,622,205,526	1,117,969,499
Distribution	$2,337,658,303	$1,309,161,594	$2,491,659,982	$1,430,933,431	2,414,659,142	1,370,047,512
General Property	$920,542,736	$454,928,515	$987,003,201	$469,804,506	953,772,969	462,366,511
Total Rate Base	**8,310,939,399**	**4,652,874,139**	**8,682,990,024**	**4,881,143,202**	**8,496,964,712**	**4,767,008,671**
Non-Utility Prop. & PPD	$1,579,085	$1,316,082	$1,579,085	$1,254,623	1,579,085	1,285,352
Total Fixed Assets	**$8,312,518,484**	**$4,654,190,221**	**$8,684,569,109**	**$4,882,397,825**	**$8,498,543,797**	**$4,768,294,023**

ANALYSIS OF DEFERRED CHARGES & CREDITS & WORKING CAPITAL

	End of year 2025	End of year 2026	AVERAGE
Current & Long Term Assets ($M)			
Deferred Charges & Credits			
Financing Charges	23.4	21.1	
Pension Charges	143.6	170.3	
FAM Deferral	(0.3)	1.2	
Storm Rider Deferral	(0.0)	-	
Rate Stabilization (RS) Deferral	-	-	
DSM Rider Deferral	0.7	0.8	
DSM Deferral	0.0	-	
Other General Charges	34.2	24.9	
Retired Assets (Roseway, Annapolis, and SmartGrid)	-	-	
Deferred Decarbonization Asset	-	-	
Cost of Removal Liability	17.4	(2.4)	
Asset Retirement Obligation	(142.3)	(149.7)	
Deferred Income Taxes	23.9	23.9	
Other Deferred Credits	(28.6)	(30.1)	
	-	-	
Long term receivable	91.3	95.3	
Allowance for materials and supplies	294.8	302.0	
Allowance for working capital	187.6	137.5	
	-	-	
Total Assigned to Fixed Assets	**$646**	**$595**	**$620**

2026 OATT DEVELOPMENT
DETERMINATION OF UNIT GENERATION ASSETS

		Actual NPV ($000)	Adjusted Unit NPV for Common Assets ($000)	Average NPV ($000)	Unit NPV ($000)		
	UNITS						
	Lingan			192,220			
Lingan 1&2 Prod Uni	Units 1& 2	31,255	23,454		39,202	Lingan 1&2 Prod Unit	31,321
Lingan 3&4 ProdUnit	Units 3 & 4	121,996	91,546		153,017	Lingan 3&4 ProdUnit	121,837
	Sub-Total	153,251	115,000				
	Common Assets	(38,252)	0				
	Total Plant	115,000	115,000		192,220		
	Pt. Tupper			105,264			
	Unit 1	0	0		0		
Pt Tupper Unit 1	Unit 2	42,632	104,849		105,264	Pt Tupper Unit 1	42,632
	Sub-Total	42,632	104,849				
	Common Assets	62,217	0				
		104,849	104,849		105,264		
	Trenton			31,741			
	Unit 1-4	0	0		0		
Trenton Unit 5 Capita	Unit 5	(2,414)	(18,462)		83,704	Trenton Unit 5 Capital	(2,414)
Trenton unit 6 Capita	Unit 6	1,499	11,461		(51,963)	Trenton unit 6 Capital	1,499
	Sub-Total	(915)	(7,001)				
	Common Assets	(6,085)	0				
		(7,001)	(7,001)		31,741		
	Tufts Cove			62,978			
TC Unit 1 Capital	Unit 1	28,748	9,394		9,322	TC Unit 1 Capital	28,751
TC Unit 2 Capital	Unit 2	40,241	13,150		13,049	TC Unit 2 Capital	40,242
TC Unit 3 Capital	Unit 3	61,761	20,183		20,027	TC Unit 3 Capital	61,770
TC Unit 6 Capital	Unit 6	63,468	20,740		20,580	TC Unit 6 Capital	63,468
	Sub-Total	194,217	63,468		62,978		
	Common Assets	(130,749)	0				
		63,468	63,468				
	Pt. Aconi						
	Unit 1			333,375	333,375		
	Wreck Cove				276,651		
	Tidal				26,039		
	Hydro - Other				378,806		
	Burnside				39,046		
	Victoria Junction				18,492		
	Tusket				11,819		
	Wind				163,496		

2026 OATT DEVELOPMENT
ALLOCATION OF DIRECT O/H POWER PRODUCTION COSTS

Steam Production	Operating Budget 2025	Operating Budget 2026	Operating Budget 2027	Average Operating Budget 2025 and 2026	Allocation of Thermal Plant Operations	Allocation of Assigned Pension Costs	Allocation of Hydro Admin. & Engineering	Allocation of Energy, Fuels & Risk Mgmt.	Total assigned PP Budget
Plant Operations:									
Operating	$15,545,430	$15,561,374	$16,020,783	$15,553,402	($15,553,402)				$0
Assigned Pension Costs	0	0	0	0	0	0			0
Biomass	6,887,691	7,080,075	7,153,099	6,983,883	1,431,379	0		618,262	9,033,524
Lingan	18,890,530	19,863,856	20,390,316	19,377,193	3,971,446	0		1,715,404	25,064,042
Tufts Cove	17,379,861	17,605,350	18,067,817	17,492,606	3,585,191	0		1,548,567	22,626,363
Trenton	13,587,996	14,094,917	14,032,696	13,841,457	2,836,871	0		1,225,342	17,903,669
Tufts Cove 6						0		-	0
Pt. Tupper	8,645,430	8,879,092	9,524,600	8,762,261	1,795,866	0		775,696	11,333,823
Point Aconi	9,432,344	9,426,945	9,733,809	9,429,645	1,932,649	0		834,778	12,197,072
Pt. Tupper Marine Terminal	0	0	0	0	0	0		-	0
Total Steam Production	**90,369,282**	**92,511,609**	**94,923,120**	**91,440,446**	**(0)**	**0**	**0**	**6,718,048**	**98,158,493**
Hydro Production									
Hydro Prod. Admin & Engineering	3,274,368	2,850,229	2,865,889	3,062,299		0	(3,062,299)		0
Wreck Cove	1,169,275	971,342	1,381,017	1,070,309		0	382,580		1,452,888
Wind	0	0	0	0		0	0		0
Tidal (Annapolis)	1,285,156	1,418,842	1,453,812	1,351,999		0	483,269		1,835,268
Other Hydro:							0		
Dickie Brook	0	0	0	0		0	0		0
Tusket	0	0	0	0		0	0		0
Bear River/Sissiboo	1,018,298	1,045,591	1,073,946	1,031,945		0	368,866		1,400,811
Avon	0	0	0	0		0	0		0
Lequille	0	0	0	0		0	0		0
St. Margaret's (+ White Rock H/M)	534,488	549,262	563,622	541,875		0	193,692		735,567
Sheet Harbour	621,046	723,265	743,567	672,156		0	240,261		912,416
Black River	931,458	1,033,280	1,061,534	982,369		0	351,146		1,333,515
Mersey	2,042,126	2,095,148	2,147,109	2,068,637		0	739,430		2,808,067
Roseway	0	0	0	0		0	0		0
Harmony	0	0	0	0		0	0		0
Fall River	0	0	0	0		0	0		0
Milton	819,462	876,199	899,517	847,831		0	303,055		1,150,886
Nictaux Paradise/Paradise	0	0	0	0		0	0		0
Total Hydro Production	**11,695,677**	**11,563,158**	**12,190,013**	**11,629,418**	**0**	**0**	**0**		**11,629,418**
Gas Turbine									
Tufts Cove #4						0		-	0
Tufts Cove #5						0		-	0
Burnside	1,398,880	1,462,180	1,526,270	1,430,530		0		126,640	1,557,170
Victoria Junction	287,798	299,902	347,014	293,850		0		26,014	319,864
Tusket	181,170	210,054	254,920	195,612		0		17,317	212,929
LM Building	732,769	748,887	765,073	740,828		0		65,583	806,411
Total Gas Turbine Production	2,600,617	2,721,023	2,893,277	2,660,820	0	0	0	235,554	2,896,374
Wind									
Little Brook	0	0	0	0					
Grand Etang	0	0	0	0					
Nuttby	3,307,425	2,524,410	2,571,398	2,915,918					
Digby	1,545,320	1,567,501	1,596,777	1,556,411					
Tupper	647,391	659,595	672,034	653,493					
Sable	404,278	411,831	419,529	408,055					
South Canoe	3,456,660	3,375,030	3,438,730	3,415,845					
Pubnico	0	0	0	0					
ECEI	0	0	0	0					
Total Wind Turbine Production	9,361,074	8,538,367	8,698,468	8,949,721	0	0	0	0	0
Solar									
Amherst	124,205	131,914	140,881	128,060					
	0	0	0	0					
Energy, Fuels & Risk Management	6,870,324	7,036,880	7,221,203	6,953,602		0		(6,953,602)	0
Total Power Production	**$ 121,021,179**	**$ 122,502,951**	**$ 126,066,962**	**$ 121,762,065**	**$ (0)**	**$ -**	**$ 0**	**$ 0**	**$ 112,684,285**

Embedded Cost of Ancillary Services

TABLE E4-8

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
REVENUE REQUIREMENT SUMMARY

Service	2026 GRA Unit Revenue Requirement		2014 GRA Unit Revenue Requirement			Difference		% Diff.
Voltage Control and Reactive Supply	$4,117,997	$/yr	$4,328,964	$/yr	$/yr	($210,967)	$/yr	-5%
Regulation Cost	$159.35	$/kW-yr	$87.49	$/kW-yr	$/kW-yr	$72	$/kW-yr	82%
Load Following Cost	$ 172.64	$/kW-yr	$120.77	$/kW-yr	$/kW-yr	$52	$/kW-yr	43%
Operating Reserve - Spinning	$131.45	$/kW-yr	$118.42	$/kW-yr	$/kW-yr	$13	$/kW-yr	11%
Operating Reserve - Supplemental - 10 Minute	$122.07	$/kW-yr	$56.41	$/kW-yr	$/kW-yr	$66	$/kW-yr	116%
Operating Reserve - Supplemental - 30 Minute	$120.25	$/kW-yr	$131.95	$/kW-yr	$/kW-yr	($12)	$/kW-yr	-9%
	2026 Total Revenue Requirement		**2014 Total Revenue Requirement**					
Voltage Control and Reactive Supply	$4,118	$000/yr	$4,329	$000/yr	$000/yr	($211)	$000/yr	-5%
Regulation Cost	5,099	$000/yr	2,275	$000/yr	$000/yr	$2,824	$000/yr	124%
Load Following Cost	30,213	$000/yr	17,150	$000/yr	$000/yr	$13,063	$000/yr	76%
Operating Reserve - Spinning	4,206	$000/yr	2,961	$000/yr	$000/yr	$1,246	$000/yr	42%
Operating Reserve - Supplemental - 10 Minute	16,601	$000/yr	5,641	$000/yr	$000/yr	$10,960	$000/yr	194%
Operating Reserve - Supplemental - 30 Minute	6,013	$000/yr	6,598	$000/yr	$000/yr	($585)	$000/yr	-9%
Total Annual Revenue Requirement	**$66,250**	$000/yr	**$38,953**	$000/yr	$000/yr	$27,297	$000/yr	70%

2027

		TRANSMISSION SERVICE RATES ($/MW)		
Schedule	**Description**	**2026 Proposed**	**2027 Proposed**	**% Variance**
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/Monthly	$348.14	$241.37	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Network Service/Rate Monthly	$319.10	$216.52	-32.1%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/Monthly	$162.79	$176.94	8.7%
Schedule 2	Reactive Supply & Voltage Control/Network Services/Monthly	$149.20	$158.72	6.4%
Schedule 3	Regulation and Frequency Respponse Service (Regulation Point to Point)/Monthly	$219.03	$229.94	5.0%
Schedule 3	Regulation and Frequency Respponse Service (Regulation Network)/Monthly	$219.03	$229.94	5.0%
Schedule 3	Regulation and Frequency Respponse Service (Load Following Point to Point)/Monthly	$909.20	$930.71	2.4%
Schedule 3	Regulation and Frequency Respponse Service (Load Following Network)/Monthly	$909.20	$930.71	2.4%
Schedule 5	Operating Reserve - Spinning Reserve Service (Point-to-Point)/Monthly	$180.69	$184.82	2.3%
Schedule 5	Operating Reserve - Spinning Reserve Service (Network)/Monthly	$180.69	$184.82	2.3%
Schedule 6	Operating Reserve - Supplemental Reserve Service (10 min Point-to-Point)/Monthly	$529.59	$562.62	6.2%
Schedule 6	Operating Reserve - Supplemental Reserve Service (10 min Network)/Monthly	$529.59	$562.62	6.2%
Schedule 6	Operating Reserve - Supplemental Reserve Service (30 min Point-to-Point)/Monthly	$258.28	$262.62	1.7%
Schedule 6	Operating Reserve - Supplemental Reserve Service (30 min Network)/Monthly	$258.28	$262.62	1.7%
Schedule 7, 8	OATT Point-To-Point Transmission Service/Monthly	$5,333.01	$6,308.33	18.3%
Schedule 10	OATT Network Transmission Service/Monthly Billing	$4,888.13	$5,658.78	15.8%
Point-toPoint				
Ancillary Generation		$2,607.70	$2,589.01	-0.7%
Transmission		$5,333.01	$6,308.33	18.3%
Subtotal		$7,940.71	$8,897.33	12.0%
Network				
Ancillary Generation		$2,565.08	$2,545.94	-0.7%
Transmission		$4,888.13	$5,658.78	15.8%
Subtotal		$7,453.20	$8,204.72	10.1%

Schedule	Description	TRANSMISSION SERVICE RATES ($/MW)		
		2026 Proposed	2027 Proposed	% Variance
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/Yearly	$4,177.65	$2,896.44	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/Monthly	$348.14	$241.37	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/Weekly	$80.34	$55.70	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/On-Peak Daily	$16.07	$11.14	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/Off-Peak Daily	$11.45	$7.94	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/On-Peak Hourly	$1.00	$0.70	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Point-To-Point/Off-Peak Hourly	$0.48	$0.33	-30.7%
Schedule 1	Sched., Sys. Cntrl. & Disp. For Network Service/Rate Monthly	$319.10	$216.52	-32.1%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/Yearly	$1,953.42	$2,123.23	8.7%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/Monthly	$162.79	$176.94	8.7%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/Weekly	$37.57	$40.83	8.7%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/On Peak Daily	$7.51	$8.17	8.7%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/Off Peak Daily	$5.35	$5.82	8.7%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/On Peak Hourly	$0.47	$0.51	8.7%
Schedule 2	Reactive Supply & Voltage Control/Pt-to-Pt/Off Peak Hourly	$0.22	$0.24	8.7%
Schedule 2	Reactive Supply & Voltage Control/Network Services/Monthly	$149.20	$158.72	6.4%
Schedule 3	Regulation and Frequency Respponse Service (Regulation Point to Point)/Yearly	$2,628.40	$2,759.26	5.0%
Schedule 3	Regulation and Frequency Respponse Service (Regulation Point to Point)/Monthly	$219.03	$229.94	5.0%
Schedule 3	Regulation and Frequency Respponse Service (Regulation Point to Point)/Weekly	$50.55	$53.06	5.0%
Schedule 3	Regulation and Frequency Respponse Service (Regulation Point to Point)/Daily	$7.20	$7.56	5.0%
Schedule 3	Regulation and Frequency Respponse Service (Regulation Network)/Monthly	$219.03	$229.94	5.0%
Schedule 3	Regulation and Frequency Respponse Service (Load Following Point to Point)/Yearly	$10,910.36	$11,168.52	2.4%
Schedule 3	Regulation and Frequency Respponse Service (Load Following Point to Point)/Monthly	$909.20	$930.71	2.4%
Schedule 3	Regulation and Frequency Respponse Service (Load Following Point to Point)/Weekly	$209.81	$214.78	2.4%
Schedule 3	Regulation and Frequency Respponse Service (Load Following Point to Point)/Daily	$29.89	$30.60	2.4%
Schedule 3	Regulation and Frequency Respponse Service (Load Following Network)/Monthly	$909.20	$930.71	2.4%
Schedule 5	Operating Reserve - Spinning Reserve Service (Point-to-Point)/Yearly	$2,168.23	$2,217.82	2.3%
Schedule 5	Operating Reserve - Spinning Reserve Service (Point-to-Point)/Monthly	$180.69	$184.82	2.3%
Schedule 5	Operating Reserve - Spinning Reserve Service (Point-to-Point)/Weekly	$41.70	$42.65	2.3%
Schedule 5	Operating Reserve - Spinning Reserve Service (Point-to-Point)/Daily	$5.94	$6.08	2.3%
Schedule 5	Operating Reserve - Spinning Reserve Service (Network)/Monthly	$180.69	$184.82	2.3%
Schedule 6	Operating Reserve - Supplemental Reserve Service (10 min Point-to-Point)/Yearly	$6,355.04	$6,751.42	6.2%
Schedule 6	Operating Reserve - Supplemental Reserve Service (10 min Point-to-Point)/Monthly	$529.59	$562.62	6.2%
Schedule 6	Operating Reserve - Supplemental Reserve Service (10 min Point-to-Point)/Weekly	$122.21	$129.84	6.2%
Schedule 6	Operating Reserve - Supplemental Reserve Service (10 min Point-to-Point)/Daily	$17.41	$18.50	6.2%
Schedule 6	Operating Reserve - Supplemental Reserve Service (10 min Network)/Monthly	$529.59	$562.62	6.2%
Schedule 6	Operating Reserve - Supplemental Reserve Service (30 min Point-to-Point)/Yearly	$3,099.33	$3,151.38	1.7%
Schedule 6	Operating Reserve - Supplemental Reserve Service (30 min Point-to-Point)/Monthly	$258.28	$262.62	1.7%
Schedule 6	Operating Reserve - Supplemental Reserve Service (30 min Point-to-Point)/Weekly	$59.60	$60.60	1.7%
Schedule 6	Operating Reserve - Supplemental Reserve Service (30 min Point-to-Point)/Daily	$8.49	$8.63	1.7%
Schedule 6	Operating Reserve - Supplemental Reserve Service (30 min Network)/Monthly	$258.28	$262.62	1.7%
Schedule 7	OATT Point-To-Point Transmission Service/Yearly	63,996.09	75,699.93	18.3%
Schedule 7, 8	OATT Point-To-Point Transmission Service/Monthly	5,333.01	6,308.33	18.3%
Schedule 7, 8	OATT Point-To-Point Transmission Service/Weekly	1,230.69	1,455.77	18.3%
Schedule 7, 8	OATT Point-To-Point Transmission Service/On-Peak Daily	246.14	291.15	18.3%
Schedule 7, 8	OATT Point-To-Point Transmission Service/Off-Peak Daily	175.33	207.40	18.3%
Schedule 8	OATT Point-To-Point Transmission Service/On-Peak Hourly	15.38	18.20	18.3%
Schedule 8	OATT Point-To-Point Transmission Service/Off-Peak Hourly	$7.31	$8.64	18.3%
Schedule 10	OATT Network Transmission Service/Monthly Billing	$4,888.13	$5,658.78	15.8%

FIGURE 5-9

NOVA SCOTIA POWER INC.
2027 TRANSMISSION REVENUE REQUIREMENT
(in $000s)

Asset Category	(1) Gross Plant (Note 1)	(2) Net Plant (Note 1)	(3) OM&G Expense	(4) Depreciation Expense	(5) Int., Taxes & Return Exp	(6) FCR Deferral	(7) Total Expenses
Bulk Network:							
Total Equipment	**$1,467,644**	**$1,158,533**	**$31,248**	**$43,526**	**$85,341**	**$0**	**$160,114**
Generation Related Transmission Assets:							
Step Up Transformers	$17,812	$12,210	$296	$607	$982	$0.00	$1,885
Radial to Generation	65,069	44,602	1,082	2,218	3,588	$0.00	$6,888
Generator Breakers	7,509	5,147	125	256	414	$0.00	$795
Total Gen. Related Transmission Assets	90,390	61,959	1,503	3,081	4,984	0	$9,568
Scheduling, System Control & Dispatch (Note 2)			**6,126**				**6,126**
Total Transmission Asset and Revenue Requirement	**1,558,034**	**1,220,492**	**$38,877**	**$46,607**	**$90,325**	**$0**	**$175,809**

NOTE:

1. Transmission Gross and Net Plant assets include allocated share of General Property assets and other assets such as deferred charges, materials inventory and net receivables.
2. Control Centre assets and related capital charges are included in the General Property assignment to Transmission assets.

FIGURE 5-10

NOVA SCOTIA POWER INC.
2027 DEMAND ALLOCATION FACTORS
(in MW Demand)

	(1)	(2)	(3)	(4)
Service	**Long-Term Firm Reservations**	**Transmission System 12 CP**	**Allocation Factors (%)**	**Billing Determinants 12 NCP**
Point-to-Point (Note 1)	330		15.60%	N/A
Network In-Province (Note 2)		1,785	84.40%	1,990
TOTAL MW	**330**	**1,785**	**100.00%**	

NOTES:

1. There is currenly one Long-Term Firm Point-to-Point Transmission Reservation (TSR400)

2.The 1,785 MW is the average of the 12 monthly Test Year Coincident Peaks. system load data resulting in a coincidence factor of 89.7% which is then applied to the average of the 12 monthly Coincident System Peaks.

FIGURE 5-11

NOVA SCOTIA POWER INC.
2027 TRANSMISSION REVENUE REQUIREMENT ALLOCATION
UNIT COSTS

	(1)	(2)	(3)	(4)
Bulk Transmission Services	**Total Cost By Service (in $000s)**	**Total Usage By Service (in MW)**	**Annual $/MW-year**	**Monthly $/MW-month**
Point-to-Point Service	$24,981	330	$75,699.93	$6,308.33
Network Service	135,133	1,785	$75,699.93	$6,308.33
Total Transmission	**160,114**	**2,115**	**$75,699.93**	**$6,308.33**
Scheduling, System Control & Dispatch				
Point-to-Point Service	956	330	$2,896.44	$241.37
Network Service	5,170	1,785	$2,896.44	$241.37
Total Scheduling, System Control & Dispatch	**$6,126**	**2,115**	**$2,896.44**	**$241.37**
Grand Total	**166,241**			

NOTES:
1. Point-to-Point and Network Transmission Service costs are Bulk Network Costs from Figure 5-9 and allocated using the allocation factors from Figure 5-10.
2. Scheduling, System Control & Dispatch Service costs, from Figure 5-9, are allocated using the allocation factors from Figure 5-10.

FIGURE 5-12

NOVA SCOTIA POWER INC.
RATE CALCULATION
2027 POINT-TO-POINT TRANSMISSION SERVICE

	(1)	(2)	(3)	(4)
Service Category	**Total Cost By Service (in $000s)**	**Total Usage By Service (in MW)**	**Annual $/MW-year**	**Monthly $/MW-month**
Point-to-Point Service	$24,981	330	$75,699.93	$6,308.33
			RATES	
			$/MW-year	**$/MW-month**
Yearly		Monthly Cost * 1000	75,699.93	6,308.33
Monthly	($/MW-m)	Yearly/12		6,308.33
Weekly	($/MW-w)	Yearly/52		1,455.77
On-Peak Daily	($/MW-d)	Weekly/5		291.15
Off-peak Daily	($/MW-d)	Yearly/365		207.40
On-Peak Hourly	($/MW-h)	Daily/16		18.20
Off-Peak Hourly	($/MW-h)	Yearly/8760		8.64

NOTES:
1. Yearly Service is available only as firm service.
2. Hourly Service is available only as non-firm service.
3. Other Services are available as firm or non-firm services.

FIGURE 5-13

NOVA SCOTIA POWER INC.
RATE CALCULATION
2027 NETWORK TRANSMISSION SERVICE

	(1)	(2)	(3)	(4)
Service Category	**Annual Cost of Service ($MW-year)**	**Monthly Cost of Service ($MW-month)**	**Coincidence Factor [1]**	**Monthly ($MW-month) Billing Rate**
Network Service	$75,699.93	$6,308.33	89.70%	$5,658.78

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

Notes
(1) The Coincident Factor is the ratio between the monthly system peaks and the average of the monthly class NCP peaks from the Cost Of Service Study (COS).

FIGURE 5-14

NOVA SCOTIA POWER INC.
ANCILLIARY SERVICE RATE CALCULATION
2027 SCHEDULING, SYSTEM CONTROL AND DISPATCH

	(1)	(2)	(3)	(4)
Service	**Total Cost of Service (in $000s)**	**Total Usage (in MW)**	**Yearly Cost $/MW-year**	**Monthly Cost $/MW-month**
Scheduling, System Control & Dispatch	$956	330	$2,896.44	$241.37

Sched., Sys. Cntrl. & Disp. for Point-to-Point			Rate for Services Billed Monthly Services	$/MW-year	$/MW-month
Yearly			Monthly Cost	2,896.44	241.37
Monthly		($/MW-m)	Yearly/12		241.37
Weekly		($/MW-w)	Yearly/52		55.70
On-Peak Daily		($/MW-d)	Weekly/5		11.14
Off-peak Daily		($/MW-d)	Yearly/365		7.94
On-Peak Hourly		($/MW-h)	Daily/16		0.70
Off-Peak Hourly		($/MW-h)	Yearly/8760		0.33

	Cost of Service					
	Total Cost of Service (in $000s)	**Total Usage (in MW)**	**($MW-year)**	**($MW-month)**	**Coincidence Factor**	**Rate Monthly ($MW-month)**
Sched., Sys. Cntrl. & Disp. for Network Service	$5,170	1,785	$2,896.44	$241.37	89.7%	$216.52

NOTE:
This approach facilitates the use of non-coincident peaks for billing purposes consistent with EMGC Recommendation 28.

FIGURE 6-7

NOVA SCOTIA POWER INC.
2027 CAPACITY BASED ANCILLARY SERVICES
NOVA SCOTIA USAGE

	(1)	(2)	(3)	(4)	(5)
		Network Service Billing Determinants			
	Usage by Point-to-Point MW	Total MW	Loads that Self Supply MW	Loads that Purchase From Third Party MW	Net Usage in Tariff MW
Regulation and Frequency Response					
Regulation	0	1,990			1,990
Load Following	0	1,990			1,990
Operating Reserves (Contingency Reserves)					
Spinning (10 Minute)	0	1,990			1,990
Supplemental (10 Minute)	0	1,990			1,990
Supplemental (30 Minute)	0	1,990			1,990

NOTES:
1. The Network Billing Determinants (based on 12 NCP) are as per Figure 5-10.
2. These services apply only to Network Service loads or to point-to-point services within Nova Scotia. They do not apply to point-to-point service used for exports, because for exports, those services would be the responsibility of the customer receiving the supply. That customer would purchase these ancillary services from the transmission provider in the operating area where the load is located.

FIGURE 6-8

NOVA SCOTIA POWER INC.
CAPACITY BASED ANCILLARY SERVICES
2027 REVENUE REQUIREMENT AND RATE DESIGN

	(1) Revenue Requirement ($/kW-yr)	(2) Services Required (MW)	(3) Revenue Requirement ($000/yr)	(4) Usage (MW)	(5) Rate for Network ($/MW-yr)	(6) Rate for Network ($/MW-mo)	(7) Rate for Pt.-to-Pt. ($/MW-mo)	(8) Rate for Pt.-to-Pt. ($/MW-wk)	(9) Rate for Pt.-to-Pt. ($/MW-dy)
Regulation and Frequency Response									
Regulation	$ 171.59	32	$5,490.93	1,990	$2,759.26	$229.94	$229.94	$53.06	$7.56
Load Following	$ 181.28	122.6	$22,225.35	1,990	$11,168.52	$930.71	$930.71	$214.78	$30.60
Operating Reserves (Contingency Reserves)									
Spinning (10 Minute)	$ 137.92	32	$4,413.46	1,990	$2,217.82	$184.82	$184.82	$42.65	$6.08
Supplemental (10 Minute)	$ 133.02	101	$13,435.32	1,990	$6,751.42	$562.62	$562.62	$129.84	$18.50
Supplemental (30 Minute)	$ 125.43	50	$6,271.25	1,990	$3,151.38	$262.62	$262.62	$60.60	$8.63

NOTES:
1. Revenue Requirement is from OATT Allocation attachments

FIGURE 6-9

NOVA SCOTIA POWER INC.
REACTIVE SUPPLY AND VOLTAGE CONTROL
2027 CALCULATION OF REVENUE REQUIREMENT

		(1)	(3)	(4)	(5)	(6)
Ancillary Service	**Proxy Source**	**Capacity (MVAR)**				**Total Fixed Costs ($000/yr)**
Reactive Supply and Voltage Control						
	Static Var Compensators	1,253				$3,890.96
Revenue Requirement per VAR of capability				$/kVAR/yr		$3.11
Estimated peak VAR requirement				MVAR	228	
Additional VAR requirement for dynamic system security				MVAR	228	
	Total VAR requirement			MVAR	457	457
Revenue requirement total				$000/yr		$1,418.0

NOTES:

1. Discount Rate	5.67%				
2. Ecalation Rate	2.00%				
3. The Escalating Capital charge includes Income Tax.					
4. Total capability of generation currently on the system is	1,252.9	MVAR			
5. The requirement divided by the capability is	457	MVAR divided by	1,252.9	MVAR	36.4%

FIGURE 6-10

NOVA SCOTIA POWER INC.
2027 REACTIVE SUPPLY AND VOLTAGE CONTROL
RATE DESIGN

	(1) Revenue Requirement ($000/yr)	(2) Billing Determinants (MW)	(3) Yearly ($/MW-yr)	(4) Monthly ($/MW-mo)	(5) Weekly ($/MW-wk)	(6) On-Peak Daily ($/MW-dy)	(7) Off-Peak Daily ($/MW-dy)	(8) On-Peak Hourly ($/MW-hr)	(9) Off-Peak Hourly ($/MW-hr)
Reactive Supply and Voltage Control									
Total	$4,491								
Less: Credits	0.0								
Net	4,491								
Point-to-Point	$700.7	330	$2,123.23	$176.94	$40.83	$8.17	$5.82	$0.51	$0.24
Network Services	$3,790.2	1,990	$1,904.63	$158.72					
	4,491	2,320							

NOTES:
1. Point-to-Point and Network Services Reactive Supply and Voltage Control Revenue Requirements are segregated as per Figure 5-10, Col. 3.

FCR Deferral

2027 FCR Deferral	-

Average of Gross Fixed Assets

NPV - Steam	803
NPV - Hydro	714
NPV - Wind	154
NPV - Gas Turbine	173
GPV - LM 6000	96
GPV - Transmission	1,232
Total	3,172
Transmission Allocator	38.9%
FCR Deferral applicable to OATT	-

2027 OATT DEVELOPMENT SCHEDULE

NOVA SCOTIA POWER INC.
2027 TRANSMISSION SYSTEM REVENUE REQUIREMENT

	Original Classification	Based on Re-classification of Step-Up Transformers	Based on Re-classification of Substation Breakers	Based on Re-classification of Radial to Load	Based on Re-classification of Radial to Generation	Based on Re-classification of Step-Up Trnfrs, Radial to Gen. & Gen. Breakers
Transmission Revenue Requirement:						
O&M Expenses	$31,248	$30,952	$31,123	$31,248	$30,166	$29,745
Depreciation	43,526	42,919	43,270	43,526	41,308	40,445
Interest, Taxes & Return	85,341	84,358	84,927	85,341	81,752	80,356
FCR	0	$0	$0	$0	$0	$0
SUB-TOTAL	160,114	158,229	159,320	160,114	153,226	150,545
Scheduling, System Control & Dispatch	6,126	6,126	6,126	6,126	6,126	6,126
TOTAL EXPENSES	**$166,241**	**$164,355**	**$165,446**	**$166,241**	**$159,352**	**$156,672**

Determination of Trans. O&M Expenses: (in $000)	
Direct Expenses:	
Customer Operations - Control Centre	$3,619.3
Sub-Total	3,619.3
Customer Operations - Other Transmission	18,462.0
TOTAL	22,081.3
Assignment of Corp. O/H & Pension Costs	
Transmission Share of Corp. O/H Exp.	15,292.9
TOTAL Overhead Expenses	15,292.9
Scheduling,System Control & Dispatch (including Corp. O/H expenses)	6,126.3
Other Transmission (including Corp. O/H expenses)	31,248.0
Total Transmission Expenses	**$37,374.3**

$0.16

MONTHLY SYSTEM PEAKS

MONTH	2003 Coincident Peak (kW)	2003 Non-Coincident Demand (kW)		2003 Non- Coin. Demand + Losses (kW)		2004 Coincident Peak (kW)	2006 Coincident Peak (kW)	2007 Coincident Peak (kW)	2009 Coincident Peak (kW)	2013 Coincident Peak (kW)	2014 Coincident Peak (kW)	2019 Coincident Peak (kW)	2020 Coincident Peak (kW)	2027 Test Year Average Coincident Peak (kW)	(4) CLASS NON-COINCIDENT DMD. (KW)
January	1,948,150	2,096,434		2,347,749		2,077,800	2,185,900	2,256,300	2,260,975	2,096,776	2,071,068	2,081,070	2,070,667	2,424,228	2,819,367
February	1,898,469	2,149,916		2,385,897		2,015,600	2,130,900	2,168,700	2,228,254	2,109,394	2,093,337	2,178,342	1,986,843	2,364,746	2,589,201
March	1,797,913	2,007,633		2,203,390		1,953,500	2,002,700	2,029,500	2,116,274	1,870,832	1,816,824	2,081,256	1,900,343	2,084,552	2,306,282
April	1,673,321	1,880,568		2,037,465		1,729,500	1,799,000	1,840,900	1,876,549	1,704,488	1,599,229	1,720,835	1,494,047	1,754,518	2,005,763
May	1,669,467	1,812,900		1,970,045		1,597,700	1,910,700	1,664,300	1,723,228	1,459,601	1,461,033	1,490,407	1,464,354	1,487,264	1,745,504
June	1,465,392	1,853,908		2,004,327		1,503,100	1,549,800	1,559,200	1,677,208	1,343,286	1,419,523	1,235,584	1,264,254	1,372,408	1,466,420
July	1,448,934	1,695,163		1,826,468		1,535,100	1,569,100	1,586,400	1,644,035	1,415,574	1,375,413	1,257,196	1,486,013	1,428,977	1,575,132
August	1,464,221	1,767,181		1,901,496		1,564,000	1,602,000	1,609,300	1,648,902	1,379,348	1,457,650	1,288,220	1,428,756	1,444,095	1,545,354
September	1,488,409	1,907,652		2,063,595		1,514,900	1,578,700	1,589,900	1,600,840	1,350,969	1,464,994	1,214,256	1,386,187	1,374,965	1,508,478
October	1,602,647	1,898,900		2,069,360		1,668,900	1,715,800	1,720,200	1,722,514	1,561,852	1,485,323	1,382,249	1,579,005	1,543,728	1,703,118
November	1,806,068	2,047,936		2,283,323		1,926,700	1,914,700	1,925,100	1,914,656	1,629,986	1,695,951	1,779,617	1,660,220	1,931,880	2,226,274
December	2,013,671	2,095,759		2,373,572		2,100,600	2,175,700	2,195,000	2,205,595	2,000,000	2,000,028	1,900,572	1,910,103	2,210,055	2,389,381
Total	20,276,662	23,213,950		25,466,687		21,187,400	22,135,000	22,144,800	22,619,030	19,922,107	19,940,373	19,609,603	19,630,792	21,421,416	23,880,273
Average Monthly	**1,689,722**	**1,934,496**	**87.3%**	**2,122,224**	**79.6%**	**1,765,617**	**1,844,583**	**1,845,400**	**1,884,919**	**1,660,176**	**1,661,698**	**1,634,134**	**1,635,899**	**1,785,118**	**1,990,023**

Nova Scotia Power Inc.
2027 Transmission Tariff WACC Rate
Millions of dollars

	End of year 2026	End of year 2027		AVERAGE
Deferred Charges & Credits:				
Deferred Charges & Credits				
Financing Charges	21.1	20.0		20.5
Pension Charges	170.3	197.8		184.0
FAM Deferral	1.2	(1.7)		(0.2)
Storm Rider Deferral	-	-		-
Rate Stabilization (RS) Deferral	-	-		-
DSM Rider Deferral	0.8	0.1		0.4
DSM Deferral	-	-		-
Other General Charges	24.9	16.9		20.9
Retired Assets (Roseway, Annapolis, a	-	-		-
Deferred Decarbonization Asset	-	-		-
Cost of Removal Liability	(2.4)	(31.2)		(16.8)
Asset Retirement Obligation	(149.7)	(157.6)		(153.7)
Deferred Income Taxes	23.9	15.5		19.7
Other Deferred Credits	(30.1)	(31.8)		(30.9)
	-	-		
Long term receivable	95.3	99.5		97.4
Allowance for materials and supplies	302.0	287.0		294.5
Allowance for working capital	137.5	114.7		126.1
Total Assigned to Fixed Assets	$594.8	$529.2		$562.007
% Allocated To Transmission				**22.4%**
Additional Deferred Chgs. & W/C assigned to Trans.				**$125.767**

	End of year 2026	End of year 2027		AVERAGE
Fixed Assets				
GPV - Transmission Plant - TLand	14.573	14.564		14.6
GPV - Steam Production	$2,079.6	$2,150.7		$2,115.2
GPV - Hydro	$873.9	$894.3		$884.1
GPV - Wind	$325.9	$327.1		$326.5
GPV - Gas Turbine	$212.8	$226.0		$219.4
GPV - Solar/Smart Grid	$1.6	$1.6		$1.6
GPV - LM 6000	$105.8	$115.5		$110.7
GPV Transmission	$1,712.2	$1,799.9	-$198.0	1,558.0
GPV Distribution	$2,491.7	$2,650.5	$198.0	2,769.1
GPV General Property	$987.0	$1,043.6		1,015.297
Total GPV of Fixed Assets	**$8,790.4**	**$9,209.3**		**8,999.840**
% Transmission to Total Assets				**19.5%**
Additional Deferred Chgs. & W/C assigned to Trans.				**$109.665**
NPV - Steam Production	772.3	832.8		802.6
NPV - Hydro	696.3	731.6		713.9
NPV - Wind	158.5	148.8		153.7
NPV - Solar	1.3	1.2		1.2
NPV - Gas Turbine	168.9	177.7		173.3
NPV - LM 6000	92.8	99.6		96.2
NPV Transmission	1,197.1	1,267.8	-$187.9	1,044.5
NPV Distribution	1,431.0	1,557.8	$187.9	1,682.3
NPV General Property	470.0	468.4		469.2
Total NPV of Fixed Assets	4,988.1	5,285.6		**5,136.9**
% Transmission to Total Assets	26.5%	26.3%		**22.4%**

2027 GRA OATT DEVELOPMENT SCHEDULE

December 31, 2027 Fixed Asset Balance

		Annual Depreciation
Composite Transmission Depreciation Rate		**3.23%**
Composite General Property Depreciation Rate		**6.70%**
	(in $000)	**(in $000)**
Depreciated Plant:		
Average Transmission	$1,044,537	
Average share of General Property	104,996	
Average share of Deferred Charges & Working Cap.	125,767	
Total assigned Depreciated Plant	$1,275,300	
Transmission Depreciable Gross Plant	$1,572,603	
Transmission Land Value	(14,569)	
Total Transmission Plant	$1,558,034	
share of General Property	198,116	
Sub-Total	1,756,150	
share of Deferred Charges & Working Capital	109,665	
	$1,865,815	
Percent Un-depreciated	**65%**	
Step-up Transformers:		
1979 Transfer - Original Plant Value	$6,216	
1997 Transfer - Original Plant Value	8,658	
Sub-Total	$14,874	
Share of General Property	1,891	
Total	$16,765	
share of Deferred Charges & Working Capital	1,047	
Total Gross Assets including Deferred Chgs & W/C	$17,812	
Depreciated Plant Value	$10,897	$607
share of Deferred Charges & Working Capital	1,312	
Total including Deferred Chgs & W/C	$12,210	
Radial to Generation:		
Original Plant Value - 69kV Lines	$44,386	
Original Plant Value - 230kV Lines	7,070	
Original Plant Value - 230kV Substation	2,880	
Sub-Total	$54,336	
Share of General Property	6,909	
Total	$61,245	
share of Deferred Charges & Working Capital	3,825	
Total Gross Assets including Deferred Chgs & W/C	$65,069	
Depreciated Plant Value	$39,809	$2,218
share of Deferred Charges & Working Capital	4,793	
Total including Deferred Chgs & W/C	$44,602	

2027 GRA OATT DEVELOPMENT SCHEDULE

December 31, 2027 Fixed Asset Balance

		Annual Depreciation
Radial to Load:		
Original Plant Value - 69kV Lines	$0	
Sub-Total	$0	
Share of General Property	0	
Total	$0	
share of Deferred Charges & Working Capital	0	
Total Gross Assets including Deferred Chgs & W/C	$0	
Depreciated Plant Value	$0	$0
share of Deferred Charges & Working Capital	0	
Total including Deferred Chgs & W/C	$0	
Breakers:		
Original Plant Value - 138 kV	$1,670	
Original Plant Value - 230 kV	2,760	
Original Plant Value - 345 kV	1,840	
Sub-Total	$6,270	
Share of General Property	797	
Total	$7,067	
share of Deferred Charges & Working Capital	441	
Total Gross Assets including Deferred Chgs & W/C	$7,509	
Depreciated Plant Value	$4,594	$256
share of Deferred Charges & Working Capital	553	
Total including Deferred Chgs & W/C	$5,147	
SUB-TOTAL	$55,300	$3,081
share of Deferred Charges & Working Capital	6,658	
Total including Deferred Chgs & W/C	$61,959	
Total Net Transmission Plant ($M)	**$1,149,533**	
% Step-up Transformers to Total	**0.95%**	
% Radial to Generation	**3.46%**	
% Radial to Load	**0.00%**	
% Generator Breakers	**0.40%**	

NOVA SCOTIA POWER INC.
ANALYSIS OF TRANSMISSION PLANT

	69 kV Voltage			138 kV Voltage		230 kV Voltage			345 kV Voltage		
	Radial to Load (in $M)	Radial to Gen. (in $M)	Balance (in $M)	Breakers (in $M)	Balance (in $M)	Radial to Gen. (in $M)	Breakers (in $M)	Balance (in $M)	Breakers (in $M)	Balance (in $M)	TOTAL (in $M)
Transmission Associated with Lingan #1 & #2											
STATIONS:											
Lingan Terminals #1							$0.30	$1.48			$1.78
Lingan Terminals #2							1.10	5.39			6.49
VJ Terminal					0.14						0.14
Port Hastings Substation								5.91			5.91
Onslow Substation								10.26			10.26
Brushy Hill Site								0.07			0.07
Brushy Hill Substation								5.67			5.67
Brushy Hill Bus								0.62			0.62
LINES:											
Lingan - Victoria Junction					0.97			2.22			3.19
Upgrade 230 kV Lingan to Port Hastings								0.22			0.22
ROW Lingan - Victoria Junction					0.66						0.66
Onslow - Port Hastings								4.64			4.64
ROW Trenton - Port Hastings								0.89			0.89
Upgrade 230 kV Onslow to Brushy Hill								1.31			1.31
Onslow - Brushy Hill								6.80			6.80
ROW Onslow - Brushy Hill								0.62			0.62
											49.27
Transmission associated with Wreck Cove											
Wreck Cove - Glen Tosh Terminal Equip.											
ROW Wreck Cove - Glen Tosh											
138 kV Wreck Cove - Glen Tosh					5.50						5.50
Transmission associated with Lingan #3 & #4											
STATIONS:											
Lingan 230 kV Substation							0.90	4.37			5.27
Port Hastings 230 kV Substation								2.01			2.01
Onslow 230 kV Substation								2.63			2.63
Brushy Hill 230 kV Substation								4.72			4.72
LINES:											
ROW Onslow - Port Hastings								1.72			1.72
ROW Clearing Lingan - Port Hastings								1.08			1.08
ROW Clearing Port Hastings - Onslow								1.39			1.39
ROW Clearing Onslow - Brushy Hill								0.59			0.59
Lingan - Port Hastings								8.53			8.53
Port Hastings - Onslow								9.34			9.34
Strait of Canso Crossing								5.31			5.31
Onslow - Brushy Hill								7.33			7.33

NOVA SCOTIA POWER INC.
ANALYSIS OF TRANSMISSION PLANT

	69 kV Voltage			138 kV Voltage		230 kV Voltage			345 kV Voltage		
	Radial to Load (in $M)	Radial to Gen. (in $M)	Balance (in $M)	Breakers (in $M)	Balance (in $M)	Radial to Gen. (in $M)	Breakers (in $M)	Balance (in $M)	Breakers (in $M)	Balance (in $M)	TOTAL (in $M)
											49.92
Transmission associated with Brushy Hill - Bridgewater											
STATIONS:											
Bridgewater Substation					4.35			1.45			5.80
Brushy Hill Terminal								0.60			0.60
Bridgewater Terminal								3.70			3.70
Telecommunications								1.80			1.80
LINES:											
ROW Brushy Hill - Bridgewater								1.50			1.50
Clearing Brushy Hill - Bridgewater								0.80			0.80
Brushy Hill - Bridgewater								5.00			5.00
Upgrade Brushy Hill - Bridgewater								1.60			1.60
											20.80
Transmission associated with Trenton #6											
STATIONS:											
Lakeside Transformer										6.39	6.39
Hopewell Substation										8.09	8.09
Onslow Substation										12.34	12.34
Trenton Substation					2.15						2.15
Lakeside Substation										0.66	0.66
Telecommunications										2.00	2.00
Land										1.00	1.00
LINES:											
Lakeside - Onslow										21.38	21.38
Onslow - Hopewell										10.99	10.99
Hopewell - Trenton					5.58						5.58
											70.58
Transmission associated with Pt. Aconi											
STATIONS:											
Woodbine 230/345 kV Substation							0.46	2.24	1.84	8.97	13.51
Telecommunications										2.44	2.44
Hopewell 345 kV Terminal										2.39	2.39
Pt. Aconi 230 kV Substation						2.26					2.26
Springhill Capacitor Bank					1.04						1.04
Pt. Aconi Construction						0.62					0.62
Sysco 230 kV Breaker								0.99			0.99
Lingan Modifications								0.52			0.52
LINES:											
ROW Woodbine - Pt. Aconi								1.91			1.91

NOVA SCOTIA POWER INC.
ANALYSIS OF TRANSMISSION PLANT

	69 kV Voltage			138 kV Voltage		230 kV Voltage			345 kV Voltage		
	Radial to Load (in $M)	Radial to Gen. (in $M)	Balance (in $M)	Breakers (in $M)	Balance (in $M)	Radial to Gen. (in $M)	Breakers (in $M)	Balance (in $M)	Breakers (in $M)	Balance (in $M)	TOTAL (in $M)
ROW Woodbine - Port Hastings										2.09	2.09
Woodbine - Hopewell										40.20	40.20
Pt. Aconi - Woodbine						7.07					7.07
Woodbine - Sysco								3.21			3.21
ROW Woodbine - Victoria Junction								0.37			0.37
											78.62
NS - NB Intertie											
ROW Onslow - NB Border										0.27	0.27
Onslow - NB Border										7.49	7.49
138 kV Terminal					0.22						0.22
345 kV Terminal										0.43	0.43
345 kV / 230 kV Transformers										1.75	1.75
											10.16
Additional Stations - Generation											
138kV Substation - Pt. Tupper				0.26	1.26						1.52
138kv Substation - Tufts Cove				0.75	3.64						4.39
138kV Substation - Trenton				0.66	3.21						3.87
TOTAL				**$1.67**	**$28.72**	**$9.95**	**$2.76**	**$120.81**	**$1.84**	**$128.88**	**$294.63**
PERCENT OF TOTAL				**0.6%**	**9.7%**	**3.4%**	**0.9%**	**41.0%**	**0.6%**	**43.7%**	**100.0%**
Modification from Original Calculation:											
50 / 50 split of bal. In Trans. Plant (Note 1)			631.70		631.70						1,263.40
69kV Radials to Load/Gen./Balance	0.00	44.39	(44.39)								
Revised Trans. Plant from above	0.00	0.00	0.00	1.67	28.72	9.95	2.76	120.81	1.84	128.88	294.63
TOTAL	$0.00	$44.39	$587.31	$1.67	$660.42	$9.95	$2.76	$120.81	$1.84	$128.88	$1,558.03
PERCENT OF TOTAL	**0.0%**	**2.8%**	**37.7%**	**0.1%**	**42.4%**	**0.6%**	**0.2%**	**7.8%**	**0.1%**	**8.3%**	**100.0%**

Below 69kV Percentage of Total	**40.5%**
138kV & Above Percentage of Total	**59.5%**

Note 1: 69kV vs 138kV split was based on kilometres of line (1666 km - 69kV & 1786 km - 138 kV)

NOVA SCOTIA POWER INC.
69KV RADIAL LINES

L5004	Sackville	Rockingham	10.40	
L5039	Lakeside	Spryfield	8.31	
L5014	St Croix	Burlington	10.60	
L5021	Canaan	Klondike	7.10	
L5023	Waterville Tap	Waterville	1.10	
L5024	Tremont	Kingston	4.70	
L5028	Onslow	Stewiacke	**10.30**	-- 18.4 km included due to serving Industrial Load
L5030	Black River Rd	Aberdeen	**0.00**	-- 2.9 km included due to connecting to Wind Generation
L5031	Mill Lake	Robinson Cor	19.80	
L5033	Canaan	Hillaton	12.10	
L5036	BerwickTp	berwick	1.95	
L5037	EastRiver	Canexel	**0.00**	-- 3.68 km included due to serving Industrial Load
L5040	Onslow	Tatamagouche	**0.00**	-- 42.8 km included due to connecting to Wind Generation
L5042	Farell	Albro	2.00	
L5044	MiddletonTp	Middleton	3.90	
L5046	Wolf Tap	WolfvilleRidge	2.40	
L5047	Tap	Bridgetown	3.10	
L5048	EGreenH	Lockport	5.50	
L5054	Weymouth	Saulnierville	**0.00**	-- 23.30 km included due to connecting to Wind Generation
L5057	Tap	Cornwallis	2.10	
L5058	Springhill	Pugwash	**0.00**	-- 39 km included due to serving Industrial Load
L5502	Trenton	Abercrombie	6.00	
L5503	Hastings	Cleveland	**0.00**	--12.7 km included due to connecting to Wind Generation
L5505	Whycocomagh	Aberdeen	11.10	
L5506	Abercombie	Pictou	**2.70**	--5.4 km included due to connecting to Wind Generation
L5508	Abercombie	KimberlyClark	**0.00**	-- 1.50 km included due to serving Industrial Load
L5511	Trafalgar	Up Muquodoboit	31.70	
L5521	Onslow	WillowLn	**0.00**	-- 4.4 km included due to connecting to Wind Generation
L5522	Onslow	Walker	**0.00**	-- Line Retired
L5527	SalmonRiver	Canso	57.00	
L5533	Gulch	Conway	**0.00**	--13.2 km included due to connecting to Wind Generation
L5539	Milton	Liverpool	8.50	
L5545	Bridgewate	HighSt	5.20	
L5547	Westhavers	Lunenburg	18.20	
L5548	Maccan	Brownell	16.80	
L5549	Maccan	Hickman	**0.00**	-- 12.70 km included due to serving Industrial Load
L5550	Maccan	Parsboro	33.30	
L5551	Lunenburg	Riverport	9.80	
L5559	Whycocomagh	SWMargaree	**0.00**	-- 38.78 km included due to connecting to Wind Generation
L5565	Seaboard	AlbertBridge	18.10	
L5569	tap	TerraceSt	1.60	
L5579	SW Margaree	Cheticamp	**0.00**	-- 41.20 km included due to connecting to Wind Generation

			69kV Radial to Load set to zero due to inclusion in Bulk
	Load	**0.00**	**Network Services (Total km = 325.36)**
	Gen	117.20	km
	Total	117.20	km
	Total 69kV	1,668.00	km
69kV Radial to Load		0.00%	
69kV Radial to Generation		7.03%	
Total		7.03%	
	Total Xmn	83	
	138 and up	53.8	
	69 etc	29.2	
	excluded	2	
	percentage	2.47%	

NOVA SCOTIA POWER INC.
69KV RADIAL GENERATION LINES

L5019	Canann Rd	Hollow B	4.7	
L5020	Hollow B	Methals	9.2	
L5035	HellsGate	Canaan	0	0.8
L5050	Sissiboo	FourthLk	16.3	
L5540	Milton	Deep B and Cow	2.3	
:5580	tap	Lingan Wind	2.3	
L5581	Gulliver's Cove	Conway	16.6	
L7015	Pt Aconi	Woodbine	46.3	
L5056	tap	Annapolis	3.9	
L5555	Gannon	Aconi	15.6	
L5556	Tap	Donkin	0	11.5
Total			**117.2** km	

TABLE E1-1

Nova Scotia Power Inc.
2027 Transmission Tariff WACC Rate
Millions of dollars

1) Interest (Carrying Cost)

a) Weighted Average Cost of Capital - Pretax

	Proportion	Cost	Extended
ST Debt	4.83%	2.73%	0.13%
LT Debt	55.17%	3.51%	1.94%
Common	40.00%	9.00%	3.60%
	100.00%		5.67%

WACC - pretax cost	5.67%

b) Additional income tax for common equity

Extended equity cost	3.60%
Effective tax rate (excluding surtax)	29.0%
Income tax	1.47%

WACC - equity tax cost	1.47%

c) Large Corporations Tax

Ave. NPV - Transmission	$1,044.537
Ave. NPV - assigned GP	104.996
Ave. Deferred Chgs & W/C	125.767
NPV - Total Transmission	$1,275.300

d) Grants in Lieu of Property Tax

Total 2022 Forecasted Expense	$51.5
Transmission % of Total Plant	22.4%
Transmission Allocated Amount	$11.5
Percentage of NBV	0.90%

WACC - Grants in Lieu of Property Tax	0.90%

Total WACC - Interest / Carrying Cost	**8.05%**

Nova Scotia Power Inc.
2027 Transmission Tariff WACC Rate
Millions of dollars

2) Depreciation

a) Depreciation Expense

Gross Transmission Assets ($M) - Y/A 2026/2027	$1,558.034	
Less: Non depreciable land ($M) - Y/A 2026/2027	14.57	
Net Gross Transmission Assets ($M)	1,572.603	
Gross Assigned Gen. Prop. Assets ($M) -Y/A 2026/2027	198.116	
Total Gross assigned Trans. Assets ($M)	1,770.719	
Depreciation Rate - Transmission	3.23%	
Depreciation Rate - General Property	6.70%	
Depreciation Expense ($M)	$59.990	
Depreciation Expense		**$59.990**

b) Tax Effect

UCC Balance - Class 1 {4%} ($M)		
CCA Deduction ($M)		
Plus: Net Depreciation (above)		
Net tax expense (deduction)		
Tax Impact		
Total tax effected		
Tax Effected (CCA Deduction vs. Depreciation Exp.)		**$0.000**
Total Depreciation Charge ($M)		**$59.990**

NOTE:
1) Estimated UCC % of Gross Accounting Value based on estimates only.

2027 Embedded Cost of Ancillary Services

TABLE E4-2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
VOLTAGE CONTROL and REACTIVE SUPPORT SERVICES REVENUE REQUIREMENT

Unit	Generator Nameplate Rating					Generator Net Book Value	Fixed Charge Rate	MVAR Production 97 percentile	Allocation to Reactive Power	Allocated Generator Cost	Exciter Cost Ratio	Exciter Cost	Total Gen/Exciter Allocation	Unit Exciter Rating		Ratio of Exciter to Unit Ratings	Exciter Capacity **(Note 4)**	Unit Reactive Capacity Factor	Exciter Energy Consumption Cost
	MVA	MW	MVAR	Peak MW	PRACTICAL MVAR	$				$		$	$	kVA	kW		$		$
Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19
Formula			**(Note 2)**	**(Note 3)**	= sqrt((1*1) - (4*4))				= (5*5)/(1*1)	= 6*9		= 6*11	= 7*(10+12)			= 15/2/1000	= 6*7*16		= 15/1000*8760*18*T46
Lingan 1	177.0	150.0	94.0	161.8	71.8	$1,265,775	39.03%	15.50	16.44%	$208,064	8%	$101,262	$120,745	1430	858	0.57%	$2,826	29.41%	$222,832
Lingan 2	177.0	150.0	94.0	156.0	83.6	$1,265,775	39.03%	13.20	22.32%	$282,536	8%	$101,262	$149,815	1430	858	0.57%	$2,826	8.25%	$62,502
Lingan 3	177.0	150.0	94.0	162.0	71.3	$4,780,060	39.03%	14.50	16.2%	$775,850	8%	$382,405	$452,123	1430	858	0.57%	$10,673	30.05%	$227,696
Lingan 4	177.0	150.0	94.0	162.0	71.3	$4,780,060	39.03%	13.50	16.2%	$775,850	8%	$382,405	$452,123	1430	858	0.57%	$10,673	24.80%	$187,910
Tufts Cove 1	117.0	100.0	60.7	83.0	60.7	$849,784	72.38%	8.70	26.9%	$229,005	10%	$84,978	$227,257	639	383	0.38%	$2,358	36.13%	$122,304
Tufts Cove 2	117.0	100.0	60.7	97.0	60.7	$775,879	72.38%	9.70	26.9%	$209,089	8%	$62,070	$196,262	424	255	0.25%	$1,430	36.11%	$81,189
Tufts Cove 3	177.0	150.0	94.0	153.0	89.0	$1,048,416	72.38%	22.00	25.3%	$265,041	8%	$83,873	$252,540	1968	1181	0.79%	$5,974	35.88%	$374,087
Tufts Cove 4	60.0	54.0	26.2	49.0	26.2	$12,303,254	15.92%	5.30	19.0%	$2,337,618	8%	$984,260	$528,791	413	248	0.46%	$8,995	45.24%	$99,065
Tufts Cove 5	60.0	54.0	26.2	49.0	26.2	$7,711,074	16.23%	4.60	19.0%	$1,465,104	8%	$616,886	$337,827	413	248	0.46%	$5,746	46.95%	$102,815
Tufts Cove 6	59.8	46.0	38.1	46.0	38.1	$12,626,986	18.44%	4.80	40.7%	$5,145,391	8%	$1,010,159	$1,135,076	413	250	0.0	$12,654	30.04%	$66,310
Trenton 5	177.0	150.0	94.0	159.0	77.8	($1,020,345)	111.61%	16.40	19.3%	($196,976)	8%	($81,628)	($310,963)	1402	841	0.56%	($6,387)	13.46%	$99,961
Trenton 6	188.0	160.0	98.7	160.0	98.7	$3,158,664	111.61%	19.30	27.6%	$870,813	8%	$252,693	$1,254,001	1700	1020	0.64%	$22,475	35.38%	$318,627
Pt. Tupper 2	177.0	150.0	94.0	155.0	85.5	$6,536,227	32.95%	19.50	23.3%	$1,523,847	8%	$522,898	$674,391	1186	711	0.47%	$10,214	31.77%	$199,601
Pt. Aconi 1	218.0	185.0	115.3	184.0	115.3	$11,668,114	19.30%	14.50	28.0%	$3,265,176	8%	$933,449	$810,404	1800	1080	0.58%	$13,148	36.21%	$345,361
Wreck Cove 1	112.0	100.0	50.4	106.0	36.2	$3,754,492	13.47%	7.10	10.4%	$391,492	8%	$300,359	$93,159	575	345	0.35%	$1,744	0.40%	$1,229
Wreck Cove 2	112.0	100.0	50.4	106.0	36.2	$3,754,492	13.47%	8.10	10.4%	$391,492	8%	$300,359	$93,159	575	345	0.35%	$1,744	17.89%	$54,504
Annapolis Tidal (Note 5)	0.0	0.0	0.0	0.0	0.0	$634,275	36.68%	0.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Wind (Note 1)	0.0	0.0	0.0	0.0	0.0	$0		0.0											$0
Other Hydro	181.0	163.0	78.7	163.0	78.7	$29,841,248	16.15%	18.0	18.9%	$0	8%	$2,387,300	$385,478	1358	815	0.50%	$24,078	23.00%	$165,395
Burnside 1	35.0	30.0	18.0	30.0	18.0	$2,448,729	18.54%	2.90	26.5%	$649,663	8%	$195,898	$156,760	169	102	0.34%	$1,537	0.53%	$471
Burnside 2	35.0	30.0	18.0	30.0	18.0	$2,448,729	18.54%	0.00	26.53%	$649,663	8%	$195,898	$156,760	169	102	0.34%	$1,537	0.34%	$305
Burnside 3	35.0	30.0	18.0	30.0	18.0	$2,448,729	18.54%	1.00	26.53%	$649,663	8%	$195,898	$156,760	169	102	0.34%	$1,537	0.44%	$395
Burnside 4	35.0	30.0	18.0	30.0	18.0	$2,448,729	18.54%	0.00	26.53%	$649,663	8%	$195,898	$156,760	169	102	0.34%	$1,537	0.36%	$326
Victoria Junction 1	35.0	30.0	18.0	30.0	18.0	$1,792,927	17.87%	4.90	26.53%	$475,675	8%	$143,434	$110,645	169	102	0.34%	$1,085	2.66%	$2,390
Victoria Junction 2	35.0	30.0	18.0	30.0	18.0	$1,792,927	17.87%	4.80	26.53%	$475,675	8%	$143,434	$110,645	169	102	0.34%	$1,085	4.06%	$3,639
Tusket 1 (Note 6)	35.0	30.0	18.0	30.3	17.5	$2,456,016	26.92%	0.00	25.05%	$615,327	8%	$196,481	$218,575	169	102	0.34%	$2,239	2.37%	$2,129
TOTALS	2,708.8	2,322.0	1,389.5	2,362.1	1,252.9	$121,571,014		228.3		$22,104,720		$9,691,935	$7,919,093				$141,729		$2,741,045

NOTES:

1. Current wind generation does not provide continuous voltage control. IPP embedded in PPA
2. Nameplate based on MVA and rated Power Factor.
3. Gross generator peak capacity.
4. Value of increased generator capacity required to operate exciter.
5. Unit not currently available for generation.
6. Tusket CT rebuilt 2019 2020, returned to service Dec 2020

Total VAR Requirements Mvar (Col. 8 doubled)	456.6
Total Reactive Support Costs - (Col.13+Col.17+Col.19)	$10,801,867
Ratio of VAR Requirements to Sum of Generator VAR Ratings	36.4%
Support services to Maritime Link STATCOM benefit	$554,307
Total Reactive Support Costs	**$4,490,880**

Average Cost of System Losses ($MWh)	$100.80

2027 Embedded Cost of Ancillary Services

TABLE E4-3

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
REGULATION REVENUE REQUIREMENT

Unit	Generator Nameplate Capacity MW	Regulating Capacity MW	Regulating Ramp Rate MW/min	Time on AGC Hours	Regulating Capacity MWh	Ramp Rate Weighting Factor	Weighted Capacity to Regulate MWh	Participation Percentage	Net Book Value $/kW	Fixed Charge Rate	$/kW-yr	Weighted Annual Cost $/kW
Column	1	2	3	4	5	6	7	8	9	10	11	12
Formula		**(Note 1)**	**(Note 2)**	**(Note 3)**	= 2*4	= 3/(Sum of 3)	= 5*6	= 7/(Sum of 7)			= 9*10	= 8*11
Lingan 1	150	25	1.0	3,058.8	76,469	1%	503	1%	$335.88	39.03%	$131.11	$ 1.10
Lingan 2	150	25	1.0	0.0	-	1%	0	0%	$335.88	39.03%	$131.11	$ -
Lingan 3	150	25	1.0	3,195.0	79,875	1%	525	1%	$335.88	39.03%	$131.11	$ 1.15
Lingan 4	150	25	1.0	3,790.3	94,756	1%	623	1%	$335.88	39.03%	$131.11	$ 1.36
Tufts Cove 1	100	10	1.0	0.0	-	1%	0	0%	$177.10	72.38%	$128.18	$ -
Tufts Cove 2	100	11	1.5	3,376.0	37,136	1%	366	1%	$177.10	72.38%	$128.18	$ 0.78
Tufts Cove 3	150	52	1.5	6,379.0	331,708	1%	3,273	5%	$177.10	72.38%	$128.18	$ 6.98
Tufts Cove 4	54	30	10.0	6,268.3	188,048	7%	12,372	21%	$1,139.19	15.92%	$181.34	$ 37.32
Tufts Cove 5	54	30	10.0	6,419.8	192,593	7%	12,671	21%	$713.99	16.23%	$115.85	$ 24.42
Tufts Cove 6	46	0	0.0	0.0	-	0%	0	0%	$180.39	10.39%	$18.74	$ -
Trenton 5	150	30	1.0	0.0	-	1%	0	0%	$114.96	111.61%	$128.32	$ -
Trenton 6	160	25	2.0	3,926.5	98,163	1%	1,292	2%	$114.96	111.61%	$128.32	$ 2.76
Pt. Tupper 2	150	70	1.0	3,633.8	254,363	1%	1,673	3%	$726.25	32.95%	$239.29	$ 6.66
Pt. Aconi 1	185	0	0.0	0.0	-	0%	0	0%	$1,802.03	19.30%	$347.82	$ -
Wreck Cove 1	100	60	15.0	2,792.3	167,535	10%	16,533	28%	$1,501.80	13.47%	$202.22	$ 55.62
Wreck Cove 2	100	60	15.0	1,647.5	98,850	10%	9,755	16%	$1,501.80	13.47%	$202.22	$ 32.82
Annapolis Tidal	0	0	0.0	0.0	-	0%	0	0%	$737.53	36.68%	$270.51	$ -
Other Hydro	163	40	20.0	0.0	-	13%	0	0%	$2,615.36	16.15%	$422.30	$ -
Burnside 1	30	25	10.0	87.5	2,188	7%	144	0%	$408.12	18.54%	$75.66	$ 0.18
Burnside 2	30	25	10.0	56.0	1,400	7%	92	0%	$408.12	18.54%	$75.66	$ 0.12
Burnside 3	30	25	10.0	55.0	1,375	7%	90	0%	$408.12	18.54%	$75.66	$ 0.11
Burnside 4	30	25	10.0	45.5	1,138	7%	75	0%	$408.12	18.54%	$75.66	$ 0.09
Victoria Junction 1	30	25	10.0	45.5	1,138	7%	75	0%	$298.82	17.87%	$53.40	$ 0.07
Victoria Junction 2	30	25	10.0	22.0	550	7%	36	0%	$298.82	17.87%	$53.40	$ 0.03
Tusket 4	30	10	10.0	17.5	175	7%	12	0%	$511.67	26.92%	$137.76	$ 0.03
TOTALS	2322	678	152.0	44816	1,627,457	100%	60,111	100%				$ 171.59

NOTES:

1. Capacity assigned to Automatic Generation Control.
2. Unit tested capability for ramping control
3. Two year average (SCADA records)

2027 Embedded Cost of Ancillary Services

TABLE E4-4

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
LOAD FOLLOWING REVENUE REQUIREMENT

Unit	Type	Net Book Value $/kW	Fixed Charge Rate		Contribution to Load Following Winter morning MW-h	Unit Contribution	Weighted Annual Cost $/kW
Column		1	2	3	4	5	6
Formula				= 1*2		= 4/(Sum of 4)	= 3*5
Lingan 1	Thermal	$335.88	39.03%	$131.11	1,244	9%	$ 11.59
Lingan 2	Thermal	$335.88	39.03%	$131.11	1,743	12%	$ 16.23
Lingan 3	Thermal	$335.88	39.03%	$131.11	672	5%	$ 6.26
Lingan 4	Thermal	$335.88	39.03%	$131.11	933	7%	$ 8.69
Tufts Cove 1	Thermal	$177.10	72.38%	$128.18	42	0%	$ 0.38
Tufts Cove 2	Thermal	$177.10	72.38%	$128.18	510	4%	$ 4.64
Tufts Cove 3	Thermal	$177.10	72.38%	$128.18	1,357	10%	$ 12.36
Tufts Cove 4	Thermal	$1,139.19	15.92%	$181.34	-	0%	$ -
Tufts Cove 5	Thermal	$713.99	16.23%	$115.85	127	1%	$ 1.05
Tufts Cove 6	Thermal	$180.39	18.44%	$33.26	-	0%	$ -
Trenton 5	Thermal	$114.96	111.61%	$128.32	773	5%	$ 7.05
Trenton 6	Thermal	$114.96	111.61%	$128.32	338	2%	$ 3.08
Pt. Tupper 2	Thermal	$726.25	32.95%	$239.29	830	6%	$ 14.11
Pt. Aconi 1	Thermal	$1,802.03	19.30%	$347.82	705	5%	$ 17.42
Wreck Cove 1	Hydro	$1,501.80	13.47%	$202.22	2,782	20%	$ 39.96
Wreck Cove 2	Hydro	$1,501.80	13.47%	$202.22	1,280	9%	$ 18.39
Annapolis Tidal	Hydro	$737.53	36.68%	$270.51	-	0%	$ -
Other Hydro	Hydro	$2,615.36	16.15%	$422.30	654	5%	$ 19.62
Burnside 1	LFO	$408.12	18.54%	$75.66	35	0%	$ 0.19
Burnside 2	LFO	$408.12	18.54%	$75.66	5	0%	$ 0.03
Burnside 3	LFO	$408.12	18.54%	$75.66	24	0%	$ 0.13
Burnside 4	LFO	$408.12	18.54%	$75.66	24	0%	$ 0.13
TOTALS					14,078	100%	$ 181.28

NOTES:

1. Average one-hour load pickup morning peak November 2023 - March 2024 (SCADA records)

2027 Embedded Cost of Ancillary Services

TABLE E4-5

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SPINNING 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Spinning Reserve (10 Minutes)						
											Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
Column		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
Formula					= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**		= Min (1,9*10)		**(Note 4)**	= Max (0,Min(1-7,10))*6*11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	$335.88	39.03%	$131.11	484,073	5440	89.0	0.593	1.0	10.0	1	-	54,405	54,405	6%	$ 7.26
Lingan 2	Thermal	150	$335.88	39.03%	$131.11	144,577	1663	86.9	0.580	1.0	10.0	1	-	16,630	16,630	2%	$ 2.22
Lingan 3	Thermal	150	$335.88	39.03%	$131.11	508,205	5757	88.3	0.589	1.0	10.0	1	-	57,567	57,567	6%	$ 7.68
Lingan 4	Thermal	150	$335.88	39.03%	$131.11	416,791	4870	85.6	0.571	1.0	10.0	1	-	48,697	48,697	5%	$ 6.50
Tufts Cove 1	Thermal	100	$177.10	72.38%	$128.18	376,185	5676	66.3	0.663	1.0	10.0	0	-	-	-	0%	$ -
Tufts Cove 2	Thermal	100	$177.10	72.38%	$128.18	390,992	5616	69.6	0.696	1.5	15.0	1	-	84,242	84,242	9%	$ 10.99
Tufts Cove 3	Thermal	150	$177.10	72.38%	$128.18	723,364	6881	105.1	0.701	1.5	15.0	1	-	103,220	103,220	11%	$ 13.47
Tufts Cove 4	Gas	54	$1,139.19	15.92%	$181.34	267,466	7673	34.9	0.646	10.0	32.0	1	-	146,852	146,852	15%	$ 27.11
Tufts Cove 5	Gas	54	$713.99	16.23%	$115.85	277,536	7788	35.6	0.660	10.0	32.0	1	-	143,006	143,006	15%	$ 16.87
Tufts Cove 6	Thermal	46	$180.39	18.44%	$33.26	163,524	6523	25.1	0.545	1.0	10.0	1	-	65,225	65,225	7%	$ 2.21
Trenton 5	Thermal	150	$114.96	111.61%	$128.32	229,447	2568	89.4	0.596	1.0	10.0	1	-	25,679	25,679	3%	$ 3.35
Trenton 6	Thermal	160	$114.96	111.61%	$128.32	635,172	6121	103.8	0.649	2.0	20.0	1	-	122,429	122,429	12%	$ 15.99
Pt. Tupper 2	Thermal	150	$726.25	32.95%	$239.29	522,857	5310	98.5	0.656	1.0	10.0	1	-	53,100	53,100	5%	$ 12.94
Pt. Aconi 1	Thermal	185	$1,802.03	19.30%	$347.82	783,261	6839	114.5	0.619	0.0	0.0	0	-	-	-	0%	$ -
Wreck Cove 1	Hydro	100	$1,501.80	13.47%	$202.22	2,945	1594	1.8	0.018	15.0	32.0	1	-	51,008	51,008	5%	$ 10.50
Wreck Cove 2	Hydro	100	$1,501.80	13.47%	$202.22	381,457	2706	141.0	1.410	15.0	32.0	1	-	-	-	0%	$ -
Annapolis Tidal	Hydro	0	$737.53	36.68%	$270.51	0	0	0.0	0.000	0.0	0.0	0	-	-	-	0%	$ -
Other Hydro	Hydro	163	$2,615.36	16.15%	$422.30	0	0	0.0	0.000	20.0	32.0	0	-	-	-	0%	$ -
Burnside 1	Diesel	30	$408.12	18.54%	$75.66	3,614	197	18.4	0.613	10.0	30.0	1	-	2,283	2,283	0%	$ 0.18
Burnside 2	Diesel	30	$408.12	18.54%	$75.66	3,355	174	19.3	0.643	10.0	30.0	1	-	1,864	1,864	0%	$ 0.14
Burnside 3	Diesel	30	$408.12	18.54%	$75.66	2,896	180	16.1	0.536	10.0	30.0	1	-	2,510	2,510	0%	$ 0.19
Burnside 4	Diesel	30	$408.12	18.54%	$75.66	1,490	93	16.0	0.533	10.0	30.0	1	-	1,306	1,306	0%	$ 0.10
Victoria Junction 1	Diesel	30	$298.82	17.87%	$53.40	839	42	20.1	0.671	10.0	30.0	1	-	411	411	0%	$ 0.02
Victoria Junction 2	Diesel	30	$298.82	17.87%	$53.40	1,063	63	16.8	0.561	10.0	30.0	1	-	832	832	0%	$ 0.05
Tusket 1	Diesel	30	$511.67	26.92%	$137.76	40	37	1.1	0.036	10.0	30.0	1	-	1,057	1,057	0%	$ 0.15
													-				
TOTALS		2322	$15,764.85			6,321,149		1,343.1		153.0			0	982,322	982,322	100%	$ 137.92

NOTES:

1. Average 2023- 2024
2. Average 2023 - 2024 (SCADA records)
3. Time available to operate, two year average
4. Non-firm exports assigned to units - this no longer applies because as per regulation can no longer include recallable sales/exports.

2027 Embedded Cost of Ancillary Services

TABLE E4-6
TABLE E4-6

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 10 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Generator Nameplate Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Supplemental 10 Minute Reserve						
											Response 0 - 10 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW
	Column	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
	Formula				= 2*3	**(Note 1)**	**(Note 2)**	= 5/6	**(Note 3)**	**(Note 4)**	= Min (1,9*10)		**(Note 5)**	Thermal = Max (0,Min(1-7,10))*6 *11 Hyd & Diesel = 1*8*8760 - 5 *11	= 12+13	= 14/(Sum of 14)	= 4*15
Lingan 1	Thermal	150	$335.88	39.03%	$131.11	484,073	5,440.5	89.0	0.593	1.0	10.0	0	-	-	-	0%	$ -
Lingan 2	Thermal	150	$335.88	39.03%	$131.11	144,577	1,663.0	86.9	0.580	1.0	10.0	0	-	-	-	0%	$ -
Lingan 3	Thermal	150	$335.88	39.03%	$131.11	508,205	5,756.7	88.3	0.589	1.0	10.0	0	-	-	-	0%	$ -
Lingan 4	Thermal	150	$335.88	39.03%	$131.11	416,791	4,869.7	85.6	0.571	1.0	10.0	0	-	-	-	0%	$ -
Tufts Cove 1	Thermal	100	$177.10	72.38%	$128.18	376,185	5,676.1	66.3	0.663	1.0	10.0	0	-	-	-	0%	$ -
Tufts Cove 2	Thermal	100	$177.10	72.38%	$128.18	390,992	5,616.1	69.6	0.696	1.5	15.0	0	-	-	-	0%	$ -
Tufts Cove 3	Thermal	150	$177.10	72.38%	$128.18	723,364	6,881.3	105.1	0.701	1.5	15.0	0	-	-	-	0%	$ -
Tufts Cove 4	Gas	54	$1,139.19	15.92%	$181.34	267,466	7,672.6	34.9	0.646	10.0	54.0	0	-	-	-	0%	$ -
Tufts Cove 5	Gas	54	$713.99	16.23%	$115.85	277,536	7,787.8	35.6	0.660	10.0	54.0	0	-	-	-	0%	$ -
Tufts Cove 6	Thermal	46	$180.39	18.44%	$33.26	163,524	6,522.5	25.1	0.545	1.0	10.0	0	-	-	-	0%	$ -
Trenton 5	Thermal	150	$114.96	111.61%	$128.32	229,447	2,567.9	89.4	0.596	1.0	10.0	0	-	-	-	0%	$ -
Trenton 6	Thermal	160	$114.96	111.61%	$128.32	635,172	6,121.4	103.8	0.649	2.0	20.0	0	-	-	-	0%	$ -
Pt. Tupper 2	Thermal	150	$726.25	32.95%	$239.29	522,857	5,310.0	98.5	0.656	1.0	10.0	0	-	-	-	0%	$ -
Pt. Aconi 1	Thermal	185	$1,802.03	19.30%	$347.82	783,261	6,839.4	114.5	0.619	0.0	0.0	0	-	-	-	0%	$ -
Wreck Cove 1	Hydro	100	$1,501.80	13.47%	$202.22	2,945	1,594.0	1.8	0.018	15.0	32.0	1	-	13,240	13,240	1%	$ 1.49
Wreck Cove 2	Hydro	100	$1,501.80	13.47%	$202.22	381,457	2,706.0	141.0	1.410	15.0	32.0	1	-	853,414	853,414	47%	$ 96.01
Annapolis Tidal	Hydro	0	$737.53	36.68%	$270.51	0	0.0	0.0	0.000	0.0	0.0	0	-	-	-	0%	$ -
Other Hydro	Hydro	163	$2,615.36	16.15%	$422.30	0	0.0	0.0	0.000	20.0	163.0	0	-	-	-	0%	$ -
Burnside 1	Diesel	30	$408.12	18.54%	$75.66	3,614	196.5	18.4	0.613	10.0	30.0	1	-	157,452	157,452	9%	$ 6.63
Burnside 2	Diesel	30	$408.12	18.54%	$75.66	3,355	174.0	19.3	0.643	10.0	30.0	1	-	165,589	165,589	9%	$ 6.97
Burnside 3	Diesel	30	$408.12	18.54%	$75.66	2,896	180.2	16.1	0.536	10.0	30.0	1	-	137,903	137,903	8%	$ 5.80
Burnside 4	Diesel	30	$408.12	18.54%	$75.66	1,490	93.2	16.0	0.533	10.0	30.0	1	-	138,537	138,537	8%	$ 5.83
Victoria Junction 1	Diesel	30	$298.82	17.87%	$53.40	839	41.7	20.1	0.671	10.0	30.0	1	-	175,510	175,510	10%	$ 5.21
Victoria Junction 2	Diesel	30	$298.82	17.87%	$53.40	1,063	63.1	16.8	0.561	10.0	30.0	1	-	146,366	146,366	8%	$ 4.35
Tusket 1	Diesel	30	$511.67	26.92%	$137.76	40	36.6	1.1	0.036	10.0	30.0	1	-	9,522	9,522	1%	$ 0.73
TOTALS		2322	$15,764.85			6,321,149		1,343.1		153.0			0	1,797,534	1,797,534	100%	$ 133.02

NOTES:

1. Average 2023- 2024
2. Average 2023 - 2024 (SCADA records)
3. Time available to operate, two year average
4. Unit tested capability for ramping control
5. Non-firm exports assigned to units (2011)
6. Wreck Cove Change of Response does not affect the weighted Annual Cost

2027 Embedded Cost of Ancillary Services

TABLE E4-7

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
SUPPLEMENTAL 30 MINUTE RESERVE REVENUE REQUIREMENT

Unit	Type	Installed Capacity MW	Net Book Value $/kW	Fixed Charge Rate		Annual Generation MW-h	Time Connected To Load Hours	Average Generation MW	Equivalent Availability Factor	Unit Response Rate MW/Minute	Supplemental 30 Minute Reserve							
											Response 10 - 30 Min. MW	Used Yes = 1 No = 0	Actual Recallable Sales MWh	Potential Reserve MWh	Total Reserve MWh	Unit/Inter. Contribution	Weighted Annual Cost $/kW	
Column		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	
Formula					= 2*3	(Note 1)	(Note 2)	= 5/6	(Note 3)	(Note 4)	= Min (1,9*20)		(Note 5)	Thermal = Max (0,Min(1-7,10))*6*11 Hyd & Diesel = ((1*8*8760)- 5)*11	= 12+13	= 14/(Sum of 14)	= 4*15	
Lingan 1	Thermal	150	$335.88	39.03%	$131.11	484,073	5,440.5	89.0	0.593	1.0	20.0	1	-	108,810	108,810	6.21%	$	8.15
Lingan 2	Thermal	150	$335.88	39.03%	$131.11	144,577	1,663.0	86.9	0.580	1.0	20.0	1	-	33,259	33,259	1.90%	$	2.49
Lingan 3	Thermal	150	$335.88	39.03%	$131.11	508,205	5,756.7	88.3	0.589	1.0	20.0	1	-	115,133	115,133	6.57%	$	8.62
Lingan 4	Thermal	150	$335.88	39.03%	$131.11	416,791	4,869.7	85.6	0.571	1.0	20.0	1	-	97,395	97,395	5.56%	$	7.29
Tufts Cove 1	Thermal	100	$177.10	72.38%	$128.18	376,185	5,676.1	66.3	0.663	1.0	20.0	0	-	-	-	0.00%	$	-
Tufts Cove 2	Thermal	100	$177.10	72.38%	$128.18	390,992	5,616.1	69.6	0.696	1.5	30.0	1	-	168,484	168,484	9.62%	$	12.33
Tufts Cove 3	Thermal	150	$177.10	72.38%	$128.18	723,364	6,881.3	105.1	0.701	1.5	30.0	1	-	206,440	206,440	11.79%	$	15.11
Tufts Cove 4	Gas	54	$1,139.19	15.92%	$181.34	267,466	7,672.6	34.9	0.646	10.0	54.0	1	-	146,852	146,852	8.39%	$	15.21
Tufts Cove 5	Gas	54	$713.99	16.23%	$115.85	277,536	7,787.8	35.6	0.660	10.0	54.0	1	-	143,006	143,006	8.17%	$	9.46
Tufts Cove 6	Thermal	46	$180.39	18.44%	$33.26	163,524	6,522.5	25.1	0.545	1.0	20.0	1		130,450	130,450	0		2
Trenton 5	Thermal	150	$114.96	111.61%	$128.32	229,447	2,567.9	89.4	0.596	1.0	20.0	1	-	51,358	51,358	2.93%	$	3.76
Trenton 6	Thermal	160	$114.96	111.61%	$128.32	635,172	6,121.4	103.8	0.649	2.0	40.0	1	-	244,858	244,858	13.98%	$	17.94
Pt. Tupper 2	Thermal	150	$726.25	32.95%	$239.29	522,857	5,310.0	98.5	0.656	1.0	20.0	1	-	106,201	106,201	6.06%	$	14.51
Pt. Aconi 1	Thermal	185	$1,802.03	19.30%	$347.82	783,261	6,839.4	114.5	0.619	0.0	0.0	0	-	-	-	0.00%	$	-
Wreck Cove 1	Hydro	100	$1,501.80	13.47%	$202.22	2,945	1,594.0	1.8	0.018	15.0	32.0	0	-	-	-	0.00%	$	-
Wreck Cove 2	Hydro	100	$1,501.80	13.47%	$202.22	381,457	2,706.0	141.0	1.410	15.0	32.0	0	-	-	-	0.00%	$	-
Annapolis Tidal	Hydro	0	$737.53	36.68%	$270.51	0	0.0		0.000	0.0	0.0	0	-	-	-	0.00%	$	-
Other Hydro	Hydro	163	$2,615.36	16.15%	$422.30	0	0.0	0.0	0.000	20.0	163.0	0	-	-	-	0.00%	$	-
Burnside 1	Diesel	30	$408.12	18.54%	$75.66	3,614	196.5	18.4	0.613	10.0	30.0	0.25	-	38,982	38,982	2.23%	$	1.68
Burnside 2	Diesel	30	$408.12	18.54%	$75.66	3,355	174.0	19.3	0.643	10.0	30.0	0.24	-	40,536	40,536	2.31%	$	1.75
Burnside 3	Diesel	30	$408.12	18.54%	$75.66	2,896	180.2	16.1	0.536	10.0	30.0	0.25	-	34,736	34,736	1.98%	$	1.50
Burnside 4	Diesel	30	$408.12	18.54%	$75.66	1,490	93.2	16.0	0.533	10.0	30.0	0.27	-	37,185	37,185	2.12%	$	1.61
Victoria Junction 1	Diesel	30	$298.82	17.87%	$53.40	839	41.7	20.1	0.671	10.0	30.0	0.18	-	32,020	32,020	1.83%	$	0.98
Victoria Junction 2	Diesel	30	$298.82	17.87%	$53.40	1,063	63.1	16.8	0.561	10.0	30.0	0.09	-	13,855	13,855	0.79%	$	0.42
Tusket 1	Diesel	30	$511.67	26.92%	$137.76	40	36.6	1.1	0.036	10.0	30.0	0.19	-	1,792	1,792	0.10%	$	0.14
TOTALS		2322	$15,764.85			6,321,149		1,343.1		153.0			0	1,751,352	1,751,352	100.00%	$	125.43

NOTES:

1. Average 2023- 2024
2. Average 2023 - 2024 (SCADA records)
3. Time available to operate, two year average
4. Unit tested capability for ramping control
5. Non-firm exports assigned to units

Power Production Average Load Report (MWh) - Net Generation by Unit
2024

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	82,534	53,609	52,807	34,659	47,385	19,273	21,415	67,068	48,082	25,895	-	49,020	501,747.05
Lingan 2	21,820	30,394	(0)	-	-	10,799	-	42,292	14,414	10,045	13,059	19,969	162,792.44
Lingan 3	84,213	65,735	23,153	-	15,868	41,003	48,201	43,698	27,473	43,106	57,044	69,499	518,993.04
Lingan 4	60,341	48,883	23,997	46,422	6,496	-	12,211	39,015	23,999	35,067	19,134	60,405	375,970.88
Tufts Cove 1	17,191	14,005	24,113	52,158	50,081	17,009	24,163	30,054	51,003	41,034	43,882	47,728	412,421.50
Tufts Cove 2	24,957	43,321	54,311	58,439	42,556	49,984	51,827	55,933	20,489	-	(0)	-	401,817.32
Tufts Cove 3	71,334	59,661	61,655	(251)	78,498	84,159	82,698	89,080	77,955	80,042	48,033	67,286	800,150.38
Tufts Cove 4	24,915	24,279	26,513	27,019	10,653	15,929	22,793	27,133	23,490	25,660	25,451	21,161	274,996.05
Tufts Cove 5	26,458	25,116	25,219	28,191	25,038	2,221	21,371	26,545	25,681	27,936	27,108	29,466	290,350.51
Tufts Cove 6	16,054	16,039	16,877	22,597	9,540	1,998	13,058	21,972	15,021	19,707	18,429	18,265	189,557.03
Trenton 5	52,319	59,648	13,102	(1,105)	(276)	-	(0)	(381)	31,038	41,638	43,813	36,491	276,287.60
Trenton 6	89,172	45,270	46,783	61,328	27,543	11,226	55,492	15,446	38,937	70,639	54,934	65,185	581,956.07
Pt. Tupper 2	92,599	57,178	32,756	49,744	22,853	-	28,935	71,636	63,017	49,237	24,380	70,701	563,036.29
Pt. Aconi 1	108,894	86,554	87,904	83,755	75,281	34,920	73,087	55,612	(1,805)	325	87,643	90,268	782,438.05
Wreck Cove 1	00.0	00.0	00.0	00.0	00.0	00.0	1857.0	8412.0	27.0	00.0	-113.1	1597.5	11,780.43
Wreck Cove 2	39916.8	22890.3	28988.7	42337.1	41501.6	23390.0	4688.0	5093.3	481.5	-107.1	00.0	00.0	209,180.12
Annapolis Tidal	-	-	-	-	-	-	-	-	-	-	-	-	0.00
Wind	19,824	20,485	26,193	20,190	14,960	19,147	16,969	12,980	14,693	22,467	32,935	23,291	244,135.27
Other Hydro	67,408	55,552	73,259	82,889	43,118	17,435	23,651	13,332	17,333	15,824	19,482	35,320	464,603.15
Burnside 1	622.7	660.3	87.2	-21.4	-8.5	-6.2	-9.6	589.4	150.9	717.3	582.4	693.5	4,057.85
Burnside 2	578.9	519.6	323.9	12.0	-11.3	64.3	7.8	398.4	200.7	624.1	437.9	677.9	3,834.23
Burnside 3	456.3	421.1	363.7	183.6	-14.9	87.0	9.8	283.6	214.3	256.3	386.0	564.7	3,211.48
Burnside 4	54.9	340.2	232.4	132.3	10.6	69.3	-1.6	242.6	53.0	231.3	161.0	539.1	2,065.07
Victoria Junction 1	39	188	61	117	(3)	11	23	68	(9)	190	20	48	753.61
Victoria Junction 2	146	170	91	122	20	13	13	97	14	252	69	134	1,142.32
Tusket 1	(44)	7	26	56	(14)	39	14	(24)	(3)	(9)	(17)	16	46.41

Power Production Average Load Report (Hours) - Operating Hours
2024

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	718.39	511.36	573.66	460.48	684.85	277.53	345.33	744.00	669.10	349.38	0.00	477.20	5,811.28
Lingan 2	198.22	340.52	0.00	0.00	0.00	177.60	0.00	712.07	262.38	111.48	167.00	185.42	2,154.69
Lingan 3	742.63	646.55	220.25	0.00	218.13	660.30	722.63	588.66	450.30	579.94	688.76	670.46	6,188.61
Lingan 4	540.52	478.60	294.41	627.87	80.07	0.00	186.93	573.61	393.82	513.88	250.94	659.67	4,600.32
Tufts Cove 1	306.91	230.10	373.38	720.00	715.68	271.33	376.31	439.03	720.00	574.45	633.61	744.00	6,104.80
Tufts Cove 2	381.23	642.14	712.59	720.00	549.54	687.72	744.00	744.00	309.71	0.00	0.00	0.00	5,490.93
Tufts Cove 3	744.00	600.50	516.71	0.00	628.89	720.00	744.00	744.00	720.00	720.06	429.39	650.80	7,218.35
Tufts Cove 4	683.72	668.97	736.99	698.75	282.60	497.60	704.96	725.36	685.48	715.81	710.34	596.06	7,706.64
Tufts Cove 5	715.95	680.58	715.93	709.49	687.31	87.85	642.84	743.99	701.42	719.39	700.38	743.98	7,849.11
Tufts Cove 6	672.00	686.00	684.00	661.00	404.00	162.00	527.00	729.00	540.00	566.00	634.00	675.00	6,940.00
Trenton 5	492.74	661.11	132.12	0.00	0.00	0.00	0.00	0.00	442.74	438.64	480.32	430.50	3,078.17
Trenton 6	632.52	584.72	499.18	623.99	331.80	193.98	673.88	216.15	470.83	637.93	530.98	656.84	6,052.80
Pt. Tupper 2	744.00	531.13	331.51	568.84	281.37	0.00	383.47	743.94	720.00	555.81	268.20	700.97	5,829.24
Pt. Aconi 1	744.00	616.46	744.00	720.00	744.00	480.20	653.86	493.38	0.00	44.32	695.31	694.39	6,629.92
Wreck Cove 1	368.00	269.00	253.00	409.00	345.00	324.00	336.00	64.00	95.00	196.00	100.00	429.00	3,188.00
Wreck Cove 2	85.00	102.00	86.00	130.00	167.00	121.00	172.00	68.00	0.00	3.00	57.00	0.00	991.00
Annapolis Tidal	0	0	0	0	0	0	0	0	0	0	0	0.00	
Wind	0	0	0	0	0	0	0	0	0	0	0	0	
Other Hydro	0	0	0	0	0	0	0	0	0	0	0	0	
Burnside 1	34	30	5	0	0	0	0	34	8	37	29	40	217.05
Burnside 2	29	22	17	1	0	4	1	24	11	32	17	35	192.07
Burnside 3	22	18	15	10	0	5	1	17	7	13	14	29	151.93
Burnside 4	5	16	12	8	2	4	1	13	3	12	6	30	112.19
Victoria Junction 1	2.02	8.36	4.51	6.07	0.53	0.91	1.1	3.26	0	10.82	1.71	2.89	42.18
Victoria Junction 2	5.95	7.59	5.01	5.71	1.42	1.04	0.91	5.15	1.08	13.69	3.73	7.6	58.88
Tusket 1	0	2.79	4.09	3.4	1.28	3.7	1.7	0.09	0.2	0	0.73	3.28	21.26

Power Production Average Load Report (MW) - Average Load
2024

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	114.89	104.84	92.05	75.27	69.19	69.44	62.01	90.15	71.86	74.12	N/A	102.72	86.34
Lingan 2	110.08	89.26	N/A	N/A	N/A	60.81	N/A	59.39	54.94	90.10	78.20	107.70	75.55
Lingan 3	113.40	101.67	105.12	N/A	72.75	62.10	66.70	74.23	61.01	74.33	82.82	103.66	83.86
Lingan 4	111.64	102.14	81.51	73.94	81.13	N/A	65.32	68.02	60.94	68.24	76.25	91.57	81.73
Tufts Cove 1	56.01	60.87	64.58	72.44	69.98	62.69	64.21	68.46	70.84	71.43	69.26	64.15	67.56
Tufts Cove 2	65.46	67.46	76.22	81.17	77.44	72.68	69.66	75.18	66.16	N/A	N/A	N/A	73.18
Tufts Cove 3	95.88	99.35	119.32	N/A	124.82	116.89	111.15	119.73	108.27	111.16	111.86	103.39	110.85
Tufts Cove 4	36.44	36.29	35.98	38.67	37.70	32.01	32.33	37.41	34.27	35.85	35.83	35.50	35.68
Tufts Cove 5	36.96	36.90	35.23	39.73	36.43	25.28	33.25	35.68	36.61	38.83	38.71	39.61	36.99
Tufts Cove 6	23.89	23.38	24.67	34.19	23.61	12.33	24.78	30.14	27.82	34.82	29.07	27.06	27.31
Trenton 5	106.18	90.22	99.17	N/A	N/A	N/A	N/A	N/A	70.10	94.93	91.22	84.76	89.76
Trenton 6	140.98	77.42	93.72	98.28	83.01	57.87	82.35	71.46	82.70	110.73	103.46	99.24	96.15
Pt. Tupper 2	124.46	107.65	98.81	87.45	81.22	N/A	75.46	96.29	87.52	88.59	90.90	100.86	96.59
Pt. Aconi 1	146.36	140.41	118.15	116.33	101.18	72.72	111.78	112.72	N/A	7.34	126.05	130.00	118.02
Wreck Cove 1	N/A	N/A	N/A	N/A	N/A	N/A	5.53	131.44	0.28	N/A	N/A	3.72	3.70
Wreck Cove 2	469.61	224.41	337.08	325.67	248.51	193.31	27.26	74.90	#DIV/0!	N/A	N/A	N/A	211.08
Annapolis Tidal	0	0	0	0	0	0	0	0	0	0	0	0	
Wind													
Other Hydro													
Burnside 1	18.1	22.1	19.0	0.0	0.0	0.0	-120.3	17.2	18.8	19.5	20.4	17.2	18.70
Burnside 2	20.2	23.9	19.2	19.6	-43.4	16.6	7.1	16.7	18.4	19.6	25.5	19.2	19.96
Burnside 3	20.6	23.5	23.6	19.0	0.0	16.5	8.0	16.8	29.1	19.5	27.5	19.5	21.14
Burnside 4	12.0	21.8	18.8	15.8	5.6	15.5	-3.2	18.5	17.7	18.6	25.4	18.2	18.41
Victoria Junction 1	19.2	22.5	13.6	19.3	-6.1	12.6	20.7	21.0	0.0	17.6	11.8	16.6	17.87
Victoria Junction 2	24.6	22.5	18.2	21.4	13.8	12.9	14.2	18.8	13.2	18.4	18.4	17.7	19.40
Tusket CT	0.0	2.7	6.3	16.5	-11.2	10.5	8.1	-264.2	-13.9	0.0	-23.5	5.0	2.18

Generation Statistics(MWh) - Hydro

2024

Hydro													
Little Brook Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Grand Etang Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Dickie Brook Hydro	1,585	887	1,263	1,583	771	192	571	651	336	438	420	870	9,567
Tusket Hydro	1,211	804	871	1,070	76	(13)	(8)	(7)	9	383	163	1,044	5,604
Bear River Hydro System	3,806	3,864	3,411	5,457	2,496	401	562	217	217	767	4,498	4,386	30,082
Sissiboo/Wevmouth System	8,487	6,939	12,719	12,873	6,496	4,882	2,957	3,448	1,869	1,125	2,579	4,471	68,846
Avon Hydro System	2,939	1,338	4,373	3,236	266	30	781	263	676	266	466	1,260	15,894
Lequille Hydro System	3,698	1,816	6,833	4,944	367	14	(26)	(20)	(15)	1,135	358	(7)	19,096
Nictaux/Paradise System	5,998	5,129	4,917	6,170	1,986	760	3,654	2,093	1,248	1,946	2,127	3,606	39,634
Paradise System	(8)	(19)	(7)	(10)	(5)	72	3,075	3,560	1,528	2,057	1,375	2,087	13,706
Annapolis Tidal Power	-	-	-	-	-	-	-	-	-	-	-	-	-
St.Marqaret's Hydro Syste	4,676	2,282	3,467	6,218	1,807	33	(33)	22	110	108	120	495	19,306
Sheet Harbour Hydro Syste	4,347	1,947	4,349	5,042	842	588	2,075	1,018	103	64	435	1,781	22,591
Black River Hydro System	15,420	11,158	13,479	13,463	5,464	2,191	5,487	625	4,816	3,901	3,854	7,096	86,954
Mersey Hydro System	14,890	19,202	17,264	22,504	22,519	8,278	4,537	1,461	6,416	3,565	3,062	8,036	131,736
Roseway & Harmony Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-
Harmony Hydro System	-	-	-	-	-	-	-	-	-	-	-	-	-
Wreck Cove Hydro System	39,917	22,890	28,989	42,337	41,502	23,390	6,545	13,505	509	(107)	(113)	1,598	220,961
Fall River Hydro	359	204	321	340	34	6	17	1	19	69	25	194	1,589
TOTAL	107,325	78,442	102,248	125,226	84,620	40,825	30,196	26,837	17,842	15,717	19,369	36,917	685,564

Power Production Average Load Report (MWh) - Net Generation by Unit
2023

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	47,798	73,499	43,337	0	0	0	46,622	59,505	58,166	45,755	52,562	37,200	464,444
Lingan 2	46,965	48,494	4,632	0	0	0	0	0	0	0	11,593	3,480	115,164
Lingan 3	45,796	56,957	73,988	70,842	23,379	59,549	22,451	28,605	17,543	21,060	27,925	45,505	493,600
Lingan 4	70,734	42,550	53,431	69,500	41,719	12,627	54,327	13,128	39,902	20,237	0	41,538	459,692
Tufts Cove 1	17,433	40,991	7,361	46,521	20,590	47,785	28,067	0	15,998	50,992	43,708	21,602	341,048
Tufts Cove 2	38,700	33,986	38,803	48,163	45,856	20,912	34,263	44,824	42,079	13,649	0	18,040	379,275
Tufts Cove 3	63,072	43,392	66,005	-196	49,949	59,518	67,843	78,470	73,573	26,002	64,128	58,684	650,440
Tufts Cove 4	25,121	21,311	25,620	13,002	8,794	20,332	22,747	23,888	24,480	24,774	22,919	27,003	259,991
Tufts Cove 5	27,185	23,626	26,171	23,888	18,750	9,681	20,964	19,123	23,172	22,692	23,336	26,302	264,888
Tufts Cove 6	17,389	12,171	14,478	10,438	4,116	3,911	10,174	10,237	13,380	11,560	13,858	17,652	139,363
Trenton 5	24,897	57,586	38,633	12,010	-587	-843	-966	-705	-285	-790	37,573	16,496	183,020
Trenton 6	92,476	64,569	101,725	86,763	60,804	34,919	30,768	-51	53,080	16,056	71,836	76,487	689,434
Pt. Tupper 2	64,475	79,193	80,414	6,552	8,367	18,556	34,932	24,482	45,673	5,334	63,349	49,399	480,727
Pt. Aconi 1	99,154	58,126	83,596	30,120	45,001	78,623	81,932	56,906	7,758	70,036	72,693	98,676	782,620
Wreck Cove 1	0	0	0	0	0	0	0	0	0	0	0	0	0
Wreck Cove 2	60,481	43,779	27,214	9,804	19,088	20,727	11,746	-175	1,776	41,648	23,384	53,773	313,246
Annapolis Tidal	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	16,591	20,112	18,864	15,774	22,957	13,573	11,206	13,404	12,635	16,394	20,432	21,552	203,493
Other Hydro	94,581	71,590	64,987	42,432	32,107	38,543	46,417	47,515	53,186	39,408	41,234	57,954	629,953
Burnside 1	853.8	1033.1	61.8	251.6	228.5	161.5	135.1	17.9	46.7	19.0	40.4	332.9	3,182
Burnside 2	720.4	882.5	52.6	195.1	94.8	261.9	35.3	93.9	7.7	28.9	53.1	473.8	2,900
Burnside 3	460.2	1095.0	77.1	70.1	84.8	123.1	39.9	15.4	1.9	44.6	20.6	262.1	2,295
Burnside 4	-62.9	409.2	-4.4	151.2	-18.0	165.7	13.0	48.7	-0.9	64.0	1.3	239.4	1,006
Victoria Junction 1	382.1	314.3	14.7	94.8	62.8	-18.1	7.0	-4.9	-12.3	-11.2	-19.6	112.3	922
Victoria Junction 2	236.4	316.3	16.9	128.2	11.0	60.4	102.5	16.4	8.6	0.0	-1.5	66.1	961
Tusket 1	-39.6	582.8	-46.6	-35.8	40.0	81.8	43.9	-13.9	-24.4	-31.0	43.6	56.4	657

Power Production Average Load Report (Hours) - Operating Hours
2023

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	497.81	669.89	414.23	0.00	0.00	0.00	539.16	744.00	656.85	570.79	591.52	385.42	5,069.67
Lingan 2	481.17	447.74	48.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	157.91	36.33	1,171.23
Lingan 3	449.82	501.10	741.34	720.00	261.90	718.74	288.65	384.21	238.31	246.48	296.64	477.54	5,324.73
Lingan 4	744.00	400.63	556.08	684.58	528.31	159.22	652.66	174.98	457.54	289.47	0.00	491.69	5,139.16
Tufts Cove 1	278.06	672.00	131.50	705.04	331.97	720.00	430.71	0.00	251.44	744.00	646.67	335.94	5,247.33
Tufts Cove 2	622.94	477.20	632.77	685.96	647.75	305.38	516.58	700.60	632.34	203.16	0.00	316.67	5,741.35
Tufts Cove 3	595.82	496.28	743.56	0.00	478.18	536.20	657.55	744.00	694.71	254.47	699.53	644.02	6,544.32
Tufts Cove 4	702.84	614.99	723.83	382.13	305.35	667.13	700.10	724.77	712.27	704.58	656.47	744.00	7,638.46
Tufts Cove 5	734.12	662.62	734.16	643.07	545.05	309.31	661.06	623.61	708.88	689.98	685.48	729.21	7,726.55
Tufts Cove 6	674.00	569.00	646.00	531.00	269.00	150.00	400.00	502.00	570.00	524.00	606.00	664.00	6,105.00
Trenton 5	286.30	620.03	364.86	141.08	0.00	0.00	0.00	0.00	0.00	0.00	470.69	174.66	2,057.62
Trenton 6	744.00	563.20	744.00	720.00	596.40	397.76	336.40	0.00	527.15	199.18	720.00	642.00	6,190.09
Pt. Tupper 2	617.32	672.00	744.00	70.55	105.30	200.65	406.85	286.58	478.63	50.03	640.61	518.29	4,790.81
Pt. Aconi 1	744.00	477.82	733.97	311.37	441.35	720.00	744.00	598.97	97.94	744.00	720.00	715.43	7,048.85
Wreck Cove 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wreck Cove 2	733.00	631.00	435.00	131.00	305.00	340.00	160.00	0.00	77.00	522.00	372.00	715.00	4,421.00
Annapolis Tidal													
Wind													
Other Hydro													
Burnside 1	44.96	52.06	5.14	13.42	11.36	9.57	6.31	1.71	2.93	2.22	5.67	20.68	176.03
Burnside 2	35.78	45.41	3.60	10.66	4.64	14.30	1.84	5.57	0.54	2.83	5.42	25.24	155.83
Burnside 3	47.51	88.41	5.26	27.39	9.47	7.51	2.33	1.60	0.70	2.60	1.21	14.48	208.47
Burnside 4	0.38	34.33	2.17	5.98	0.55	8.80	1.65	3.49	0.98	1.29	0.98	13.60	74.20
Victoria Junction 1	5.92	16.53	0.94	4.27	3.68	0.00	1.14	0.63	0.31	0.79	0.00	6.95	41.16
Victoria Junction 2	12.89	30.36	1.46	6.58	1.48	3.91	5.58	0.38	0.66	0.00	0.28	3.83	67.41
Tusket 1	0.07	28.14	0.00	0.00	3.62	6.25	4.96	1.26	0.25	0.01	1.64	5.66	51.86

Power Production Average Load Report (MW) - Average Load
2023

Unit	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Lingan 1	92.00	85.02	178.62	N/A	N/A	N/A	41.64	38.45	26.71	36.90	47.21	118.07	91.61
Lingan 2	147.00	95.03	1,111.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00	1,143.36	98.33
Lingan 3	38.75	81.80	9.93	64.61	78.62	66.49	97.23	0.00	67.13	206.88	147.34	45.24	92.70
Lingan 4	52.02	84.83	69.78	70.35	86.80	131.34	52.50	256.16	91.97	47.15	N/A	36.69	89.45
Tufts Cove 1	226.83	64.57	501.94	-0.28	150.46	82.66	157.51	N/A	292.60	34.95	99.17	174.69	64.99
Tufts Cove 2	40.33	44.66	40.49	18.95	13.58	66.58	44.03	34.10	38.71	121.94	N/A	85.27	66.06
Tufts Cove 3	45.63	47.61	35.20	N/A	39.21	18.05	31.88	25.70	33.35	89.17	33.36	40.84	99.39
Tufts Cove 4	24.74	19.79	20.00	27.32	13.48	5.86	14.53	14.12	18.78	16.41	21.11	23.73	34.04
Tufts Cove 5	33.91	86.91	52.62	18.68	-1.08	-2.72	-1.46	-1.13	-0.40	-1.14	54.81	22.62	34.28
Tufts Cove 6	137.21	113.48	157.47	163.40	226.04	232.79	76.92	-0.10	93.12	30.64	118.54	115.19	22.83
Trenton 5	225.20	127.73	220.40	46.44	N/A	N/A	N/A	N/A	N/A	N/A	134.59	282.83	88.95
Trenton 6	133.27	103.21	112.36	41.83	75.45	197.66	243.55	N/A	14.72	351.62	100.96	153.70	111.38
Pt. Tupper 2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.34
Pt. Aconi 1	81.29	91.62	37.08	31.49	43.25	28.79	15.79	-0.29	18.14	55.98	32.48	75.16	111.03
Wreck Cove 1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Wreck Cove 2	82.51	69.38	62.56	74.84	62.58	60.96	73.41	0.00	23.07	79.79	62.86	75.21	70.85
Annapolis Tidal													
Wind													
Other Hydro													
Burnside 1	18.99	19.84	12.03	18.75	20.11	16.87	21.41	10.47	15.92	8.56	7.12	16.10	18.08
Burnside 2	20.13	19.43	14.62	18.30	20.42	18.32	19.18	16.86	14.20	10.20	9.79	18.77	18.61
Burnside 3	9.69	12.39	14.67	2.56	8.95	16.39	17.14	9.63	2.69	17.17	17.01	18.10	11.01
Burnside 4	-165.43	11.92	-2.05	25.28	-32.76	18.83	7.90	13.94	-0.88	49.60	1.34	17.60	13.56
Victoria Junction 1	64.55	19.01	15.68	22.20	17.07	0.00	6.16	-7.85	-39.81	-14.23	0.00	16.16	22.40
Victoria Junction 2	18.34	10.42	11.59	19.48	7.41	15.45	18.37	43.07	13.04	0.00	-5.36	17.25	14.26

Generation Statistics(MWh) - Hydro
2023

Hydro													
Little Brook Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Grand Etang Wind Turbine	-	-	-	-	-	-	-	-	-	-	-	-	-
Dickie Brook Hydro	874	724	752	(57)	1,395	717	856	559	562	659	583	1,539	9,164
Tusket Hydro	1,146	1,090	1,087	785	90	241	1,130	800	1,070	1,008	709	1,108	10,264
Bear River Hydro System	4,964	4,919	5,370	2,583	475	3,733	3,531	3,272	4,492	4,604	2,608	4,078	44,631
Sissiboo/Weymouth System	12,144	8,638	9,593	6,642	3,295	7,222	8,325	7,456	6,903	2,502	6,792	5,563	85,076
Avon Hydro System	3,641	1,676	764	812	727	1,489	2,278	3,615	3,229	980	1,495	2,726	23,433
Lequille Hydro System	7,449	2,909	1,847	2,284	154	1,969	3,093	1,459	2,959	1,801	1,369	3,645	30,936
Nictaux/Paradise System	6,116	4,575	6,196	4,385	2,667	3,004	4,295	3,401	4,895	4,482	3,647	5,738	53,400
Paradise System	3,455	2,403	3,260	2,279	965	1,390	1,540	(6)	(138)	(77)	182	(9)	15,243
Annapolis Tidal Power	-	-	-	-	-	-	-	-	-	-	-	-	-
St.Margaret's Hydro Syste	3,959	3,593	2,532	499	765	385	1,920	3,039	4,442	662	1,860	4,017	27,673
Sheet Harbour Hydro Syste	6,244	4,362	3,110	2,554	2,247	2,953	4,259	3,346	3,602	3,206	2,615	3,537	42,034
Black River Hydro System	15,437	13,736	10,261	5,202	4,421	3,729	3,457	2,170	3,948	3,005	4,758	12,789	82,912
Mersey Hydro System	28,807	22,743	20,091	14,361	14,828	11,594	11,401	18,074	16,918	16,380	14,452	12,935	202,584
Roseway & Harmony Hydro	(13)	(4)	(28)	(12)	(5)	(1)	(1)	-	-	-	-	-	(64)
Harmony Hydro System	-	-	-	-	-	-	-	-	-	-	-	-	-
Wreck Cove Hydro System	60,481	43,779	27,214	9,804	19,088	20,727	11,746	(175)	1,776	41,648	23,384	53,773	313,246
Fall River Hydro	357	227	152	114	84	120	332	329	303	195	165	289	2,667
TOTAL	-	-	-	-	-	-	-	-	-	-	-	-	943,199

Nameplate	Maximum Poss ble Output	2023 Capacity Factor	2024 Capacity Factor	2023-2024 Average Capacity Factor	Average Reactive (MVAR)	Unit Average reactive factor	Unit Ramp Rate (MW/Min)
150.00	1,314,000.00	35.3%	38.2%	36.8%	0.80	29.41%	1.0
150.00	1,314,000.00	8.8%	12.4%	10.6%	0.78	8.25%	1.0
150.00	1,314,000.00	37.6%	39.5%	38.5%	0.78	30.05%	1.0
150.00	1,314,000.00	35.0%	28.6%	31.8%	0.78	24.80%	1.0
100.00	876,000.00	38.9%	47.1%	43.0%	0.84	36.13%	1.0
100.00	876,000.00	43.3%	45.9%	44.6%	0.81	36.11%	1.5
150.00	1,314,000.00	49.5%	60.9%	55.2%	0.65	35.88%	1.5
54.00	473,040.00	55.0%	58.1%	56.5%	0.80	45.24%	10.0
54.00	473,040.00	56.0%	61.4%	58.7%	0.80	46.95%	10.0
50.00	438,000.00	31.8%	43.3%	37.5%	0.80	30.04%	
150.00	1,314,000.00	13.9%	21.0%	17.5%	0.77	13.46%	1.0
160.00	1,401,600.00	49.2%	41.5%	45.4%	0.78	35.38%	2.0
150.00	1,314,000.00	36.6%	42.8%	39.7%	0.80	31.77%	1.0
185.00	1,620,600.00	48.3%	48.3%	48.3%	0.75	36.21%	0.0
100.00	876,000.00	0.0%	1.3%	0.7%	0.60	0.40%	15.0
100.00	876,000.00	35.8%	23.9%	29.8%	0.60	17.89%	15.0
-	-	0%	0%	0%	0.60	0.00%	0.0
-	-	0%	0%	0%	0.00	0.00%	0.0
163.00	1,427,880.00	44.1%	32.5%	38.3%	0.60	23.00%	20.0
30.00	262,800.00	1.2%	1.5%	1.4%	0.80	0.53%	10.0
30.00	262,800.00	1.1%	1.5%	1.3%	0.80	0.34%	10.0
30.00	262,800.00	0.9%	1.2%	1.0%	0.80	0.44%	10.0
30.00	262,800.00	0.4%	0.8%	0.6%	0.80	0.36%	10.0
30.00	262,800.00	0.4%	0.3%	0.3%	0.80	2.66%	10.0
30.00	262,800.00	0.4%	0.4%	0.4%	0.80	4.06%	10.0
30.00	262,800.00	0.3%	0.0%	0.1%	0.80	2.37%	10.0

COMBUSTION TURBINES IN SYNCHRONOUS CONDENSER MODE.

														2023	2024	2023-2024	MVAr		
2023	Mvar Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	TOTAL	Average	RATED	MAX MVh	Mvar CF
	BS1	143.2	145.4	34.7	70.8	54.7	38.3	282.2	224.3	40.2	11.5	19.0	62.2	1126.6	533.5	830.1	18.03	157923.1	0.526%
	BS2	64.1	114.9	12.9	20.6	10.3	53.7	183.1	168.8	17.5	11.8	18.3	41.1	717.0	357.0	537.0	18.03	157923.1	0.340%
	BS3	104.4	221.1	28.3	21.6	20.8	67.7	232.4	87.4	51.5	14.3	6.9	58.7	915.2	477.4	696.3	18.03	157923.1	0.441%
	BS4	7.6	0.0	14.3	13.0	1.4	52.5	437.0	175.3	54.4	4.5	2.3	48.1	810.5	337.9	574.2	18.03	157923.1	0.364%
	Hours																		
	BS1	69	73	12	22	22	26	255	210	29	17	13	32						
	BS2	54	57	11	16	9	57	207	222	25	17	17	40						
	BS3	41	74	10	11	8	48	296	124	26	6	3	23						
	BS4	5	37	6	9	2	38	357	186	24	4	2	26						
	BS1	2.1	2.0	2.9	3.2	2.5	1.5	1.1	1.1	1.4	0.7	1.5	1.9						
	BS2	1.2	2.0	1.2	1.3	1.1	0.9	0.9	0.8	0.7	0.7	1.1	1.0						
	BS3	2.5	3.0	2.8	2.0	2.6	1.4	0.8	0.7	2.0	2.4	2.3	2.6						
	BS4	1.5	0.0	2.4	1.4	0.7	1.4	1.2	0.9	2.3	1.1	1.2	1.8						

2024	Mvar Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	BS1	148.4	70.0	10.4	0.0	0.0	0.0	2.7	89.9	10.0	51.2	72.5	78.4	533.5
	BS2	79.3	33.7	39.5	4.8	2.4	10.0	5.9	30.0	20.7	35.8	39.5	55.3	357.0
	BS3	91.9	112.7	48.8	23.1	0.0	17.9	7.5	37.9	16.8	29.0	46.9	44.8	477.4
	BS4	65.5	0.0	55.1	19.4	5.5	16.0	3.5	30.9	9.4	41.8	24.5	66.4	337.9
	Hours													
	BS1	51	41	11	0	0	0	2	49	15	53	46	61	
	BS2	43	34	27	5	2	5	3	34	18	44	28	49	
	BS3	38	35	26	16	0	6	4	23	11	20	22	37	
	BS4	12	26	22	15	3	6	3	20	6	20	10	41	
	BS1	2.9	1.7	0.9	0.0	0.0	0.0	1.3	1.8	0.7	1.0	1.6	1.3	
	BS2	1.8	1.0	1.5	1.0	1.2	2.0	2.0	0.9	1.2	0.8	1.4	1.1	
	BS3	2.4	3.2	1.9	1.4	0.0	3.0	1.9	1.6	1.5	1.5	2.1	1.2	
	BS4	5.5	0.0	2.5	1.3	1.8	2.7	1.2	1.5	1.6	2.1	2.5	1.6	

Year		Month												2023	2024	2023-2024	MVAr		
2023	Mvar Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL	TOTAL	Average	RATED	MAX MVh	Mvar CF
	VJ1	582.1	554.9	29.1	341.6	597.1	891.7	790.7	589.9	852.1	731.9	637.4	427.3	7026.1	1389.1	4207.6	18.03	157923.1	2.664%
	VJ2	497.5	757.2	848.6	721.1	602.1	976.3	1133.7	796.3	591.2	0.0	728.6	730.7	8383.4	4432.5	6408.0	18.03	157923.1	4.058%
	TK4	3.5	478.6	0.0	0.0	144.9	1348.9	969.4	1121.9	323.8	139.6	3.8	7.2	4541.6	2745.0	3643.3	17.52	153465.1	2.374%
	Hours																		
	VJ1	413	394	23	194	531	713	740	742	720	739	715	387						
	VJ2	349	327	721	651	421	627	743	742	441	0	682	510						
	TK4	0	0	0	0	56	630	429	727	218	87	9	12						
	VJ1	1.4	1.4	1.3	1.8	1.1	1.3	1.1	0.8	1.2	1.0	0.9	1.1						
	VJ2	1.4	2.3	1.2	1.1	1.4	1.6	1.5	1.1	1.3	0.0	1.1	1.4						
	TK4	0.0	0.0	0.0	0.0	2.6	2.1	2.3	1.5	1.5	1.6	0.4	0.6						

Year		Month												
2024	Mvar Production	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	TOTAL
	VJ1	58.5	5.9	230.5	63.0	292.0	7.6	295.6	38.9	0.0	66.8	275.9	54.2	1389.1
	VJ2	1268.2	75.3	323.4	494.0	300.9	469.9	396.9	115.1	227.7	524.2	200.2	37.0	4432.5
	TK4	0.0	10.1	326.3	8.1	1163.1	567.3	661.2	2.6	0.3	0.0	2.3	3.7	2745.0
	Hours													
	VJ1	5	12	117	91	249	9	202	44	0	59	299	35	
	VJ2	728	43	228	352	314	449	167	51	59	223	181	32	
	TK4	0	0	117	8	617	318	280	4	1	0	9	10	
	VJ1	11.7	0.5	2.0	0.7	1.2	0.8	1.5	0.9	0.0	1.1	0.9	1.5	
	VJ2	1.7	1.8	1.4	1.4	1.0	1.0	2.4	2.3	3.9	2.4	1.1	1.2	
	TK4	0.0	0.0	2.8	1.0	1.9	1.8	2.4	0.6	0.3	0.0	0.3	0.4	

Performance Factors

Unit	2024 Operating Hours	2024 Average Production	2024 factor	2023 Operating Hours	2023 Average Production	2023 factor	2023 - 2024 2-year Average Hours	2023 - 2024 2-year Average factor	2023 - 2024 2-year Average Avg Prod	2023 - 2024 2-year Average Annual Prod	Time on AGC - 2 year average 2019	Time on AGC - 2 year average 2020	Time on AGC - 2 year average Average	Equivalent Availability Factor
Lingan 1	5,811.28	86.34	0.575601297	5,069.67	91.61	0.610749	150	5440	0.593	89.0	484,073	2382	3735.5	3059	59.3%
Lingan 2	2,154.69	75.55	0.503684032	1,171.23	98.33	0.655513	150	1663	0.580	86.9	144,577	0	0	0	58.0%
Lingan 3	6,188.61	83.86	0.559084123	5,324.73	92.70	0.617997	150	5757	0.589	88.3	508,205	3349	3041	3195	58.9%
Lingan 4	4,600.32	81.73	0.544847427	5,139.16	89.45	0.596326	150	4870	0.571	85.6	416,791	3768.5	3812	3790	57.1%
Tufts Cove 1	6,104.80	67.56	0.675569223	5,247.33	64.99	0.649945	100	5676	0.663	66.3	376,185	0	0	0	66.3%
Tufts Cove 2	5,490.93	73.18	0.731783714	5,741.35	66.06	0.660603	100	5616	0.696	69.6	390,992	2235	4517	3376	69.6%
Tufts Cove 3	7,218.35	110.85	0.738996564	6,544.32	99.39	0.6626	150	6881	0.701	105.1	723,364	5409	7349	6379	70.1%
Tufts Cove 4	7,706.64	35.68	0.660796337	7,638.46	34.04	0.630317	54	7673	0.646	34.9	267,466	5538.5	6998	6268	64.6%
Tufts Cove 5	7,849.11	36.99	0.685028149	7,726.55	34.28	0.634868	54	7788	0.660	35.6	277,536	5899	6940.5	6420	66.0%
Tufts Cove 6	6,940.00	27.31	0.593775937	6,105.00	22.83	0.496255	46	6523	0.545	25.1	163,524	0	0	0	54.5%
Trenton 5	3,078.17	89.76	0.598380631	2,057.62	88.95	0.592984	150	2568	0.596	89.4	229,447				59.6%
Trenton 6	6,052.80	96.15	0.600916172	6,190.09	111.38	0.696107	160	6121	0.649	103.8	635,172	2760.5	5092.5	3927	64.9%
Pt. Tupper 2	5,829.24	96.59	0.643921899	4,790.81	100.34	0.668958	150	5310	0.656	98.5	522,857	3794	3473.5	3634	65.6%
Pt. Aconi 1	6,629.92	118.02	0.637925477	7,048.85	111.03	0.600151	185	6839	0.619	114.5	783,261				61.9%
Wreck Cove 1	3,188.00	3.70	0.036952428	0.00	0.00	0	100	1594	0.018	1.8	2,945	2639.5	2945	2792	1.8%
Wreck Cove 2	991.00	211.08	2.110798375	4,421.00	70.85	0.708541	100	2706	1.410	141.0	381,457	2458	837	1648	141.0%
Annapolis Tidal															
Wind															
Other Hydro															
Burnside 1	217.05	18.70	0.623182063	176.03	18.08	0.602585	30	197	0.613	18.4	3,614	98	77	88	61.3%
Burnside 2	192.07	19.96	0.665422676	155.83	18.61	0.620301	30	174	0.643	19.3	3,355	43.5	68.5	56	64.3%
Burnside 3	151.93	21.14	0.704596196	208.47	11.01	0.366937	30	180	0.536	16.1	2,896	52.5	57.5	55	53.6%
Burnside 4	112.19	18.41	6.136E-01	74.20	13.56	0.452085	30	93	0.533	16.0	1,490	33.5	57.5	46	53.3%
Victoria Junction 1	42.18	17.87	0.595551604	41.16	22.40	0.746527	30	42	0.671	20.1	839	28	16	22	67.1%
Victoria Junction 2	58.88	19.40	0.646694407	67.41	14.26	0.475292	30	63	0.561	16.8	1,063				56.1%
Tusket 1	21.26	2.18	0.072770461	51.86	0.00	0	30	37	0.036	1.1	40				3.6%

18

Victoria Junction	450	725
Burnside	4063	6800

Monthly Power Production Average Load Report
SCADA Data

2027 Embedded Cost of Ancillary Services

TABLE E4-1

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
GENERATING STATION UNIT SPECIFIC FIXED CHARGE RATE SUMMARY

	Lingan	Tufts Cove	Tufts Cove 6	Trenton	Pt. Tupper	Pt. Aconi	Sub-Total Thermal Gen.	Wreck Cove	Annapolis Tidal Power	Other Hydro	Total Hydro	Wind Generation	Tufts Cove 4	Tufts Cove 5	Other Combustion Turbines	Total Combustion Turbines	Total Generation
Generator Nameplate Capacity kW's	600,000	350,000	350,000	310,000	150,000	185,000	1,945,000	200,000	17,200	163,000	380,200	1,300	54,000	54,000	204,000	312,000	2,637,200
Gross Plant Cost	$626,257,798	$105,204,349	$103,322,853	$245,716,948	$216,129,304	$314,368,616	$1,610,999,868	$365,826,463	$22,867,472	$535,319,696	$924,013,632	$0	$69,136,924	$45,743,934	##########	$219,388,279	$2,754,401,779
Gross Plant Cost/kW	$1,043.76	$300.58	$295.21	$792.64	$1,440.86	$1,699.29	$828.28	$1,829.13	$1,329.50	$3,284.17	$6,442.81	$0.00	$1,280.31	$847.11	$512.29	$703.17	$1,044.44
Net Plant Value	$201,527,819	$61,983,305	$63,134,932	$35,638,644	$108,937,119	$333,374,676	$804,596,494	$300,359,340	$12,685,503	$426,303,537	$739,348,380	$0	$61,516,268	$38,555,371	$72,420,569	$172,492,209	$1,716,437,084
Net Plant Value/kW	$335.88	$177.10	$180.39	$114.96	$726.25	$1,802.03	$413.67	$1,501.80	$737.53	$2,615.36	$4,854.69	$0.00	$1,139.19	$713.99	$355.00	$552.86	$650.86
- share of General Property Plant	$20,758,268	$6,384,558	$6,503,181	$3,670,940	$11,221,011	$34,339,084	$82,877,041	$30,938,357	$1,306,664	$43,911,173	$76,156,193	$0	$6,336,451	$3,971,376	$7,459,643	$17,767,470	$176,800,704
- share of Deferred Chgs & W/C	$26,343	$8,102	$8,253	$4,659	$14,240	$43,578	$105,174	$39,262	$1,658	$55,725	$96,645	$0	$8,041	$5,040	$9,467	$22,548	$224,367
Total NPV incl. GP & Deferred Chgs.	$222,312,429	$68,375,965	$69,646,365	$39,314,243	$120,172,370	$367,757,338	$887,578,710	$331,336,958	$13,993,825	$470,270,435	$815,601,219	$0	$67,860,761	$42,531,787	$79,889,679	$190,282,227	$1,893,462,155
OM&G (Direct)	$25,064,042	$22,626,363	$0	$17,903,669	$11,333,823	$12,197,072	$89,124,969	$1,452,888	$1,835,268	$7,190,376	$10,478,532	$0	$0	$0	$2,089,963	$2,089,963	$101,693,464
OM&G (Overhead)	$12,127,291	$10,947,814	$0	$8,662,729	$5,483,895	$5,901,579	$43,123,307	$702,983	$887,998	$3,479,079	$5,070,060	$0	$0	$0	$1,011,233	$1,011,233	$49,204,600
Grants in Lieu	$2,485,015	$764,309	$778,509	$439,456	$1,343,290	$4,110,802	$9,921,381	$3,703,694	$156,423	$5,256,697	$9,116,815	$0	$758,550	$475,422	$893,009	$2,126,980	$21,165,176
Depreciation (Direct)	$13,902,923	$3,282,376	$3,440,651	$6,437,784	$5,251,942	$7,859,215	$40,174,891	$4,792,327	$413,901	$9,390,535	$14,596,763	$0	$2,302,260	$1,523,273	$4,408,272	$8,233,804	$63,005,459
Depr. (General Property)	$6,631,529	$1,565,654	$1,641,149	$3,070,746	$2,505,114	$3,748,752	$19,162,944	$2,285,883	$197,426	$4,479,173	$6,962,482	$0	$1,098,150	$726,583	$2,102,693	$3,927,426	$30,052,852
Interest	$7,533,646	$2,317,101	$2,360,152	$1,332,267	$4,072,359	$12,462,432	$30,077,957	$11,228,231	$474,218	$15,936,360	$27,638,809	$0	$2,299,642	$1,441,302	$2,707,273	$6,448,217	$64,164,983
Preferred Dividends	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Corporate Taxes	$538,252	$165,549	$168,624	$95,186	$290,955	$890,396	$2,148,962	$802,217	$33,881	$1,138,596	$1,974,694	$0	$164,301	$102,976	$193,425	$460,702	$4,584,357
Return	$10,383,367	$3,193,581	$3,252,916	$1,836,219	$5,612,794	$17,176,544	$41,455,420	$15,475,487	$653,598	$21,964,540	$38,093,626	$0	$3,169,518	$1,986,498	$3,731,343	$8,887,358	$88,436,404
TOTAL	$78,666,064	$44,862,746	$11,642,002	$39,778,055	$35,894,172	$64,346,793	$275,189,831	$40,443,709	$4,652,714	$68,835,356	$113,931,779	$0	$9,792,420	$6,256,054	$17,137,211	$33,185,684	$422,307,295
OM&G	18.45%	54.17%	0.00%	74.54%	15.44%	5.43%	16.44%	0.72%	21.47%	2.50%	2.10%	0.00%	0.00%	0.00%	4.28%	1.80%	8.79%
Depreciation	10.19%	7.82%	8.05%	26.68%	7.12%	3.48%	7.37%	2.36%	4.82%	3.25%	2.92%	0.00%	5.53%	5.84%	8.99%	7.05%	5.42%
Sub-Total	28.64%	61.99%	8.05%	101.22%	22.56%	8.91%	23.81%	3.07%	26.29%	5.76%	5.02%	0.00%	5.53%	5.84%	13.27%	8.85%	14.21%
Grants in Lieu	1.23%	1.23%	1.23%	1.23%	1.23%	1.23%	1.23%	1.23%	1.23%	1.23%	1.23%	0.00%	1.23%	1.23%	1.23%	1.23%	1.23%
Interest	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	3.74%	0.00%	3.74%	3.74%	3.74%	3.74%	3.74%
Preferred Dividends	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Corporate Taxes	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.27%	0.00%	0.27%	0.27%	0.27%	0.27%	0.27%
Return	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	5.15%	0.00%	5.15%	5.15%	5.15%	5.15%	5.15%
Cost of Capital	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	10.39%	0.00%	10.39%	10.39%	10.39%	10.39%	10.39%
FIXED CHARGE RATE	**39.03%**	**72.38%**	**18.44%**	**111.61%**	**32.95%**	**19.30%**	**34.20%**	**13.47%**	**36.68%**	**16.15%**	**15.41%**	**0.00%**	**15.92%**	**16.23%**	**23.66%**	**19.24%**	**24.60%**

Exh 5 of COSS: 2027 ALLOCATION OF OPERATING EXPENSES

(AMOUNT IN THOUSANDS OF DOLLARS)

(8)	OPER. & MAINT. - STEAM	$113,383.8
(9)	OPER. & MAINT. - HYDRO	$4,460.7
(10)	OPER. & MAINT. - WIND	$15,886.4
(11)	OPER. & MAINT. - BIOMASS	$12,725.3
(12)	OPER. & MAINT. - LM6000	$1,223.0
(13)	OPER. & MAINT. - OTHER CT's	$3,218.8
(14)	DSM	$0.0
(15)	FCR DEFERRAL	$0.0
(16)	REG. AFFAIRS - ADVOCACY EXPE	$1,343.1
(16)	GRANTS IN LIEU OF TAXES	$21,165.2
(17)	DEPRECIATION:	
(18)	STEAM	$48,026.1
(19)	HYDRO	$16,631.7
(20)	WIND	$12,844.3
(21)	LM6000	$7,100.9
(22)	GAS TURBINE - OTHER	$3,119.7
(23)	GENERAL PROPERTY	$18,179.9
(24)	INTEREST NET OF AFUDC	$64,165.0
(25)	PREFERRED DIVIDENDS	$0.0
(26)	CORPORATE TAXES	$4,584.4
(27)	NON-OPERATING REVENUE:	$0.0
(28)	EXPORT SALES	$0.0
(29)	STEAM AND ASH SALES	-$5,037.6
(30)	OTHER REVENUE	-$3,269.9
(31)	RETURN (PROFIT/LOSS)	$88,436.4

NOTES:

1. The Gross and Net Asset Values have been averaged based on actual year-end balances for 2026 and 2027.
2. OM&G and Capital Related Expenses have been based on the 2026 to 20247GRA .
3. The percentages are calculated on "Total NPV incl. GP and Deferred Charges" since the capital-related expenses such as interest, taxes and return reflect NSPI's total capitalization.

DETAIL OF HYDRO FACILITIES

	Wreck Cove & Gisbourne	Avon	Black River	Lequille & Nict & Para	Mersey	Bear River & Sissiboo	Tusket	Roseway & Harmony	St. Margarets	Sheet Harbour	Dickie Brook	Fall River	Annapolis Tidal	Total Hydro
Installed Capacity kW's	204000	7000	22000	22000	42000	37000	2000	1000	10000	11000	4000	1000	17200	380200
Gross Plant Cost	$365,826,463	$26,532,542	$82,844,639	$49,474,234	$72,622,798	$73,226,215	$31,405,669	$58,130,746	$57,639,393	$61,793,233	$16,759,435	$4,890,791	$22,867,472	$924,013,632
Gross Plant Cost/kW	$1,793.27	$3,790.36	$3,765.67	$2,248.83	$1,729.11	$1,979.09	$15,702.83	$58,130.75	$5,763.94	$5,617.57	$4,189.86	$4,890.79	$1,329.50	$2,430.34
Net Book Value	$300,359,340	$18,988,077	$71,964,499	$40,945,206	$55,796,876	$60,054,238	$25,592,188	$42,017,570	$41,235,620	$50,505,636	$13,197,848	$6,005,779	$12,685,503	$739,348,380
Net Book Value/kW	$1,472.35	$2,712.58	$3,271.11	$1,861.15	$1,328.50	$1,623.09	$12,796.09	$42,017.57	$4,123.56	$4,591.42	$3,299.46	$6,005.78	$737.53	$1,944.63
- share of General Property Plant	$30,938,357	$1,955,857	$7,412,666	$4,217,540	$5,747,328	$6,185,855	$2,636,110	$4,327,998	$4,247,453	$5,202,307	$1,359,437	$618,622	$1,306,664	$76,156,193
- share of Deferred Chgs & W/C	$392,621	$24,821	$94,070	$53,522	$72,936	$78,501	$33,453	$54,924	$53,902	$66,019	$17,252	$7,851	$16,582	$966,454
Total NPV incl. GP & Deferred Chgs.	$331,690,317	$20,968,755	$79,471,235	$45,216,268	$61,617,140	$66,318,594	$28,261,752	$46,400,492	$45,536,975	$55,773,962	$14,574,537	$6,632,252	$14,008,749	$816,471,027
OM&G (Direct)	$1,452,888	$0	$1,333,515	$0	$2,808,067	$1,400,811	$0	$0	$735,567	$912,416	$0	$0	$1,835,268	$10,478,532
OM&G (Overhead)	$702,983	$0	$645,224	$0	$1,358,689	$677,785	$0	$0	$355,906	$441,474	$0	$0	$887,998	$5,070,060
Grants in Lieu	$2,081,180	$150,943	$471,302	$281,458	$413,150	$416,583	$178,666	$330,705	$327,909	$351,541	$95,344	$27,824	$130,093	$5,256,697
Depreciation (Direct)	$4,792,327	$501,465	$1,168,109	$865,799	$1,358,642	$988,554	$549,599	$1,063,793	$1,152,788	$1,316,196	$350,272	$75,318	$413,901	$14,596,763
Depr. (General Property)	$1,470,577	$153,880	$358,447	$265,680	$416,914	$303,348	$168,650	$326,436	$353,745	$403,889	$107,485	$23,112	$127,010	$4,479,173
Interest	$6,309,368	$457,604	$1,428,812	$853,277	$1,252,517	$1,262,924	$541,650	$1,002,574	$994,100	$1,065,741	$289,048	$84,351	$394,393	$15,936,360
Preferred Dividends	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Corporate Taxes	$450,782	$32,694	$102,083	$60,964	$89,488	$90,231	$38,699	$71,630	$71,025	$76,143	$20,651	$6,027	$28,178	$1,138,596
Return	$8,695,987	$630,700	$1,969,283	$1,176,042	$1,726,302	$1,740,645	$746,538	$1,381,814	$1,370,134	$1,468,874	$398,385	$116,258	$543,578	$21,964,540
TOTAL	$25,956,091	$1,927,286	$7,476,775	$3,503,219	$9,423,768	$6,880,882	$2,223,803	$4,176,953	$5,361,175	$6,036,275	$1,261,186	$332,890	$4,360,419	$78,920,721
OM&G	0.72%	0.00%	2.75%	0.00%	7.47%	3.46%	0.00%	0.00%	2.65%	2.68%	0.00%	0.00%	21.47%	2.10%
Depreciation	2.09%	3.45%	2.12%	2.76%	3.18%	2.15%	2.81%	3.31%	3.65%	3.41%	3.47%	1.64%	4.26%	2.58%
Sub-Total	2.80%	3.45%	4.87%	2.76%	10.65%	5.61%	2.81%	3.31%	6.30%	6.09%	3.47%	1.64%	25.73%	4.68%
Grants in Lieu	0.69%	0.79%	0.65%	0.69%	0.74%	0.69%	0.70%	0.79%	0.80%	0.70%	0.72%	0.46%	1.03%	0.71%
Interest	2.10%	2.41%	1.99%	2.08%	2.24%	2.10%	2.12%	2.39%	2.41%	2.11%	2.19%	1.40%	3.11%	2.16%
Preferred Dividends	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Corporate Taxes	0.15%	0.17%	0.14%	0.15%	0.16%	0.15%	0.15%	0.17%	0.17%	0.15%	0.16%	0.10%	0.22%	0.15%
Return	2.90%	3.32%	2.74%	2.87%	3.09%	2.90%	2.92%	3.29%	3.32%	2.91%	3.02%	1.94%	4.29%	2.97%
FIXED CHARGE RATE	**8.64%**	**10.15%**	**10.39%**	**8.56%**	**16.89%**	**11.46%**	**8.69%**	**9.94%**	**13.00%**	**11.95%**	**9.56%**	**5.54%**	**34.37%**	**10.67%**

SUMMARY OF HYDRO FACILITIES

	Wreck Cove	Annapolis Tidal	Wind Generation	Other Hydro	Total Hydro
Installed Capacity kW's	200000	17200	1300	163000	381500
Gross Plant Cost	$365,826,463	$22,867,472	$0	$535,319,696	$924,013,632
Gross Plant Cost/kW	$1,793.27	$1,329.50	$0.00	$3,284.17	$2,422.05
Net Book Value	$300,359,340	$12,685,503	$0	$426,303,537	$739,348,380
Net Book Value/kW	$1,472.35	$737.53	$0.00	$2,615.36	$1,938.00
- share of General Property Plant	$30,938,357	$1,306,664		$43,911,173	$76,156,193
- share of Deferred Chgs & W/C	$392,621	$16,582		$557,251	$966,454
Total NPV incl. GP & Deferred Chgs.	$331,690,317	$14,008,749	$0	$470,771,961	$816,471,027
OM&G (Direct)	$1,452,888	$1,835,268	$0	$7,190,376	$10,478,532
OM&G (Overhead)	$702,983	$887,998	$0	$3,479,079	$5,070,060
Grants in Lieu	$2,081,180	$130,093	$0	$3,045,424	$5,256,697
Depreciation (Direct)	$4,792,327	$413,901	$0	$9,390,535	$14,596,763
Depr. (General Property)	$1,470,577	$127,010	$0	$2,881,586	$4,479,173
Interest	$6,309,368	$394,393	$0	$9,232,599	$15,936,360
Preferred Dividends	$0	$0	$0	$0	$0
Corporate Taxes	$450,782	$28,178	$0	$659,636	$1,138,596
Return	$8,695,987	$543,578	$0	$12,724,976	$21,964,540
TOTAL	$25,956,091	$4,360,419	$0	$48,604,211	$78,920,721
OM&G	0.72%	21.47%	0.00%	2.50%	2.10%
Depreciation	2.09%	4.26%	0.00%	2.88%	2.58%
Sub-Total	2.80%	25.73%	0.00%	5.38%	4.68%
Grants in Lieu	0.69%	1.03%	0.00%	0.71%	0.71%
Interest	2.10%	3.11%	0.00%	2.17%	2.16%
Preferred Dividends	0.00%	0.00%	0.00%	0.00%	0.00%
Corporate Taxes	0.15%	0.22%	0.00%	0.15%	0.15%
Return	2.90%	4.29%	0.00%	2.98%	2.97%
FIXED CHARGE RATE	**8.64%**	**34.37%**	**0.00%**	**11.40%**	**10.67%**

NSPI **Embedded Cost of Ancillary Services**

TABLE E4-1
Page 2 of 2

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES

DETAIL OF COMBUSTION TURBINES

	Burnside	Victoria Junction	Tusket	Tufts Cove 4	Tufts Cove 5	Total Combustion Turbines
Installed Capacity kW's	120000	60000	24000	54000	54000	312000
Gross Plant Cost	$61,820,099	$25,848,924	$21,104,330	$69,136,924	$45,743,934	$223,654,212
Gross Plant Cost/kW	$515.17	$430.82	$879.35	$1,280.31	$847.11	$3,952.75
Net Book Value	$48,974,573	$17,929,275	$12,280,079	$61,516,268	$38,555,371	$179,255,567
Net Book Value/kW	$408.12	$298.82	$511.67	$1,139.19	$713.99	$3,071.79
- share of General Property Plant	5,044,600	1,846,796	1,264,903	6,336,451	3,971,376	$18,464,126
- share of Deferred Chgs & W/C	6,402	2,344	1,605	8,041	5,040	$23,432
Total NPV incl. GP & Deferred Chgs.	$54,025,575	$19,778,414	$13,546,588	$67,860,761	$42,531,787	$197,743,124
OM&G (Direct)	$1,557,170	$319,864	$212,929	$0	$0	$2,089,963
OM&G (Overhead)	$753,440	$154,767	$103,026	$0	$0	$1,011,233
Grants in Lieu	$603,899	$221,084	$151,424	$758,550	$475,422	$2,210,379
Depreciation (Direct)	$1,137,490	$586,771	$1,160,738	$2,302,260	$1,523,273	$6,710,531
Depr. (General Property)	$542,569	$279,883	$553,658	$1,098,150	$726,583	$3,200,843
Interest	$1,830,800	$670,244	$459,062	$2,299,642	$1,441,302	$6,701,050
Preferred Dividends	$0	$0	$0	$0	$0	$0
Corporate Taxes	$130,804	$47,887	$32,798	$164,301	$102,976	$478,766
Return	$2,523,329	$923,774	$632,709	$3,169,518	$1,986,498	$9,235,828
TOTAL	$9,079,502	$3,204,272	$3,306,345	$9,792,420	$6,256,054	$31,638,593
OM&G	4.7%	2.6%	2.6%	0.0%	0.0%	1.7%
Depreciation	3.4%	4.8%	14.0%	5.5%	5.8%	5.5%
Sub-Total	8.1%	7.5%	16.5%	5.5%	5.8%	7.3%
Grants in Lieu	1.2%	1.2%	1.2%	1.2%	1.2%	1.2%
Interest	3.7%	3.7%	3.7%	3.7%	3.7%	3.7%
Preferred Dividends	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Corporate Taxes	0.3%	0.3%	0.3%	0.3%	0.3%	0.3%
Return	5.2%	5.2%	5.2%	5.2%	5.2%	5.2%
Cost of Capital	10.4%	10.4%	10.4%	10.4%	10.4%	10.4%
FIXED CHARGE RATE	**18.54%**	**17.87%**	**26.92%**	**15.92%**	**16.23%**	**17.65%**

2027 OATT DEVELOPMENT
DETERMINATION OF AVERAGE FIXED ASSETS, DEFERRED CHARGES & WORKING CAPITAL

ANALYSIS OF FIXED ASSETS as of December 31, 2027

	Gross Plant Value Dec. 2026	Net Plant Value Dec. 2026	Gross Plant Value Dec. 2027	Net Plant Value Dec. 2027	Gross Plant Value Average	Net Plant Value Average
Steam Production						
Lingan	$525,286,052	$119,551,286	$727,229,544	$283,504,351	$626,257,798	$201,527,819
Tufts Cove	104,189,612	63,897,672	106,219,087	60,068,938	105,204,349	61,983,305
Tufts Cove # 6	$101,585,436	$63,780,565	$105,060,270	$62,489,298	103,322,853	63,134,932
Trenton	$283,372,384	$70,482,075	$208,061,513	$795,214	245,716,948	35,638,644
Pt. Tupper	$209,709,321	$105,678,929	$222,549,287	$112,195,309	216,129,304	108,937,119
Point Aconi	$355,232,137	$333,374,676	$273,505,095	$333,374,676	314,368,616	333,374,676
Total In-Service Generation	1,579,374,941	756,765,203	1,642,624,796	852,427,786	1,610,999,868	804,596,494
Strait Marine Terminal	$26,878,399	$6,230,607	$23,801,240	$3,485,285	25,339,820	4,857,946
Non-operational & General	$473,333,385	$4,408,046	$484,318,343	-$33,194,656	478,825,864	(14,393,305)
Steam Generation Plant - S	$2,079,586,725	$767,403,857	$2,150,744,379	$822,718,415	2,115,165,552	795,061,136
Hydro Production						
Wreck Cove	$350,248,856	$287,083,468	$381,404,071	$313,635,212	365,826,463	300,359,340
Wind					0	0
Tidal (Annapolis)	$45,641,253	$25,586,531	$93,691	-$215,524	22,867,472	12,685,503
Other Hydro:						
Dickie Brook	$16,759,435	$13,435,625	$16,759,435	$12,960,071	16,759,435	13,197,848
Tusket	$24,912,318	$18,641,073	$37,899,021	$32,543,304	31,405,669	25,592,188
Bear River/Sissiboo	$71,709,254	$58,792,742	$74,743,177	$61,315,734	73,226,215	60,054,238
Avon	$26,532,542	$19,242,147	$26,532,542	$18,734,008	26,532,542	18,988,077
Lequille	$49,590,886	$41,595,764	$49,357,582	$40,294,649	49,474,234	40,945,206
St. Margaret's	$56,522,139	$40,409,975	$58,756,646	$42,061,264	57,639,393	41,235,620
Sheet Harbour	$60,866,314	$49,915,740	$62,720,152	$51,095,531	61,793,233	50,505,636
Black River	$79,520,941	$68,596,480	$86,168,338	$75,332,518	82,844,639	71,964,499
Mersey	$69,442,945	$51,775,080	$75,802,650	$59,818,671	72,622,798	55,796,876
Roseway	$56,522,139	$40,409,975	$58,756,646	$42,061,264	57,639,393	41,235,620
Harmony	$491,353	$780,122	$491,353	$783,778	491,353	781,950
Fall River	$4,890,791	$6,066,667	$4,890,791	$5,944,891	4,890,791	6,005,779
Total In-Service Generation	**913,651,167**	**722,331,388**	**934,376,096**	**756,365,372**	**924,013,632**	**739,348,380**
Non-operational & General	-$39,708,707	-$31,516,041	-$40,066,223	-$36,468,187	(39,887,465)	(33,992,114)
Total Hydro Production	873,942,461	690,815,347	894,309,873	719,897,184	884,126,167	705,356,266
Wind Tubine						
Wind Turbine	$325,868,816	$158,353,757	$327,053,293	$148,513,304	326,461,055	153,433,531
Total Wind	325,868,816	158,353,757	327,053,293	148,513,304	326,461,055	153,433,531
Gas Turbine						
Tufts Cove #4	$60,754,030	$53,744,509	$69,136,924	$61,516,268	69,136,924	61,516,268
Tufts Cove #5	$45,076,326	$39,057,561	$46,411,542	$38,053,182	45,743,934	38,555,371
Burnside	$60,457,136	$47,806,253	$63,183,063	$50,142,893	61,820,099	48,974,573
Victoria Junction	$25,771,435	$18,226,654	$25,926,414	$17,631,896	25,848,924	17,929,275
Tusket	$20,788,377	$12,133,886	$21,420,283	$12,426,272	21,104,330	12,280,079
Total In-Service Generation	212,847,304	170,968,862	226,078,226	179,770,511	219,462,765	175,369,687
Other GTs	-$74,486	-$2,602,775	-$74,486	-$3,152,179	(74,486)	(2,877,477)
Total Gas Turbine	$212,772,818	$168,366,087	$226,003,740	$176,618,332	219,388,279	172,492,209
Total Generation Assets	**3,492,170,819**	**1,784,939,048**	**3,598,111,284**	**1,867,747,235**	**3,545,141,052**	**1,826,343,141**
Transmission	$1,712,156,022	$1,195,466,218	$1,799,915,212	$1,264,445,237	1,756,035,617	1,229,955,727
Distribution	$2,491,659,982	$1,430,933,431	$2,650,537,387	$1,557,701,103	2,571,098,684	1,494,317,267
General Property	$987,003,201	$469,804,506	$1,043,589,961	$467,915,297	1,015,296,581	468,859,901
Total Rate Base	**8,682,990,024**	**4,881,143,202**	**9,092,153,844**	**5,157,808,871**	**8,887,571,934**	**5,019,476,037**
Non-Utility Prop. & PPD	$1,579,085	$1,254,623	$1,579,085	$1,193,163	1,579,085	1,223,893
Total Fixed Assets	**$8,684,569,109**	**$4,882,397,825**	**$9,093,732,929**	**$5,159,002,034**	**$8,889,151,019**	**$5,020,699,930**

ANALYSIS OF DEFERRED CHARGES & CREDITS & WORKING CAPITAL

AVERAGE	End of year 2026	End of year 2027
Current & Long Term Assets ($M)		
Financing Charges	21.1	20.0
Pension Charges	170.3	197.8
FAM Deferral	1.2	(1.7)
Storm Rider Deferral	0.0	0.0
Rate Stabilization (RS) Deferral	0.0	0.0
DSM Rider Deferral	0.8	0.1
DSM Deferral	0.0	0.0
Other General Charges	24.9	16.9
Retired Assets (Roseway, Annapolis, and SmartGrid)	0.0	0.0
Deferred Decarbonization Asset	0.0	0.0
Cost of Removal Liability	(2.4)	(31.2)
Asset Retirement Obligation	(149.7)	(157.6)
Deferred Income Taxes	23.9	15.5
Other Deferred Credits	(30.1)	(31.8)
	0.0	0.0
Long term receivable	95.3	99.5
Allowance for materials and supplies	302.0	287.0
Allowance for working capital	137.5	114.7
Total Assigned to Fixed Assets	**$595**	**$529**

2027 OATT DEVELOPMENT
DETERMINATION OF UNIT GENERATION ASSETS

		Actual NPV ($000)	Adjusted Unit NPV for Common Assets ($000)	Average NPV ($000)	Unit NPV ($000)		
	UNITS						
	Lingan			201,528			
Lingan 1&2 Prod Unit	Units 1& 2	36,051	51,807		42,192	Lingan 1&2 Prod Unit	36,238
Lingan 3&4 ProdUnit	Units 3 & 4	136,144	195,645		159,335	Lingan 3&4 ProdUnit	135,821
	Sub-Total	172,196	247,453				
	Common Assets	75,257	0				
	Total Plant	247,453	247,453		201,528		
	Pt. Tupper			108,937			
	Unit 1	0	0		0		
Pt Tupper Unit 1	Unit 2	54,995	112,195		108,937	Pt Tupper Unit 1	54,995
	Sub-Total	54,995	112,195				
	Common Assets	57,200	0				
		112,195	112,195		108,937		
	Trenton			35,639			
	Unit 1-4	0	0		0		
Trenton Unit 5 Capita	Unit 5	(2,655)	(379)		(17,006)	Trenton Unit 5 Capital	(2,655)
Trenton unit 6 Capital	Unit 6	8,218	1,175		52,644	Trenton unit 6 Capital	8,218
	Sub-Total	5,563	795				
	Common Assets	(4,768)	0				
		795	795		35,639		
	Tufts Cove			61,983			
TC Unit 1 Capital	Unit 1	50,820	14,279		14,163	TC Unit 1 Capital	50,828
TC Unit 2 Capital	Unit 2	46,400	13,037		12,931	TC Unit 2 Capital	46,401
TC Unit 3 Capital	Unit 3	62,698	17,616		17,474	TC Unit 3 Capital	62,716
TC Unit 6 Capital	Unit 6	62,489	17,557		17,415	TC Unit 6 Capital	62,490
	Sub-Total	222,407	62,489		61,983		
	Common Assets	(159,918)	0				
		62,489	62,489				
	Pt. Aconi						
	Unit 1			333,375	333,375		
	Wreck Cove				300,359		
	Tidal				12,686		
	Hydro - Other				426,304		
	Burnside				48,975		
	Victoria Junction				17,929		
	Tusket				12,280		
	Wind				153,434		

2027 OATT DEVELOPMENT
ALLOCATION OF DIRECT O/H POWER PRODUCTION COSTS

Steam Production	Operating Budget 2025	Operating Budget 2026	Operating Budget 2027	Average Operating Budget 2025 and 2026	Allocation of Thermal Plant Operations	Allocation of Assigned Pension Costs	Allocation of Hydro Admin. & Engineering	Allocation of Energy, Fuels & Risk Mgmt.	Total assigned PP Budget
Plant Operations:									
Operating	$15,545,430	$15,561,374	$16,020,783	$15,553,402	($15,553,402)				$0
Assigned Pension Costs	0	0	0	0	0	0			0
Biomass	6,887,691	7,080,075	7,153,099	6,983,883	1,431,379	0		618,262	9,033,524
Lingan	18,890,530	19,863,856	20,390,316	19,377,193	3,971,446	0		1,715,404	25,064,042
Tufts Cove	17,379,861	17,605,350	18,067,817	17,492,606	3,585,191	0		1,548,567	22,626,363
Trenton	13,587,996	14,094,917	14,032,696	13,841,457	2,836,871	0		1,225,342	17,903,669
Tufts Cove 6						0		-	0
Pt. Tupper	8,645,430	8,879,092	9,524,600	8,762,261	1,795,866	0		775,696	11,333,823
Point Aconi	9,432,344	9,426,945	9,733,809	9,429,645	1,932,649	0		834,778	12,197,072
Pt. Tupper Marine Terminal	0	0	0	0	0	0		-	0
Total Steam Production	**90,369,282**	**92,511,609**	**94,923,120**	**91,440,446**	**(0)**	**0**	**0**	**6,718,048**	**98,158,493**
Hydro Production									
Hydro Prod. Admin & Engineering	3,274,368	2,850,229	2,865,889	3,062,299		0	(3,062,299)		0
Wreck Cove	1,169,275	971,342	1,381,017	1,070,309		0	382,580		1,452,888
Wind	0	0	0	0		0	0		0
Tidal (Annapolis)	1,285,156	1,418,842	1,453,812	1,351,999		0	483,269		1,835,268
Other Hydro:							0		
Dickie Brook	0	0	0	0		0	0		0
Tusket	0	0	0	0		0	0		0
Bear River/Sissiboo	1,018,298	1,045,591	1,073,946	1,031,945		0	368,866		1,400,811
Avon	0	0	0	0		0	0		0
Lequille	0	0	0	0		0	0		0
St. Margaret's (+ White Rock H/M)	534,488	549,262	563,622	541,875		0	193,692		735,567
Sheet Harbour	621,046	723,265	743,567	672,156		0	240,261		912,416
Black River	931,458	1,033,280	1,061,534	982,369		0	351,146		1,333,515
Mersey	2,042,126	2,095,148	2,147,109	2,068,637		0	739,430		2,808,067
Roseway	0	0	0	0		0	0		0
Harmony	0	0	0	0		0	0		0
Fall River	0	0	0	0		0	0		0
Milton	819,462	876,199	899,517	847,831		0	303,055		1,150,886
Nictaux Paradise/Paradise	0	0	0	0		0	0		0
Total Hydro Production	**11,695,677**	**11,563,158**	**12,190,013**	**11,629,418**	**0**	**0**	**0**		**11,629,418**
Gas Turbine									
Tufts Cove #4						0		-	0
Tufts Cove #5						0		-	0
Burnside	1,398,880	1,462,180	1,526,270	1,430,530		0		126,640	1,557,170
Victoria Junction	287,798	299,902	347,014	293,850		0		26,014	319,864
Tusket	181,170	210,054	254,920	195,612		0		17,317	212,929
LM Building	732,769	748,887	765,073	740,828		0		65,583	806,411
Total Gas Turbine Production	2,600,617	2,721,023	2,893,277	2,660,820	0	0	0	235,554	2,896,374
Wind									
Little Brook	0	0	0	0					
Grand Etang	0	0	0	0					
Nuttby	3,307,425	2,524,410	2,571,398	2,915,918					
Digby	1,545,320	1,567,501	1,596,777	1,556,411					
Tupper	647,391	659,595	672,034	653,493					
Sable	404,278	411,831	419,529	408,055					
South Canoe	3,456,660	3,375,030	3,438,730	3,415,845					
Pubnico	0	0	0	0					
ECEI	0	0	0	0					
Total Wind Turbine Production	9,361,074	8,538,367	8,698,468	8,949,721	0	0	0	0	0
Solar									
Amherst	124,205	131,914	140,881	128,060					
	0	0	0	0					
Energy, Fuels & Risk Management	6,870,324	7,036,880	7,221,203	6,953,602		0		(6,953,602)	0
Total Power Production	**$ 121,021,179**	**$ 122,502,951**	**$ 126,066,962**	**$ 121,762,065**	**$ (0)**	**$ -**	**$ 0**	**$ 0**	**$ 112,684,285**

Embedded Cost of Ancillary Services

TABLE E4-8

NOVA SCOTIA POWER INC.
EMBEDDED COST OF ANCILLARY SERVICES
REVENUE REQUIREMENT SUMMARY

Service	2027 GRA Unit Revenue Requirement		2026 GRA Unit Revenue Requirement			Difference		% Diff.
Voltage Control and Reactive Supply	$4,490,880	$/yr	$4,117,997	$/yr	$/yr	$372,882	$/yr	9%
Regulation Cost	$171.59	$/kW-yr	$159.35	$/kW-yr	$/kW-yr	$12	$/kW-yr	8%
Load Following Cost	$ 181.28	$/kW-yr	$ 172.64	$/kW-yr	$/kW-yr	$9	$/kW-yr	5%
Operating Reserve - Spinning	$137.92	$/kW-yr	$131.45	$/kW-yr	$/kW-yr	$6	$/kW-yr	5%
Operating Reserve - Supplemental - 10 Minute	$133.02	$/kW-yr	$122.07	$/kW-yr	$/kW-yr	$11	$/kW-yr	9%
Operating Reserve - Supplemental - 30 Minute	$125.43	$/kW-yr	$120.25	$/kW-yr	$/kW-yr	$5	$/kW-yr	4%
	2027 Total Revenue Requirement		**2026 GRA Unit Revenue Requirement**					
Voltage Control and Reactive Supply	$4,491	$000/yr	$4,118	$000/yr	$000/yr	$373	$000/yr	9%
Regulation Cost	5,491	$000/yr	5,099	$000/yr	$000/yr	$392	$000/yr	8%
Load Following Cost	31,725	$000/yr	30,213	$000/yr	$000/yr	$1,512	$000/yr	5%
Operating Reserve - Spinning	4,413	$000/yr	4,206	$000/yr	$000/yr	$207	$000/yr	5%
Operating Reserve - Supplemental - 10 Minute	18,091	$000/yr	16,601	$000/yr	$000/yr	$1,490	$000/yr	9%
Operating Reserve - Supplemental - 30 Minute	6,271	$000/yr	6,013	$000/yr	$000/yr	$259	$000/yr	4%
Total Annual Revenue Requirement	**$70,482**	$000/yr	**$66,250**	$000/yr	$000/yr	$4,232	$000/yr	6%

2025-2027 TARIFF VAR REPORT

RESIDENTIAL TARIFFS						
All Domestic Service Rates	**units**	**Current**	**2026 Proposed**	**2027 Proposed**	**2026**	**2027**
Customer Charge	$/mo	19.17	20.24	21.38	6%	6%
Energy Charge	¢/kWh	1.852	3.031	3.244	64%	7%
COMMERCIAL TARIFFS						
All Small General Rates	**units**	**Current**	**2026 Proposed**	**2027 Proposed**		
Customer Charge	$/mo	21.280	22.16	23.07	4%	4%
Energy Charge	¢/kWh	2.107	2.549	2.730	21%	7%
All General Rates						
Demand Charge	$/kW	5.150	6.282	6.707	22%	7%
Transformer Ownership Credit	$/kW	(0.320)	(0.320)	(0.320)	0%	0%
Large General Rate						
Demand Charge (Ratcheted)	$/kVA	4.872	3.130	3.222	-36%	3%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	(0.320)	0%	0%
INDUSTRIAL TARIFFS						
Small Industrial Rate	**units**	**Current**	**2026 Proposed**	**2027 Proposed**		
Demand Charge	$/kVA	5.178	5.137	5.455	-1%	6%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	(0.320)	0%	0%
Medium Industrial Rate						
Demand Charge	$/kVA	3.639	3.260	3.296	-10%	1%
Transformer Ownership Credit	$/kVA	(0.320)	(0.320)	(0.320)	0%	0%
Large Industrial Rate						
Demand Charge (Ratcheted) Distribution-connected	$/kVA	2.118	2.643	2.797	25%	6%
Demand Charge (Ratcheted) Transmission-connected	$/kVA	0.270	0.436	0.420	62%	-4%
Transformer Ownership Credit (applicable only to the distribution-connected customers)	$/kVA	(0.320)	(0.320)	(0.320)	0%	0%
OTHER TARIFFS						
Outdoor Recreational Light Rate	**units**	**Current**	**2026 Proposed**	**2027 Proposed**		
Energy Charge	¢/kWh	3.747	6.207	6.538	66%	5%
Miscellaneous Small Loads Rate						
Demand Charge	$/kW	14.166	23.988	25.093	69%	5%

2026 PROOF OF REVENUE

Proposed Distribution Tariffs	Distribution Usage in KWhs			Demand in kWs or kVa			Base Charge			Total Revenue
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	GWS or GVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (in millions)	Base Charge	Revenue (millions)	(millions)
Residential Sector										
Domestic Service Tariff (Standard Offer)	4,587.9	$0.03031	$139.1	NA	NA	NA	5.58	$20.24	$ 113.0	$252.1
Domestic Service Time-of-Day Tariff	298.4	$0.03031	$9.0	NA	NA	NA	0.17	$20.24	$ 3.4	$12.4
Domestic Service Time-of-Use Tariff	219.0	$0.03031	$6.6				0.04	$20.24	$ 0.9	$7.5
Domestic Service Critical Peak Pricing Tariff	108.4	$0.03031	$3.3				0.07	$20.24	$ 1.3	$4.6
Total	**5,213.8**		**$158.0**	**NA**	**NA**	**NA**	**5.8592**		**$ 118.61**	**$276.6**
Commercial Sector										
Small General Tariff (Standard Offer)	352.0	$0.02549	$9.0				0.33	$22.16	$ 7.26	$16.2
Small General Time-of-Use Tariff	1.0	$0.02549	$0.0				0.00	$22.16	$ 0.02	$0.0
Small General Critical Peak Pricing Tariff	0.5	$0.02549	$0.0				0.00	$22.16	$ 0.00	$0.0
Small General	**353.4**		**$9.0**	**-**		**$0.0**	0.33		**$ 7.3**	**$16.3**
General Tariff	2,217.0	NA	NA	6.1	$6.282	$38.4				$38.4
General Time-of-Use Tariff	2.0	NA	NA	0.0	$6.282	$0.0				$0.0
General Critical Peak Pricing Tariff	0.5	NA	NA	0.0	$6.282	$0.0				$0.0
General Demand	**2,219.4**	**NA**	**NA**	**6.1**	**$6.282**	**$38.4**				**$38.4**
Large General										
Without Trans. Own.	215.2	NA	NA	0.5	$3.130	$1.5				$1.5
With Trans. Own.	143.4	NA	NA	0.3	$3.130	$0.9				$0.9
Sub-total	**358.6**	NA	NA	**0.761**		**$2.4**				**$2.4**
Total	**2,931.4**		**$ 9.0**	**6.9**		**$40.8**	**0.3288**		**$ 7.3**	**$57.1**
Industrial Sector										
Small Industrial	255.1	NA	NA	0.9	$5.137	$4.8				$4.8
Medium Industrial	438.6	NA	NA	1.3	$3.260	$4.2				$4.2
Large Industrial Firm		NA	NA							
Transmission Connected										
Without Trans. Own.	-	NA	NA	-	$0.436	$0.0				$0.0
With Trans. Own.	39.0	NA	NA	0.08	$0.436	$0.0				$0.0
Sub-total	39.0			0.08						$0.0
Distribution Connected										
Without Trans. Own.	34.5	NA	NA	0.1	$2.643	$0.2				$0.2
With Trans. Own.	24.8	NA	NA	0.03	$2.323	$0.1				$0.1
Sub-total	59.3	NA	NA	0.1		$0.3				$0.3
Large Industrial Interr.										
Transmission Connected										
Without Trans. Own.	-	NA	NA	-	$0.436	$0.0				$0.0
With Trans. Own.	344.0	NA	NA	0.7	$0.436	$0.3				$0.3
	344.0			0.7		$0.3				$0.3
Distribution Connected										
Without Trans. Own.	128.7			0.4	$2.643	$1.0				$1.0
With Trans. Own.	126.5			0.3	$2.323	$0.7				$0.7
Sub-total	255.3	NA	NA	0.7		$1.8				$1.8
Total Large Industrial	**697.6**	**NA**	**NA**	**1.61**		**$2.4**				**$2.418**
Total Industrial	**1,391.3**	**NA**	**NA**	**3.812**		**$11.4**	**0.0**		**0.0**	**$11.4**
Other										
Unmetered	77.0	$0.06207	$ 4.8							$4.8
Total Above-the-line	**9,613.5**		**$ 171.8**	**10.7**		**$52.2**	**6.2**		**$ 125.9**	**$349.9**

2027 PROOF OF REVENUE

Proposed Distribution Tariffs	Distribution Usage in KWhs			Demand in kWs or kVa			Base Charge			Total Revenue
Above-the-line Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	GWS or GVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (in millions)	Base Charge	Revenue (millions)	(millions)
Residential Sector										
Domestic Service Tariff (Standard Offer)	4,269.1	$0.03244	$138.5	NA	NA	NA	5.52	$21.38	$ 118.0	$256.5
Domestic Service Time-of-Day Tariff	303.6	$0.03244	$9.8	NA	NA	NA	0.17	$21.38	$ 3.6	$13.4
Domestic Service Time-of-Use Tariff	402.2	$0.03244	$13.0				0.05	$21.38	$ 1.2	$14.2
Domestic Service Critical Peak Pricing Tariff	199.4	$0.03244	$6.5				0.10	$21.38	$ 2.1	$8.6
Total	**5,174.3**		**$167.9**	**NA**	**NA**	**NA**	**5.8393**		**$ 124.83**	**$292.7**
Commercial Sector										
Small General Tariff (Standard Offer)	354.9	$0.02730	$9.7				0.33	$23.07	$ 7.59	$17.3
Small General Time-of-Use Tariff	1.0	$0.02730	$0.0				0.00	$23.07	$ 0.02	$0.1
Small General Critical Peak Pricing Tariff	0.5	$0.02730	$0.0				0.00	$23.07	$ 0.00	$0.0
Small General	**356.3**		**$9.7**	**-**		**$0.0**	0.33		**$ 7.6**	**$17.3**
General Tariff	2,163.0	NA	NA	6.0	$6.707	$40.0				$40.0
General Time-of-Use Tariff	2.0	NA	NA	0.0	$6.707	$0.0				$0.0
General Critical Peak Pricing Tariff	0.4	NA	NA	0.0	$6.707	$0.0				$0.0
General Demand	**2,165.4**	**NA**	**NA**	**6.0**	**$6.707**	**$40.0**				**$40.0**
Large General										
Without Trans. Own.	213.6	NA	NA	0.5	$3.222	$1.5				$1.5
With Trans. Own.	143.4	NA	NA	0.3	$3.222	$0.9				$0.9
Sub-total	**357.1**	NA	NA	**0.8**		**$2.5**				**$2.5**
Total	**2,878.8**		**$ 9.7**	**6.7**		**$42.5**	**0.3299**		**$ 7.6**	**$59.8**
Industrial Sector										
Small Industrial	254.5	NA	NA	0.9	$5.455	$5.1				$5.1
Medium Industrial	414.5	NA	NA	1.2	$3.296	$4.0				$4.0
Large Industrial Firm		NA	NA							
Transmission Connected										
Without Trans. Own.	-	NA	NA	-	$0.420	$0.0				$0.0
With Trans. Own.	39.0	NA	NA	0.08	$0.420	$0.0				$0.0
Sub-total	39.0			0.08						$0.0
Distribution Connected										
Without Trans. Own.	33.7	NA	NA	0.1	$2.797	$0.3				$0.3
With Trans. Own.	24.8	NA	NA	0.03	$2.477	$0.1				$0.1
Sub-total	58.4	NA	NA	0.1		$0.3				$0.3
Large Industrial Interr.										
Transmission Connected										
Without Trans. Own.	-	NA	NA	-	$0.420	$0.0				$0.0
With Trans. Own.	344.0	NA	NA	0.7	$0.420	$0.3				$0.3
	344.0			0.7		$0.3				$0.3
Distribution Connected										
Without Trans. Own.	137.6			0.4	$2.797	$1.0				$1.0
With Trans. Own.	115.5			0.3	$2.477	$0.8				$0.8
Sub-total	253.1	NA	NA	0.7		$1.8				$1.8
Total Large Industrial	**694.6**	**NA**	**NA**	**1.55**		**$2.4**				**$2.4**
Total Industrial	**1,363.6**	**NA**	**NA**	**3.679**		**$11.5**	**0.0**		**0.0**	**$11.5**
Other										
Unmetered	77.0	$0.06538	$ 5.0			$0.0				$5.0
Total Above-the-line	**9,493.7**		**$ 182.6**	**10.4**		**$53.9**	**6.2**		**$ 132.4**	**$369.0**

DISTRIBUTION TARIFF TABLE- 2025, 2026 and 2027

Rate Class	Customer Charge $/month			Distribution Charge ¢/kWh			Demand Charge $/kVA or $/kW			Minimum Monthly Charge $/month			Transformer Ownership Credit $/kVa		
	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed
All Domestic Service Rates	19.17	20.24	21.38	2.383	3.031	3.244				19.17	20.24	21.38			
All Small General Rates	21.28	22.16	23.07	2.107	2.549	2.730				21.28	22.16	23.07			
All General Rates							5.150	6.282	6.707	21.28	22.16	23.07	(0.32)	(0.32)	(0.32)
Large General Rate							4.872	3.130	3.222	21.28	22.16	23.07	(0.32)	(0.32)	(0.32)
Small Industrial Rate							5.178	5.137	5.455	21.28	22.16	23.07	(0.32)	(0.32)	(0.32)
Medium Industrial Rate							3.639	3.260	3.296	21.28	22.16	23.07	(0.32)	(0.32)	(0.32)
Large Industrial Rate Distribution-connected							2.118	2.643	2.797	21.28	22.16	23.07	(0.32)	(0.32)	(0.32)
Large Industrial Rate Transmission-connected							0.270	0.436	0.420	21.28	22.16	23.07			
Outdoor Recreational Light Rate				3.400	6.207	6.538									
Unmetered Service Rates							14.166	23.988	25.093	21.28	22.16	23.07			
Miscellaneous Small Loads							14.166	23.988	25.093	21.28	22.16	23.07			

DISTRIBUTION TARIFF TABLE- 2025, 2026 and 2027

Rate Class	Percent change														
	Customer Charge $/month			Distribution Charge ¢/kWh			Demand Charge $/kVA or $/kW			Minimum Monthly Charge $/month			Transformer Ownership Credit $/kVa		
	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed	Current	2026 Proposed	2027 Proposed
All Domestic Service Rates		6%	6%		27%	7%									
All Small General Rates		4%	4%		21%	7%									
All General Rates								22%	7%		4%	4%		0%	0%
Large General Rate								-36%	3%		4%	4%		0%	0%
Small Industrial Rate								-1%	6%		4%	4%		0%	0%
Medium Industrial Rate								-10%	1%		4%	4%		0%	0%
Large Industrial Rate Distribution-connected															
Large Industrial Rate Transmission-connected								62%	-4%		4%	4%			
Outdoor Recreational Light Rate					83%	5%									
Unmetered Service Rates								69%	5%		4%	4%			
Miscellaneous Small Loads								69%	5%		4%	4%			

2026 DT STREETLIGHT RATES

STEP 1 - DETERMINATION OF UNIT REVENUES OF POWER AND ENERGY SERVICE

Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load

		Charge		Annual Revenue		
		Before Adj.	After Adj.	Before Adj.	After Adj.	% Change
Photocell Operation (4000 burning hours per year)						
Demand Charge $/kW (annual)		23.988	23.988	$287.86	$287.86	0.000%
Energy Charge :						
1st Block : 1st 200 kW.h (annual)	2,400	0.00000	0.00000	0.00	0.00	
2nd Block : All additional (annual)	1,600	0.00000	0.00000	0.00	0.00	
				$287.86	$287.86	0.000%
Rate per kW.h	4,000			**$0.07196**	**$0.07196**	0.000%

		Charge		Annual	Annual Revenue	
		Before Adj.	After Adj.	Before Adj.	After Adj.	% Change
Continuous Burning (8760 burning hours per year)						
Demand Charge $/kW (annual)		23.9881378	23.9881	$287.86	$287.86	0.000%
Energy Charge :						
1st Block : 1st 200 kW.h (annual)	2,400	0.00000	0.00000	0.00	0.00	
2nd Block : All additional (annual)	6,360	0.00000	0.00000	0.00	0.00	
				$287.86	$287.86	0.000%
Rate per kW.h	8,760			**$0.03286**	**$0.03286**	0.000%

2027 DT STREETLIGHT RATES

STEP 1 - DETERMINATION OF UNIT REVENUES OF POWER AND ENERGY SERVICE

Based on Misc. Small Loads Tariff Rate Components & 1kW lighting load

		Charge		Annual Revenue		
		Before Adj.	After Adj.	Before Adj.	After Adj.	% Change
Photocell Operation (4000 burning hours per year)						
Demand Charge $/kW (annual)		25.093	25.093	$301.11	$301.11	0.000%
Energy Charge :						
1st Block : 1st 200 kW.h (annual)	2,400	0.00000	0.00000	0.00	0.00	
2nd Block : All additional (annual)	1,600	0.00000	0.00000	0.00	0.00	
				$301.11	$301.11	0.000%
Rate per kW.h	4,000			**$0.07528**	**$0.07528**	0.000%

		Charge		Annual	Annual Revenue	
		Before Adj.	After Adj.	Before Adj.	After Adj.	% Change
Continuous Burning (8760 burning hours per year)						
Demand Charge $/kW (annual)		25.0925756	25.0926	$301.11	$301.11	0.000%
Energy Charge :						
1st Block : 1st 200 kW.h (annual)	2,400	0.00000	0.00000	0.00	0.00	
2nd Block : All additional (annual)	6,360	0.00000	0.00000	0.00	0.00	
				$301.11	$301.11	0.000%
Rate per kW.h	8,760			**$0.03437**	**$0.03437**	0.000%

Requirement:

Load Forecast Report

Submission:

Please refer to Partially Confidential Attachment 1.

Nova Scotia Utility and Review Board

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

2024 Load Forecast Report

April 30, 2024

REDACTED

TABLE OF CONTENTS

1.0 Executive Summary 6
2.0 Introduction 10
3.0 Forecasting Approach 14
4.0 Discussion of Major Inputs 16
4.1 Historical Class Sales and Energy Data 16
4.2 Weather Data 17
4.3 Economic Information 23
4.4 End-Use Intensity Trends 30
4.5 Price Data 51
4.6 Demand Side Management 54
4.7 Renewable to Retail 57
5.0 Residential Sector 58
6.0 Commerical Sector 64
6.1 Small General Service 66
6.2 General Service 67
6.3 Large General Service 68
7.0 Industrial and Municipal Sectors 71
7.1 Small Industrial 71
7.2 Medium Industrial 72
7.3 Other Industrial Rate Classes 73
7.4 Municipal 76
8.0 System Losses and Unbilled Sales 77
9.0 Net System Requirement 78
10.0 Peak Demand 81
11.0 Sensitivity Analysis 97

List of Figures

Figure 1: Historical and Predicted Annual Net System Requirement 7
Figure 2: Historical and Predicted Annual System Peak 8
Figure 3: Historic and Forecast Net System Requirement and System Peak 9
Figure 4: Forecast Approach 15
Figure 5: 10 Year Normal Monthly HDDs and CDDs 18
Figure 6: Historic Annual HDD 18
Figure 7: HDD Trend 19
Figure 8: CDD Trend 20
Figure 9: Annual HDD and CDD Over Time 21
Figure 10: Rolling 10 Year Average of Annual Evening Min Trend 22
Figure 11: Yearly Change in Customers, Population, and Housing Completions 24
Figure 12: Household Size 25
Figure 13: Residential Economic Drivers 26
Figure 14: Commercial Economic Drivers 27
Figure 15: Industrial Economic Drivers 28
Figure 16: Economic Forecast Comparison 29
Figure 17: E3 Residential Space Heating Saturation 32
Figure 18: E3 Commercial Space Heating Saturation 32
Figure 19: Commercial Space Heating Saturation Comparison 33
Figure 20: Heat Pump Energy and Peak Comparison 33
Figure 21: Heat Pump Forecast 34
Figure 22: Heating Intensity Comparison 35
Figure 23: Water Heater Forecast 36
Figure 24: EV Forecast 38
Figure 25: EV Mileage Assumptions and Load/Peak Modeling Results 39
Figure 26: EV Impact to Energy and Peak Forecasts (cumulative) 40
Figure 27: PV Impact to Energy (cumulative) 43
Figure 28: Potential Peak Impacts from Batteries 45
Figure 29: Residential End-Use Intensities 47
Figure 30: Historical and Projected Small General Commercial End-Use Intensity (kWh/m^2) 48
Figure 31: Historical and Projected General Commercial End-Use Intensity (kWh/m^2) 49
Figure 32: Commercial and Industrial Electrification Forecasts (cumulative) 50
Figure 33: Historical and projected real electricity prices (real dollars per kWh) 52
Figure 34: TVP Price Elasticity Estimates 53
Figure 35: Annual Forecast Residential DSM Savings (incremental) 56
Figure 36: RTR Forecast by Class 57
Figure 37: Comparison of Forecast to Actuals 58
Figure 38: Comparison of Forecast to Actuals – One Year Ahead. 59
Figure 39: Historical and Forecast Annual Residential Sales 60
Figure 40: Building Characteristics and Structural Index 61
Figure 41: Residential Sales Components by Year 62

Figure 42: Illustrative Contribution of Specific End Uses 63
Figure 43: Commercial Class Sales 65
Figure 44 Commercial Sales vs Economic Indicators 66
Figure 45: Historical and Forecast Annual Small General Sales 67
Figure 46: Historical and Forecast Annual General Demand Sales 68
Figure 47: Large General Annual Growth (GWh) 69
Figure 48: Historical and Forecast Annual Large General Sales 70
Figure 49: Historical and Forecast Annual Small Industrial Sales 72
Figure 50: Historical and Forecast Annual Medium Industrial Sales 73
Figure 51: Large Industrial Annual Growth (GWh) 74
Figure 52: Historical and Forecast Annual Other Industrial Sales 75
Figure 53: 2023 Variance to Actual 78
Figure 54: Historical and Forecast Annual NSR 79
Figure 55: Forecast Components 80
Figure 56: Demand Response 82
Figure 57: Peak Regression Coefficients 84
Figure 58: Historical and Forecast System Peak (no DR) 85
Figure 59: Historical and Forecast Firm Peak (including DR) 86
Figure 60: Weather-Normalized Firm Peak (including DR) 87
Figure 61: Peak Contribution Components (MW) 87
Figure 62: Forecast Peak Variance vs Actuals 88
Figure 63: Comparison of Peak Forecast to Actuals – One Year Ahead 89
Figure 64: Peak Contribution Components (MW) 90
Figure 65: Residential End-Use Peak Shares 91
Figure 66: Commercial End-Use Peak Shares 92
Figure 67: 2023 Load Research Data vs System Generation, 2023 Annual Peak 93
Figure 68: 2023 Monthly Load Research Data vs System Generation 94
Figure 69: Monthly historical Residential LRS load at peak and forecasts 95
Figure 70: System Energy Sensitivity 98
Figure 71: System Peak Sensitivity 99
Figure 72: 2022 Evergreen IRP Scenarios Comparison 100

Attachments (Electronic Only)

Attachment 1: Residential Intensities
Attachment 2: Commercial Small General Intensities
Attachment 3: Commercial General Intensities
Attachment 4: 10-Year Forecast Classes (Partially Confidential)
Attachment 5: Residential Model Inputs & Outputs
Attachment 6: Small General Model
Attachment 7: General Demand Model
Attachment 8: Small Industrial Model
Attachment 9: Medium Industrial Model
Attachment 10: Peak Model Inputs

Appendices

Appendix A: 2024 NS Power Forecast
Appendix B: Forecast Model Details
Appendix C: Forecast Comparison (Partially Confidential)
Appendix D: Forecast Sensitivity (Partially Confidential)
Appendix E: Stakeholder Presentation

1.0 EXECUTIVE SUMMARY

In accordance with the Nova Scotia Wholesale Electricity and Renewable to Retail Market Rules, Nova Scotia Power Incorporated (NS Power, the Company) is required to provide the Nova Scotia Utility and Review Board (NSUARB, Board) with its 10-year energy and demand forecast by the end of April each year for the 10-year period beginning in the following January (Load Forecast).

The 2024 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for the period 2024 to 2034. In addition, it describes the considerations, assumptions, and methodology used in the preparation of the forecast. The Load Forecast provides the basis for the planning and overall operating activities to serve customer load.

The Load Forecast is based on analyses of sales history, weather, end-use saturations and efficiencies, economic indicators, customer surveys, technological and demographic changes in the market, and the availability of other energy sources.

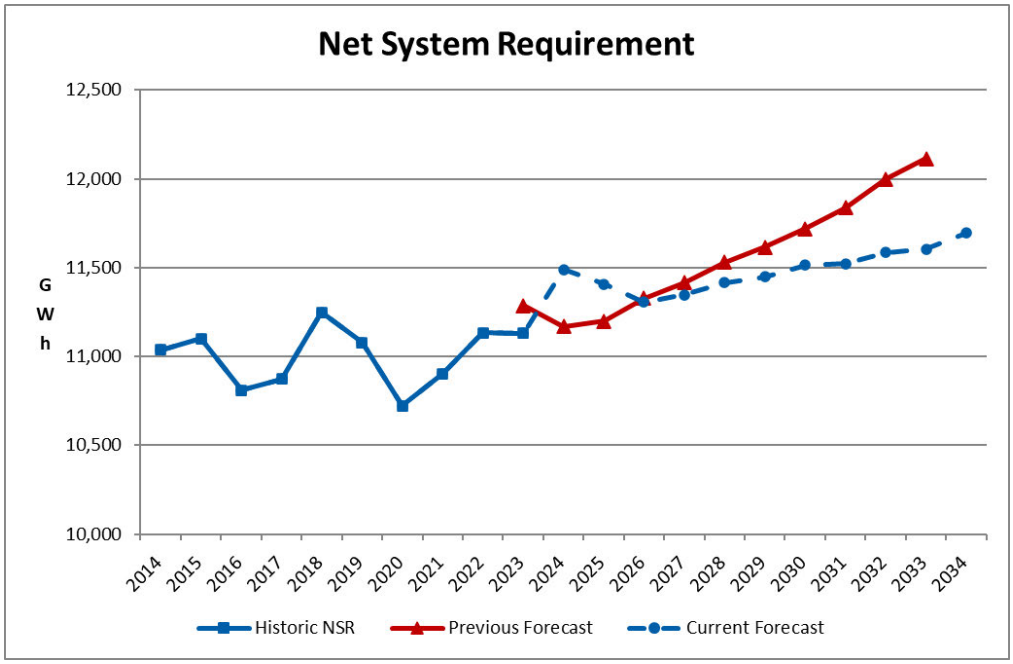
As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, energy efficiency program effectiveness, the health of the economy, government policy, the impact of electrification, changes in large customer loads, the number of electric appliances and end-use equipment installed, and changes in technology.

NS Power continues to use and refine Statistically Adjusted End-Use (SAE) models to forecast load for the residential and commercial rate classes. The SAE models explicitly incorporate end-use energy intensity projections into the Load Forecast. End-use energy forecasts derived from the residential and commercial SAE models are then combined with an econometric-based industrial forecast and customer specific forecasts for NS Power's

large customers to develop an energy forecast for the province, also referred to as the Net System Requirement (NSR).

Compared to the 2023 Load Forecast, the 2024 Load Forecast shows higher growth in the near term due to more new customer additions and higher average use when adjusted for weather in 2023. Mid- to long-term growth is driven by sustained customer growth, Electric Vehicle (EV) sales, though estimated EV sales are lower than in 2023 due to the federal zero-emissions vehicle sales targets applying only at the national level, not the provincial level. Sales through the Renewable to Retail (RTR) market will reduce load in the 2025-2026 timeframe by approximately 250 GWh. In the long term, energy sales will be reduced by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside structured DSM programs, as well as increased behind-the-meter small scale solar installations. The net result is a forecast average annual increase of 0.2 percent. Annual historic and forecast NSR are shown below in **Figure 1.**

Figure 1: Historical and Predicted Annual Net System Requirement



In addition to annual energy requirements, NS Power forecasts system peak demand. Customer growth, electrification of heating and increased EV sales will increase the peak, while DSM and DR activities will reduce the peak. Compared to 2023, the near-term peak forecast is higher due to increased impact from electric heating loads, while in the long term the peak forecast is reduced due to lower EV sales and adoption of a hybrid heating scenario in alignment with Nova Scotia's Clean Power Plan and NS Power's Evergreen IRP. As a result, the system peak demand is expected to increase at an average of 1.4 percent annually over the forecast period, as shown in **Figure 2.**

Figure 2: Historical and Predicted Annual System Peak

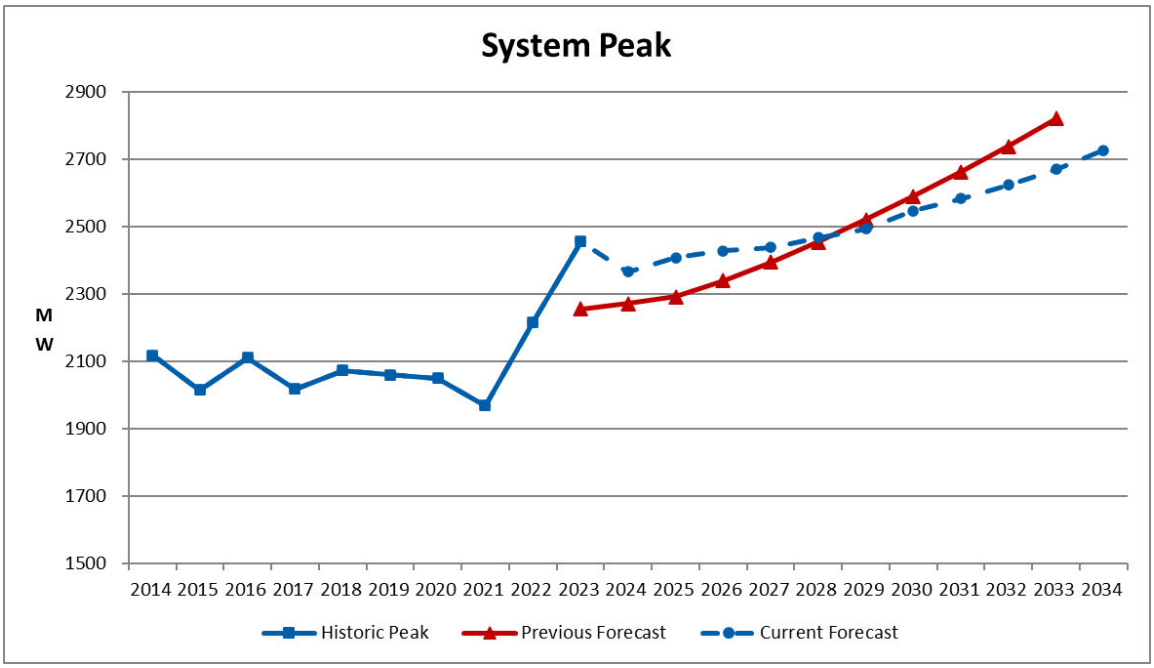


Figure 3 below shows the changes to system load and system peak over the historic and forecast periods.

Figure 3: Historic and Forecast Net System Requirement and System Peak

Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
2014	11,037	-1.4	2,118	4.2
2015	11,099	0.6	2,015	-4.9
2016	10,809	-2.6	2,111	4.8
2017	10,873	0.6	2,018	-4.4
2018	11,250	3.5	2,073	2.7
2019	11,077	-1.5	2,060	-0.6
2020	10,723	-3.2	2,050	-0.5
2021	10,902	1.7	1,968	-4.0
2022	11,134	2.1	2,216	12.6
2023	11,131	0.0	2,455	10.8
2024F	11,490	3.2	2,365	-3.7
2025F	11,409	-0.7	2,408	1.8
2026F	11,306	-0.9	2,428	0.8
2027F	11,347	0.4	2,437	0.4
2028F	11,416	0.6	2,466	1.2
2029F	11,448	0.3	2,493	1.1
2030F	11,514	0.6	2,547	2.2
2031F	11,523	0.1	2,583	1.4
2032F	11,585	0.5	2,623	1.5
2033F	11,605	0.2	2,670	1.8
2034F	11,695	0.8	2,727	2.1

2.0 INTRODUCTION

NS Power annually develops a forecast of energy sales and peak demand requirements to assess the effects of end-use and economic factors on the future power system load and load shape. The forecast is a foundational input to the overall planning, budgeting and operating activities of the Company. Produced in the winter of 2023-2024 and using information available at the time, this forecast covers the period of 2024-2034. Unless otherwise noted, reported average annual growth rates are for the 2024-2034 period.

In 2023, the NSUARB initiated a paper hearing process to review the 2023 Load Forecast Report.[1] The Consumer Advocate (CA), the Small Business Advocate (SBA), the Industrial Group (IG), EfficiencyOne (E1), and Eastward Energy (EE) registered and took part as intervenors. In addition, Board Counsel engaged Synapse Energy Economics (Synapse) to review and provide a report on NS Power's 2023 Load Forecast.

Following NS Power's response to Information Requests (IRs), filing of evidence by intervenors and Board Counsel and Reply Evidence by NS Power, the Board issued its Decision respecting NS Power's 2023 Load Forecast. The Board noted that "NS Power has agreed to many of the intervenors' recommendations and acknowledges this commitment towards continuous improvement of the Load Forecast."[2] The Board further stated as follows:

> The Board directs NS Power to proceed with implementing the recommendations it has agreed to in the next Load Forecast report, including:
>
> - the IRP, SGNS, AMI, TVP Pilot outcomes;
> - reviewing the assumptions applied in the model to reduce carbon emissions; and,
> - assessing the historical load of survey sales realization, to compare how the historical load compares with the survey results.

[1] NSUARB Hearing Order, 2023 Load Forecast Report (M11108), May 2, 2023.
[2] Nova Scotia Power Inc. 2023 Load Forecast Report, UARB Decision, November 7, 2023, page 6 (M11108).

In addition to the above directives, the Board encourages NS Power to include information on each of the following in future load forecasts:

- Evaluate the elasticity used in the SAE model with the elasticity estimation from the TVP Pilot EM&V in matter M11267 and assess if the results provide a more robust model.
- Evaluate the input variables in the residential model and test, over a period of time, if alternative inputs make the residential model more robust, considering the following:
    - Given the continued population growth in Nova Scotia and ongoing housing shortage, re-evaluate the use of housing completions for the near-term.
    - Consider incorporating household size and age of household residents, to determine if a better understanding on demand load by time of day is achieved.
    - Revisiting the short-term economic inputs provided by the Conference Board of Canada to ensure the data is close to what is used in the forecasts of Canada's major Banks.
    - Revisit the model's EV adoption rates to ensure that the model's inputs are in keeping with the data reported by Statistics Canada and Nova Scotia Open data.
    - With respect to the status of large infrastructure projects, NS Power is encouraged to maintain communications with those customers to ensure system adequacy.

//

The Board expects NS Power to continue exploring all realistic scenarios related to commercial hydrogen production and, where there is sufficient data, incorporate them to the extent possible, in load forecast modelling.

The Board notes that there is a significant variance between the 2022 forecast and the actual Net System Requirement of 234 GWh. This variance has been attributed to the COVID-19 pandemic and heat pump installations, which are confounding factors during a year of warm weather. The Board finds that given the size of the unexplained variance, this category needs to be revisited. NS Power is encouraged to consider the following potential effects on load:

- cooling demand during the summer months;
- increased demand from customers upgrading the electrical capacity of their homes to accommodate heat pumps and large back-up generators; and,
- any other factors that NS Power considers a driver to increased electricity demand in the residential class.

> The Board directs NS Power to examine the 2022 unexplained variance and report on its findings in the 2024 Load Forecast Report.[3]

In accordance with the Board's direction, NS Power revised and enhanced the 2024 Load Forecast in the following manner:

- The EV forecast has been updated to reflect the fact that the federal zero-emission vehicle (ZEV) mandate applies only at the national level, not provincial. Please refer to **Section 4.4**.
- In line with the Evergreen IRP the hybrid electrification scenario for building heat is now integrated into the forecast and is discussed in **Section 4.4**.
- A summary of the Smart Grid and Demand Response projects is provided in **Sections 4.4** and **10**.
- A discussion of the economic inputs, including housing completions and median income, is provided in **Section 4.3**.
- The potential impact of the proposed hydrogen production facilities is provided as a scenario in **Appendix D**.
- An analysis of the residential forecast variance for 2022 and 2023 is provided in **Section 5.0**.

[3] Ibid, pages 6-7 (M11108).

Summary of Stakeholder Consultations

On April 11, 2024, NS Power conducted a stakeholder session by videoconference with representatives of the NSUARB, the Consumer Advocate (CA), the Small Business Advocate (SBA), the Industrial Group (IG), EfficiencyOne (E1) and Eastward Energy. The agenda and presentation materials are included in **Appendix E**. The NS Power Load Forecast team discussed the following changes to the 2024 Load Forecast:

- Updated building heating assumptions;
- Updated electric vehicle (EV) forecast;
- E3 hybrid heating scenario;
- Renewable to retail impact on the forecast;
- Updated assumptions around small-scale solar;
- Class level trends;
- Variance of prior forecast to actuals; and
- Discussion of ongoing forecasting work.

3.0 FORECASTING APPROACH

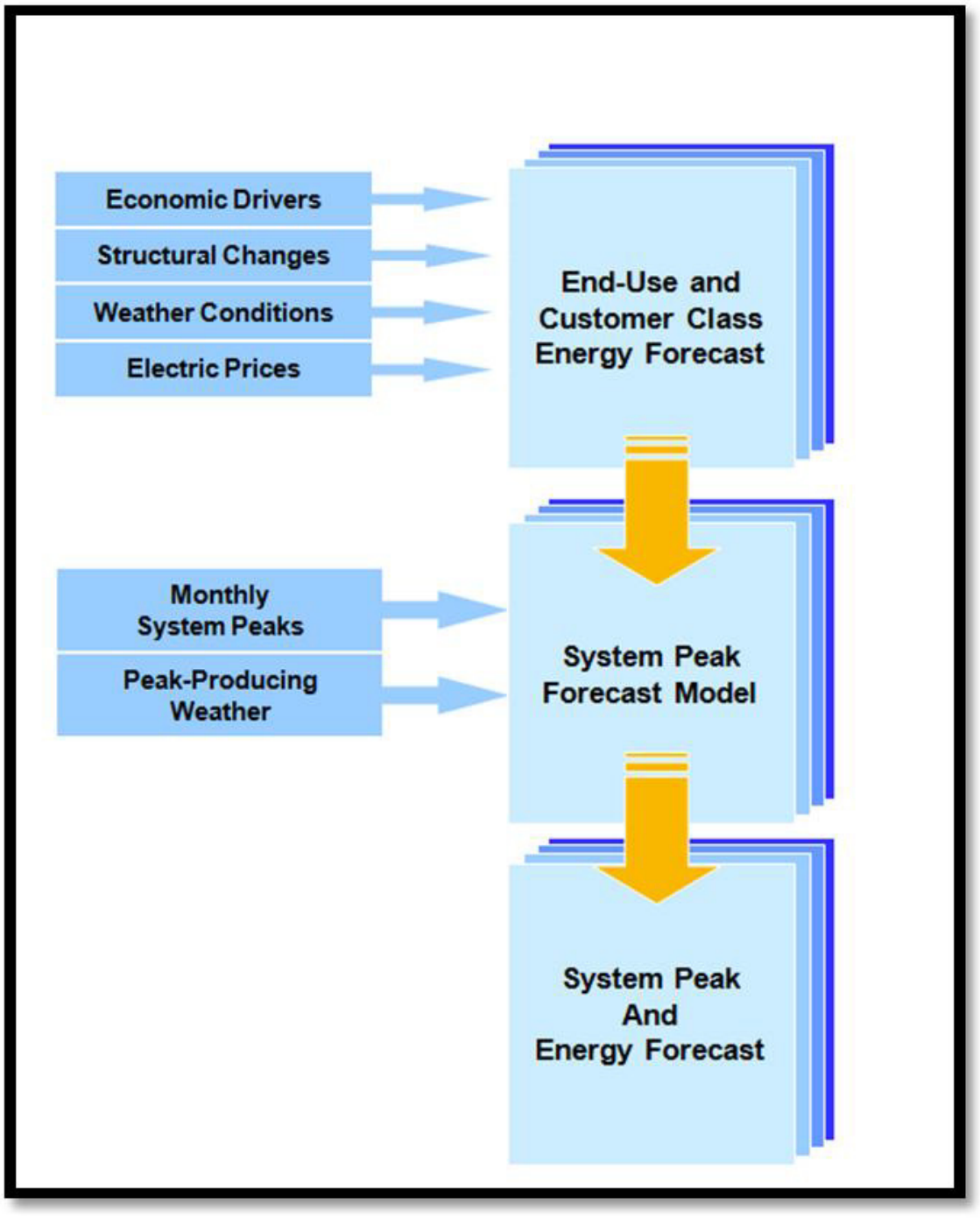
NS Power continues to use a set of SAE models for the Residential[4] and Commercial[5] rate classes, an econometric model for the Small and Medium Industrial classes, and customer surveys and historical data for the Large Industrial[6] customer classes.

The SAE model is a hybrid of the econometric and end-use methodologies, incorporating economic and end-use forecast variables into one model. An end-use model is a bottom-up approach that estimates the energy consumption of a customer group by summing the energy usage of all the appliances and equipment used by those customers. End-use forecasts are driven by trends in appliance usage and efficiency trends for that equipment. An econometric model describes the historical relationship between electricity consumption and independent economic indicators on provincial economic forecasts as a method to forecast future electricity sales.

The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price, and weather. End-use efficiency projections include the expected impact of new standards and naturally occurring efficiency gains (efficiency improvements such as improvements in underlying technology that are not explicitly incentivized). In the long term, both economics and structural changes drive energy and demand growth. Structural changes are captured in the residential forecast model through the SAE model specifications. **Figure 4** shows the general forecast approach used in the SAE models.

[4] References to the Residential class include Domestic Service and Domestic Service Time-of-Day.
[5] References to the Commercial class include Small General, General and Large General unless specified otherwise.
[6] References to the Industrial class include the Small, Medium and Large Industrial classes unless specified otherwise.

Figure 4: Forecast Approach



4.0 DISCUSSION OF MAJOR INPUTS

4.1 Historical Class Sales and Energy Data

The Load Forecast is developed using NS Power's "billed" sales rather than "accrued" sales. Billed sales refer to the amount of energy billed to customers in a given period such as a calendar month or year. Accrued sales recognize the amount of energy generated and consumed during that specific time period. Due to the periodic nature and delays inherent in any meter reading and billing process, billed sales vary from accrued sales on a monthly basis but are essentially the same on an annual scale.

Historical monthly billed sales are the primary dependent variables in the linear regression models used in developing the forecast. For the 2024 Load Forecast, the residential and commercial energy forecasts are estimated using monthly billed sales data for the period January 2014 to December 2023. The industrial forecasts use the periods January 2014 to December 2023 (Small Industrial) and January 2006 to December 2023 (Medium Industrial) to improve the model fit.

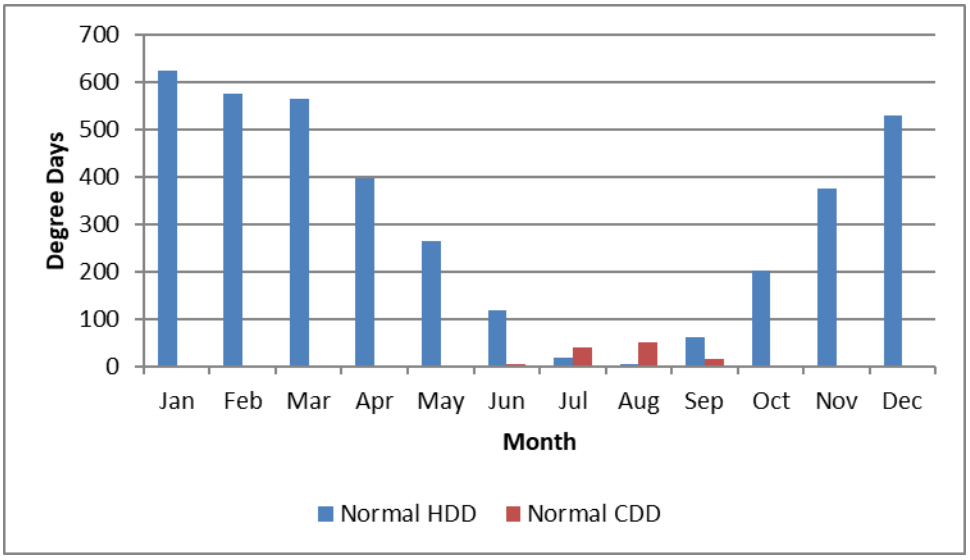
For the peak demand forecast, historical system monthly energy and monthly demand data is derived from system hourly load data for the period January 2014 to December 2023. Large customer peak demand is forecast separately.

The Renewable to Retail (RtR) electricity market was established in Nova Scotia in 2016 to enable independent licensed retailers to sell renewable energy generated within the province directly to NS Power's retail customers. The impact of this input is discussed in **Section 4.7**.

4.2 Weather Data

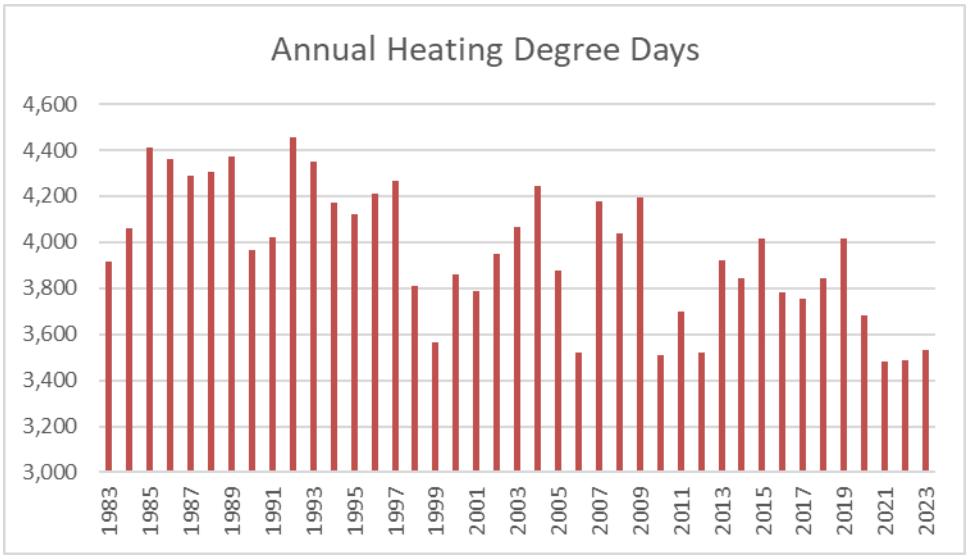
Weather conditions have the largest single impact on month-to-month variation in electric sales. The impacts of temperature are captured by monthly Heating Degree Day (HDD) and Cooling Degree Day (CDD) variables. HDD are a common measure of heating requirement based on the degree difference between the daily mean temperature and a given reference temperature. The reference temperature of 18 degrees Celsius (°C) is used for these calculations. 18°C is assumed to be a comfortable room temperature below which space heating is generally required and above which space cooling is also required. Monthly HDD and CDD are calculated from Environment Canada hourly temperature information for the Shearwater Airport. Normal monthly HDD and CDD, as shown in **Figure 5** below, are calculated using 10 years of actual weather data covering the period January 2014 to December 2023. The average temperature continues to show a warming trend: the 30-year average annual HDD is 3,864 while the 10-year average is 3,743.

Figure 5: 10 Year Normal Monthly HDDs and CDDs



The annual number of HDD has been declining as a result of climate trends, as shown in **Figure 6**.

Figure 6: Historic Annual HDD



To reflect the general warming trend as seen in the 30-year vs 10-year averages, a trend is applied to the annual HDD and CDD variables. These trends are based on regression analysis of 30 years of historic data using a 10-year moving average (to smooth the series), with HDD decreasing by approximately 17 HDD/year, and CDD increasing by approximately 1.4 CDD/year. See **Figure 7** below for HDD and **Figure 8** below for CDD.

Figure 7: HDD Trend

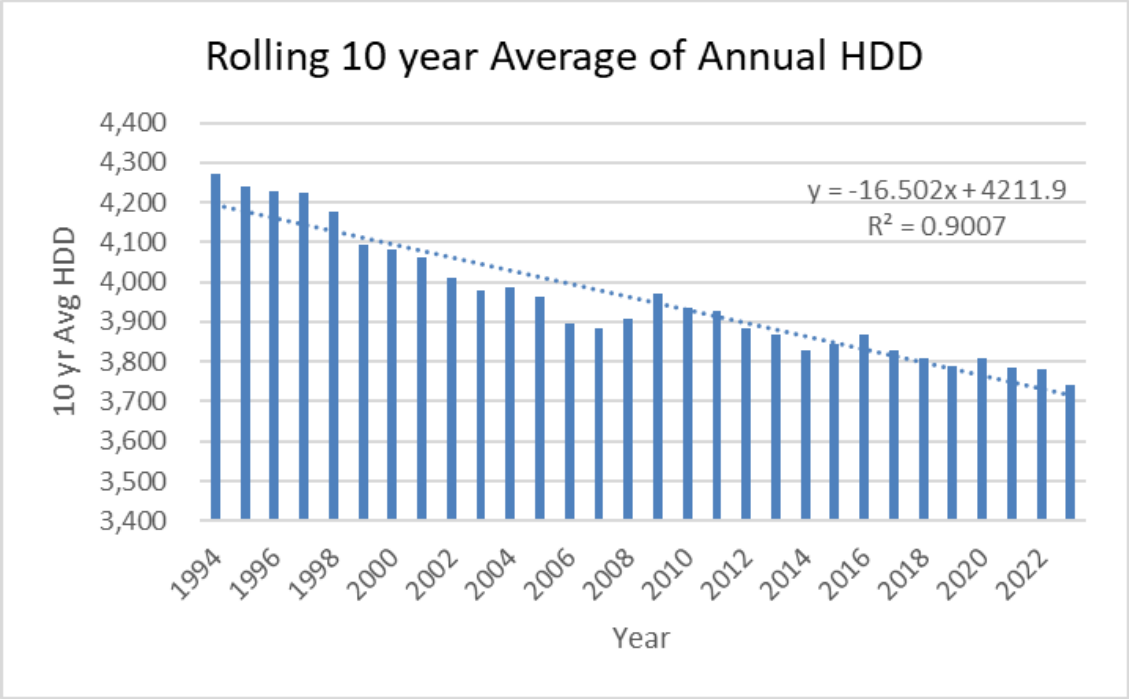
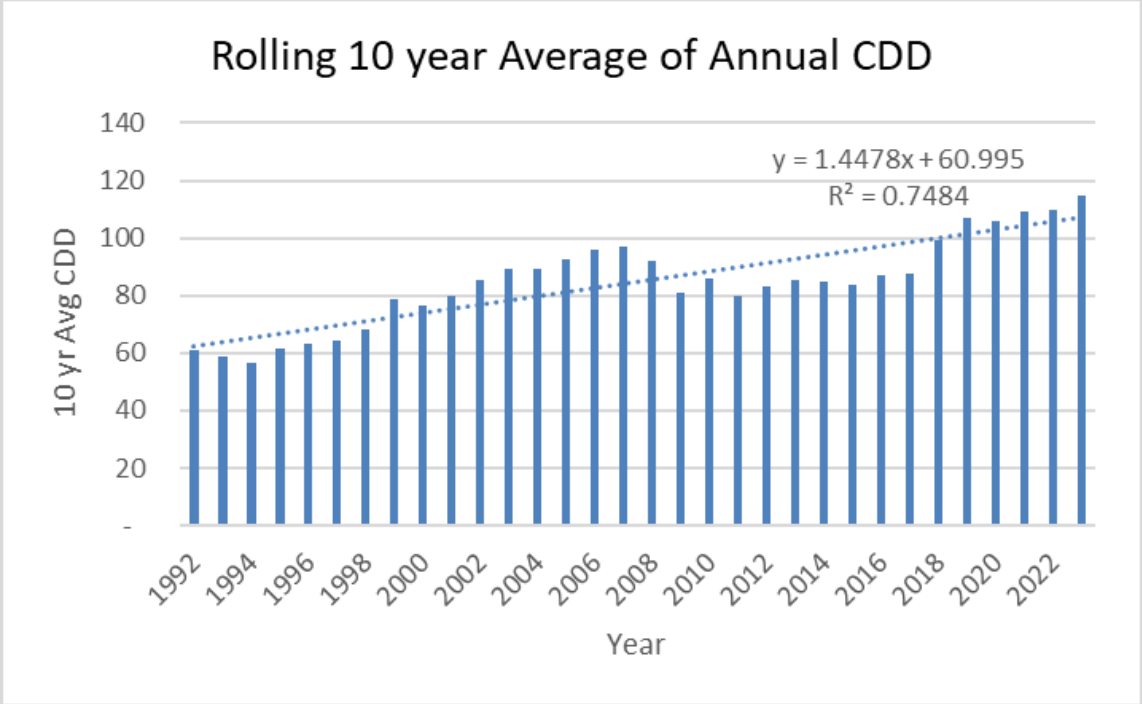
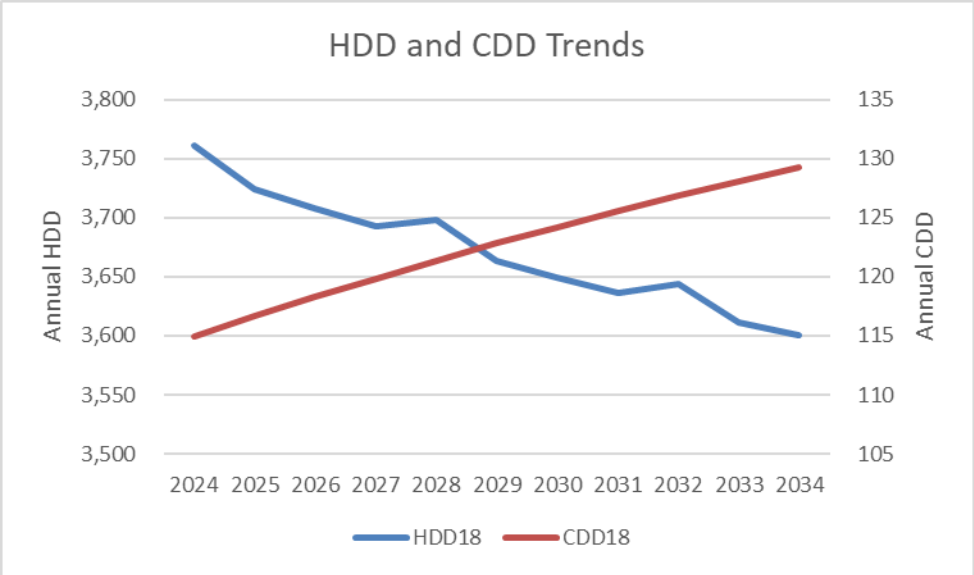


Figure 8: CDD Trend



These trends are reduced over time (approximately 40 years) such that the average annual HDD is not forced to 0 and the average annual CDD does not increase indefinitely. **Figure 9** shows how the HDD and CDD variables evolve over the 10-year forecast period. 2024 represents the 10-year average (and includes the impact of the extra day in February), and by 2034 the annual HDD value is reduced to 3,600 while the CDD value has increased to 129. The implication of this change is a reduced winter heating load and an increased summer cooling load in both the Residential and Commercial classes. The bumps in 2024, 2028 and 2032 are due to leap years which have an extra day in February.

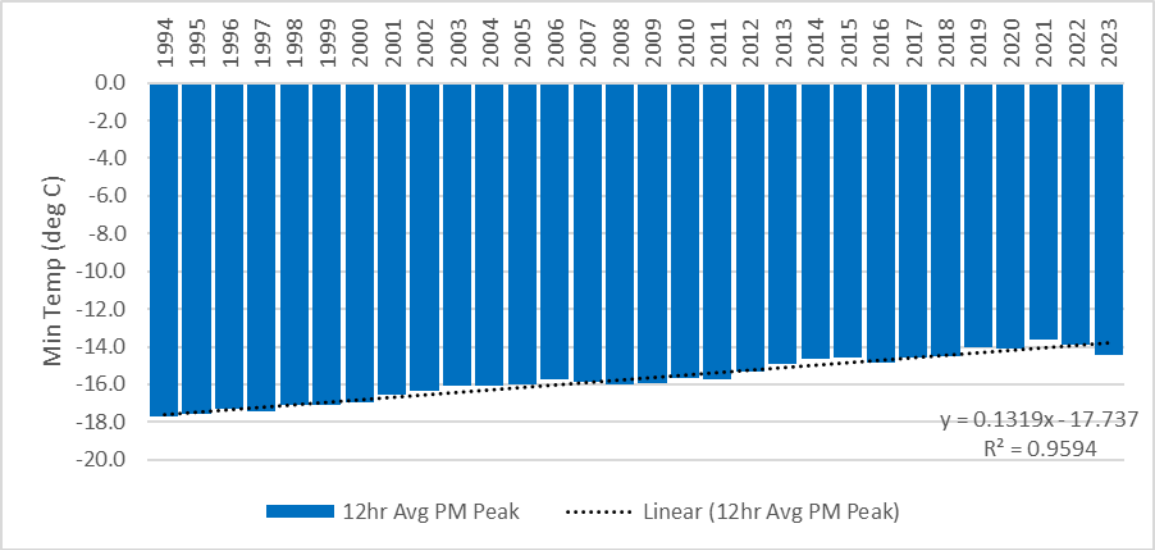
Figure 9: Annual HDD and CDD Over Time



Like the 2023 model, for the 2024 peak model the temperature input uses a 12-hour lagged temperature in combination with an average daily wind speed variable. 10-year averages for both parameters serve as the forecast variables, with an average 12 hour lagged temperature of -14.4°C and an average peak day wind speed of 17.5 km/h. The updated average temperature has decreased from -13.9°C in the 2023 forecast, contributing to an increased peak forecast in 2024.

The other factor included in the peak forecast temperature is a trend similar to the one included in the annual HDD calculations. Looking at a rolling 10-year average of annual 12 hour lagged average minimum temperatures shows that the minimum is increasing at a rate of around 0.13 degrees per year, as shown in **Figure 10**. Like the trend in the HDD series, the peak trend also tapers off over a period of approximately 40 years.

Figure 10: Rolling 10 Year Average of Annual Evening Min Trend



Several resources were consulted that support these assumptions. The Climate Atlas of Canada[7] provides estimates for annual HDD as well as number of "Winter Days" that are -15° or colder under different climate change scenarios between now and 2050. Annual HDD for Halifax is forecast to decline to a 30 year average of 3597 between 2021 and 2050 under the scenario where greenhouse gas emissions continue at present rates, or to 3636 where emissions slow. The number of "Winter Days" is forecast to decrease from a 30 year average of 13 (between 1976 and 2005) to around 6 under both scenarios. Both trends are in line with the trends being applied to annual HDD and peak temperature increases in the forecast. Research on trends in New England[8] points to general warming patterns both in terms of average temperatures as well as minimum and maximum temperatures.

[7] https://climateatlas.ca/map/canada
[8] Overall Warming with Reduced Seasonality: Temperature Change in New England, USA, 1900-2020, Stephen S. Young and Joshua S. Young, 2001

4.3 Economic Information

Economic and other provincial statistics used in the load forecast are from the Conference Board of Canada's 20-year forecast. This forecast provides a provincial perspective and considers specific Nova Scotia projects and demographics.

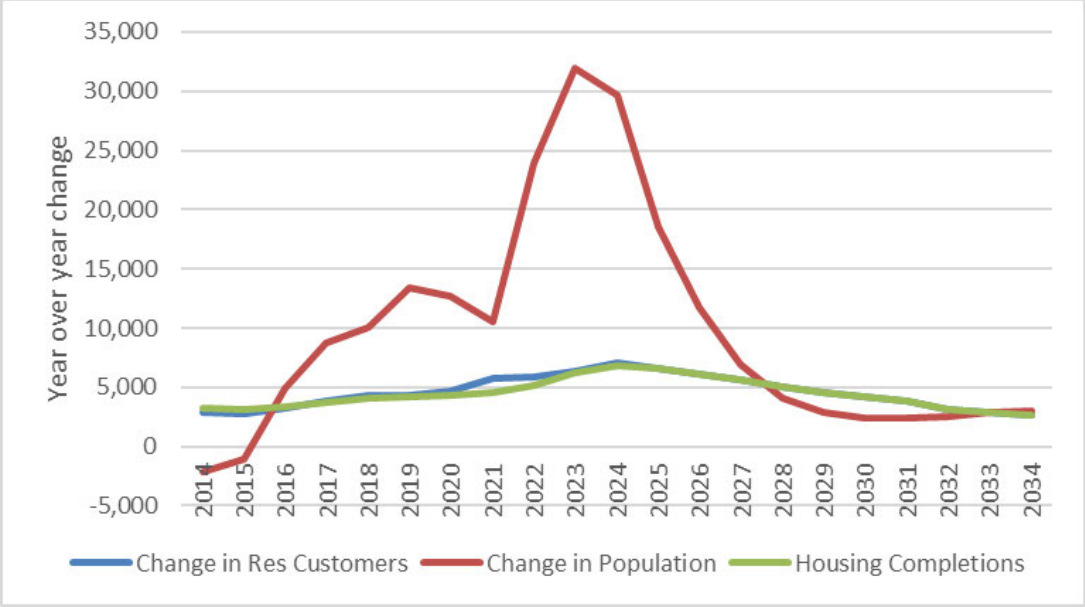
In the SAE framework, economic data drives the utilization of the end-use stock over the forecast period. The impact of increased work-from-home activity on the residential class (resulting in increased sales) is handled by a distinct variable rather than relying on the economic variables. New housing completions for both single-family and multi-unit buildings are used in generating residential customer forecasts. Growth of new customers is expected to remain positive but decrease over time, as population growth slows from the expected peak in 2023. As noted in its Decision[9], the NSUARB directed that:

- Given the continued population growth in Nova Scotia and ongoing housing shortage, re-evaluate the use of housing completions for the near-term.
- Consider incorporating household size and age of household residents, to determine if a better understanding on demand load by time of day is achieved.

Housing completion numbers continue to be highly correlated with residential customer count, as seen in **Figure 11**, and continue to be the most appropriate indicator in the near term. NS Power is aware of the ongoing housing shortage in the province and will continue to monitor any government initiatives that address the shortage and increase housing supply.

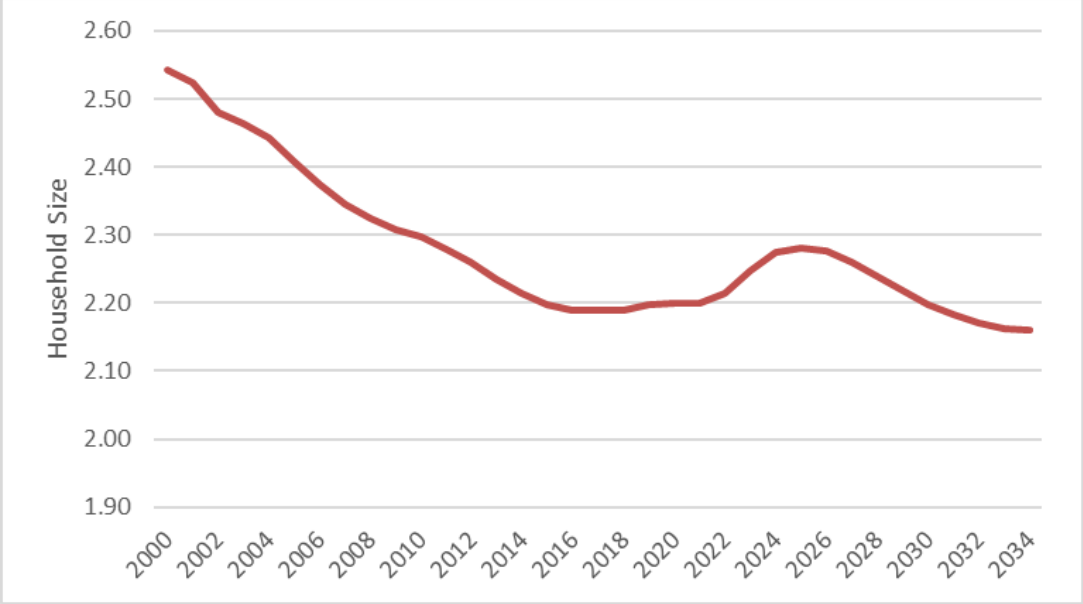
[9] Nova Scotia Power Inc. 2023 Load Forecast Report, UARB Decision, November 7, 2023, page 6 (M11108).

Figure 11: Yearly Change in Customers, Population, and Housing Completions



Regarding household size, population is currently used in combination with customer count to estimate average household size in the SAE model via the Heat Use, Cool Use, and Other Use variables (see **Appendix B**). As this number increases or decreases, the utilization rate of the corresponding usage variable will increase or decrease as well. **Figure 12** shows how the Household Size variable changes over time:

Figure 12: Household Size



Household Size decreased steadily from 2000 to 2016 as population growth stagnated while new housing continued to increase. From 2016 to 2022 the average household size was steady around 2.2, but between 2022 and 2025 household size increases as population increases, with a decline after 2025 as population growth slows.

In the commercial models, non-manufacturing gross domestic product (GDP) and non-manufacturing employment continue to be used. In the industrial sector, rate classes are forecast using an econometric framework, with manufacturing GDP and manufacturing employment used as the economic drivers. The regression timescale for the medium industrial model remains longer than the other class models (17 years vs 10 years for the residential model) to help improve the relevance of the economic variable in the small industrial model (the model produces a high P-value on the economic variable using a 10-year timeframe) and to help improve the fit in the medium industrial model (adjusted R-squared of 0.281 for 10 years vs 0.684 for 17 years**). Figures 13, 14** and **15** summarize the economic drivers, on an annual basis, used in the 2024 Load Forecast. For financial measures, the variables have been adjusted to constant dollars, eliminating the inflation effects from the series.

Figure 13: Residential Economic Drivers

Year	New Construction (number)	% Change	Household Compensation (mil $2002)	% Change
2014	3,262		17,254	
2015	3,184	-2.4	17,488	1.4
2016	3,327	4.5	17,118	-2.1
2017	3,698	11.1	17,517	2.3
2018	4,036	9.2	18,036	3.0
2019	4,183	3.6	18,061	0.1
2020	4,365	4.4	18,077	0.1
2021	4,614	5.7	18,945	4.8
2022	5,167	12.0	19,148	1.1
2023	6,206	20.1	19,637	2.6
2024	7,021	13.1	20,089	2.3
2025	6,614	-5.8	20,562	2.4
2026	6,169	-6.7	20,949	1.9
2027	5,695	-7.7	21,244	1.4
2028	5,084	-10.7	21,522	1.3
2029	4,591	-9.7	21,771	1.2
2030	4,174	-9.1	22,018	1.1
2031	3,809	-8.7	22,267	1.1
2032	3,158	-17.1	22,525	1.2
2033	2,898	-8.2	22,813	1.3
2034	2,660	-8.2	23,124	1.4
14-23		7.4		1.4
24-34		-9.5		1.4

Figure 14: Commercial Economic Drivers

Year	Non-Manufacturing GDP (mil $2012)	% Change	Non-Manufacturing Employment (000)	% Change
2014	32,350		418	
2015	32,571	0.7	416	-0.6
2016	33,027	1.4	414	-0.3
2017	33,723	2.1	417	0.6
2018	34,264	1.6	419	0.6
2019	35,352	3.2	431	2.8
2020	34,134	-3.4	411	-4.8
2021	36,191	6.0	435	6.0
2022	37,231	2.9	450	3.5
2023	37,536	0.8	459	1.9
2024	37,842	0.8	460	0.3
2025	38,734	2.4	468	1.6
2026	39,582	2.2	473	1.1
2027	40,403	2.1	479	1.2
2028	41,220	2.0	484	1.2
2029	41,835	1.5	489	1.0
2030	42,314	1.1	493	0.9
2031	42,851	1.3	498	0.9
2032	43,378	1.2	502	0.9
2033	43,907	1.2	507	1.0
2034	44,418	1.2	513	1.1
14-23		1.7		1.0
24-34		1.6		1.1

Figure 15: Industrial Economic Drivers

Year	Manufacturing GDP (mil $2012)	% Change	Manufacturing Employment (000)	% Change
2014	2,397		30	
2015	2,443	1.9	28	-4.5
2016	2,462	0.8	29	2.2
2017	2,490	1.2	31	5.4
2018	2,577	3.5	33	6.8
2019	2,736	6.1	34	2.9
2020	2,600	-4.9	33	-2.5
2021	2,809	8.0	33	0.8
2022	2,780	-1.0	35	4.9
2023	2,761	-0.7	36	4.1
2024	2,765	0.1	36	-0.1
2025	2,870	3.8	36	0.8
2026	2,970	3.5	36	0.3
2027	3,073	3.5	37	0.3
2028	3,178	3.4	37	0.5
2029	3,285	3.4	37	0.5
2030	3,394	3.3	37	0.7
2031	3,503	3.2	37	0.6
2032	3,609	3.0	38	0.7
2033	3,716	3.0	38	0.8
2034	3,823	2.9	38	0.9
14-23		1.6		2.2
24-34		3.3		0.6

The major Canadian banks provide short term (1-2 year) forecast for some of the key economic indicators, and these are provided in **Figure 16**. The Conference Board of Canada forecast is in line with the forecasts from the banks.

Figure 16: Economic Forecast Comparison

	GDP		Employment		Housing Starts	
	2024	2025	2024	2025	2024	2025
Conference Board of Canada	0.8%	2.5%	0.2%	1.6%	6762	6491
BMO[10]	0.9%	1.6%	0.8%	1.0%	10000	8000
RBC[11]	1.2%	2.3%	1.2%	1.7%	7600	7000
TD[12]	1.0%	1.2%	0.8%	0.3%	6400	5900
National Bank[13]	0.1%	0.9%	0.8%	0.9%	6000	6200

[10] BMO Provincial Economic Outlook, Dec 2023
[11] RBC Provincial Forecast, Dec 2023
[12] TD Provincial Economic Forecast Dec 2023
[13] National Bank of Canada Monthly Economic Monitor, Dec 2023

4.4 End-Use Intensity Trends

In addition to economic data, the SAE model also uses end-use data, in the form of saturations and efficiencies, from NRCan and the US Energy Information Agency (EIA). NRCan data for the residential sector is specific to Nova Scotia, while NRCan data for the commercial sector is for Atlantic Canada. EIA data is for New England and is calibrated to fit existing Nova Scotia data.

The approach to developing the individual end-use intensities is to start with historical NRCan end-use saturation trends combined with data derived from surveys and use year-over-year changes in saturation projections and end-use efficiency estimates for the New England Census Division. The resulting end-use intensity trend is then compared with end-use energy estimates from NRCan. If necessary, it is then adjusted so that the resulting intensities are consistent with NRCan reported end-use consumption and actual average use derived from NS Power billing data.

In the case of end uses where there is little historical activity or where future behaviour is expected to vary significantly from the existing data set due to targeted programs, these are modeled outside the average use intensities. EVs and rooftop solar photovoltaic (PV) continue to be modeled outside the average use intensities as they have little historic data. This method also allows these items to be tracked more directly to help fine-tune future forecasts. The PV forecast has been updated based on actual installations in 2023. Key end uses are discussed individually below.

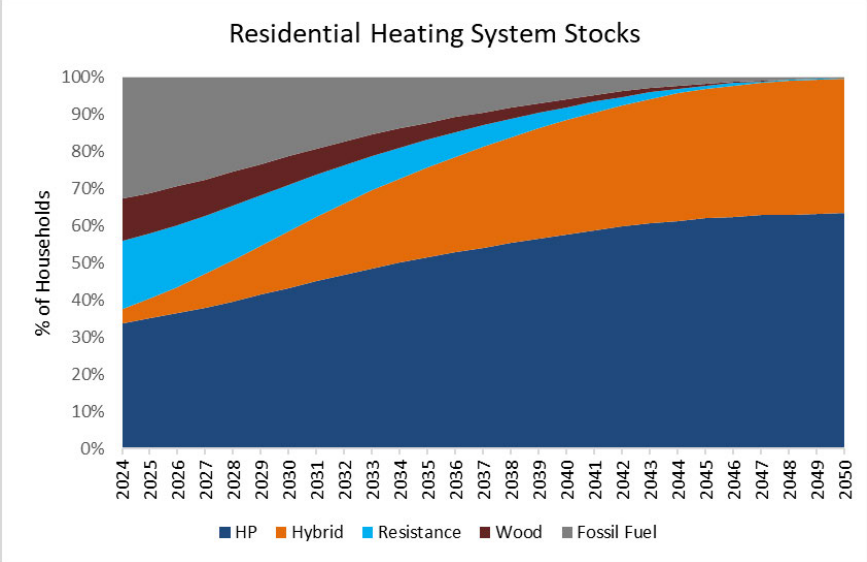
As with the 2023 Load Forecast, the forecasts developed by third party consultant E3 for space heating and EV load shapes are used. The space heating forecast uses the uptake required to meet stated emission goals over the next 20 years, without assuming any specific changes to regulations or incentives, though both are possible in the timeframe of the current 10-year load forecast.

Heat Pumps

Heat pump usage continues to grow in the province as more customers find heat pumps an efficient way to heat and cool buildings as well as providing environmental and financial benefits. The end-use model uses an estimated saturation of 44 percent of customers supplying their heat via heat pumps in 2024. The estimated number of customers who installed heat pumps in 2023 was almost 20,900, in line with the 2023 forecast. This level of uptake is expected to continue in the near term given the continued availability of grants and financing ($300/ton for qualifying mini splits, $500/ton for qualifying ducted systems and up to $30,000 for oil conversions for low and median income households). The result is continued strong uptake that is expected to continue through the forecast period. As part of the updates for 2024, the E3 scenario used in the forecast has been updated to the hybrid scenario, where a portion of customers adopting heat pumps retain their non-electric backup heating systems to provide heating on the coldest days. This assumption is in line with the Nova Scotia Power Electrification Strategy Report released in late 2023, which states "Winter peak impacts on the electricity system from cold-climate heat pumps can be mitigated by encouraging hybrid (mini-split) systems and best-in-class performing heat pumps." [14] As stated in response to E1 IR-02 in the 2024 Annual Capital Expenditure proceeding, "The province's 2030 Clean Power Plan calls for peak management, demand response and efficiency investments to reduce 150 MW of peak and peak growth by 2030. The Hybrid Peak Mitigation electrification scenario, with its modeled peak reduction of 100 MW beyond those achieved via the demand response and efficiency programming incorporated in the Base DSM scenario, is the scenario studied in the Evergreen IRP which most closely matches this objective." [15] The forecast continues to assume 100 percent heat pump saturation in the residential sector in order to achieve carbon reduction targets of net-zero by 2050 as shown in **Figure 17.**

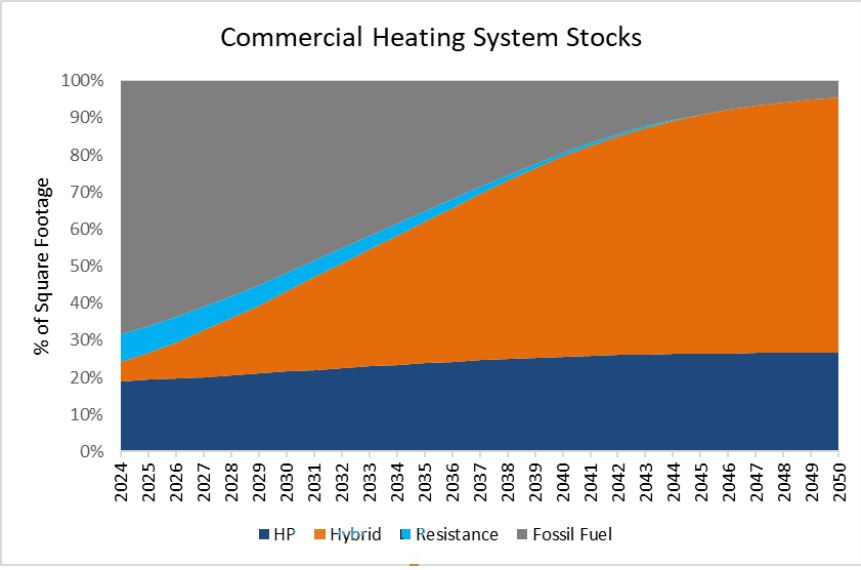
[14] The Economics of Electrification in Nova Scotia, Energy+Environmental Economics, Oct 2023, page 7
[15] 2024 ACE Plan (M11458), EfficiencyOne IR-02 part (b), February 9, 2024, page 3.

Figure 17: E3 Residential Space Heating Saturation



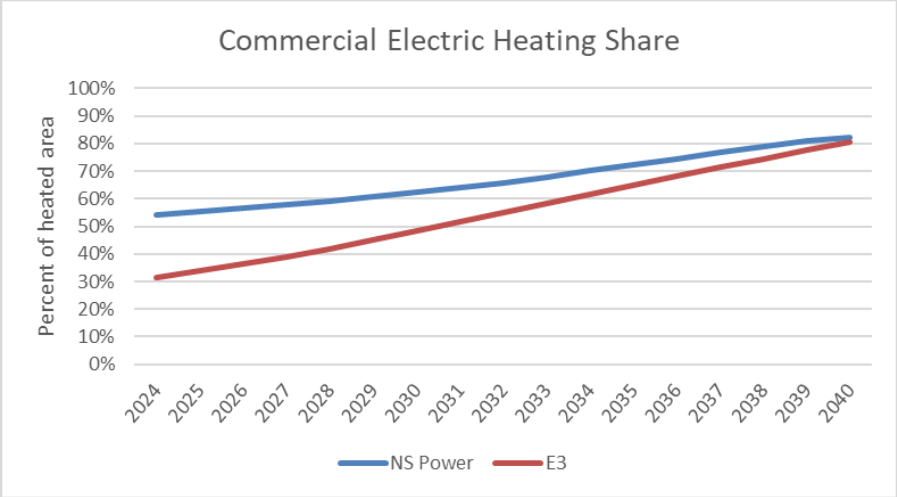
On the commercial side, the E3 electric heating stock model has a similar trajectory to that of the residential model (see **Figure 18**) but has a higher adoption of hybrid systems and does not reach 100 percent by 2050 as there will be a portion of the buildings that may not be able to fully convert.

Figure 18: E3 Commercial Space Heating Saturation



E3 saturation estimates had a lower starting point than the NS Power models, so the NS Power series was adjusted to meet the E3 series by around 2040 as shown in **Figure 19**, resulting in a slightly lower trajectory.

Figure 19: Commercial Space Heating Saturation Comparison



For the 2024 forecast, energy and peak values predicted by the SAE models are higher than the E3 hybrid scenario models where some of the heating requirements are handled by the secondary non-electric heat source. **Figure 20** shows the estimated energy and peak impact from the NS Power models compared to the E3 projections, as well as the corresponding adjustments to the energy and peak forecast values. These adjustments are applied to the model to estimate the impact of the hybrid scenario.

Figure 20: Heat Pump Energy and Peak Comparison

Year	NS Power HP Energy (GWh)	E3 HP Energy (GWh)	Change in Energy Forecast (GWh)	NS Power HP Peak (MW)	E3 HP Peak (MW)	Change in Peak Forecast (MW)
2030	242	74	-154	110	83	-27
2035	481	205	-262	219	176	-43

E3 commercial values adjusted to account for share difference

Figure 21 shows the forecast for residential installations and changes to saturation and intensity over the forecast period.

Figure 21: Heat Pump Forecast

Year	Total Cumulative New Installs	% Install Non-Elec. Heat	% Install Elec. Heat	Overall % Sat. for Heating	Overall Heating Intensity (kWh/house)	Overall % Sat. for Cooling	Overall Cooling Intensity (kWh/house)
2024	21,187	68	32	44	2,066	55	220
2025	42,586	68	32	47	2,271	59	234
2026	63,771	68	32	51	2,454	63	247
2027	84,744	68	32	54	2,636	67	261
2028	104,983	68	32	58	2,814	71	273
2029	124,513	68	32	61	2,973	75	285
2030	143,360	68	32	64	3,128	78	297
2031	161,547	68	32	67	3,277	81	308
2032	178,825	68	32	70	3,422	85	318
2033	195,240	68	32	73	3,554	88	328
2034	210,833	68	32	75	3,680	90	337

The overall heating intensity has increased compared to the 2023 forecast as a result of adjustments made in response to the "unallocated" variance in the residential class results (discussed in **Section 9**). The heat pump heating component intensities were adjusted to account for the fact that the large unallocated variance occurred mainly in the winter months and was determined to be primarily weather dependent. The increase in heating intensity is likely due to increased hours of heating resulting from increased work-from-home activity but may also be driven by higher overall equipment intensity (higher temperature setpoints, more heating load served by the heat pumps). Compared to the 2023 intensities, overall heating intensities have increased by approximately 39 percent, as shown in **Figure 22**.

Figure 22: Heating Intensity Comparison

Year	2024 Heating Intensity (kWh/house)	2023 Heating Intensity (kWh/house)	Change (Percentage)
2024	2,066	1,511	+37
2025	2,271	1,639	+39
2026	2,454	1,770	+39
2027	2,636	1,899	+39
2028	2,814	2,026	+39
2029	2,973	2,140	+39
2030	3,128	2,250	+39
2031	3,277	2,357	+39
2032	3,422	2,459	+39
2033	3,554	2,552	+39
2034	3,680	2,631	+40

Water Heaters

NS Power anticipates that some customers who convert their oil heating systems to heat pumps will also convert their hot water supply to electric hot water tanks because of the annual operating savings. Growth is expected to remain steady, with saturation increasing to 88 percent by 2034. As part of a joint demand response working group, NS Power and E1 are continuing with a program that involves controlling water heaters directly to achieve benefits to the system (see **Section 10)**. **Figure 23** shows the expected changes in saturation and overall intensity over the forecast period. The efficiency improvements of heat pump hot water heaters are still not incorporated into the forecast as uptake is still small (114 in 2021 and 163 in 2022 according the 2022 DSM Programs Evaluation Report filed by EfficiencyOne[16]) despite an available rebate of $400.

[16] 2022 DSM Programs Evaluation Reports, Residential Efficient Product Rebates Program, EfficiencyOne, Table 20, page 30.

Figure 23: Water Heater Forecast

Year	Overall % Saturation	Overall Intensity (kWh/household)
2024	73	1,633
2025	76	1,675
2026	78	1,711
2027	80	1,745
2028	82	1,777
2029	83	1,807
2030	84	1,822
2031	85	1,837
2032	86	1,852
2033	87	1,867
2034	88	1,881

Electric Vehicles (EVs)

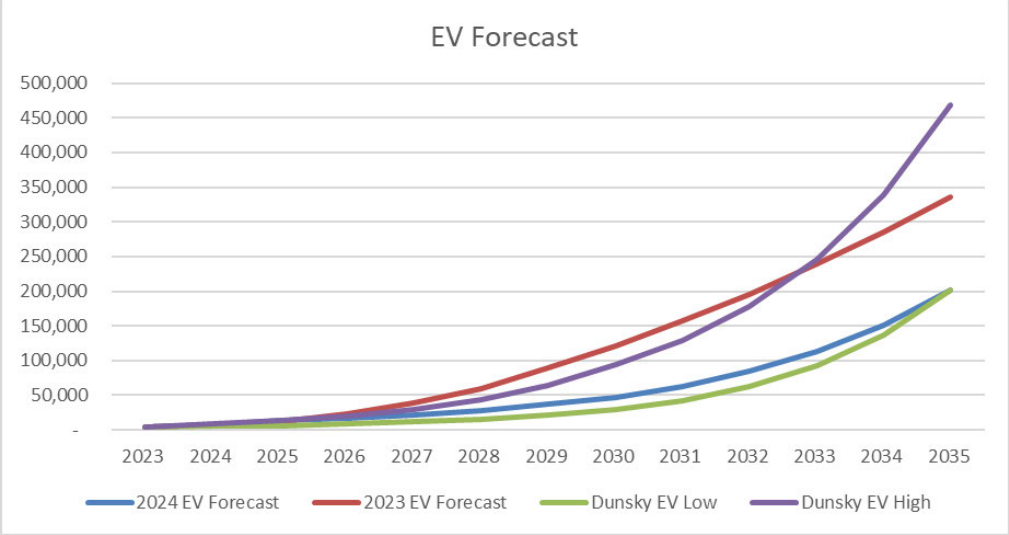
The existing federal incentives remain unchanged for 2024 at $5000 for light duty battery electric vehicles (BEVs) and long range plug-in hybrid electric vehicles (PHEVs), $2500 for short range PHEVs, and up to $200,000 for medium and heavy-duty vehicles. The provincial government continues to provide incentives of $3000 for new BEVs and long range PHEVs, $2000 for used BEVs and new short range PHEVs, and $1000 for used short range PHEVs. It is estimated that there were approximately 4100 BEV + PHEVs (together considered as EVs) in the province as of the end of 2023. The EV forecast has been updated for 2024 based on the report entitled "Ensuring ZEV Adoption in Nova Scotia"[17], with a provincial vehicle sales forecast that aligns with the federal sales targets of 20 percent by 2026, 60 percent by 2030 and 100 percent by 2035[18], but takes into account the fact that the sales targets are at the national level and sales in Nova Scotia will likely lag larger

[17] https://ecologyaction.ca/sites/default/files/2023-05/RegionalZEVAdoptionOptions_Dunsky_March2023.pdf, prepared by Dunksy Energy+Climate Advisors for the Ecology Action Center
[18] https://tc.canada.ca/en/road-transportation/innovative-technologies/zero-emission-vehicles/canada-s-zero-emission-vehicle-zev-sales-targets

markets like Ontario, Quebec and British Columbia. According to the report, "Taking together the current state of ZEV adoption in Nova Scotia and the trends observed in the U.S. under rules with little or no regional requirements, it is reasonable to expect that adoption in Nova Scotia will continue to lag behind the national targets for several years, with this gap narrowing as the federal annual sales targets increase to 100% in 2035."[19] In the report two adoption forecasts are provided, a low scenario where sales in Nova Scotia lag the federal mandates, and a high scenario where sales are distributed evenly across the provinces. The 2024 forecast aligns with the low scenario but is adjusted for recent trends. The low scenario has 6300 EVs on the road by 2025, which would imply sales of around 1100/year from the 2023 starting point of 4100 EVs. Estimated numbers for EVs in Nova Scotia indicate that sales have been roughly doubling for the last several years (500 in 2021, 1000 in 2022, 2200 in 2023), and if the trend were to continue the estimate for 2025 would be closer to 17,000. To account for the higher growth in recent years, the high scenario is used for 2025, 50 percent of the high scenario was used for 2030, and the forecast aligns with the low scenario for 2035. A comparison of the 2024, 2023, Dunsky Low and Dunsky High scenarios is shown the **Figure 24**.

[19] https://ecologyaction.ca/sites/default/files/2023-05/RegionalZEVAdoptionOptions_Dunsky_March2023.pdf, prepared by Dunksy Energy+Climate Advisors for the Ecology Action Center, page 16.

Figure 24: EV Forecast



The forecast includes both light-duty vehicles (LDV) as well as medium-duty vehicles (MDV) such as delivery trucks and other medium-duty fleet vehicles, and heavy-duty vehicles (HDV) focusing on buses. The revised EV forecast estimates that Nova Scotia will have over 150,000 EVs on the road by 2034, mostly made up of LDVs compared to a forecast of 285,000 vehicles by 2034 in the 2023 Load Forecast.

The impact of EVs on energy sales and peak demand depends on several factors including the types of vehicles adopted (plug-in hybrid vs battery electric), charging capacity (anywhere from 3 kW_{ac} to 20 kW_{ac} depending on vehicle limits and home charger type, and much higher for commercial DC Fast Chargers), driving patterns, temperature and access to charging. E3 provided estimates of total load and normalized per-vehicle electric vehicle load shapes over the course of the year based on E3's EV Load Shaping Tool. E3's tool simulates driving and charging electric vehicles in Nova Scotia, based on a bottom-up modelling approach that simulates driving and charging of thousands of EV drivers, and produces a load shape that captures the diversity of driving behavior, EV types, and charging access across the Nova Scotia driving population. **Figure 25** shows the EV load and peak demand contribution estimated from the load shapes provided by E3.

Figure 25: EV Mileage Assumptions and Load/Peak Modeling Results

Vehicle Type	Avg km/year [20]	Avg kWh/year	Avg kW/vehicle on Peak
LDV	17,427	3,485	0.9
MDV	22,779	8,205	1.6
HDV	62,888	113,890	7.3

The peak impact assumes that 70 percent of charging is managed (including direct control through EV smart charging vehicle-grid-integration controlled by a distributed energy resource management system, and influenced by rates) and 30 percent of charging is unmanaged. The load and peak demand contributions account for a mix of vehicle types and charging infrastructure based on the projected split of EV adoption by vehicle type and charger installation and utilization by EVs. The overall average peak contribution in E3's "blended" managed and unmanaged charging scenario is 0.9 kW/vehicle, compared to an overall peak contribution of 1.6 kW/vehicle in the unmanaged scenario. The management of charging in this scenario was based on minimizing the cost of electricity to charge using residential electric rates like the existing time of use tariffs currently in the pilot stage, coupled with vehicle-grid-integration (EV smart charging) coordinated using technology like a distributed energy resource management system (DERMS) as tested in the Smart Grid Nova Scotia pilot to smooth large spikes in charging that would occur during switches from peak to off-peak rate periods.

Figure 26 provides the estimated energy and peak impacts that correspond to the number of EVs in the forecast, along with a sensitivity showing potential peak impact without managed charging measures; this sensitivity assumes an average peak demand of 1.6 kW/vehicle based on the E3 unmanaged model.

[20] Based on the *NRCan 2009 Canadian Vehicle Survey Summary Report,* https://oee.nrcan.gc.ca/publications/statistics/cvs/2009/appendix-1.cfm?graph=11

Figure 26: EV Impact to Energy and Peak Forecasts (cumulative)

Year	New EVs	Load (GWh)	Peak @ 0.9kW/vehicle (MW)	Peak @ 1.6kW/vehicle (MW)
2024	3,387	12	3	6
2025	9,491	34	9	16
2026	13,466	51	12	22
2027	18,587	75	17	31
2028	25,167	107	24	42
2029	33,586	144	32	56
2030	44,365	189	42	74
2031	60,545	249	57	101
2032	82,105	326	76	136
2033	110,852	426	102	183
2034	149,197	560	136	245

Nova Scotia-specific information on the peak and energy impact of EVs was explored through the Smart Grid Nova Scotia (SGNS) Project. A final report was submitted to the UARB in March 2024.[21] Through the project, 100 EV smart chargers were deployed under a ChargePoint pilot program where data collection and control of Electric Vehicle Supply Equipment (EVSE) provided capability for the utility to influence charging times by sending curtailment events. The project also established an EV telemetry pilot with *ev.energy* in which up to 160 drivers enrolled their vehicles and again capability for the utility to influence charging times by sending curtailment events as well as enabled the *ev.energy* smart-charging algorithm to shape charging patterns, influenced by a user-controllable "ready-by" time. Results of these pilots are detailed in the SGNS Final Report.

Appendix C of the Smart Grid Nova Scotia Final Report includes a discussion of electric vehicle charging characteristics in Nova Scotia as observed by the Smart Grid Nova Scotia project.

[21] Smart Grid Nova Scotia (SGNS) Project Final Report (M11621), March 15, 2024.

The maximum contribution to the 17:00 – 19:00 evening peak demand from participants in the SGNS project was calculated in both the ChargePoint program and the ev.energy program. In the winter months (December through February), the ChargePoint customers had an average evening peak contribution of 0.24 kW/vehicle, while the ev.energy customers had an average evening peak contribution of 0.65 kW/vehicle. Both average peaks are unmanaged.

During the ChargePoint pilot the non-coincident peak occurred on April 6, 2023 for the 15-minute interval ending at 18:30 as vehicles were charging at 15 of 46 available chargers at a total aggregate power of 107.2 kW. This represented an unmanaged evening peak impact of 2.33 kW per enrolled vehicle.

During the ev.energy pilot the non-coincident peak occurred on June 4, 2023 for the 30-minute interval ending at 19:00 as 34 of 160 enrolled vehicles were charging at a total aggregate power of 306.8 kW. This represented an unmanaged evening peak impact of 1.92 kW per enrolled vehicle.

Section 4.1.1.4 of SGNS Final Report details the Demand Response observed per Enrolled EV under the ChargePoint and ev.energy pilots. The response varied between the two technology providers, but in the first hour the response at system peak time on average was 0.35 kW.

Solar Generation (PV)

Solar generation consists of two main types – distributed small-scale solar (mainly rooftop) that falls under NS Power's net metering program, and small- to large-scale generation that is fed directly onto the grid via power purchase agreements or direct utility ownership.[22] In the Load Forecast, only the former is considered, as it serves as a reduction in load mainly in the Residential class. The 2023 Load Forecast was for 2,268 new installations, while the actual number was 2,233, for a cumulative total of 8,221 (72 MW) by the end of the year.[23] As of 2023, the average installed capacity is approximately 8.3 kW for residential customers and 28 kW for non-residential, and total annual net metering solar generation is estimated at 78.8 GWh. The average capacity factor is estimated to be 12.5 percent.

The number of solar installations is expected to increase in the coming years as a result of continued initiatives such as Property Assessed Clean Energy Programs (e.g. Solar City in Halifax), and the continuation of the provincial SolarHomes rebate of $0.30/W of installed capacity and updated legislation that allows for larger commercial installations. The forecast has been updated to reflect these recent trends, with total installed capacity of almost 674 MW by 2034. This assumes that rebates continue to be available in the coming years. The overall impact is shown in **Figure 27**. There is no forecast reduction in NS Power peak demand, as solar generation occurs at times non-coincident with NS Power's system peak (refer to **Section 10** for further discussion on peak impacts).

[22] The Smart Grid Nova Scotia solar garden in Amherst falls under direct utility ownership.
[23] NS Power, 2023 Net Metering Report, January 31, 2024.

Figure 27: PV Impact to Energy (cumulative)

Year	Total New Installs	Load (GWh)	Peak (MW)
2024	3,019	-33	0
2025	6,361	-70	0
2026	10,062	-111	0
2027	14,163	-158	0
2028	18,708	-209	0
2029	23,746	-267	0
2030	29,334	-331	0
2031	35,480	-410	0
2032	42,241	-490	0
2033	49,678	-577	0
2034	56,738	-660	0

New Technologies

The 2024 Load Forecast does not assume a significant amount of distributed solar/battery storage combinations or storage only deployments. The cost of home batteries is still relatively expensive, in the range of $15,000-$20,000[24] for a single battery and installation (for 5-7 kW batteries). This is more expensive than the cost of a gas-powered generator, which varies from as little as $1,000 for a moderately sized stand-alone generator to supply plug loads (also around 5-7 kW), up to $10,000 or more for an installed whole-home generator. Currently, the only major driver for residential batteries is for back-up power, so gas generators are a more cost-effective solution. The Time Variable Pricing (TVP) rates currently being piloted might start to encourage battery installation either alone or in conjunction with solar panels, but the initial costs associated with batteries are still high. As battery technology improves and costs come down over time, this is likely to change,

[24] https://www.zdnet.com/home-and-office/energy/best-home-battery/ estimate of $12000-$20000 USD installed.

but research in these areas is ongoing and timelines for significant shifts in this technology are unknown.

The use of home battery storage was explored through the SGNS Project and coordinated through a utility DERMS as a virtual power plant for load shifting, demand response, and other grid-aware use cases. Performance data on both stand-alone battery backup and PV/battery combinations is included and presented in Section 4.2 of the Appendix A – Impact Analysis Report of the Project Final Report.[25] Key results included demonstration of load following demand response modes in evening peak periods of 1 – 1.5kW over four-hour events, shifting load to periods of lower marginal cost and emissions, and delivering avoided capacity, and avoided transmission & distribution benefits. Of note, when uncontrolled/uncoordinated, home batteries may recharge at full power following an outage event, exacerbating local cold load pickup events or system peaks following a larger event. This is discussed in Section 3.4 of the Appendix A – Impact Analysis Report of the Project Final Report.

In addition to vehicle-grid-integration (VGI) EV smart charging as discussed above, the Project demonstrated the use of EV batteries in vehicle-to-grid (V2G) technology to return power to commercial buildings to lower peak demand, including both the coordination of demand response but also localized, automated demand charge management. These results are presented as 'Proof of Concept' and discussed in detail in Section 4.1.2 of the Appendix A - Impact Analysis Report of the Project Final Report. Key outcomes demonstrated the promise of the technology to shift load from periods of higher marginal cost and emissions to lower marginal cost and emissions and offer peak demand response, similar to stationary battery technology, but with the added dimension of vehicle availability (a measure of whether the vehicle is plugged in and able to charge/discharge).

[25] Smart Grid Nova Scotia (SGNS) Project Final Report (M11621), March 15, 2024.

The technology required for V2G is still in development and is not widely available, but a few manufacturers have included the capability in existing vehicles (the Nissan Leaf is one example) or have announced that they will provide V2G capability in the near future. For true V2G capabilities, which would not only allow a vehicle to power a home or building, but also allow energy to be fed onto the grid, there is still development required on the technology as well as the codes and standards to allow that functionality.

Data from the project demonstrates that when coordinated (as with a utility DERMS), energy demand from DERs like EVs and recharging stationary batteries can be smoothed or coordinated to avoid coinciding with system peak or localized system anomalies and constraints while avoiding creating new peak periods or contributing to snapback (as with time varying rates). Energy limited devices like batteries and vehicle-to-grid can also discharge to support the system, further capitalizing on the coordinated opportunity of distributed energy resources. For example, **Figure 28** below shows a range of peak mitigation based on residential customer battery uptake scenarios (by 2034) that assume optimal utility level control. These are illustrative estimates based on the 5 kW batteries utilized in the SGNS project, should those batteries be able to discharge their full capacity to the grid (in practice the available demand reduction would be lower than shown).

Figure 28: Potential Peak Impacts from Batteries

Technology	Residential Share (%)			
	50%	**25%**	**10%**	**5%**
Battery Peak Impact - No Control (MW)	0	0	0	0
Battery Peak Impact - Optimal DR Control (MW)	(1,367)	(683)	(273)	(137)

The impacts of technologies related to direct load control (DLC) of heating and hot water loads are discussed in **Section 10**.

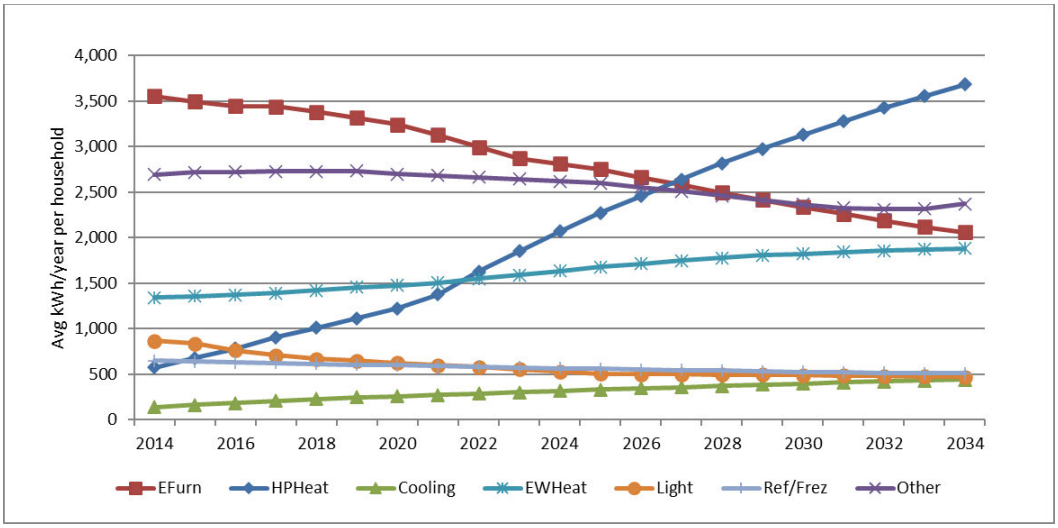
Intensities

Figure 29 provides an estimate of the resulting residential end-use intensities. This figure represents the intensities that are inputs to the XHeat, XCool and XOther variables; they are not direct inputs to the forecast. The relative contribution of each will change based on the coefficient applied to the XHeat, XCool and XOther variables.

PV and EV are modeled outside the regression but are estimated in the "Other" category below in order to illustrate their impact relative to other end uses. A summary of the impact of the different variables post-regression is included in **Section 5**, while a complete breakdown of each element before and after the regression is provided in **Appendix B**. The end uses listed include:

- EFurn: electric baseboard and electric forced air furnaces and secondary electric heaters
- HPHeat: heat pump electric heat
- Cooling: room and central air conditioners, as well as heat pump cooling
- EWHeat: electric water heaters
- Lights: indoor lighting
- Ref/Frez: primary and secondary refrigerators and deep freezes
- Other: all other major appliances (stoves, dishwashers, clothes washers and dryers, televisions) as well as smaller appliances such as computers, dehumidifiers, microwaves, etc. This category also includes solar generation (photovoltaic or PV) and EV forecasts.

Figure 29: Residential End-Use Intensities



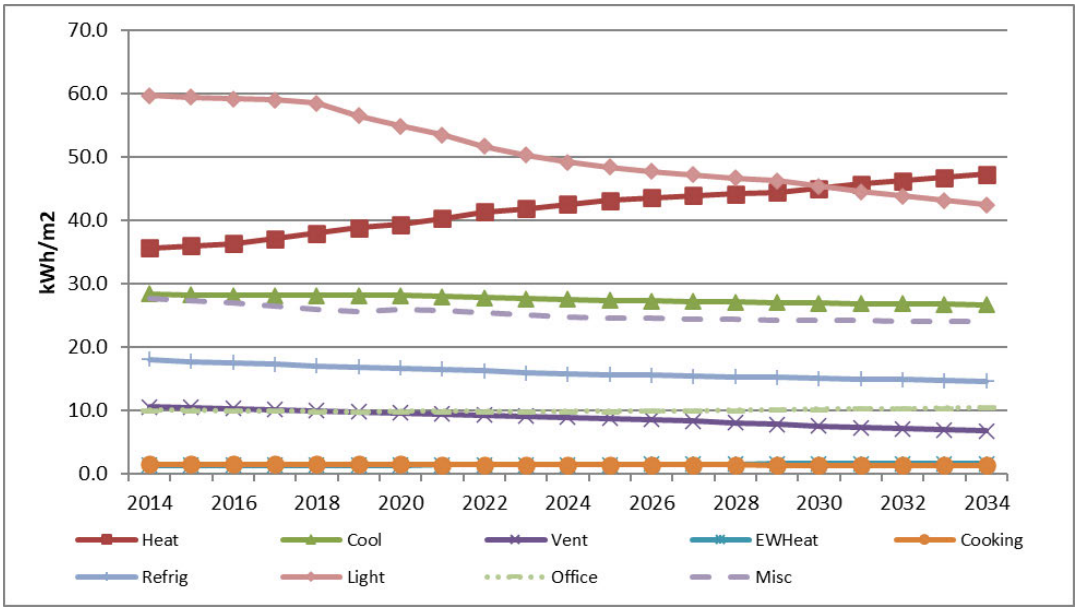
The intensity trends are similar to those in prior forecasts. The use of heat pumps for space heating is forecast to increase steadily throughout the forecast period including the conversion of both electric baseboard and non-electric homes. Offsetting this increase is a corresponding decrease in electric baseboard heating. Heat pumps also drive an increase in cooling intensity, but not during periods of peak demand. Electric water heating is expected to increase slowly as saturation increases, mainly due to conversions of non-electrically heated households to heat pumps. Lighting and refrigerators/freezers show a slow decline related to natural increases in efficiency. The forecast in the "Other" category is much lower by 2034, due mainly to reduced assumptions around EV sales and increased PV generation. Supporting data for the residential end-use intensities is included in **Attachment 1**.

The end-use intensities for the commercial models are done on a per square metre basis, rather than per customer. The forecasts for the end-use intensities are set out in **Figures 30** and **31** below. The end uses listed include:

- Heat: electric heating
- Cool: air conditioning
- Vent: ventilation

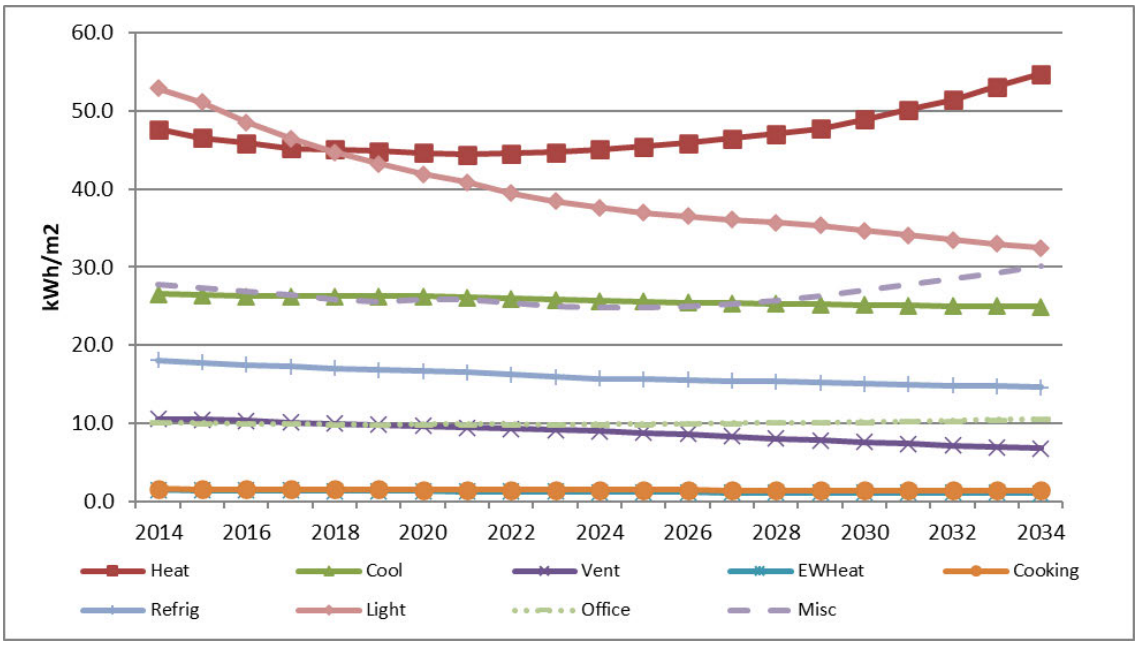
- EWHeat: electric water heaters
- Cooking: electric stoves
- Refrig: refrigerators and freezers
- Light: indoor and outdoor lighting
- Office: computers and printers
- Misc: other loads including motors, servers, escalators, medical equipment, etc.

Figure 30: Historical and Projected Small General Commercial End-Use Intensity (kWh/m^2)



Supporting data for Small General commercial end-use intensities is included in **Attachment 2**.

Figure 31: Historical and Projected General Commercial End-Use Intensity (kWh/m²)



Supporting data for General commercial end-use intensities is included in **Attachment 3.**

For the 2024 Load Forecast, data from the EIA 2021 Annual Energy Outlook uses the same baseline data (2015 Residential Energy Consumption Survey and 2012 Commercial Building Energy Consumption Survey) as the 2023 Load Forecast. Small scale solar and EV load has been included in the Miscellaneous category.

Commercial and Industrial Growth

The commercial and industrial sectors are projected to see targeted growth as a result of the federal and provincial push to net-zero emissions and the resulting electrification programs designed to reduce customers' annual energy usage and lower their carbon emissions. These programs involve converting heating loads to electricity (mainly from oil), accelerating the uptake of electric cooling technologies, and examining opportunities to power industrial processes through electrification. Large Industrial customers are

evaluated on a case-by-case basis to try to enable the use of electricity while providing benefits to the system (such as through the interruptible rider). Forecasts by class (including new projects in the Large General and Large Industrial classes) are shown in **Figure 32**.

Figure 32: Commercial and Industrial Electrification Forecasts (cumulative)

Year	LrgGen (GWh)	SmInd (GWh)	MedInd (GWh)	LrgInd (GWh)	Coinc. Peak (MW)
2024	2	0	1	3	0
2025	5	1	4	4	1
2026	8	1	5	4	2
2027	11	1	7	5	2
2028	13	1	8	6	3
2029	15	2	10	7	4
2030	16	3	11	8	4
2031	18	3	13	9	5
2032	19	4	14	9	5
2033	20	4	16	10	6
2034	20	4	16	10	6

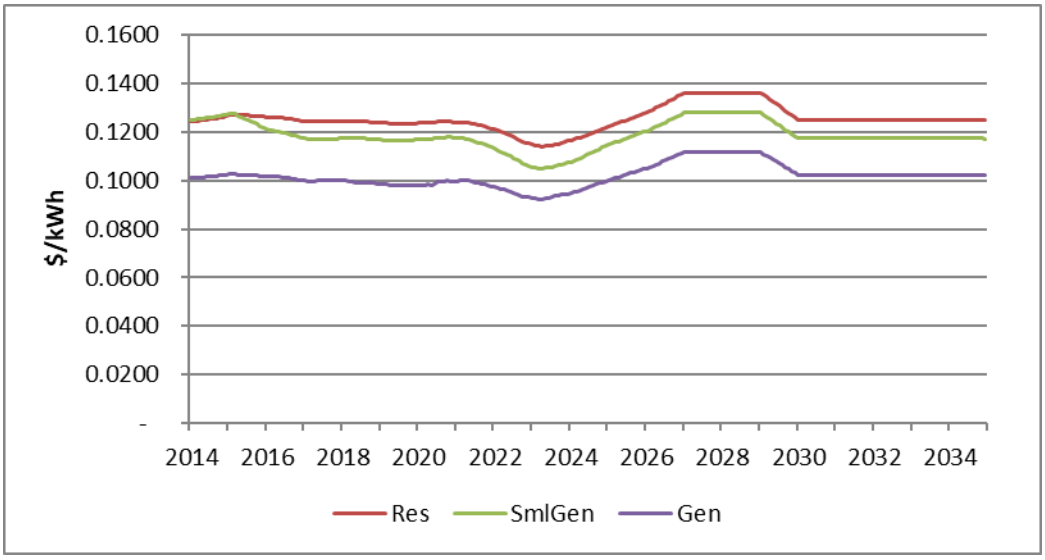
4.5 Price Data

Price data is an input to the SAE forecasts for the residential, small general and general services classes, and the price series is calculated from historical billed sales and billed revenues. Revenue per kWh is first calculated and translated to a real dollar basis; the price variable itself is then derived as a 12-month moving average of the real revenue per kWh series. The 12-month moving average uncouples the current month sales/revenue relationship, smooths out the price series, and provides a reasonable expectation as to how customers respond to price over time.

In the forecast period, the nominal price of electricity for 2024 is based on an average increase of 7.7 percent in the 2024 FAM AA/BA Application, which includes the Base Cost of Fuel Increase approved as part of the 2023-2024 GRA and the BA Rider approved in April of 2024.[26] 2025 is forecast to increase to account for projected increased fuel costs while 2026 is forecast to increase to account for recovery of outstanding fuel costs over a period of 3 years, while the remaining years are forecast to increase at an average of 2 percent per year (with the exception of 2029 where the prior increase for outstanding fuel costs is removed), or around the rate of inflation, which results in a flat profile in real terms. **Figure 33** shows price forecasts by class.

[26] 2024 FAM AA/BA Application M11393 - January 29, 2024, page 10.

Figure 33: Historical and projected real electricity prices (real dollars per kWh)



Prices impact the class sales through imposed price elasticities. The SAE models are estimated using a price elasticity of -0.15. Another item raised in the NSUARB decision[27] is to "Evaluate the elasticity used in the SAE model with the elasticity estimation from the TVP Pilot EM&V in matter M11267 and assess if the results provide a more robust model." The TVP Pilot estimates two elasticities:[28]

- Own/daily price elasticity captures the change in the level of overall consumption due to the changes in the average daily price.
- Substitution price elasticity captures customers' ability to substitute inexpensive off-peak consumption for more expensive peak consumption.

These elasticity estimations are based on subsets of customers (those enrolled in the TVP pilot) and represent changes in demand relative to hourly or daily pricing changes, and so are not necessarily directly comparable to the longer term time frame of the load forecast or to the population as a whole. The elasticity in the load forecast model represents changes

[27] Nova Scotia Power Inc. 2023 Load Forecast Report, UARB Decision, November 7, 2023, page 6 (M11108).
[28] M09777 Time Varying Pricing Pilot Program Nova Scotia Power Year Two Report, July 28 2023

in consumption behaviour in response to year-over-year price changes. The estimated elasticities for the two TVP rates are shown in **Figure 34**.

Figure 34: TVP Price Elasticity Estimates

Price Elasticity Metric	TOU	CPP
Daily Price Elasticity	-0.458 ±0.152	-0.084 ±0.091
Inter-Period Substitution Price Elasticity	-0.186 ±0.006	-0.161 ±0.007

Although the Daily Price Elasticity for the TOU rate is significantly higher than that used in the load forecast, the Inter Period Substitution values are similar. A scenario using the daily price elasticity value of -0.458 in the Residential model is included in **Appendix D** (**Figure D8**), and even if the elasticity is tripled the resulting impact to sales in 2034 is only -1%, and the differences in the model statistics are negligeable. In the SAE model the price elasticity does impact sales, but it is not a large driver compared to other components of the model such as the intensities or inputs like DSM and EVs. The current value of elasticity is reasonable to capture the impact on sales from changes in price.

4.6 Demand Side Management

Demand Side Management (DSM) and conservation plans continue to play a role in the use of electricity in Nova Scotia, and the forecast takes the projected energy and demand savings into account. Between 2022 and 2025, DSM amounts are based on E1's proposed supply agreement.[29] Beyond 2025, DSM amounts are based on E1's 2019 Potential Study[30] base case scenario. These values are all in line with past assumptions about future DSM.

In order to highlight the impact of DSM in the province, the forecast amounts are subtracted from the results of the forecast regression models. As with other jurisdictions and utilities with significant DSM activity, NS Power must address the issue of double counting the impact of DSM savings. The forecast is a regression model based on sales which include past DSM activity, and past DSM also has an influence on other inputs to the load forecast such as price, end-use appliance efficiency and economic variables. Subtracting 100 percent of forecast DSM activities results in a model that understates sales because it has taken DSM into account in both the regression (via the historic data) and in the projected end-use data. The effect of DSM on non-sales related inputs also makes it unrealistic to add historic DSM into past sales to produce a "without DSM" forecast – the impact of DSM would have to also be removed from price, overall appliance efficiency and provincial economics.

To address the issue of double counting, the approach used is the same as that used in prior forecasts: to introduce cumulative historical DSM savings as reported by E1 to the regression model as a load modifying variable and allow the model to determine what level of DSM is already included in other variables. Assuming future DSM activities are similar to historic activities, the coefficient applied to historic DSM will also apply to the forecast DSM. This does not imply that a portion of DSM activities is not taking place or that

[29] M10473, EfficiencyOne 2023-2025 DSM Resource Plan Filing, March 11, 2022.
[30] M08929, Exhibit N-1, EfficiencyOne, DSM Potential Study, August 14, 2019.

forecast DSM is overstated; rather, it is a way of accounting for DSM that is captured elsewhere in the forecast. The methodology is not specific to DSM and could be applied to other variables that need to be highlighted in the forecast provided they have similar characteristics (historical trend, potentially included in other inputs, and some information about future impact).

In the Residential model, adding the historic DSM improves the fit of the Residential model (R squared of 0.989 vs 0.988 without the DSM variable, and a mean absolute percent error (MAPE) of 2.18 percent vs 2.30 percent without the variable). By including this variable, the corresponding coefficient, as determined by the regression model, is an indication of the amount of DSM not captured by the other variables. If the coefficient is -1, no DSM is included in other variables, or in practical terms the regression model determined 100 percent of the DSM savings were required to explain the annual change in historical load levels. If the coefficient is 0, 100 percent of the DSM is included in other variables. As can be seen in the Residential model results, the coefficient on the DSM variable is -0.556 (similar to prior values) meaning 44.4 percent of savings are already accounted for in the regression, and 55.6 percent are not captured by other variables, and need to be included in the forecast.

For the Commercial and Industrial classes, a combined model was created to identify the level of DSM already captured by other variables. DSM impacts are not provided for Commercial and Industrial customers by rate class or by month, so by creating a combined model for these classes, the level of uncertainty around allocating historical DSM savings across rate classes and months of the year is reduced. The DSM variable coefficient is similar to prior years: -0.448, meaning future years in the load forecast should be adjusted by 45 percent of the forecast DSM amounts. The adjusted R-squared for the model is 0.821 while the MAPE is 2.75, indicating a good fit overall. **Figure 35** shows the DSM levels (at the generator) incorporated into the forecast.

Figure 35: Annual Forecast Residential DSM Savings (incremental)

Year	Forecast Residential DSM savings (GWh)	Forecast Commercial DSM savings (GWh)	Forecast Industrial DSM savings (GWh)	DSM captured by Residential end use forecast (GWh)	DSM captured by Comm/Ind end use forecast (GWh)	DSM Adjustment for Residential with Coefficient (GWh)	DSM Adjustment for Comm/Ind with Coefficient (GWh)
2024	60.9	69.4	12.3	27.0	45.1	33.9	36.6
2025	65.6	71.3	12.6	29.1	46.3	36.5	37.6
2026	69.6	56.7	10.0	30.9	36.8	38.7	29.9
2027	71.6	55.7	9.8	31.8	36.2	39.8	29.4
2028	73.0	62.9	11.1	32.4	40.8	40.6	33.2
2029	73.7	52.2	9.2	32.7	33.9	41.0	27.5
2030	73.3	51.0	9.0	32.5	33.1	40.8	26.9
2031	74.1	48.0	8.5	32.9	31.2	41.2	25.3
2032	73.2	46.8	8.3	32.5	30.4	40.7	24.7
2033	71.3	43.4	7.7	31.7	28.2	39.6	22.9
2034	69.1	44.0	7.8	30.7	28.6	38.4	23.2

The methodology used to determine the DSM coefficient only works for levels of DSM that have been relatively consistent throughout the historical data set and does not imply that only a portion of future DSM will impact sales. If forecasts for DSM change significantly then this methodology will have to be revisited. One potential approach might be to treat net new incremental levels of DSM (those above the historical norm) as not being embedded in the forecast variables and subtracted at 100 percent for a period of time, but this will have to be evaluated with any proposed change to DSM levels.

A breakdown of the impact of DSM by class is provided in **Section 9**.

4.7 Renewable to Retail

One application has been submitted by a third party to the NSUARB for approval as a Licensed Retail Supplier (LRS) to provide service under the RTR tariffs starting in 2025.[31] The service is forecast to produce 340 GWh of energy through wind production when fully operational in 2026, and will serve approximately 250 GWh of load with 31 percent serving residential customers, 45 percent serving commercial customers, and 24 percent serving industrial customers. The corresponding energy amounts have been subtracted from the forecast starting in 2025 as outlined in **Figure 36**. Although load will be migrating from the various customer classes to the RTR market, part of the energy required to supply those customers will be provided by NS Power as top-up under the Energy Balancing Service tariff (approximately 140 GWh). The peak forecast remains unchanged as NS Power is required to serve the full peak of these customers if needed.

Figure 36: RTR Forecast by Class

Class	2025 Impact (GWh)	2026+ Impact (GWh)
Residential	18	75
Small General	1	7
General Demand	23	97
Large General	2	8
Small Industrial	1	4
Medium Industrial	10	39
Large Industrial	5	16
Total	**61**	**246**

[31] The effective date for sales from a retail supplier to a retail customer to commence under s.3C(1) of the Electricity Act has not been set. As such, the licence issued by the NSUARB included a condition that no sales can occur before the effective date prescribed by the Governor in Council. In addition, it is a condition of the license issued by the NSUARB that if no electricity is sold to a customer under the authority of the license by December 31, 2024, the Licensed Retail Supplier must apply to the NSUARB to show cause why the licence should not be cancelled at that time (M10293).

5.0 RESIDENTIAL SECTOR

The Residential sales forecast is generated as the product of a residential average use forecast and a customer count forecast. The residential average use model is specified using a SAE model structure and the customer count forecast is based on forecast housing completions. Full details on the residential SAE model can be found in **Appendix B** and in **Attachment 5**. As outlined in **Section 4.4**, projections for EVs and residential solar are added to the modeled load projection. New customers are also added outside of the model.

On a weather normalized basis, residential sales grew by 1.6 percent between 2022 and 2023 due to continued work-from-home activity, increased number of new customers, and an increased number of heat pumps. **Figure 37** shows a breakdown of the different components for 2021, 2022 and 2023 actuals vs forecast and weather normalized totals, and the 2024 forecast.

Figure 37: Comparison of Forecast to Actuals

Year	2021	2022	2023	2024
Forecast Sales	4718	4715	4830	5175
Weather variance	-141	-127	-126	-
Other variance	+42	+263	+230	-
Actual Sales	4619	4851	4934	-
Weather-adjusted sales	4760	4978	5060	5175

As discussed in **Section 4.4**, the "Other variance" amounts for 2022 and 2023 were found to be related to large variances in the winter months and are assumed to be mostly heating related, though they may also include portions that are not weather dependent. As a test of the updates to the residential class, for the last three filings of the Load Forecast Report (LFR), the most recent year (12 months) of their respective actual load was held for testing, and the 10 prior years were used to run the residential SAE model. Then a statistical comparison of the model fit for the 12 most recent months (which also include actual weather) can be made to each LFR (each of which has its own assumptions about

electrification). The 2024 updates to heating intensity (see **Figure 22**) reduce the variance significantly as shown in **Figure 38**:

Figure 38: Comparison of Forecast to Actuals – One Year Ahead.

Load Forecast Report	Year forecasted	MAD[32]	MAPE[33]	Predicted Avg Sales (kWh/cust)	Customer Count	Sales Forecast (GWh)	Actual Sales (GWh)	Variance (GWh)	% Variance
2022	2021	20.4	2.6%	9,531	482,771	4,601	4,661	59.5	1.3%
2023	2022	48.9	6.4%	9,641	488,654	4,711	4,822	110.6	2.3%
2024	2023	15.4	1.8%	10,064	495,055	4,982	4,986	3.8	0.1%

The adjusted heating intensities are expected to result in a smaller unexplained variance in future years.

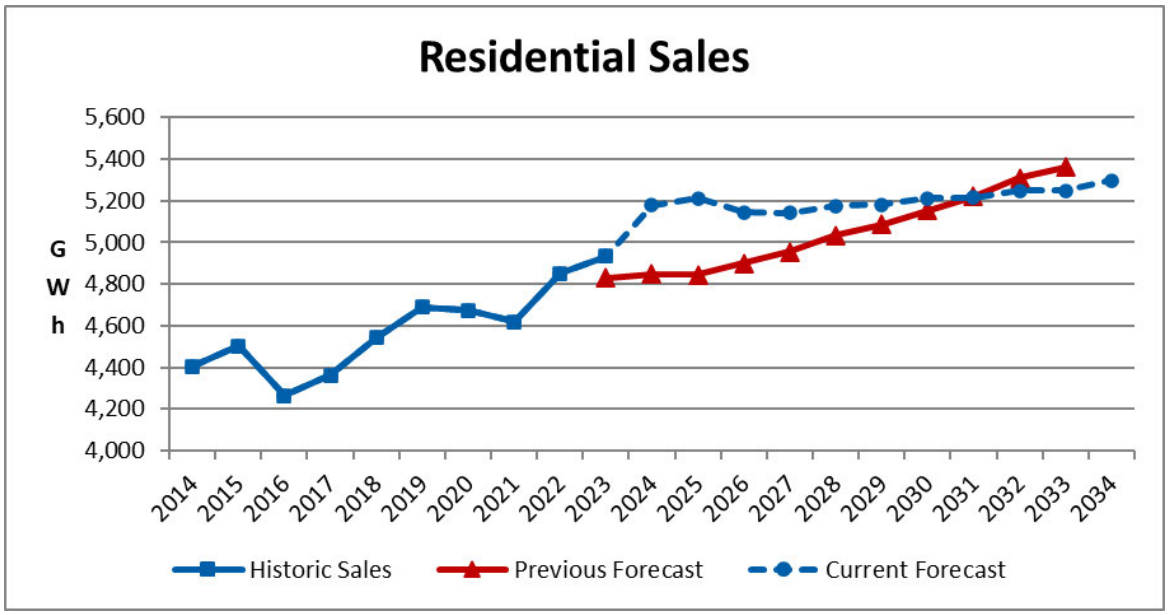
The COVID-19 variable that was added in 2020 continues to be used. The variable is reduced after July 2022 to reflect the end of specific restrictions. The impact of the variable to the Residential forecast is approximately +100 GWh in 2024 and beyond, and assumes that the increase in recent years which is attributed to more people working from home on a regular basis will continue. As the historic sales data begins to encompass more of the post-COVID years it is expected that this variable will continue to decrease in magnitude in future forecasts.

2023 was higher than forecast despite being a warm year, and 2024 sales are expected to be in line with the 2023 weather normalized results. A decline in 2026 is the result of load migrating to the RTR market, while the long-term change from increasing to flat sales is driven by the lower EV forecast as well as the increased behind the meter solar forecast. As with previous forecasts, new customers and increased electric heating will increase sales, while DSM and naturally occurring efficiency improvements will decrease sales over

[32] Mean absolute deviation.
[33] Mean absolute percentage error.

time. Over the 2024-2034 period, forecast sales in this class increase 0.2 percent annually. Historical and forecast annual residential sector loads are shown in **Figure 39**.

Figure 39: Historical and Forecast Annual Residential Sales



The forecast for new construction in 2023 was for 6,177 units, while actual customer growth was 6,401. Nova Scotia's population continues to increase (see **Figure 11**) through immigration from abroad and from other provinces. The Conference Board of Canada predicts continued population growth, with almost 87,000 more people in the province by 2034. New housing is expected to be almost 52,000 new units by 2034, with 35,700 new multi-unit residences and 16,200 single family homes. Single-family homes are assumed to use approximately 16,000 kWh per year on average, while multi-unit homes use 4,860 kWh per year on average. In addition to using these averages, a structural index was applied that considers building shell efficiency (BSE from the EIA forecast) as well as projected changes in house size. Building efficiency is expected to improve, although based on calibration done in 2013, improvements are expected to be lower in Nova Scotia than in the EIA forecast for New England. While efficiency is expected to increase, house size

is also expected to continue increasing, albeit at a slower rate than in previous years. These two factors combined lead to a steady average use per new residential customer. Building shell efficiency, floor area and the resulting structural index are in **Figure 40.** Future surveys will help to identify trends in this area.

Figure 40: Building Characteristics and Structural Index

Year	BSE Heat EIA (New England)	BSE Heat NS	Floor Area (m^2)	Structural Index
2024	0.925	0.968	152.9	1.000
2025	0.920	0.967	153.2	1.001
2026	0.914	0.965	153.4	1.001
2027	0.908	0.964	153.7	1.001
2028	0.901	0.962	153.9	1.000
2029	0.895	0.959	154.0	0.999
2030	0.888	0.957	154.2	0.997
2031	0.881	0.954	154.3	0.995
2032	0.874	0.951	154.4	0.992
2033	0.868	0.949	154.5	0.991
2034	0.862	0.948	154.6	0.990

Figure 41 provides a breakdown of the components of the Residential forecast at the system level. Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2024 to 2034.

Figure 41: Residential Sales Components by Year

Year	Regression Model Output (GWh)	New Cust. (GWh)	Hybrid Adjust. (GWh)	Solar Impact (GWh)	EV Impact (GWh)	RTR Sales (GWh)	DSM Adjust. (GWh)	Total Sales (GWh)	Total Res. DSM [34](GWh)	DSM captured by end uses [35](GWH)
2024	5181	62	0	-44	10	0	-30	5180	-55	-24
2025	5220	120	0	-71	23	-18	-63	5211	-114	-51
2026	5240	173	-26	-99	31	-75	-98	5146	-177	-79
2027	5271	220	-53	-131	41	-75	-133	5140	-241	-108
2028	5349	262	-79	-165	54	-75	-170	5176	-307	-137
2029	5403	300	-106	-204	71	-75	-207	5183	-373	-166
2030	5483	333	-132	-246	93	-75	-243	5213	-439	-196
2031	5522	363	-144	-298	126	-75	-280	5215	-506	-226
2032	5585	386	-155	-350	172	-75	-317	5248	-572	-255
2033	5605	408	-166	-407	235	-75	-352	5249	-636	-284
2034	5647	428	-177	-461	322	-75	-387	5298	-698	-311

Figure 42 provides an approximation of the heat pump heating, heat pump cooling, electric baseboard, and water heater loads at the system level (these are included in the Regression Model Output column). This approximation uses the same methodology as outlined in the response to NSUARB IR-12 (e) from the 2020 Load Forecast, where the end-use intensity is multiplied by the number of existing customers, the appropriate X coefficient from the regression model, and either the HeatUse variable or the CoolUse variable (see **Appendix B** for details of these components). As this assumes that the X variables apply equally to all end uses, which may not be the case, the numbers are illustrative only. These numbers also do not include any DSM amounts that would impact the specific end use.

[34] Total DSM is the amount from Figure 20, adjusted for losses and with approximately 0.4 percent allocated to the Municipal class customers.
[35] These amounts are embedded in the Regression Model Output column through the end use efficiency estimates, i.e. the amount not captured by the DSM coefficient.

Figure 42: Illustrative Contribution of Specific End Uses

Year	HP Heat (GWh)	HP Cool (GWh)	Baseboard Heat (GWh)	Water Heat (GWh)
2024	980	136	1025	816
2025	1067	146	979	831
2026	1142	155	922	843
2027	1214	165	864	855
2028	1297	176	821	873
2029	1363	187	773	888
2030	1442	198	735	904
2031	1506	207	691	912
2032	1577	217	653	923
2033	1626	226	611	929
2034	1680	235	577	937

6.0 COMMERICAL SECTOR

The Commercial SAE model creates a unique forecast for the Small General and General rate classes. Like the residential model, the commercial SAE models express monthly sales as a function of heating, cooling, and other loads. The Small General forecast is based on a monthly SAE average use model and a separate customer forecast. The General rate class model is estimated on a total monthly sales basis (class level sales vs customer level) where total monthly billed sales is a function of total monthly heating requirements, cooling requirements, and other use. The end-use variables are constructed by interacting annual end-use intensity projections that capture end-use intensity trends, with GDP and employment, real price, monthly HDD and CDD and a variable accounting for the number of days in each month. As discussed in the introduction, employment by sector has been added to the commercial intensity models to calibrate the underlying NRCan data for the Atlantic provinces to Nova Scotia specifically.

A detailed breakdown of the two commercial SAE models is provided in **Appendix B** and in **Attachments 6** and **7**. Although sales were negatively impacted by the COVID-19 pandemic in 2020 and 2021, commercial sales rebounded in 2022 along with the economy, and grew in 2023 (though less than forecast). **Figure 43** shows the drop in 2020 and 2021 followed by the rebound in 2022.

For 2024, the impact of RTR has increased (-112 GWh compared to -64 GWh in the 2023 forecast), and the EV load has decreased (+244 GWh by 2034 compared to +403 GWH in the 2023 forecast), resulting in lower growth than the previous forecast.

Figure 43: Commercial Class Sales

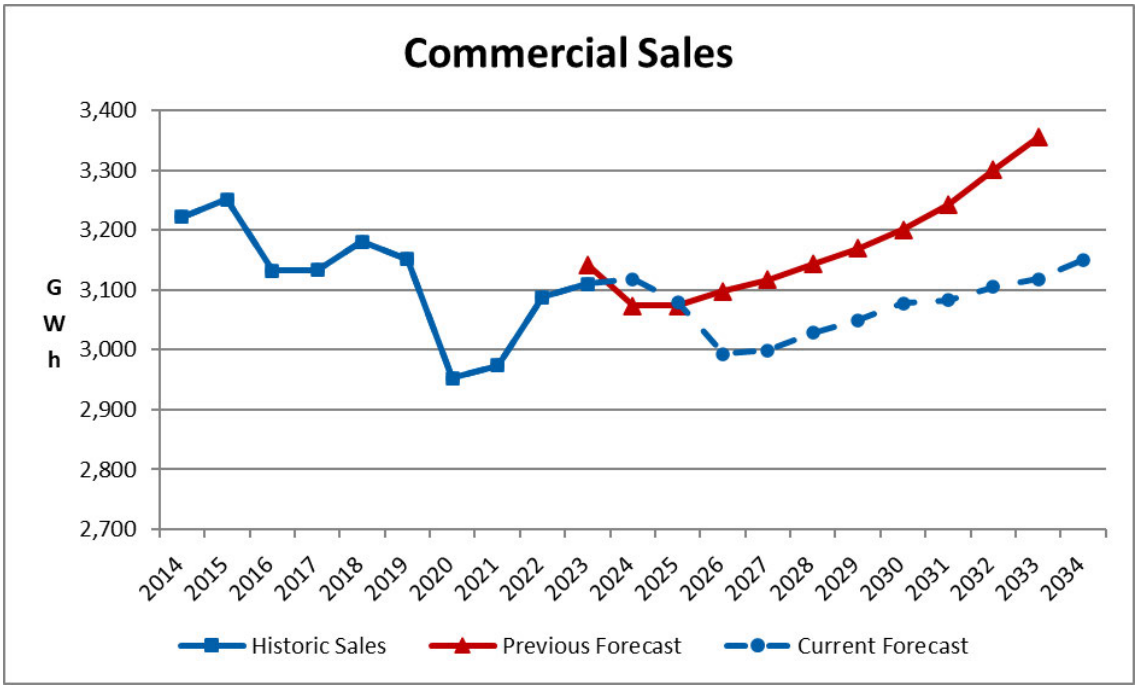
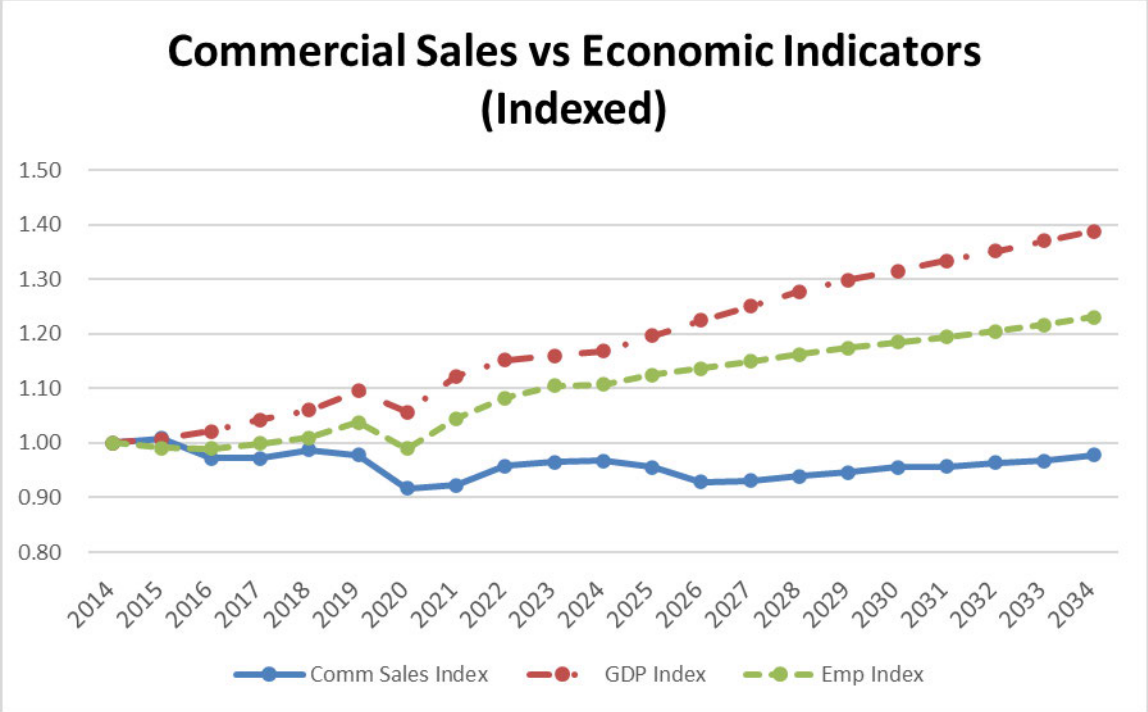


Figure 44 shows a comparison of commercial energy sales to both GDP and employment indicators for Nova Scotia. The sharp drop in 2020 is of a relatively similar magnitude in all three measures. Sales continue to lag the rebound in the economic variables, likely related to reduced opening hours at many retail establishments. A specific COVID variable was added to the General rate class model in 2023 to help account for the likely continued lag in sales in the forecast years (around -57 GWh/year).

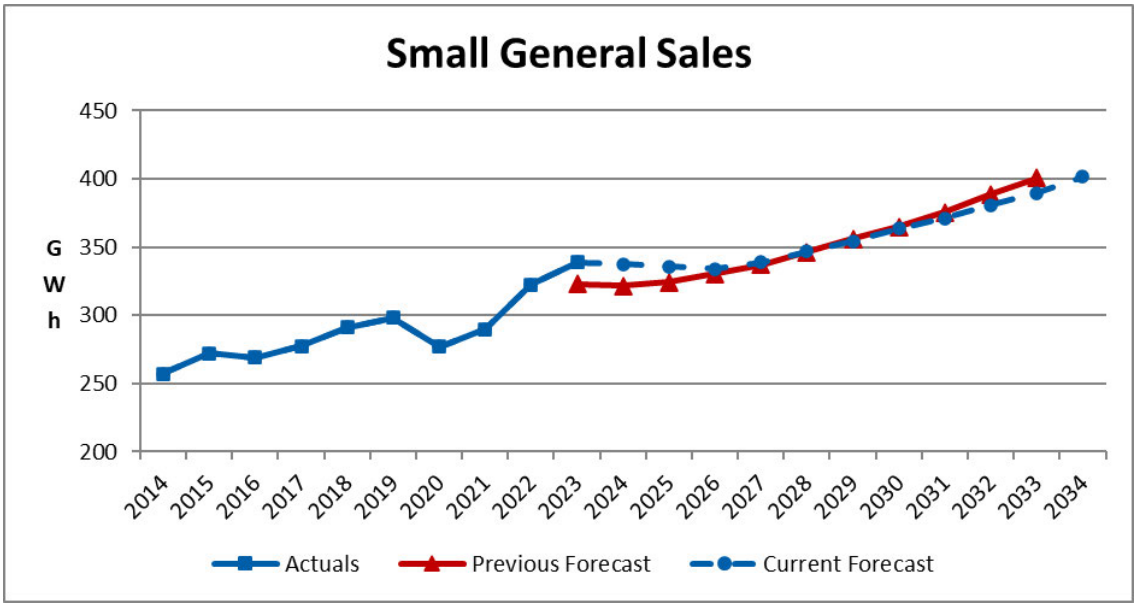
Figure 44 Commercial Sales vs Economic Indicators



6.1 Small General Service

Historical and forecast Small General service loads are shown in **Figure 45**. Small General service load shows an average annual increase of 1.8 percent compared to an increase of 2.2 percent per year in the 2023 Load Forecast. Commercial electrification of heating will be offset by a combination of DSM and decreased intensity forecasts for the ventilation, lighting and miscellaneous end uses. As with the 2023 Load Forecast, the heating penetration from the residential class was used as the end-use intensities are similar.

Figure 45: Historical and Forecast Annual Small General Sales

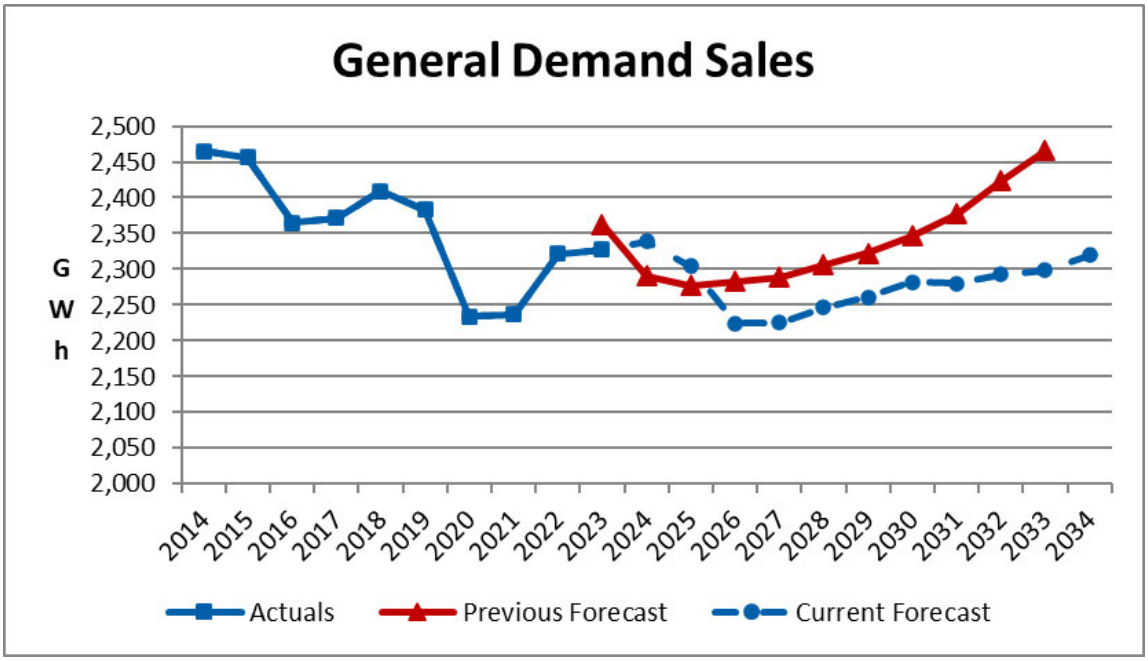


Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2024 to 2034. Total change between 2024 and 2034 is an increase of 19 percent.

6.2 General Service

Historical and forecast General class sales are shown in **Figure 46**. General class load is expected to decrease by 0.1 percent per year during the 10-year forecast period, compared to an increase of 0.4 percent in the 2023 Load Forecast. The primary changes to the forecast include lower EV load as well as the commercial energy impact of the hybrid heating scenario. Increased space heating will continue to be offset by DSM programs as well as increased efficiency of the lighting and miscellaneous end uses. A drop in sales in 2026 is related to sales shifting to the RTR market (-97 GWh per year), and higher solar generation will reduce sales by a further 198 GWh by 2034.

Figure 46: Historical and Forecast Annual General Demand Sales



Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2024 to 2034. Total change between 2024 and 2034 is a decrease of 0.8 percent.

6.3 Large General Service

The Large General class shows slower growth than the 2023 forecast due to revised estimates of large project completion. The class is forecast using a combination of customer survey and historical sales information. Customers are surveyed annually to determine their electricity requirements over the next three-year period. In addition, NS Power personnel are in regular contact with key customers within this class. Details on planned production levels or equipment changes help inform energy requirement expectations. In the absence of survey or publicly available information, load levels are forecast to be flat before the impact of any DSM activities. As requested in the 2024 Board Decision, **Figure 47** compares the previous two forecasts for large customer growth in the Large General class

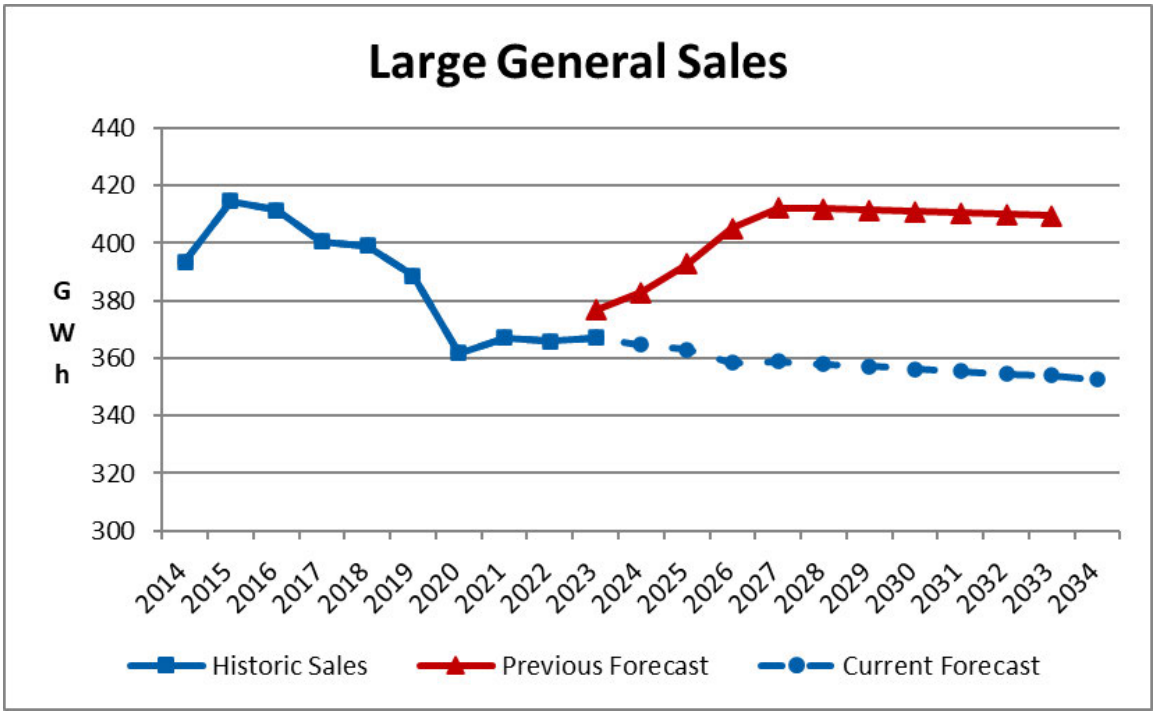
with actual year over year changes, and the resulting 2024 forecast which has been adjusted to account for the over estimation in prior years.

Figure 47: Large General Annual Growth (GWh)

Year	2022	2023	2024	2025	2026	2027	2028
2022 Forecast	12	29	22	19	0	0	0
2023 Forecast		7	10	16	11	6	2
Actual year over year	-1	1					
2024 Forecast			2	3	3	3	2

For the 2024 survey, nine customers indicated no change to consumption, eight indicated an increase and two did not respond. Growth in this class is expected to be driven by institutional facilities, in particular expansions at several hospital sites in the province, though at a slower pace than in the 2023 forecast. The overall forecast has a decrease of approximately 12 GWh by 2034 as shown in **Figure 48**. The decline is due to DSM outweighing projected growth.

Figure 48: Historical and Forecast Annual Large General Sales



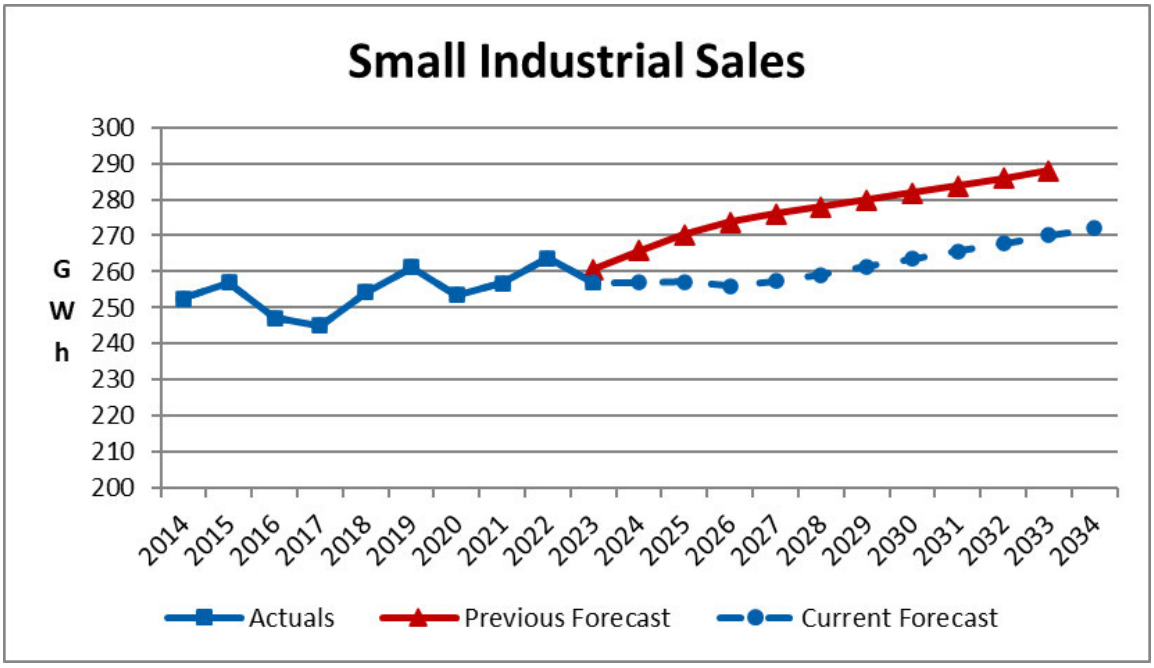
7.0 INDUSTRIAL AND MUNICIPAL SECTORS

The forecast models for the Small Industrial and Medium Industrial classes are econometric-based models (i.e. dependent on economic variables). Provincial manufacturing GDP is used as the primary economic variable in the Small Industrial forecast and manufacturing employment is used for the Medium Industrial class. The Small and Medium Industrial class models are developed using monthly sales information, as opposed to annual sales, in order to align the timeframes of industrial models with those of the residential and commercial forecast models. This is required in order to implement an end-use-based peak forecast for the commercial and residential sectors. Supporting data is included in **Attachments 8** and **9.**

7.1 Small Industrial

Figure 49 depicts historical and projected sales for the Small Industrial class. Sales in this class have been flat for the last 10 years and are expected to grow at 0.6 percent annually over the forecast period due to underlying economic growth offset by a migration of load to RTR (4 GWh).

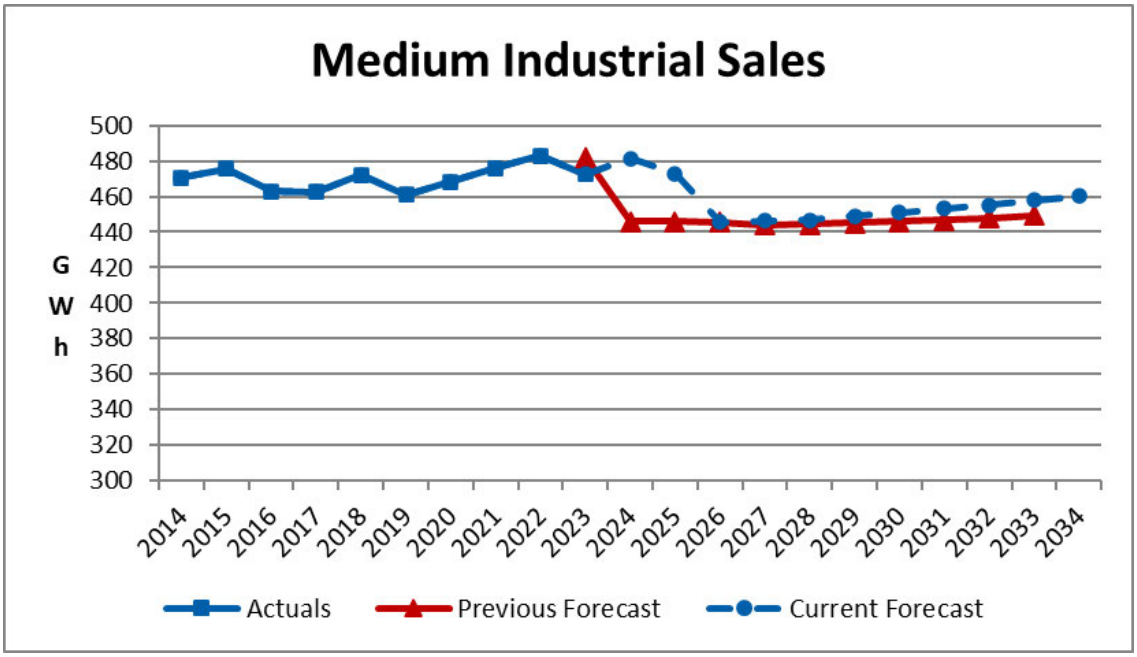
Figure 49: Historical and Forecast Annual Small Industrial Sales



7.2 Medium Industrial

Figure 50 depicts historical and projected sales for the Medium Industrial class. Load in this class has been flat since 2014. There was an increase in sales between 2019 and 2022 due to several new facilities ramping up production and minimal impact from the COVID-19 pandemic restrictions. Sales are expected to decline in 2026 as load migrates to the RTR market (39 GWh), resulting in an average decline of 0.4 percent over the forecast period.

Figure 50: Historical and Forecast Annual Medium Industrial Sales



7.3 Other Industrial Rate Classes

Other Industrial rate classes include Large Industrial, Large Industrial Interruptible, Generation Replacement and Load Following, One-Part Real Time Pricing, Shore Power, and the Extra Large Industrial Active Demand Control tariff.

Like the Large General rate class, load for these rate classes is forecast using a combination of customer survey and historical sales information. Customers are surveyed regularly to gather their electricity requirements over the next three-year period. Details on planned production levels or equipment changes help inform expectations on energy sales. In the absence of any survey or general public information, load levels are forecast as being flat. For the 2024 survey, twenty-one said energy consumption would remain the same, eight indicated consumption would increase, and one customer did not respond. One customer makes up over [redacted] of sales within this class and is forecast to increase load by [redacted] in 2024 compared to 2023 actuals, or a decrease of [redacted] compared to the 2023

forecast. Another Large Industrial customer has temporarily reduced load to the point that they have migrated to the Medium Industrial class, but are expected to ramp up operations in 2026, offsetting load migration to the RTR market (16 GWh).

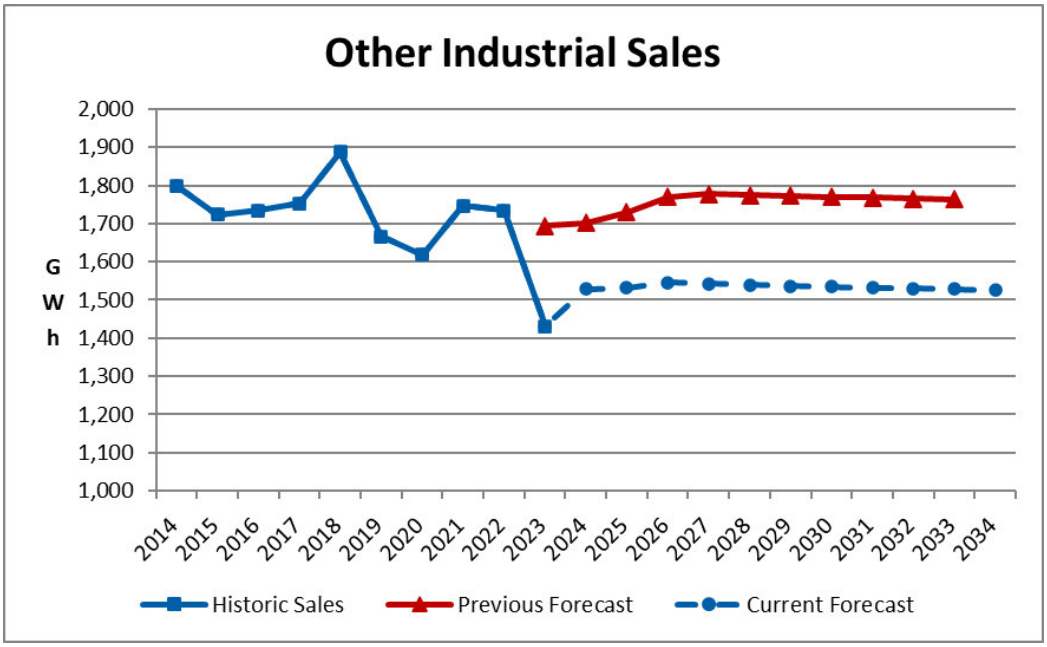
Although discussions with customers have indicated that several new facilities or expansions are expected in various industries in the coming years, there is uncertainty in the timing and magnitude of these changes. As with the customer growth in the Large General class, **Figure 51** compares the assumptions from previous forecasts to actual year over year changes. Based on the discrepancy between past estimates and actuals, the forecast for 2024 has been adjusted to account for over estimation in previous years.

Figure 51: Large Industrial Annual Growth (GWh)

Year	2022	2023	2024	2025	2026	2027	2028
2022 Forecast	11	13	36	30	1	1	1
2023 Forecast	0	3	10	49	29	10	1
Actual year over year	-6	-24					
2024 Forecast			3	1	0	1	1

Figure 52 shows the historic and forecast sales for the Other Industrial sector.

Figure 52: Historical and Forecast Annual Other Industrial Sales



7.4 Municipal

The Municipal class comprises municipal electric utilities that purchase wholesale electricity from NS Power and distribute it within their own service territories. Utility loads within these municipalities include customers in residential, commercial and industrial sectors. Energy in this class also includes the losses incurred by the municipal utilities in meeting their electricity requirements.

Since 2007, the municipal electric utilities have been able to source their electricity from providers other than NS Power through the Open Access Transmission Tariff (OATT). Four municipal electric utility customers were sourcing approximately half of their energy requirement from suppliers other than NS Power, and in 2020 increased their energy purchases to 100 percent from third parties, resulting in a reduction in municipal load of about 150 GWh from historic levels. These customers have their load served by a combination of in-province generation and either the bundled municipal rate (2023 and 2024) or imported third-party generation in combination with energy under the Wholesale Market Backup/Top-Up (BUTU) Tariff in cases where their third-party supply is unavailable or interrupted. They have applied for third-party supply in 2025 and this is assumed to be their supply arrangement after 2025.

Because NS Power is required to provide back-up capacity, including reserve margin, to the municipal electric utilities taking third-party supply in the near term and must continue to plan for serving these customers in the long term, the full amount of the municipal electric utilities' peak demand is included in the Load Forecast.

8.0 SYSTEM LOSSES AND UNBILLED SALES

The difference between energy generated for use within provincial borders and the total NS Power billed sales comprises transmission and distribution system losses as well as changes to the level of unbilled sales. Energy generated and sold but not yet billed is referred to as "Unbilled" sales. System losses averaged 6.5 percent of NSR over the past five years and are forecast to remain in the 6.0 to 7.0 percent range over the 10-year forecast period.

9.0 NET SYSTEM REQUIREMENT

The NSR is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses, within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. **Figure 53** provides a breakdown of the significant variances between forecast and actuals for 2023.

Figure 53: 2023 Variance to Actual

	Res	Comm	Ind	Other	Losses	NSR
2023 Forecast	4,830	3,142	2,436	138	742	11,288
Est. Weather Impact	-126	-25		-3	-11	-164
Large Customer New Projects			-3			-3
Large Customer Actuals			-260			-260
Unexplained Variance	230	-8	-12	19	40	270
2023 Actual	4,934	3,110	2,161	154	772	11,131

Note that the largest variances are due to weather, the unexplained variance in the residential class (discussed in **Section 5**), and the variance in large customer actuals ([redacted] of which is related to a single customer). Like 2022, 2023 was a very warm year overall, with 3,530 HDD compared to the 10-year average of 3,743. The estimated weather impact, while sizeable, it is still within the P10/P90 typical uncertainty shown in Appendix D over the years (e.g., the 2024 estimate is +/- 234 GWh). The weather impact captures both the variance in heating load in the winter months and the variance in cooling load during the summer.

From 2024 to 2034, NSR is forecast to increase at an average of 0.2 percent per year, driven mainly by new customers, space heating and EV adoption, with solar, DSM and RTR migration offsetting sales. Annual NSR is shown below in **Figure 54**. Forecast NSR values and the contribution to NSR from the different sectors can be found in **Appendix A**.

Figure 54: Historical and Forecast Annual NSR

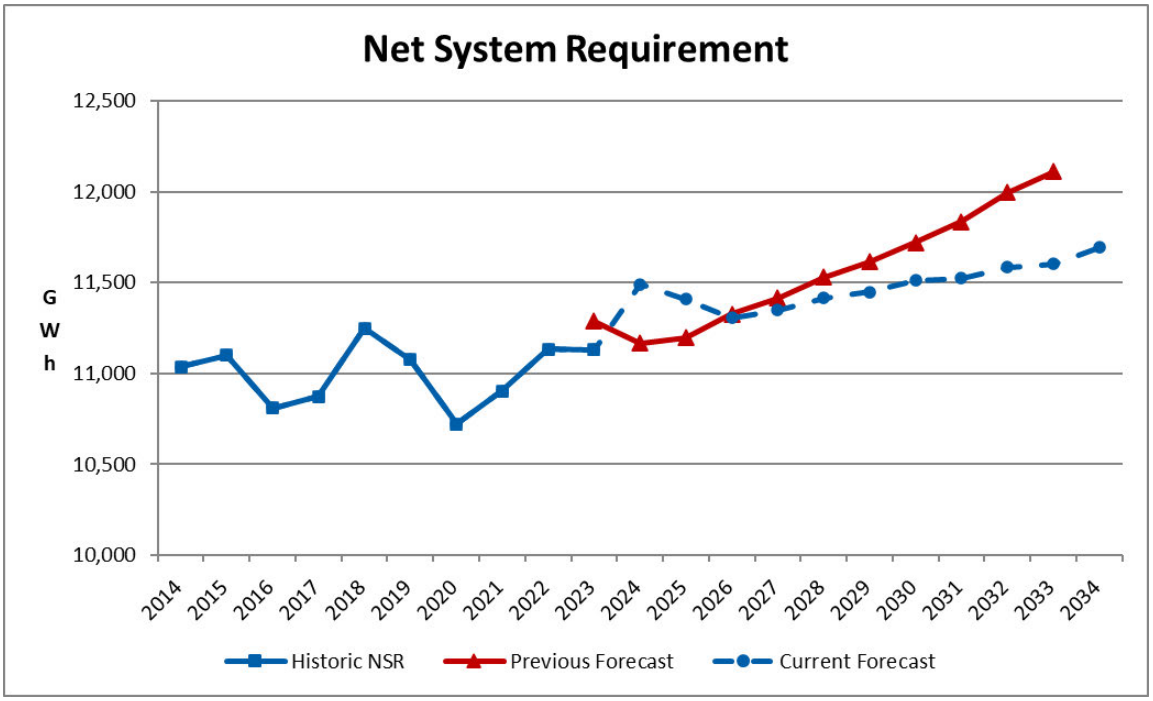


Figure 55 provides a breakdown of the various components of the change in the forecast from 2024 to 2034. Data for all classes is included in **Attachment 4.**

Figure 55: Forecast Components

GWh	Res	Comm	Ind	Other	Losses	NSR
2024 Forecast	**5,180**	**3,118**	**2,267**	**159**	**767**	**11,490**
Model	466	352	41	-82	69	986
New Customers	366	32				398
Solar	-416	-210				-627
EV	312	236				548
C&I Electrification		9	25			34
Large Customer Projects		9	42			50
Hybrid Model Adjustment	-177	-63				-240
RTR	-75	-112	-59	139		-246
DSM	-356	-221	-57	-3	-61	-699
2034 Forecast	**5,298**	**3,151**	**2,258**	**213**	**775**	**11,695**
Total DSM forecast	-695	-558	-98	-7	-124	-1,483
DSM captured in underlying models	-339	-337	-41	-4	-63	-784

10.0 PEAK DEMAND

The total system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads. Due to the weather-sensitive load component in Nova Scotia, the total system peak occurs in the period from December through February.

Since 2015 NS Power has employed an end-use approach to deriving the peak forecast. The breakdown of energy into heating, cooling, and other load components from the energy SAE forecasts was used as an input into the peak forecast. This allowed for the impact of changing heating and cooling requirements, which drive the peak in most months, to be reflected in the peak forecast (but does not provide details of the specific underlying end uses). Details about the peak forecast model can be found in **Appendix B** and in **Attachment 10**.

For the 2024 Load Forecast, and consistent with the 2023 Load Forecast, peak mitigation for EVs as well as a contribution from forecast demand response (DR) activities are included. For 2024, the impact of the hybrid heating scenario modeled by E3 and used in the current Evergreen IRP models has been added to the peak (refer to **Figure 20**). The peak estimates for EVs are informed by E3's modeling as outlined in **Section 4.4**, with a combination of managed and unmanaged charging. DR savings amounts are based on the demand reduction amounts included in the 2022 Evergreen IRP. The individual programs within the 'Base' program are modeled and include Direct Load Control (DLC), Time Variable Pricing (TVP) and BNI Curtailment. The achievable potential of these programs was used in the Load Forecast. NS Power's IRP Action Plan has targeted 75 MW of capacity for DR deployment by 2025. The estimates in the Load Forecast have been moved back to 2028 to align with the current program development and expected ramp-up for both DLC and CPP. DR forecasts continue to use an effective load carrying capacity (ELCC) of 48 percent to account for the fact that the full nameplate capacity will not be available

at all times, and this value will be reassessed as more information is gathered through the implementation of DR programs.

Annual DR totals by program are provided in **Figure 56**.

Figure 56: Demand Response

Year	**Direct Load Control (MW)**	**TVP Rate(MW)**	**Business, Non-Profit & Industrial Curtailment (MW)**	**Total (MW)**	**Total with ELCC (MW)**
2024	0	2	0	2	1
2025	4	4	1	9	4
2026	12	12	2	26	12
2027	24	22	4	50	24
2028	36	32	6	74	36
2029	39	36	7	82	39
2030	39	35	6	81	39
2031	39	35	6	80	39
2032	39	34	6	79	38
2033	39	34	6	79	38
2034	38	33	6	78	37

A pilot project was completed in 2021 and 2022 in conjunction with E1 to investigate direct load control through water heater controls. Through the project 201 water heater controllers were procured and installed in residential homes, and testing was completed to demonstrate the benefit of utility-managed load shift events. Results from the pilot, as presented in E1's 2023 DSM Programs Evaluation Report[36], indicated that the average available DR capacity per controller during the utility winter peak period is 385 W. Results indicated that capacity tends to be lower during the last hour of a four-hour event. Results also indicated that available DR capacity per controller during mornings and evenings were 430 W and 359 W, respectively.

[36] 2023 DSM Programs Evaluation Reports, March 28 2024, Residential Demand Response Final Report page 8

NS Power is also working with E1 on a two-phase pilot project to investigate automatic and manual control of various loads for commercial and industrial (C&I) customers. Results from the winter 2022/2023 season, as presented in E1's 2023 DSM Programs Evaluation Report[37], indicated total available DR capacity at the generator of 2.365 MW for the 9 participating C&I customers. Results also indicated that available capacity tends to vary from event to event and be lower than enrolled capacity, and that available capacity tends to vary depending on time of day, with capacity being higher in mornings than evenings. Customer recruitment was scaled up during 2023 for the 2023/2024 winter season, with the addition of 39 new customers. DR capacity results for the winter 2023/2024 season are still being evaluated.

NS Power is also working with E1 on the Eco Shift pilot which involves directly controlling residential smart thermostats, electric vehicles (EVs), EV chargers, and batteries. The two-year pilot was launched in December 2023 and recruitment of eligible smart thermostats, EVs, and EV chargers was completed. Recruitment of batteries is expected to become available in 2024. DR capacity results for the winter 2023/2024 season are still being evaluated.

As the DR projects in conjunction with E1 continue to progress, data collected will be used to inform forecast assumptions. Learnings from these pilots will be incorporated in future Load Forecasts. The impact of these initiatives, at least within the 10-year timeframe of this forecast, is expected to fall within the sensitivity analysis provided in **Section 11**. Like the interruptible load, DR programs are a resource that can be called upon if required, but they will not inherently reduce demand. In recognition of this, peak reduction from DR is included in the firm peak but is excluded from the system peak.

For the 2024 Load Forecast, as discussed in **Section 4.2,** the assumed peak temperature inputs use a lagging 12-hour average as well as windspeed. The coefficients used for peak

[37] Ibid, Business, Non-profit, and Institutional Demand Response Final Report, page 22.

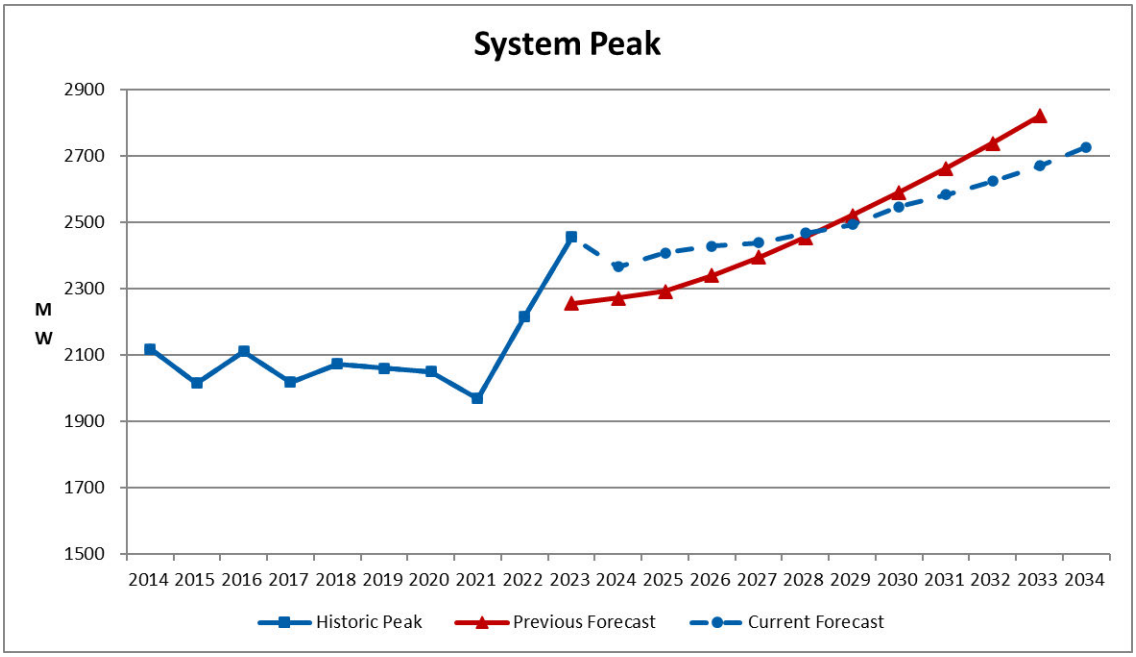
normalization are the same as those used in the 2023 forecast and are described in **Figure 57** below:

Figure 57: Peak Regression Coefficients

Coefficient	Value	Description
Weekdays	30.5	Peaks that occur on weekdays will be 30.5MW higher than those on weekends, all else being equal.
Wind	2.7	Average daily windspeed will add 2.7MW for every 1km/hr. 10 year average is 18.8 km/hr on peak days.
12hrAvgLag	-28.0	12 hour lagging average of temperature, for a drop of 1 degree Celsius the peak will increase 28MW.

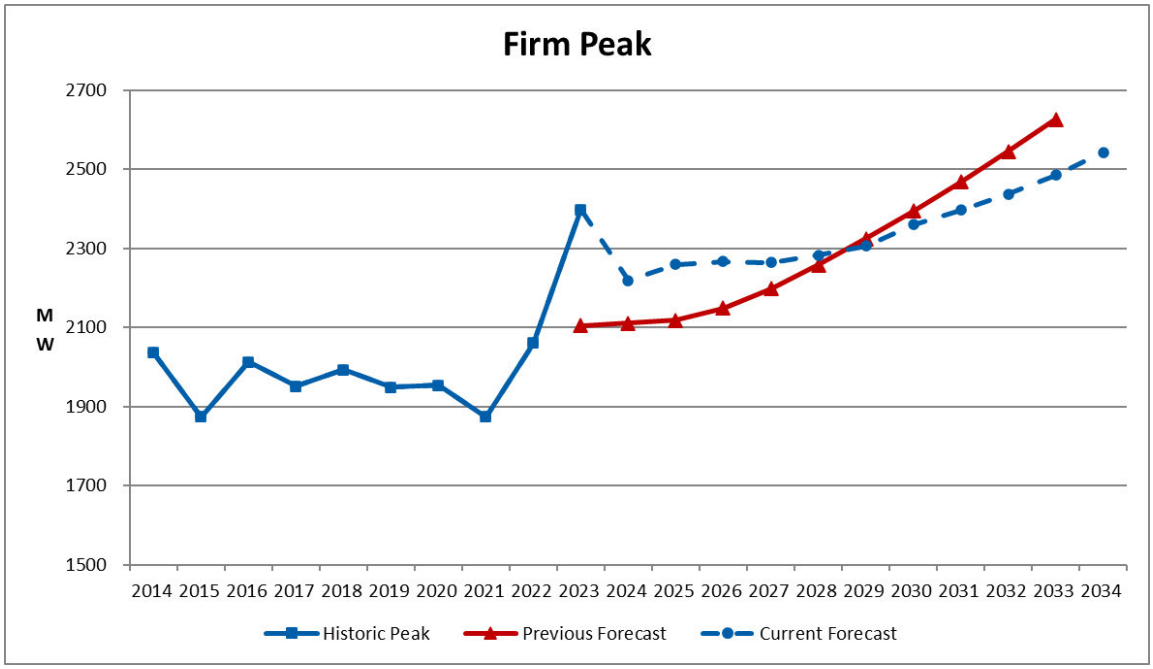
The peak contribution from large customer classes continues to be calculated from historical coincident load factors for each of the rate classes, and the large customer forecast is added to the accrued class forecast to obtain the total system peak. The forecast system peak for 2024 to 2034 is shown below in **Figure 58**, and is expected to increase by 1.4 percent annually. The peak is higher in the near term due mainly to the increased estimated heating load (refer to **Section 4.4**) as well as the updated 10 year average of the peak temperature from -13.9 to -14.4 degrees Celsius. In the long term the peak forecast has decreased from the 2023 forecast due to less impact from EVs as well as the impact of the hybrid heating scenario.

Figure 58: Historical and Forecast System Peak (no DR)



As indicated in **Figure 59**, the firm peak (system peak less interruptible and DR) is expected to increase by 1.4 percent annually.

Figure 59: Historical and Forecast Firm Peak (including DR)



Forecast peak values, firm peak and interruptible peak information can be found in **Appendix A**.

Normalizing the firm peak for temperature, wind and weekday/weekend (and for lighting load in 2019 and 2023), the historic trend shows a better fit with the forecast peaks as shown in **Figure 60**.

Figure 60: Weather-Normalized Firm Peak (including DR)

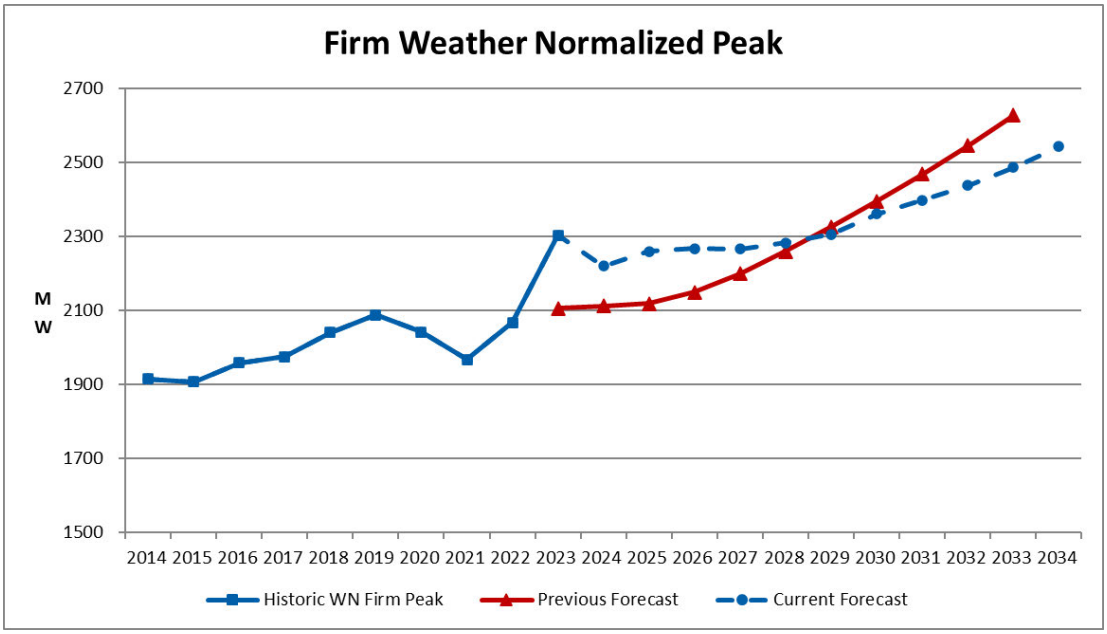


Figure 61 below shows the breakdown of the peak forecast by the various components.

Figure 61: Peak Contribution Components (MW)

	Modeled Peak (MW)	Res Heat (MW)	EV (MW)	DR (MW)	Hybrid (MW)	C&I Elect. (MW)	Large Cust. (MW)	DSM (MW)	Firm Peak (MW)	Inter. Cust. (MW)	System Peak (MW)
2024	2,125	2	6	-1	-	0	104	-16	2219	144	2,365
2034	2,505	13	156	-37	-68	4	115	-145	2542	147	2,727
2034 (no EV mitigation)	2,505	13	281	-37	-68	4	115	-145	2670	147	2,851

Modeled peak is the end-use forecast portion that represents the peak contribution of the Residential, Small and General Demand, Small and Medium Industrial classes, as well as losses. The contributions of the various growth programs discussed in the End-Use Intensity section are then added (including their associated losses), as well as large customer and interruptible customer contributions, and finally DSM. As discussed in

Section 4.4, the EV contribution to peak is expected to be partially mitigated via utility managed charging. The firm peak without EV peak mitigation (assuming 1.6 kW/ vehicle without mitigation) would grow at 1.9 percent per year, and the overall impact in 2034 would be to add approximately 128 MW to the peak compared to the base assumptions. The space heating contribution to peak based on E3's hybrid modeling (as discussed in **Section 4.4**) is also included, and is estimated to reduce peak by around 68 MW in 2034.

Analysis of 2023 Actual Peak

The 2023 system peak occurred at noon on Saturday, February 4 and was the highest peak recorded to date. It was the coldest day in almost 20 years with a 12-hour lagging average temperature of -22.8°C and a daily average windspeed of 28.4 km/h. Large customer interruptions were called at the time of peak, reducing their contribution to system peak. The recorded peak was 2,455 MW with a firm peak of 2,398 MW, while the normalized firm peak is estimated to be 2,302 MW. **Figure 62** provides a breakdown of actual system peak compared to the forecast for 2022.

Figure 62: Forecast Peak Variance vs Actuals

	MW
2023 Forecast Peak	**2,256**
Interruptible	-88
Weather (-22.8°C 12hr lag avg)	+250
Wind (28.4 km/h daily avg)	+26
Weekend	-30
Lighting (estimated)	-150
Unexplained	+191
2023 Feb Peak	**2,455**

The nature of this peak is one that falls outside the abilities of a regression model to accurately predict, even when adjusting for weather, day of week and time of day (lighting). All those predictors are based on average, or close to average values, as the majority of the

historic data on which these are modeled would be close to average, which is why the "Unexplained" portion is so large compared to a peak set under more typical conditions. This peak would be best evaluated by comparison to a low probability "tail" estimate, such as a P90, as that would cover the more extreme possibilities as far as weather is concerned. As shown in **Section 11**, the P90 value for 2024 is 2,580 MW, which would encompass the 2023 peak.

The increase to heating intensity in the 2024 forecast corrects for the unexplained variance on the energy side (refer to **Figure 38**), but it also impacts the forecast peak loads, and helps address the unexplained variance in the 2023 peak. Similar to the analysis of residential energy actuals versus forecast, as a test, the modeled peak[38] can be run, holding off the last 12 months of actuals of each of the last 3 LFRs. The end-use assumptions vary between forecasts, and **Figure 63** below shows that with the updated assumptions for 2024, and once accounting for weather, the uncertainty for 2023 is reduced and in line with previous years, even when in 2023 the peak experienced a rare mid-day occurrence.

Figure 63: Comparison of Peak Forecast to Actuals – One Year Ahead.

Load Forecast Report	Year forecasted	MAD	MAPE	Predicted Peak[39] (MW)	Peak Actual (MW)	Difference (MW)	% Difference
2022	2021	35.2	2.6%	1,718.2	1,783.5	-65.3	-3.7%
2023	2022	55.2	4.3%	1,986.7	1,967.6	19.1	1.0%
2024	2023	52.0	3.6%	2,266.5	2,302.1	-35.6	-1.5%

[38] Modeled peak does not include all components, it is based on a regression of the system load less large customers.
[39] The 2023 Predicted accrued Peak was adjusted by subtracting about 150 MW of lighting that would be included in a normalized peak.

Solar Impact to Peak

One question raised in the 2023 forecast proceeding was for quantitative information on the impact of solar production on peak demand. Hourly data from six community solar farms of varying size (10 kW to 67 kW) was compared to system hourly data to determine the coincidence factor (percentage of nameplate capacity at system peak time) on a monthly basis. As previously assumed, the coincidence factor in the winter months was 0 as the system peaks occurred in the evening. In the summer months, the coincidence factor was higher than previously assumed, varying from 21 percent in June to 39 percent in September. The factors by month are provided in **Figure 64**. As these are impacted by both weather patterns affecting solar production (cloud cover) as well as the timing of the system peak, both of which can vary independently from year to year, the coincident factors will have to be monitored and updated in future forecasts. Since the annual system peak forecast is assumed to occur on a cold January evening after sunset, the coincidence factor impacting the maximum demand is unlikely to change in the near term.

Figure 64: Peak Contribution Components (MW)

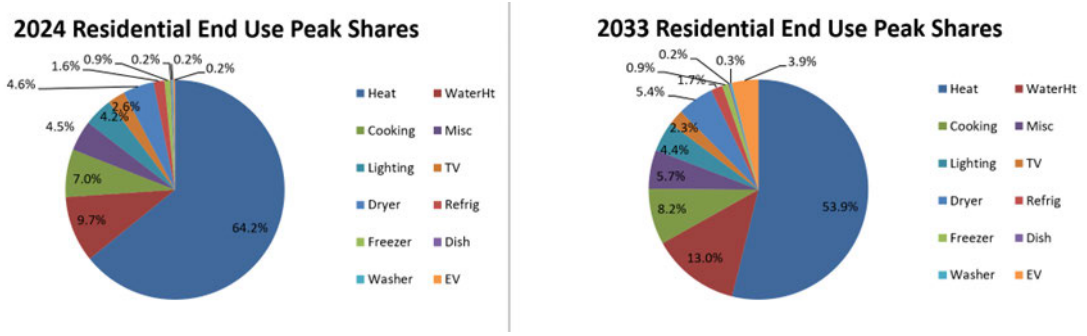
	Previous Coincident Factor Estimate (percent)	Updated Coincidence Factor (percent)
January	0	0
February	0	0
March	0	1
April	0	1
May	0	10
June	10	21
July	15	35
August	15	33
September	10	39
October	0	5
November	0	0
December	0	0

End Use Peak Estimates

While the Load Forecast is a good statistical fit for the historical data, it presents challenges when trying to assess the contribution of individual end uses to peak by class. The overall peak forecast looks at the heating, cooling, and other variables across the Residential and Commercial classes. To illustrate the impact of the individual end uses on the peak for the individual classes, the coincident peak contribution of each class (Residential, Commercial and Industrial) is derived from load research data and fit to the energy amounts from the end-use models. The individual end-use shapes are then fit to the end-use intensity energy amounts from the end-use models.

Figure 65 below shows illustrative breakdowns of contribution to peak by Residential end use.

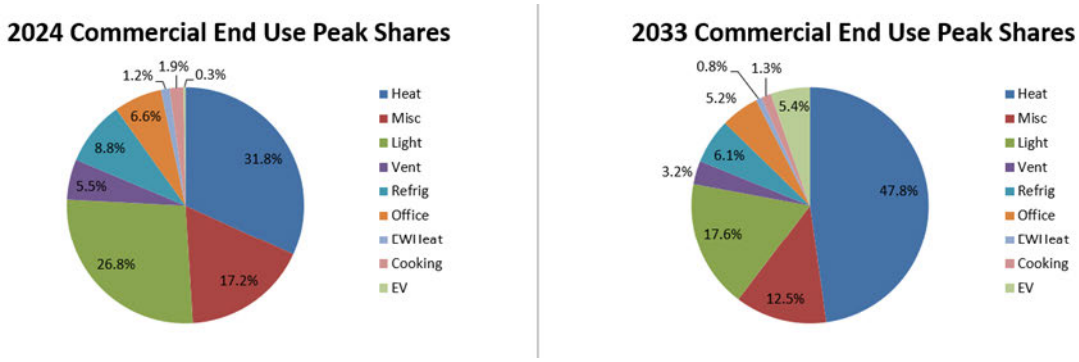
Figure 65: Residential End-Use Peak Shares



Over the forecast period the peak contribution of most end uses stays stable, with the EV contribution increasing from 0.2 percent in 2024 to 3.9 percent of the total by 2033. This scenario also shows an overall decrease in the relative contribution to peak from electric heating sources that fall from 64.2 percent to 53.9 percent.

Figure 66 shows the breakdown in the contribution to peak by Commercial end use.

Figure 66: Commercial End-Use Peak Shares



The trend in the Commercial classes shows that the heating component of the peak is expected to increase significantly over the forecast period, driven by the increased space heating electrification and commercial EVs. All other categories decreased through the forecast period.

Current Class Coincident Peak Demand Research

NS Power has been exploring ways of using interval data to understand peak at the class level from a bottom-up perspective, as discussed in prior Load Forecast reports. NS Power currently forecasts system peak at the aggregate level, as it is the most complete and granular information available (provided by the generation stations). Once peak information is obtained, the system peak is disaggregated into rate class contributions based on historic load factors, losses, and load research data. This year marks the first year in which the available AMI information has been incorporated into analyses instead of the older method which used the Load Research Sample (LRS).

Figures 67 and **68** show the 2023 combined AMI for each customer class. The "rest" category is the sum of all the fully sampled (100 percent) classes, including Large Industrial customers. Rates 2 and 3 are Residential (non-all-electric and all-electric) classes and Rate 11 is the General Demand class. To create these figures, the sum of all the available AMI

meters, per hour, per class, is later adjusted so the monthly totals correspond to revenue class sales information. Figure 69 shows how having an improved hourly resolution due to AMI makes the sum of all customer classes follow generation with greater accuracy and smoothness (the gap is system energy losses). In contrast, in previous years, similar plots would exhibit sharp edges that reflect the statistical uncertainty of the LRS information, increasingly degrading year after year.

Figure 67: 2023 AMI class load shapes vs System Generation, 2023 Annual Peak

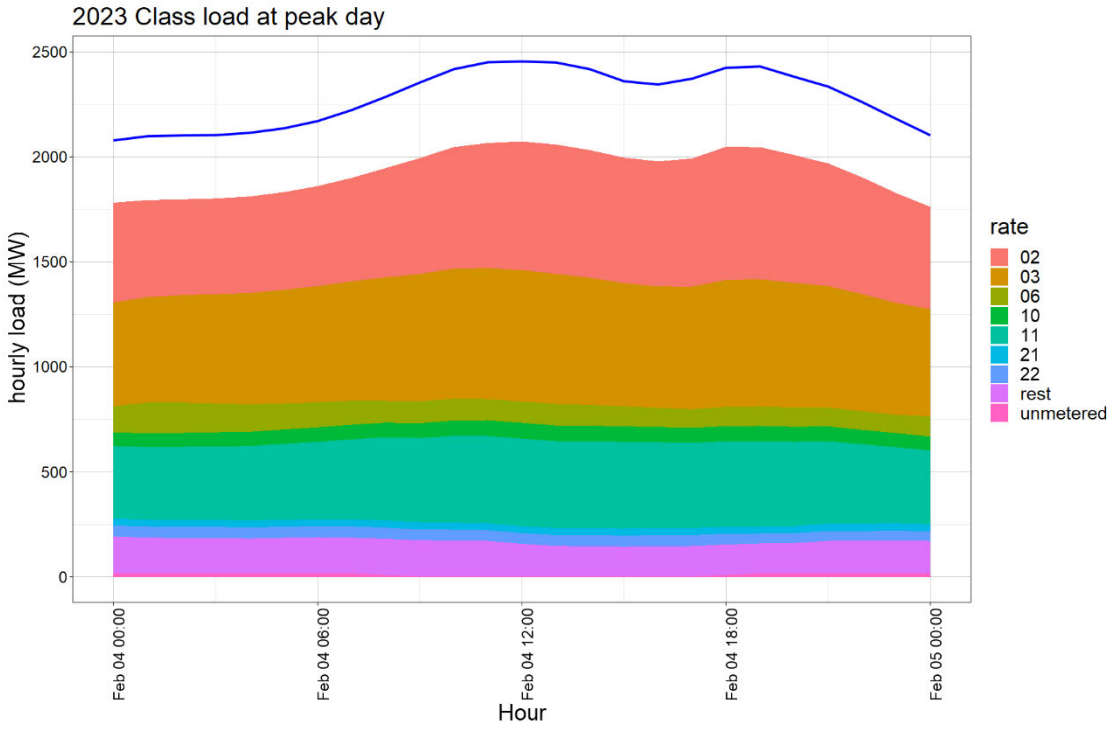
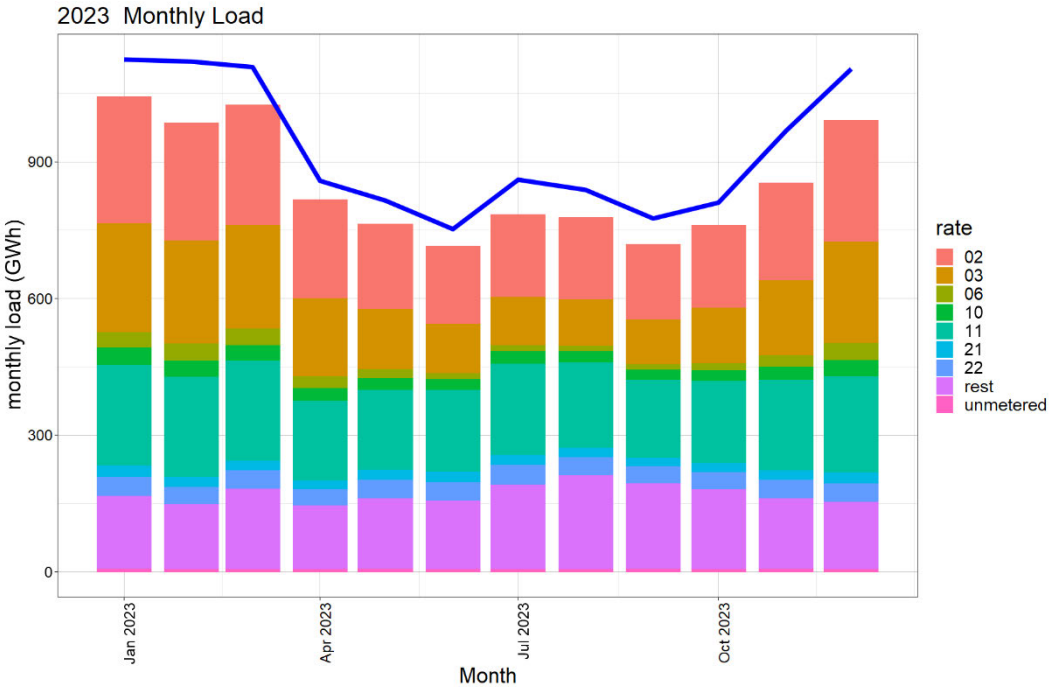


Figure 68: 2023 Monthly Load Research Data vs System Generation



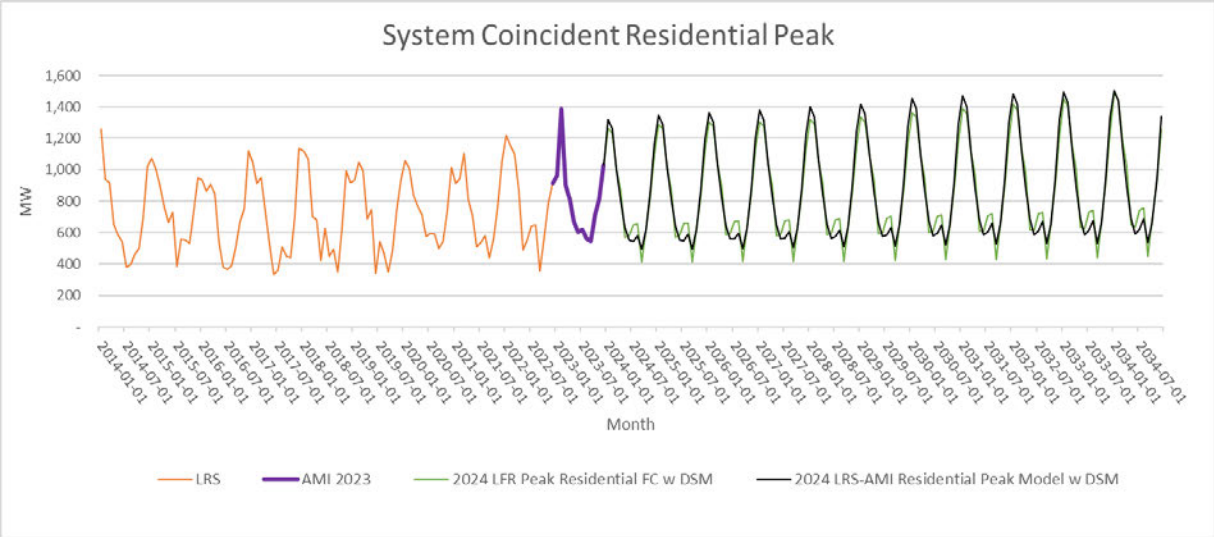
Class coincident peak demand forecast using LRS and the AMI future

The 2024 class contribution to peak analysis is still focused on the residential class as it is less noisy and more weather dependent than any other class, which aligns well with the Peak SAE model, which is mostly dependent on peak weather. However, this year marks the first year where an entire residential hourly data series has been calculated solely relying on AMI.

This model does not need all 8760 hours available each year, only residential loads at the hour of system peak in each month of the historical series. In addition, only peak weather, relevant residential end uses and economics are needed in the right-hand side of the SAE Peak Demand equation (see **Appendix B**). **Figure 69** shows historical information, the

current residential system coincident demand forecast (top-down model), and the resulting forecast informed by the LRS-AMI historical series (bottom-up).

Figure 69: Monthly historical Residential LRS load at peak and forecasts



Both the current residential peak demand forecast (green line) and the LRS peak experimental model (black line) are designed to produce a January peak forecast for a system design temperature of -14.4°C (the remaining months follow normal peak weather distributions) following the same conventions as the current system peak forecast, including the wind speed adjustment.

Differences between the forecast green (top-down) and black lines (bottom-up) highlight the different approaches and cover a range from near zero MW in the early years to 100 MW. The top-down class peak estimates rely on load factors that are updated once a year for the relevant system peak month. There is no growth model for load factors; therefore, residential trends are derived from system trends. For the current report, and as both methods show similar forecasting results (given how close they are in the early forecast years), the top-down approach continues to be used, as the top-down approach starts at

system peak (the sum of all customer classes) and then AMI informed load factors are used to disaggregate it into all the classes. In the future, when a bottom-up forecast is used for all classes, the sum of all will be unlikely to match the system peak due to statistical modeling errors and therefore an extra step for adjustments will need to be made.

Other than speeding up the process of data acquisition and improving precision, AMI may also be used for county/regional forecasts, which may shed light on how sales and peak evolve throughout the province and help with distribution and transmission planning. Electrification may have different impacts in different areas of the province, depending on local adoption trends, with regional sales trends reflecting this diversity. And in terms of peak demand, whose magnitude may also differ across regions, may also show that the time of peak is shifting depending on geography.

The class load shapes obtained through AMI will also be used to test end-use sensitivities. For example, the Residential peak model shown above, can be used to test how changing end-use stock and efficiencies affect the magnitude of the residential peak. So far, the historical end-use series is comprised of information provided by NRCan, NS Power surveys, and analyst adjustments (for example, to align trends with E3 scenarios); however, ongoing work with end-use disaggregation may be used to update/validate end-use assumptions (depending on accuracy per appliance type) and then used to evaluate the impact to the Residential peak.

11.0 SENSITIVITY ANALYSIS

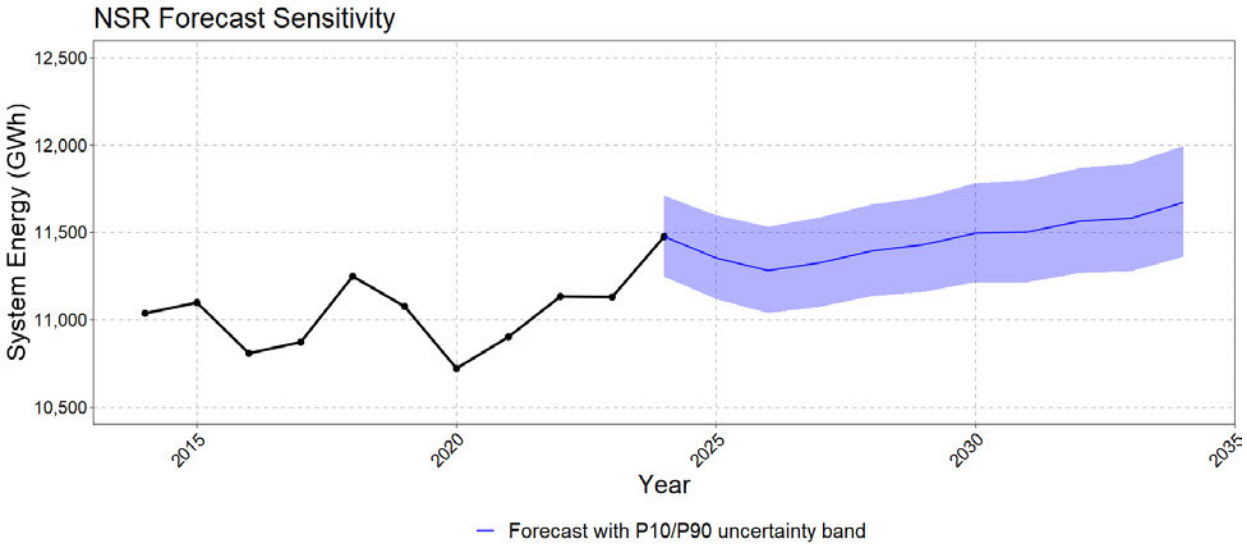
The sales and peak forecasts are fundamentally uncertain and depend on many variables, including economics, weather, adoption of distributed generation, electricity rates and DSM. Although each of these variables is forecast discretely, the uncertainty in these data sets will impact the load forecast to varying degrees. Load can also be affected by extraordinary events such as economic events, strikes, trade disputes, natural disasters, pandemics, and volatility in commodities.

In 2017, based on recommendations from Synapse on the 2016 Load Forecast, NS Power developed a P10/P90 probability analysis using the Monte Carlo simulation approach. This was to create a high and low range for the forecast that encompasses possible (not extreme) scenarios. A full description of the sensitivity methodology is contained in Appendix D.

The probable distribution of future load is estimated by sampling 10,000 random trial values of the economics and weather each year, using their respective historical distributions.

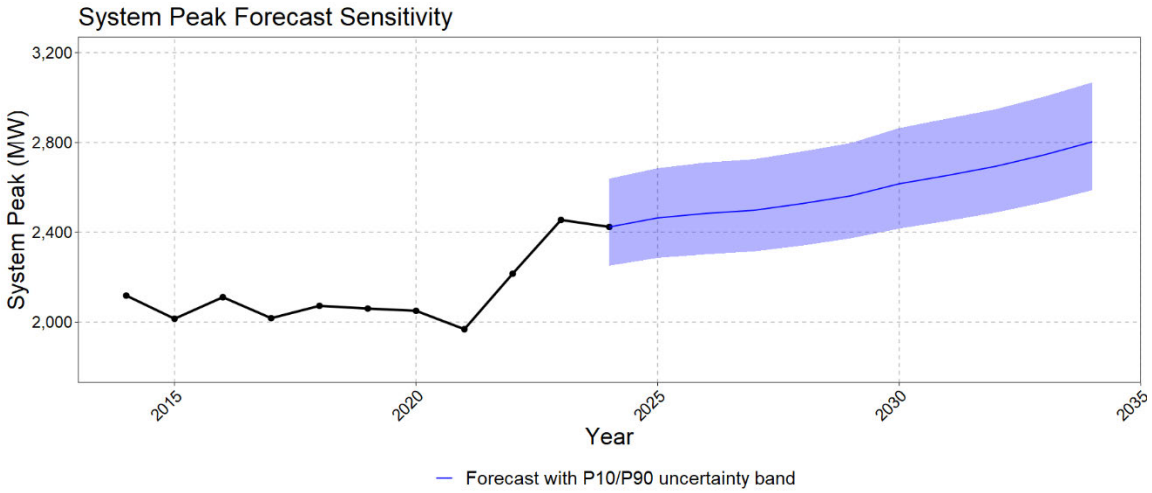
Figure 70 shows the sensitivity bands, which are represented by the shaded regions. These represent a range from the low 10th percentile to the high 90th percentiles (there is a 10/90 percent probability that the forecast will be below/above these shaded areas). These P10/P90 bands cover a range of approximately 468-646 GWh during the 10-year period, which is explained mainly by the impact of weather variation (HDD) and economic impact in the long term. The black line and points represent actual system totals.

Figure 70: System Energy Sensitivity



Similarly, a P10/P90 scenario was created for peak demand using a random sampling of weather and economic drivers. The width of the P10/P90 envelope is approximately 430-530 MW, reflecting the greater overall variation in the peak. **Figure 71** shows the peak forecast, which includes the latest adjustments (wind and 12-hour temperature averages) to the peak end-use model.

Figure 71: System Peak Sensitivity



This analysis provides a potential range of outcomes for the 2024 Load Forecast. Energy is most sensitive to economics over the long term, while peak is most sensitive to temperature. In addition, peak is more variable overall. The impacts of other inputs that cannot easily be represented by probabilistic analysis are provided in **Figure D8** in **Appendix D**.

Evergreen IRP Comparison

Figure 72 below compares the 2023 Load Forecast, the 2024 Load Forecast, and the Company's Evergreen IRP cases with Base DSM. The Evergreen IRP analysis incorporated the 2022 Load Forecast as its central planning case, which had a much lower estimate for load served through the RTR market (29 GWh compared to 246 GWh in the present forecast), as well as lower initial peak expectations. There are no specific assumptions around incentives that might impact EV and heat pump uptake; the values represent a slow ramp-up of uptake of these technologies that would allow interim sales targets as well as the target of net zero emissions by 2050 to be achieved. There will be more policy and regulation changes related to decarbonization targets in the course of the

10-year timeframe of this forecast, but the scenario developed represents the likely trajectories of these technologies.

Figure 72: 2022 Evergreen IRP Scenarios Comparison

Item	2024 NSR Energy (GWh)	2024 Firm Peak (MW)	2034 NSR Energy (GWh)	2034 Firm Peak (MW)
2023 Load Forecast	11,168	2,111	12,272	2,710
2024 Load Forecast	11,490	2,219	11,695	2,542
Evergreen IRP E1 – Current Policy and Trends	11,236	2,055	11,710	2,454
Evergreen IRP E2 – Hybrid Peak Mitigation	11,236	2,055	11,605	2,336
Evergreen IRP E3 – Accelerated Electrification	11,236	2,142	12,573	2,881

Appendix A – Forecast Values

2024 NS Power Load Forecast

1.1 Table A1: Energy Requirement – 2024 NS Power Forecast Energy Forecast

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Municipal and Other	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
2014	4,404	1.0	3,222	-0.7	2,522	-3.1	198	-1.4	691	11,037	-1.4
2015	4,504	2.3	3,251	0.9	2,456	-2.6	197	-0.2	691	11,099	0.6
2016	4,264	-5.3	3,133	-3.7	2,444	-0.5	179	-9.2	789	10,809	-2.6
2017	4,363	2.3	3,133	0.0	2,461	0.7	163	-9.0	753	10,873	0.6
2018	4,542	4.1	3,181	1.5	2,614	6.2	154	-5.7	758	11,250	3.5
2019	4,688	3.2	3,151	-0.9	2,388	-8.7	146	-4.7	704	11,077	-1.5
2020	4,675	-0.3	2,957	-6.2	2,343	-1.9	68	-53.6	688	10,731	-3.1
2021	4,619	-1.2%	2,973	0.7%	2,480	6.0%	72	5.6%	757	10,902	1.7%
2022	4,851	5.0%	3,088	3.9%	2,480	0.0%	69	-3.5%	645	11,134	2.1%
2023	4,934	1.7%	3,110	0.7%	2,161	-12.9%	154	122.5%	772	11,131	0.0%
2024	5,180	5.0%	3,118	0.3%	2,267	4.9%	159	3.3%	767	11,490	3.2%
2025	5,211	0.6%	3,080	-1.2%	2,263	-0.2%	93	-41.8%	763	11,409	-0.7%
2026	5,146	-1.3%	2,993	-2.8%	2,247	-0.7%	171	84.8%	750	11,306	-0.9%
2027	5,140	-0.1%	3,000	0.2%	2,246	0.0%	211	23.5%	751	11,347	0.4%
2028	5,176	0.7%	3,028	0.9%	2,245	0.0%	212	0.2%	755	11,416	0.6%
2029	5,183	0.1%	3,049	0.7%	2,247	0.1%	212	0.1%	757	11,448	0.3%
2030	5,213	0.6%	3,078	0.9%	2,249	0.1%	212	0.2%	762	11,514	0.6%
2031	5,215	0.0%	3,083	0.2%	2,251	0.1%	212	0.1%	762	11,523	0.1%
2032	5,248	0.6%	3,105	0.7%	2,253	0.1%	213	0.2%	767	11,585	0.5%
2033	5,249	0.0%	3,119	0.4%	2,256	0.1%	213	0.0%	768	11,605	0.2%
2034	5,298	0.9%	3,151	1.0%	2,258	0.1%	213	0.1%	775	11,695	0.8%

Table A2: Coincident Peak Demand - 2024 NS Power Forecast Peak Forecast

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only, MW)	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)	Temp at Peak (deg C)	12hr Lag Temp (deg C)	Notes
2014	83	-	2,036	2,118	4.2	-19	-18	January 2 weekday evening
2015	141	-	1,874	2,015	-4.9	-12	-12	January 6 weekday evening
2016	98	-	2,013	2,111	4.8	-14	-15	December 16 weekday evening
2017	67	-	1,951	2,018	-4.4	-13	-13	December 28 weekday evening (between holidays)
2018	80	-	1,993	2,073	2.7	-12	-13	January 7 weekend evening
2019	111	-	1,949	2,060	-0.6	-15	-14	February 27 weekday morning (min lighting load)
2020	96	-	1,954	2,050	-0.5	-13	-10	January 17 weekday evening
2021	94	-	1,875	1,968	-4.0	-10	-10	March 2 weekday evening
2022	155	-	2,061	2,216	12.6	-15	-14	January 11 weekday evening
2023	58	-	2,397	2,455	10.8	-22	-23	February 4 weekend noon
2024	144	1	2,219	2,365	-3.7		-14	Forecast
2025	144	4	2,259	2,408	1.8		-14	Forecast
2026	149	12	2,267	2,428	0.8		-14	Forecast
2027	148	24	2,265	2,437	0.4		-14	Forecast
2028	148	36	2,283	2,466	1.2		-14	Forecast
2029	148	39	2,306	2,493	1.1		-14	Forecast
2030	148	39	2,360	2,547	2.2		-14	Forecast
2031	147	39	2,397	2,583	1.4		-14	Forecast
2032	147	38	2,438	2,623	1.5		-14	Forecast
2033	147	38	2,485	2,670	1.8		-13	Forecast
2034	147	38	2,542	2,727	2.1		-13	Forecast

Appendix B – Forecast Model Details

2024 NS Power Load Forecast

Residential Model Detail

The residential average use SAE model is defined as a function of the three primary end uses – cooling (*XCool*), heating (*XHeat*) and other use (*XOther*):

$$ResAvgUse_m = b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + b_4 \times AvgEESavings_m + b_5 \times CovidVariable_m + \sum Binaries + ARMA$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$$XHeat = HeatUse \times HeatIndex$$

HeatUse is defined as:

$$HeatUse_{y,m} = \left(\frac{HDD_{y,m}}{HDD_{15}}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{15}}\right)^{HHSizeElas} \times \left(\frac{ResEcon_{y,m}}{ResEcon_{15}}\right)^{HHIncElas} \times \left(\frac{Price_{y,m}}{Price_{15}}\right)^{PriceElas}$$

Where $HDD_{y,m}$ is the Heating Degree Day for a given month *m* of the year *y*, *HHSize* is the average household size, *ResEcon* is Employment Compensation divided by House Hold population, *Price* is the price of electricity for the specific customer class. Each variable uses its own elasticity, and the base line year is 2015.

HeatIndex is defined as:

$$HeatIndex = \text{f(Heating Saturation, Efficiency, Shell Integrity, Square Footage)}$$

The cooling variable is defined as:

$$XCool = CoolUse \times CoolIndex$$

CoolUse is defined as:

$$CoolUse_{y,m} = \left(\frac{CDD_{y,m}}{CDD_{15}}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{15}}\right)^{HHSizeElas} \times \left(\frac{ResEcon_{y,m}}{ResEcon_{15}}\right)^{HHIncElas} \times \left(\frac{Price_{y,m}}{Price_{15}}\right)^{PriceElas}$$

Where $CDD_{y,m}$ is the Cooling Degree Day for a given month *m* of the year *y*, *HHSize* is the average household size, *ResEcon* is Employment Compensation divided by House Hold population, *Price* is the price of electricity for the specific customer class. Each variable uses its own elasticity, and the base line year is 2015.

CoolIndex is defined as:

CoolIndex = f(Cooling Saturation, Efficiency, Shell Integrity, Square Footage)

XOther captures non-weather sensitive end uses:

XOther = *OtherUse* × *OtherIndex*

OtherUse is calculated as

$$OtherUse_{y,m} = \left(\frac{CDays_{y,m}}{30.44}\right) \times \left(\frac{HHSize_{y,m}}{HHSize_{15}}\right)^{HHSizeElas} \times \left(\frac{ResEcon_{y,m}}{ResEcon_{15}}\right)^{HHIncElas} \times \left(\frac{Price_{y,m}}{Price_{15}}\right)^{PriceElas}$$

Where $CDays_{y,m}$ is the number of days for a given month *m* of the year *y*, *HHSize* is the average household size, *ResEcon* is Employment Compensation divided by House Hold population, *Price* is the price of electricity for the specific customer class. Each accompanied by its own elasticities. Base line year is 2015.

OtherIndex is defined as:

$$OtherIndex_{y,m} = \sum_{Type} EI_{15}^{Type} \times \frac{\left(Sat_{y}^{Type} / Eff_{y}^{Type}\right)}{\left(Sat_{15}^{Type} / Eff_{15}^{Type}\right)} \times MoMult_{m}^{Type}$$

Where *Type* is an end-use, Sat_y^{Type} is the saturation (shares) of an end-use of given *Type* for a particular year *y*, Eff_y^{Type} is the efficiency of an end-use of given *Type* for a particular year *y*, and EI_{15}^{Type} is a reference year (2015) calibration weight per end-use *Type*. The factors:

$$EI_{15}^{Type} \times \frac{\left(Sat_y^{Type} / Eff_y^{Type}\right)}{\left(Sat_{15}^{Type} / Eff_{15}^{Type}\right)}$$

are the annual intensities in the Intensities tab in Attachment 1 - Residential Intensities of the Load Forecast Report for each relevant end-use and converted to monthly values using the $MoMult_m^{Type}$ factor.

Where

OtherUse = f(Seasonal Use Pattern, Household Income, Household Size, and Price)

OtherIndex = g(Other Appliance Saturation and Efficiency Trends)

The *AvgEESavings* term captures E1's DSM past reported savings for the residential class. The associated regression coefficient, b_4, assesses the portion of embedded DSM activity that is already included in the billed sales information. The negative sign of b_4 indicates that DSM activity reduces load.

The COVID variable is a binary that starts in July 2020 and attempts to mirror the impacts of COVID on load. It starts with a value of 1, is reduced to 0.65 in August 2022. As discussed in **Section 5**, this variable was used to explain the increase in residential load from people working from home during the pandemic and stays in the forecast at a reduced level to recognize permanent changes related to working patterns.

Binary shift variables are added to the model for the months of January, August, September, and October to improve model fit and particular monthly trends, while binaries for April and May of 2015 and October 2022 to compensate for anomalies in the billing data during this period related to delayed meter reads. An additional binary was added for February 2018 to correct for high

residual values. After running the linear regression with the main variables, the residuals show a slight autocorrelation, which happens when a model does not take into account relatively small drivers that should explain the dependent variable (in this case, sales). To help eliminate this autocorrelation, a moving average, MA, of period 1, MA(1) was added, which estimates the autocorrelation with its the predecessor.

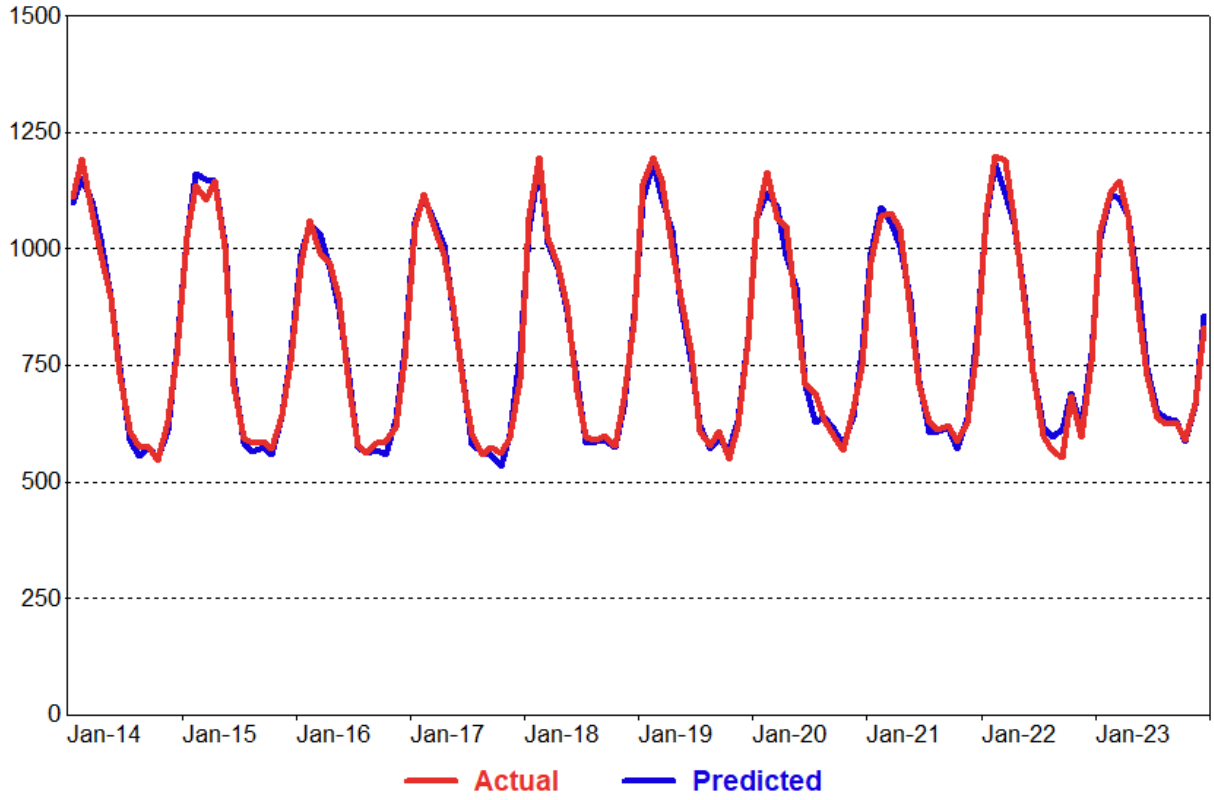
Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRes.WtXHeat	0.923	0.024	38.044	0.00%
MStructRes.WtXCool	1.094	0.259	4.222	0.01%
MStructRes.WtXOther	1.03	0.039	26.32	0.00%
MSales.AvgEESavingsProfiled	-0.556	0.199	-2.793	0.62%
MBin.Jan	77.035	7.386	10.429	0.00%
MBin.Aug	53.829	13.937	3.862	0.02%
MBin.Sep	77.941	18.424	4.23	0.01%
MBin.Oct	45.054	11.565	3.896	0.02%
MBin.Apr15	85.798	24.931	3.441	0.08%
MBin.May15	89.61	24.68	3.631	0.04%
MBin.Feb18	62.30	21.74	2.866	0.50%
MBin.CovidVariable	25.611	9.099	2.815	0.58%
MBin.Oct22	140.062	22.657	6.182	0.00%
MA(1)	0.506	0.094	5.412	0.00%

Residential Model Statistics

Model Statistics	
Iterations	21
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.989
Adjusted R-Squared	0.987
AIC	6.481
BIC	6.806
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-545.11
Model Sum of Squares	5,407,511.96
Sum of Squared Errors	61,990.34
Mean Squared Error	584.81

Model Statistics	
Std. Error of Regression	24.18
Mean Abs. Dev. (MAD)	17.4
Mean Abs. % Err. (MAPE)	2.18%
Durbin-Watson Statistic	2.069
Durbin-H Statistic	#NA
Ljung-Box Statistic	21.71
Prob (Ljung-Box)	0.5968
Skewness	0.264
Kurtosis	3.786
Jarque-Bera	4.49
Prob (Jarque-Bera)	0.1059

Residential SAE Model Fit



Residential Model 2024-2034 Reconciliation

The following tables provide details reflecting the changes between 2024 and 2034 forecast years. Some of the numbers have small discrepancies compared to those used in the final annual figures as there is a conversion between monthly data at the model level to annual data at the system level.

Residential Load – Post Regression (GWh)

	Existing Customer Average Use from Regression Model (kWh/year)	New Cust. Load	EVs	Solar	RTR	Hybrid	Res DSM Adjustment	Res Sales		Total Res DSM (at the meter)	DSM captured by end uses
2024	10,468	62	10	(44)	-	-	(30)	5,180		(55)	(24)
2034	11,411	428	322	(461)	(75)	(177)	(388)	5,298		(698)	(310)
Change to load	9.0%	7.0%	6.0%	-8.0%	-1.4%	-3.4%	-6.9%	2.3%			

Res Sales = Existing Customer + New Customer + EV + Solar + RTR + Hybrid + DSM

Existing customer load is calculated as Res Average Use (10,468 kWh/customer in 2024, 11,411 kWh/customer in 2034) x number of customers as of 2024 (495,055). The tables below show the appliance information incorporated in the end-use input tables.

Residential Average Use –Regression

	XHeat	XCool	XOther	AvgEE Savings	Binaries	ARMA	COVID Variable	Res Average Use
2024	4,712	392	5,560	(637)	254	(13)	200	10,468
2034	5,300	619	5,675	(637)	254	-	200	11,411
Change to load	5.6%	2.2%	1.1%	0.0%	0.0%	0.1%	0.0%	9.0%

Res Avg Use = XHeat + XCool + XOther + AvgEESavings + Binaries + ARMA + COVID Var

Residential Input Variables – XHeat

	Intensities				Econ + Struct	Regression	
	Efurn	HP Heat	Secondary Heat	Furnace Fans	HeatUse Variable	Coeff	Total XHeat
2024	2,160	2,066	583	70	1.05	0.923	4,712
2034	1,263	3,680	734	61	1.00	0.923	5,300
Change to load	-19.0%	34.2%	3.2%	-0.2%	-4.4%	0.0%	12.5%

XHeat = (Efurn + HP Heat + Secondary Heat + Furnace Fans) x HeatUseVariable x Coeff

Note that because these factors are multiplicative, the growth rate for the intensities is multiplied by the coefficients to calculate the overall impact. For example, the contribution of Efurn is calculated as $[(Efurn_{2034}-Efurn_{2024}) \times HeatUse \times Coeff]/WtXHeat_{2024}$

Residential Input Variables – XCool

	Intensities			Econ + Struct	Regression	
	Central AC	HP Cool	Room AC	CoolUse Variable	Coefficient	Total Xcool
2024	29	220	65	1.1	1.094	392
2034	35	337	68	1.3	1.094	619
Change to load	1.4%	29.9%	0.9%	12.4%	0.0%	57.8%

XCool = (Central AC + HP Cool + Room AC) x CoolUseVariable x Coeff

Residential Input Variables – XOther

	Intensities							Econ + Struct	Reg	
	Water Heat	Cook	Ref/Frz	Wash/ Dry	TV	Light	Misc	Other Use Var	Coeff	Total Xother
2024	1,633	474	564	718	412	528	1,173	0.98	1.030	5,560
2034	1,881	473	506	727	304	467	1,273	0.98	1.030	5,675
Change to load	4.5%	0.0%	-1.0%	0.2%	-1.9%	-1.1%	1.8%	-0.3%	0.0%	2.1%

XOther = (Water Heat + Cook + Ref/Frz + Wash/Dry + TV + Light + Misc) x OtherUseVariable x Coeff

Commercial Model Detail

Small General Service

Small General Service is projected using an SAE average use model and a sales forecast is generated as the product of the average use and customer forecast.

Like the residential model, monthly Small General Service average use is defined as a function of monthly heating requirements (*XHeat*), cooling requirements (*XCool*), and other use (*XOther*). The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use intensity trends, with *GDP* and employment ($SmlGenVar_m$), real price ($Price_m$), monthly *HDD* and *CDD* and a variable accounting for the number of days in a given month:

$$XHeatm = EIheat \times Pricem^{-.15} \times SmlGenVarm \times HDDm$$

$$XCoolm = EIcool \times Pricem^{-.15} \times SmlGenVarm \times CDDm$$

$$XOtherm = EIother \times Pricem^{-.15} \times SmlGenVarm \times Daysm$$

The coefficients on price are imposed short-term price elasticities.

Several binary shift variables are added to the model to:

(1) Improve model fit using monthly binaries for March and December.
(2) Account for billing issues related to the pandemic in May and June 2020.
(3) Account for billing issues related to the hurricane Fiona in Oct 2022 and hurricane Lee in Sep 2023.
(4) Account for shifts in usage starting in 2022 (post COVID)

As in the residential model, analysis of the initial regression results indicated that the model would be improved by adding an ARMA process. A seasonal moving average of period 1, SMA(1) was used.

The monthly forecast average use sales model is then estimated as:

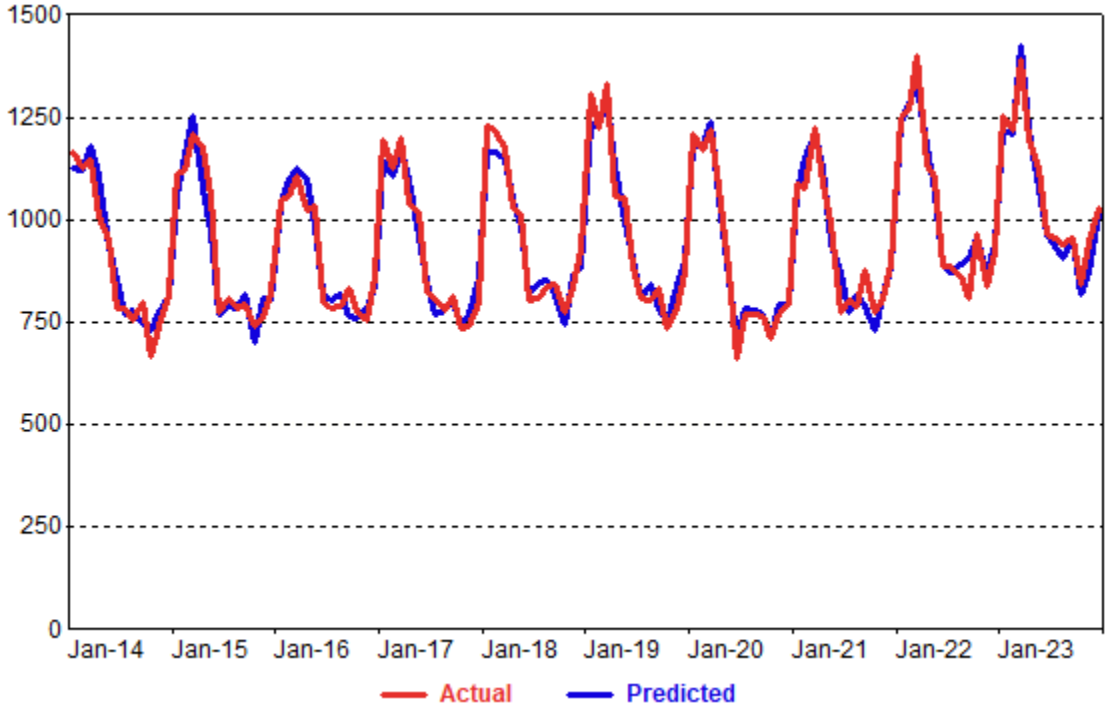
$$SmlGen_AvgUsem = b1 \times XHeatm + b2 \times XCoolm + b3 \times XOtherm + \sum Binaries + ARMA$$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructSmlGen.WtXHeat	0.856	0.037	23.347	0.00%
MStructSmlGen.WtXCool	0.330	0.042	7.797	0.00%
MStructSmlGen.WtXOther	0.727	0.021	34.013	0.00%
MBin.Mar	100.094	21.293	4.701	0.00%
MBin.Dec	-114.494	20.103	-5.695	0.00%
MBin.May20	-138.367	38.301	-3.613	0.05%
MBin.Jun20	-143.536	37.948	-3.782	0.03%
MBin.Oct22	132.146	39.609	3.336	0.12%
MBin.Sep23	156.046	45.461	3.432	0.09%
MBin.Yr22Plus	43.240	12.364	3.497	0.07%
SMA(1)	0.452	0.096	4.688	0.00%

Small General Model Statistics

Model Statistics	
Iterations	12
Adjusted Observations	120
Deg. of Freedom for Error	109
R-Squared	0.950
Adjusted R-Squared	0.945
AIC	7.580
BIC	7.835
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-614.07
Model Sum of Squares	3,720,817.94
Sum of Squared Errors	195,658.57
Mean Squared Error	1,795.03
Std. Error of Regression	42.37
Mean Abs. Dev. (MAD)	32.50
Mean Abs. % Err. (MAPE)	3.47%
Durbin-Watson Statistic	2.289
Durbin-H Statistic	#NA
Ljung-Box Statistic	70.24
Prob (Ljung-Box)	0.0000
Skewness	-0.093
Kurtosis	2.846
Jarque-Bera	0.293
Prob (Jarque-Bera)	0.8638

Small General Model Fit



Small General 2024-2034 Reconciliation

The Small General Demand customer forecast model is constructed like the residential model (including heat pump programs inside the SAE model). Adjustments done outside the regression include estimates for other commercial and industrial growth programs, PV, EV, RTR and DSM.

Historically the XHeat, XCool and XOther variables are constructed with a flat scaling factor to keep regression coefficients close to 1, which allows for easier comparison.

Small General Load – Post Regression (GWh)

	Load from Regression Model	EV	Solar	RTR	SG DSM adjustment	Small Gen Sales (with DSM)		Total SG DSM (at the meter)	DSM captured by end uses
2024	340	1	(1)	-	(3)	338		(7)	(4)
2034	409	49	(22)	(7)	(28)	402		(62)	(34)
Change	20.2%	13.9%	-6.2%	-2.0%	-7.2%	18.9%			

Small General Sales = Avg Use Existing x customer count + EV Load + Solar Load + RTR + DSM

The load from the regression model is calculated as Small Gen Average Use (12,763 kWh/customer in 2024, 13,895 kWh/customer in 2034) x number of customers (26,675 in 2024, increasing to 29,466 in 2034).

Small General Average Use –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Avg Sales (kWh)
2024	4,323	586	7,266	504	83	12,763
2034	5,182	729	7,479	504	-	13,895
Change	6.7%	1.1%	1.7%	0.0%	-0.7%	8.9%

Small General Avg Use = XHeat + XCool + XOther + Binaries + ARMA

Small General Input Variables – XHeat

	Intensities	Econ + Struct	Regression		
	Heating	HeatUse Variable	Coeff	Scaling Factor	Total XHeat (kWh)
2024	56,808	1.27	0.856	0.070	4,323
2034	63,121	1.37	0.856	0.070	5,182
Change	12.0%	7.9%	0.0%	0.0%	19.9%

XHeat = Heating x HeatUseVariable x Coeff x Scaling Factor

Note that because these factors are multiplicative, the growth rate for the intensities are multiplied by the coefficients to calculate the overall impact. For example, the contribution of Heating is calculated as $[(Heat_{2034}-Heat_{2024}) \times HeatUse \times Coeff \times Scaling]/WtXHeat_{2024}$

Small General Input Variables – XCool

	Intensities	Econ + Struct	Regression		
	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total XCool (kWh)
2024	36,759	1.38	0.330	0.035	586
2034	35,682	1.77	0.330	0.035	729
Change	-3.8%	28.3%	0.0%	0.0%	24.5%

XCool = Cooling x CoolUseVariable x Coeff x Scaling Factor

Small General Input Variables – XOther

	Intensities							Econ + Struct	Reg		
	Vent	Water Heat	Cook	Refrig	Light	Office	Misc	OtherUse Var	Coeff	Scaling Factor	Total XOther (kWh)
2024	11,963	1,963	1,918	21,022	57,077	13,164	33,072	14.26	0.727	0.005	7,266
2034	9,018	2,179	1,808	19,510	49,206	14,038	32,034	16.10	0.727	0.005	7,479
Change	-2.4%	0.2%	-0.1%	-1.2%	-6.3%	0.7%	-0.8%	12.9%	0.0%	0.0%	2.9%

XOther = (Ventilation+ Water Heat + Cook + Refrigeration + Light + Office + Misc) x OtherUseVariable x Coeff x Scaling Factor

General Service

The General Service rate class model is estimated on a total monthly sales basis where total monthly billed sales is a function of total monthly heating requirements (*XHeat*), cooling requirements (*XCool*), and other use (*XOther*). The end-use variables are constructed by interacting annual end-use intensity projections (EI) that capture end-use intensity trends, with *GDP* and employment ($GenVar_m$), real price ($Price_m$), monthly *HDD* and *CDD* and a variable accounting for the number of days in a given month:

$$XHeat_m = EIheat \times Price_m^{-.15} \times GenVar_m \times HDD_m$$

$$XCool_m = EIcool \times Price_m^{-.15} \times GenVar_m \times CDD_m$$

$$XOther_m = EIother \times Price_m^{-.15} \times GenVar_m \times Days_m$$

The coefficients on price are imposed short-term price elasticities.

Several binary shift variables are added to the model to:

(1) Improve model fit using monthly binaries for Feb 2018 and May 2023.
(2) Account for billing issues related to the pandemic in May and June 2020.
(3) Account for billing issues related to the hurricane Fiona in Sep and Oct 2022.
(4) Account for shifts in usage resulting from COVID

As in the residential model, analysis of the initial regression results indicated that the model would be improved by adding an ARMA process. A seasonal moving average of period 1, SMA(1) was used.

A monthly forecast sales model is then estimated as:

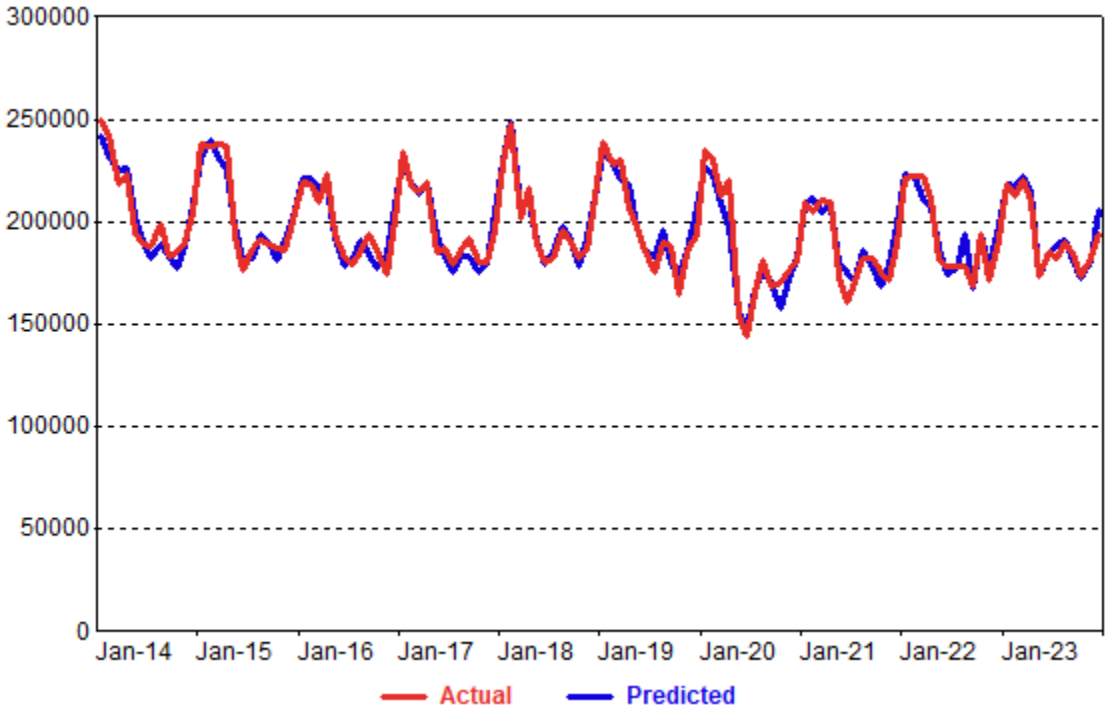
$$GenService_m = b1 \times XHeat_m + b2 \times XCool_m + b3 \times XOther_m + \sum Binaries + ARMA$$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructGen.WtXHeat	0.743	0.031	23.702	0.00%
MStructGen.WtXCool	0.698	0.063	11.070	0.00%
MStructGen.WtXOther	1.080	0.019	57.501	0.00%
MBin.Feb18	29075.854	6191.198	4.696	0.00%
MBin.May20	-28685.822	6257.015	-4.585	0.00%
MBin.Jun20	-22946.520	6252.155	-3.670	0.04%
MBin.Oct22	21179.524	6220.695	3.405	0.09%
MBin.Sep22	-20217.714	6281.321	-3.219	0.17%
MBin.COVID2020Plus	-7274.523	1645.480	-4.421	0.00%
MBin.May23	-16930.880	6502.626	-2.604	1.05%
SMA(1)	0.295	0.095	3.098	0.25%

General Service Model Statistics

Model Statistics	
Iterations	12
Adjusted Observations	120
Deg. of Freedom for Error	109
R-Squared	0.920
Adjusted R-Squared	0.912
AIC	17.628
BIC	17.883
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,216.92
Model Sum of Squares	51,702,353,576.70
Sum of Squared Errors	4,519,631,715.13
Mean Squared Error	41,464,511.15
Std. Error of Regression	6,439.29
Mean Abs. Dev. (MAD)	4,799.02
Mean Abs. % Err. (MAPE)	2.46%
Durbin-Watson Statistic	1.950
Durbin-H Statistic	#NA
Ljung-Box Statistic	32.13
Prob (Ljung-Box)	0.1239
Skewness	0.202
Kurtosis	3.516
Jarque-Bera	2.147
Prob (Jarque-Bera)	0.3419

General Service Model Fit



General Demand 2024-2034 Reconciliation

The general demand class, which makes up the largest portion of the commercial sector, is forecast as gross total sales rather than average use as is the case in the small general and residential classes.

Like the small general model, a flat scaling factor is used to adjust some of the end-use regression coefficients close to 1, making their interpretation a bit easier. Outside of the SAE regression model, adjustments include EV load, PV, RTR, Hybrid and DSM.

General Demand Load – Post Regression (GWh)

	Load Regression Model	RTR	EV	Solar	Hybrid	GD DSM Adjustment	Gen Sales (with DSM)		Total GD DSM (at the meter)	DSM captured by end uses
2024	2,365	-	6	(9)	-	(23)	2,339		(51)	(28)
2034	2,680	(97)	195	(198)	(63)	(196)	2,320		(437)	(241)
Change	13.3%	-4.1%	8.0%	-8.0%	-2.7%	-7.3%	-0.8%			

Gen Sales = Sales + RTR + EV Load + Solar Load + Hybrid + DSM

General Demand Sales –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Sales (GWh)
2024	543,197	117,739	1,767,734	(56,741)	(6,996)	2,364,934
2034	730,139	148,836	1,857,456	(56,741)	-	2,679,691
Change	7.9%	1.3%	3.8%	0.0%	0.3%	13.3%

Sales = XHeat + XCool + XOther + Binaries + ARMA

General Demand Input Variables – WtXHeat

	Intensities	Econ + Struct	Regression	
	Heating	HeatUse Variable	Coeff	Total XHeat
2024	556,051	1.31	0.743	543,197
2034	676,075	1.45	0.743	730,139
Change	23.9%	10.6%	0.0%	34.4%

XHeat = Heating x HeatUseVariable x Coeff

Note that because these factors are multiplicative, the growth rate for the intensities are multiplied by the coefficients to calculate the overall impact. For example, the contribution of Heating is calculated as $[(Heat_{2034}-Heat_{2024}) \times HeatUse \times Coeff]/WtXHeat_{2024}$

General Demand Input Variables – XCool

	Intensities	Econ + Struct	Regression		
	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total Xcool
2024	317,164	1.44	0.698	0.370	117,739
2034	307,871	1.87	0.698	0.370	148,836
Change	-3.8%	30.2%	0.0%	0.0%	26.4%

XCool = Cooling x CoolUseVariable x Coeff x Scaling Factor

General Demand Input Variables – XOther

	Intensities							Econ + Struct	Reg		
	Vent	Water Heat	Cook	Refrig	Light	Office	Misc	Other Use Var	Coeff	Scaling Factor	Total Xother
2024	110,549	14,613	17,719	194,259	464,452	121,648	305,610	14.80	1.080	0.090	1,767,734
2034	83,335	12,980	16,711	180,289	400,402	129,720	296,021	17.07	1.080	0.090	1,857,456
Change	-2.6%	-0.2%	-0.1%	-1.3%	-6.0%	0.8%	-0.9%	15.3%	0.0%	0.0%	5.1%

XOther = (Ventilation + Water Heat + Cooking + Refrigeration + Lighting + Office + Miscellaneous) x OtherUseVariable x Coeff x Scaling Factor

Industrial Econometric Model Details

Small Industrial model

$$SmlInd_Sales_m = MBin.Jan_m + MBin.Feb_m + MBin.Mar_m + MBin.Apr_m + MBin.May_m + MBin.Jun_m + MBin.Jul_m + MBin.Aug_m + MBin.Sep_m + MBin.Oct_m + MBin.Nov_m + MBin.Dec_m + MBin.Oct22 + b1 \times MEcon.ManGDP$$

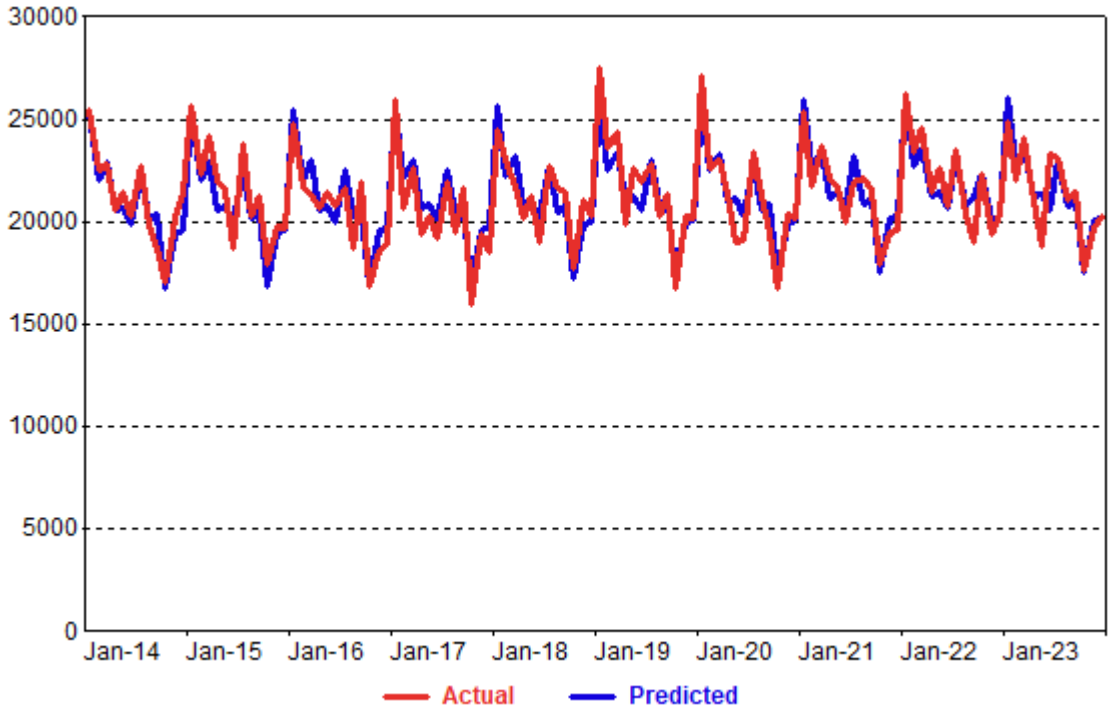
A binary variable was added for October 2022 to account for billing delays after hurricane Fiona.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	20630.178	1697.352	12.154	0.00%
MBin.Feb	17243.849	1698.709	10.151	0.00%
MBin.Mar	18141.898	1700.067	10.671	0.00%
MBin.Apr	15765.299	1701.424	9.266	0.00%
MBin.May	15948.477	1702.782	9.366	0.00%
MBin.Jun	15159.793	1704.140	8.896	0.00%
MBin.Jul	17633.568	1705.498	10.339	0.00%
MBin.Aug	15368.278	1707.436	9.001	0.00%
MBin.Sep	15647.243	1709.374	9.154	0.00%
MBin.Oct	12045.995	1703.137	7.073	0.00%
MBin.Nov	14667.587	1713.250	8.561	0.00%
MBin.Dec	14772.927	1715.188	8.613	0.00%
MBin.Oct22	4821.506	1039.802	4.637	0.00%
MEcon.ManGDP	1.961	0.644	3.046	0.29%

Small Industrial Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.829
Adjusted R-Squared	0.808
AIC	13.885
BIC	14.210
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-989.38
Model Sum of Squares	493,542,174.76
Sum of Squared Errors	101,882,733.93
Mean Squared Error	961,157.87
Std. Error of Regression	980.39
Mean Abs. Dev. (MAD)	734.82
Mean Abs. % Err. (MAPE)	3.51%
Durbin-Watson Statistic	1.883
Durbin-H Statistic	#NA
Ljung-Box Statistic	26.54
Prob (Ljung-Box)	0.3262
Skewness	-0.167
Kurtosis	3.003
Jarque-Bera	0.559
Prob (Jarque-Bera)	0.7561

Small Industrial Model Fit



Medium Industrial Model

$MedInd_Sales_m = MBin.Jan_m + MBin.Feb_m + MBin.Mar_m + MBin.Apr_m + MBin.May_m + MBin.Jun_m + MBin.Jul_m + MBin.Aug_m + MBin.Sep_m + MBin.Oct_m + MBin.Nov_m + MBin.Dec_m + MBin.Aft16 + b1 \times MEcon.ManEmp$

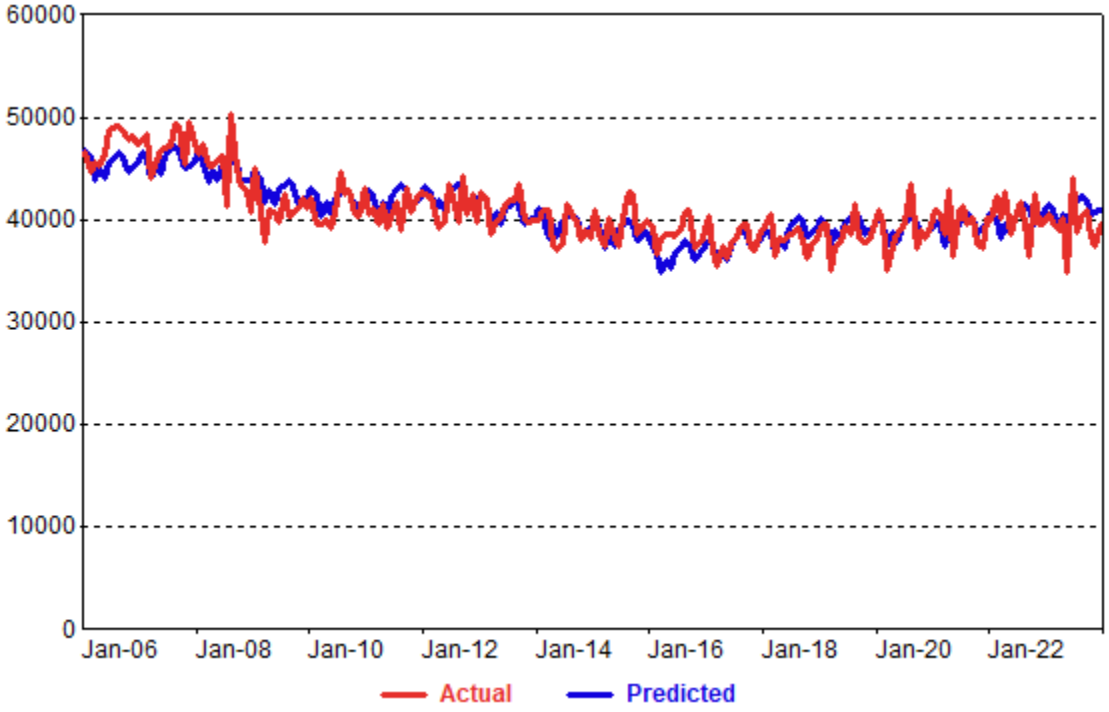
A binary variable for 2016 and subsequent years was added for improved model fit as the historic sales trend transitioned from declining to flat. As discussed in Section 4.0, a historic period of 2006–2023 was used to improve model fit.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	21608.674	1496.470	14.440	0.00%
MBin.Feb	20881.656	1495.637	13.962	0.00%
MBin.Mar	18974.978	1494.804	12.694	0.00%
MBin.Apr	20276.370	1493.971	13.572	0.00%
MBin.May	19261.195	1493.138	12.900	0.00%
MBin.Jun	20947.563	1492.305	14.037	0.00%
MBin.Jul	21334.835	1491.472	14.305	0.00%
MBin.Aug	21932.918	1491.008	14.710	0.00%
MBin.Sep	21468.132	1490.543	14.403	0.00%
MBin.Oct	19865.894	1490.079	13.332	0.00%
MBin.Nov	20256.638	1489.615	13.599	0.00%
MBin.Dec	20550.323	1489.151	13.800	0.00%
MBin.Aft16	-2479.954	258.015	-9.612	0.00%
MEcon.ManEmp	635.323	41.557	15.288	0.00%

Medium Industrial Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	216
Deg. of Freedom for Error	202
R-Squared	0.703
Adjusted R-Squared	0.684
AIC	15.079
BIC	15.298
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,921.03
Model Sum of Squares	1,591,772,636.22
Sum of Squared Errors	671,308,642.90
Mean Squared Error	3,323,310.11
Std. Error of Regression	1,822.99
Mean Abs. Dev. (MAD)	1,369.04
Mean Abs. % Err. (MAPE)	3.35%
Durbin-Watson Statistic	1.412
Durbin-H Statistic	#NA
Ljung-Box Statistic	217.83
Prob (Ljung-Box)	0.0000
Skewness	-0.070
Kurtosis	3.069
Jarque-Bera	0.222
Prob (Jarque-Bera)	0.8950

Medium Industrial Model Fit



Combined Model for Commercial and Industrial DSM Coefficient

$NonResSales_m = b1 \times NonResEESavingsProfiled_m + b2 \times GenWtXHeat_m + b3 \times GenWtXCool_m + b3 \times GenWtXOther_m + b4 \times NonResCustomers_m + MBin.Feb18_m + MBin.Oct22$

Weighted X variables from the General Service model were used to represent the underlying end uses in conjunction with the non-residential portion of historical DSM savings, as well as the number of non-residential customers to help explain underlying sales trends over time. Binary variables were added for February 2018 and October 2022 for problems with the billing.

Variable	Coefficient	StdErr	T-Stat	P-Value
MSales.EESavingsProfiled	-0.448	0.108	-4.147	0.01%
MStructGen.WtXCool	0.544	0.055	9.958	0.00%
MStructGen.WtXHeat	0.878	0.041	21.349	0.00%
MStructGen.WtXOther	0.935	0.345	2.708	0.80%
MSales.NonResCusts	3.815	1.339	2.850	0.53%
MBin.Feb18	35403.115	11151.649	3.175	0.20%
MBin.Oct22	38376.536	11218.875	3.421	0.09%

The coefficient on the EESavings variable represents the amount of DSM needed to explain historical sales trends beyond the changes in the underlying end-uses.

Combined Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	108
Deg. of Freedom for Error	101
R-Squared	0.831
Adjusted R-Squared	0.821
AIC	18.657
BIC	18.831
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,153.74
Model Sum of Squares	59,109,328,237.04
Sum of Squared Errors	12,019,848,479.24
Mean Squared Error	119,008,400.78
Std. Error of Regression	10,909.10
Mean Abs. Dev. (MAD)	8,600.90
Mean Abs. % Err. (MAPE)	2.75%
Durbin-Watson Statistic	1.855
Durbin-H Statistic	#NA
Ljung-Box Statistic	47.39
Prob (Ljung-Box)	0.0030
Skewness	0.061
Kurtosis	2.571
Jarque-Bera	0.894
Prob (Jarque-Bera)	0.6397

Peak Forecast (Accrued Classes)

The long-term system peak forecast for the accrued classes is derived through a monthly peak linear regression model that relates monthly peak demand (excluding large customer contribution) to heating, cooling, and base load requirements, as well as average daily wind:

$$Peak_m = b1 \times HeatVar_m + b2 \times CoolVar_m + b3 \times BaseVar_m + b5 \times PkWindVar_m + \sum Binaries$$

The model variables ($HeatVar_m$, $CoolVar_m$, and $BaseVar_m$) incorporate changes in heating, cooling, and base-use energy requirements (which are derived from the class sales forecast models) as well as peak-day weather conditions.

The composition of the models allows historical and forecast heating and cooling load requirement to be estimated. The model coefficients for the heating (*XHeat*) and cooling variables (*XCool*) combined with heating and cooling variable for calendar-month normal weather conditions produce an estimate of the monthly heating and cooling load requirements.

Heating requirements are calculated as:

$$HeatLoad_m = B_1 \times ResXHeat_m + C_1 \times SmlGSXHeat_m + D_1 \times GSXHeat_m$$

Where *B1, C1*, and *D1* are the coefficients on *XHeat* in the Residential, Small General Service, and General Service sales forecast models.

Cooling requirements are estimated in a similar manner. Cooling requirements are calculated as:

$$CoolLoad_m = B_2 \times ResXCool_m + C_2 \times SmlGSXCool_m + D_2 \times GSCool_m$$

Where *B2*, *C2*, and *D2* are the coefficients on *XCool* in the residential, Small General Service, and General Service sales forecast models.

In constructing the monthly peak model variables, the heating and cooling load requirements are normalized for the number of days and hours in the month by expressing heating and cooling load requirements on an average MW load basis:

$$HeatAvgMW_m = HeatLoad_m / Days_m / 24$$

$$CoolAvgMW_m = CoolLoad_m / Days_m / 24$$

The impact of peak-day weather conditions are then captured by interacting peak-day HDD and CDD with average monthly heating and cooling load requirements. *HeatAvgMW* and *CoolAvgMW* are interacted with peak-day *HDD* and *CDD* indexes, which allows the impact of peak-day *HDD* and *CDD* to change over the estimation period as the underlying heating and cooling load requirements change.

The peak model heating and cooling variables are calculated as:

$$HeatVar_m = HeatAvgMW_m \times PkHDDIdx_m$$

$$CoolVar_m = CoolAvgMW_m \times PkCDDIdx_m$$

The peak model base load variable ($BaseVar_m$) is constructed to capture the impact of loads that are not weather sensitive on peak, including residential, commercial, other end-use components along with industrial and unmetered sales. Base load requirements are calculated as:

$$BaseVar_m = \sum C_m \times mBin \times OtherLoad_m$$

Where the C_m coefficients are regression coefficients associated with the portions of $OtherLoad_m$, corresponding to a specific month of the year. In this way $BaseVar_m$ measures the strength of the non-weather sensitive load drivers in each month of the year. $OtherLoad_m$ is comprised of:

$$OtherLoad_m = ResOther_m + SmlGSOther_m + GSOther_m + SmIndSales_m + MedIndSales_m + UnMSales_m$$

Where $ResOther_m$, $SmlOther_m$ and $GSOther_m$ are the non-weather dependent portion of the sales model (including embedded DSM). For example, the energy sales model can be written as:

$$ResSales = b1 \times ResXHeat + b2 \times ResXCool + ResOther$$

Where *b1* and *b2* are regression coefficients found after running the sales model. *ResOther* can be written as:

$$ResOther_m = ResSales_m - b1 \times ResXHeat_m - b2 \times ResXCool_m$$

In this way, $ResOther_m$ (and $SmlOther_m$ and $GSOther_m$) carries the non-weather dependent variables, including past energy-related DSM activity into the peak model, whose impact was assessed through specific coefficients in the energy sales model.

The $OtherLoad_m$ requirements are normalized for the number of days and hours in the month by expressing the load requirements on an average MW load basis:

$$OtherAvgMW_m = OtherLoad_m / Days_m / 24$$

The $PkWindVar_m$ is the average daily windspeed on monthly peak days. Binaries are included for June 2020 to account for a high residual and for October 2022 to account for the impact of billing delays related to hurricane Fiona in the energy models.

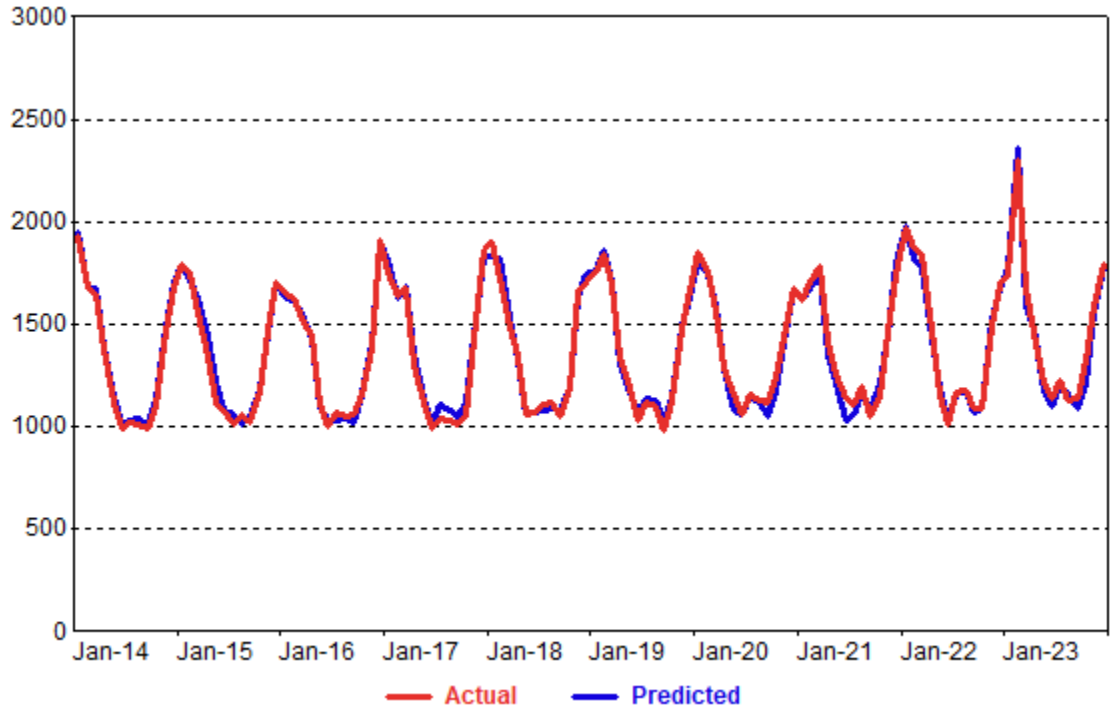
Variable	Coefficient	StdErr	T-Stat	P-Value
mVarsNew.Heat_Var	1.541	0.080	19.375	0.00%
mVarsNew.Cool_Var	1.346	0.206	6.536	0.00%
mVarsNew.Jan_Other	1.078	0.085	12.734	0.00%
mVarsNew.Feb_Other	1.007	0.096	10.524	0.00%
mVarsNew.Mar_Other	1.198	0.078	15.281	0.00%
mVarsNew.Apr_Other	1.450	0.048	29.951	0.00%
mVarsNew.May_Other	1.517	0.034	44.820	0.00%
mVarsNew.Jun_Other	1.604	0.030	52.878	0.00%
mVarsNew.Jul_Other	1.630	0.043	37.588	0.00%
mVarsNew.Aug_Other	1.463	0.052	27.947	0.00%
mVarsNew.Sep_Other	1.499	0.029	51.536	0.00%
mVarsNew.Oct_Other	1.565	0.031	50.455	0.00%
mVarsNew.Nov_Other	1.646	0.048	34.516	0.00%
mVarsNew.Dec_Other	1.478	0.074	19.926	0.00%
mPkDayWthr.PkWind	4.941	0.692	7.139	0.00%
mBin.Oct22	-235.749	45.420	-5.190	0.00%
mBin.Jun20	184.032	43.195	4.260	0.00%

Peak Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	103
R-Squared	0.984
Adjusted R-Squared	0.982
AIC	7.573345
BIC	7.968239
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-607.67331
Model Sum of Squares	11,093,127.532
Sum of Squared Errors	175,870.484
Mean Squared Error	1,707.48043
Std. Error of Regression	41.32167
Mean Abs. Dev. (MAD)	29.99085
Mean Abs. % Err. (MAPE)	2.31%
Durbin-Watson Statistic	1.402
Durbin-H Statistic	#NA
Ljung-Box Statistic	36.80
Prob (Ljung-Box)	0.0458
Skewness	0.116
Kurtosis	3.239
Jarque-Bera	0.553
Prob (Jarque-Bera)	0.7584

Peak Model Fit

As seen in the figure below (and in the model statistics above), this approach produces a good fit with historical data. Although it was not possible to produce a peak model with an explicit peak DSM variable (like the Residential model) as the associated parameters are insignificant, the indirect effects of energy related DSM in the historical data from the end use model are carried over into the peak model. Assuming there is a relationship between the DSM applied to peak savings and DSM applied to energy savings, this will result in a similar amount of DSM embedded in the peak forecast, either through the embedded portion of energy sales DSM that is present on the $OtherLoad_m$ or embedded on the accrued demand information measured at the system level.



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Appendix C

Forecast Comparison and Accuracy

Figure C1: Total Nova Scotia Energy Requirement (NSR)

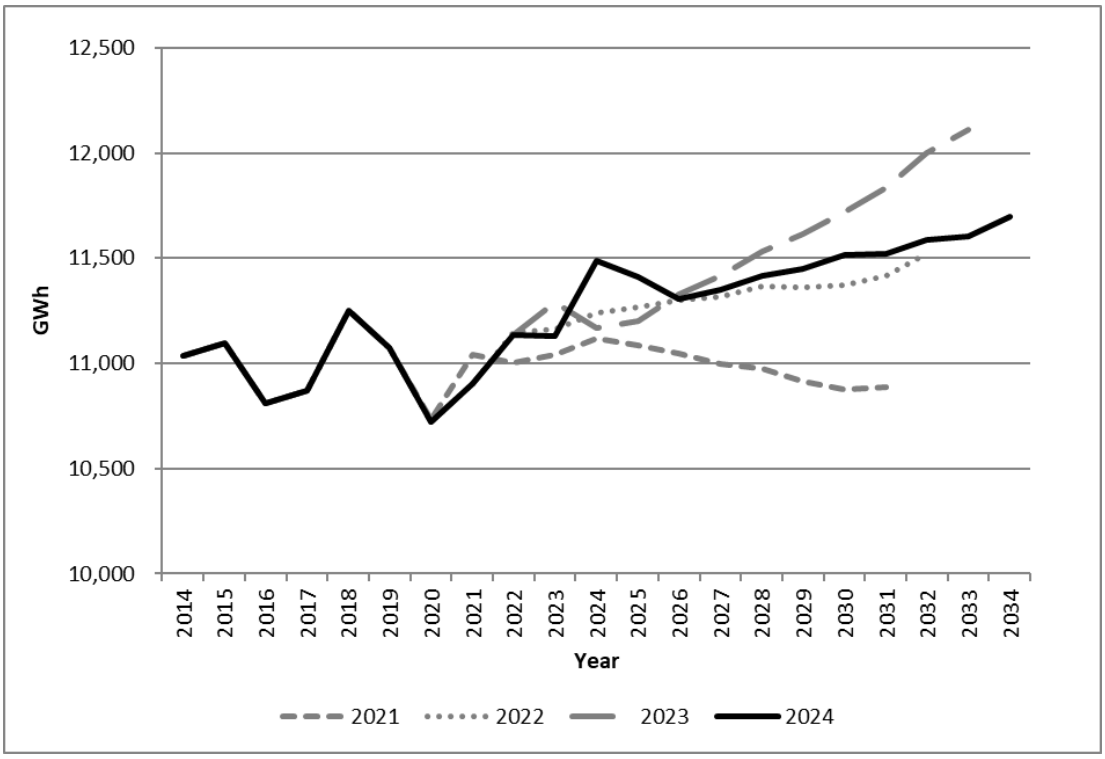


Figure C2: System Peak Demand

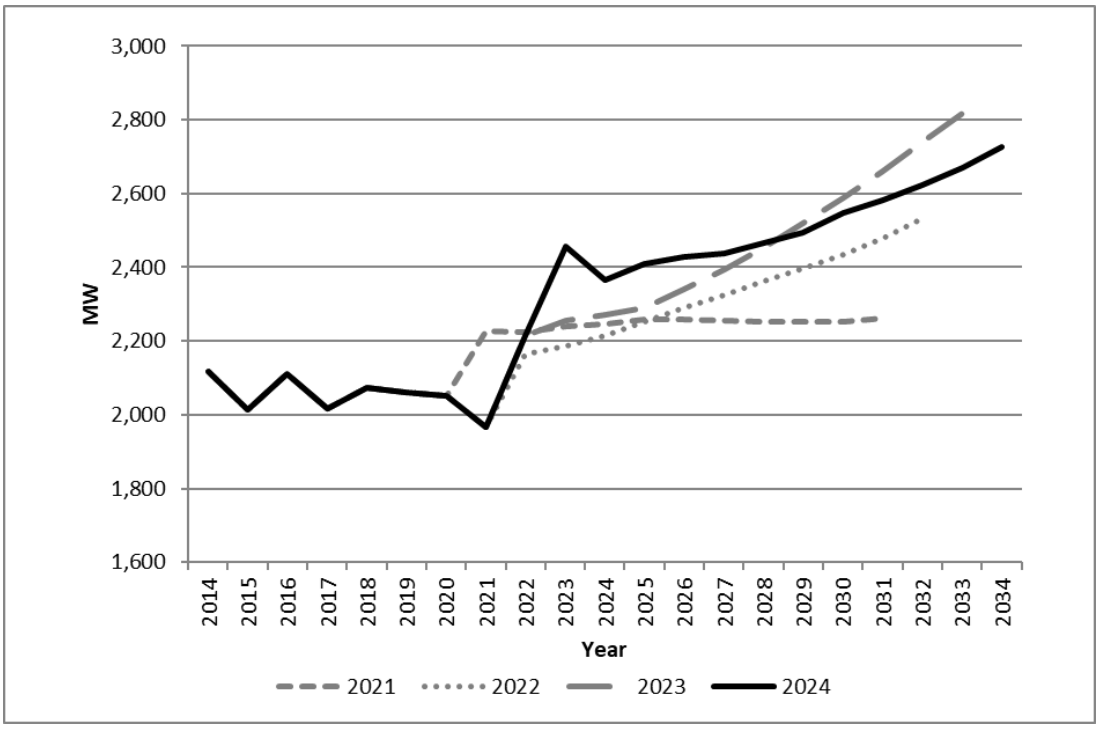


Figure C3: Firm Peak Demand

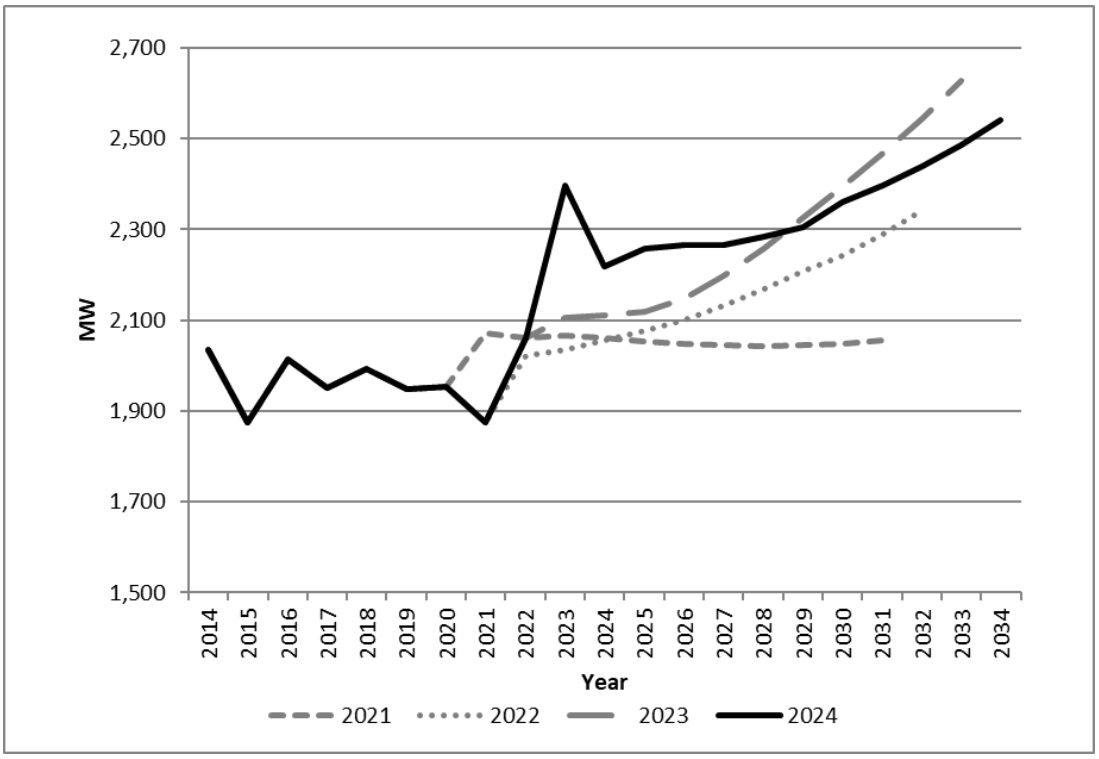


Figure C4 below provides an overview of the energy forecast accuracy. For these calculations, the load of the major pulp and paper mills is removed from the net system requirement as these contribute a significant amount of unforeseeable variance to the results. The rows show each years' 10-year forecast series with the forecast mill load removed. The row labeled "Actuals less mills" is the actual NSR with mill load removed. Each forecast year is compared to the corresponding actual value, and a 10-year average is calculated based on number of years out in the forecast series. So, a lead time of 1 would correspond to the average error of all the forecast first year estimates versus the corresponding actual value. The statistics show that on a 5-year basis the error (mean absolute percent error, or MAPE) averages just over 2 percent. Beyond 5 years the accuracy diminishes. **Figure C5** provides the same analysis for the firm peak load (the mills are not considered part of the firm load). As the peak is much more sensitive to weather, the error is larger, but averages just over 5 percent in the first 5-year period, with accuracy diminishing in later years. **Figure C6** provides the system peak accuracy, with an average of just under 5 percent in the first 5-year period.

Figure C4: Energy Forecast Accuracy

NSR less mills										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2013	9787	9790	9723	9647	9578	9603	9580	9533	9466	9434
2014		10101	10066	10063	10067	10076	10070	10071	10081	10139
2015			10013	10036	10020	9986	9918	9833	9769	9731
2016				10156	10180	10202	10233	10216	10235	10254
2017					9931	9896	9920	9891	9902	9927
2018						9944	9947	9860	9825	9779
2019							10168	10171	10146	10108
2020								10056	10109	10152
2021									10011	10049
2022										10117
Actuals minus Mills										
Percent Error										
2013	-1.9%	-3.0%	-0.9%	-2.2%	-5.7%	-6.0%	-2.7%	-4.1%	-7.0%	-9.8%
2014		0.1%	2.6%	2.0%	-0.9%	-1.4%	2.3%	1.4%	-0.9%	-3.1%
2015			2.1%	1.7%	-1.4%	-2.2%	0.7%	-1.0%	-4.0%	-7.0%
2016				2.9%	0.2%	-0.1%	3.9%	2.8%	0.6%	-2.0%
2017					-2.3%	-3.1%	0.7%	-0.5%	-2.7%	-5.1%
2018						-2.6%	1.0%	-0.8%	-3.5%	-6.5%
2019							3.3%	2.4%	-0.3%	-3.4%
2020								1.2%	-0.7%	-3.0%
2021									-1.6%	-3.9%
2022										-3.3%

NSR less mills										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Statistics										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	-0.2%	-0.3%	-0.5%	-1.3%	-2.1%	-1.9%	-1.8%	-4.0%	-5.0%	-9.8%
MAPE:	2.1%	2.1%	1.1%	2.4%	3.3%	3.0%	2.5%	4.0%	5.0%	9.8%

Figure C5: Firm Peak Forecast Accuracy

Firm Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2013	1,939	1,950	1,948	1,944	1,935	1,943	1,939	1,934	1,925	1,923
2014		1,940	1,932	1,916	1,911	1,907	1,910	1,899	1,896	1,894
2015			1,892	1,896	1,897	1,889	1,878	1,859	1,847	1,837
2016				1,987	2,009	2,023	2,033	2,041	2,051	2,057
2017					1,993	2,010	2,029	2,038	2,054	2,073
2018						2,001	2,015	2,016	2,021	2,028
2019							2,070	2,073	2,078	2,080
2020								2,085	2,053	2,059
2021									2,062	2,065
2022										2,035
Actual Firm Peak:	2,036	1861.3	2013.6	1,951	1,993	1,949	1954	1,875	2,061	2,397
Percent Error										
2013	-4.7%	4.8%	-3.3%	-0.4%	-2.9%	-0.3%	-0.8%	3.2%	-6.6%	-19.8%
2014		4.2%	-4.1%	-1.8%	-4.1%	-2.2%	-2.3%	1.3%	-8.0%	-21.0%
2015			-6.0%	-2.8%	-4.8%	-3.1%	-3.9%	-0.8%	-10.4%	-23.4%
2016				1.8%	0.8%	3.8%	4.0%	8.9%	-0.5%	-14.2%
2017					0.0%	3.1%	3.8%	8.7%	-0.3%	-13.5%
2018						2.7%	3.1%	7.5%	-1.9%	-15.4%
2019							5.9%	10.6%	0.8%	-13.2%
2020								11.2%	-0.4%	-14.1%
2021									0.1%	-13.9%
2022										-15.1%

Firm Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Statistics										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	0.0%	0.1%	-1.0%	-1.4%	-2.6%	-3.5%	-6.0%	-9.4%	-13.8%	-19.8%
MAPE:	5.2%	4.8%	5.0%	5.1%	5.6%	3.5%	6.7%	11.5%	13.8%	19.8%

Figure C6: System Peak Forecast Accuracy

System Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
2013	2,077	2,089	2,086	2,083	2,074	2,082	1,947	1,942	1,932	1,930
2014		2,078	2,062	2,057	2,053	2,051	2,045	2,042	2,039	2,048
2015			2,031	2,035	2,036	2,028	2,016	1,997	1,985	1,975
2016				2,130	2,156	2,170	2,180	2,188	2,197	2,203
2017					2,149	2,166	2,184	2,193	2,208	2,227
2018						2,157	2,172	2,174	2,178	2,184
2019							2,234	2,243	2,248	2,249
2020								2,237	2,212	2,220
2021									2,225	2,240
2022										2,185
Actual System Peak:	2,118	2,015	2,111	2,018	2,073	2,060	2,050	1,968	2,216	2,455
Percent Error										
2013	-1.9%	3.7%	-1.2%	3.2%	0.1%	1.1%	-5.0%	-1.3%	-12.8%	-21.4%
2014		3.1%	-2.3%	2.0%	-0.9%	-0.5%	-0.3%	3.7%	-8.0%	-16.6%
2015			-3.8%	0.9%	-1.8%	-1.6%	-1.7%	1.5%	-10.4%	-19.6%
2016				5.6%	4.0%	5.3%	6.3%	11.2%	-0.8%	-10.3%
2017					3.7%	5.1%	6.5%	11.4%	-0.3%	-9.3%
2018						4.7%	5.9%	10.4%	-1.7%	-11.0%
2019							9.0%	14.0%	1.5%	-8.4%
2020								13.6%	-0.2%	-9.6%
2021									0.4%	-8.8%
2022										-11.0%

System Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Statistics										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	2.3%	2.5%	1.6%	1.2%	-0.4%	-1.6%	-5.5%	-9.6%	-14.7%	-21.4%
MAPE:	5.7%	5.0%	4.8%	4.8%	4.1%	2.6%	7.4%	9.6%	14.7%	21.4%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Appendix D

Forecast Sensitivity Analysis

Sensitivity Analysis

The P10/P90 sensitivity analysis used Monte Carlo simulation for the economic and weather variables.

The algorithm uses the following sequence

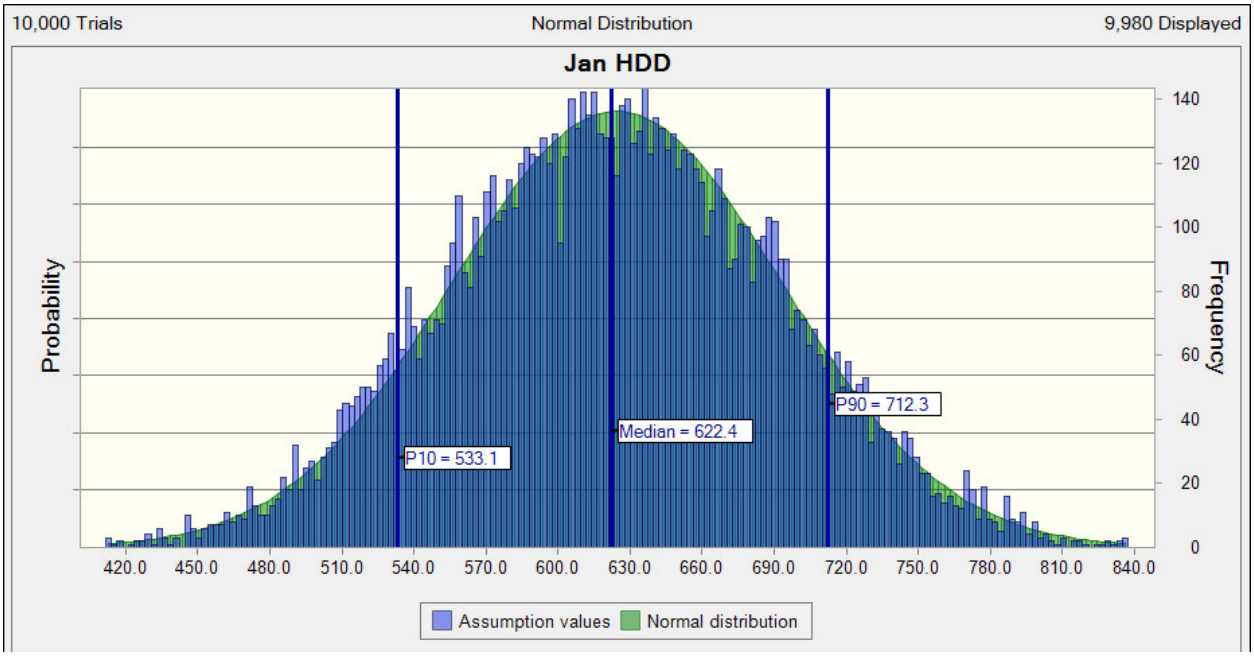
1. Once the deterministic SAE class regression models are completed, the regression coefficients are exported into the Monte Carlo tool, called Oracle Crystal Ball (MS Excel add-on).

2. The Monte Carlo process assumes that the regression coefficients are held constant throughout the simulation, the historical variation of the inputs (predictors, independent variables) will affect the forecast prediction, in a probabilistic way. In other words, the simulations help to understand how the underlying SAE forecast responds to changes to the inputs based on historical variation.

3. For 2024 the historical variation of monthly and peak day weather (20 years of hourly temperatures expressed in HDDs and CDDs) and economic drivers (20 years of annual data, as obtained from Conference Board of Canada Economic models) was used.

4. The variation of the weather and economic drivers is treated as Normal distributions (see **Figure D1**).

Figure D1: Distribution of January HDD



5. Oracle's Crystal Ball runs about 10,000 trials, taking a random set of numbers from the relevant variables for each trial. For example, the random HDD variable for January (above), would have a Normal distributed weight, meaning that after 10,000 trials, a histogram of the variable will have an average and standard deviation that coincides with the distribution of the last 20 years.

6. Incorporating variability in the individual end uses is still in progress, as it is difficult to produce a distribution for historical end use data. EIA and NRCan have revised their historical data sets in recent years, making historical variation studies challenging. However, as noted in previous sections, heat pumps are included in the input SAE models, and therefore their contributions to load will have an impact in the simulations as well.

7. At the end of the Monte Carlo run, 10,000 output forecast points are produced, each year represented by 10,000 possible outputs, with Normal distributed averages and standard deviations, which are the result of the different combination of the random variable trials.

These distributions are shown in **Figure D2** for energy and **Figure D3** for peak (both before the impact of DSM). 10th (10%) and 90th (90%) percentiles can easily be obtained from Normal distributions and so they are highlighted in D2.

Figure D2: Distribution of Energy (Before DSM)

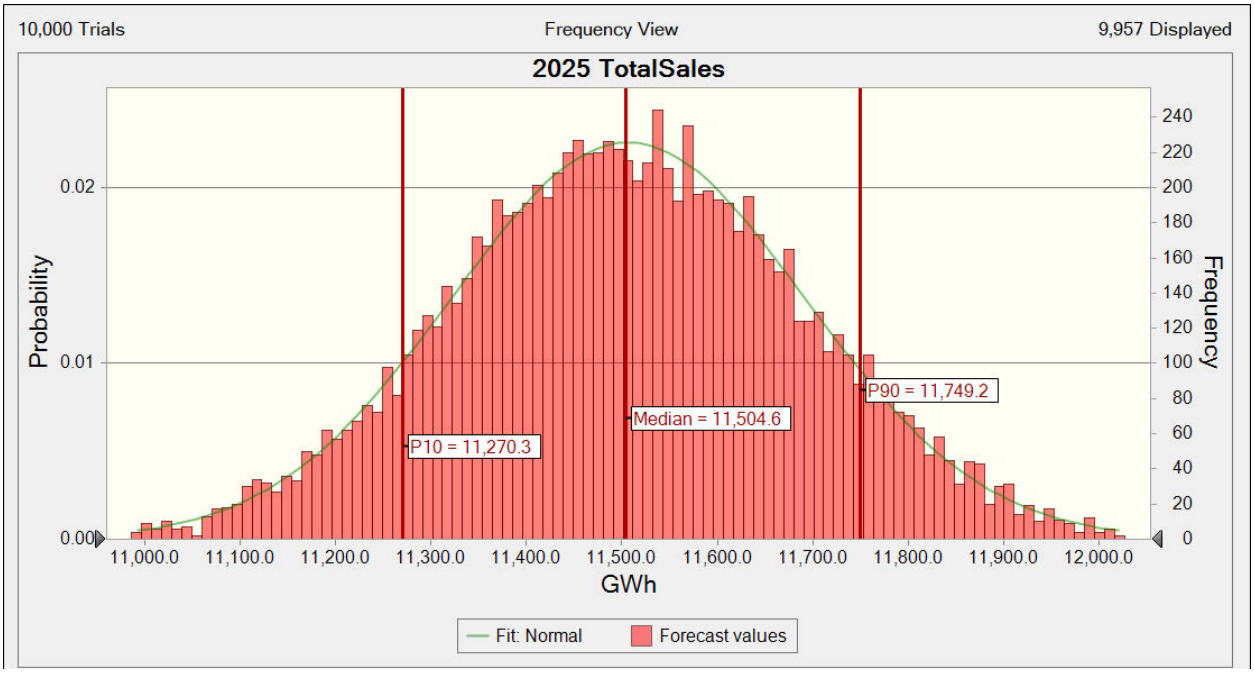
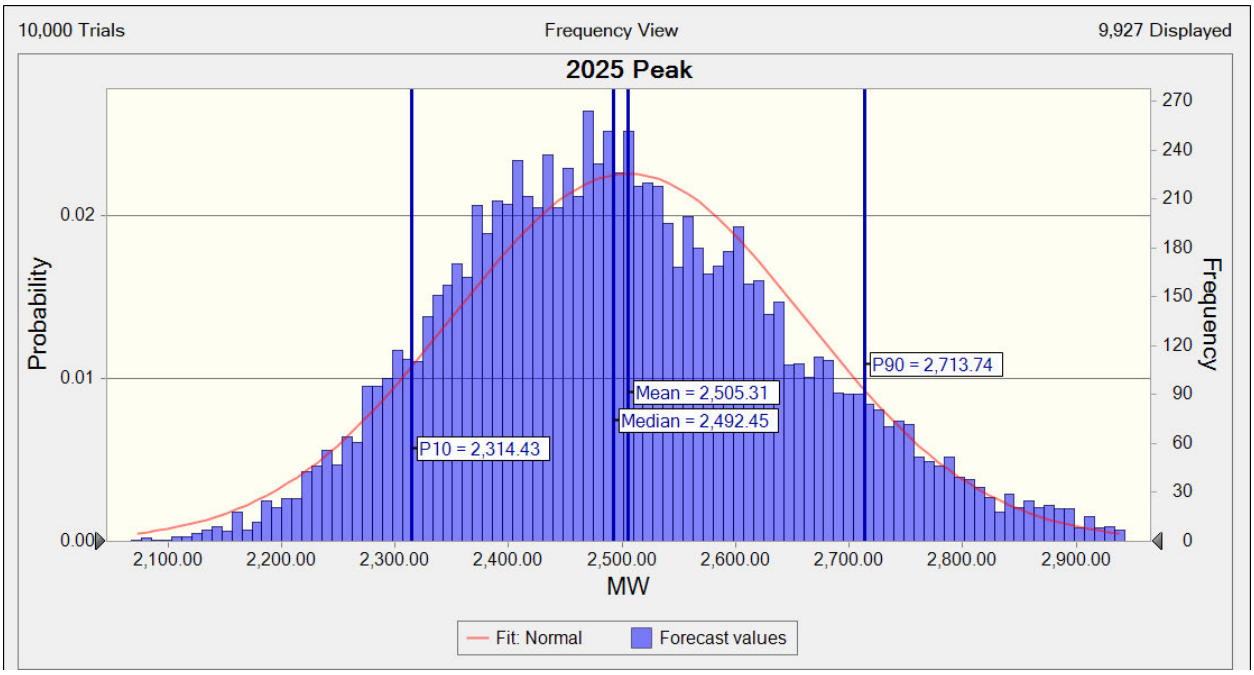
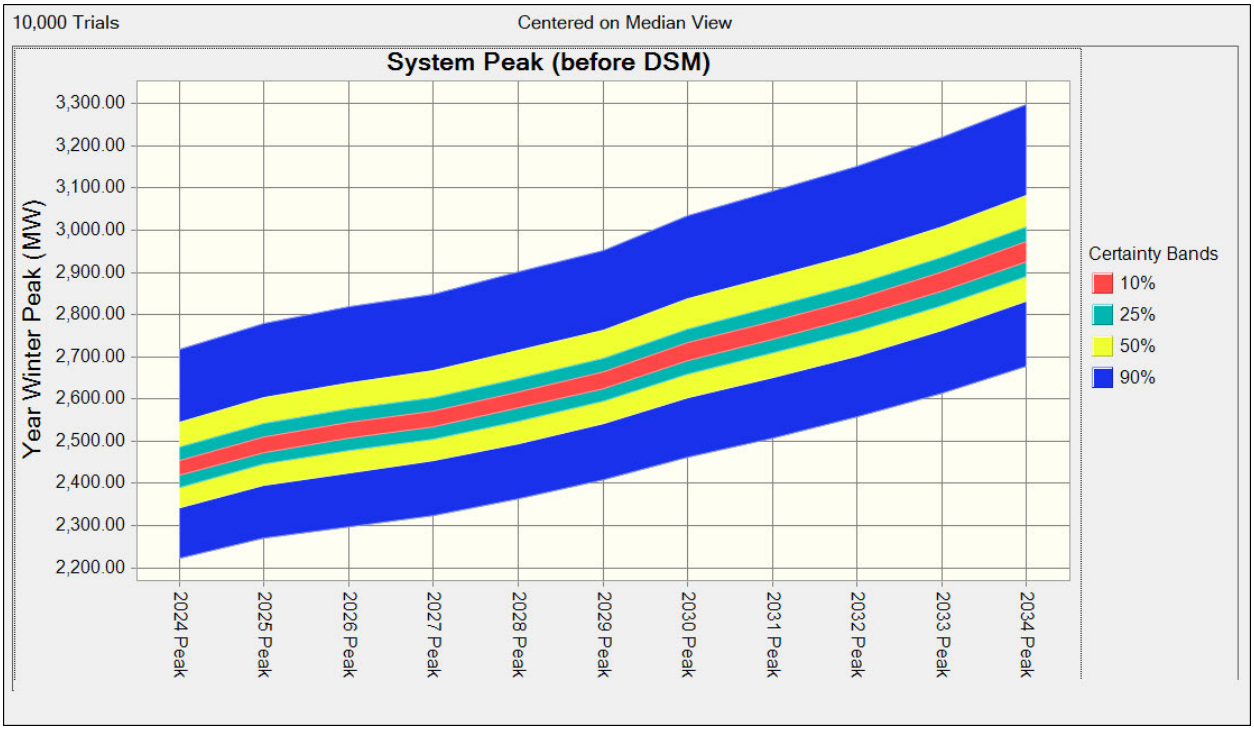


Figure D3: Distribution of Peak (Residential, Commercial and Small and Medium Industrial)



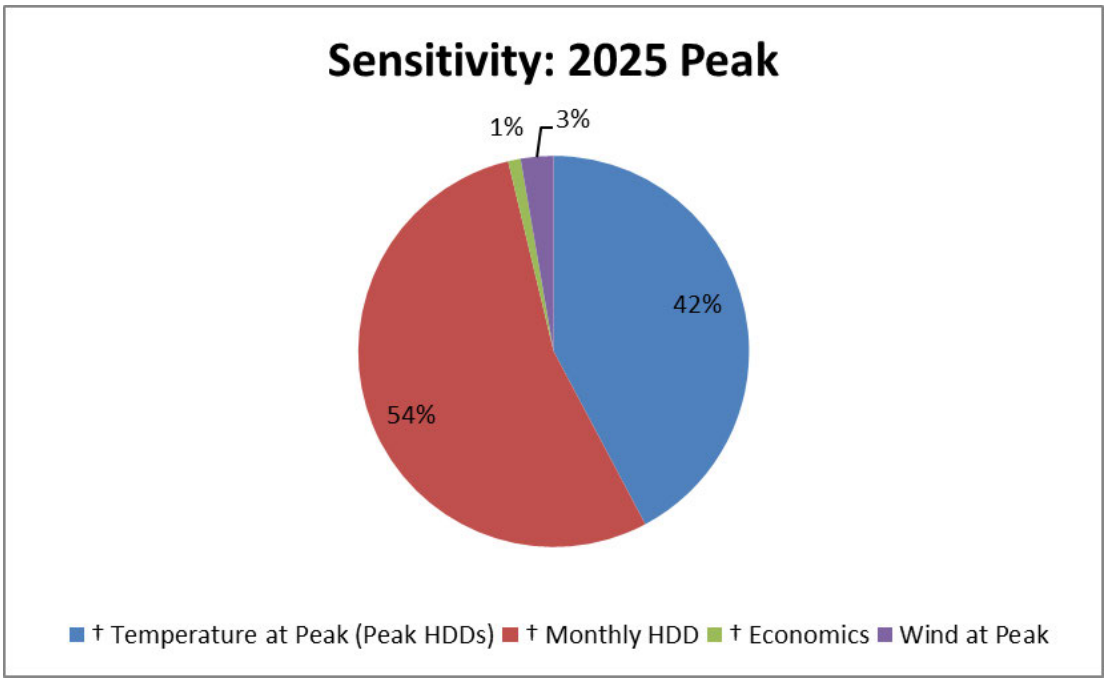
8. From these annual forecast distributions, the various probabilistic forecasts can be obtained as well as sensitivity diagrams that show the relative impact of the variables in each year. In **Figure D4** the probabilities of system peak forecasts (before DSM) around the median are shown. The area contained between blue borders represents a range of peaks that has a 90% chance of occurring; the yellow area highlights a 50% chance, and so on.

Figure D4: Peak Forecast (Residential, Commercial and Small and Medium Industrial)



The asymmetry in this figure, seen as the off-centre median, is explained by the bias introduced by plotting the maximum monthly Peak of a given year. Every month has a normal distributed daily Peak HDD, however by using the MAX function a skewed quasi-normal distribution is created when it selects the maximum Peak HDD from the 12 available months. Peak Demand and its associated SAE model are mostly sensitive to the Peak HDD temperature, however, as shown in **Figure D5**, the Monthly HDD has surpassed Peak HDD importance (which now is based in a 12-hour average) in 2025 as year-long residential heating had an impact on sales, and therefore, that impact (sensitive to monthly variations) was translated into Peak Demand.

Figure D5: Relative Sensitivity of Peak



In terms of the sensitivity of the energy sales forecast to the various input variables, **Figures D6 and D7** show that in the near term, weather represents the strongest sensitivity, while in the long term, economics becomes dominant. This is mainly due to the compounding effect of economics over time, as opposed to weather which will only impact a particular year. By 2034 the cumulative impact of the economic variables makes economics rival weather in forecast sensitivity. The monthly (rather than cumulative) nature of HDD means it has much less relative impact in the long term.

Figure D6: Sensitivity of Energy Forecast (2025)

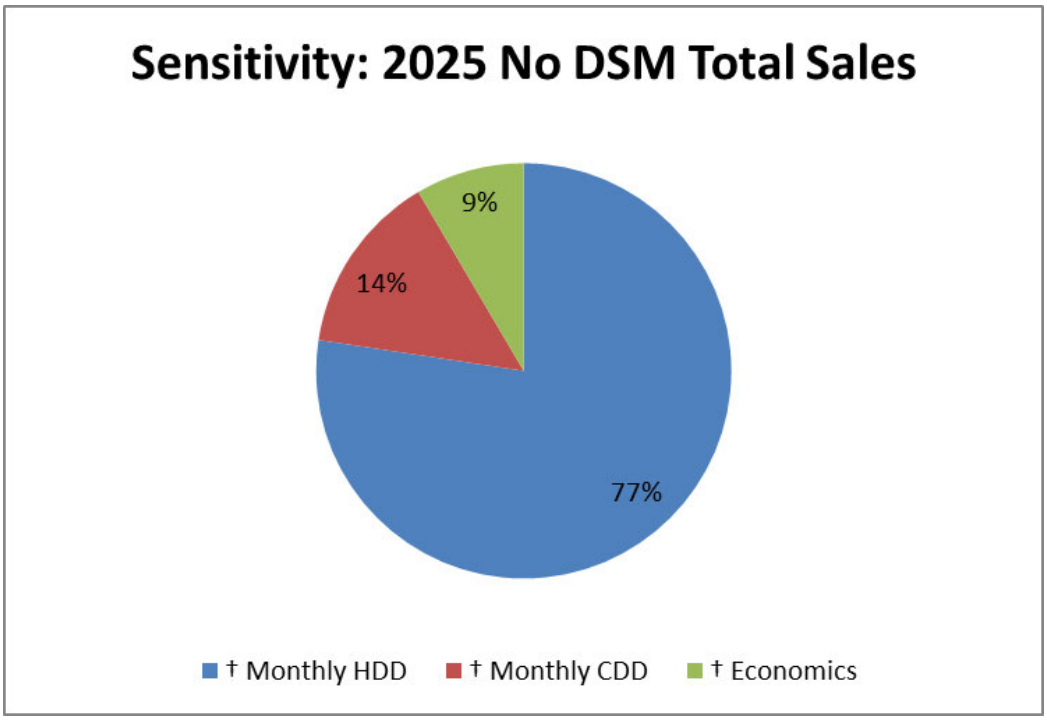
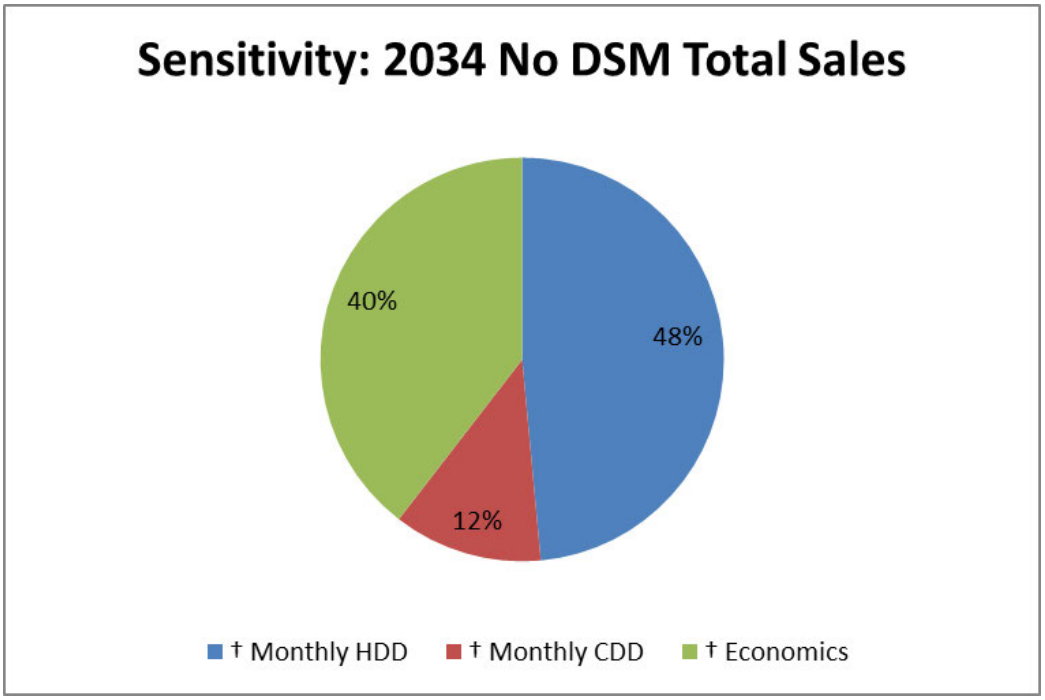


Figure D7: Sensitivity of Energy Forecast (2034)



In terms of relative magnitude of the sensitivities, on the energy side DSM, [redacted] and EVs are the main drivers, while on the peak side DSM, EVs, hybrid heating peak mitigation and weather/economics are all similar. **Figure D8** shows the relative impact of these items.

Figure D8: Relative Impact of Inputs

Item	2024 Energy (GWh	2024 Peak (MW)	2034 Energy (GWh)	2034 Peak (MW)
Included in Forecast				
DSM (base case)	-143	-26	-1483	-266
Solar PV	-55	0	-681	0
[redacted]				
EV (current forecast)	18	6	566	156
Other Possible Scenarios				
EV (current forecast, no peak mitigation)	18	10	566	281
2 Hydrogen Production Facilities (firm supply portion)	0	0	824	130
Battery (5% share by 2033)	0	0	0	-135
Weather/Economics P10/P90	+/-234	+/-215	+/-323	+/-265
Price Elasticity of -0.458	32	0	-57	0

At this time, any potential impacts of the proposed hydrogen facilities on the NS Power's Net System Requirement and System Peak are still being evaluated. NS Power understands that two proposed projects have indicated a potential combined firm demand of 130 MW, which is reflected in **Figure D8**. In this sensitivity, the energy required by the facilities is assumed to be mostly self-supplied, with some top up supply from NS Power. The development of this new sector will continue to be monitored in future Load Forecast Reports.

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APRIL 11, 2024

2024 10yr Preliminary Forecast

Purpose

- As in previous years, this presentation on the preliminary 10-year load forecast provides an opportunity to discuss improvements and updates to the forecast and allow stakeholders to ask questions. This allows for feedback to be integrated in the final report and to ensure any outstanding issues are addressed.

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Agenda

- Summary of Changes from 2023 Forecast
- Preliminary Results by Class
- Ongoing Work

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Timeline

- November 2023: NSUARB Load Forecast Decision released
- December 2023 – March 2024: Forecast preparation
- April 2024: Stakeholder meeting to discuss updates and preliminary results
- April 30, 2024: 2024 Load Forecast Report submitted to the NSUARB

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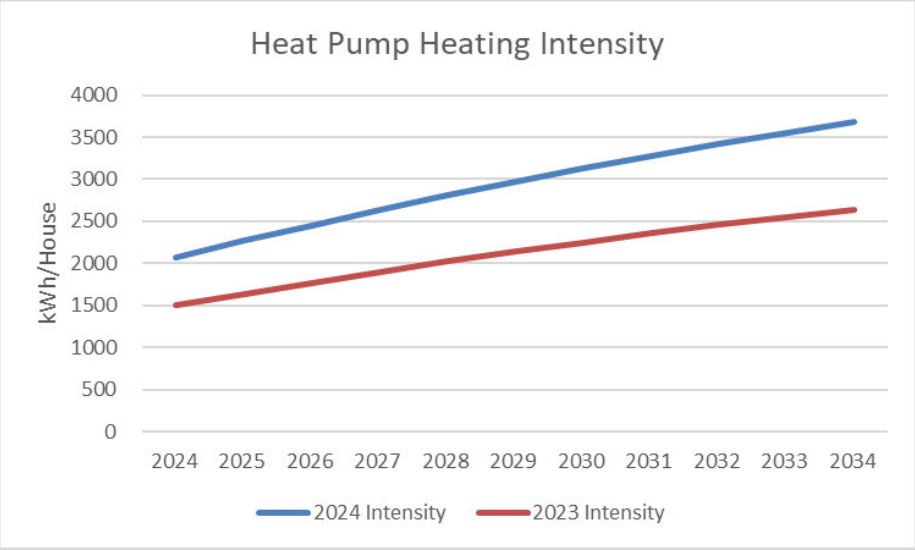
Changes from 2023

Input	Data Source
Heating intensity	Residential heating intensity updated to reflect 2022 and 2023 actual results.
EVs	Vehicle sales updated to reflect the fact that government mandates (20% zero emissions vehicle sales by 2026, 60% by 2030, 100% by 2035) are at the national level, not the provincial level.
Electrification of heating	E3 forecast for electrification of residential and commercial heating based on “Hybrid” scenario.
RTR in the forecast	RTR load expected in 2025 (61 GWh) and 2026 (246 GWh).
Increased solar generation	Behind the meter solar generation expected to increase compared to the 2023 forecast driven by commercial class.

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Heating Intensity

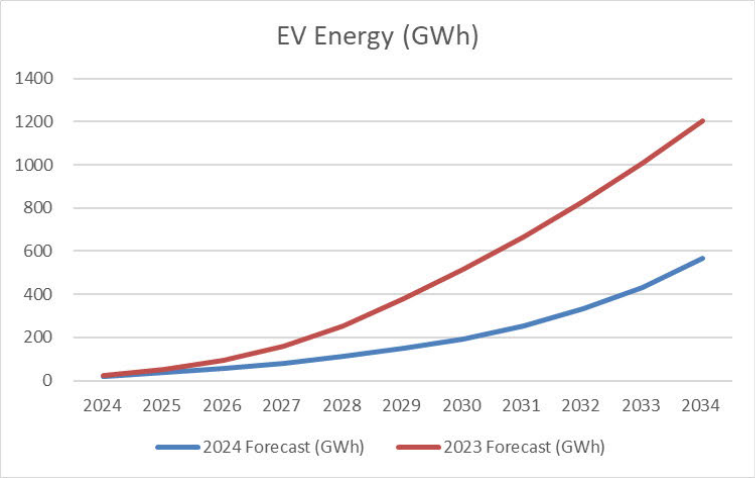
- Both 2022 and 2023 had significant unexplained variances in the Residential class when the impact of weather is included.
- Variances were greatest in winter months, indicating that missing load is likely heating related.
- Heating intensity of heat pumps was increased to account for the missing heating load in the forecast.

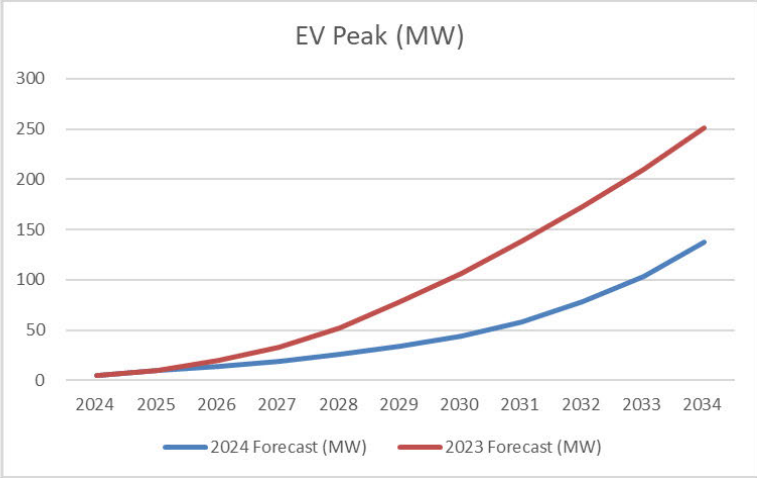


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EVs

- 2024 forecast has been updated to account for the fact that the federal government's zero emissions vehicle (ZEV) sales targets of 60% by 2030 and 100% by 2035 apply at the national level and NS sales will lag.
- EV load shapes are used for energy and peak (managed and unmanaged peak impact).
- 2023 forecast had 1202 GWh (282K vehicles, including medium and heavy-duty) by 2034, while the 2024 forecast has 566 GWh (149K vehicles).
- The peak forecast has decreased from 251 MW to 137 MW in 2034.



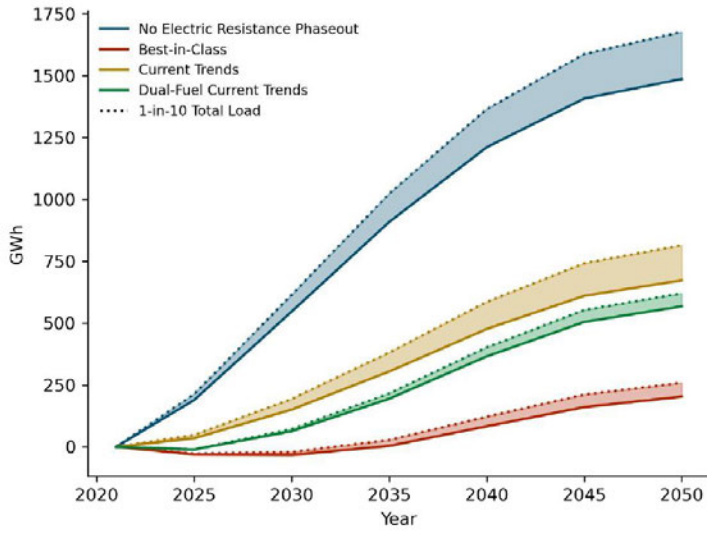


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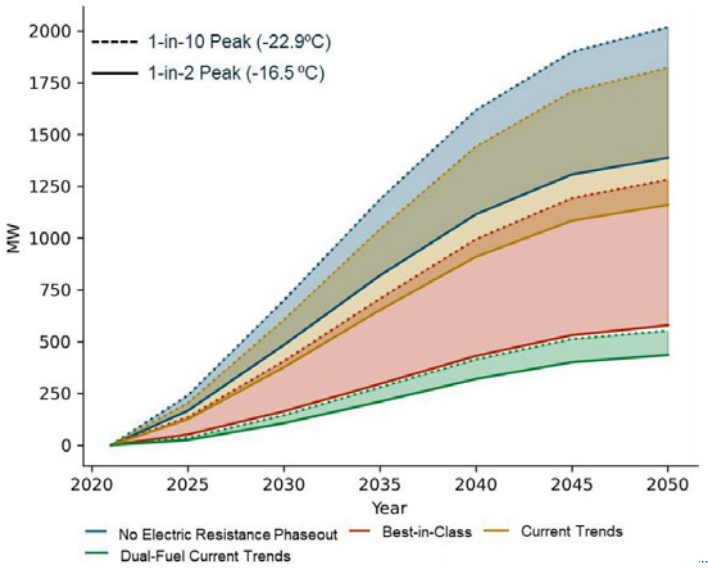
Electrification of Heating

- Using E3 “Hybrid” scenario, aligned with IRP Evergreen.
- The hybrid scenario (dual fuel) has the potential reduction in peak impact by using existing non-electric backup heat to serve peak loads.
- The graphs below show the incremental change in energy consumption and impact on overall peak load.

Incremental Load from Electrification (GWh)



Peak Impact of Electrification (MW)



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Renewable to Retail

- RTR participation is expected to start in late 2025 (340 GWh of wind production), with a total reduction of 246 GWh compared to an estimated reduction of 116 GWh in the 2023 forecast.
- Customer sales are expected to be as follows and are removed from the forecast:

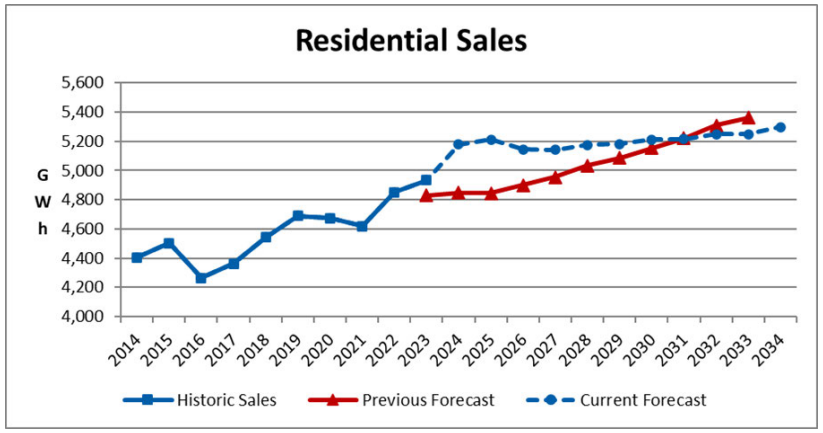
Class	2025 Impact (GWh)	2026+ Impact (GWh)
Residential	18	75
Small General	1	7
General Demand	23	97
Large General	2	8
Small Industrial	1	4
Medium Industrial	10	39
Large Industrial	5	16
Total	**61**	**246**

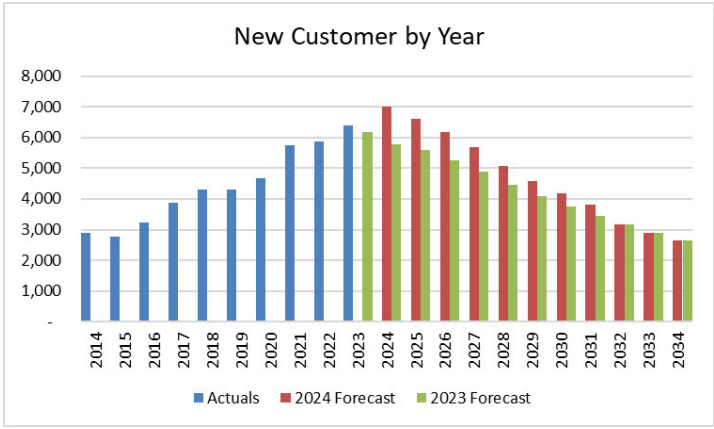
Small Scale Solar

- Small scale solar uptake continues to be strong: as of 2023 approximately 71.7 MW of solar generation has been installed (19.8 MW in 2023).
  - Rebates are still available for residential solar projects ($0.30/watt from the provincial programs).
  - Changes to net metering legislation will likely result in more interest from commercial customers.
  - Given the continued strong uptake and changes to legislation, the long-term forecast has been adjusted to reflect increased solar penetration in the next 10 years – installed capacity of 674MW by 2034 (compared to 609MW in the 2023 forecast).

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Forecast Comparison - Residential

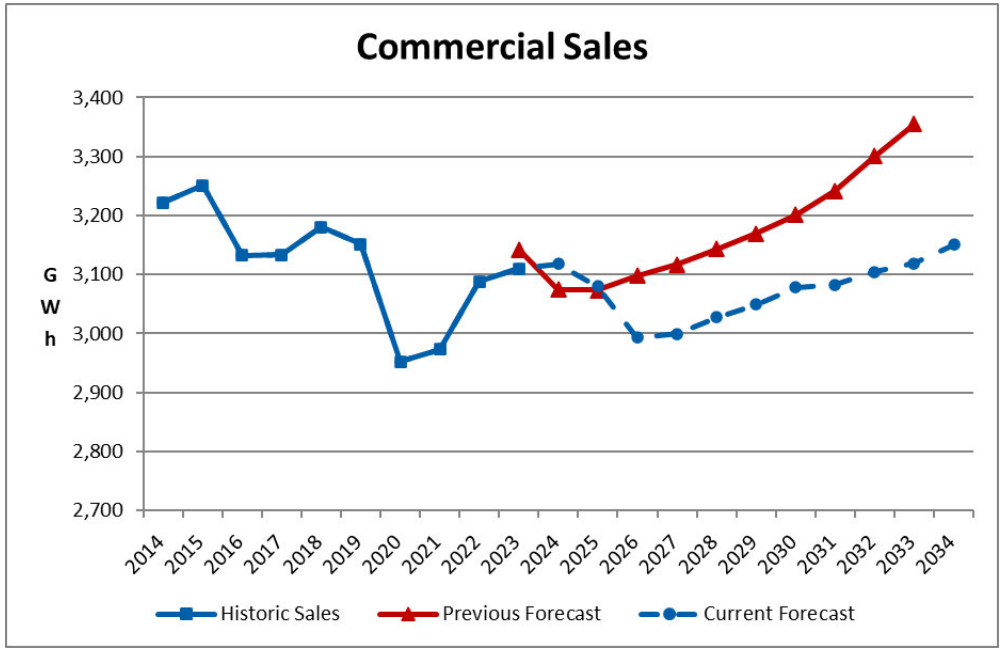




Weather in 2023 was warmer than normal, with an impact of -126 GWh on load. Sales are expected to be driven higher by electric heating and new customers and partly offset by continued DSM, with a reduction in 2025/2026 related to RTR. Forecast new customer growth is higher than the 2023 forecast, with 6K more customers by 2034.

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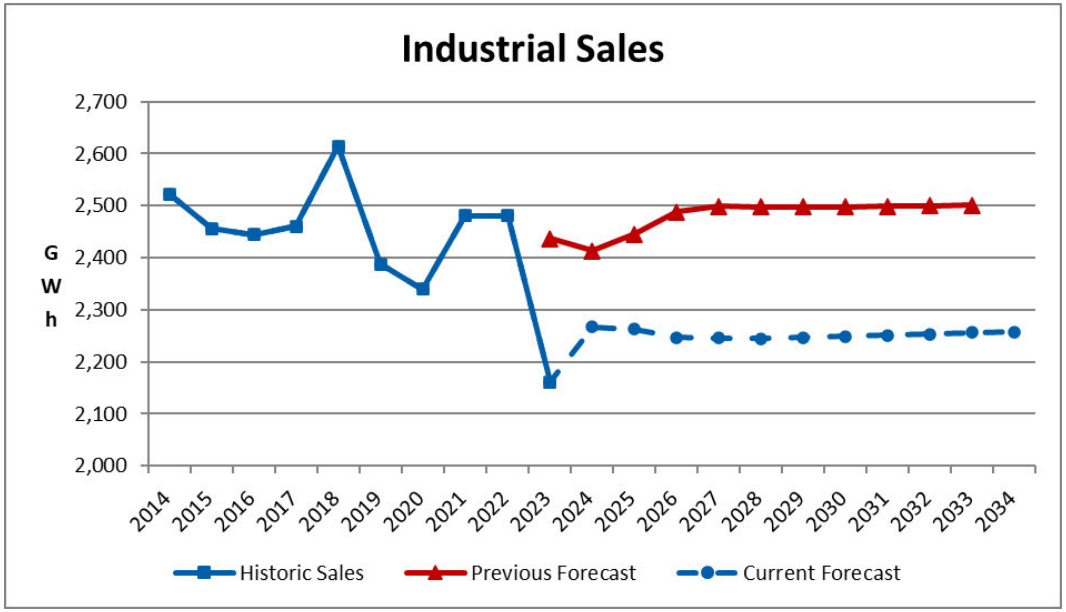
Forecast Comparison - Commercial



The significant changes to the forecast for 2024 are a larger drop in load between 2025 and 2026 due to the introduction of RTR, with lower growth from EVs.

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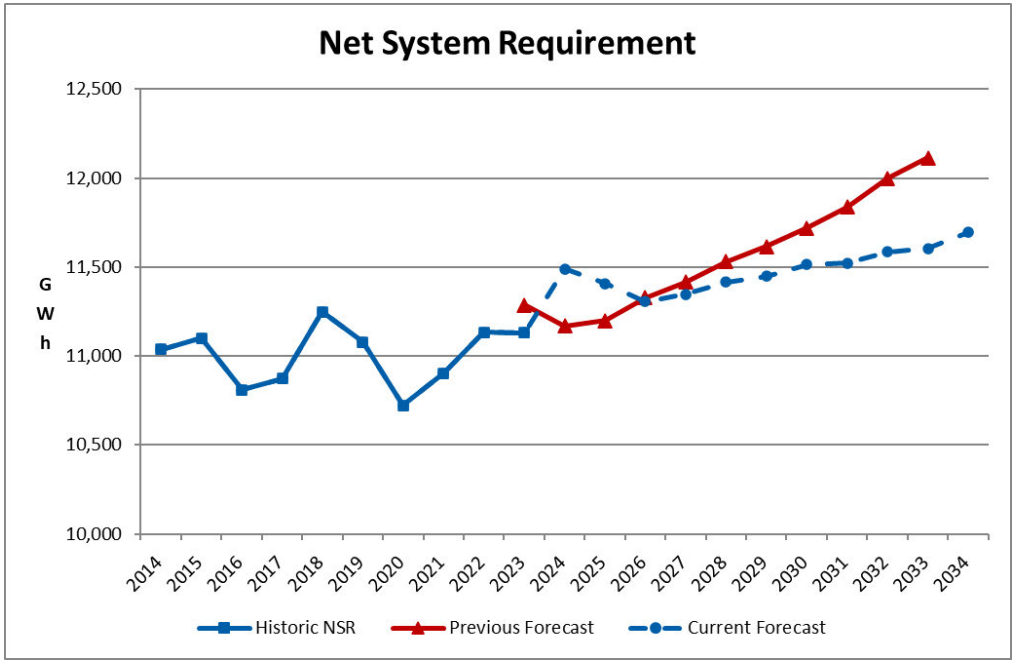
Forecast Comparison - Industrial



The Industrial class shows a drop compared to the 2022 forecast, mainly driven by a lower forecast for a large customer and lower growth assumptions for large customers.

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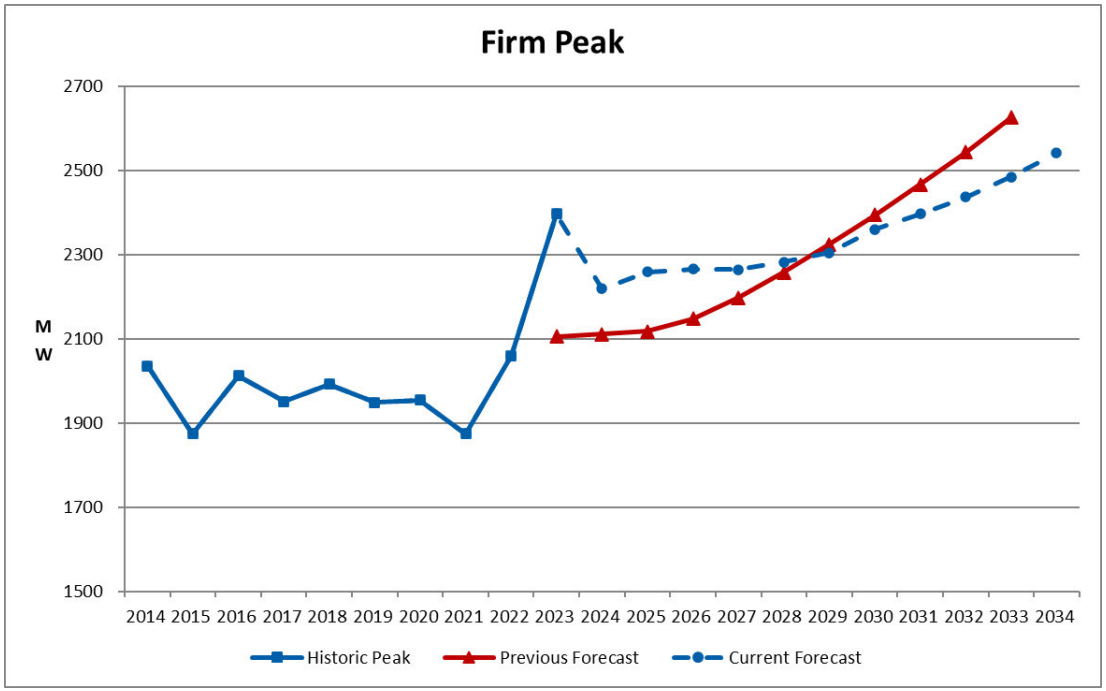
Forecast Comparison – Energy



2024 forecast shows higher growth than 2023 in the near term, driven mainly by a combination of increased heating intensities in the Residential class as well as a higher forecast for new residential customers. The decrease in 2025 and 2026 is a result of sales shifting to RTR.

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Forecast Comparison – Peak



The peak forecast is higher than the 2023 forecast in the near term as a result of higher heating intensity and higher forecast for new customers, but is lower than the 2023 forecast in the long term as a result of the revised EV forecast and the integration of the E3 hybrid scenario.

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2023 Forecast to Actuals

Below is an estimate of the major variances between the 2023 forecast and 2023 actuals for both energy and peak.

Item	GWh
2023 Forecast NSR	11,288
• Weather impact	-164
• Residential pickup	230
• Large customer actuals	-263
• Other variance	40
2023 Actual NSR	11,131

Item	MW
2023 Forecast Peak	2256
• Interruptibles	-88
• Weather (-22.8 12hr avg)	250
• Wind (avg 28.4 vs 18.8)	26
• Weekend	-30
• Lighting (estimated)	-150
• Other variance	191
2023 Actual Peak	2455

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Other items addressed

- Update on potential impact of pilot projects
- Update on impact of solar generation to peak
- Relative impact of hydrogen production added in sensitivities
- Update on AMI integration
- Review of assumptions around large customer growth
- Review of economic inputs and household size
- Review of price elasticity estimate

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Ongoing work for future reports

- Integrating AMI data into the sales and peak forecast
- Impact of electrification/emissions targets
- Continuing evaluation of the impact of new technologies (time variable pricing, direct load control, etc.)

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2024 Load Forecast Report Attachments 1-10 have been filed electronically. Attachment 4 is confidential.

Requirement:

Fuel Price Forecasts (industry forecasts used to indicate future trends in gas, oil and coal prices).

Submission:

The following industry information has been used to develop the fuel forecast used in NS Power's 2026-2027 General Rate Application:

- Price strip for Henry Hub natural gas from NYMEX
- Algonquin CityGate, AECO, and Dawn Platts natural gas basis from
- Intercontinental Exchange (ICE)
- Price strip for WTI crude oil from NYMEX
- Price strip for LFO from NYMEX
- CoalDesk, LLC Price Forecast for coal pricing
- Jacobs' Consultancy "PACE" Index for petroleum coke
- ISO New England Massachusetts Hub electricity prices from Intercontinental
- Exchange (ICE)

Requirement:

Lead-Lag Study

Submission:

Please refer to Attachment 1.

CASH WORKING CAPITAL / LEAD-LAG STUDY REPORT

Prepared for Nova Scotia Power Inc.

April 2025

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MANAGEMENT CONSULTANTS

TABLE OF CONTENTS

Introduction 1

1. Summary Of Results 3
2. Revenue Lag 4
3. Fuel Expenses 7
4. Labour OM&G Expenses 9
5. Non-Labour OM&G Expenses 12
6. Grants in Lieu of Taxes 15
7. Taxes 16
8. Demand-Side Management Program 21
9. Cash Working Capital Requirements (2026-2027) 22

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INTRODUCTION

The purpose of this report is to present the results of the lead-lag study conducted on behalf of Nova Scotia Power, Inc ("NSPI" or the "Company"). The Company submits this report as part of its base rate filing before the Nova Scotia Utility and Review Board. The lead-lag study was used to determine the Company's Cash Working Capital ("CWC") requirement, which is included in the Company's rate base.

Cash Working Capital

The term "working capital" refers to the net funds required by the Company to finance goods and services used to provide service to customers from the time those goods and services are paid for by the Company to the time that payment is received from customers. Goods and services considered in this lead-lag study include: Fuels expenses; Operations, Maintenance and General ("OM&G") expenses (including labour and non-labour); Income Taxes; Grants in Lieu of Taxes; Sales Taxes (including Harmonized Sales Tax ("HST"), Goods and Services Tax ("GST"), and Provincial Sales Tax ("PST")); and Demand-Side Management ("DSM") program payments.

Lead-Lag Methodology

The Company's cash working capital requirement was determined by applying the results of the lead-lag study to test year expenses. The lead-lag study compares differences between the Company's revenue lag and expense leads. The revenue lag represents the number of days from the time customers receive their electric service to the time customers pay for their electric service, *i.e.*, when the funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations. The expense lead represents the number of days from the time the Company receives goods and services used to provide electric service to the time payments are made for those goods and services, *i.e.*, when the funds are no longer available to the Company. The longer the expense lead, the less cash the Company needs to fund its day-to-day operations. Together, the revenue lag and expense leads are used to measure the lead-lag days. The lead-lag days are then applied to the Company's test period expenses to derive the CWC requirement, which is included in the Company's rate base.

A lead-lag study is an industry-recognized method of determining a utility's cash working capital requirement. The National Association of Regulatory Utility Commissioners ("NARUC") Rate Case and Audit Manual identifies the lead-lag study as one of the methods commonly used by regulators to measure the amount of cash working capital required for inclusion in a revenue requirement calculation. The NARUC Manual states:

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> "While the lead-lag study can be more time consuming and costly than other more simplistic methods, the results tend to be more individualized to a specific company. Under this method, one is attempting to measure the actual time between a utility's out-of-pocket payment of expenses to provide service and the collection of revenues for service. The weighted average of the net lag days times the average daily expense yields a positive or negative requirement for cash working capital."[1]

Data

The lead-lag study was based on financial data from January 1, 2023 through December 31, 2023. The financial data consisted of billed revenues, accounts receivable balances, Fuel and OM&G expenses, taxes, and DSM payments. The financial data generally included service periods, payment dates, and payment amounts.

Report Structure

The report is organized into the following sections:

- Section 1: Summary of Results
- Section 2: Revenue Lag
- Section 3: Fuel Expenses
- Section 4: Labour-Related OM&G Expenses
- Section 5: Non-Labour Related OM&G Expenses
- Section 6: Grants in Lieu of Taxes
- Section 7: Taxes
- Section 8: Demand-Side Management Program
- Cash Working Capital Requirements (2026 and 2027)

[1] Rate Case and Audit Manual Prepared by NARUC Staff Subcommittee on Accounting and Finance (2003), p. 20

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1. SUMMARY OF RESULTS

The results of the Company's lead-lag study show a working capital requirement of $108.2 million based on 2023 operating expenses, as summarized in Figure 1 (below). The Company's working capital requirements for 2026 through 2027 are presented in Section 9 (below).

Figure 1: Cash Working Capital Requirement (2023)

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 1 Summary

Line	Description	2023 Amount	Average Daily Amount	Revenue / Collection Lag	Section	Expense Lead	Section	Net (Lead)/Lag Days	Working Capital Requirement
1	Fuels	$ 776,958,003	$ 2,128,652	49.91	2	(23.02)	3	26.88	$ 57,228,331
2	OM&G Labour	190,891,579	522,991	49.91	2	(26.02)	4	23.89	12,492,536
3	OM&G Expenses (Excluding Labour)	131,002,662	358,911	49.91	2	(31.80)	5	18.11	6,498,381
4	Grants In Lieu of Taxes	45,050,390	123,426	49.91	2	134.80	6	184.71	22,797,567
5	Income Taxes	(230,054)	(630)	49.91	2	(60.50)	7	(10.59)	6,677
6	HST Collected	255,700,378	700,549	32.85	7	(43.68)	7	(10.83)	(7,586,538)
7	HST / GST Paid (excluding capital-related)	96,249,959	263,699	45.63	7	(9.08)	7	36.55	9,637,258
8	DSM	49,851,481	136,579	49.91	2	2.45	8	52.36	7,151,947
9	**Operating Expenses (Lead-Lag Analysis)**	**$ 1,545,474,399**	**$ 4,234,176**						**$ 108,226,158**
10	**Operating Expenses (Excluded)**								
11	Future income tax expense	$ (3,903,646)							
12	Depreciation Expense	258,058,198							
13	Accretion Expense	7,582,557							
14	FAM Deferral	(78,262,496)							
15	DSM Deferral	(20,272,862)							
16	Regulatory Amortization	8,556,347							
17	AFUDC, FAM, Other Deferred Financing Costs	(22,602,158)							
18	Interest	191,411,567							
19	Other Expense, Net	(22,968,809)							
20	Bad Debt	3,843,434							
21	**Total Operating Expenses (Excluded)**	**$ 321,642,133**							
22	**Total Expenses**	**$ 1,867,116,532**							**$ 108,226,158**

The Figure shows revenue lags and expense leads associated with eight expense categories totaling $1,545 million. The Figure also shows expenses not included in calculation of the Company's cash working capital requirement totaling $321.6 million since they are considered non-cash items for purposes of deriving the cash working capital requirement.

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2. REVENUE LAG

The revenue lag represents the number of days from the time customers receive their electric service to the time customers pay for electric service, *i.e.,* when funds are available to the Company. The longer the revenue lag, the more cash the Company needs to finance its day-to-day operations.

The revenue lag was primarily based on four classes of customer revenues.

1. Bi-Monthly Customers: Residential, Commercial, Industrial, and Non-Profit customers billed every other month.
2. Monthly Customers: Residential, Commercial, Industrial, and Non-Profit customers billed every month.
3. Large Customers: Large Commercial and Industrial customers billed or accrued at month-end.
4. Other Customers: Open Access Transmission Service (OS), Wiring Permits (WP) and Miscellaneous customers (AR).

The revenue lag reflects the service period, billing lag and collection lag associated with each class of revenues.

Results

The results of the Company's lead-lag study show a revenue lag of 49.91 days, as summarized in Figure 2 (below). The Figure shows the revenue lag was based on the service lag, billing lag and collection lag for each class of revenues, weighted by revenues, and then summed across all classes of revenues.

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Figure 2: Revenue Lag

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 2 Revenue Lag

Line	Classes	Revenues w/ HST & w/o Bad Debt Expense	% of Revenue	Service Lag	Billing Lag	Collection Lag	Total Revenue Lag	Weighted Revenue Lag
1	Bi-Monthly	$ 1,016,767,793	54.4%	30.42	2.00	31.88	64.30	35.00
2	Monthly	544,938,649	29.2%	15.21	2.00	15.92	33.13	9.66
3	Large Customers	265,397,117	14.2%	11.35	0.00	14.40	25.74	3.66
4	Other (OS, AR, WP)	40,500,961	2.2%	0.08	7.00	65.65	72.73	1.58
5	Export Revenues	271,546	0.0%	15.30	5.90	13.52	34.72	0.01
6	Total	$ 1,867,876,067						49.91

Note: All revenues include HST and exclude Bad Debt Expenses

Methodology

The revenue lag was based on the sum of three components: (1) the service lag; (2) the billing lag; and (3) the collection lag.

Service Lag

The service lag measures the average number of days in the service period. The service lag in this lead-lag study was based on the midpoint of the service period, which reflects that electricity is delivered evenly over the service period.

The service lag for Bi-Monthly Customers was based on the mid-point of a two-month service period, or 30.42 days.[2] The service lag for Monthly Customers was based on the mid-point of a one-month service period, or 15.21 days.[3] The service lag for the other revenue classes was based on the mid-point of their respective service periods.

Billing Lag

The billing lag measures the number of days from the time meters are read to the time bills are recorded and sent to customers.

[2] Mid-point of two-month period during a year. ((365/12) x 2) / 2 = 30.42 days

[3] Mid-point of one-month period during a year. (365/12) / 2 = 15.21 days

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The billing lag for Bi-Monthly and Monthly Customers was two days, and for Large Customers zero days as these customers have automated meter reading installed. The billing lag for the other revenue classes was based on their respective billing lags.

Collection Lag

The collection lag measures the number of days from the time bills are recorded and sent to customers to the time customer payments are received (i.e., funds are available to the Company).

The collection lag for Bi-Monthly, Monthly, and other (OS, AR) customers was based on the accounts receivable turnover, as expressed in the equations (below).

$$Collection\ Lag\ = \frac{365}{Accounts\ Receivables\ Turnover}$$

Where:

$$Accounts\ Receivable\ Turnover\ = \frac{Sales\ Revenues}{Average\ Accounts\ Receivables}$$

Specifically, the collection lag was based on the number of days to recover or "turnover" the accounts receivables. The accounts receivables turnover is based on annual sales divided by average accounts receivables.

The collection lag was determined by rate class, weighted by sales revenues, and then summed across all rate classes. The sales revenues exclude bad debt expenses, consistent with sales revenues included in accounts receivables.

The collection lag for large customers and power export revenues was based on the number of days between the billing date and revenue collection date.

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3. FUEL EXPENSES

Lead days for fuel expenses were based on the Company's payment process for fuel expenses. Fuel expenses evaluated in this study included fuel for electric power generation (such as natural gas and coal), additives used in electric power generation, solid fuel handling costs, and purchased power expenses.

Fuel expenses were calculated separately for the following:

- Natural Gas
- Heavy Fuel Oil (Bunker C)
- Light Fuel Oil
- Solid Fuel (Coal and Petroleum Coke)
- Solid Fuel Handling Costs
- Imports
- Maritime Link Assessment
- Additives
- Diesel
- IPPs
- Independent Power Producer (IPP) Recoveries[4]
- Additives-Powder Activated Carbon/Calcium Chloride
- Biomass

Results

The results of the Company's lead-lag study show lead days for fuel expenses of 23.02 days, as summarized in Figure 3 (below). Lead days were measured separately by fuel type as the number of days from the midpoint of the service period to the payment date, weighted by payments, and then summed across fuel types.

[4] NSPI owns 49% of South Canoe and Sable Wind Farms and receives IPP revenue for its ownership share. This is circular. NSPI recognizes purchased power expense for 100% of wind generation and later receives 49% of this amount back and recognizes it as an offset to purchased power expense.

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Figure 3: Lead Days for Fuels Expenses

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 3 Fuels

Line	Fuel Type		Net Payment Amount	Weighted Net (Lead) / Lag Days	Weighting Factor	Total Weighted Net (Lead) / Lag Days
1	Natural Gas	$	159,689,768	(39.36)	17.4%	(6.83)
2	Heavy Fuel Oil (Bunker C)		19,016,269	(15.54)	2.1%	(0.32)
3	Light Fuel Oil		6,414,640	(39.58)	0.7%	(0.28)
4	Solid Fuel (Coal)		324,297,581	(16.55)	35.2%	(5.83)
5	Solid Fuel Handling Costs		5,599,621	(35.89)	0.6%	(0.22)
6	Imports		59,827,485	(36.12)	6.5%	(2.35)
7	Maritime Link		162,588,761	5.53	17.7%	0.98
8	Additives		2,946,891	(61.94)	0.3%	(0.20)
9	Diesel		6,999,407	(63.70)	0.8%	(0.48)
10	IPP's		152,696,758	(41.08)	16.6%	(6.82)
11	IPP Revenue		(2,938,521)	(53.70)	-0.3%	0.17
12	Additives-PAC/Calcium Chloride		8,357,041	(19.43)	0.9%	(0.18)
13	Biomass		14,564,662	(41.90)	1.6%	(0.66)
14	Total	$	920,060,362		100.0%	(23.02)

Methodology

Lead days were measured separately for each fuel type as the number of days from the midpoint of the service period to the payment date. Lead days were determined based on a review of fuel invoices in 2023.

The midpoint of the service period for fuel placed into inventory, including heavy and light fuel oil, solid fuel, additives, diesel, and biomass, was based on the receipt date since upon receipt the fuel is placed into inventory and included in the Company's rate base. The midpoint of the service period for the other fuels, including natural gas and purchased power, was based on the service period for each invoice.

The payment date was based on the Company's records for each invoice.

Lead days were measured separately for each invoice as the number of days from the midpoint of the service period to the payment date, weighted by payment amount, and then summed across invoices for each fuel type.

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4. LABOUR OM&G EXPENSES

Lead days for labour-related OM&G expenses were based on the Company's process for employee payroll, variable compensation payments, payroll taxes, benefit payments, and other deductions. Lead days were measured as the number of days from the midpoint of each pay period to the payment date, weighted by payments, and then summed across all payments.

Lead days for regular payroll expenses were based on the Company's payroll process, which pays employees on a bi-weekly basis. Payroll expenses in the first and last payroll period were prorated to reflect the 2023 portion of payroll expenses. Lead days were measured as the number of days from the midpoint of each payroll period to the payroll payment date.

Lead days for variable compensation payments were measured as the number of days from the midpoint of the performance period to the payment date. The study excluded non-regulated variable compensation payments.

Lead days for payroll taxes, including Employee Income Taxes, the Employee and Employer portions of the Canada Pension Plan ("CPP") and Employment Insurance ("EI"), were measured as the number of days from the midpoint of each payroll period to the payment date.

Lead days for payroll deductions, including life, long-term disability, dental and medical insurance, pension contributions, were measured as the number of days from the midpoint of each payroll period to the payment date.

Results

The results of the Company's lead-lag study show lead days for labour-related OM&G expenses of 26.02 days, as summarized in Figure 4 (below).

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Figure 4: Labour-related OM&G Expense Lead

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 4 OM&G Labour

Line	Description	(Lead) / Lag Days	Net Pay, Taxes & Benefits	Weighting Factor	Weighted (Lead) / Lag Days
1	**Bi-Weekly Payroll**				
2	Bi-Weekly Payroll	(15.00)	$ 134,741,992	52.4%	(7.86)
3	Bi-Weekly Payroll Taxes	(22.56)	77,683,199	30.2%	(6.81)
4	Benefits Deductions / Payments	(24.12)	8,847,150	3.4%	(0.83)
5	Other Deductions - Payroll Dates	(15.00)	1,440,147	0.6%	(0.08)
6	Other Deductions - Non-Payroll Dates	(25.58)	26,227,423	10.2%	(2.61)
7	**Variable Compensation**				
8	Variable Compensation	(241.50)	5,229,513	2.0%	(4.91)
9	Variable Compensation Taxes	(241.50)	2,702,108	1.1%	(2.54)
10	Variable Compensation Other Deductions	(241.50)	344,597	0.1%	(0.32)
11	Variable Compensation Other Deductions	(241.50)	37,533	0.0%	(0.04)
12	Variable Compensation Other Deductions	(241.50)	22,832	0.0%	(0.02)
13	Variable Compensation Other Deductions	(241.50)	5,019	0.0%	(0.00)
14	Variable Compensation Other Deductions	(241.50)	229	0.0%	(0.00)
15	Total (Lead) / Lag Days		$ 257,281,743	100.0%	(26.02)

Methodology

Lead days for labour-related OM&G expenses were measured as the number of days from the midpoint of each payroll period to the payment date.

Lead days for regular payroll expenses were based on the Company's payroll process, which pays employees on a bi-weekly basis. Payroll expenses were prorated to reflect a full calendar year of payroll expenses. Lead days were measured as the number of days from the midpoint of each payroll period to the payroll payment date. The midpoint of the payroll period reflects 7 days, or one-half of the 14-day payroll period. Payroll payment dates are generally on the Friday following the end of a payroll period.

Lead days for variable compensation payments were measured as the number of days from the midpoint of the 2022 performance period to the 2023 payment date. The midpoint of the variable compensation performance period reflects 182.50 days, or one-half of the 365-day performance period. The variable compensation payments were made at the end of February 2023.

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Lead days for payroll taxes, including Employee Income Taxes, the Employee and Employer portions of the Canada Pension Plan ("CPP") and Employment Insurance ("EI"), were measured as the number of days from the midpoint of each payroll period to the payment date. Tax payments for regular payroll are generally processed two to three weeks after each payroll payment date. Tax payments for variable compensation payments are generally processed the same day as the variable compensation payment date.

Lead days for benefits payments and payroll deductions, including life, long-term disability, dental and medical insurance and pension contributions, were measured as the number of days from the midpoint of each payroll period to the payment date. Benefits payments are generally processed on the first day of the month of the pay period start. Payroll deductions are generally based on the following schedule:

1) Paid on same date as payroll payment date (Union dues, Garnishment);
2) Paid one week after payroll payment date (Pension Payments);
3) Paid five days after payroll payment date (Pension Payments);
4) Paid quarterly (Employee Common Share Purchase Plan deductions); and
5) Paid the same date as payroll tax payments (taxes).

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5. NON-LABOUR OM&G EXPENSES

Lead days for non-labour OM&G expenses were measured separately for 13 categories of expenses based on the sum of three components: (1) service period lead i.e., mid-point of the service period, (2) lead days from the end of the service period to the invoice date; and (3) lead days from the invoice date to the payment date, as shown in Figure 5 (below).

The sample represents 56.80 percent of total non-labour OM&G payments. Service period lead and lead days to invoice date were measured for each invoice in the sample based on a review of the actual invoices.

The third component, lead days from the invoice date to the payment date, was based on the full population of invoices paid by the Company during the test year.

Figure 5: Non-Labour OM&G Sample Statistics

OM&G Category	Total Amount	% of Total	Sample Amount	Sample Amount %	Sampling Methodology
CONTRACTS	$ 89,280,310	49.1%	$ 48,679,735	54.5%	Top 125 Invoices
CONSULTING	15,225,213	8.4%	5,944,860	39.0%	Top 25 Invoices
RENTAL AND MAINTENANCE OF EQUIPMENT	10,249,119	5.6%	4,996,913	48.8%	Top 15 Invoices
CORPORATE CREDIT CARD CLEARING	7,044,567	3.9%	3,645,858	51.8%	Top 25 Invoices
FLEET FUEL	5,327,534	2.9%	4,314,842	81.0%	Top 20 Invoices
MATERIALS	5,247,037	2.9%	1,219,231	23.2%	Top 50 Invoices
EXTERNAL LEGAL AUDIT	4,511,498	2.5%	3,812,778	84.5%	Top 25 Invoices
TELEPHONES	3,879,881	2.1%	3,625,383	93.4%	Top 20 Invoices
WATER	3,761,174	2.1%	2,815,686	74.9%	Top 25 Invoices
CONTRACTS ASH DISPOSAL	1,644,302	0.9%	1,027,543	62.5%	Top 15 Invoices
Other OM&G	18,040,381	9.9%	5,633,340	31.2%	Top 65 Invoices
INSURANCE	8,422,240	4.6%	8,422,240	100.0%	All Invoices
CORPORATE SUPPORT	9,217,844	5.1%	9,217,844	100.0%	Payment Schedule
Total	**$ 181,851,101**	**100%**	**$ 103,356,252**	**56.8%**	

Lead days were also measured for corporate support and insurance expenses that are allocated from the parent company. The Company receives corporate support services from Emera and pays for the allocated expenses on a monthly basis.

Results

The results of the Company's lead-lag study show lead days for Non-Labour OM&G Expenses of 31.80 days, as summarized in Figure 6 (below).

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Figure 6: Non-Labour OM&G Expense Lead

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 5 OM&G Non-Labour

Line	Description	Net Pay, Taxes & Benefits	Service Period Mid-Point Days	Service Period End to Invoice Days	Invoice to Payment Lead Days	Total (Lead) / Lag Days	Weighting Factor	Total Weighted (Lead) / Lag Days
1	Contracts	$ 89,280,310	(23.57)	19.81	(39.56)	(43.31)	49.1%	(21.27)
2	Consulting	15,225,213	(61.36)	50.64	(60.75)	(71.47)	8.4%	(5.98)
3	Rental And Maintenance Of Equipment	10,249,119	(124.64)	216.08	(41.00)	50.44	5.6%	2.84
4	Corporate Credit Card Clearing	7,044,567	(22.32)	18.26	(31.84)	(35.91)	3.9%	(1.39)
5	Fleet Fuel	5,327,534	(15.18)	(0.57)	(37.91)	(53.66)	2.9%	(1.57)
6	Materials	5,247,037	(1.57)	(2.48)	(43.94)	(47.98)	2.9%	(1.38)
7	External Legal Audit	4,511,498	(15.24)	(11.30)	(42.41)	(68.94)	2.5%	(1.71)
8	Telephones	3,879,881	(15.45)	6.20	(36.58)	(45.83)	2.1%	(0.98)
9	Water	3,761,174	(23.48)	(18.95)	(33.30)	(75.73)	2.1%	(1.57)
10	Contracts Ash Disposal	1,644,302	(14.86)	0.46	(41.95)	(56.36)	0.9%	(0.51)
11	Insurance	8,422,240	(180.78)	294.44	(40.79)	72.87	4.6%	3.37
12	Corporate Support	9,217,844	(15.23)		(18.54)	(33.77)	5.1%	(1.71)
13	Other OM&G	18,040,381	(114.17)	163.74	(49.01)	0.55	9.9%	0.05
14	Total	$ 181,851,101					100.0%	(31.80)

Methodology

Lead days for non-labour OM&G expenses were measured separately for 13 categories of expenses based on the sum of three components: (1) service period lead i.e., mid-point of the service period, (2) lead days from the end of the service period to the invoice date; and (3) lead days from the invoice date to the payment date, as shown in Figure 6 (above).

Service period lead and lead days from the service period end to the invoice date were based on a sample of invoices paid by the Company during the test year. The sample represents 56.80 percent of total non-labour OM&G expenses. Lead days were measured for each invoice in the sample as the number of days from the midpoint of the service period to the invoice date. Invoices were then weighted by expense amount and summed to determine the lead days. The study relies on a sample of invoices to measure the lead days since service periods were not readily available electronically and required detailed inspection of individual invoices. The sampling methodology is presented in Figure 5 (above).

Lead days from the invoice date to the payment date were based on the full population of invoices paid by the Company during the test year. Lead days were measured for each invoice as the number of days

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from the invoice date to the payment date. Invoices were then weighted by expense amount and summed to determine the lead days.

Lead days were also measured for the Company's expenses related to corporate support. Lead days for these expenses were based on the monthly payment schedule.

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6. GRANTS IN LIEU OF TAXES

Lead days for Grants in Lieu of Taxes were based on the midpoint of the taxing or service period to the payment date. The Company is exempt from paying municipal taxes other than deed transfer tax under the Nova Scotia Power Privatization Act. Instead, the Act directs the Company to pay each year on January 31 and June 1 two installments of Grants in Lieu of Taxes to the Government of Nova Scotia.

Results

The results of the Company's lead-lag study show lead days for Grants in Lieu of Taxes of 134.80 days, as summarized in Figure 7 (below).

Figure 7: Grants in Lieu of Taxes Expense (Lead) / Lag

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 6 Grants In Lieu of Taxes

Line	Service Period Start	Service Period End	Service Period Mid-Point	Payment Date	Invoice Amount (Excl. HST)	Payment (Lead) / Lag Days	Total (Lead) / Lag Days	Weighting Factor	Total Weighted Net (Lead) / Lag
1	1/1/2023	3/31/2023	(45.00)	6/1/2022	$ 5,491,271	303.00	258.00	12.2%	31.45
2	1/1/2023	12/31/2023	(182.50)	1/31/2023	21,965,086	334.00	151.50	48.8%	73.87
3	4/1/2023	12/31/2023	(137.50)	6/1/2023	17,594,033	213.00	75.50	39.1%	29.49
4	Total				$ 45,050,390			100.0%	134.80

Methodology

Lead days for Grants in Lieu of Taxes were based on the midpoint of the Grant or service period and the payment dates. Lead days were measured as the number of days from the midpoint of the service period to the payment date, weighted by payment amount and then summed across all payments.

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7. TAXES

Lead days for Taxes were based on the midpoint of the taxing period and the payment date. Taxes examined in this lead-lag study include: Harmonized Sales Tax ("HST"); Provincial Sales Tax ("PST") Rebates; Goods and Services Tax ("GST"); and Federal and Provincial Income Tax.

Lead days for HST collections and payments were measured separately.

1) HST Collections, which represent Company receipts or collections from customers, power exports, and natural gas sales.

2) HST Payments, which represent Company payments on fuels and OM&G expenses, as these are the most significant expenses.[5]

Lead days for PST rebates were measured separately for eligible customers, such as customers taking service under the Domestic Bi-Monthly rate schedules.

Lead days for GST were measured separately for goods imported into Canada (e.g., solid fuels). The Company is generally required to pay GST on imports from the 25th of the previous month to the 24th of the current month on the last business day of the current month. GST is recovered as an ITC when the current month's HST return is filed at the end of the following month.

The Company makes installments on its federal and provincial income taxes at the end of each month. These taxes are combined under the heading Income Taxes. Where the actual tax expense exceeds the amount of the installments, there is a final true-up at the end of February of the following year. Where the actual tax expense is less than the amount of the installments, a refund is received after the Company files its tax return. Lead days for Income Tax payments were determined based on expected tax installments and true-up payments.

[5] HST is not reflected on charges related to the Company's affiliates nor on exports to the New England Independent System Operator ("ISO-NE").

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Results

The results of the Company's lead-lag study show net lead days for HST collections of 10.83 days, net lag days for HST / GST payments of 36.55 days and expected lead days for income taxes of 60.50 days, 553.96 days, and 85.00 days in 2023, 2026, and 2027, respectively, as summarized in Figure 8 (below).

Figure 8: Taxes Lead / Lag Days

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 7 Taxes

Line	Tax Type	Weighted Revenue Lag Days	Weighted Expense (Lead) / Lag Days	Net (Lead) / Lag Days
1	HST Collected	32.85	(43.68)	(10.83)
2	HST / GST Paid (excluding capital-related)	45.63	(9.08)	36.55
3	Income Taxes			
4	2023	49.91	(60.50)	(10.59)
5	2025	49.91	(549.75)	(499.84)
6	2026	49.91	(553.96)	(504.05)
7	2027	49.91	(85.00)	(35.10)

The lead days in 2026 reflect that customers receive the benefit of an Investment Tax Credit ("ITC") related to the Company's investment in an energy storage project prior to the Company's receipt of the ITC in 2026 and 2027.

Methodology

HST Collections

HST is collected on sales to customers, power exports, and natural gas sales. The collection lag associated with HST collections was based on the collection lag used in the revenue lag.

The Company generally submits payments one month after the end of service month for HST collections from customers. Power exports are generally throughout the month, with the invoice dated the following month. As a result, HST is not paid to the government until two months following the sales month.

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The Company's customers who purchase energy for their homes (such as Domestic Bi-Monthly customers) are eligible for a rebate equivalent to the provincial portion of the HST. Accordingly, for these customers, the collection lag is broken into two portions: 1) HST collections from customers, and 2) PST Rebate refund from Government. The collection lag for customer collections is considered the same as determined in the revenue lag analysis. The collection lag for PST Rebate is determined based on when NSPI received refunds from the Government. PST rebate refunds from the Government were generally delayed during 2023 which is not expected in the future. As a result, the study reflects the refund schedule from 2019 period which was utilized in the Company's prior study.

The net lead-lag days for HST collections are summarized in Figure 9 (below).

Figure 9: HST Collections Lead / Lag Days

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 7.1 HST Collected

Line	Customer Type	$ Amount Collected	Weighted Average Collection Lag	Weighted Average Payment Lead	Net (Lead) / Lag Days	Weighting Factor	Weighted Net (Lead) / Lag Days
1	Regular Customers	$ 80,759,793	17.73	(45.63)	(27.90)	31.6%	(8.81)
2	Regular Customers Subject to PST	133,254,889	45.33	(45.63)	(0.29)	52.1%	(0.15)
3	Large Customers	34,563,133	14.40	(30.42)	(16.02)	13.5%	(2.17)
4	Other Customers (AR, OS)	5,239,773	73.12	(45.63)	27.49	2.0%	0.56
5	Grid Sales	35,419	19.42	(61.34)	(41.93)	0.0%	(0.01)
6	Natural Gas Sales	1,847,372	24.92	(60.46)	(35.54)	0.7%	(0.26)
7	Total	$ 255,700,378	32.85	(43.68)	(10.83)	100.0%	(10.83)

Note: Regular customers represent the Company's monthly and bi-monthly billed customers, excluding Large Customers

HST Payments

HST payments were evaluated for Fuels and Non-Labour OM&G expenses. Lead days for HST payments for Fuels and Non-Labour OM&G expenses were based on lead days, respectively, for Fuels and Non-Labour OM&G expenses.

HST payments and HST collections are netted (as Input Tax Credits (ITC)) to determine the amount to be remitted to the Government. The ITCs can be claimed on the return for the month in which they are

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paid or become payable, filed at the end of the following month. This translates to a 45 days' lead in receiving the ITC refunds.

Lead days on HST payments were based on the number of days to receive the ITC refund and the number of days on HST payments.

GST Payments

GST is paid by NSPI on goods that are imported into Canada (e.g., solid fuels). NSPI is generally required to pay the GST on imports from the 25th of the previous month to the 24th of the current month on the last business day of the current month. The payment lead for the GST payments is calculated as difference between mid-point of service period and payment dates.

This GST is recovered as an ITC when the current month's HST return is filed at the end of the following month. The ITCs can be claimed on the return for the month in which they are paid or become payable, filed at the end of the following month. This translates to a 45 days' lead in receiving the ITC refunds.

The average number of days to refund are netted against the average GST payment leads to determine the net lead on GST payments.

The net lead-lag days for HST / GST Payments are summarized in Figure 10 (below).

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Figure 10: HST / GST Payments Lead / Lag Days

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 7.2 HST / GST Payments

Line	Expense Type	HST / GST Paid	Weighted Average Collection Lag	Weighted Average Payment Lead	Net (Lead) / Lag Days	Weighting Factor	Weighted Net (Lead) / Lag Days
1	HST Paid on Fuels Expenses	$ 61,644,298	45.63	(11.97)	33.66	64.0%	21.55
2	HST Paid on OM&G Expenses	19,885,337	45.63	(3.30)	42.33	20.7%	8.74
3	Division III GST Paid on Import	14,720,324	45.63	(4.78)	40.85	15.3%	6.25
4	Total	$ 96,249,959	45.63	(9.08)	36.55		36.55

Income Taxes

Lead days for Income Tax payments were determined based on expected tax installments and true-up payments / refunds.

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8. DEMAND-SIDE MANAGEMENT PROGRAM

Lead days for the Company's DSM program payments are based on the payment schedule to the third-party service provider for the DSM program.

Results

The analysis shows lead days for DSM payments of 2.46 days based on the DSM payment schedule, as shown in Figure 11 (below).

Figure 11: DSM Payments Lead / Lag Results

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 8 Calculation of DSM Payments Lead

Line	Month	Service Period Start	Service Period End	Service Period Mid-Point	Payment Date	Payment (Lead) / Lag Days	Total (Lead) / Lag Days	Payment Amount	Weighting Factor	Net (Lead) / Lag Days
1	January	1/1/2023	1/31/2023	(15.50)	1/20/2023	11.00	(4.50)	$ 4,393,902	8.3%	(0.37)
2	February	2/1/2023	2/28/2023	(14.00)	3/8/2023	(8.00)	(22.00)	4,393,902	8.3%	(1.83)
3	March	3/1/2023	3/31/2023	(15.50)	3/8/2023	23.00	7.50	4,393,902	8.3%	0.62
4	April	4/1/2023	4/30/2023	(15.00)	4/5/2023	25.00	10.00	4,393,902	8.3%	0.83
5	May	5/1/2023	5/31/2023	(15.50)	5/5/2023	26.00	10.50	4,393,902	8.3%	0.87
6	June	6/1/2023	6/30/2023	(15.00)	6/9/2023	21.00	6.00	4,393,902	8.3%	0.50
7	July	7/1/2023	7/31/2023	(15.50)	7/14/2023	17.00	1.50	4,393,902	8.3%	0.12
8	August	8/1/2023	8/31/2023	(15.50)	8/9/2023	22.00	6.50	4,393,902	8.3%	0.54
9	September	9/1/2023	9/30/2023	(15.00)	9/13/2023	17.00	2.00	4,393,902	8.3%	0.17
10	October	10/1/2023	10/31/2023	(15.50)	10/13/2023	18.00	2.50	4,393,902	8.3%	0.21
11	November	11/1/2023	11/30/2023	(15.00)	11/8/2023	22.00	7.00	4,393,902	8.3%	0.58
12	December	12/1/2023	12/31/2023	(15.50)	12/13/2023	18.00	2.50	4,393,904	8.3%	0.21
13	DSM Payments (Lead) / Lag Days							$52,726,826	100.0%	2.46

Methodology

Lead days for DSM payments were based on the midpoint of the service period and the payment dates. The Company usually makes payments to the third-party service provider during the month of service.

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9. CASH WORKING CAPITAL REQUIREMENTS (2026-2027)

The cash working capital requirements determined through the lead-lag study for the years 2023, 2026, and 2027, respectively, are shown in Figures 12, 13 and 14 (below).

Figure 12: Cash Working Capital Requirement (2023)

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 1 Summary

Line	Description	2023 Amount	Average Daily Amount	Revenue / Collection Lag	Section	Expense Lead	Section	Net (Lead)/Lag Days	Working Capital Requirement
1	Fuels	$ 776,958,003	$ 2,128,652	49.91	2	(23.02)	3	26.88	$ 57,228,331
2	OM&G Labour	190,891,579	522,991	49.91	2	(26.02)	4	23.89	12,492,536
3	OM&G Expenses (Excluding Labour)	131,002,662	358,911	49.91	2	(31.80)	5	18.11	6,498,381
4	Grants In Lieu of Taxes	45,050,390	123,426	49.91	2	134.80	6	184.71	22,797,567
5	Income Taxes	(230,054)	(630)	49.91	2	(60.50)	7	(10.59)	6,677
6	HST Collected	255,700,378	700,549	32.85	7	(43.68)	7	(10.83)	(7,586,538)
7	HST / GST Paid (excluding capital-related)	96,249,959	263,699	45.63	7	(9.08)	7	36.55	9,637,258
8	DSM	49,851,481	136,579	49.91	2	2.46	8	52.36	7,151,947
9	**Operating Expenses (Lead-Lag Analysis)**	**$ 1,545,474,399**	**$ 4,234,176**						**$ 108,226,158**
10	**Operating Expenses (Excluded)**								
11	Future income tax expense	$ (3,903,646)							
12	Depreciation Expense	258,058,198							
13	Accretion Expense	7,682,557							
14	FAM Deferral	(78,262,496)							
15	DSM Deferral	(20,272,862)							
16	Regulatory Amortization	8,656,347							
17	AFUDC, FAM, Other Deferred Financing Costs	(22,602,158)							
18	Interest	191,411,567							
19	Other Expense, Net	(22,968,809)							
20	Bad Debt	3,843,434							
21	**Total Operating Expenses (Excluded)**	**$ 321,642,133**							
22	**Total Expenses**	**$ 1,867,116,532**							**$ 108,226,158**

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Figure 13: Cash Working Capital Requirement (2026)

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 1 Summary

Line	Description	2026 Amount	Average Daily Amount	Revenue / Collection Lag	Section	Expense Lead	Section	Net (Lead)/Lag Days	Working Capital Requirement
1	Fuels	$ 918,612,695	$ 2,516,747	49.91	2	(23.02)	3	26.88	$ 67,662,178
2	OM&G Labour	229,653,670	629,188	49.91	2	(26.02)	4	23.89	15,029,248
3	OM&G Expenses (Excluding Labour)	125,989,641	345,177	49.91	2	(31.80)	5	18.11	6,249,710
4	Grants In Lieu of Taxes	50,476,397	138,291	49.91	2	134.80	6	184.71	25,543,375
5	Income Taxes	(17,932,580)	(49,130)	49.91	2	(553.96)	7	(504.05)	24,764,262
6	HST Collected	298,706,130	818,373	32.85	7	(43.68)	7	(10.83)	(8,862,503)
7	HST / GST Paid (excluding capital-related)	79,188,446	216,955	45.63	7	(9.08)	7	36.55	7,928,933
8	DSM	63,750,000	174,658	49.91	2	2.46	8	52.36	9,145,899
9	**Operating Expenses (Lead-Lag Analysis)**	**$ 1,748,444,399**	**$ 4,790,259**						**$ 147,461,103**
10	**Operating Expenses (Excluded)**								
11	Future income tax expense	$ 0							
12	Depreciation Expense	287,012,283							
13	Accretion Expense	14,524,005							
14	FAM Deferral	(2,084,107)							
15	DSM Deferral	(177,185)							
16	Regulatory Amortization	9,097,413							
17	AFUDC, FAM, Other Deferred Financing Costs	(25,815,799)							
18	Interest	166,466,374							
19	Other Expense, Net	(22,653,943)							
20	Bad Debt	5,162,009							
21	**Total Operating Expenses (Excluded)**	**$ 431,531,049**							
22	**Total Expenses**	**$ 2,179,975,448**							**$ 147,461,103**

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Figure 14: Cash Working Capital Requirement (2027)

Nova Scotia Power Inc.
Lead-Lag Study
Cash Working Capital Requirement
Section 1 Summary

Line	Description	2027 Amount	Average Daily Amount	Revenue / Collection Lag	Section	Expense Lead	Section	Net (Lead)/Lag Days	Working Capital Requirement
1	Fuels	$ 918,352,313	$ 2,516,034	49.91	2	(23.02)	3	26.88	$ 67,643,000
2	OM&G Labour	233,216,587	638,950	49.91	2	(26.02)	4	23.89	15,262,416
3	OM&G Expenses (Excluding Labour)	128,453,186	351,927	49.91	2	(31.80)	5	18.11	6,371,914
4	Grants In Lieu of Taxes	51,548,504	141,229	49.91	2	134.80	6	184.71	26,085,911
5	Income Taxes	357,000	978	49.91	2	(85.00)	7	(35.10)	(34,329)
6	HST Collected	310,632,442	851,048	32.85	7	(43.68)	7	(10.83)	(9,216,353)
7	HST / GST Paid (excluding capital-related)	85,804,676	235,081	45.63	7	(9.08)	7	36.55	8,591,399
8	DSM	63,750,000	174,658	49.91	2	2.46	8	52.36	9,145,899
9	**Operating Expenses (Lead-Lag Analysis)**	**$ 1,792,114,709**	**$ 4,909,903**						**$ 123,849,857**
10	**Operating Expenses (Excluded)**								
11	Future income tax expense	$ 8,444,309							
12	Depreciation Expense	306,051,238							
13	Accretion Expense	15,538,088							
14	FAM Deferral	1,806,848							
15	DSM Deferral	651,137							
16	Regulatory Amortization	9,278,893							
17	AFUDC, FAM, Other Deferred Financing Costs	(17,105,761)							
18	Interest	169,496,031							
19	Other Expense, Net	(23,353,943)							
20	Bad Debt	5,265,249							
21	**Total Operating Expenses (Excluded)**	**$ 476,072,088**							
22	**Total Expenses**	**$ 2,268,186,797**							**$ 123,849,857**

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