REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Utility and Review Board

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

2020-2022 Fuel Stability Plan

Nova Scotia Power Inc.
Application

June 27, 2019

REDACTED

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1.0 EXECUTIVE SUMMARY

Nova Scotia Power Inc. (NS Power, the Company) is committed to providing stable and affordable rates for customers; it has kept annual overall average fuel rate increases in line with inflation since 2013 and has not raised non-fuel rates since 2014. The Company is looking to build on this commitment to customers and is proposing another three-year fuel stability plan with rate increases averaging 2 percent per year over the next three years.

As the Company is in the final year of the current fuel stability plan, NS Power needs to reset the Base Cost of Fuel (BCF) starting in 2020. This will result in fuel rate increases which primarily reflect the evolving environmental landscape and ongoing changes in the way energy is generated. Over the last decade, NS Power has moved from a utility that primarily generated electricity using coal to a utility with a diverse generation portfolio that will serve at least 40 percent of its electricity sales from renewable energy sources, and approaching 60 percent from non-emitting sources, beginning in 2020.

A significant change is completion of the Maritime Link, which will provide Nova Scotians with renewable energy and capacity from Newfoundland and Labrador. The Company's ongoing transformation in generation and energy supply is aligned with public expectations and public policy regarding environmental stewardship and responsibility. Federal and provincial regulations have decreased the amount of greenhouse gases and other emissions which provinces and utilities can produce. NS Power has achieved this significant transformation to clean energy while holding customer rate increases consistent with inflation since 2013.

Since 2005, NS Power has reduced its carbon dioxide emissions by 35 percent, its sulphur dioxide and mercury emissions by 40 percent and its nitrogen oxide emissions by 54 percent. Prior to completing its updated fuel forecast for 2020-2022, NS Environment advised NS Power that it would be proposing amendments to the *Air Quality Regulations*

respecting sulphur dioxide emissions.[1] Nova Scotia's *Air Quality Regulations* have been driving a steady decrease in sulphur dioxide emissions since 2005. The current regulations call for another round of decreases starting in 2020. That requirement assumed Muskrat Falls would be online by 2020. Given the delay with Muskrat Falls, the provincial government is allowing NS Power some flexibility in order to avoid significant rate increases for Nova Scotians, while continuing Nova Scotia's downward trend with sulphur dioxide emissions. NS Power estimates that this relief results in a reduction of the three-year BCF in excess of approximately $100 million, which is directly passed on to customers.

Fuel and purchased power costs constitute NS Power's single largest expense category, comprising approximately 45 percent of the total cost of electricity service. The forecast cost of the fuel and purchased power required to provide electricity for customers over the next three years has increased to approximately $2.2 billion. These costs have increased for several reasons since the last BCF forecast was filed with the UARB:

- The 2017-2019 Fuel Stability Plan addressed BCF and rate changes from 2017-2019; this design resulted in a forecast rate increase of 5.3 percent overall to recover the BCF in 2020;
- Some commodity costs have significantly increased since 2016;
- The delay in the flow of Muskrat Falls energy requires the purchase of replacement energy; and
- Nova Scotia no longer has access to offshore natural gas and must procure its supply primarily from the US.

[1] Please refer to Appendix B for a copy of the letter from the Minister of Environment to Karen Hutt dated May 16, 2019.

On their own, these factors would result in uneven rate changes for customers over the next three years. NS Power's focus was to develop a plan that would enable continued stable and predictable rates.

The proposed fuel stability plan includes the following measures which provide rate relief for customers:

- Application of the Fuel Adjustment Mechanism (FAM) balance as of the end of 2019 (including the $53.6 million 2020 Maritime Link Depreciation Credit);
- Application of the $15 million DSM HST rebate to the FAM balance;
- Provincial government changes to sulphur dioxide emission requirements to reflect the delay in timing of the Muskrat Falls energy; and
- Continued hedging of commodity prices to provide stable costs over the next three years.

These factors have enabled NS Power to develop fuel rates which can be smoothed over the next three years, resulting in an average increase of 2 percent each year, in line with inflation. This results in a rate increase of 1.5 percent each year for the Residential classes, 2.3 percent for the Commercial classes, 3.7 percent for the Industrial classes, and 2.3 percent for the Other classes. At the end of the fuel stability period, the FAM balance would be reduced to a forecast of approximately $44 million.

This fuel stability plan results in a further three-year period of inflationary fuel rate increases that allows NS Power to continue its renewable transformation in a way which is affordable and predictable for customers.

2.0 INTRODUCTION

NS Power is seeking to implement another three-year stability period, during which the BCF forecast will be smoothed to provide a consistent overall percentage rate increase in line with inflation each year.

The forecast fuel and purchased power costs from 2020 to 2022 (2020-2022 Fuel Stability Period) amount to $2.2 billion in total. The BCF forecast for this three-year period has increased by approximately $275 million compared to the forecast for the 2017-2019 Fuel Stability Period. NS Power is forecasting fuel and purchased power costs of $733.8 million in 2020, $738.7 million in 2021, and $732.1 million in 2022. Fuel is a direct pass-through cost, and customers ultimately only pay the actual fuel costs. Actual fuel costs for Fuel Adjustment Mechanism (FAM) customers will be tracked during the 2020-2022 Fuel Stability Period and will be trued up at the end of the period. The application of smoothed rates will mitigate the impact of volatile swings in fuel pricing for customers.

The application of smoothed rate increases[2] allows customers to plan and budget for electricity pricing over several years. In the 2011 Actual Adjustment/Balance Adjustment (AA/BA) application, the Nova Scotia Utility and Review Board (UARB) noted that an element of deferral is implicit in the nature of the FAM, and that a deferral is "a reasonable regulatory approach that fully attempts to strike the required balance between the interests of the utility and its customers in all the circumstances."[3]

The combination of smoothing fuel rate increases and using a regulatory FAM deferral over several years provides stability for both the utility and for customers. This tool has been used several times, including as part of the 2011 BCF and AA/BA applications, the 2013/2014 General Rate Application and the 2017-2019 Fuel Stability Plan Application.

[2] NSPI 2011 Base Cost of Fuel Application, Decision, 2010 NSUARB 219, November 18, 2010, at paras. 146-152.
[3] NSPI 2011 FAM AA/BA, Decision, 2010 NSUARB 235, December 8, 2010, at para. 17.

The FAM authorizes the UARB to consider appropriate mechanisms to assist customers if there is an increase to a customer class of more than 10 percent over the rate payable in the prior year or in any circumstances where it believes an increase is not acceptable or in the public interest. The Plan of Administration (POA) specifically contemplates the possibility of a deferral. Section 5.0 (Audit and Oversight) contains the following:

> **Significant FAM Changes**
> Where, in the absence of a General Rate Application, an increase for any customer class of more than 10 percent compared with the rate payable in the prior year is caused by the application of the FAM procedures, the Board should consider appropriate measures to assist customers.
>
> The Board will monitor the operation of the FAM closely and reserves the right to intervene in any circumstance where it believes an increase to a customer class is not acceptable or in the public interest and take such steps as it considers appropriate to assist such customers including deferring a part of the increase for collection in a future time period.

This is a specific authorization which supplements the powers of the UARB under Section 44 of the *Public Utilities Act*:

> **Orders by Board respecting rates and charges of utility**
> **44** The Board may make from time to time such orders as it deems just in respect to the tolls, rates and charges to be paid to any public utility for services rendered or facilities provided, and amend or rescind such orders or make new orders in substitution therefor. R.S., c. 380, s. 44.

As noted in Figure 1 below, if NS Power were to apply for a three-year BCF reset for the 2020-2022 Fuel Stability Period without proposed smoothing, FAM customers would face the following rate increases on average: -0.3 percent in 2020, 8.3 percent in 2021

and -0.1 percent in 2022.[4] The class percentage increases in 2020 would vary from -2.7 percent for the Residential class to 8.4 percent for the Large Industrial class and then would swing in 2021 to vary from 1.0 percent for the Large Industrial class to 10.5 percent for the Residential class.[5]

Figure 1 – 2020-2022 Rates without Smoothing and Application of the FAM Balance in 2020

	2020	2021	2022
Residential Class	-2.7%	10.5%	-0.1%
Commercial Classes	0.9%	7.2%	-0.1%
Industrial Classes	6.8%	2.7%	0.0%
Other Classes	2.2%	5.1%	-0.1%
Total Classes Overall	-0.3%	8.3%	-0.1%

Based on the three-year BCF forecast, NS Power is applying for an average 2 percent overall annual increase in FAM customer rates for each year of the 2020-2022 Fuel Stability Period and a deferred FAM balance, presently forecast at approximately $44 million, for collection from customers following the 2020-2022 Fuel Stability Period. This projected FAM deferral balance equates to 2 percent of forecast fuel and purchased power costs over the proposed Fuel Stability Period. Rate pressures and the resulting fuel cost forecast are detailed further below.

[4] This assumes return of approximately $54.1 million of FAM AA/BA amount through FAM riders and approximately $53.6 million through a one-time bill credit to customers in 2020. See M07718, NSPML 2016 Interim Cost Assessment Application, Order, November 2, 2017, page 3, paragraph 4.

[5] As part of the 2017-2019 Fuel Stability Plan, the Medium and Large Industrial classes chose the assumption that Muskrat Falls energy would commence on April 1, 2019, and the Residential and Commercial classes chose a later date of January 1, 2020. This has resulted in the Medium and Industrial Classes paying a lower fuel rate relative to the other FAM classes, which contributes now to larger relative overall fuel rate increases for those rate classes going into 2020.

The proposed overall rate increases are set out in Figure 2 below.

Figure 2 – 2020-2022 Rates with Smoothing and Application of the FAM Balance

	2020	2021	2022
Residential Class	1.5%	1.5%	1.5%
Commercial Classes	2.3%	2.3%	2.3%
Industrial Classes	3.7%	3.7%	3.7%
Other Classes	2.3%	2.3%	2.3%
Total Classes Overall	2.0%	2.0%	2.0%

The proposed 2020-2022 Fuel Stability Plan includes the following:

- the offset associated with application of the FAM balance to the BCF rates, made up of the actual FAM balance amount to the end of 2018 in the amount of $160.8 million over-recovery (based on 2017 AA/BA and 2018 AA/BA amounts and non-fuel revenues above NS Power's approved range for 2017 and 2018) (the FAM Balance to end of 2018), including $53.6 million of Maritime Link depreciation credit, currently required to be returned to customers through an on-bill credit in 2020;

- the projected 2019 FAM AA/BA of $107 million over-recovery (based on AA/BA actual values from January to April 2019 of $139.6 million over-recovery and forecast AA/BA of $31.9 million under-recovery for remainder of 2019) (the projected FAM Balance to end of 2019);[6] and

- approximately $15 million DSM HST credit to customers.

[6] Subject to UARB approval in the 2019 FAM AA/BA proceeding later in 2019.

As noted above, NS Power is seeking approval to return the $53.6 million Maritime Link depreciation credit owing in 2020 through the FAM balance in rates, rather than through an on-bill credit as previously directed. In both cases, customers will receive the $53.6 million Maritime Link credit that is being collected in rates in 2019, but allowing these funds to be applied directly as an offset to rates starting in 2020 will reduce the amount required to be collected over 2020-2022.

NS Power seeks an order approving the creation of a three-year Fuel Stability Plan, and its proposed BCF for each year during the 2020-2022 Fuel Stability Period as set out below and in the Appendices to this Application, confirmation of the final AA/BA amounts for 2017 and 2018, and direction that the 2019 AA/BA amount, subject to later determination in 2019 by the UARB, be included in the 2020-2022 Fuel Stability Plan, and FAM AA/BA rates for 2020.

3.0 FUEL COST PRESSURES IN 2020-2022

Since 2013, the Company has maintained average annual overall fuel rate increases that are in line with inflation. However, the cost of fuel and energy has increased since the 2017-2019 Fuel Stability Plan.

In addition to commodity cost increases in the cost of fuel and purchased power, there are environmental requirements which create additional fuel cost pressures that NS Power must manage on behalf of customers.

Under the *Renewable Electricity Standards* (RES),[7] 40 percent of the electricity provided to customers must come from renewable sources in 2020. As noted in Section 7.6 below, NS Power's average cost of purchased renewable energy during the 2020-2022 Fuel Stability Period is approximately $93/MWh as compared to anticipated costs of non-renewable energy of approximately $54/MWh.

A significant contributor to renewable energy sources beginning in 2020 is the anticipated flow of energy across the Maritime Link. NS Power forecasts receiving 520 GWh under the base block of energy and 105 GWh of supplemental energy in 2020 (jointly the NS Block), and forecasts 894 GWh and 240 GWh respectively on an annual basis after that. NS Power will also have access to surplus energy at market-based rates pursuant to the Energy Access Agreement.

In addition to the RES requirements, there are other environmental considerations which have an impact on fuel costs. The Province has implemented regulations under the *Environment Act* which address environmental compliance. The *Greenhouse Gas Emissions Regulations*[8] prescribe a reduced amount of emissions in the years 2020 and

[7] *Renewable Electricity Regulations* made under Section 5 of the *Electricity Act*, S.N.S. 2004, c. 25.
[8] *Greenhouse Gas Emissions Regulations* made under subsection 28(6) and Section 112 of the *Environment Act*, S.N.S. 994-95, c. 1.

2021-2024. NS Power is limited to 7.5 million tonnes (CO_2 equivalent) in 2020 and an average of 6.875 million tonnes in each of 2021 and 2022.

The *Cap-and-Trade Program Regulations*[9] prescribe the amount of free carbon allocations for NS Power in the years 2019-2022. NS Power is limited to 6.33 million tonnes, 5.52 million tonnes, 5.12 million tonnes and 5.09 million tonnes in the years 2019 through 2022 respectively. NS Power will be responsible for purchasing credits to offset carbon emissions beyond these limits.

Nova Scotia Environment (NSE) has advised NS Power that it intends to propose amendments to the *Air Quality Regulations* which will lessen the reduction in the sulphur dioxide (SO_2) cap for the 2020-2022 Fuel Stability Period. Please refer to Appendix B. Specifically, the Province proposes to have an annual SO_2 cap of 60,900 tonnes for 2020, a multi-year SO_2 cap of 90,000 tonnes for 2021 and 2022, and a multi-year SO_2 cap of 68,000 tonnes for 2023 and 2024. The Province also proposes to cap actual mercury emissions at 65 kg in 2020 and 45 kg in 2021 and 2022. NS Power will be able to use mercury diversion credits to account for the difference between the regulated cap of 35 kg and actual emissions.

NS Power has achieved significant reductions in emissions from 2005 to 2018. CO_2 has been reduced by 35 percent; mercury and SO_2 have each been reduced by 40 percent; and nitrogen oxide (NO_x) emissions have been reduced by 54 percent. NS Power is committed to meeting or exceeding its environmental requirements during the 2020-2022 Fuel Stability Period.

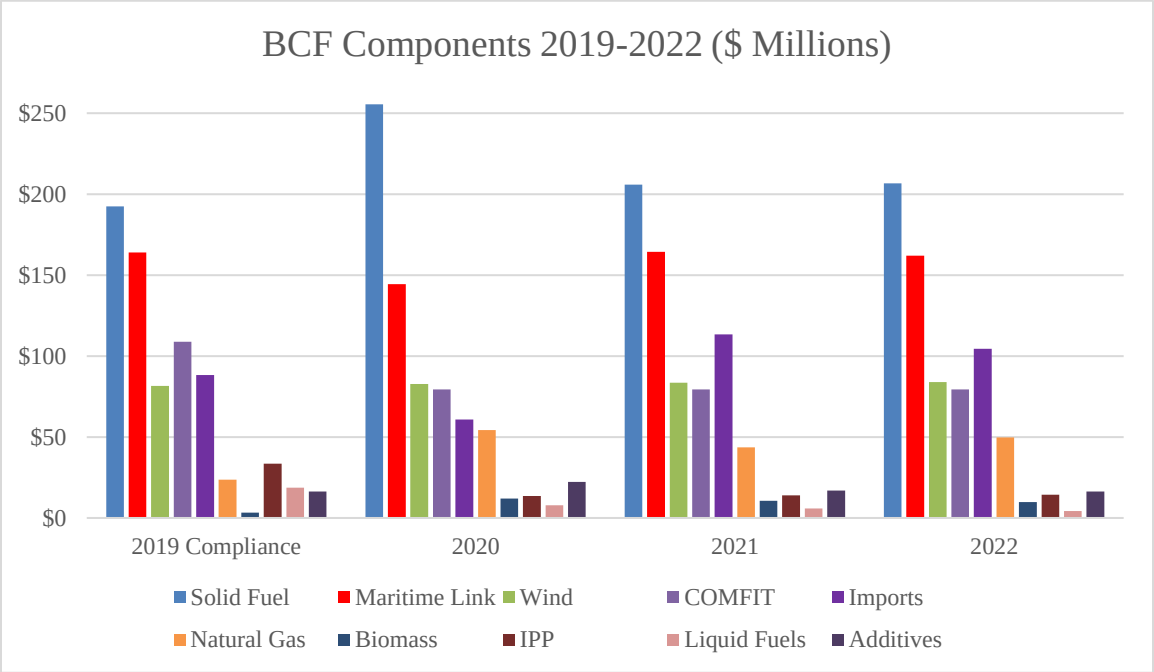
NS Power has forecast receipt of energy from Muskrat Falls to commence June 1, 2020. Consistent with the Board's decision on the 2018/2019 Interim Assessment,[10] the 2020

[9] *Cap-and-Trade Program Regulations* made under Section 112Q of the *Environment Act*, S.N.S. 1994-952, c. 1.
[10] M07718, 2018/2019 NSPML Interim Cost Assessment Application, Decision, 2017 NSUARB 149, September 11, 2017.

BCF does not include recovery of Maritime Link depreciation costs for the first five months of 2020. In the 2017-2019 Fuel Stability Period, the Maritime Link Assessment for 2018 and 2019 was smoothed over the three years along with other fuel costs. NSP Maritime Link Inc. (NSPML) has filed an application for approval of an interim cost assessment from NS Power for the Maritime Link continuing January 1, 2020.[11]

Figure 3 below shows the comparison between the cost drivers in the 2019 BCF Compliance filing compared to the cost drivers for the 2020-2022 Fuel Stability Period.

Figure 3 – Overview of Cost Drivers from 2019 BCF to 2020-2022 Period



As noted below, the price of commodities is volatile, and NS Power will continue to mitigate price fluctuations through its hedging program. This will limit the impact to customer fuel rates which would otherwise result from swings in commodity prices.

[11] M09277, NSPML 2020 Interim Cost Assessment Application, filed June 14, 2019.

4.0 FAM FRAMEWORK

4.1 FAM Plan of Administration (POA)

The POA outlines the application and administration of the FAM. It includes descriptions of the base cost of fuel, adjustment components, calculation methodologies, audit provisions, and stakeholder review and discovery, all of which have been developed in conjunction with stakeholders and approved by the UARB.

NS Power files revisions to the POA and appendices either on its own or in response to UARB directives or legislation.

The current POA was approved by the UARB[12] as part of NS Power's 2017-2019 Fuel Stability Plan application in 2016. The POA in place for the 2017-2019 Fuel Stability Plan reflected the legislative requirement in the *Electricity Plan Implementation (2015) Act* (EPIA) for a three-year BCF. The POA states that the BCF can be reset in a General Rate Application, every second year as part of the FAM adjustment process, or as directed by legislation or an order of the UARB.

NS Power is seeking to build on the success of the 2017-2019 Fuel Stability Plan and is seeking another three-year period of fuel stability. Accordingly, NS Power seeks to amend the POA to reflect the inclusion of another three-year BCF. As noted in NS Power's 2017-2019 Fuel Stability Plan Application, the POA was not designed to capture multi-year fuel forecasting and rate applications. Rather, the POA and the appendices were designed for implementation on an annual or biennial basis. However, the POA can accommodate a three-year forecast period with adjustment to some of the components of the POA and the fuel forecasting appendices.

[12] Revised in 2019 to reflect the creation of NS Power Energy Marketing Inc. (NSPEMI) in M0891.

In addition to allowing for a three-year BCF, NS Power is also seeking changes to the POA to reflect cap-and-trade costs and changes to the annual AA/BA reporting as part of this Application. Details of the POA changes are outlined in Section 4.4 below.

4.2 FAM Components

The UARB approved the implementation of the FAM in the 2009 General Rate Application (GRA) effective January 1, 2009. The FAM was originally structured to have three rate components: the BCF, the AA and the BA, and an incentive component. The incentive component was removed from the 2017-2019 POA and NS Power is not seeking to reinstate the incentive during the 2020-2022 Fuel Stability Period.

The rate components of the FAM are described below.

4.2.1 Base Cost of Fuel

NS Power resets its BCF in accordance with the POA.

The BCF is the test year forecast of fuel, energy and purchased power costs, which are incorporated into customer rates. Under this proposed three-year fuel stability period, there are three separate test years: 2020, 2021 and 2022.

The forecast methodology is found in Appendix B of the FAM POA. The BCF amount is used to calculate the fuel and purchased power cost component of customer electricity rates beginning on January 1 of each applicable test year.

The difference between NS Power's actual fuel costs and fuel costs established to be recovered through the BCF component of rates accumulates each month in the FAM as a regulatory asset (if NS Power under-recovers its actual fuel costs) or as a regulatory liability (if NS Power over-recovers its actual fuel costs).

Any under- or over-recovery (and associated interest) for the 2020-2022 Fuel Stability Period will be adjusted as part of the FAM filings to adjust rates for 2023, similar to the process for the 2017-2019 Fuel Stability Period.

4.2.2 Actual Adjustment (AA)

The AA represents the difference in the current year between the amount spent on fuel and the fuel-related revenue recovered from customers. At year end, the under- or over-recovered amount (plus the applicable interest) will be the total FAM deferral amount for that year. For purposes of establishing customer fuel rates to recover or return the FAM deferral amount, and as noted in Section 4.3 below, NS Power files an application which includes 12 months of actual fuel data (October to September).

The total deferral amount is divided by the upcoming year's sales forecast in order to determine the AA rate. For the 2020-2022 Fuel Stability Period, the AA amount is proposed to be tracked for each of the three calendar years and reconciled in 2022 for the 2023 AA/BA Application, similar to the process for the 2017-2019 Fuel Stability Period.

4.2.3 Balance Adjustment (BA)

The BA represents the difference in the prior year between the actual fuel costs and the fuel-related revenue recovered from customers. As noted above, although the FAM AA calculation uses 12 months of actual data so a balancing adjustment is no longer required to true up the actual fuel costs during the year,[13] there are additional amounts carried over from previous years which form part of the BA.

The BA comprises previously deferred FAM amounts and any residual amount of the AA related to previous years not fully refunded or recovered by the AA. The BA rate is

[13] Although the actual AA figures will be based on 12 months of actuals, there can still be a BA based on the difference between the forecast sales and the actual sales. The AA is set based on forecast sales for the year, but actual AA recovery could be different, resulting in a BA.

established using the cumulative under- or over-recovery divided by forecast sales for the period. Residual BA at the end of a year is applied to the following year and is used in the determination of future BA rates. In this way, only actual costs are recovered from customers.

For the 2020-2022 Fuel Stability Period, the BA will be calculated separately for each of the three calendar years and is proposed to be carried forward to the 2023 AA/BA Application, similar to the process for the 2017-2019 Fuel Stability Period.

4.3 AA/BA Reporting and Application Process

The AA/BA application was previously filed in November of each year for rates effective January 1 of the following year. That process included ten months of actual data (January to October) and two months of forecast data (November and December). Following a consultation process involving NS Power and members of the FAM Small Working Group, the timing of the AA/BA reporting was amended to use actual fuel data from October 1 to September 30 each year to allow for a filing in October. The UARB approved this change in July 2018 to be effective for the AA/BA filing in 2019.[14]

During the 2017-2019 Fuel Stability Period, NS Power filed its actual AA/BA information based on actual data from January to December for 2017 and 2018 in conjunction with the January Monthly FAM reports. For 2019, NS Power is filing its actual January-April AA/BA data in conjunction with this Application and will provide updated information to the end of September as part of the AA/BA filing in October.

As part of the 2017-2019 Fuel Stability Plan, NS Power has continued to track variances to fuel and purchased power costs during the 2017-2019 Fuel Stability Period and will

[14] M08656, NSPI AA/BA Process including 2016/2017 FAM Audit Timeline, UARB Letter, NSUARB-NSPI-P-887, July 4, 2018.

true-up and address those variances as part of the FAM rates to be applied after December 31, 2019. NS Power is seeking approval for the 2017 and 2018 AA/BA amounts. It is including in its proposal the actual 2019 AA/BA amounts to the end of April 2019 and forecast AA/BA amounts to the end of December 2019 subject to confirmation of the final 2019 AA/BA amounts in a UARB process later this year. The 2017-2019 AA/BA recovery amounts are included as Appendix C. NS Power is seeking a waiver of the requirements for the revised AA/BA process approved by the UARB in July 2018. The reason for this is to allow for inclusion of forecast amounts for October, November and December to be captured in the 2020-2022 Fuel Stability Plan.

As with the 2017-2019 Fuel Stability Plan and subject to UARB approval, NS Power intends to track the AA/BA amounts during the 2020-2022 Fuel Stability Period and will file an application in 2022 for approval of the 2020-2022 AA/BA rates effective January 1, 2023.

4.4 Plan of Administration Documentation

Some of the POA documentation needs to be modified to reflect NS Power's current practices and the proposed fuel stability period.

4.4.1 Plan of Administration

The POA main document has been updated to refer to the 2020-2022 Fuel Stability Period and the years 2020, 2021 and 2022 as appropriate. NS Power is also submitting updates to the POA for changes arising from the cap-and-trade regulations and changes to the AA/BA process approved by the UARB and seeks approval of these changes as part of this Application. A copy of the proposed POA with revisions is provided as Appendix D – POA Main Document.

The revisions to the POA main document are as follows:

4.4.1.1 *Three-Year Fuel Stability Period*

References to the proposed 2020-2022 Fuel Stability Period are updated on pages 1, 6, 8, 23, and 30 of the redline POA main document.

4.4.1.2 *AA/BA Process*

In accordance with the AA/BA process changes proposed by The Liberty Consulting Group in its report dated April 20, 2018 and the UARB's decision letter of July 4, 2018, the AA/BA process is being amended so that the rates are based on actual values from October to September (Q4 of the previous year and Q1-Q3 of the current year). These changes are reflected on pages 3, 4, 5, 8, 9, 27, 29, and 30 of the redline POA main document.

4.4.1.3 *GHG Emission Compliance Program Costs*

GHG Emission Compliance Program costs will flow through the FAM as an allowable Fuel and Purchased Power Cost. This is reflected on pages 10, 13, 14, 16, 19, and 20 of the redline POA main document.

4.4.1.4 *Chart of Accounts*

NS Power updated its Chart of Accounts in 2017 following the implementation of the Enterprise Resource Planning system. The Allowable Fuel and Purchased Power Costs have been updated with the new Chart of Accounts information. These changes are reflected on pages 10, 12, 13-18, and 20 of the redline POA main document.

4.4.1.5 *Calculation of Fuel Costs*

References to the treatment of earnings above the allowed range of return and treatment of tax benefits from the South Canoe and Sable wind projects have been removed as this was an item specific to the legislative requirements for the 2017-2019 Fuel Stability Plan and is no longer applicable.

The POA may have to be further amended in 2020 following the conclusion of the 2016-2017 FAM Audit process.

4.4.2 Appendix A – FAM Calculations

The FAM Calculation model will be modified to reflect the new AA/BA calculation process. The Word Calculations which describe the FAM calculation model inputs will also be revised to reflect the revised AA/BA calculation process. NS Power will file the updated FAM Calculation model and Word Calculations as part of its compliance filing in the fall. The Cost of Service Allocations for each rate class during each year of the 2020-2022 Fuel Stability Period which form part of POA Appendix A have been updated and are included as Appendix G to this Application.

4.4.3 Appendix B – Forecasting Methodology

Appendix B of the POA is the forecasting methodology used by the Company for fuel and load forecasting purposes. NS Power has made the following changes to POA Appendix B.

Section 2 – Load Forecasting

The load forecasting section now refers to the 10-year load forecast filed with the UARB each year for a complete description of the model.

NS Power uses a Statistically Adjusted End-Use (SAE) model to forecast the residential and commercial rate classes. The residential and commercial SAE models are 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 a Net System Requirement (NSR).

Section 3 – Fuel Forecast

NS Power's forecasting methodology for solid fuel follows the POA methodology discussed in Section 7.2.

Given the material changes resulting from the closure of Nova Scotia's two offshore production projects in 2018, natural gas forecasting now includes transportation costs. Premiums are forecast using the most recent RFP premium or discount rather than historical information.

Heavy fuel oil forecasting now includes the InterContinental Exchange as a pricing source, and forward pricing may use Brent crude prices.

Solid fuel indices have been updated, and NS Power has added SO_2 and mercury precipitation removal to the fuel forecasting section.

Section 4 – Resource Characterization

Steam generating unit minimum up and down time (two-shifting) capabilities, unit start-up costs and times and shutdown penalties have been added to POA Appendix B. Forced outage repair time, ramp rate capability, emissions content, fuel blend elements and reserve requirements have also been included.

There is also a new section which provides for the forecast of energy from Muskrat Falls over the Maritime Link.

There is also information on tidal and solar energy forecasting.

Section 6 – Export Power

Export power pricing methodology has been updated to assume that all export energy is priced nominally.

Section 7 – Import Power

Import power pricing forecasting has been updated to remove the reference to the Joint Dispatch Agreement and now refers to ISO New England as the purchase point.

Forecasting for the 2020-2022 period was done in accordance with the revised methodologies included in POA Appendix B. NS Power has included both a redline and a clean version of POA Appendix B as part of this filing.

4.4.4 Appendix C – Reporting Requirements and Templates

The reporting requirements and templates have not changed since the revisions to the POA to reflect the inclusion of NS Power Energy Marketing Inc. The UARB approved those changes on February 14, 2019 as part of matter M08911. The description of the reporting requirements and templates and templates for the FAM monthly, quarterly and annual reports are included for completeness of the POA.

4.4.5 Appendix D – FAM Calendars

NS Power has prepared draft FAM calendars for 2020, 2021 and 2022. The calendars include the regular reporting dates for the monthly, quarterly (subject to confirmation) and annual FAM reports, as well as the annual Natural Gas Reports and Maritime Link Benefit Reports (in 2020 only). NS Power has assumed that there will continue to be biennial FAM Audits and has drafted dates for the Audit process for 2020 and 2022. Proposed filing dates for the AA/BA reports during the Fuel Stability Period and the

AA/BA application in 2022 for 2023 are also included on the draft calendars. Other than firm filing dates, proposed dates are subject to UARB modification and Approval.

4.4.6 Appendix E – Proposed FAM Tariffs

The proposed FAM tariffs for 2020-2022 included as POA Appendix E are set out in Appendix J (clean) and Appendix K (redline) of this Application.

NS Power requests approval of the proposed POA changes as part of this Application.

5.0 APPLICATION OF 2017-2019 FUEL STABILITY PERIOD AA/BA

Consistent with the EPIA[15] and the UARB's decision on the 2017-2019 Fuel Stability Plan[16] the FAM AA/BA Riders have not been in effect during the 2017-2019 Fuel Stability Period. Variances between actual and recovered costs, as approved for forecast recovery during this period, will be addressed through FAM-related rate adjustments to be implemented on January 1, 2020.

As directed by the UARB,[17] the Company filed annual FAM AA/BA reports in January 2018 and 2019 providing actual full calendar year results for 2017 and 2018, respectively. These reports provided the same level of detail as under otherwise applicable FAM AA/BA Rider applications and have been subject to the Information Request (IR)-based examination process.

The UARB approved a revised FAM AA/BA Rider process using 12 months of actuals from the October to September time frame, starting with the 2019 process to set the AA/BA for 2020. NS Power proposes the FAM AA/BA Application filing date be moved to the beginning of the fourth week of October. This replaces the full calendar-year based timeframe made up of ten months of actuals and two months of forecast data with the FAM AA/BA Application filed in the second week of November. Please refer to Section 4.3 above.

For the purposes of this Application, NS Power included outstanding 2020 FAM AA/BA balances by rate class, based on actual cost and revenue data from January 2017 to April 2019 and projected data for May 2019 to December 2019.[18] Given the forecast high BCF

[15] EPIA, s. 11 (1).
[16] M07349, NSPI 2017-2019 Fuel Stability Plan and Base Cost of Fuel Reset, Decision, 2016 NSUARB 129, July 19, 2016, para [50].
[17] M07703, NSPI AA/BA Reporting for 2017 and 2018, Board's Correspondence, November 16, 2017.
[18] Projected data is based on the Q1 Forecast from February 2019.

under-recovery in 2019[19] as well as NS Power's proposal to suspend the FAM AA/BA Riders in years 2021 and 2022, it is better for FAM customers not to defer the repayment of the imbalance from Q4 2019 until the 2023 FAM AA riders come into effect three years later.

Please refer to Appendices C1 – C6 for FAM AA/BA amounts by rate class in years 2018 to 2020.

The Company proposes that the FAM AA/BA amounts, including the 2019 Maritime Link depreciation cost credit due for a one-time refund in 2020,[20] be recovered/returned in 2020 through the FAM AA/BA Riders. During years 2021 and 2022, the FAM AA/BA Riders are proposed to be set at zero. The overall rate smoothing during the 2020-2022 Fuel Stability Period, as discussed in the Cost of Service and Proposed Rates section, will be achieved by adjusting the BCF rate component in 2020.

The Company proposes to monitor annual imbalances between actual and recovered costs during the first two years of the 2020-2022 Fuel Stability Period through annual FAM AA/BA reports filed in January of 2021 and 2022 and to file the 2023 FAM AA/BA application in October 2022 for recovery/return of any outstanding FAM amounts in 2023. This approach would follow the FAM process used by the Board during the 2017-2019 Fuel Stability Plan.

[19] Rate classes other than those represented by CA and SBA experienced relatively higher BCF under recovery because they had their 2017-2019 RSP rates based on the lower cost assumption that the NS Block of energy was going to be available in January 1, 2020. The CA and SBA chose the assumption that the NS Block of energy would be available in April 2019.

[20] M07718, NSPML Application for approval of an interim cost assessment, Decision, 2017-NSUARB-149, September 11, 2017, para [143].

6.0 SOLID FUEL PORTFOLIO, CONTRACTS AND TRANSPORTATION

6.1 Fuel Portfolio

In accordance with its Fuel Manual, NS Power procures and manages a reliable and competitively priced supply of fuel on a system-wide evaluated cost basis for its generation fleet, consistent with regulatory and environmental requirements. The fuel and power procurement policy incorporates a portfolio approach to procurement. Appendices A OE-01E and OE-01J provide detailed information on the composition of the solid fuel portfolio.

Hedging of solid fuel positions will be based on the Company's Fuel Hedging Plan set out in the NS Power Fuel Manual and included in Appendix A OE-01J. The Fuel Hedging Plan is detailed in Section 12 below and builds upon the success of the 2017-2019 Hedging Plan with slight modifications. For price stability, there are times when NS Power enters into financial hedges in advance of physical purchases. Financial hedges in place for the 2020-2022 Fuel Stability Period are shown as a percentage of total requirements in Appendix A OE-01J.

Physical fuel requirements are determined by the Portfolio Optimization team using PLEXOS dispatch optimization software. NS Power reviews its contracted physical commitments on an ongoing basis, while monitoring its requirements and changes in market conditions to ensure the fuel portfolio is optimized to produce the lowest overall cost while meeting environmental requirements. Forecast volumetric requirements change over time, and minimum expected volumes are used to guide targets for hedging using physical purchases. In addition to physical contracts, financial coal hedges have been executed for [redacted] for 2020, [redacted] for 2021, and [redacted] has been financially hedged for 2022 as of the forecast date (May 17, 2019). Please refer to Figure 4 below.

Figure 4 – CONFIDENTIAL Comparative Physical Solid Fuel Portfolio

NS Power Solid Fuel Portfolio Table				
(in thousands of metric tonnes)				
YEAR	2020 BCF	2021 BCF	2022 BCF	2023 BCF
Contracted	[redacted]			
Open				
Total				
Physical Contracted percentage				
Open Physical percentage				

6.2 Fuel Contracts

6.2.1 Long-Term Contracts

Long-term contracts are contracts which have duration of four years or more.

NS Power has [redacted] for solid fuel within the 2020-2022 Fuel Stability Period for which the contract term spans four years or more as set out in

Figure 5. Volumes associated with these contracts are shown in Appendix A OE-01E.

Figure 5 – CONFIDENTIAL Long-Term Solid Fuel Contracts

Supplier	Solid Fuel Type	Contract Start Date	Contract Expiry
[redacted]			

6.2.2 Medium-Term Contracts

Medium-term contracts are defined as contracts with duration of one to three years.

NS Power has [redacted] for solid fuel within the 2020-2022 Fuel Stability Period for which the term spans one to three years as set out in Figure 6. Volumes associated with these contracts are shown in Appendix A OE-01E.

Figure 6 – CONFIDENTIAL Medium-Term Solid Fuel Contracts

Supplier	Solid Fuel Type	Contract	Contract
[redacted]			

6.2.3 Short-Term Contracts

The balance of NS Power's solid fuel requirements is purchased on a short-term basis. This amount varies based on overall consumption and contractual volume options.

6.2.4 Transportation Contracts

NS Power receives solid fuel at two port facilities. Both the International Pier (INP), located in Sydney and the Point Tupper Marine Terminal (PTMT) located in Point Tupper receive self-unloading vessels that typically originate from the eastern seaboard of North America and South America. PTMT can also handle bulker vessels.

NS Power purchases most coal on a free-on-board load port basis and is therefore responsible for the procurement of ocean freight. This provides transportation price stability along with flexibility and optimization of delivery schedules. Petroleum coke purchases are often made on an as-delivered basis with the supplier responsible for freight.

The type of freight NS Power uses depends primarily on economics but, as noted above, deliveries to the INP are currently limited to self-unloaders. PTMT can accommodate most vessel types.

[redacted]. NS Power intends to complete an RFP for ocean freight in 2020 before its current contract expires.

7.0 FUELS FORECAST AND FACTORS AFFECTING RATES

7.1 Fuel Stability Period Snapshot

Fuel costs include the delivered cost of solid fuels, natural gas, oil, and purchased power, offset by the net proceeds from export energy sales.

The 2020-2022 Fuel Stability Plan is forecast to rise by $275 million from $1.930 billion over three years in the 2017-2019 BCF Compliance forecast to $2.205 billion over three years in the 2020-2022 BCF forecast.

The primary forecast cost drivers going forward (as well as in the recent past) relate to legislated environmental requirements, such as reduced emissions, achievement of the 40 percent renewable requirement, and renewable feed-in tariffs (e.g. Community Feed-in Tariff (COMFIT)).

The Maritime Link will enable NS Power to meet the legislated requirement of supplying 40 percent of sales from renewable energy in 2020. With the completion of the regional energy loop created by the Maritime Link, the Nova Scotia system will benefit from increased system reliability and security. The loop will also assist with the balancing of renewable generation resources. In addition, NS Power will be well-positioned to access additional competitive energy markets, in a manner not previously possible, to obtain value for customers through the import (or export) of energy via the Maritime Link. NS Power forecasts [redacted] of surplus energy at a cost of [redacted] over the 2020-2022 Fuel Stability Period.

COMFIT costs forecast for 2020 are lower than those forecast in the 2019 BCF Compliance budget but are expected to remain stable during the 2020-2022 Fuel Stability Period as most forecast projects are now online.

Total solid fuel costs for 2020-2022 have increased approximately $100 million compared to the forecast 2017-2019 Fuel Stability Period due to a significant increase in market pricing.

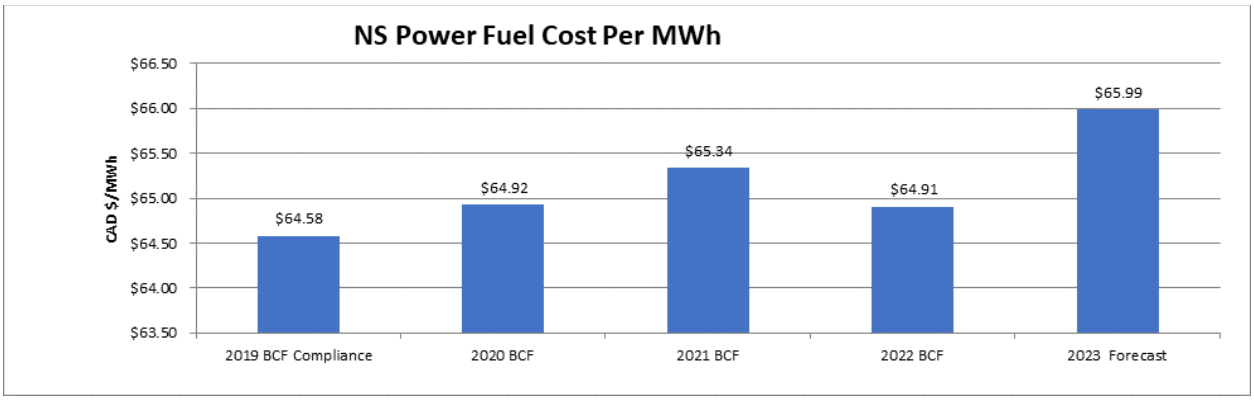
Import costs are expected to increase over the period, primarily due to increased forecast volume of surplus energy from Muskrat Falls and energy imported through the interconnection between Nova Scotia and New Brunswick, and will offset decreased volume of energy generated by solid fuel and natural gas.

Foreign exchange (FX) expense related to US Dollar fuel transactions is expected to increase costs by approximately $129 million over the 2020-2022 Fuel Stability Period as compared to the 2017-2019 Fuel Stability Period. This is due to both an increase in quantity of required US Dollars and an increase in the average achieved FX rate inclusive of FX hedges.

Independent Power Producer (IPP) costs will decrease compared to the 2017-2019 Fuel Stability Period due to canceled and delayed Tidal Feed-in Tariff (Tidal FIT) projects, which had costs previously forecast at $530/MWh.

As illustrated in Figure 7, the cost of fuel increases from $64.58/MWh in 2019 BCF Compliance to $64.92/MWh in 2020, and $65.34/MWh in 2021, and then decreases to $64.91/MWh in 2022.

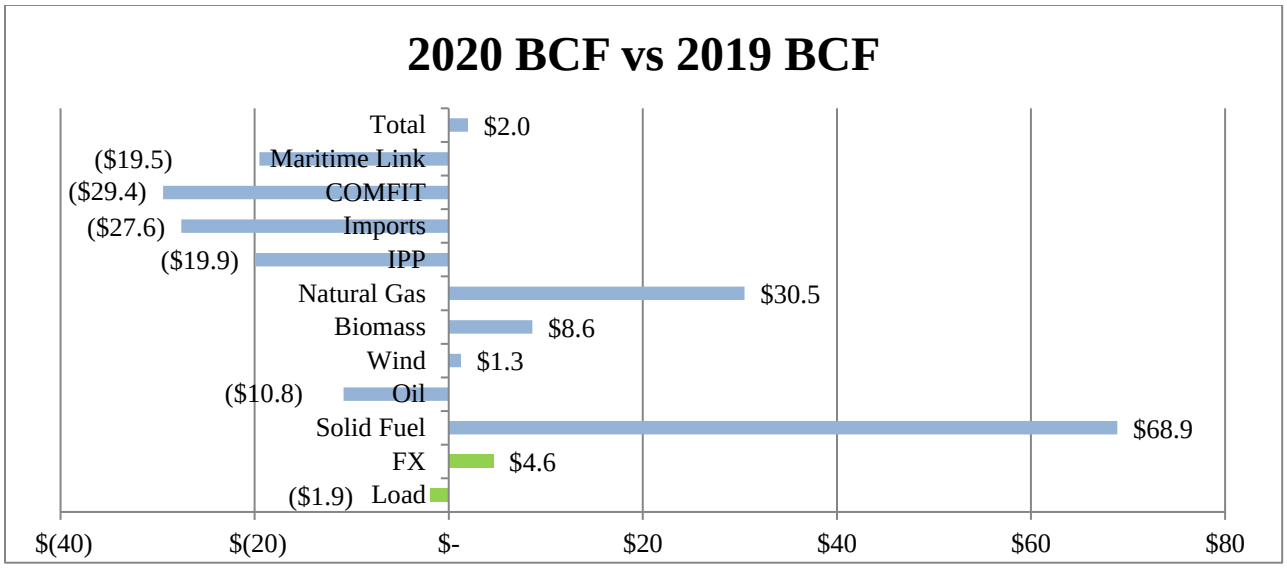
Figure 7 – NS Power Fuel and Purchased Power Costs Per MWh 2018-2023



The component parts which make up the fuel and purchased power mix of the BCF vary over the Fuel Stability Period. As shown below in Figure 8, there is a total overall forecast increase of $2 million in the 2020 BCF over the 2019 BCF Compliance budget. The largest single component of the change compared to the 2019 BCF Compliance budget is a $68.9 million increase in solid fuel costs, primarily due to the absence of the NS Block of energy over the Maritime Link in the first five months of 2020. Forecast Maritime Link interim assessment costs have decreased by $19.5 million in 2020[21], primarily due to the removal of depreciation prior to the forecast commencement of the NS Block on June 1, 2020. Natural gas costs have also increased $30.5 million, primarily due to increases in commodity pricing following the closure of Nova Scotia's two offshore natural gas projects in 2018. These increased costs are partially offset by reduced COMFIT and IPP costs of $49.3 million, due to cancelled and delayed projects, in addition to reduced import costs of $27.6 million due to lower surplus volumes.

[21] M09277, NSPML 2020 Interim Assessment Application, June 14, 2019.

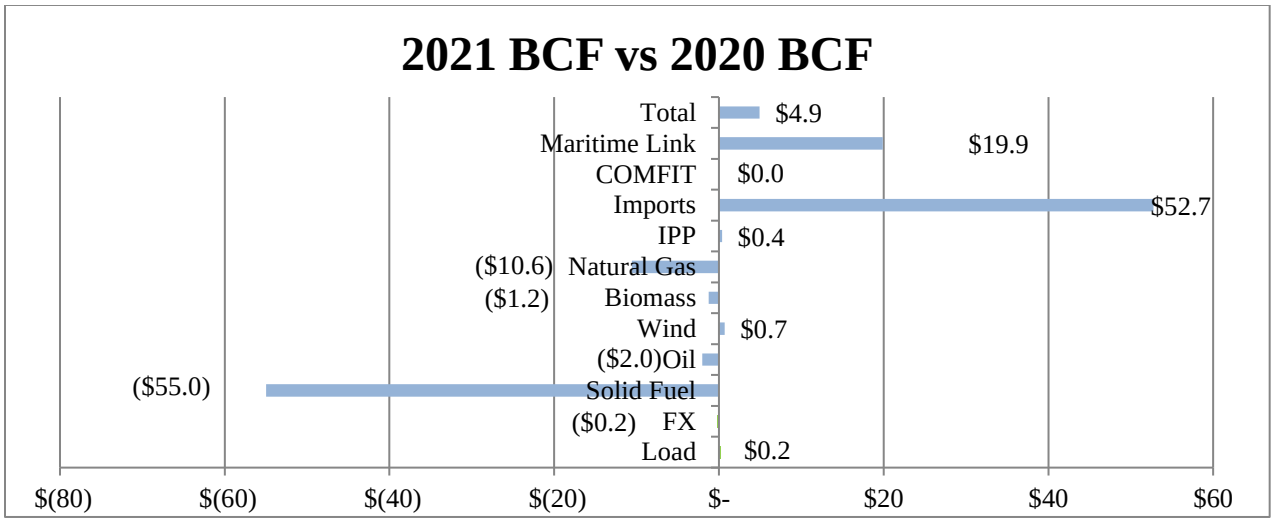
Figure 8 – 2020 BCF Component Cost Changes vs 2019 BCF Compliance Filing



FX (Foreign Exchange) & Load impact costs are included within the other cost components and are displayed separately for informational purposes.

As shown in Figure 9 below, the total BCF costs in 2021 are expected to increase $4.9 million from 2020. Forecast Maritime Link assessment costs will increase by approximately $19.9 million, reflecting the full year of depreciation expense, and imports will increase by $52.7 million due to increased surplus volumes. In 2021, there is a forecast decrease in fossil fuel cost: solid fuel is expected to drop by approximately $55.0 million, natural gas will drop by $10.6 million, and fuel oil will decrease in cost by approximately $2.0 million.

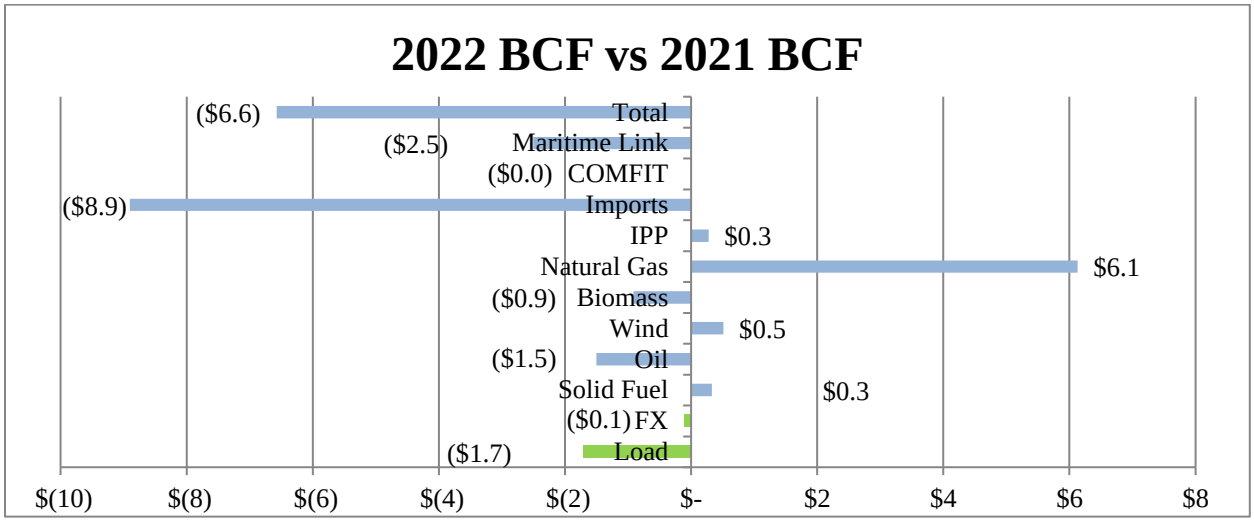
Figure 9 – 2021 BCF Component Cost Changes vs 2020 BCF



FX (Foreign Exchange) & Load impact costs are included within the other cost components and are displayed separately for informational purposes.

As noted in Figure 10 below, in 2022, there will be a relatively minor changes in commodity component costs from 2021. The total decrease is $6.6 million, comprised of decreased import costs of $8.9 million and forecast Maritime Link assessment costs of $2.5 million, partially offset by an increase in natural gas cost of $6.1 million.

Figure 10 – 2022 BCF Component Cost Changes vs 2021 BCF



FX (Foreign Exchange) & Load impact costs are included within the other cost components and are displayed separately for informational purposes.

Figure 11 – CONFIDENTIAL Comparison of Cost of Fuel/MWh 2019-2022

[redacted]

Figure 11b – CONFIDENTIAL Surplus Included with ML Fuel/MWh 2020-2022

[redacted]

Figure 11 above shows the costs for the 2019 BCF Refresh and the 2020-2022 Fuel Stability Plan by fuel type. Figure 11b shows the impact of surplus energy moved from Imports to ML category. As can be seen, solid fuel and HFO costs increase in each succeeding year of the 2020-2022 BCF compared to the 2019 BCF Refresh. Natural gas costs also increase until the anticipated commencement of NS Power's TransCanada Pipeline and PNGTS transportation service in late 2021. Muskrat Falls surplus energy costs, on a dollar per MWh basis, are forecast to be consistent over the three-year Fuel Stability Period. IPP & COMFIT costs are reduced significantly from the 2019 BCF Refresh with delayed and cancelled tidal, wind and biomass COMFIT projects. Biomass costs on a per MWh basis were high in 2019 due to low volumes consumed in conjunction with fixed fuel handling fees.

Figures 12-15 below show the breakdown of the BCF in each year by fuel and purchased power type (including the 2019 BCF Refresh for comparison), and the associated costs. Moving into 2022, fossil fuel costs decrease proportionately as renewable costs increase.

Figure 12 – 2019 Breakdown of BCF by Fuel and Purchased Power Type

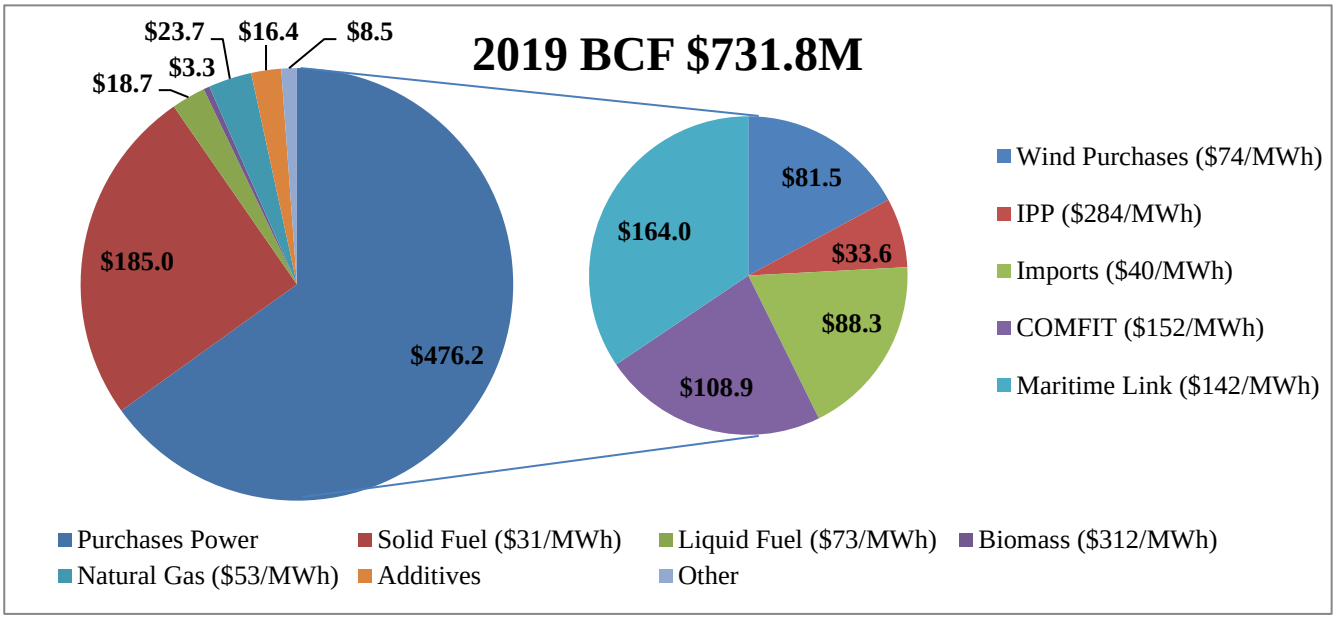


Figure 13 – 2020 Breakdown of BCF by Fuel and Purchased Power Type

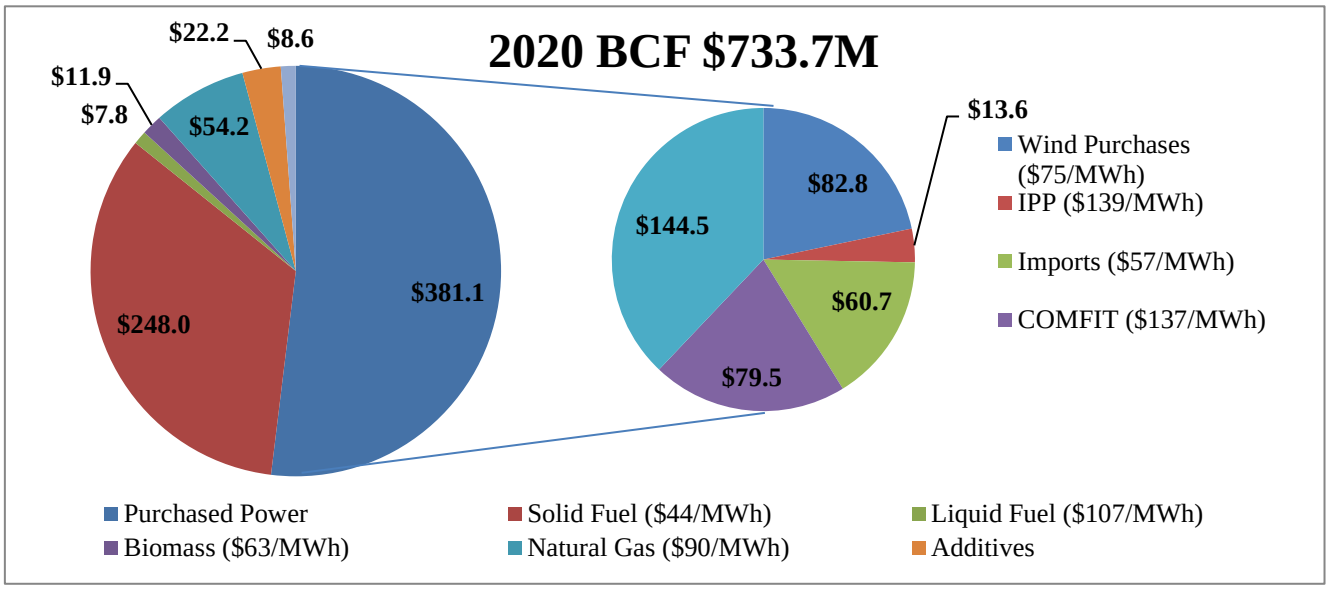


Figure 14 – 2021 Breakdown of BCF by Fuel and Purchased Power Type

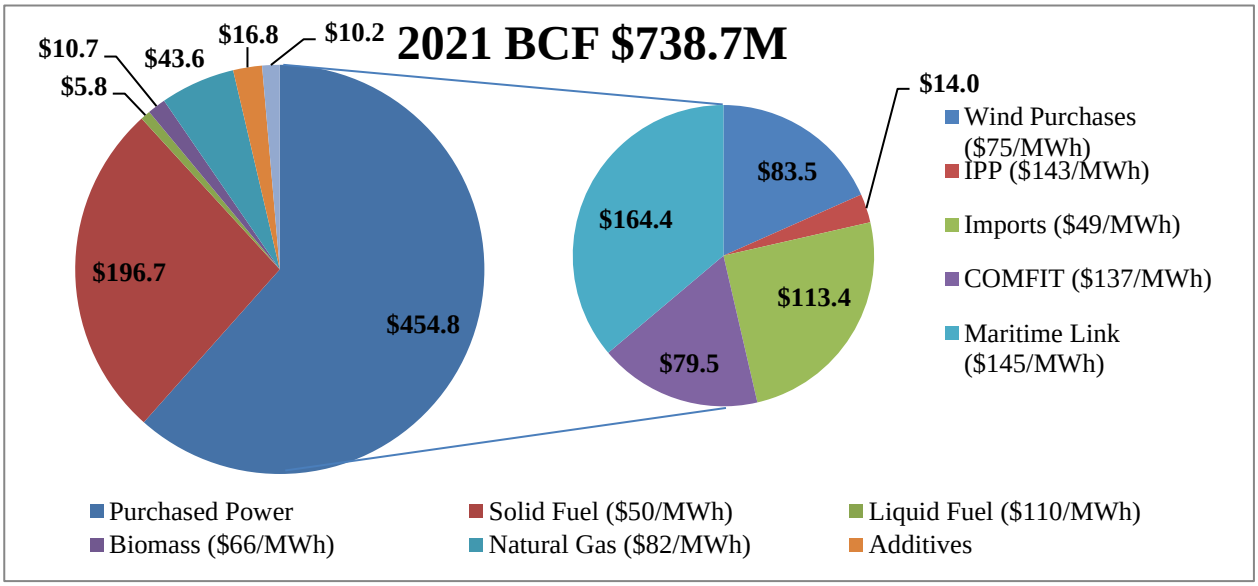
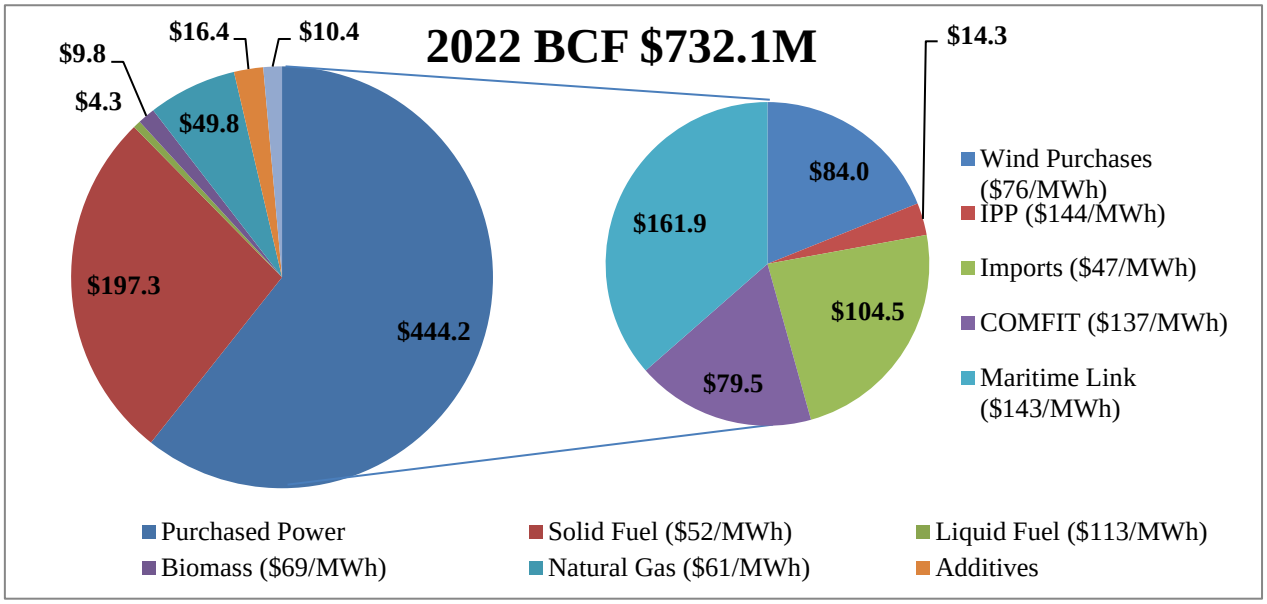


Figure 15 – 2022 Breakdown of BCF by Fuel and Purchased Power Type



The following sections provide details on NS Power's 2020-2022 fuel requirements compared to the 2019 BCF Refresh. All commodities purchased in United States Dollars (USD) have been converted to Canadian Dollars (CAD) at NS Power's forecast blended achieved exchange rate of [redacted] for each USD in 2020, $[redacted] in 2021 and [redacted] in 2022. The derivation of this exchange rate is described in Section 7.9 of this Application.

7.2 Solid Fuel

In developing the solid fuel figures for this Application, NS Power followed the fuel forecast methodology outlined in Appendix B of the FAM POA, with the following updates:

- For the low sulphur / low Btu coal forecast pricing, the forward price strips and indices weightings have been updated from [redacted] to [redacted] This update accounts for the current market trend of low sulphur / low Btu coal priced based on API 2 – BCI 7.

- The low sulphur / high Btu coal forecast pricing is based on [redacted]. This update accounts for the current market trend of low sulphur coal/ high Btu coal priced based on API 4. The API 4 and API 2 indices were obtained from InterContinental Exchange as published near the start of the fuel forecast development in accordance with the FAM POA.

- Petroleum coke pricing was determined based on supplier bids and the petcoke pricing published by PACE.

Solid fuel is used at four generating facilities: Lingan, Point Aconi, Point Tupper and Trenton. Most of the coal and all the petroleum coke consumed at these stations is imported. NS Power purchases domestic coal if it is available, meets environmental requirements, and is competitively priced.

Confidential Figure 16 compares the forecast mix of solid fuels from the Company's 2020-2022 BCF to the mix in the 2019 BCF Refresh.[22]

Figure 16 – CONFIDENTIAL Solid Fuel Mix 2019 BCF Refresh and 2020-2022 BCF

Solid Fuel Type	2019 BCF	2020 BCF	2021 BCF	2022 BCF
Import Coal	[redacted]			
Low-Sulphur (<1.1% Sulphur)				
Mid-Sulphur (<3.5% Sulphur)				
Domestic				
Petcoke				
Total				

Compared to the 2019 BCF Refresh, coal pricing is higher in the 2020 to 2022 Fuel Stability Period.

While NS Power will continue to utilize a mix of lower sulphur and higher sulphur solid fuels through the 2020-2022 Fuel Stability Period, coal utilization in 2020 is further offset by increased renewables. The [redacted]

[22] NS Power, 2017-2019 Fuel Stability Plan Reply Evidence and Fuel Refresh, May 27, 2016 (M07348).

[redacted] and an increase in imported coal starting in 2020.

The forecast price for solid fuel in years 2020 to 2022 represents an increase of 44 to 68 percent in the unit price of solid fuel relative to the 2019 BCF Refresh.

7.2.1 Environmental Compliance

NS Power is required to manage air emissions within annual limits set by regulation. The air emission compliance limits specified in the *Air Quality Regulations* were amended November 21, 2014 and became effective January 1, 2015. The changes which are described in Appendix A OP-14 call for total emission limits over multi-year periods and include annual caps.

As previously noted, NS Power was advised by the Minister of Environment that the province intends to propose amendments to the *Air Quality Regulations* respecting the SO_2 cap for a three-year period from 2020 to 2022. The revised emissions requirements are shown below in Figure 17 below.

Emissions allowances for mercury (Hg) had previously been amended for the 2020-2022 Fuel Stability Period, and the amendments include the introduction of a mercury diversion program as described below in Section 7.2.2. The *Air Quality Regulations* were amended again on October 12, 2017 and included the provision to use mercury credits for compliance beginning in 2020. Mercury emission limits are also shown in Figure 17. GHG emissions are governed by multi-year cumulative allowances, which must be achieved for compliance, under the Greenhouse Gas Emission Regulations, as set out in Figure 18. The Cap-and-Trade Program Regulations which became effective in November 2018 include the annual free allowances for GHG emissions for NS Power.

Figure 17 – Annual Emission Allowance Caps of SO_2, NOx and Hg

Year(s)	SO_2 Tonnes			NOx Tonnes		Hg Kg[1]
	Unit Maximum	Annual	Cumulative	Annual	Cumulative	Annual
2014		72,500		21,365		65
2015-2019	42,775	72,500	304,500	21,365	96,140	65
2020[2]	TBD	60,900	TBD	14,955		35
2021-2022[2]	TBD	90,000	TBD	14,955	56,000	35
2023-2024[2]	TBD	68,000	TBD	11,500		35
2025	13,760	28,000	104,000	11,500	44,000	35

1. Mercury diversion credits can be used to account for the difference between the regulated cap of 35 kg and actual emissions. NSE has indicated NS Power can use up to 30kg of diversion credits in 2020 up to 10kg of diversion credits in subsequent years.
2. Annual maximum caps were not defined in the 2019 proposed amendments to the *Air Quality Regulations*; however, NSE has indicated new regulations will be adjusted accordingly.

SO_2 is governed by annual maximum limits as well as a multi-year cumulative emission limit of 304,500 tonnes for 2015 to 2019. The forecast emissions over the 2020-2022 period were modelled to account for access to renewable energy from the Maritime Link NS Block forecast to displace solid fuel in June 2020. The revised SO_2 emission limits for 2020-2022 will result in significant savings in solid fuel costs for customers.

As set out in Figure 17, mercury is governed by annual limits. Mercury diversion credits will play an important fuel and purchased power cost reduction role with respect to mercury compliance in the 2020-2022 period, as described in Section 7.2.2.

The forecast emissions for NOx and GHG for 2020-2022 are within the regulated annual allowances.

7.2.2 Mercury Diversion

Amendments to the provincial *Air Quality Regulations* in November 2014 and October 2017 included the introduction of a new Mercury Diversion Program. The program enables NS Power to obtain credit for diverting mercury-containing products from the environment in Nova Scotia, provided diversion credits are available to compensate for mercury emissions above 35 kg, as discussed below.

Beginning in 2020, the mercury credits can be used to compensate for the annual emissions of mercury that exceeded 65 kg in years 2010 to 2013, as well as for compliance from 2020 onwards (the difference between the regulated cap of 35 kg and actual emissions). The Mercury Diversion Program started in 2015 and can continue until the end of 2024. NS Power can use credits to the end of 2030. NS Power submits an annual diversion plan to the Minister of Environment for approval. The objective of this program is to divert mercury from the environment in Nova Scotia in an innovative, safe, environmentally friendly and cost-effective manner.

The program may include:

- Diversion of mercury-containing products collected from the public
- Diversion of streetlights (NS Power-owned and/or other)
- Diversion of other mercury-containing products recovered through existing or new programs

The Diversion program offers potential savings as it is forecast to cost $170,000 per kilogram less to divert a kilogram of mercury than it does for powder-activated carbon (PAC) to remove a kilogram of mercury from stack emissions. Fuel costs may also be reduced. The average annual forecast emissions over the 2020-2022 period are approximately 65 kg in 2020 and 45 kg annually in 2021-2022 with diversion credits applied to bring the mercury emissions down to the required level. Diversion credit application provides an opportunity to generate energy using mercury abatement systems at their nominal injection rates without being subject to high costs associated with increased sorbent injection rates, premium sorbent procurement, and fuel re-blending. The Mercury Diversion program therefore lowers costs for customers while maintaining environmental benefits.

7.2.3 Cap-and-Trade

On January 1, 2019 Nova Scotia's cap-and-trade program came into effect. NS Power has filed as Appendix D an amended FAM POA to include cap-and-trade program costs and revenues as allowable fuel costs. GHG emissions are governed by multi-year cumulative allowances as shown in Figure 18.

The *Cap-and-Trade Program Regulations* include the annual free allowances for GHG emissions for NS Power.

Figure 18 – Multi-year Greenhouse Gas Emission Limits

Year	GHG Cumulative Million tonnes
2014-2016	26.32
2017-2019	24.06
2020	7.5 (annual)
2021-2024	27.5

Year	GHG Cumulative Million tonnes
2025	6 (annual)
2026-2029	21.5
2030	4.5 (annual)

Figure 19 – Greenhouse Gas Free Allowances 2019-2022

Year	GHG Free Allowances Million tonnes
2019	6.334
2020	5.517
2021	5.120
2022	5.087

NS Power thermal facilities that meet the CO_2 emissions threshold for cap-and-trade (50,000 tonnes) are not required to pay fuel surcharges on fuel consumed for electricity generation. Fuel consumed for onsite activities via mobile equipment is subject to a fuel surcharge under the *Cap-and-Trade Program Regulations*.

As the Port Hawkesbury Biomass facility and the combustion turbine sites do not meet the emissions threshold, fuel consumed on those sites will be subject to fuel surcharges under the *Cap-and-Trade Program Regulations*.

7.3 Natural Gas

Figure 11 above shows the cost per MWh of natural gas in the 2020-2022 Fuel Stability Period compared to the 2019 BCF Refresh. Figures 13-15 also show the total costs of the natural gas in each year. NS Power forecasts the average cost of natural gas consumed,

including transportation charges to Tufts Cove, to range from [redacted] to [redacted]. The price reflects no domestic gas supply. Incremental supply sourced from distant markets increases the delivered cost due to pipeline charges relative to previous periods.

The 2020 price represents [redacted] percent in the unit price of natural gas relative to the 2019 BCF Refresh budget, and the 2021 and 2022 prices represent a [redacted]

NS Power manages financial exposure to changes in the market price of natural gas through hedging, including the use of swaps.[23] See Section 12.0 for further detail about NS Power's hedging strategy during the 2020-2022 period.

Natural gas prices in this Application are produced using forward price curves in accordance with the POA.[24]

7.3.1 Natural Gas – Cost Pressures

Forecast natural gas requirements for 2020 are significantly higher than the 2019 BCF Refresh. However, for 2021 the requirements decline considerably, returning to 2019 levels. For 2022, the requirements increase again. The primary driver for the requirements is supply availability at prices competitive with solid fuel, the availability of imports via the Maritime Link and gas being a lower emitting fuel than solid fuel. Gas

[23] Swap contracts are financial instruments used to lower volatility in pricing terms for a supply contract.
[24] Forward price curves refer to a graph of future prices decided upon by both buyer and seller for any given commodity.

supply either has to be sourced from the TransCanada Pipeline Ltd. (TCPL) system and shipped across multiple pipelines or sourced from the Algonquin system once the Atlantic Bridge expansion is fully placed in service, which is forecast to occur in 2021 and provides a limited amount of additional capacity into the Maritimes & Northeast Pipeline.

In order to secure the necessary natural gas for its operations, NS Power has executed precedent agreements with TCPL and Portland Natural Gas Transmission System with the intent to enter into long-term contracts for firm pipeline transportation service starting in late 2021. NS Power is seeking a contract for 20,000 MMBtu per day for a 15-year term.[25] This will benefit customers by providing additional fuel price and rate stability, increased fuel supply diversification, reduced emissions, and enhanced reliability and supply security.

7.4 Heavy Fuel Oil

Depending on the relative market prices of each fuel, Tufts Cove may generate using HFO rather than natural gas in the dual-fired steam boilers (Units 1-3).

NS Power forecasts consuming [redacted] barrels of HFO in 2020, [redacted] barrels in 2021, and [redacted] barrels in 2022, compared to [redacted] barrels forecast in the 2019 BCF Refresh.

The forecast price of HFO is [redacted] in 2020, or approximately [redacted] delivered. The 2020-2022 prices are relatively constant, but [redacted] than the 2019 BCF Refresh.

[25] The *Approvals of Natural Gas Transportation Contracts Regulations* (N.S. Reg. 80/2019), effective June 4, 2019 and made pursuant to the *Public Utilities Act* permit the UARB to approve transportation contracts greater than two years' duration.

7.5 Light Fuel Oil

LFO accounts for a very small portion of the BCF: approximately 2.56 percent in 2020, 1.17 percent in 2021, and 0.70 percent in 2022. NS Power expects to consume [redacted] gallons of LFO in 2020 as start-up fuel in its thermal units and for operation of the oil-fired combustion turbines, [redacted] gallons in 2021 and [redacted] gallons in 2022. The quantity of LFO forecast is higher in 2020 and 2021 than the 2019 BCF Refresh consumption of [redacted] gallons, reflecting projected higher peak demand requirements. The forecast price for LFO in 2020 is [redacted]. This is a [redacted] per MMBtu relative to the 2019 BCF Refresh budget. For 2021 and 2022 the price [redacted] 2019 levels.

7.6 Renewable Energy

7.6.1 NS Power-Owned Renewables

The renewable energy generated by NS Power comes from hydro, tidal, wind and biomass.

The level of hydro and tidal generation forecast for 2020-2022 is based on a 23-year rolling average, in accordance with Section 4.10 of POA Appendix B. The use of this methodology results in a forecast of 960.5 GWh for 2020, 952.0 GWh for 2021 and 955.2 GWh for 2022. This forecast is slightly lower than the 2019 BCF Refresh of 977.6 GWh.

The wind generation forecast for NS Power-owned sites is based on a three-year rolling average. NS Power forecasts annual generation of 143 GWh from Nuttby Mountain and 120 GWh from the Digby wind farm for a total of 263 GWh during each year of the 2020-2022 Fuel Stability Period. This is consistent with the 2019 BCF Refresh. However, there is no forecast generation from the Grand Etang wind turbine, as it is no longer operational. This represents a change from the 2019 BCF Refresh.

The Port Hawkesbury Biomass Plant (PHB) went into service in July 2013. PHB is a 60 MW co-generation plant operated by NS Power that produces renewable electricity. Port Hawkesbury Paper (PHP) draws steam from PHB for its paper-making process. Biomass procurement and management has evolved since July 2013, in particular with respect to winter blending, including the use of higher cost round wood to help manage moisture which naturally occurs with freshly harvested biomass forest fibre. Practices have been shared with the FAM Small Working Group and are included in Revision 10 of the Fuel Manual, in accordance with the letter from the Board dated January 26, 2016. Revision 10 of the Fuel Manual is included in Appendix A OE-01F.

Confidential Figure 20 below illustrates the current forecast pricing for biomass relative to the 2019 BCF Refresh.

Figure 20 – CONFIDENTIAL Biomass Cost Comparison 2019-2022

Port Hawkesbury Biomass Cost Summary				
	2019 BCF Refresh	**2020**	**2021**	**2022**
Fuel Costs ($ Millions)	[redacted]			
Energy (GWh)				
Fuel Costs ($/MWh)				

The operation of PHB is subject to the RES. Section 5(2A) of the RES requires NS Power to maintain PHB available as a base-loaded cogeneration facility and NS Power must operate PHB on an economic dispatch basis or as required for system reliability. Specifically, Section 5(2A) states:

> **(2A)** NSPI must maintain the Port Hawkesbury biomass power generation plant available as a base load cogeneration facility and NSPI must operate the plant on an economic dispatch basis or as required for system reliability.

Section 6A (1) of the RES requires that 40 percent of NS Power's annual energy sales be through renewable energy generation beginning in 2020:

> **6A (1)** Each year beginning with the calendar year 2020, each load-serving entity must supply its customers with renewable electricity in an amount equal to or greater than 40% of the total amount of electricity supplied to its customers as measured at the customers' meters for that year.

In early 2019, NS Power notified the Province in writing of its achievement of over 3,178 GWh of renewable energy in 2018 and a total of 29.9 percent of energy sales from renewable generation in the year 2018. The PHB plant is projected to generate [redacted] volumes compared to the 2019 BCF Refresh due to [redacted] economics through the 2020-2022 period, including GHG pricing with the implementation of the Cap-and-Trade program.

7.6.2 IPP and Feed-in Tariff Contracts

NS Power has Power Purchase Agreements (PPAs) with IPPs and COMFIT developers for renewable energy from various sources. The IPP generation is grouped into two categories for forecasting purposes: IPP Wind and IPP Other (which includes biomass, biogas, hydro and tidal). COMFIT projects are forecast separately and include generation from wind, biomass, biogas, run-of-river hydro and small tidal.

Generation forecasts for IPP and COMFIT sites are based on a three-year rolling average when the data is available. If a three-year generation history is not available, the expected annual net output of the facility is used.

The IPP forecast for the 2020-2022 period is set out in Confidential

Figure 21 below:

Figure 21 – CONFIDENTIAL Forecast IPP Generation 2019-2022

	2019 BCF Refresh		2020		2021		2022	
	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)	Capacity (MW)	Generation (GWh)
IPP Wind	[redacted]							
IPP Other								
TOTAL								

Included in the IPP Wind forecast are the Point Tupper, South Canoe and Sable wind farms. The 2020-2022 annual generation forecast for these sites is [redacted] GWh for Point Tupper, [redacted] GWh for South Canoe and [redacted] GWh for Sable Wind.

Now that most projects are online and the Tidal FIT program is not forecast to deliver energy during the 2020-2022 Rate Stability Period, the IPP Other category is consistent year over year and is slightly lower than in the 2019 BCF Refresh. The Tidal FIT program was established by the government of Nova Scotia in 2013 to encourage the development of tidal energy projects in Nova Scotia. Projects are submitted to and approved by the Nova Scotia Department of Energy and Mines (DOEM). The Tidal FIT Energy Rates ($/MWh) and standard PPA were set and approved by the UARB through regulatory proceedings completed in 2013 and 2015, respectively. NS Power does not forecast any of these projects coming into service during the 2020-2022 Fuel Stability Period.

The COMFIT Program was established by the government of Nova Scotia in 2010 to support the development of local, distribution system connected, renewable energy

projects by municipalities, First Nations, co-operatives, universities, combined heat & power biomass facilities, community economic development investment funds, and non-profit groups. Projects are submitted to and approved by DOEM. The COMFIT energy rates ($/MWh) and standard PPA were set and approved by the Board through a regulatory proceeding completed in 2011. The COMFIT forecast for the 2020-2022 Fuel Stability Period is set out in Figure 22 below.

Figure 22 – COMFIT Forecast 2019 – 2022

	2019 BCF Refresh		2020		2021		2022	
	Installed Capacity (MW)	Generation (GWh)	Installed Capacity (MW)	Generation (GWh)	Installed Capacity (MW)	Generation (GWh)	Installed Capacity (MW)	Generation (GWh)
COMFIT	179.5	715.2	155.8	578.2	155.8	578.2	155.8	578.2
% Total Fuel Cost	16.7%		10.8%		10.8%		10.9%	
% Generation	6.3%		5.1%		5.1%		5.1%	

The decrease in COMFIT capacity over the 2019 BCF Refresh is a result of fewer COMFIT projects coming in to service than previously forecast. The government closed the COMFIT program in August 2015, and as a result no new projects will be approved by DOEM. Previously approved projects will continue to operate under their existing timelines.

COMFIT site generation is based on a thee-year average for projects that have been in service for that duration. In the absence of historical data, annual net output provided by each COMFIT developer was used for the COMFIT forecast. However, in the cases where the annual net output was very high, NS Power applied a capacity factor cap of 40 percent for large wind and 25 percent for small wind to reflect more likely generation.

7.7 Imports

Over the 2020-2022 period, there are two ways in which energy will be imported into Nova Scotia: imports through the Maritime Link and imports through the interconnection between Nova Scotia and New Brunswick. For the purpose of this Application, imports are defined as imports through the interconnection between Nova Scotia and New Brunswick and the surplus energy imported through the Maritime Link. The NS Block imported through the Maritime Link is not included in the definition of imports in this Application.

As shown in Figure 23, the total volume of imported energy over the 2020-2022 period ranges from approximately [redacted] to [redacted] GWh. The primary drivers for the [redacted] in volume relative to 2018 and forecast for 2019 are the availability of surplus energy in 2020 through 2022 and the forecast pricing of imports relative to other alternatives over the 2020 to 2022 forecast period.

Figure 23 – CONFIDENTIAL Forecast Import Volumes and Pricing 2018-2022

	2018 Actuals	2019 BCF Refresh	2020	2021	2022
NB to NS Import Volume (GWh)	[redacted]				
Actual & Forecast Cost of NB to NS Imports ($ million)					
Actual & Forecast Cost of NB to NS Imports ($/MWh)					
Maritime Link Surplus Energy Volume (GWh)					
Maritime Link Surplus Energy Forecast Cost ($ million)					
Maritime Link Surplus Energy Forecast Cost ($/MWh)					
Total Import Volume (GWh)					
Total Cost of Imports ($ million)					
Total Cost of Imports ($/MWh)					

The methodology used to forecast the price of imports is described in Section 7.0 of the POA Appendix B.

The pricing assumption used for Muskrat Falls surplus energy is [redacted]

As illustrated in Figure 23 the forecast volume of Muskrat Falls surplus energy in 2020, 2021 and 2022 [redacted] into Nova Scotia through the interconnection with New Brunswick [redacted]

7.8 Exports

7.8.1 Renewable Energy Credits

NS Power will continue to monitor Massachusetts Class 1 Renewable Energy Credit (REC) market pricing. NS Power's Energy Marketing Desk will use current REC market pricing when making economic South Canoe wind export decisions. If more value is created with a wind export than serving internal load in any given hour, NS Power will undertake a South Canoe wind export opportunity. The economic analysis of these exports will include a forecast of any incremental costs related to GHG or other emissions. NS Power will receive one REC for each MWh of South Canoe wind delivered into ISO-NE. Once there are banked RECs in NS Power's ISO-NE GIS account, NS Power will undertake Massachusetts Class 1 REC sales in order to monetize this value for customers.

7.9 US Dollar Requirements and Foreign Exchange Rates

NS Power uses forward contracts to hedge its USD requirements for fuel. A forward contract is a commitment to purchase specific securities (in this case, USD) at an agreed-upon rate at a specific date in the future. The use of forward contracts to hedge expected

USD requirements results in increased fuel cost stability for NS Power's customers. NS Power's USD requirements are hedged based on known and forecast requirements, and the percentage of USD exposure hedged is aligned with the percentage of fuel hedged for that corresponding time period.

NS Power monitors and reports on its risk management strategies, including budgeted volumes of underlying positions not hedged and revisions to the budget volume.

A summary of the forecast percentage of USD requirements hedged and blended USD rate for each year in the BCF filing is shown in
Figure 24 below.

Figure 24 – USD Hedge Summary (Confidential)

Hedge Summary Table				
Year	**USD Volume ($ million)**	**USD Hedged ($ million)**	**% of USD Hedged**	**Average FX Rate**
2020	[redacted]			
2021				
2022				

7.10 Load Retention Tariff Customer and Impact on Fuel Forecasting

NS Power performed an analysis to determine the total fuel and purchased power costs with the Load Retention Tariff (LRT) load included and another analysis with the LRT load excluded. The difference between those two scenarios resulted in an estimated fuel and purchased power cost of [redacted] to serve the LRT load alone in 2020. Using

the same approach resulted in estimated fuel and purchased power costs of [redacted] and [redacted] to serve LRT load in 2021 and 2022 respectively.

8.0 LOAD FORECAST

Peak demand and customer energy requirements have a significant effect on NS Power's fuel cost. Growth in peak demand can affect generation planning, while growth in electric energy consumption increases total fuel costs. As such, the electric load forecast, which provides an outlook on the energy and peak demand needs by month, is an essential part of determining future fuel costs.

Electric load grows as new customers are added to the power system, and as existing customers add electrical appliances or equipment; load is tempered by the fact that new equipment tends to be more energy efficient. Electric load grows (or shrinks) with changes to the ownership and usage of certain end-uses such as space heating equipment that may be subject to competition from alternative fuel sources such as heating oil. If customers and businesses transition from electricity to other sources, load is also affected. The effect of weather conditions on the use of space heating (or cooling) equipment can also create variations in electric load. Demand side management (DSM) and the use of various tools and programs to decrease energy usage also have an impact on electric load.

The load forecast for the 2020-2022 period was conducted in accordance with amendments to FAM POA introduced and accepted during the 2016 BCF proceeding. It uses a statistically adjusted end-use (SAE) model to forecast the residential and commercial sector load and an econometric model to forecast industrial load and is based on the 10-year load forecast filed with the UARB in April 2019. Sales are forecast to decline at an average annual rate of 0.4 percent over the 2020–2022 period.

Figure 25 sets out a sector-by-sector comparison of the load forecast for the 2020-2022 period.

Figure 25 – Load Forecast by Sector 2018 - 2022

Energy (GWh)	2018 Actuals	2019 Forecast	2020 Forecast	2021 Forecast	2022 Forecast
Residential	4,542	4,551	4,493	4,473	4,479
Commercial	3,181	3,161	3,154	3,123	3,095
Industrial	2,614	2,681	2,734	2,795	2,790
Other	154	152	150	148	146
Losses	758	786	769	765	767
Net System Requirement	11,250	11,331	11,300	11,303	11,278

Across the forecast period, residential and commercial loads decline steadily at around 0.5 and 0.7 percent per year, respectively. Overall, DSM activities are expected to offset increases in electric heating intensity. Industrial load is forecast to grow at 1.3 percent per year with the expansion of an existing large industrial customer in 2020. The full details of the models used to develop the load forecast for the 2019-2022 period are found in Appendix E.

The peak is forecast to grow at 0.4 percent per year between 2019 and 2022 mainly due to increased residential electric heating, with a peak of 2,248 MW forecast for January 2022.

9.0 MARITIME LINK

9.1 Background

As part of the approval of the 2017-2019 Fuel Stability Plan, the UARB approved forecast Maritime Link Project costs in 2018 and 2019 for inclusion in rates to reflect the forecast interim assessment for the Maritime Link.

The approved assessment reflected a deferral of the 2018 and 2019 depreciation and deferred financing amortization costs collected through the 2017-2019 Fuel Stability Period. The amounts attributable to these deferrals that were collected through the 2017-2019 Fuel Stability Period for 2017 and 2018 were returned with interest to customers via an annual on-bill credit. NS Power is requesting a change to the UARB's Order of June 14, 2019 requiring NS Power to pay back the 2019 Maritime Link Assessment amount of $53.6 million as an on-bill credit in 2019 and is asking instead that the UARB direct this portion of the 2019 Maritime Link Assessment amount be returned through the FAM balance as an offset to rates.

While Nalcor is forecasting the third generating unit at Muskrat Falls to be commissioned in May 2020, NS Power's modeling has assumed that the NS Block will begin June 1, 2020, consistent also with NSPML's request for commencement of depreciation. NS Power anticipates receiving 520 GWh under the base block and 105 GWh of Supplemental Energy (jointly the NS Block) in 2020. Starting in 2021, the forecast is for 894 GWh per year under the base block and a further 240 GWh per year of Supplemental Energy.

9.2 ML Assessment and Depreciation

In accordance with the requirements of the Maritime Link Cost Recovery Regulations and the UARB's 2017 Maritime Link decision, NSPML is seeking approval[26] for a

[26] M09277, NSPML 2020 Interim Assessment Application, June 14, 2019.

continuation of the Interim Assessment as of January 1, 2020 based on the forecast costs attributable to the Maritime Link consistent with the information presented in this Application.

NSPML's forecast portion of the anticipated assessment for the Maritime Link against NS Power includes an amount for the continuation of NSPML's Interim Assessment in 2020 in the amount of $144.5 million, as well as forecast Maritime Link Project costs of $164.4 million in 2021, and $161.9 million in 2022. The 2020 Interim Assessment does not include depreciation expense prior to the forecast June 1, 2020 commencement of the Nova Scotia Block. Components of the anticipated assessment for 2020-2022 are set out in Figure 26.

9.2.1 Components of the Anticipated Assessment

Figure 26 – Breakdown of the Maritime Link anticipated assessment

Description	2020 ($Millions)	2021 ($ Millions)	2022 ($ Millions)
Depreciation	28.6	51.0	51.0
Operating & Maintenance	20.5	20.0	20.0
Debt Financing Costs	45.4	44.4	42.9
Equity Financing Costs	50.0	49.0	48.0
Total Anticipated Assessment	144.5	164.4	161.9

The basis of NS Power's 2020 forecast assessment for the Maritime Link is NSPML's June 14, 2019 application for its 2020 Interim Assessment. The basis of its 2021 and 2022 forecast are the estimates provided by NSPML.

10.0 APPLICATION OF DSM HST REFUND

Efficiency Nova Scotia Corporation, the predecessor to EfficiencyOne, the franchise holder for demand side management energy efficiency and conservation activities in the province, was successful in appealing an Excise Tax Act assessment for 2010 to 2015 by the Minister of National Revenue. The result was that Efficiency Nova Scotia recovered $14,123,207 in harmonized sales tax (HST) together with interest, for a total refund of $15,018,371 as of September 12, 2018. Under the *Electricity Efficiency and Conservation Restructuring (2014) Act*, S.N.S. 2014, c. 5, the HST refund is an asset of Efficiency Nova Scotia which accrues to the benefit of NS Power customers.

As part of the application for a 2020-2022 Demand Side Management Supply Agreement between NS Power and EfficiencyOne, the parties agreed by way of a consensus agreement and subject to UARB approval[27] that the HST refund would be returned to NS Power and applied to the FAM. The HST refund is proposed to be allocated to the various customer classes in accordance with the cost of service allocation methodology that was in place when these funds were collected from customers.

As of June 3, 2019, the HST refund (with interest) is $15,277,651. At the DSM hearing which took place June 10, 2019 EfficiencyOne and NS Power proposed that the HST amount would be included in the FAM and accounted for as part of this Application, subject to UARB approval.

For the purpose of this application, the funds have been allocated by DSM class and are reflected in the rates found in the 2020 FAM BA Cost of Service Allocation found in Appendix G. If the UARB does not approve the application of these funds to the FAM, they will be removed in the BCF Compliance Filing.

[27] 2020-2022 DSM Supply Agreement Application, M09096, Exhibit 38.

11.0 2023 FORECAST

Average fuel and purchased power costs in 2023 are forecast to be $65.99/MWh as compared to average fuel and purchased power costs of $64.91/MWh in 2022. The primary change in 2023 fuels and purchased power costs is due to the increased price of solid fuel, import energy and natural gas. As a result, fuel and purchased power costs in 2023 create moderate additional rate pressures relative to 2022.

12.0 HEDGING PLAN

Fuel costs are subject to a variety of risks including commodity market, volumetric, basis, and counterparty risk. Reducing market exposure through physical and financial hedges enables the Company to manage volatility in fuel costs and provide continued rate stability for customers.

In 2016, as a component of its Fuel Stability Plan filing and as a requirement of the *Electricity Plan Implementation (2015) Act*, the Company filed a Fuel Hedging Plan (FHP) which received approval from the Board. The FHP detailed the specific strategies, principles, and mechanisms to be used by NS Power in the 2017-2019 Rate Stabilization Period, but as stated in the FHP, "As the RSP progresses, the strategies and principles in the Plan could be validly applied to 2020 and beyond assuming similar market conditions and a continued focus on rate stabilization."

The success demonstrated by the FHP, as it largely protected customers from the significant increases in commodity prices since 2016, helps validate the approach to hedging adopted by the Company. There is no legislative requirement for the UARB to approve NS Power's Hedging Plan for the 2020-2022 Fuel Stability Period. However, NS Power intends to continue with the general hedging approach used over the 2017-2019 Fuel Stability Period, with certain modifications to incorporate changing market conditions and learnings from the experience gained over this period.

12.1 Hedging Plan Objectives

Fuel and purchased power (F&PP) costs represent the single largest component of NS Power's revenue requirement. Due to the volatile nature of global commodity markets, these costs can exhibit large and unpredictable increases and decreases over time. In order to provide rate stability for customers, NS Power will use hedging to reduce market exposure when it is cost effective to do so. Recognizing that not all risks can be hedged and that the cost of hedging may in certain circumstances outweigh the benefit of hedging, the Hedging Plan is designed to achieve two primary objectives:

1. Cost-effectively reduce the expected and actual variance in F&PP costs during the 2020-2022 Fuel Stability Period.

2. Reduce the probability of a significant increase in any fuel-related deferral resulting from under-recoveries of F&PP costs from customers through rates during the 2020-2022 Fuel Stability Period.

12.2 Hedging Principles

- Recognizing that not all risk can be removed from fuel costs, focus on reducing the overall portfolio risk when it is economic to do so.

- While hedging increases the stability and predictability of fuel costs, it does not guarantee the lowest costs are achieved.

- NS Power will target hedging [redacted] compared to [redacted] in the 2017-2019 Hedging Plan of each fuel type with periodic dynamic rebalancing of hedges and contracts to optimize the portfolio. Approximately 50 percent of NS Power's forecast FAM fuel costs for the 2020 – 2022 Fuel Stability Period relate to fixed contracts for renewable energy including the forecast Maritime Link Assessment and are therefore naturally hedged. Hedging [redacted] percent of the remaining fuel costs, which are exposed to market forces, will result in [redacted] of forecast total Fuel and Purchased Power costs being hedged.

12.3 Hedging Strategies

NS Power will employ a portfolio approach to hedging by evaluating the impact of each hedge in terms of its expected reduction in overall portfolio risk using Value at Risk ("VaR") and volumetric positions as the key metrics. Where economically available, NS Power will enter into hedges [redacted], based on the most current forecast from PLEXOS. As these forecasts are updated with new

assumptions and NS Power's expected volumetric requirements for each fuel change, the portfolio of hedges will be dynamically rebalanced to align with the new forecast. From time to time, this will result in gains or losses from hedges that are unwound but will generally be offset by corresponding changes in forecast costs of the physical requirements. The purchase of fuels denominated in US Dollars results in foreign exchange exposures which will be included in NS Power's overall portfolio risk management approach and hedged as part of the Plan in accordance with NS Power's Currency Risk Management Policy.

Due to limited liquidity in certain markets, NS Power may enter into a hedge using underlying products that are not the exact physical commodity being hedged, but are highly correlated with this commodity, and therefore provide economic protection against price movements in the underlying exposure being hedged. For example, NS Power consumes HFO for use primarily at Tufts Cove. However, the Company may not be able to hedge the exposure to HFO prices directly through the entire 2020-2022 Fuel Stability Period. In this case, other oil-based financial contracts linked, for example, to Brent Oil may be used by NS Power to provide price protection against movements in HFO prices due to the high correlation between these products. This proxy, or cross-commodity, hedging is standard practice in many markets, especially energy markets where a great diversity of physical products must be hedged with a limited number of liquid financial products.

The previous section deals primarily with managing the price risk leading up to the months in which the underlying fuels are expected to be consumed. NS Power recognizes the need to continue its risk management activities to encompass intra-month volatility and variability. Through its ability to optimize the hourly and daily dispatch of its generation fleet, NS Power will use fuel switching, physical storage capabilities, and other real optionality within its portfolio to manage intra-month fuel price variability. Where available and economic to do so, NS Power will enter into physical or financial contracts to provide additional mitigation of intra-month risk.

12.4 Hedging Mechanisms

This section provides a brief outline of some of the key hedging mechanisms expected to be used during the 2020-2022 Fuel Stability Period. It is not meant to be an exhaustive list, and other products or mechanisms may be used by NS Power. NS Power will use a combination of physical and financial contracts. A more detailed description of the products and trade types can be found in the FHP which is included in Appendix A OE-01J. The Company notes that many of these mechanisms are currently used or have been used by NS Power in the past, especially during the 2017-2019 Fuel Stability Period, and are consistent with the mechanisms in the approved FHP.

12.4.1 Physical Contracts

By entering into fixed price contracts, NS Power will agree to pay a known price for a physical fuel or purchased power, thereby eliminating exposure to underlying commodity market prices. These contracts may be for fixed volumes or may include volumetric optionality for NS Power. Generally, NS Power will enter into these contracts when it has a high degree of confidence that it will require the physical fuel at the time it will be delivered or that there is sufficient storage capacity to allow for deferral of consumption to another time period where its consumption is economic.

12.4.2 Financial Contracts

Financial contracts will primarily take the form of futures, forwards, and swaps. Generally, NS Power will be the buyer of these contracts which means it will be obligated to pay a fixed price known at the outset of the contract, and in return it will receive a floating payment (or stream of payments) linked to an underlying market price. Should market prices increase, these financial contracts will result in a net payment to NS Power which will help offset the higher price NS Power will be required to pay in the market for the underlying physical fuel or purchased power. Should the underlying market price decrease, NS Power will make a net payment to its financial counterparty,

however, it is likely that the cost to NS Power of the physical commodity will have decreased as well. In either case, the impact of financial hedging is to offset the higher or lower prices that must be paid for the physical fuel or purchased power, thereby reducing the variability in these costs and providing for greater fuel cost stability and predictability. NS Power may use a combination of centrally cleared exchange-traded and bilateral over-the-counter financial contracts. NS Power may also use options or structured physical and financial products should there be sufficient market liquidity and these products be determined to economically hedge underlying market exposures.

13.0 COST OF SERVICE AND PROPOSED RATES

A traditional BCF Application considers setting BCF rates for a single test year based on the fuel cost requirement in accordance with the approved cost of service methodology and as prescribed in the POA. However, this Application differs from the traditional approach in the following respects:

1. The Fuel Stability Plan encompasses three forward test years (2020, 2021 and 2022) and the projected fuel cost amounts under the 2020 FAM AA/BA due for recovery or refund in 2020.

2. The total amount of fuel costs to be recovered by NS Power during the 2020-2022 period is proposed to be capped at a level commensurate with an average annual increase of 2.0 percent in weighted average unit revenues for all FAM rate classes combined, with the remainder of unrecovered fuel costs proposed to be deferred and amortized for recovery after the 2020-2022 period.

3. The annual effect of fuel costs on changes in class unit revenues (c/kWh) is proposed to be smoothed such that percentage increases in average annual unit revenues (cents/kWh) are constant for each rate class during the 2020-2022 period.

4. The percentage annual increases in individual class unit revenues are proposed to be set based on the assumption that by the end of the 2020-2022 Fuel Stability Period all rate classes will have paid the same portion of their total fuel cost increase, inclusive of 2020 FAM AA/BA credits, during that period.

The Company has first determined annual fuel cost requirements by FAM rate classes partially offset by allocation of the outstanding 2020 FAM AA/BA amounts, using a single test year approach for each year in the 2020-2022 period.

13.1 Revenue Requirement by FAM rate classes

The revenue requirement is developed in the BCF proceeding by accounting for all test year fuel-related costs of service necessary to provide regulated electric service. Additionally, NS Power proposes to incorporate into this rate setting process the forecast of the 2020 FAM AA/BA amounts inclusive of deferred depreciation expenses and financing amortization expense associated with the Maritime Link, which is not proposed to be refunded as a one-time on-bill payout but rather applied through the FAM AA riders throughout 2020.

The Revenue Analysis by Rate Classes is found in Appendix F.

13.2 Cost of Service

13.2.1 Treatment of Fuel Costs

The BCF in the 2020 to 2022 test years is allocated to each class according to the UARB-approved methodology in the 2013 Cost of Service Study (COSS) Proceeding.[28]

The POA states on page 1:

> The Base Cost of Fuel can be reset in a General Rate Application, every second year as part of the FAM adjustment process, or as directed by legislation or an order of the Board[29]. A forecast of costs and load for each test year will be used to set the Base Cost of Fuel. During the Rate Stability Period, the Base Cost of Fuel is smoothed over three test years: [2020, 2021 and 2022]. The change in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each

[28] 2014 NSUARB 53 (M05473).
[29] The Base Cost of Fuel is reset for 2017-2019 under the 2017-2019 Fuel Stability Plan as directed in Section 4 of the *Electricity Plan Implementation (2015) Act*, S.N.S. 2015, c. 31.

customer class in a manner consistent with the Cost of Service Study (COSS).[30]

NS Power proposes to reset the BCF for the three calendar test years 2020, 2021, and 2022 in the Fuel Stability Period. Consistent with the manner in which fuel costs are treated from a COSS perspective in a General Rate Application, the cost responsibility for fuel costs forecast for each test year is allocated among rate classes using the procedural steps 1 through 5, and 7 from section 3.0 of the revised POA. Steps 6 and 8 are omitted as they are applicable to the AA and BA calculations.

Forecast fuel costs for each test year are first apportioned to above-the-line (ATL) and BTL classes using procedural step 1:

1. A portion of the total fuel-related costs will be assigned to the following categories of non-FAM classes based on their fuel costing principles:

    a. The below-the-line bundled service rates for Generation Replacement and Load Following (GRLF), 1P-RTP and Shore Power classes.

    b. The Load Retention Tariff (LRT) class.

    c. The unbundled tariffs: Open Access Transmission Tariff (OATT), Wholesale Market Backup/Top-up Service Tariff (BUTU), Energy Balancing Service Tariff (EBS), Renewable to Retail Market Transition Tariff (RTT).

    d. All remaining fuel-related costs will be allocated to ATL classes.

[30] Plan of Administration filed September 22, 2016.

NS Power does not forecast energy uptake under the EBS Tariff and RTT. Consistent with the COS methodology, the Company forecasts the avoided costs of loads served under these classes and deducted them from the total fuel costs to arrive at costs attributable to ATL classes.

The fuel costs are then allocated among the ATL classes by applying, with some modifications where appropriate, the procedural steps 2 through 5 for the allocation of plant fuel costs, purchased power costs and export revenue benefits.

2. For ATL classes, NS Power's fuel costs will be classified as 100 percent energy related. These costs will be allocated to each class based on its relative contribution to monthly energy requirement.

3. Fuel costs assigned to the Wholesale Market Non-Dispatchable Supplier Spill Tariff and Wholesale Market Backup/Top-up tariff will be based on avoidable fuel costs.

4. Purchased power and Import costs will be classified to demand and energy as follows.

   a. In-province purchased power from wind generation will be segregated between Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). Their classification between energy and demand related services will reflect concurrent generation planning practice of NS Power. For the rate setting purposes of the 2017-2019 Fuel Stability Plan (RSP) the Company attributed to demand 17% of installed wind capacity of NRIS projects and 0% of ERIS projects.

b. In-province purchased power from biomass generation will be classified between energy and demand in the same proportion as classification of total costs of the Port Hawkesbury biomass plant.

c. In-province purchased power from all other sources than wind and biomass will be classified to demand and energy in the same manner as to NS Power's fixed cost base load generation.

d. Maritime Link imports under Nova Scotia Block will be classified to energy and demand based on the system load factor associated with the above-the-line (FAM) classes.

e. Non-firm imports will be all classified to energy.

The demand-related portion of these costs will be allocated to each class based upon its relative coincident contribution to the three monthly system peaks (3CP) occurring in December, January and February. The energy portion of these costs, except for the non-firm imports, will be allocated to each class based on its relative contribution to annual energy requirement. Non-firm imports will be allocated to each class based on its relative contribution to monthly energy requirements.

5. Export revenues are allocated to ATL classes based on monthly energy requirements.

The revenue responsibilities for allocated fuel cost to the ATL classes are determined by applying the revenue-to-cost (R/C) ratios from the 2013 Compliance Filing for the 2014 test year in accordance with step number 6.

6. In order to ensure that allocated fuel-related costs are aligned with the revenue expected from approved rates for each class, the costs will be scaled up or down using the revenue-to-cost ratio (R/C ratio) for each class. The resultant costs by class will then be reconciled to the total ATL fuel-related costs based on their relative share of the total fuel costs.

The unit base fuel costs by class are calculated by dividing allocated revenue responsibilities for fuel costs from step 7 by forecast class kWh sales for each test year. These unit costs are then used to replace the unit fuel costs embedded in the energy charges of the current rates.

For details on fuel-related cost allocation calculations in years 2020–2022 please refer to Appendix G.

13.3 Proposed Rates

In keeping with rate design treatment of changes in the BCF, and as modified for non-fuel revenue adjustments, increases in total annual class revenues are reflected in the fuel cost components of energy charges in c/kWh. The demand and customer charges are kept intact. As a result, these components of each rate will undergo adjustments that vary from the average for the rate classes. Percentage increases on individual customer bills will therefore vary from rate class average.

The revenue responsibilities attributed to each rate class, as set out in Appendix F, form an input into the calculation of the proposed rate components shown in Appendix H.

The Proof of Revenue section included in Appendix I presents the detailed calculation for each rate component.

Consistent with Section 12(1) of the *Electricity Efficiency and Conservation Restructuring (2014) Act*, the Company removed the DSM Cost Recovery Rider clause from its base cost rate tariffs. The Annually Adjusted Rate tariffs have already been approved for use with this clause removed in prior years.

14.0 CONCLUSION

In order to maintain stable and predictable rates for customers, NS Power is proposing a further three-year Fuel Stability Plan for 2020-2022. This Fuel Stability Plan sets out the BCF for each year of the 2020-2022 Fuel Stability Period, as well as the AA/BA amounts from 2017-2019 to be applied in 2020, and a forecast of the amounts to be recovered in rates for the anticipated assessments for the Maritime Link for each of 2020, 2021 and 2022. The Fuel Stability Plan also smooths rates over the course of the 2020-2022 Fuel Stability Period such that each rate class pays the same increase in each of the three years. The average increase is 2 percent over all FAM classes.

As this Fuel Stability Plan application has been modeled using the most recent fuel forecast data from May 2019 and the hearing will be held in October 2019, a refresh (BCF update) is not necessary.

Subject to the changes required as a result of the BCF Update, NS Power requests the Board approve its 2020-2022 Fuel Stability Plan as filed, including, without limitation:

(a) creation of a three-year Fuel Stability Period from 2020-2022;

(b) amendment of the FAM Plan of Administration to permit a further three-year BCF, make provision for cap-and-trade credits, update the chart of accounts, and update the process for calculating and reporting the AA/BA amounts;

(c) a total Base Cost of Fuel of $733.8 million for the 2020 calendar year, including a forecast of $144.5 million for the anticipated assessment for the Maritime Link;

(d) a total Base Cost of Fuel of $738.7 million for the 2021 calendar year, including a forecast of $164.4 million for the anticipated assessment for the Maritime Link;

(e) a total Base Cost of Fuel of $732.1 million for the 2022 calendar year, including a forecast of $161.9 million for the anticipated assessment for the Maritime Link;

(f) approval of the 2017-2019 AA/BA amounts to be included in the FAM AA/BA rates for 2020, and direction that the 2019 FAM AA/BA amount, subject to later determination in 2019 by the UARB, be included in the FAM AA/BA rates for 2020;

(g) smoothing of the rates over the 2020-2022 Fuel Stability Period with an average annual rate increase for all FAM classes of 2.0 percent per year in each of 2020, 2021 and 2022;

(h) deferral of any remaining forecast fuel costs to the end of the 2020-2022 Fuel Stability Period;

(i) inclusion of the $14,123,207 DSM HST refund (plus interest to the end of 2019) in the FAM Balance to be applied to the 2020-2022 Fuel Stability Plan;

(j) inclusion of the 2019 Maritime Link depreciation credit of $53.6 million in the FAM balance as an offset to rates in the 2020-2022 Fuel Stability Period; and

(k) approval of the proposed Tariffs for the 2020-2022 Fuel Stability Period attached as Appendices J and K which are based on total forecast FAM customer costs.

Requirement:

Provide the most recent Load Forecast Report.

Submission:

Please refer to Attachment 1.

2019 Load Forecast Report

REDACTED

April 30, 2019

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Appendices

Appendix A: 2018 NS Power Forecast

Appendix B: Forecast Model Details

Appendix C: Forecast Comparison

Appendix D: Forecast Sensitivity

1.0 EXECUTIVE SUMMARY

In accordance with the Nova Scotia Wholesale Electricity and Renewable to Retail Market Rules, Nova Scotia Power Inc. (NS Power, the Company) is required to provide the Nova Scotia Utility and Review Board (UARB, 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 Report).

The 2019 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for the period 2019 to 2029. As well, it describes the considerations, assumptions, and methodology used in the preparation of the forecast. The NS Power Load Forecast provides the basis for the planning and overall operating activities to serve the Company's 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 price and availability of other energy sources.

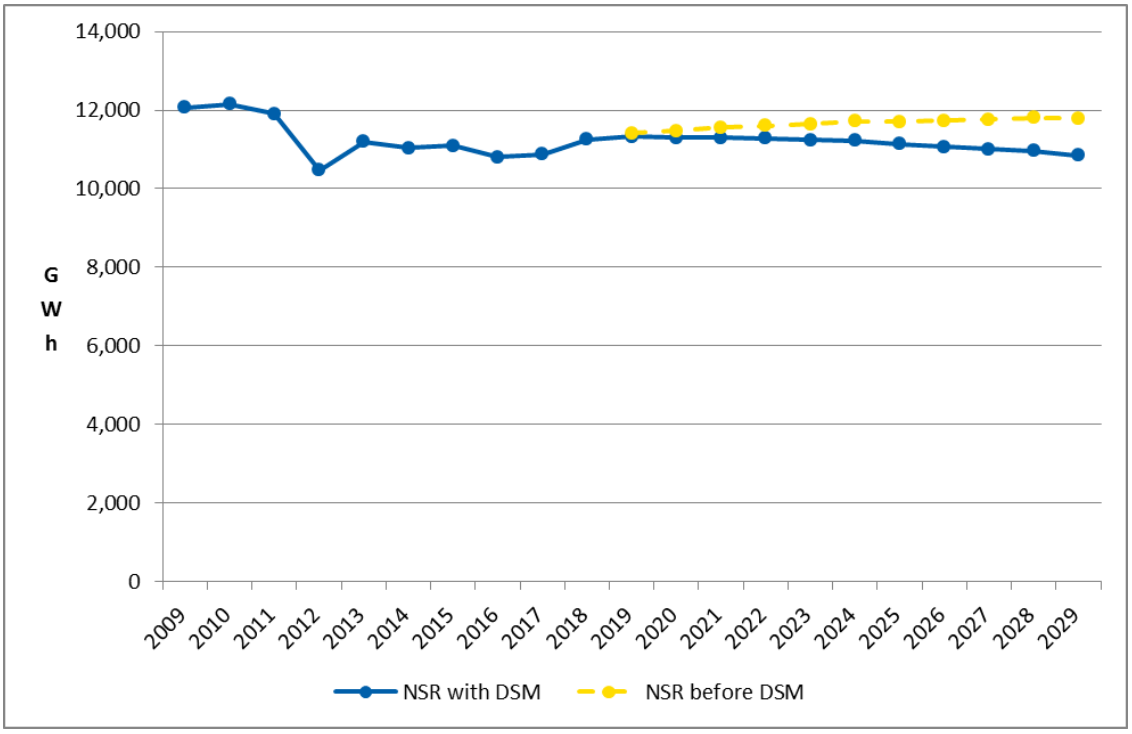
As with any forecast, there is a degree of uncertainty around actual future outcomes. In electricity forecasting, much of this uncertainty is due to the impact of variations in weather, energy efficiency program effectiveness, the health of the economy, changes in large customer loads, the number of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

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 a Net System Requirement (NSR).

In general, the NSR is expected to grow slowly over the forecast period before the impact of DSM. Anticipated growth is expected to be driven by increased electric heating in the residential sector as well as industrial growth. These will be offset by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside of structured DSM programs, as well as increased behind-the-meter small scale solar installations. The net result of these inputs is an annual decline of 0.4 percent. Annual NSR is 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. After accounting for the effects of DSM savings, system peak demand is expected to remain flat on average over the forecast period, as shown in **Figure 2**.

Figure 2: Historical and Predicted Annual System Peak

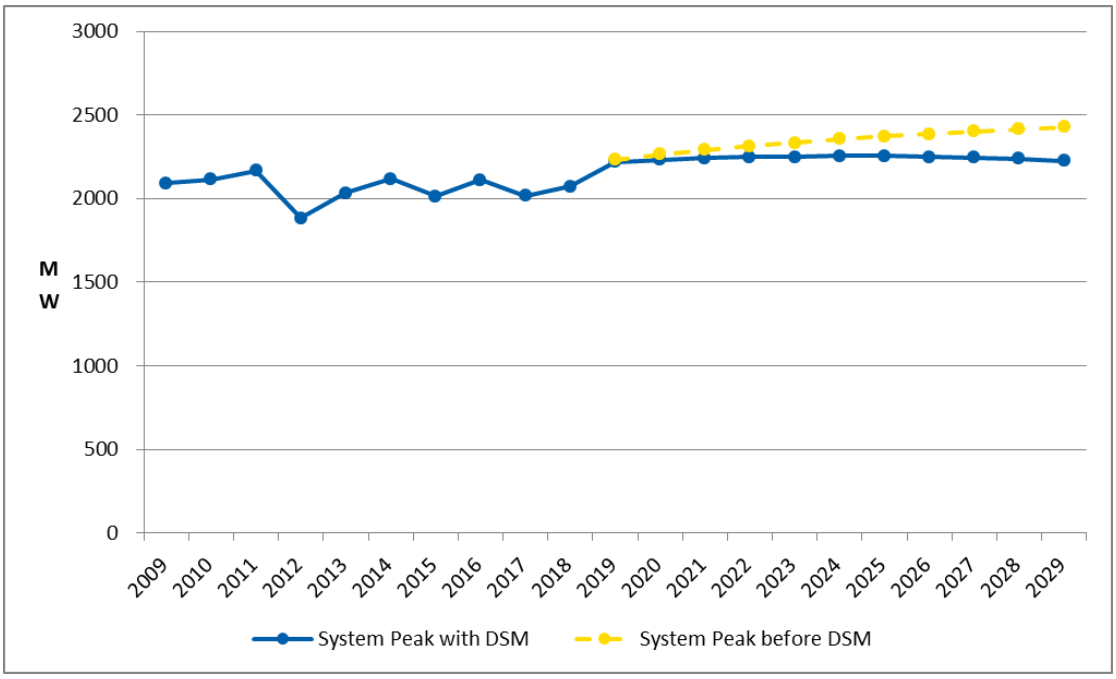


Figure 3, below, shows the changes to system load and system peak over the historic and forecast periods.

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

Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
2009	12,073	-3.7%	2,092	-4.5%
2010	12,158	0.7%	2,114	1.0%
2011	11,907	-2.1%	2,168	2.5%
2012	10,475	-12.0%	1,882	-13.2%
2013	11,194	6.9%	2,033	8.0%
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	11,331	0.7%	2,221	7.2%
2020	11,300	-0.3%	2,234	0.6%
2021	11,303	0.0%	2,243	0.4%

2022	11,278	-0.2%	2,247	0.2%
2023	11,240	-0.3%	2,249	0.1%
2024	11,220	-0.2%	2,255	0.3%
2025	11,135	-0.8%	2,255	0.0%
2026	11,069	-0.6%	2,249	-0.2%
2027	11,005	-0.6%	2,244	-0.2%
2028	10,958	-0.4%	2,238	-0.3%
2029	10,844	-1.0%	2,227	-0.5%

2.0 INTRODUCTION

NS Power annually develops a forecast of energy sales and peak demand requirements to assess the effects of customer, demographic and economic factors on the future power system load and load shape. It is a foundational input to the overall planning, budgeting and operating activities of the Company. Produced in the winter of 2018-2019 and using information available at the time, this forecast covers the period of 2019-2029. Unless otherwise noted, reported average annual growth rates are for the 2019-2029 period.

In 2018, the Nova Scotia Utility and Review Board (UARB or Board) initiated a paper hearing process to review the 2018 Load Forecast Report, as it had for the 2017 Load Forecast Report.[1] Interventions were made by the Consumer Advocate (CA), the Small Business Advocate (SBA), the Industrial Group (IG), Port Hawkesbury Paper LP (PHP), EfficiencyOne (E1), and Heritage Gas Limited (Heritage). In addition, Board Counsel engaged Synapse Energy Economics (Synapse) to review and provide a report on NS Power's 2018 Load Forecast Report.

Following response to Information Requests (IRs), filing of evidence by intervenors and Board Counsel and Reply Evidence by NS Power, the Board issued a decision respecting NS Power's 2018 Load Forecast Report. The Board recognized the progress and refinements that have been made in developing NS Power's load forecast in recent years and directed areas for continued improvement. In particular, the Board stated as follows:

[1] M08670 - Nova Scotia Power Inc. - 10 Year Energy and Demand Forecast - 2018 Load Forecast - P-194.

As noted in prior years, the Board recognizes the progress and refinements that have been made in developing recent load forecast reports. The fundamental importance of the load forecast in relation to NS Power's overall operations, including generation requirements, capital program, fuel forecasts, and customer rates, makes it essential that the input assumptions and resulting forecast present a highly accurate projection of future requirements. Variations in growth rates presented in recent annual reports highlight the lack of consistency in future projections and suggest that further refinements and detailed explanations are still needed to ensure that all relevant factors are fully considered in the analysis.

One specific issue that seems to warrant greater analysis is the adjustment factor applied to DSM savings, both energy and peak demand. Both the CA and the SBA have raised this concern. Although not raised in this year's review, Synapse also raised that concern during its review of the 2017 Load Forecast. In its memorandum dated September 26, 2017, Synapse stated:

> We note that the DSM energy load adjustments based on statistical calculations are roughly of the right order of magnitude, although some statistical measures are weak. We also raise the issue that if the DSM targets increase in the future, then an adjustment factor based on the historic DSM levels needs to be appropriately modified when applied to different future savings levels. For example, if the adjustment factor is based on historic DSM levels of 1 percent and the targets are doubled to 2 percent, the DSM adjustment reduction should be less for these greater savings levels. All this needs to be looked at carefully going forward.

In an effort to resolve these concerns prior to filing the 2019 Load Forecast report, NS Power is directed to meet with stakeholders to address this DSM adjustment issue. Also, NS Power is directed to follow through with all of the enhancements identified in this proceeding.

The Board looks forward to NS Power's filing of the 2019 Load Forecast report by April 30, 2019.[2]

Synapse's evidence provided the following comments and recommendations:

[2] M08670 - Nova Scotia Power Inc. - 10 Year Energy and Demand Forecast - 2018 Load Forecast - P-194, UARB Decision, October 26, 2018, pages 4-5.

> Overall the forecast is comprehensive and contains all the important elements. NSPI's assumptions seem reasonable, although more supporting information could be provided in some cases. Yet, while the key pieces are there, it is not always clear how they fit together to produce the final forecast.
>
> For example, in the residential sector there are the end-use intensities as presented in Figures 8 and 14 and the various adjustments and add-ins presented in Figures 9-13. NSPI does not describe the relationship between these components as they relate to the final forecast. Such a description would help in understanding the forecast. We have suggested a possible approach in our review of the residential forecast, but we encourage NSPI to consider alternative approaches.
>
> Some recommendations are:
>
> 1. The forecast report should identify and explain the differences between the most recent historical year values and those of the first forecast year. For example, how much is weather related and how much is associated with the model itself.
>
> 2. Provide a step-by-step explanation, following our residential example, of how the various components of the forecast fit together to produce the final result.
>
> 3. Further investigation and reporting of the precise impacts of equipment saturation and new technology in future forecasts should better identify the changes that are taking place.
>
> 4. Further refinement of the peak forecast to better identify system needs and measures that can be taken control and moderate them.
>
> 5. At several locations throughout this report (pages 5, 6, 7, 8, 11, and 12) we have asked for NSPI to provide further explanations of some aspects of the forecast. These explanations should be provided in NSPI's Reply materials if possible. Otherwise they should be included in the next forecast report.

In accordance with the Board's direction, NS Power has revised and enhanced the 2019 Load Forecast Report in the following manner:

- An explanation of the difference between the most recent historic year and the first forecast year for NSR and peak is provided in sections 9 and 10. (Synapse recommendation 1)

- A step by step explanation of the impact of various components of the forecast and clarification of the various components provided in sections 5 and 6, and in Appendix B. (Synapse recommendation 2)
- Analysis of various end uses is ongoing, they are discussed in detail in section 4. (Synapse recommendation 3)
- Analysis of the components of the peak is ongoing, and is discussed in detail in section 10. (Synapse recommendation 4)
- Further explanation of the large customer impacts and assumptions are included in sections 6 and 7. (Synapse recommendation 5 items that were not already addressed in NS Power's reply evidence).

Summary of Stakeholder Consultations

As noted above, in its decision on the 2018 Load Forecast Report, the UARB directed NS Power to meet with stakeholders prior to the filing of the 2019 Load Forecast Report to discuss the treatment of DSM in the load forecast. Below is the summary of relevant stakeholder consultations undertaken by NS Power in advance of completing this year's Load Forecast Report.

On December 5, 2018, members of the Load Forecast team held a WebEx meeting with David White and Jamie Hall of Synapse to discuss the issue of treatment of DSM in the forecast and enhancements to be undertaken as a result of the Board's decision on the 2018 Load Forecast Report. NS Power reviewed Synapse's recommendations as filed in its Evidence, and discussed its intended approach to address those recommendations in the 2019 Load Forecast. NS Power understood from this discussion that Synapse was generally comfortable with NS Power's approach to its recommendations and with the current method of using DSM as an input to the regression model and applying the resulting coefficient to future DSM, provided that future levels of DSM are similar to historic levels of DSM.

On April 9, 2019, NS Power held a WebEx meeting with representatives from Synapse, E1, the SBA, the CA, and counsel for the IG to discuss the treatment of DSM in the forecast and to respond to any questions. At the conclusion of the meeting, NS Power offered the opportunity for any of the participants, and/or their consultants if they wished, on the phone call to follow up with NS Power with any questions or to schedule a further discussion.

The Small Business Advocate confirmed that he would like a follow up discussion with his consultant. On April 10, 2019 NS Power held a follow-up meeting with representatives from Daymark Energy Advisors, consultant for the Small Business Advocate. The discussion focused on clarifications as to how DSM is accounted for in the forecast, and the outcome was a recommendation from Daymark to update the explanation in the load forecast report. Specifically, the requested clarifications were as follows:

- Generally try to clarify the explanation of the treatment of DSM
- Explain that the adjustment is a way of accounting for DSM that is captured elsewhere in the forecast rather than an adjustment or assumption of the effectiveness of future DSM activities
- Explain that the methodology employed is not specific to DSM but could also be used to account for any variable in the forecast provided they have similar characteristics (historical trend, potentially included in other inputs, and some information about future impact).

NS Power agreed with Daymark's recommendation and has incorporated it into the 2019 Load Forecast Report. (Please refer to the section on Demand Side Management).

Continuing Forecast Improvement Activities

In 2019 NS Power engaged Itron Inc. (Itron) for a review of the load forecast. The review is in progress and recommendations will be implemented in the 2020 load forecast. Preliminary findings show that the forecast would be improved if the heat pump and water heater end uses were modeled within the intensities/regression. Work is also under way to try and develop an end-use based peak model using end-use component peak contributions (rather than current method of using the end use components from the energy model) that fits historic data as well as the current peak model.

A large scale residential customer survey was completed by NS Power in late 2018, and included several questions on end uses within residential homes. Findings from that survey are still being analyzed and will be used to inform the 2020 load forecast.

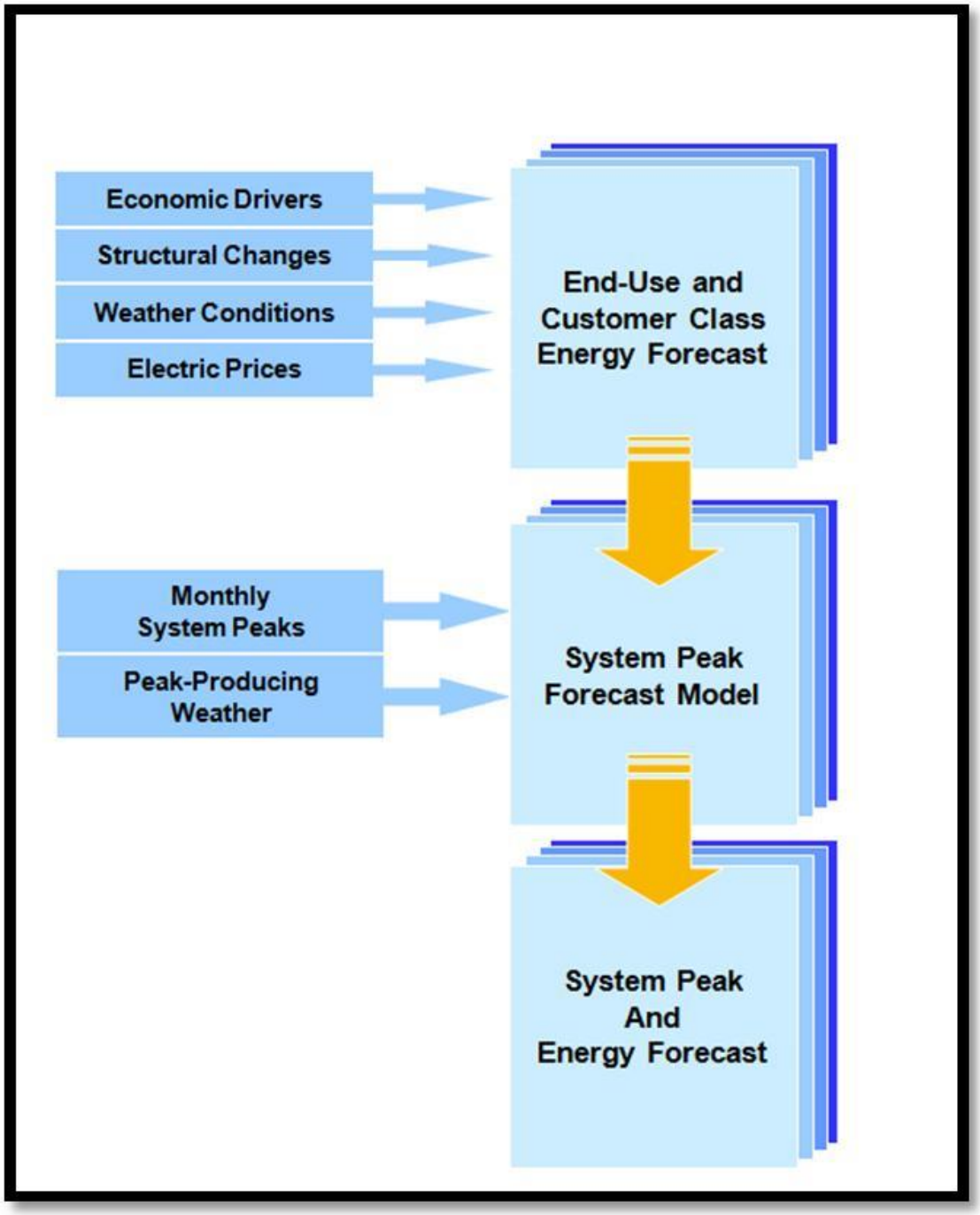
3.0 FORECASTING APPROACH

NS Power continues to use a set of SAE models for the residential and commercial rate classes, an econometric model for the small and medium industrial classes, and uses customer surveys and historical data for the large 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, onto provincial economic forecasts 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. 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.

Figure 4: Forecast Approach



4.0 DISCUSSION OF MAJOR INPUTS

Historical Class Sales and Energy Data

The load forecast is developed using NS Power "billed" sales rather than "accrued" sales. Billed sales refer to the amount of energy billed to customers in a given time period such as a calendar month or a year. Accrued sales recognize the amount of energy actually 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 will vary from accrued sales.

Historical monthly billed sales are the primary dependent variables in the linear regression models used in developing the forecast. For the 2019 forecast, the residential and commercial energy forecasts are estimated using monthly billed sales data for the period January 2009 to December 2018. The industrial forecasts use the period January 2005 to December 2018 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 2009 to December 2018. Large customer peak demand is forecast separately.

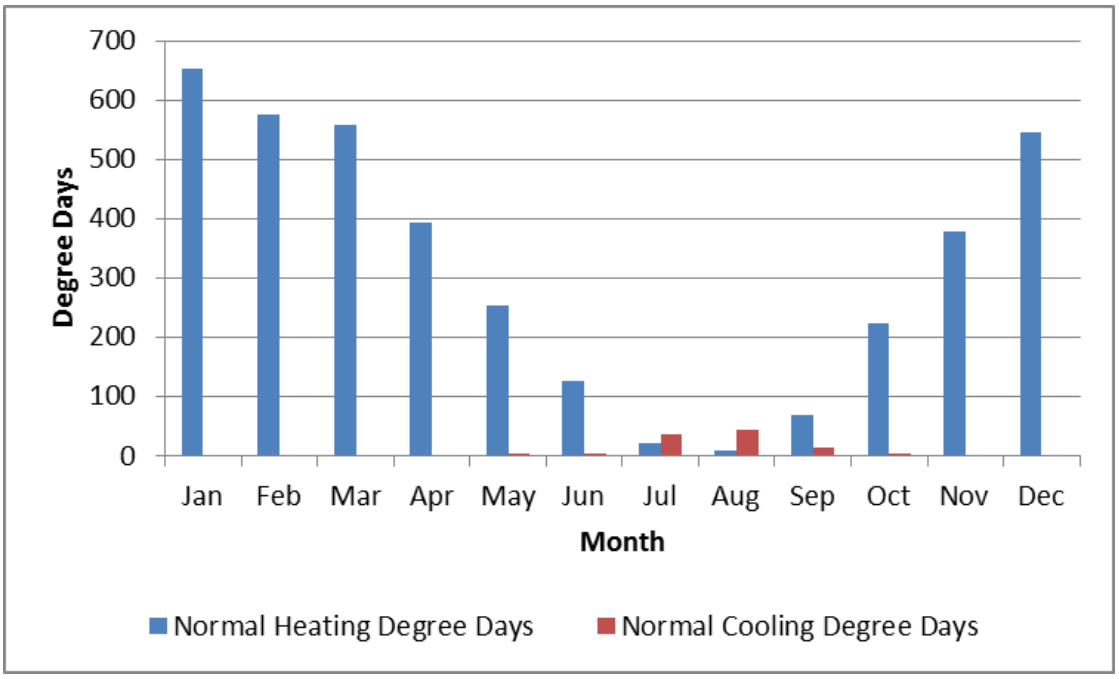
The Renewable to Retail (RtR) electricity market was established in Nova Scotia in 2016, to enable independent licensed retailers to sell renewable energy directly to NS Power's retail customers. At present, there is no indication of forthcoming market entrants so no effect on NS Power load is forecast. The two fundamental principles under the RtR legislative regime are that customers of NS Power are not to be negatively affected if some retail customers choose to purchase electricity in the RtR market, and that retail suppliers and their customers are to be responsible for all costs related to the provision of the renewable low-impact electricity in this new market. As such, from a net system

requirement perspective, NS Power must continue to plan to serve this load. Any new information on RtR uptake will be incorporated into future annual reports, if appropriate.

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. HDDs are a common measure of heating requirement based on the degree departure between the daily mean temperature and a given reference temperature. The reference temperature of 18°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, seen in **Figure 5**, are calculated using 10 years of actual weather data covering the period January 2009 to December 2018. The average temperature continues to show a warming trend – the 30-year average annual HDD is 3,964, while the 10-year average is 3,807.

Figure 5: Normal Monthly HDDs and CDDs



Economic Information

Economic and other provincial statistics used in the load forecast are from the Conference Board of Canada's *Economic Outlook*. 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. For 2019, the residential model continues to use both the retail sales (RRTS) and household income (RPDI) variables, weighted at 50/50. The retail sales variable grows at a slower rate in the near term compared to the growth in the household income variable, so weighting the two variables produces a more modest increase related to economics. New housing completions for both single family and multi-unit buildings are used in generating residential customer forecasts. In the non-residential models, non-manufacturing Gross Domestic Product (NMANGDP) and non-manufacturing employment (NMANEMP) continue to be used. In the Industrial sector, rate classes are forecast using an Econometric framework, with manufacturing GDP (MANGDP) and manufacturing employment (MANEMP) used as economic variables. The regression timescale for the industrial models was increased from 10 years to 14 years 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 0.445 for 10-year vs 0.832 for 14 year). **Figures 6, 7,** and **8** summarize the economic drivers, on an annual basis, used in the 2019 forecast. For financial measures, the variables have been adjusted to constant dollars, eliminating the inflation effects from the series.

Figure 6: Residential Economic Drivers

Year	New Construction	% Change	RPDI (mil $02)	% Change	RRTS (mil $02)	% Change
2009	3,836		18,924		10,460	
2010	3,960	3.3%	19,460	2.8%	10,699	2.3%
2011	3,662	-7.5%	19,217	-1.2%	10,674	-0.2%
2012	3,958	8.1%	19,416	1.0%	10,562	-1.0%
2013	4,670	18.0%	19,920	2.6%	10,776	2.0%
2014	3,259	-30.2%	20,022	0.5%	10,886	1.0%
2015	3,212	-1.4%	20,295	1.4%	10,861	-0.2%
2016	3,406	6.0%	20,670	1.9%	11,239	3.5%
2017	3,707	8.8%	21,385	3.5%	11,981	6.6%
2018	4,237	14.3%	21,336	-0.2%	11,970	-0.1%
2019	3,541	-16.4%	21,305	-0.1%	11,984	0.1%
2020	3,036	-14.3%	21,371	0.3%	12,003	0.2%
2021	2,913	-4.0%	21,494	0.6%	12,054	0.4%
2022	2,814	-3.4%	21,608	0.5%	12,101	0.4%
2023	2,659	-5.5%	21,763	0.7%	12,175	0.6%
2024	2,394	-10.0%	21,853	0.4%	12,244	0.6%
2025	2,200	-8.1%	21,965	0.5%	12,307	0.5%
2026	2,103	-4.4%	22,073	0.5%	12,379	0.6%
2027	1,994	-5.2%	22,189	0.5%	12,456	0.6%
2028	1,888	-5.3%	22,311	0.6%	12,533	0.6%
2029	1,781	-5.7%	22,440	0.6%	12,613	0.6%
09-18		1.1%		1.3%		1.5%
19-29		-6.6%		0.5%		0.5%

Figure 7: Commercial Economic Drivers

Year	NMANGDP (mil $07)	% Change	NMANEMP (thou)	% Change
2009	29,018		414	
2010	29,625	2.1%	419	1.1%
2011	29,664	0.1%	420	0.3%
2012	29,465	-0.7%	425	1.2%
2013	29,455	0.0%	422	-0.6%
2014	29,891	1.5%	418	-1.0%
2015	30,224	1.1%	419	0.4%
2016	30,496	0.9%	417	-0.5%
2017	30,816	1.0%	418	0.3%
2018	31,077	0.8%	424	1.3%
2019	31,393	1.0%	426	0.6%
2020	31,677	0.9%	428	0.3%
2021	31,919	0.8%	429	0.2%
2022	32,210	0.9%	429	0.1%
2023	32,501	0.9%	430	0.3%
2024	32,673	0.5%	430	-0.2%
2025	32,869	0.6%	428	-0.3%
2026	33,156	0.9%	427	-0.4%
2027	33,475	1.0%	425	-0.4%
2028	33,834	1.1%	423	-0.4%
2029	34,174	1.0%	421	-0.4%
09-18		0.8%		0.3%
19-29		0.9%		-0.1%

Figure 8: Industrial Economic Drivers

Year	MANGDP (mil $07)	% Change	MANEMP (thou)	% Change
2009	2,491		35	
2010	2,705	8.6%	33	-7.7%
2011	2,763	2.1%	33	1.1%
2012	2,651	-4.1%	33	-0.8%
2013	2,564	-3.3%	31	-6.0%
2014	2,455	-4.3%	30	-2.5%
2015	2,499	1.8%	29	-4.4%
2016	2,570	2.8%	29	1.2%
2017	2,644	2.9%	31	5.9%
2018	2,820	6.7%	31	2.1%
2019	2,840	0.7%	31	-0.2%
2020	2,895	2.0%	31	-0.3%
2021	2,997	3.5%	31	0.5%
2022	3,052	1.8%	31	-0.8%
2023	3,090	1.2%	31	-0.6%
2024	3,127	1.2%	31	-1.0%
2025	3,151	0.8%	30	-1.5%
2026	3,190	1.2%	30	-1.5%
2027	3,237	1.5%	29	-1.3%
2028	3,285	1.5%	29	-1.4%
2029	3,347	1.9%	29	-0.9%
09-18		1.4%		-1.3%
19-29		1.7%		-0.9%

End-Use Intensity Trends

In addition to the economic variables listed above, the SAE model also uses end-use data, in the form of saturations and efficiencies, from Natural Resources Canada (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 and use year-over-year changes in saturation

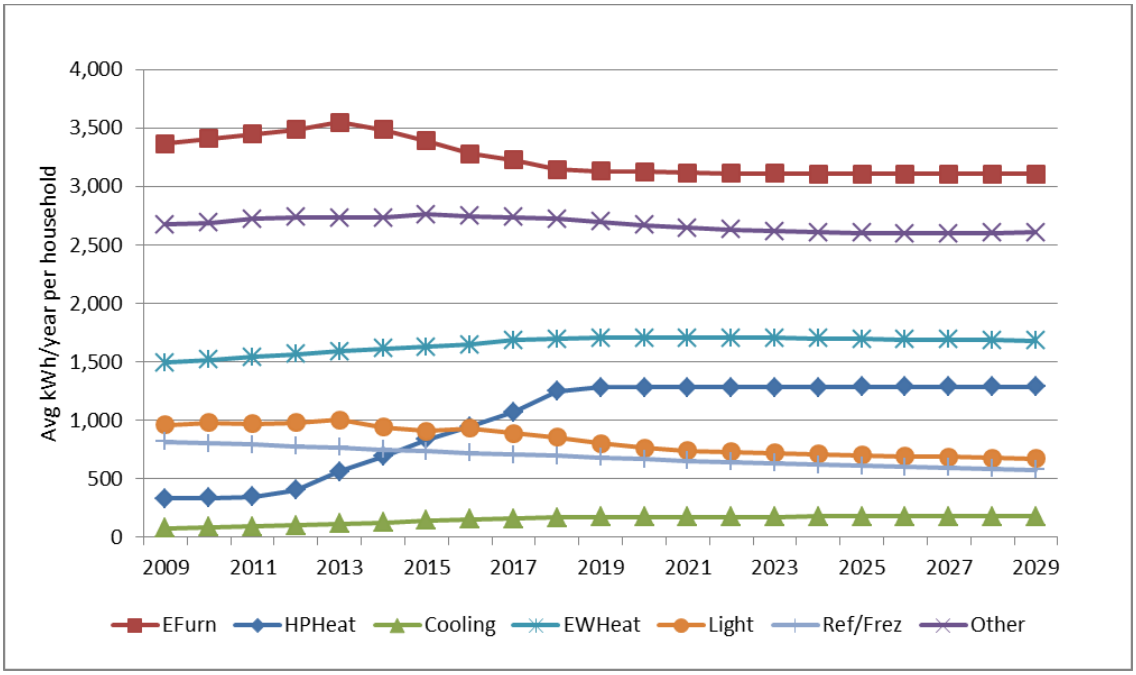
projections and end-use efficiency estimates for the New England Census Division. The resulting end-use intensity trend is then compared with end-use energy estimates from NRCan. If necessary, it is then adjusted so that the resulting intensities are consistent with NRCan reported end-use consumption and actual average use derived from NS Power billing data. The forecast for the end use intensities is shown in **Figure 9** below. 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.

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 of the average use intensities. This was done for heat pumps and hot water heaters, as well as electric vehicles (EV) and rooftop solar generation (PV) as they have little historic data. This method also allows these items to be tracked more directly to help fine-tune future forecasts. For 2019, water heater estimates and PV estimates have been updated based on recent analysis. **Figure 8** below does not include the external forecast inputs listed above; these inputs are discussed individually further on in this report. 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 that is applied to the XHeat, XCool and XOther variables. 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**.

Figure 9: Historical and Projected Residential End-Use Intensities Before Add-ins



Heat Pumps

Heat pump usage is on the rise as heat pumps are an efficient way for customers to heat and cool a building. Converting to a heat pump can help customers reduce their energy costs by up to 62 percent, and carbon emissions by up to 50 percent. At the end of 2018, the market penetration for heat pumps as both a primary and secondary source of heat was estimated at 25 percent. Compared to the 2018 load forecast, estimated installations are expected to be higher in the non-electric heat segment (65 percent vs 61 percent in 2018). This is due to higher than expected residential electricity sales in 2018 which is assumed to be mainly a result of more heat pump conversions in the non-electric heat segment than previously forecast. The market penetration is held constant in the forecast and the estimates for conversions are added in outside of the model. **Figure 10** shows the forecast number of installs and is broken down by existing heating types (non-electric

and electric). New customers are not included in these numbers as they are already captured by the new customer forecast. The installs are in-year totals and the corresponding load and peak values have been profiled annually to account for timing of installations.

Figure 10: Heat Pump Contribution to Energy and Peak Forecasts (cumulative)

Year	Total New Installs	% Non-Electric	% Electric	Load (GWh)	Peak (MW)
2019	15,180	65%	35%	34	17
2020	28,173	65%	35%	55	31
2021	41,329	65%	35%	76	46
2022	54,540	65%	35%	97	60
2023	67,784	65%	35%	118	75
2024	81,078	65%	35%	135	89
2025	90,442	65%	35%	147	98
2026	94,957	65%	35%	153	103
2027	99,101	65%	35%	158	107
2028	102,977	65%	35%	163	111
2029	105,983	65%	35%	167	111

The resulting change to load per install was based on an internal study conducted in 2015 that was similar to the results from a 2014 study carried out by Northeast Energy Efficiency Partnerships.[3] The estimated impacts for different types of heat pumps are shown in **Figure 11**. Most of the targeted installs are ductless units.

[3] http://www.neep.org/northeastmid-atlantic-air-source-heat-pump-market-strategies-report-january-2014

Figure 11: Estimated Heat Pump Impacts per Household

	Ductless		Ducted	
	Change in Energy (annual kWh)	**Change in Peak (kW)**	**Change in Energy (annual kWh)**	**Change in Peak (kW)**
Non-Electric Heat Install	+3700	+1.3	+7000	+5
Electric Heat Install	-3000	0	-7000	-1

Water Heaters

It is expected that some customers who convert their oil heating systems to heat pumps will also convert their hot water supply to electric hot water tanks due to the annual operating savings. Compared to the 2018 load forecast, expected growth from water heaters is much lower due to revised estimates of potential market penetration. Water heater load is estimated to be 3,200 kWh per tank (decreasing over time with increasing efficiency) based on a 10-year average of NRCan data for hot water heaters in Nova Scotia (2005-2014). The corresponding peak contribution is estimated to be 0.57 kW per tank, also decreasing over time, based on internal research on metered hot water tanks (the average tank is around 3kW and the coincident system peak from water heaters shows that approximately one in five water heaters is on). In the case of hot water heaters, the peak impact can potentially be mitigated through AMI enabled technology such as direct load control, the impact of which is currently being evaluated. The annual impact is shown in **Figure 12**. Note that like heat pumps, the impact of the additions is profiled throughout the year.

Figure 12: Water Heater Contribution to Energy and Peak Forecasts (cumulative)

Year	Total New Installs	Load (GWh)	Peak (MW)
2019	275	0	0
2020	804	2	0
2021	1,333	3	0
2022	1,861	5	1
2023	2,388	7	1
2024	2,916	8	1
2025	3,442	10	2
2026	3,968	12	2
2027	4,492	13	2
2028	4,492	14	3
2029	4,492	14	3

Electric Vehicles (EVs)

Estimates for EV penetration are similar to those used in the 2018 load forecast. According to Electric Mobility Canada, at the end of 2018 there were approximately 223 EVs in Nova Scotia, and there are currently no incentives for purchasing an EV in Nova Scotia. Although the federal government recently announced a national incentive program, no details have been provided and it has not been taken into account for this load forecast. The current EV forecast is a high-level estimate that considers future vehicle availability, vehicle battery range, Electric Mobility Canada's forecast growth of the Canadian EV market, and several global forecasts. Compared to Electric Mobility Canada's forecast, a more conservative projection has been developed for Nova Scotia to account for local demographics and current limitations on purchase and infrastructure incentives. This forecast has EVs making up approximately 7 percent of total vehicle stock (around 46,000 vehicles) by 2029, with approximately 70 percent being battery EVs and 30 percent being plug in hybrids. A report prepared for the New York State

Energy Research and Development Authority[4] provides a range of per vehicle peak demand of 0.3 kW (where an off-peak charging incentive exists) to 1.0 kW (for no incentive) in the evening (hours of 1700-1800). The 0.6 kW value assumes there will be some mechanism in place (likely rate based) to discourage charging on peak. This value corresponds to around 10-15 percent of vehicles charging on peak. Although there is no mechanism in place at present, the impact to peak is not forecast to be significant until 2024 – 2026. In **Figure 13** the estimated energy and peak impacts are listed, along with potential peak impact without mitigation measures, which assumes an average of 1.3 kW/vehicle, or around 20-30 percent charging on peak depending on the mix of vehicle and charger types. NS Power is currently looking to obtain data sets that will help in validating peak impacts of residential EV charging (for example from the Amherst smart grid project announced in January).

Figure 13: EV Impact to Energy and Peak Forecasts (cumulative)

Year	New EVs	Load (GWh)	Peak @ 0.6kW/vehicle (MW)	Peak @ 1.3kW/vehicle (MW)
2019	195	1	0	0
2020	567	2	0	1
2021	1,272	4	1	2
2022	2,539	8	2	3
2023	4,743	15	3	6
2024	8,464	26	5	10
2025	14,540	45	9	18
2026	21,919	69	14	28
2027	29,298	94	19	38
2028	36,677	118	24	48
2029	45,531	147	30	59

[4] NYSERDA. 2015. "Electricity Pricing Strategies to Reduce Grid Impacts from Plug-in Electric Vehicle Charging in New York State," NYSERDA Report 15-17. Prepared by M.J. Bradley & Associates LLC. nyserda.ny.gov/about/publications

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. In the load forecast, only the former is considered, as it serves as a reduction in load mainly in the residential class. As of 2018 there were 532 residential solar installations and 49 installations in all other customer classes in the net metering program. As of 2018, the average installed capacity is approximately 6.3kW for residential customers and 16.8kW for non-residential, and total annual net metering solar generation is estimated at 5.3 GWh based on contractor estimates using a capacity factor of around 14 percent, which is higher than the capacity factor of 12-12.5 percent estimated by NRCan's "Photovoltaic Potential and Insolation Dataset" for Nova Scotia. The number of solar installations is expected to increase in the coming years as a result of initiatives such as Property Assessed Clean Energy Programs (e.g. Solar City in Halifax) as well as the provincial SolarHomes rebate of $1/W of installed capacity. The number of new residential installations in the forecast has been updated based on a study by Dunsky for the Canadian Solar Industries Association[5]. This study modeled the uptake of solar generation between 2019 and 2025 based on several possible scenarios – the scenario used for this forecast is "Maintain Current Market Activity", which assumes the SolarHomes rebate continues for several years into 2023. Based on that scenario, the overall number of installs is reduced from previous forecasts, but the average installed capacity is estimated to be 8 kW, with a total of 42 MW added by 2025 in the residential sector and 170 MW added by 2030. The 2019 load forecast also includes an assumption for commercial installations based on actual data for 2018, which indicates non-residential installs accounting for approximately 20 percent of total installed capacity.

[5] Nova Scotia Residential Solar Market Outlook and Labour Force Study Final Report - April 2019 prepared by Dunsky Energy Consulting. https://www.cansia.ca/uploads/7/2/5/1/72513707/cansia_nova_scotia_residential_solar_market_outlook_and_labor_force_study_-_final_report__2019-04-09_.pdf

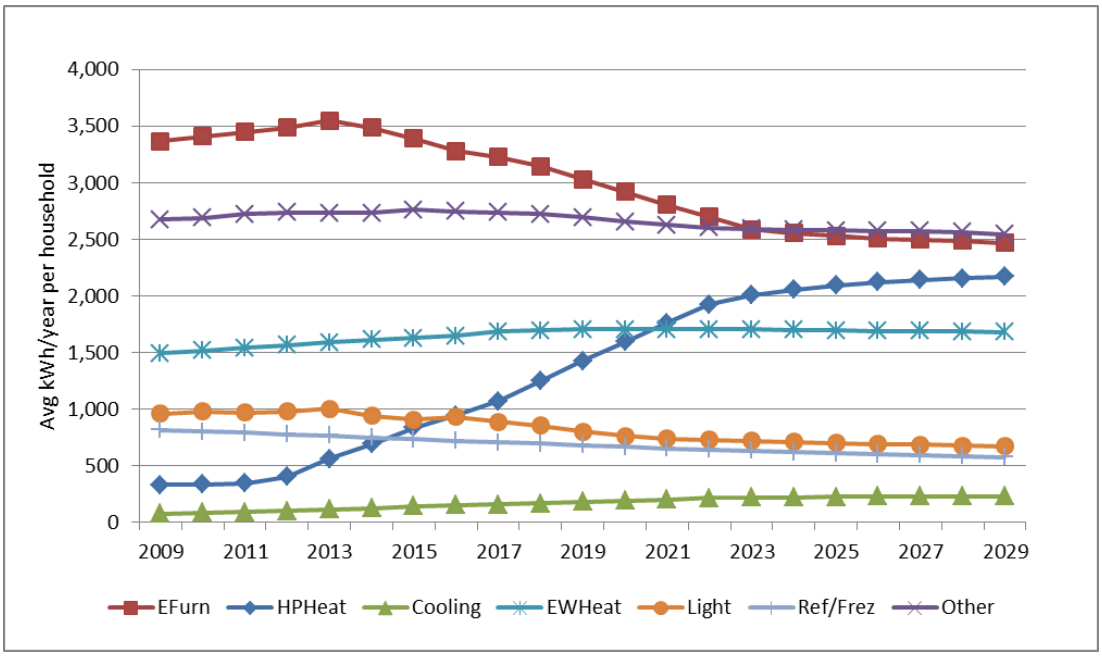
The overall impact is shown in **Figure 14**. Energy amounts are forecast based on a capacity factor of 12.5 percent as used in the Dunsky study. There is no anticipated impact to peak as generation occurs at times non-coincident with NS Power's system peak (winter evenings). This also assumes there is no significant amount of combined solar/battery storage. The estimated number of installs for 2019 is significantly higher than 2018 but is in line with the number of recent net metering applications received by NS Power. This increase is mainly related to the SolarHomes rebate on solar installations.

Figure 14: PV Impact to Energy (cumulative)

Year	Total New Installs	Load (GWh)	Peak (MW)
2019	483	-5	0
2020	966	-10	0
2021	1,476	-15	0
2022	2,037	-20	0
2023	2,651	-27	0
2024	3,839	-39	0
2025	5,537	-56	0
2026	8,019	-81	0
2027	10,435	-105	0
2028	13,579	-137	0
2029	17,670	-178	0

Figure 15 shows an estimate of the resulting end use intensities with these forecasts included. PV and EV are included in the "Other" category.

Figure 15: Residential End-Use Intensities Including Estimated Add-ins



The intensity trends are similar to those in the 2018 load forecast and show a decreasing trend overall. Electric heating is expected to show a small increase over the forecast period with heat pumps displacing both baseboard electric and oil heat due to the annual savings from heat pump efficiency. Heat pumps also drive cooling intensity up over time but not during periods of peak demand. Water heat is expected to remain stable over the forecast period as increased penetration is offset by increased efficiency. Lighting and refrigerators/freezers show a slow decline related to natural increases in efficiency, and increases in the "Other" category (which includes EVs) are now expected to be offset by PV generation.

The end use intensities for the commercial models are done on a per square metre basis, rather than per customer. The forecast for the end use intensities are set out in **Figure 16 and 17** below. The end uses listed include:

- Heat: electric heating
- Cool: air conditioning

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

Figure 16: Historical and Projected Small General Commercial End-Use Intensity (kWh/m^2)

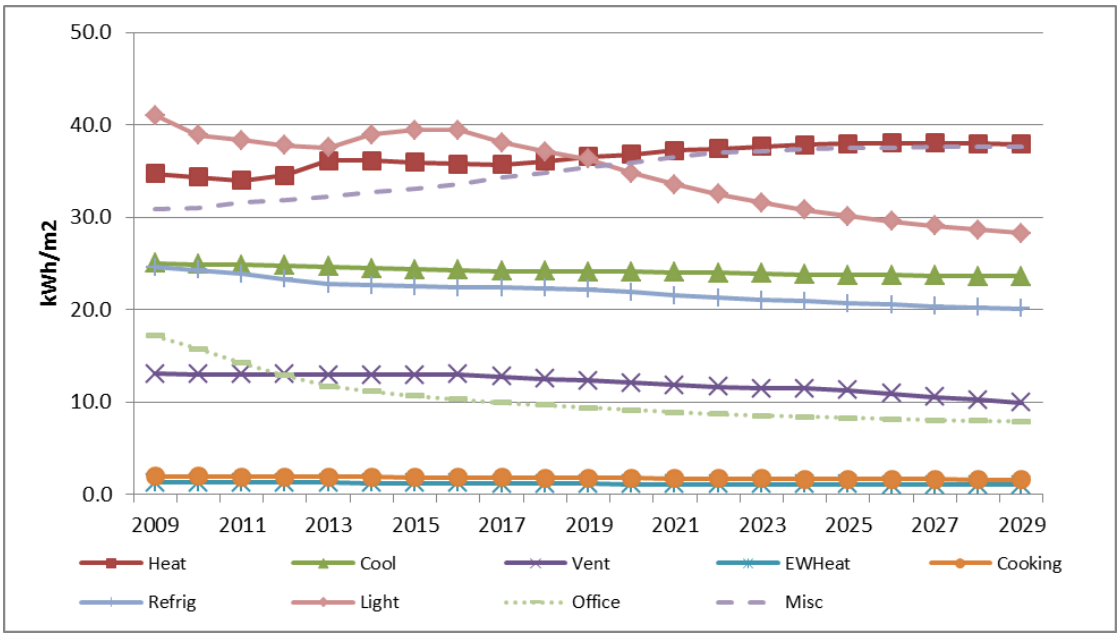
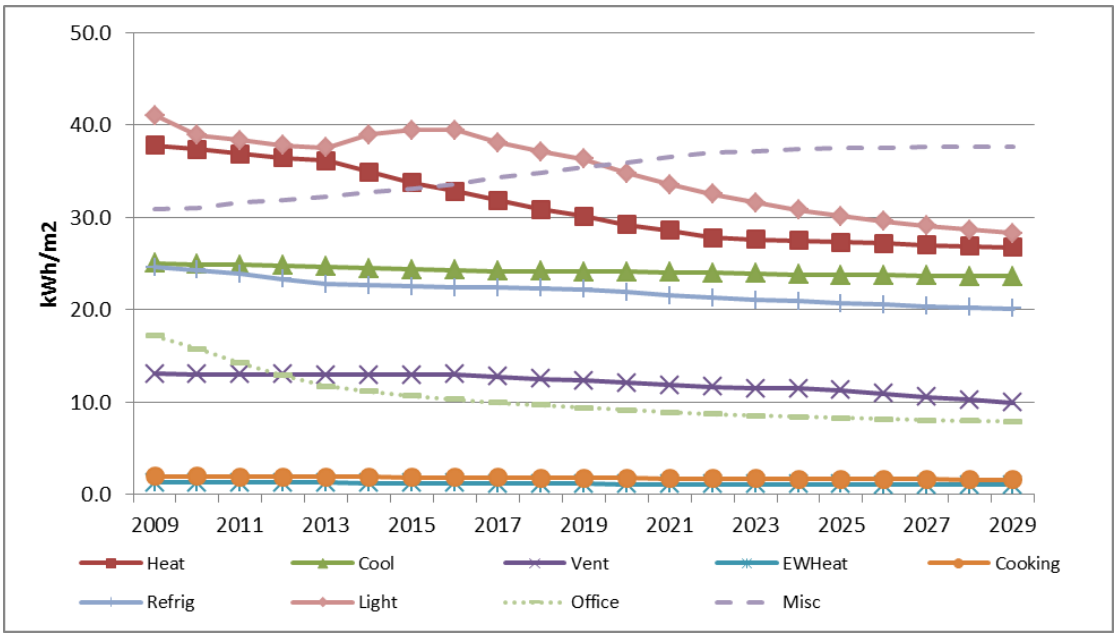


Figure 17: Historical and Projected General Commercial End-Use Intensity (kWh/m^2)



For the 2019 forecast, data from the EIA 2018 Annual Energy Outlook uses the same baseline data (2012 Commercial Building Energy Consumption Survey) as the 2018 forecast. The updated historic NRCan data for the commercial class has changed compared to 2018, adjusting overall base year intensity upward from 148 kWh/m^2 in the 2018 forecast to 181 kWh/m^2 in the 2019 forecast. Although all end uses were impacted, the major change was in the heating and lighting intensities. Forecast trends remain the same with an overall declining trend in most categories and an increasing trend in the miscellaneous category.

<u>Commercial and Industrial Programs</u>

Like the residential sector, the commercial and industrial sectors are projected to see targeted growth as a result of 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 looking at opportunities to power industrial processes

through electrification (as shown in **Figure 18).** 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).

Figure 18: Commercial and Industrial Contribution to Energy and Peak Forecasts

Year	SmGen (GWh)	GenDemand (GWh)	LrgGen (GWh)	SmInd (GWh)	MedInd (GWh)	LrgInd (GWh)	Peak (MW)
2019	4	14	0	0	0	0	2
2020	9	33	0	0	1	0	6
2021	15	53	5	0	1	2	10
2022	20	70	6	1	2	3	14
2023	24	83	6	2	2	5	17
2024	25	88	6	3	3	5	18
2025	26	90	6	3	3	7	18
2026	27	93	6	4	3	7	19
2027	27	94	6	5	3	8	19
2028	27	96	6	6	4	8	20
2029	28	97	6	6	4	8	20

Price Data

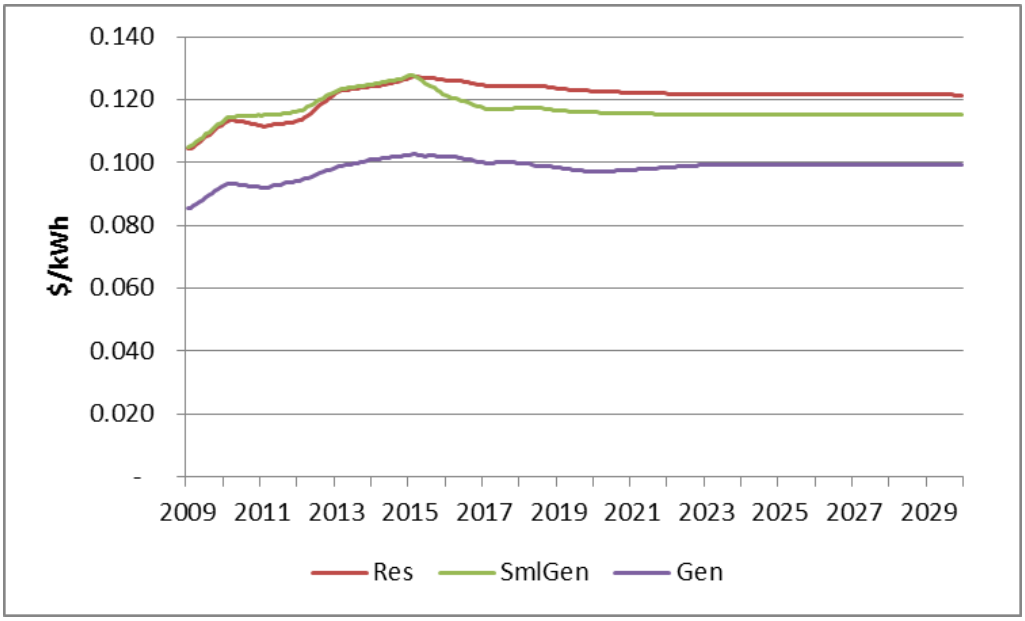
The price series is calculated from historical billed sales and billed revenues. Revenue per kWh is first calculated and translated to a real dollar basis; the price variable itself is then derived as a 12-month moving average of the real revenue per kWh series. The 12-month moving average uncouples 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 each of the calendar years 2017, 2018 and 2019 is based on the rates included in the Company's Fuel Stability Plan and Base Cost of Fuel Reset dated March 7, 2016.[6] For the period from 2017 to 2019

[6] M07348, 2017-2019 Fuel Stability Plan and Base Cost of Fuel Reset, March 7, 2016.

inclusive, the average nominal price is increased at 1.5 percent per year. Beyond 2019, the nominal price of electricity changes at an average of 2 percent per year, or around inflation. **Figure 19** shows price forecasts by class.

Figure 19: Historical and projected real electricity prices (dollars per kWh)



Prices impact the class sales through imposed price elasticities. The SAE models are estimated using a -0.15 price elasticity. This elasticity estimate was provided by Itron during the development of the SAE model and is based on studies and their experience working with other utilities and developing forecasting models. Though the elasticities are small, relatively strong price increases will have a measurable impact on sales.

Demand Side Management

Demand Side Management 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. NS Power uses the DSM targets approved by the Board to modify

its forecast. In August 2015, the Board approved a DSM plan covering the 2016–2018 period.[7]

2019 DSM savings are similar to 2018 levels and align with the DSM expenditure level of E1's UARB- approved contract for the 2019 DSM Supply Agreement between E1 and NS Power and projects an incremental annual net energy savings of 127.2 GWh and an incremental annual net demand savings of 20.2 MW. Beyond 2019, DSM savings equal the base DSM scenario from the 2014 Integrated Resource Plan. The base DSM scenario was chosen as the 2020–2029 DSM forecast, because the average annual savings in the base DSM forecast best match the expected average annual DSM savings from the 2017 to 2019 period. It is expected that the DSM forecast will be adjusted for the 2020 load forecast with inputs from the upcoming 2020-2022 DSM agreement, and any other relevant regulatory processes.

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 has to 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 even the 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.

[7] Decision 2015 NSUARB 204, M06733, Application for approval of a Supply Agreement for Electricity Efficiency and Conservation Activities between Efficiency One and Nova Scotia Power Inc., August 12, 2015.

To address the issue of double counting, the approach used is the same as that used in the 2018 load forecast – 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 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 (adjusted R squared of 0.99 vs 0.986 without the DSM 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 -0.623 (similar to prior values) meaning 38 percent of savings is already accounted for in the regression, and 62 percent is not captured by other variables, and needs 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 the 2018 value, and the statistics of the model continue to improve and indicate it is a better fit than in 2018 (adjusted R squared of 0.808 vs 0. 795), as well as a more significant DSM variable than in 2018 (p-value of 0.01 percent vs 3.26 percent). The coefficient is -0.623[8] meaning future years in the load forecast should only be adjusted by 62 percent of the forecast DSM amounts. **Figure 20** shows the DSM levels incorporated into the forecast.

[8] For 2019 this is the same as the residential coefficient, but only by coincidence, they are calculated independently.

Figure 20: Annual Forecast DSM Savings

Year	Forecast Residential DSM savings (GWh)	Forecast Commercial and Industrial DSM savings (GWh)	DSM Adjustment for Residential with Coefficient (GWh)	DSM Adjustment for Commercial and Industrial with Coefficient (GWh)
2019	55.5	71.7	34.6	44.7
2020	58.4	75.5	36.4	47.0
2021	56.8	73.3	35.4	45.7
2022	55.7	71.9	34.7	44.8
2023	55.2	71.4	34.4	44.5
2024	55.6	71.8	34.6	44.7
2025	56.8	73.3	35.4	45.7
2026	59.2	76.4	36.9	47.6
2027	62.6	80.9	39.0	50.4
2028	66.9	86.5	41.7	53.9
2029	71.3	92.0	44.4	57.3

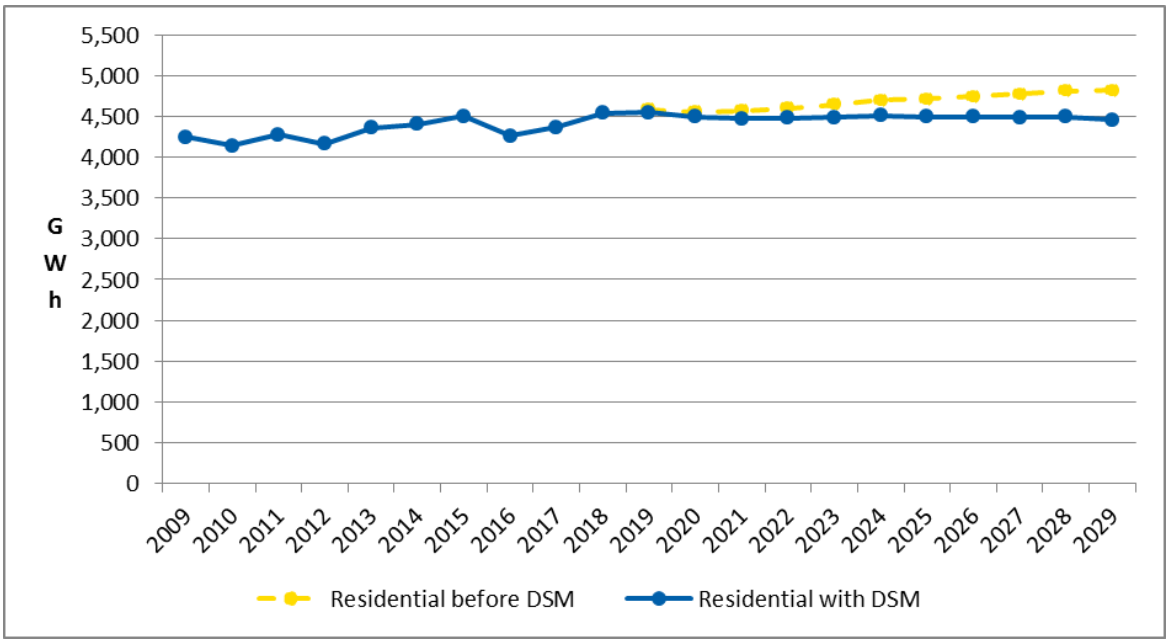
The methodology used to determine the DSM coefficient only works for levels of DSM that have been relatively consistent throughout the historical data set, and does not imply that only a portion of future DSM will impact sales. If forecasts for DSM change significantly then this methodology will have 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.

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 an SAE model structure and the customer forecast is based on forecast housing starts. Full details on the residential SAE model can be found in **Appendix B**. As outlined in the End Use Intensity Trends, programs related to heat pumps and hot water heaters, as well as projections for EVs and residential solar are added to the modeled load growth projection.

Residential sales dropped between 2015 and 2016, but have been growing since then, driven mainly by increased electric heating. 2018 in particular saw a jump in sales – year over year growth was 4.1 percent, with weather accounting for approximately 1.7 percent. From 2018 to 2019, growth is forecast to be 1.5 percent on a weather normalized basis. The increase in residential load since 2015 has increased projections in the near term, but the overall trend is similar to the 2018 forecast showing a slight decline over the forecast period. Historical and forecast annual residential sector loads are shown in **Figure 21**. Residential sector load is anticipated to decline by 0.2 percent annually during the 10 year forecast period.

Figure 21: Historical and Forecast Annual Residential Sales



New customers in the residential class are separated into single family and multi-unit categories. Analysis of billing data for the past two years for new buildings (built within the last 2-10 years) in both categories has confirmed new single-family homes use around 16,000 kWh per year on average while multi-unit homes use 4,860 kWh per year on average. 1,366 homes were used for the single-family average, of which 1,074 had sufficient billing data history. 1,932 multi-unit homes were used for the multi-unit average, of which 1,492 had sufficient billing data. Most of these samples were in or near the Halifax area, as this corresponds with the location of the majority of new homes being built. In addition to using these averages, a structural index was applied that takes into account 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 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 slight expected increase in average use per new residential customer. Building shell efficiency, floor area and the resulting structural index are in

Figure 22. Analysis of both building efficiency and house size is ongoing – in this forecast they are similar to what was forecast in the 2018 load forecast.

Figure 22: Building Characteristics and Structural Index

Year	BSE Heat EIA (New England)	BSE Heat NS	Floor Area (m2)	Structural Index
2019	0.934	0.982	147.0	1.000
2020	0.928	0.980	147.3	1.000
2021	0.922	0.979	147.6	1.000
2022	0.916	0.978	147.8	1.001
2023	0.911	0.977	148.0	1.001
2024	0.905	0.976	148.2	1.002
2025	0.900	0.975	148.4	1.002
2026	0.895	0.974	148.6	1.003
2027	0.890	0.974	148.7	1.003
2028	0.886	0.974	148.9	1.005
2029	0.882	0.974	149.0	1.005

Please refer to Appendix B for tables with a detailed breakdown of the changes from 2019 to 2029. A high level summary of the impact of those changes is as follows:

- Change to existing average use model contributes to a decline of 3.9 percent due to increased efficiency in the underlying end uses;
- New customers add 5.8 percent;
- Heat pumps are expected to add 2.9 percent;
- EVs are expected to add 3.2 percent;
- Hot water heaters are expected to add 0.3 percent;
- Solar is expected to reduce sales by 3 percent; and
- DSM will reduce sales by a further 7.2 percent.

Total change between 2019 and 2029 is a decrease of 2 percent.

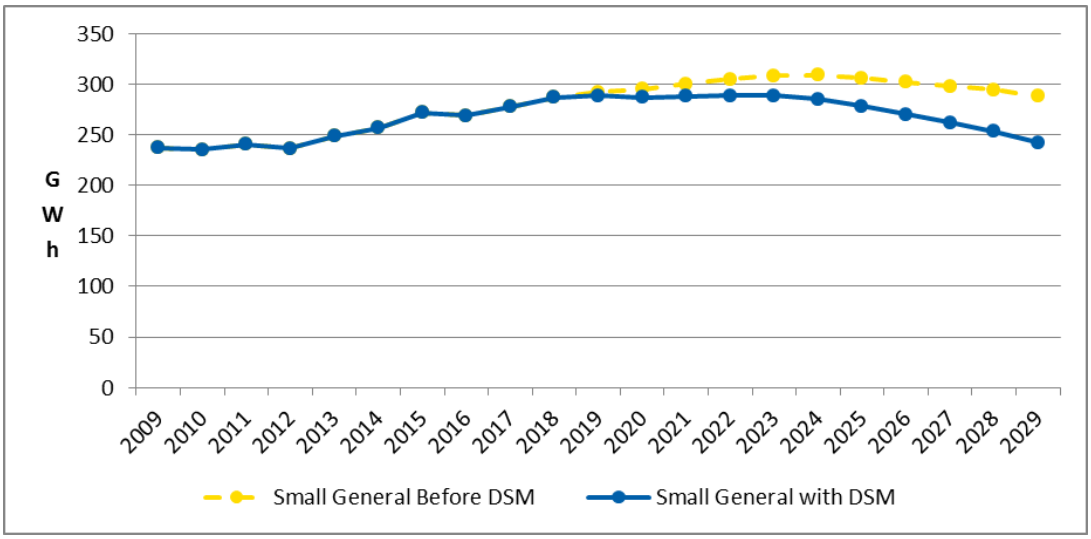
6.0 COMMERCIAL SECTOR

The Commercial SAE model creates a unique forecast for the Small General and General Service 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 Service forecast is based on a monthly SAE average use model and a separate customer forecast. The General Service 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 (EI) 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 a given month. A detailed breakdown of the two commercial SAE models is provided in **Appendix B.** Overall sales are expected to be lower than that forecast in the 2018 load forecast.

Small General Service

Historical and forecast Small General Service loads are shown in **Figure 23**. Small General Service load shows a greater decline in the 2019 forecast: 1.7 percent per year over the 10-year forecast period compared to 0.7 percent in the 2018 load forecast. This is driven by a combination of DSM and decreased intensity forecasts for the ventilation, lighting and miscellaneous end uses. The EIA forecast assumes greater LED lighting penetration in the commercial sector, along with greater ventilation efficiency driven by improvements in equipment performance (for example, increased use of variable frequency drives). Partly offsetting these declines is an increase in the heating intensity. For 2019, the year-over-year change in heating penetration from the residential class was applied to the small general class as they are similar in average use characteristics.

Figure 23: Historical and Forecast Annual Small General Sales



Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2019 to 2029. A high level summary of the impact of those changes is as follows:

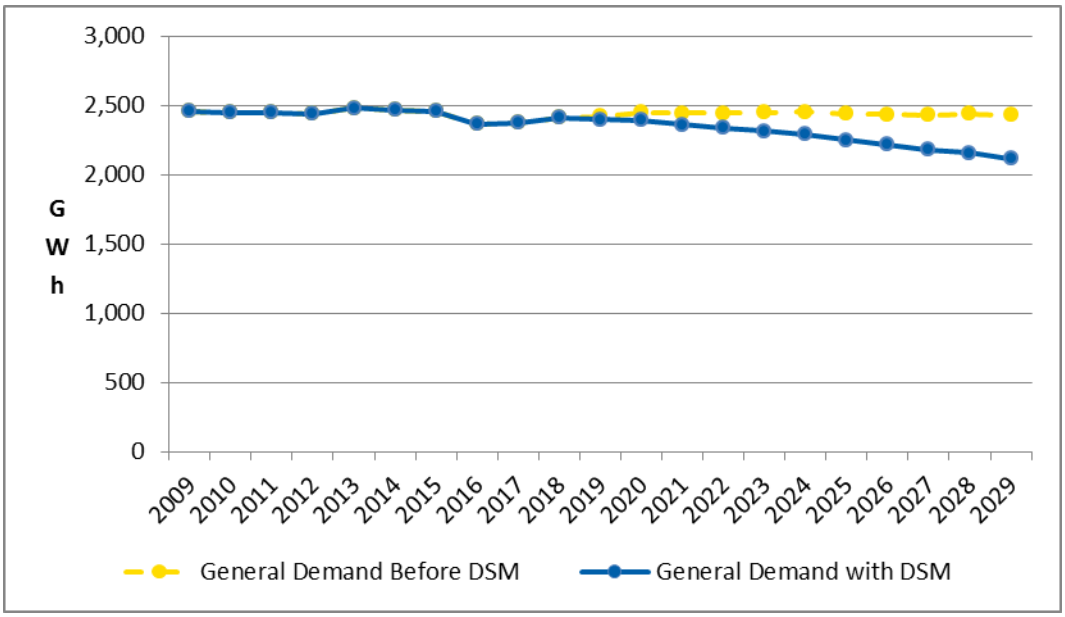
- Change to existing average use model contributes to a decline of 3.6 percent due to increased efficiency in the underlying end uses;
- Growth programs (mainly heat pumps) are expected to add 8.1 percent;
- Solar is expected to reduce sales by 5.9 percent; and
- DSM will reduce sales by a further 14.4 percent.

Total change between 2019 and 2029 is a decrease of 16.1 percent.

General Service

Historical and forecast General Service sales are shown in **Figure 24**. General Service load is expected to decline by 1.2 percent per year during the 10-year forecast period, compared to a decline of 0.8 percent in the 2018 forecast. Like the small general class, the decline is driven by DSM and changes in the forecasts for ventilation, lighting and miscellaneous end uses.

Figure 24: Historical and Forecast Annual General Demand Sales



Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2019 to 2029. A high level summary of the impact of those changes is as follows:

- Change to existing average use model contributes to a decline of 2.3 percent due to increased efficiency in the underlying end uses;
- Growth programs (mainly heat pumps) are expected to add 3.4 percent;
- Solar is expected to reduce sales by 0.7 percent; and
- DSM will reduce sales by a further 11.9 percent.

Total change between 2019 and 2029 is a decrease of 11.7 percent.

Large General Service

Large General Service is forecast using a combination of customer survey and historical sales information. Customers are surveyed regularly to determine their electricity requirements over the next three-year period. Details on planned production levels or equipment changes help inform energy requirement expectations. In absence of survey or publicly available information, load levels are forecast as being flat before the impact

of any DSM activities. Four of the 19 large general customers replied to the annual survey: one indicated no change, two indicated a slight decrease and one indicated a slight increase in energy consumption. The only major impact to the large general class over the 10 year period is DSM, which accounts for the 9.4 percent decrease overall.

7.0 INDUSTRIAL SECTOR

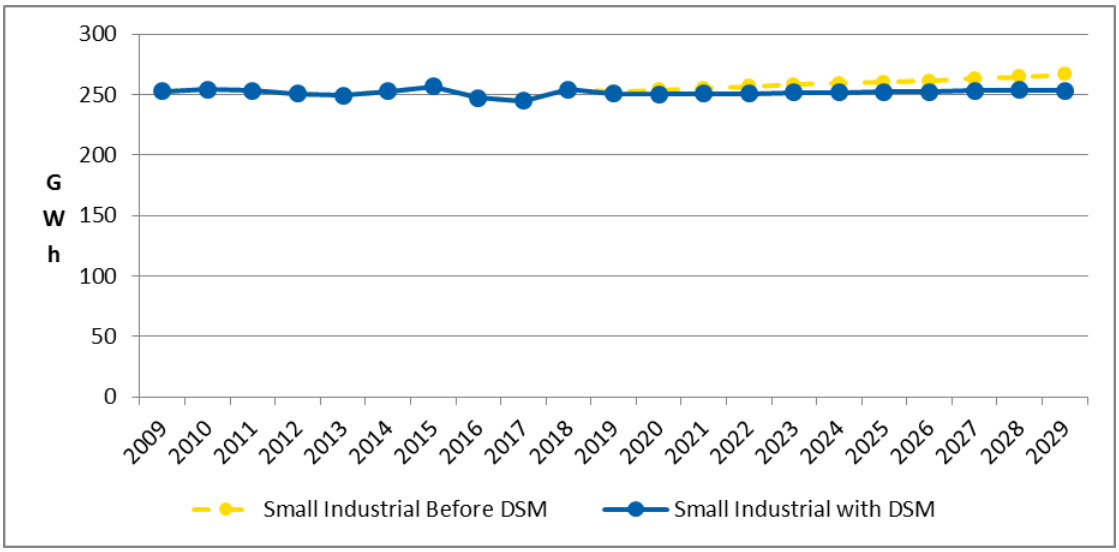
The forecast models for the Small Industrial and Medium Industrial rate classes are econometric-based models (i.e. dependant on economic variables). Provincial GDP is used as the primary economic variable in the Small Industrial forecast and manufacturing employment is used for the Medium Industrial class.

The Small and Medium Industrial rate 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.

Small Industrial

Figure 25 depicts historical and projected sales for the Small Industrial rate class. Sales in this class have been flat for the last 10 years and are expected to remain essentially flat, with growth of 0.1 percent annually over the forecast period due to underlying economic growth.

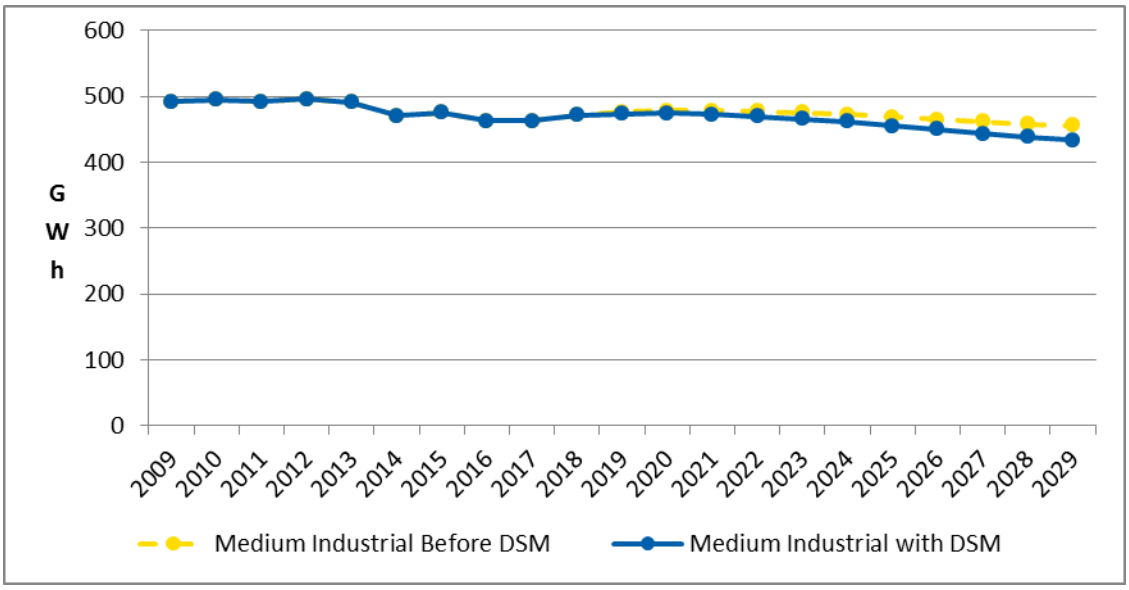
Figure 25: Historical and Forecast Annual Small Industrial Sales



Medium Industrial

Figure 26 depicts historical and projected sales for the Medium Industrial rate class. Load in this class has been decreasing since the 2008 recession, primarily due to the closures or reduced operations of the class participants. Forecast sales are expected to decline over the forecast period, with an average decrease of 0.9 percent driven by a combination of DSM and a declining manufacturing employment forecast.

Figure 26: Historical and Forecast Annual Medium Industrial Sales



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 Load Retention Tariff. The Load Retention Tariff ends in 2019 and a determination will be made as to how the customer currently taking service under that tariff may take service after the end of the Load Retention Tariff term, but pending that determination, for the purposes of this forecast, it is assumed that this customer's load will continue to be served under this tariff for the duration of the forecast.

Like the Large General Service rate class, load for these rate classes is forecast using a combination of customer survey and historical sales information. Customers are surveyed regularly in order to gather their forecast monthly electricity requirements over the next three-year period. Details on planned production levels or equipment changes help inform energy requirements expectations. In the absence of any survey or general public information, load levels are forecast as being flat. One response was received from the annual survey, reporting a slight increase in energy use. Regarding changes from 2018, NS Power is aware of several expansion projects, as well as customers who are ramping

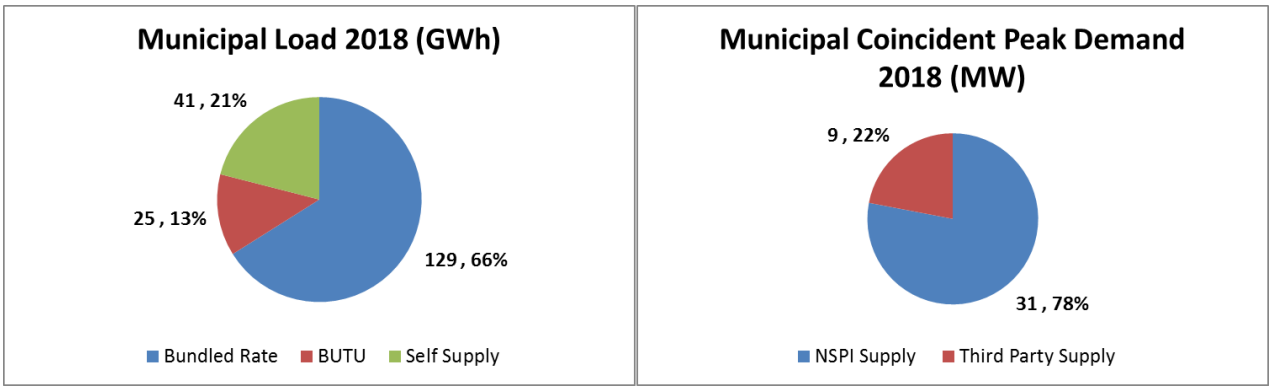
up operations that are likely to add a total of around 40 GWh in 2019. Several new facilities in the mining and cannabis production sectors are also expected to open in the coming years. Based on discussions with customers, these are expected to add cumulatively 12 GWh in 2019, 55 GWh in 2020 and 95 GWh in 2021 and beyond.

Municipal

This 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. These losses are estimated to average approximately 4 percent of sales.

NS Power's Open Access Transmission Tariff (OATT) is available to each of the six municipal utilities. Since 2007 it has been possible for these municipalities to source their electricity from providers other than NS Power. Several municipal customers currently source part of their energy requirement from suppliers other than NS Power, resulting in a reduction in municipal load of around 70 GWh from historic levels. These customers have their load served by a combination of third party generation, the bundled Municipal rate, and the Back-Up Top-Up (BUTU) rate. For the 2019 forecast the BUTU amount is included in the municipal amount. **Figure 27** shows the amount of energy provided to the municipal utilities under the bundled municipal rate, the BUTU rate, and the energy provided by third parties. It also shows the amount of demand provided by each source of supply at the time of the 2018 peak. Even if the municipal customers were to source all of their energy from third parties, their ability to supply their peak demand would depend on the source of the supply.

Figure 27: Energy Supply to Municipalities



8.0 SYSTEM LOSSES AND UNBILLED SALES

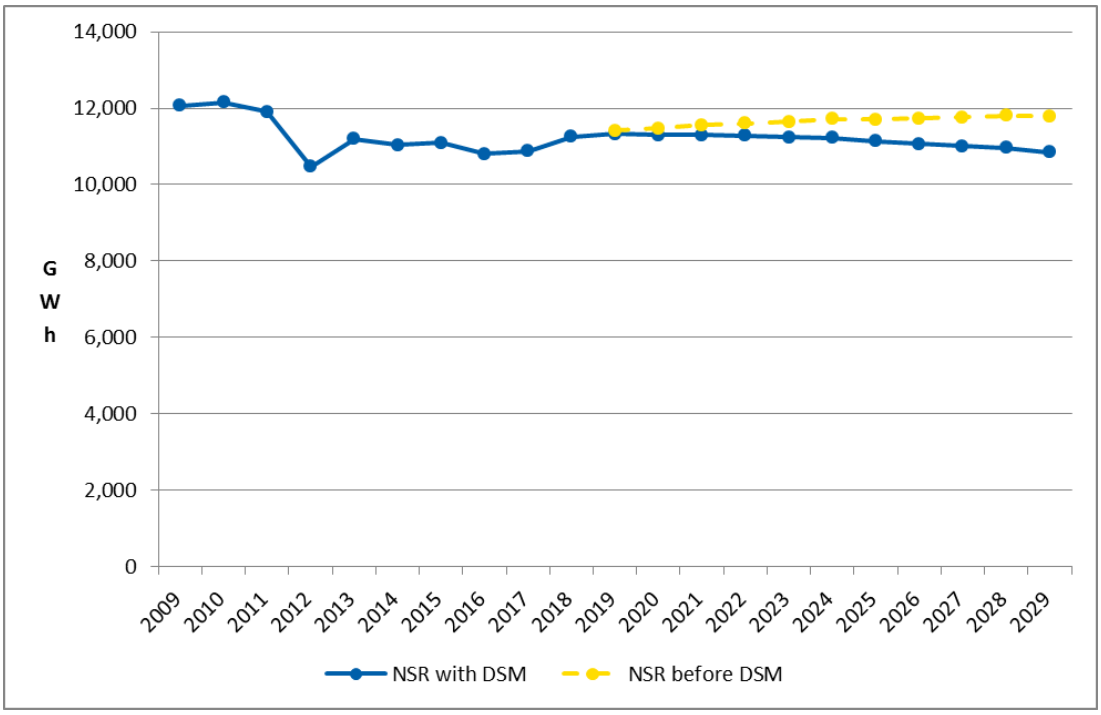
The difference between energy generated for use within provincial borders and the total NS Power billed sales comprises transmission and distribution system losses as well as changes to the level of unbilled sales. Energy generated and sold but not yet billed is referred to as "Unbilled" sales. System losses averaged 6.7 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.

In 2018, the NSR for the province increased by 3.5 percent over 2017, primarily due to favourable weather (0.9 percent), higher industrial load (1.3 percent) and underlying growth in the residential and commercial classes (1.4 percent). When adjusted for weather, the growth from 2018 actuals to 2019 forecast is 1.6 percent overall, with almost equal contributions from increased residential load and large industrial customer growth from new customers. From 2019 to 2029, NSR is forecast to decline at 0.4 percent per year, slightly lower than the 2018 load forecast. Without DSM effects, growth would be an average of 0.3 percent annually. Annual NSR is shown in **Figure 28**. Forecast NSR values and the contribution to NSR from the different sectors can be found in **Appendix A**.

Figure 28: Historical and Forecast Annual NSR



10.0 PEAK DEMAND

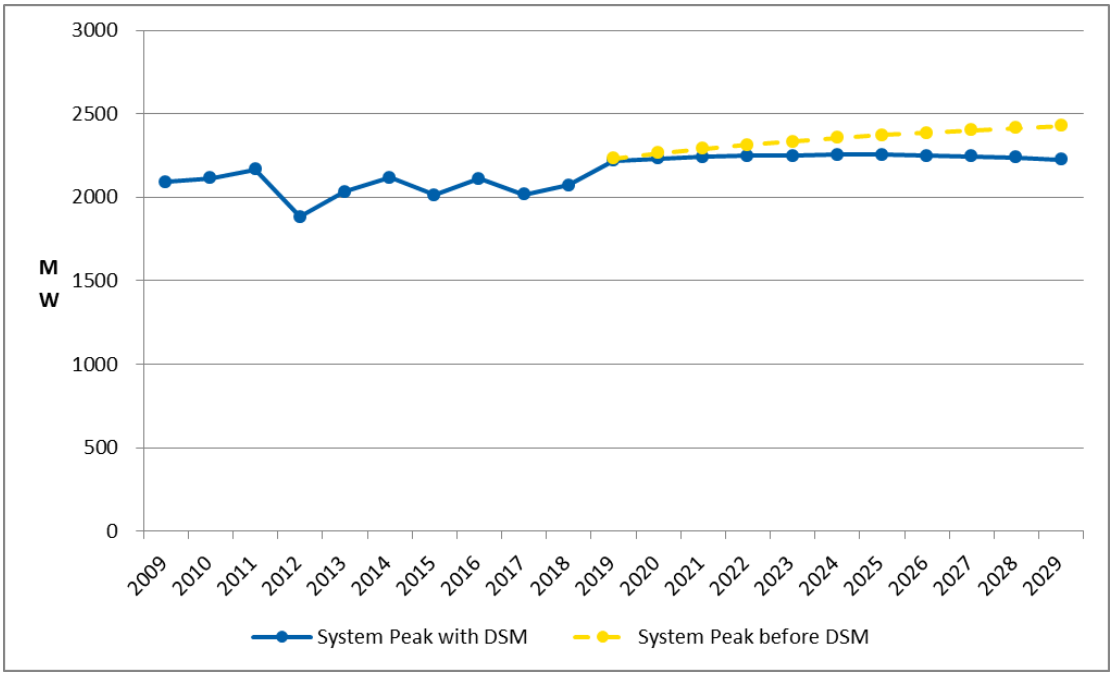
The total system peak is defined as the highest single hourly average demand experienced in a year. It includes both firm and interruptible loads. Due to the weather-sensitive load component in Nova Scotia, the total system peak occurs in the period from December through February.

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. Full details about the peak forecast can be found in **Appendix B**.

There are no specific peak mitigation programs taken into account for the forecast, with the exception of the peak contribution of EVs. EVs are expected to be similar to other jurisdictions for which there is some data on the impact of peak mitigation measures. Possibilities for peak mitigation include items such as direct load control (space heating, hot water heating, or EVs), integration of battery storage, or rate design (time of use, critical peak pricing or other rates enabled by an AMI deployment). Critical peak pricing, for instance, is expected to contribute as much as 26MW of savings on peak by 2022. Although combinations of the above are likely to be implemented within Nova Scotia in the next 5-10 years, the amount of uncertainty surrounding the specific combinations or impacts makes it difficult to estimate. As rate design initiatives progress, in particular with the possibilities provided by AMI deployment, estimates for peak reduction will be updated in future load forecasts. The impact of any of these initiatives, at least within the 10 year timeframe of this forecast, is likely to fall within the sensitivity analysis provided in Section 11.

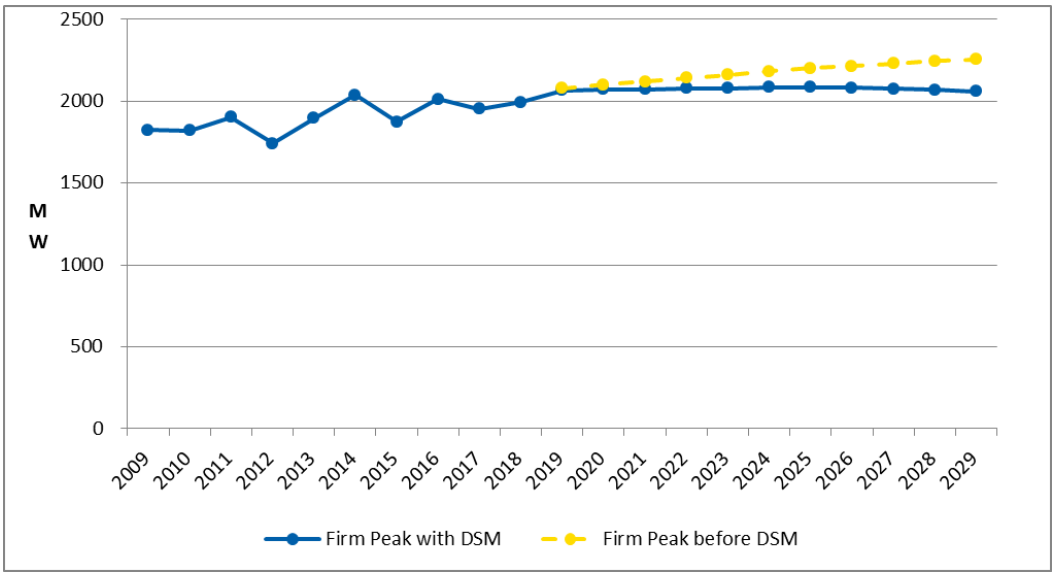
The peak contribution from large customer classes continues to be calculated from historical coincident load factors for each of the rate classes and the large customer forecast is added to the accrued class forecast to get the total system peak. The forecast system peak for 2019 to 2029 is shown below in **Figure 29**. Without DSM, growth would be 0.8 percent annually but growth is forecast to be flat when DSM is included.

Figure 29: Historical and Forecast System Peak



The system peak is made up of firm and interruptible components. As indicated in **Figure 30**, the firm peak is expected to grow by 0.8 percent annually before the impact of DSM. Increased electric heating is the main driver of this increase, but it is expected to be offset by DSM activities, resulting in no growth between 2019 and 2029.

Figure 30: Historical and Forecast Firm Peak



Forecast peak values, along with firm peak and interruptible peak information can be found in **Appendix A**. As discussed in the End Use Intensity section, around half the EV contribution to peak is assumed to be mitigated in the peak forecast. The firm peak without EV peak mitigation (assuming twice the forecast EV peak with mitigation) would grow at 0.1 percent per year, and the overall impact in 2029 would be to add around 35 MW to the peak. **Figure 31** below shows the breakdown of the peak forecast by the various components. 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.

Figure 31: Peak Contribution Components (MW)

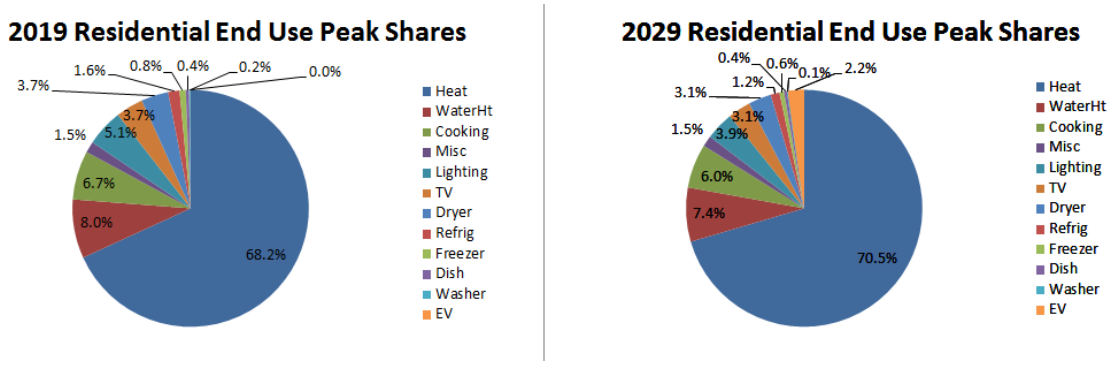
	Modeled Peak	HP	EV	HW	C&I Growth	Large Cust.	Inter. Cust.	DSM	System Peak
2019	1,960	17	0	0	3	98	156	-13	2,221
2029	1,989	111	30	3	20	96	173	-194	2,228
2029 (no EV mitigation)	1,989	111	65	3	20	96	173	-194	2,263

The 2018 firm peak occurred in early January at a temperature of -11.7 degrees C and was 1,993 MW. Although this was close to the 2018 forecast firm peak of 2,001 MW, the peak temperature was warmer than the design temperature of -15 degrees C. Accounting for the warmer temperature, the peak would have likely been around 2,060 MW, which is slightly below the 2019 forecast firm peak of 2,066 MW.

While the forecast is a good statistical fit for the historical data, it present 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. In order 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.

The residential class saw an increase in heating load in 2018 – peak share was estimated at 60% in the 2018 load forecast versus 68% in the 2019 load forecast. Although sales show a decreasing trend overall, electric heat penetration is expected to increase as can be seen in **Figure 32** below, which shows the breakdown in contribution to peak by residential end use.

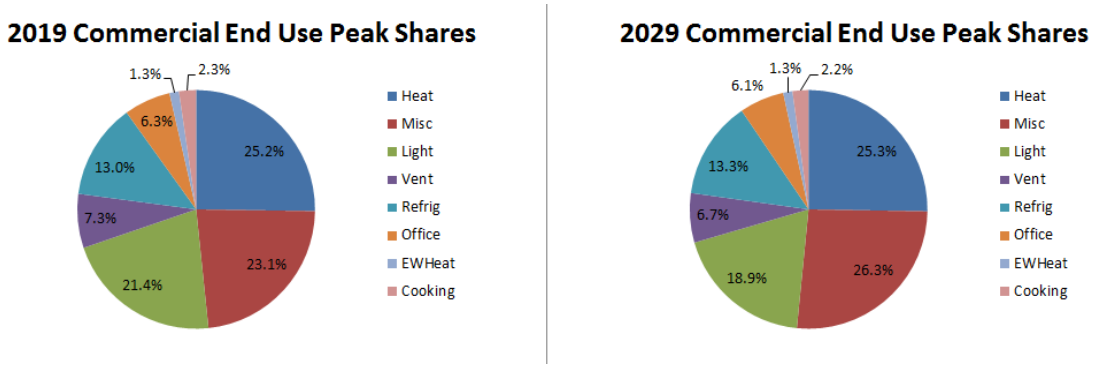
Figure 32: Residential End-Use Peak Shares



Over the forecast period, the peak contribution from heating and EVs grows, while all other end-uses decline as a percentage of the peak. Heating in particular shows a much bigger contribution to peak in 2029 as electric heat becomes more widespread due to a combination of new homes using electric heat and heat pumps being installed in existing homes displacing other heating sources. Efficient heat pumps continue to replace electric baseboard heat and decrease energy sales related to heating, but they have not contributed a similar amount to peak mitigation as resistance heat is still required at peak temperatures. Combined with DSM efforts to reduce energy consumption, this causes the disconnect between the energy forecast that has negative growth in sales and an increasing forecast for firm system peak.

Figure 33 shows the breakdown in the contribution to peak by commercial end use. The largest change in the commercial sector is the peak contribution from miscellaneous end-use growing and lighting declining.

Figure 33: Commercial End-Use Peak Shares



The trend in the commercial class shows that the heating component of the peak is expected to remain unchanged over the forecast period. All other categories decrease through the forecast period. The miscellaneous intensities, which include everything from elevator loads to medical equipment to other office plug-in loads, show an increasing trend over the forecast period and a corresponding increase in peak contribution.

Future Peak Demand Work

In order to further refine the peak forecast model, load research data will be investigated to disaggregate the peak components by class. This would potentially help break out the various end-use components at the class level, as well as potentially allow class level DSM to be integrated directly into the model. Work was completed in 2018 to update the load research sample, and integration of this data with the load forecast is ongoing.

11.0 SENSITIVITY ANALSYSIS

The sales and peak forecasts are fundamentally uncertain and dependent on many variables such as 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. Additionally, load can be affected by extraordinary events such as economic crises, strikes, trade disputes, natural disasters and volatility in commodities.

In 2017, based on recommendations from Synapse on the 2016 Load Forecast,[9] 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 can be found in **Appendix D**.

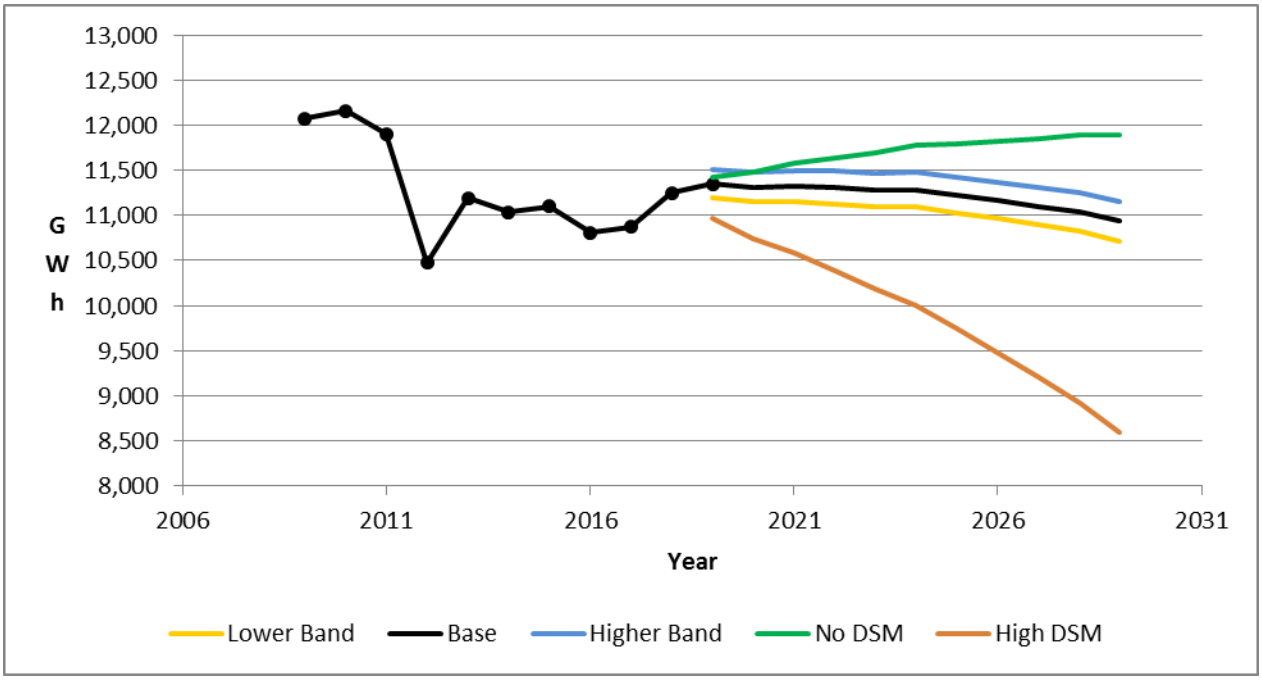
The probable distribution of future load is estimated by sampling 10,000 random trial values of the economic, weather, and price drivers each year using their respective historical distributions. For the 2019 sensitivity model, DSM was added outside of the Monte Carlo simulation based on the Low and High DSM values from the 2014 IRP. Modelling the individual end uses using a Monte Carlo simulation is still in progress and has not been completed for this iteration of the forecast.

Figure 34 shows the 2019 energy forecast in black, surrounded by a low band in yellow representing the 10th percentile, (there is a 90 percent probability that the forecast will be above the yellow line), and by a high band in blue, representing the 90th percentile, (there is a 10 percent probability that the forecast will be above the blue line). These P10/P90 bands cover a range of about 200-400 GWh, which is explained mainly by the impact of weather variation (HDD) and some economic impact in the long term. The green and

[9] M07448, Findings Regarding the NSPI 2016 Load Forecast, Synapse Energy Economics, August 31, 2016.

brown lines represent the envelope of the no (green) and high (orange) DSM amounts. The high DSM line assumes 100 percent of future DSM is impacting the forecast (there is no coefficient applied to future DSM programs).

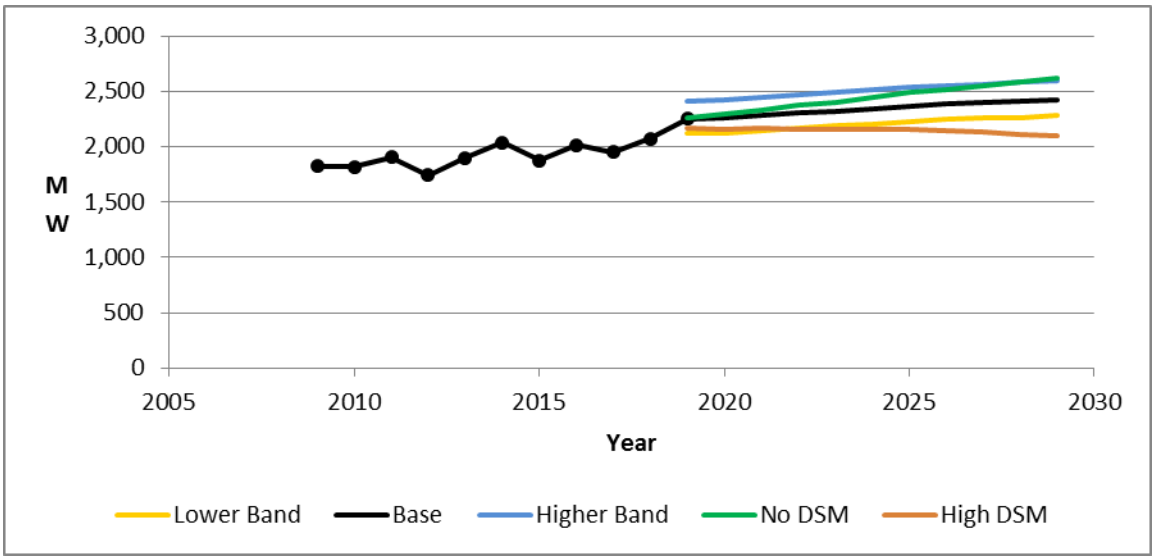
Figure 34: System Energy Sensitivity



DSM represents a much larger source of variability when compared to the potential impact of weather or economics. For a comparison of the impact of various inputs on the forecast, see Figure D9 in in the **Appendix D**.

Similarly, a P10/P90 scenario was created for peak demand using random sampling of weather and economic drivers, overlaid with a no DSM scenario and the 2014 IRP high DSM scenario. The width of the P10/P90 envelope is about 297-313 MW, and unlike the energy forecast, where DSM dominates the variance, the peak is mainly dominated by the variation of Peak day HDD, resulting in enough variation that even the DSM scenarios fall mostly within the bands as seen in **Figure 35**.

Figure 35: System Peak Sensitivity



Load Forecast

Appendices

Appendix A – Forecast Values

2019 NS Power Forecast

Table A1: Energy Requirement – 2019 NS Power Forecast
Energy Forecast with Future DSM Program Effects

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Municipal	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
2009	4,244	2.1%	3,224	-0.3%	3,638	-12.3%	198	0.3%	769	12,073	-3.7%
2010	4,144	-2.4%	3,211	-0.4%	3,912	7.5%	193	-2.5%	697	12,158	0.7%
2011	4,275	3.2%	3,217	0.2%	3,515	-10.2%	191	-1.0%	709	11,907	-2.1%
2012	4,160	-2.7%	3,196	-0.6%	2,164	-38.4%	191	0.0%	763	10,475	-12.0%
2013	4,362	4.8%	3,244	1.5%	2,604	20.3%	201	4.8%	784	11,194	6.9%
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	4,551	0.2%	3,161	-0.6%	2,681	2.6%	152	-1.0%	786	11,331	0.7%
2020	4,493	-1.3%	3,154	-0.2%	2,734	2.0%	150	-1.5%	769	11,300	-0.3%
2021	4,473	-0.5%	3,123	-1.0%	2,795	2.2%	148	-1.5%	765	11,303	0.0%
2022	4,479	0.1%	3,095	-0.9%	2,790	-0.2%	146	-1.1%	767	11,278	-0.2%
2023	4,490	0.2%	3,070	-0.8%	2,785	-0.2%	133	-9.2%	762	11,240	-0.3%
2024	4,511	0.5%	3,040	-1.0%	2,777	-0.3%	132	-0.8%	760	11,220	-0.2%
2025	4,496	-0.3%	2,987	-1.7%	2,768	-0.3%	130	-1.5%	754	11,135	-0.8%
2026	4,492	-0.1%	2,942	-1.5%	2,759	-0.3%	128	-1.2%	748	11,069	-0.6%
2027	4,489	-0.1%	2,896	-1.5%	2,750	-0.3%	127	-1.2%	743	11,005	-0.6%
2028	4,493	0.1%	2,858	-1.3%	2,741	-0.3%	126	-0.9%	739	10,958	-0.4%
2029	4,459	-0.8%	2,801	-2.0%	2,731	-0.4%	124	-1.6%	730	10,844	-1.0%

Table A2: Energy Requirement – 2019 NS Power Forecast

Energy Forecast before Future DSM Program Effects

1

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Municipal	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
2009	4,244	2.1%	3,224	-0.3%	3,638	-12.3%	198	0.3%	769	12,073	-3.7%
2010	4,144	-2.4%	3,211	-0.4%	3,912	7.5%	193	-2.5%	697	12,158	0.7%
2011	4,275	3.2%	3,217	0.2%	3,515	-10.2%	191	-1.0%	709	11,907	-2.1%
2012	4,160	-2.7%	3,196	-0.6%	2,164	-38.4%	191	0.0%	763	10,475	-12.0%
2013	4,362	4.8%	3,244	1.5%	2,604	20.3%	201	4.8%	784	11,194	6.9%
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	4,582	0.9%	3,195	0.4%	2,689	2.9%	154	0.1%	792	11,412	1.4%
2020	4,556	-0.6%	3,224	0.9%	2,750	2.3%	153	-0.4%	783	11,466	0.5%
2021	4,567	0.2%	3,229	0.1%	2,819	2.5%	153	-0.4%	785	11,552	0.8%
2022	4,604	0.8%	3,236	0.2%	2,822	0.1%	153	0.0%	794	11,608	0.5%
2023	4,646	0.9%	3,245	0.3%	2,824	0.1%	141	-7.8%	795	11,650	0.4%
2024	4,697	1.1%	3,249	0.1%	2,824	0.0%	141	0.4%	800	11,712	0.5%
2025	4,713	0.3%	3,232	-0.5%	2,823	0.0%	141	-0.2%	801	11,709	0.0%
2026	4,742	0.6%	3,222	-0.3%	2,822	0.0%	141	0.1%	802	11,729	0.2%
2027	4,773	0.7%	3,216	-0.2%	2,822	0.0%	141	0.2%	804	11,757	0.2%
2028	4,815	0.9%	3,219	0.1%	2,822	0.0%	142	0.5%	808	11,807	0.4%
2029	4,819	0.1%	3,206	-0.4%	2,822	0.0%	142	0.0%	807	11,797	-0.1%

Table A3: Coincident Peak Demand - 2019 NS Power Forecast

Peak Forecast with Future DSM Program Effects

Year	Interruptible Contribution to Peak (MW)	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)
2009	268	1,824	2,092	-4.5%
2010	295	1,820	2,114	1.0%
2011	265	1,903	2,168	2.5%
2012	141	1,740	1,882	-13.2%
2013	136	1,897	2,033	8.0%
2014	83	2,036	2,118	4.2%
2015	141	1,874	2,015	-4.9%
2016	98	2,013	2,111	4.8%
2017	67	1,951	2,018	-4.4%
2018	80	1,993	2,073	2.7%
2019	155	2,066	2,221	7.2%
2020	163	2,070	2,234	0.6%
2021	170	2,073	2,243	0.4%
2022	170	2,078	2,248	0.2%
2023	170	2,080	2,249	0.1%
2024	170	2,086	2,255	0.3%
2025	169	2,086	2,255	0.0%
2026	169	2,081	2,250	-0.2%
2027	169	2,076	2,245	-0.2%
2028	168	2,070	2,239	-0.3%
2029	168	2,060	2,228	-0.5%

Table A4: Coincident Peak Demand - 2019 NS Power Forecast

Peak Forecast before Future DSM Program Effects

Year	Interruptible Contribution to Peak (MW)	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)
2009	268	1,824	2,092	-4.5%
2010	295	1,820	2,114	1.0%
2011	265	1,903	2,168	2.5%
2012	141	1,740	1,882	-13.2%
2013	136	1,897	2,033	8.0%
2014	83	2,036	2,118	4.2%
2015	141	1,874	2,015	-4.9%
2016	98	2,013	2,111	4.8%
2017	67	1,951	2,018	-4.4%
2018	80	1,993	2,073	2.7%
2019	156	2,078	2,234	7.8%
2020	165	2,100	2,265	1.4%
2021	173	2,119	2,292	1.2%
2022	173	2,141	2,314	1.0%
2023	173	2,160	2,333	0.8%
2024	173	2,183	2,356	1.0%
2025	173	2,201	2,374	0.8%
2026	173	2,214	2,387	0.6%
2027	173	2,229	2,402	0.6%
2028	173	2,244	2,417	0.6%
2029	173	2,255	2,428	0.5%

Appendix B –Forecast Model Details

2018 NS Power 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*):

$$ResAvgUse_m = b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + b_4 \times AvgEESavings_m$$

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:

$$XHeat = HeatUse \times HeatIndex$$

Where

HeatUse = f(HDD, Household Income, Household Size, and Price)

HeatIndex = g(Heating Saturation, Efficiency, Shell Integrity, Square Footage)

The cooling variable is defined as:

$$XCool = CoolUse \times CoolIndex$$

Where

CoolUse = f(CDD, Household Income, Household Size, and Price)

CoolIndex = g(Cooling Saturation, Efficiency, Shell Integrity, Square Footage)

XOther captures non-weather sensitive end-uses:

$$XOther = OtherUse \times OtherIndex$$

Where

OtherUse = f(Seasonal Use Pattern, Household Income, Household Size, and Price)

OtherIndex = g(Other Appliance Saturation and Efficiency Trends)

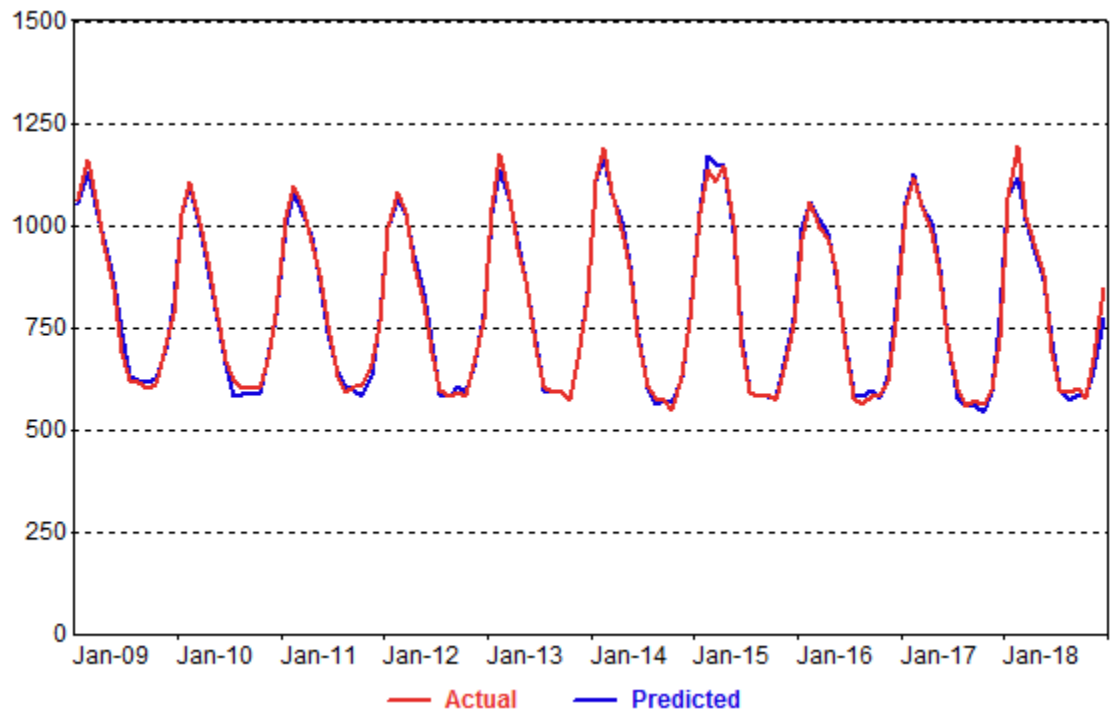
The *AvgEESavings* term captures Efficiency One's DSM past reported savings for the residential class. The associated regression coefficient, b_4, assesses the portion of embedded DSM activity that is already included in the billed sales information. The negative sign of b_4 indicates that DSM activity reduces load. 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 compensate for an anomaly in the billing data during this period related to delayed meter reads. After running the linear regression with the main variables the residuals show a slight autocorrelation, which happens when a model doesn't take into account relatively small drivers that should explain the dependent variable (in this case, sales). To help eliminate this autocorrelation, a seasonal moving average, SMA, of period 1, SMA(1) were added. SMA(1) estimates the autocorrelation with its the predecessor of 12 months ago.

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRes.WtXHeat	0.838	0.019	43.996	0.00%
MStructRes.WtXCool	0.845	0.206	4.11	0.01%
MStructRes.WtXOther	0.981	0.019	50.519	0.00%
MSales.AvgEESavings	-0.623	0.094	-6.639	0.00%
MBin.May15	77.312	17.089	4.524	0.00%
MBin.Apr15	88.318	17.25	5.12	0.00%
MBin.Aug	77.19	12.75	6.054	0.00%
MBin.Jan	76.758	10.6	7.241	0.00%
MBin.Sep	86.68	14.662	5.912	0.00%
MBin.Oct	51.621	12.732	4.054	0.01%
SMA(1)	0.58	0.109	5.32	0.00%

Residential Model Statistics

Model Statistics	
Iterations	18
Adjusted Observations	120
Deg. of Freedom for Error	109
R-Squared	0.991
Adjusted R-Squared	0.990
AIC	6.130
BIC	6.385
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-527.05
Model Sum of Squares	4,785,246.98
Sum of Squared Errors	45,880.37
Mean Squared Error	420.92
Std. Error of Regression	20.52
Mean Abs. Dev. (MAD)	14.71
Mean Abs. % Err. (MAPE)	1.88%
Durbin-Watson Statistic	1.328
Durbin-H Statistic	#NA
Ljung-Box Statistic	22.96
Prob (Ljung-Box)	0.5221
Skewness	0.655
Kurtosis	5.714
Jarque-Bera	45.397
Prob (Jarque-Bera)	0.0000

Residential SAE Model Fit



Residential Model 2019-2029 Reconciliation

As requested by Synapse, the following tables provide details reflecting the changes between 2019 and 2029 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 Cust Load (Reg. Model)	New Cust Load	Heat Pumps	EVs	Hot Water	Solar	Res Sales (before DSM)	DSM	Res Sales (with DSM)
2019	4,520	41	34	1	0	(4)	4,592	(31)	4,562
2029	4,341	305	167	147	14	(142)	4,833	(361)	4,472
Change	-3.9%	5.8%	2.9%	3.2%	0.3%	-3.0%	5.2%	-7.2%	-2.0%

Res Sales = Existing Customer Load + New Customer Load + Heat Pump Load + EV Load + Hot Water Load + Solar Load + DSM

Existing customer load is calculated as Res Average Use (9,658 kWh/cust in 2019, 9,275 kWh/cust in 2029) x number of customers as of 2018 (468,049).

Residential Average Use –Regression

	XHeat	XCool	XOther	AvgEE Savings	Binaries	ARMA	Res Average Use
2019	3,999	180	5,779	(720)	292	127	9,658
2029	4,021	188	5,493	(720)	292	0	9,275
Change	0.2%	0.1%	-3.0%	0.0%	0.0%	-1.3%	-4.0%

Res Avg Use = XHeat + XCool + XOther + AvgEESavings + Binaries + ARMA

Residential Input Variables – XHeat

	Intensities				Econ + Struct	Regression	
	Efurn	HP Heat	Secondary Heat	Furnace Fans	HeatUse Variable	Coeff	Total XHeat
2019	2,815	1,284	172	148	1.08	0.838	3,999
2029	2,830	1,291	173	108	1.09	0.838	4,021
Change	0.4%	0.2%	0.0%	-0.9%	0.9%	0.0%	0.5%

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 $[(Efurn_{2029}-Efurn_{2019}) \times HeatUse \times Coeff]/WtXHeat_{2019}$

Residential Input Variables – XCool

	Intensities			Econ + Struct	Regression	
	Central AC	HP Cool	Room AC	CoolUse Variable	Coefficient	Total Xcool
2019	36	82	50	1.3	0.845	180
2029	39	83	52	1.3	0.845	188
Change	1.4%	0.5%	1.5%	0.8%	0.0%	4.4%

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
2019	1,705	572	682	740	761	801	630	1.0	0.981	5,779
2029	1,683	569	580	671	701	673	666	1.0	0.981	5,439
Change	-0.4%	0.0%	-1.8%	-1.2%	-1.0%	-2.2%	0.6%	0.0%	0.0%	-5.9%

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:

$$XHeat_m = EI_{heat} \times Price_m^{-.15} \times SmlGenVar_m \times HDD_m$$

$$XCool_m = EI_{cool} \times Price_m^{-.15} \times SmlGenVar_m \times CDD_m$$

$$XOther_m = EI_{other} \times Price_m^{-.15} \times SmlGenVar_m \times Days_m$$

The coefficients on price are imposed short-term price elasticities.

Several binary shift variables are added to the model to:

(1) Compensate for the change in the rate class specification, which came into effect in November 2014, allowing commercial customers consuming 32,000 to 42,000 kWh per year to choose whether to take service under the Small General rate or the General rate

(2) Improve model fit using monthly binaries for March, September and December.

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), and a autoregressive process of period 1, AR(1) were used. Autocorrelated errors can be understood as a propagation of uncertainty from one month to the immediate next, a sort of

momentum between consecutive measurements. The regression model weights all measurements (sales) the same, however more recent measurements may shed better light on the current forecast than measurements from years ago.

The monthly forecast average use sales model is then estimated as:

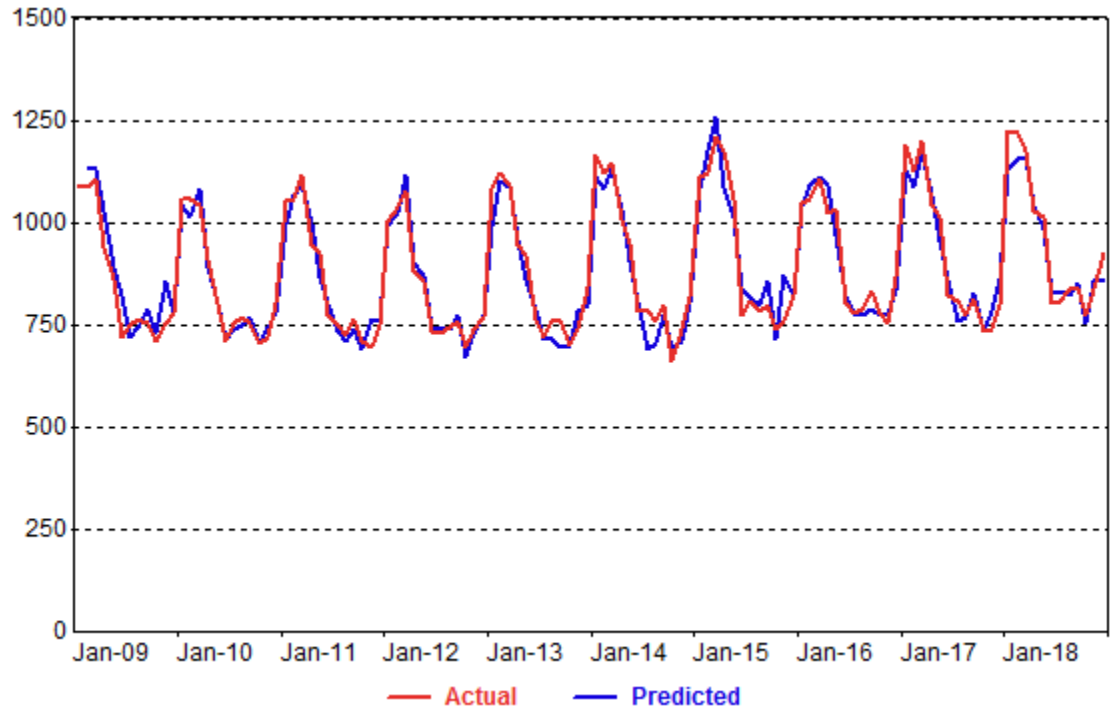
$$SmlGen\_AvgUse_m = b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + MBin.Aft15 + MBin.Mar + MBin.Sep + MBin.Dec + SMA(1) + AR(1)$$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructSmlGen.WtXHeat	0.727	0.038	18.943	0.00%
MStructSmlGen.WtXCool	0.137	0.030	4.517	0.00%
MStructSmlGen.WtXOther	0.703	0.019	37.597	0.00%
MBin.Mar	104.264	20.441	5.101	0.00%
MBin.Sep	66.149	21.618	3.060	0.28%
MBin.Dec	-100.238	20.920	-4.791	0.00%
MBin.Aft13	65.642	13.080	5.018	0.00%
AR(1)	0.216	0.100	2.165	3.26%
SMA(1)	0.543	0.085	6.371	0.00%

Small General Model Statistics

Model Statistics	
Iterations	14
Adjusted Observations	119
Deg. of Freedom for Error	110
R-Squared	0.931
Adjusted R-Squared	0.926
AIC	7.587
BIC	7.797
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-611.27
Model Sum of Squares	2,735,621.64
Sum of Squared Errors	201,726.28
Mean Squared Error	1,833.88
Std. Error of Regression	42.82
Mean Abs. Dev. (MAD)	32.47
Mean Abs. % Err. (MAPE)	3.67%
Durbin-Watson Statistic	1.981
Durbin-H Statistic	#NA
Ljung-Box Statistic	40.35
Prob (Ljung-Box)	0.0196
Skewness	-0.194
Kurtosis	3.197
Jarque-Bera	0.938

Small General Model Fit



Small General 2019-2029 Reconciliation

The Small General Demand customer forecast model is constructed like the residential model. Adjustments done outside the regression include estimates for commercial and industrial growth programs (mainly heat pumps), PV 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	NSPI C&I Programs	Solar	Small Gen Sales (before DSM)	DSM	Small Gen Sales (with DSM)
2019	289	4	(0)	292	(4)	288
2029	278	28	(18)	288	(46)	242
Change	-3.6%	8.1%	-5.9%	-1.5%	-14.4%	-16.1%

Small General Sales = Avg Use Existing x customer count forecast+ NSPI C&I Programs + Solar Load + DSM

The load from the regression model is calculated as Small Gen Average Use (11,300 kWh/cust in 2019, 10,629 kWh/cust in 2029) x number of customers (25,545 in 2019, increasing to 26,158 in 2029).

Small General Average Use –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Avg Sales (kWh)
2019	2,893	211	7,198	858	140	11,300
2029	3,030	209	6,532	858	(0)	10,629
Change	1.2%	0.0%	-5.9%	0.0%	-1.2%	-5.9%

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)
2019	50,079	1.14	0.727	0.070	2,893
2029	51,933	1.15	0.727	0.070	3,030
Change	3.7%	1.0%	0.0%	0.0%	4.7%

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 [($Heat_{2029}$-$Heat_{2019}$) x HeatUse x Coeff x Scaling]/$WtXHeat_{2019}$

Small General Input Variables – XCool

	Intensities	Econ + Struct	Regression		
	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total XCool (kWh)
2019	33,056	1.33	0.137	0.035	211
2029	32,414	1.34	0.137	0.035	209
Change	-2.0%	0.8%	0.0%	0.0%	-1.1%

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)
2019	16,880	1,601	2,456	30,418	49,759	12,891	48,551	12.60	0.703	0.005	7,198
2029	13,607	1,425	2,230	27,608	38,837	10,899	51,572	12.71	0.703	0.005	6,532
Change	-2.0%	-0.1%	-0.1%	-1.7%	-6.8%	-1.2%	1.9%	0.9%	0.0%	0.0%	-9.2%

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.

Like the Small General model, binaries are added for the change in billing rate class threshold.

A monthly forecast sales model is then estimated as:

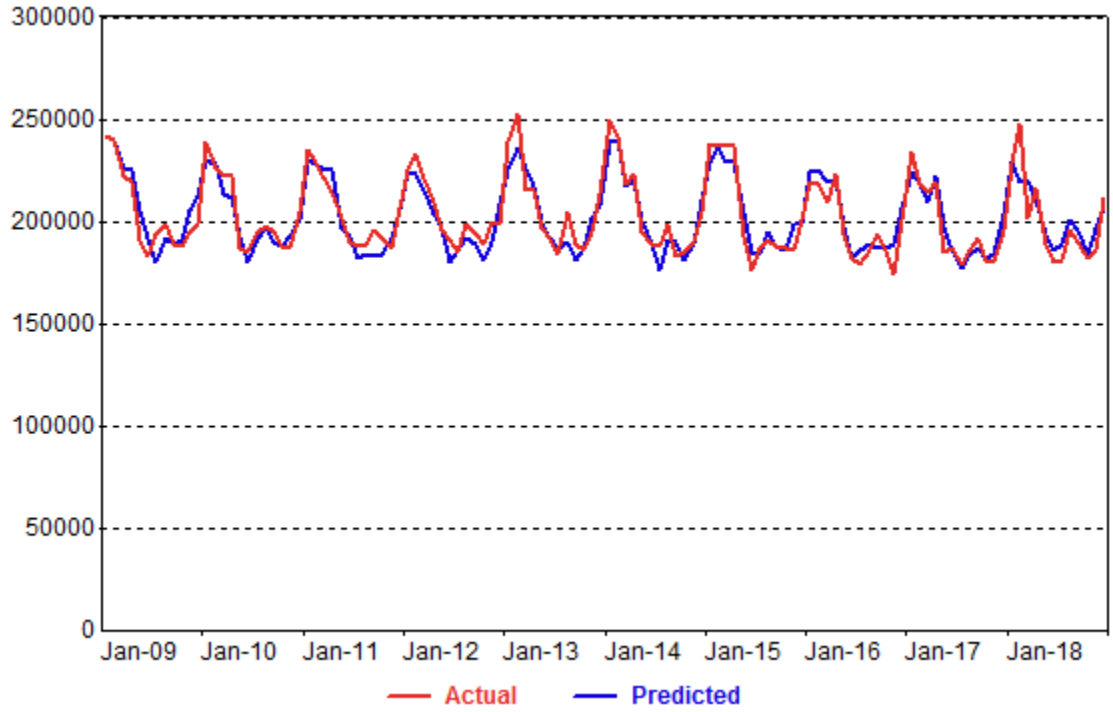
$$GenService_m = b1 \times XHeat_m + b2 \times XCool_m + MBin.Aug08 + MBin.Aft13 + AR(1) + SMA(1)$$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructGen.WtXHeat	0.696	0.051	13.597	0.00%
MStructGen.WtXCool	0.260	0.051	5.080	0.00%
MStructGen.WtXOther	1.009	0.021	47.168	0.00%
MBin.Aft13	5699.159	2633.310	2.164	3.25%
AR(1)	0.316	0.089	3.540	0.06%
SMA(1)	0.577	0.090	6.389	0.00%

General Service Model Statistics

Model Statistics	
Iterations	14
Adjusted Observations	119
Deg. of Freedom for Error	113
R-Squared	0.843
Adjusted R-Squared	0.836
AIC	17.955
BIC	18.095
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,231.16
Model Sum of Squares	36,223,779,935.89
Sum of Squared Errors	6,751,754,834.03
Mean Squared Error	59,750,042.78
Std. Error of Regression	7,729.82
Mean Abs. Dev. (MAD)	5,965.25
Mean Abs. % Err. (MAPE)	2.94%
Durbin-Watson Statistic	1.958
Durbin-H Statistic	#NA
Ljung-Box Statistic	32.08
Prob (Ljung-Box)	0.1251
Skewness	0.249
Kurtosis	3.484
Jarque-Bera	2.389
Prob (Jarque-Bera)	0.3029

General Service Model Fit



General Demand 2019-2029 Reconciliation

The general demand class, which makes up the largest portion of the commercial sector, is forecasted 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 for NS Power commercial growth programs (mainly heat pumps), PV and DSM.

General Demand Load – Post Regression (GWh)

	Load Regression Model	NSPI C&I Programs	Solar	Gen Sales (before DSM)	DSM	Gen Sales (with DSM)
2019	2,408	14	(0)	2,421	(27)	2,395
2029	2,351	97	(18)	2,431	(316)	2,115
Change	-2.3%	3.4%	-0.7%	0.4%	-11.9%	-11.7%

Gen Sales = Sales + NSPI C&I Programs+ Solar Load + DSM

General Demand Sales –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Sales (MWh)
2019	345,122	44,887	1,969,713	68,390	(20,405)	2,407,707
2029	329,680	47,369	1,905,996	68,390	0	2,351,435
Change	-0.6%	0.1%	-2.6%	0.0%	0.8%	-2.3%

Sales = XHeat + XCool + XOther + Binaries + ARMA

General Demand Input Variables – WtXHeat

	Intensities	Econ + Struct	Regression		
	Heating	HeatUse Variable	Coeff	Scaling Factor	Total XHeat
2019	412,365	1.20	0.696	1	345,122
2029	366,018	1.29	0.696	1	329,680
Change	-12.1%	7.6%	0.0%	0.0%	-4.5%

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 [($Heat_{2029}$-$Heat_{2019}$) x HeatUse x Coeff x Scaling]/$WtXHeat_{2019}$

General Demand Input Variables – XCool

	Intensities	Econ + Struct	Regression		
	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total Xcool
2019	330,451	1.41	0.260	0.370	44,887
2029	324,033	1.52	0.260	0.370	47,369
Change	-14.3%	7.6%	0.0%	0.0%	5.5%

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
2019	168,746	16,008	24,555	304,083	497,421	128,871	485,345	13.35	1.009	0.090	1,969,713
2029	136,023	14,247	22,289	275,987	388,239	108,952	515,549	14.36	1.009	0.090	1,905,996
Change	-2.2%	-0.1%	-0.2%	-1.9%	-7.2%	-1.3%	2.0%	7.6%	0.0%	0.0%	-3.2%

XOther = (Ventilation + Water Heat + Cooking + Refrigeration + Lighting + Office + Miscelaneous) x OtherUseVariable x Coeff x Scaling Factor

Industrial Econometric Model Details

Small Industrial model

$SmlInd\_Sales_m = BinJan_m + BinFeb_m + BinMar_m + BinApr_m + BinMay_m + BinJun_m + BinJul_m + BinAug_m + BinSep_m + BinOct_m + BinNov_m + BinDec_m + BinJul08 + BinAug08 + BinAft17 + b1 \times GDP$

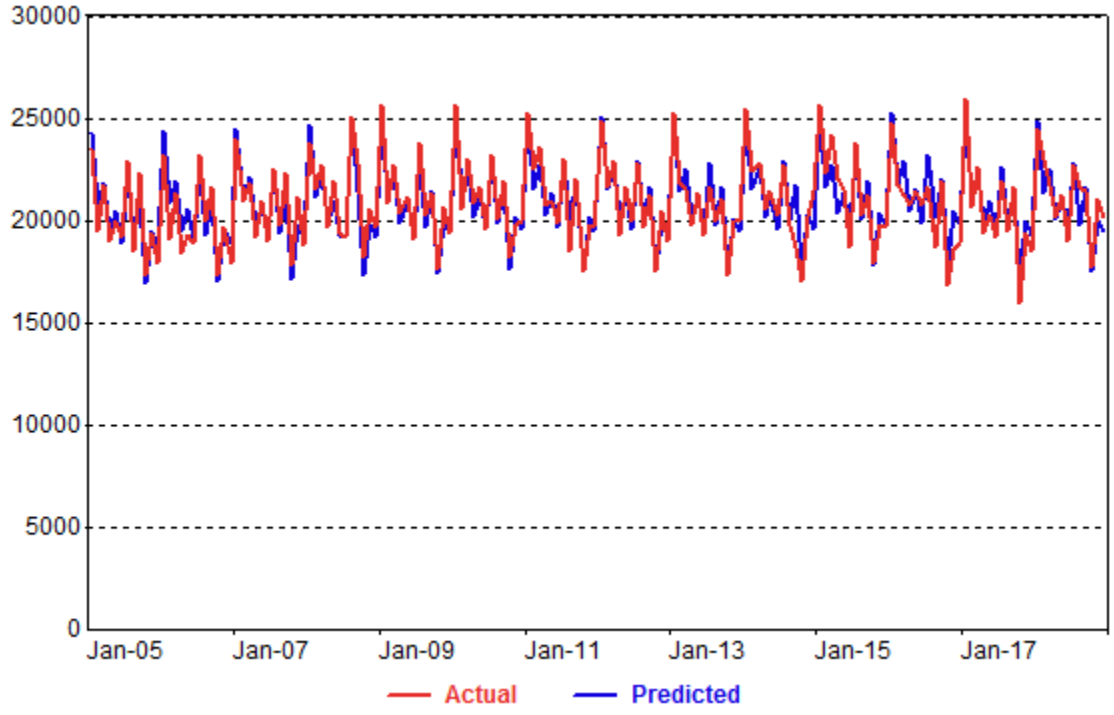
Binary variables for July and August 2008 were added to the model in order to isolate an anomaly in the billing data during this time. Class sales are lower than normal in July and higher than normal in August because billing which was supposed to occur on the last day of July was delayed and actually occurred on the first day of August. A binary was also added for 2017 as the model overestimated the most recent year of sales. As discussed in Section 4.0, a historic period of 2005 – 2018 was used to improve model fit.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	13266.167	2474.615	5.361	0.00%
MBin.Feb	9758.628	2476.479	3.941	0.01%
MBin.Mar	10858.567	2478.342	4.381	0.00%
MBin.Apr	8419.392	2480.206	3.395	0.09%
MBin.May	9472.188	2482.069	3.816	0.02%
MBin.Jun	7832.359	2483.933	3.153	0.20%
MBin.Jul	11154.332	2488.403	4.483	0.00%
MBin.Aug	8110.544	2490.365	3.257	0.14%
MBin.Sep	9921.100	2489.451	3.985	0.01%
MBin.Oct	5818.135	2491.279	2.335	2.08%
MBin.Nov	8385.029	2493.106	3.363	0.10%
MBin.Dec	7722.800	2494.934	3.095	0.23%
MBin.Jul08	-3446.989	820.617	-4.200	0.00%
MBin.Aug08	5422.102	820.680	6.607	0.00%
MBin.Aft17	-697.189	226.233	-3.082	0.25%
MEcon.GDPIdx	11026.329	2354.155	4.684	0.00%

Small Industrial Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	168
Deg. of Freedom for Error	152
R-Squared	0.864
Adjusted R-Squared	0.851
AIC	13.434
BIC	13.732
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,350.86
Model Sum of Squares	604,247,555.03
Sum of Squared Errors	94,845,337.60
Mean Squared Error	623,982.48
Std. Error of Regression	789.93
Mean Abs. Dev. (MAD)	568.42
Mean Abs. % Err. (MAPE)	2.76%
Durbin-Watson Statistic	1.525
Durbin-H Statistic	#NA
Ljung-Box Statistic	59.08
Prob (Ljung-Box)	0.0001
Skewness	-0.435
Kurtosis	4.210
Jarque-Bera	15.532
Prob (Jarque-Bera)	0.0004

Small Industrial Model Fit



Medium Industrial Model

$$MedInd\_Sales_m = BinJan_m + BinFeb_m + BinMar_m + BinApr_m + BinMay_m + BinJun_m + BinJul_m + BinAug_m + BinSep_m + BinOct_m + BinNov_m + BinDec_m + BinJul08 + BinAug08 + b1 \times ManEmp + AR(1)$$

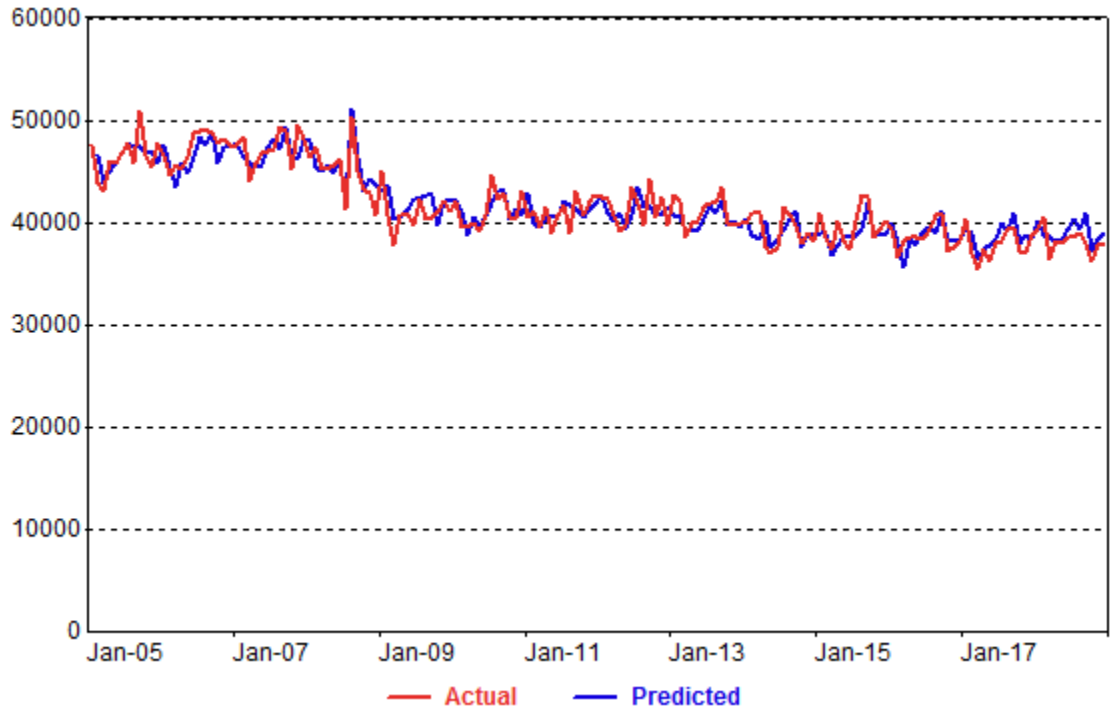
Binary variables for July and August 2008 were added to isolate an anomaly in the billing data during this period. Class sales are lower than normal in July and higher than normal in August because billing which was supposed to occur on the last day of July was delayed and actually occurred on the first day of August. An AR variable was added to improve model results. As discussed in Section 4.0, a historic period of 2005 – 2018 was used to improve model fit.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	17947.121	2010.459	8.927	0.00%
MBin.Feb	16762.948	2022.874	8.287	0.00%
MBin.Mar	15296.029	2027.929	7.543	0.00%
MBin.Apr	16285.075	2028.725	8.027	0.00%
MBin.May	16057.486	2027.181	7.921	0.00%
MBin.Jun	17082.943	2024.379	8.439	0.00%
MBin.Jul	18235.241	2016.728	9.042	0.00%
MBin.Aug	17920.584	2014.315	8.897	0.00%
MBin.Sep	18903.354	2015.255	9.380	0.00%
MBin.Oct	16385.886	2012.237	8.143	0.00%
MBin.Nov	17197.431	2009.168	8.559	0.00%
MBin.Dec	17251.425	2006.073	8.600	0.00%
MBin.Aug08	-5262.709	1483.154	-3.548	0.05%
MBin.Jul08	5062.896	1482.394	3.415	0.08%
MEcon.ManEmpIdx	29737.890	2376.599	12.513	0.00%
AR(1)	0.524	0.070	7.541	0.00%

Medium Industrial Model Statistics

Model Statistics	
Iterations	8
Adjusted Observations	167
Deg. of Freedom for Error	151
R-Squared	0.847
Adjusted R-Squared	0.832
AIC	14.679
BIC	14.977
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,446.64
Model Sum of Squares	1,814,648,983.43
Sum of Squared Errors	326,884,762.41
Mean Squared Error	2,164,799.75
Std. Error of Regression	1,471.33
Mean Abs. Dev. (MAD)	1,106.53
Mean Abs. % Err. (MAPE)	2.66%
Durbin-Watson Statistic	2.200
Durbin-H Statistic	#NA
Ljung-Box Statistic	76.07
Prob (Ljung-Box)	0.0000
Skewness	0.158
Kurtosis	2.640
Jarque-Bera	1.597
Prob (Jarque-Bera)	0.4500

Medium Industrial Model Fit



Combined Model for Commercial and Industrial DSM Coefficient

$NonResSales_m = b1 \times NonResEESavings_m + b2 \times GenWtXHeat_m + b3 \times GenWtXCool_m + b3 \times GenWtXOther_m + BinYr11to14_m + BinDec_m + b4 \times NonResCustomers_m$

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 similar to those used in the underlying commercial and industrial models.

Variable	Coefficient	StdErr	T-Stat	P-Value
MSales.EESavings	-0.623	0.148	-4.201	0.01%
MStructGen.WtXHeat	0.619	0.059	10.559	0.00%
MStructGen.WtXCool	0.900	0.048	18.735	0.00%
MStructGen.WtXOther	0.975	0.359	2.718	0.76%
MBin.Yr11to14	9726.136	2783.344	3.494	0.07%
MBin.Dec	-17918.743	3747.530	-4.781	0.00%
MSales.NonResCusts	5.268	1.636	3.220	0.17%

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. When compared with the 2018 model, the significance of this variable has improved (P-value of 0.01% vs 3.26%).

Combined Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	113
R-Squared	0.818
Adjusted R-Squared	0.808
AIC	18.683
BIC	18.846
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,284.26
Model Sum of Squares	62,360,366,492.09
Sum of Squared Errors	13,882,459,764.26
Mean Squared Error	122,853,626.23
Std. Error of Regression	11,083.94
Mean Abs. Dev. (MAD)	8,908.34
Mean Abs. % Err. (MAPE)	2.25%
Durbin-Watson Statistic	1.665
Durbin-H Statistic	#NA
Ljung-Box Statistic	32.25
Prob (Ljung-Box)	0.1210
Skewness	0.384
Kurtosis	2.942
Jarque-Bera	2.965
Prob (Jarque-Bera)	0.2271

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:

$$Peak_m = b1 \times HeatVar_m + b2 \times CoolVar_m + b3 \times BaseVar_m$$

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:

$$HeatLoad_m = B1 \times ResXHeat_m + C1 \times SmlGSXHeat_m + D1 \times GSXHeat_m$$

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 B_2, C_2, and D_2 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 indexed to 2005 and interacted with peak-day *HDD* and *CDD* creating the variables $HeatIdx_m$ and $CoolIdx_m$. This interaction 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:

$$HeatVar_m = HeatIdx_m \times PkHDD_m$$
$$CoolVar_m = CoolIdx_m \times PkCDD_m$$

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 also $SmlOther_m$ 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:

$$OtherAvgMW_m = OtherLoad_m / Days_m / 24$$

Variable mBin.Feb10 is used to correct an anomaly in the historic data, and mBin.AftJun18 is a launch variable that helps to align the Peak Forecast with peak values seen in February 2019 actuals (firm peak of 1,954 MW occurring at -15 degrees Celsius at 8am, it would not include the typical lighting load seen in an evening peak).

Variable	Coefficient	StdErr	T-Stat	P-Value
mVars.Cool_Var	1.752	0.709	2.472	1.51%
mVars.Heat_Var	1.537	0.082	18.655	0.00%
mVars.Jan_Other	1.236	0.068	18.283	0.00%
mVars.Feb_Other	1.282	0.071	17.938	0.00%
mVars.Mar_Other	1.410	0.056	25.361	0.00%
mVars.Apr_Other	1.568	0.036	44.121	0.00%
mVars.May_Other	1.557	0.024	65.096	0.00%
mVars.Jun_Other	1.676	0.021	80.646	0.00%
mVars.Jul_Other	1.675	0.024	70.150	0.00%
mVars.Aug_Other	1.560	0.026	59.384	0.00%
mVars.Sep_Other	1.499	0.020	75.652	0.00%
mVars.Oct_Other	1.561	0.020	76.279	0.00%
mVars.Nov_Other	1.709	0.033	51.112	0.00%
mVars.Dec_Other	1.639	0.056	29.410	0.00%
mBin.Feb10	239.055	41.447	5.768	0.00%
mBin.AftJun18	52.988	17.291	3.064	0.28%

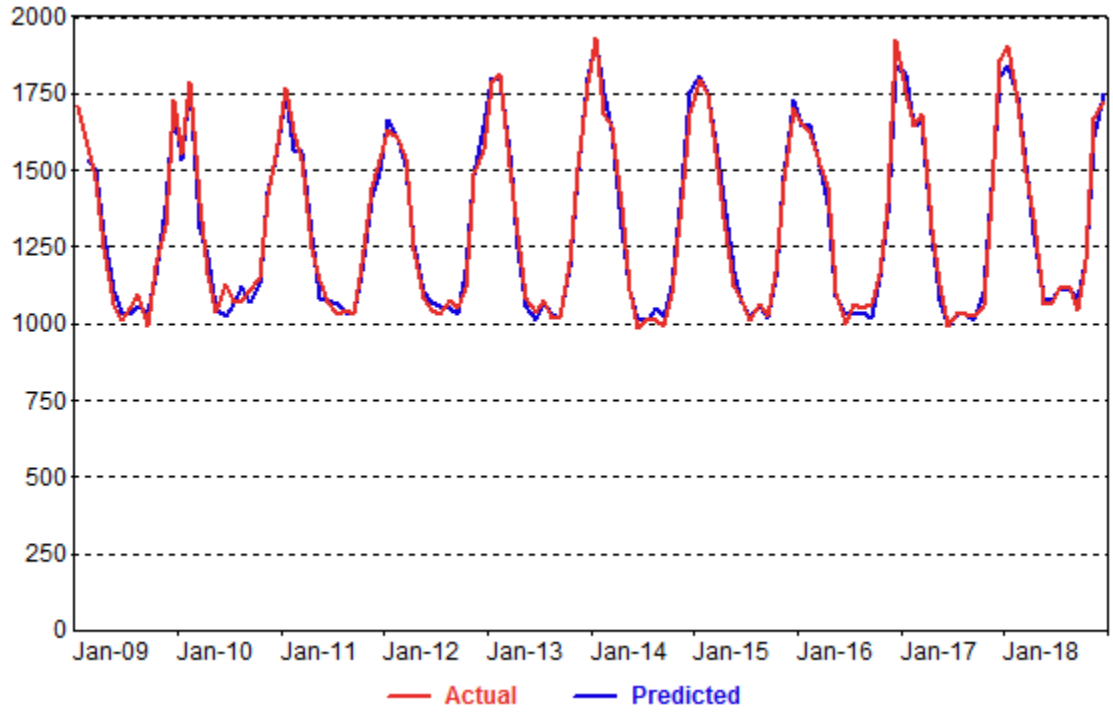
Peak Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	119
Deg. of Freedom for Error	103
R-Squared	0.984
Adjusted R-Squared	0.982
AIC	7.429
BIC	7.803
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-594.89
Model Sum of Squares	9,392,714.58
Sum of Squared Errors	153,189.87
Mean Squared Error	1,487.28
Std. Error of Regression	38.57
Mean Abs. Dev. (MAD)	28.74
Mean Abs. % Err. (MAPE)	2.22%
Durbin-Watson Statistic	2.025
Durbin-H Statistic	#NA
Ljung-Box Statistic	28.68
Prob (Ljung-Box)	0.2326
Skewness	0.239
Kurtosis	2.900
Jarque-Bera	1.180
Prob (Jarque-Bera)	0.5544

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.

Peak Model Fit



Appendix C

Forecast Comparison

Figure C1: Total Nova Scotia Energy Requirement (NSR) with DSM

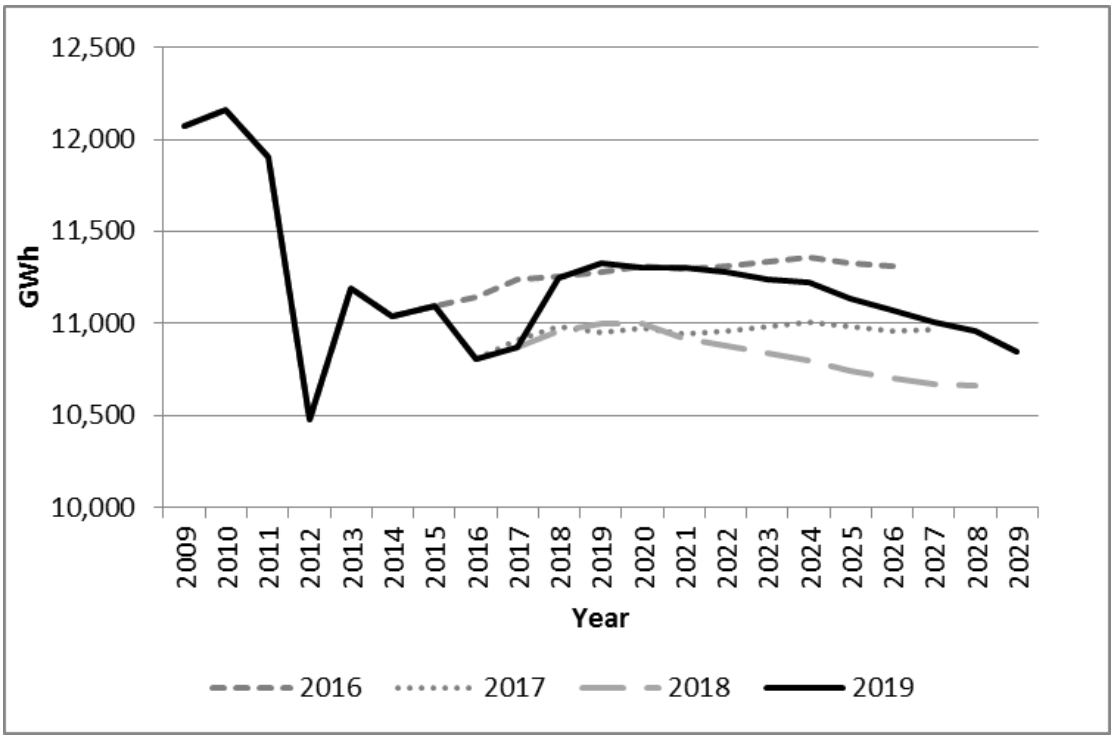


Figure C2: Total Nova Scotia Energy Requirement (NSR) before DSM

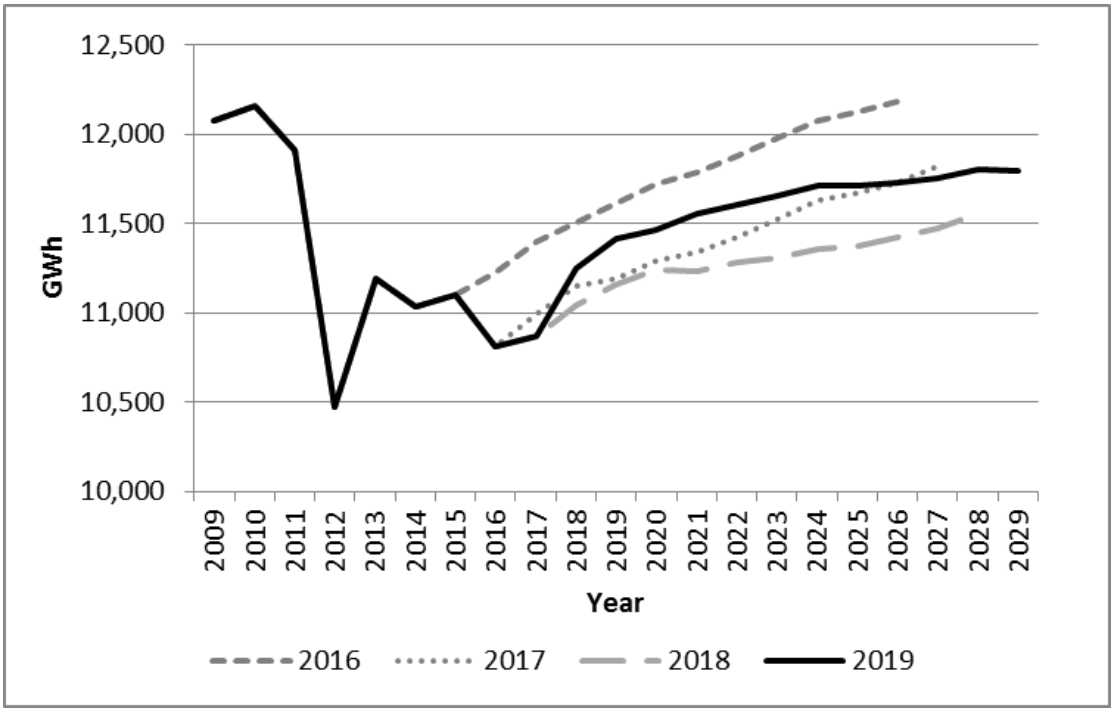


Figure C3: System Peak Demand with DSM

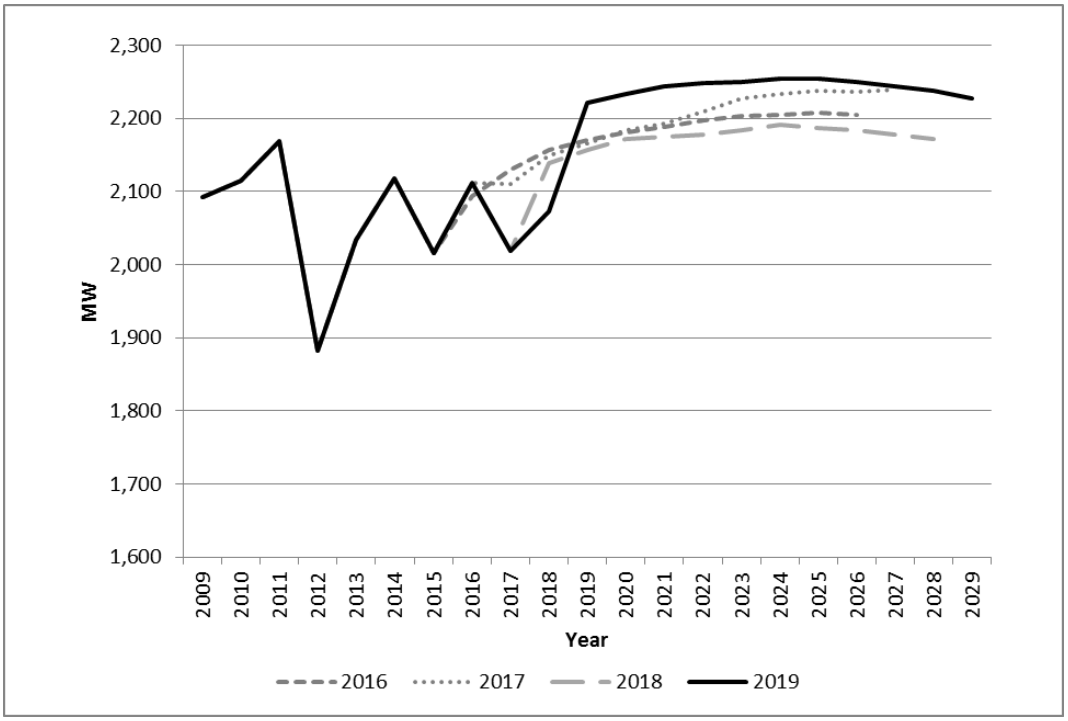


Figure C4: System Peak Demand before DSM

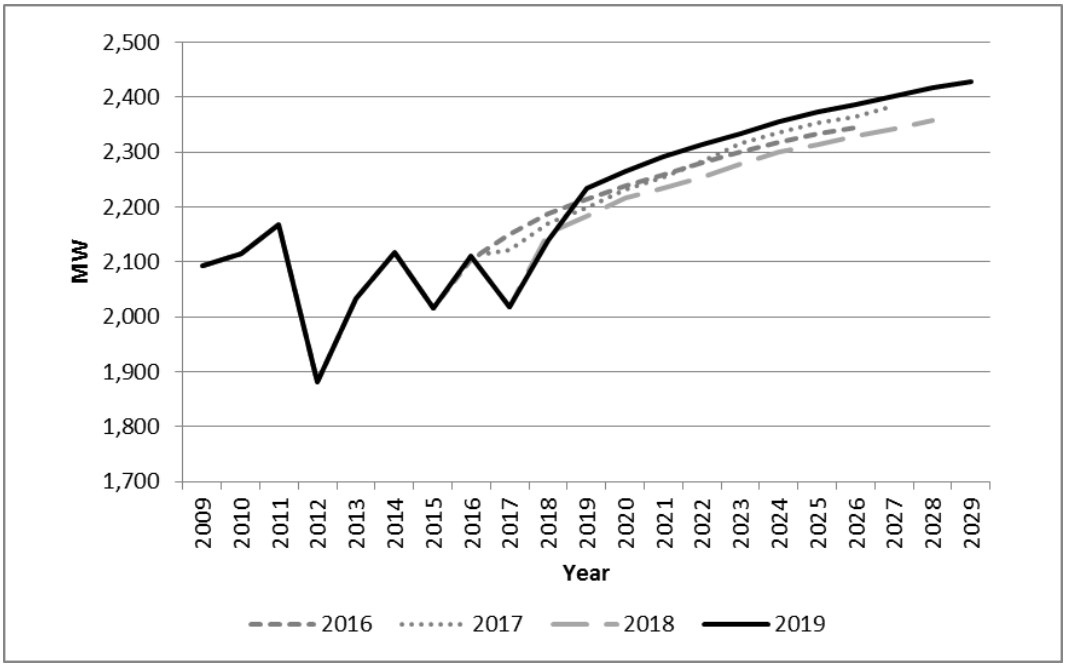


Figure C5: Firm Peak Demand with DSM

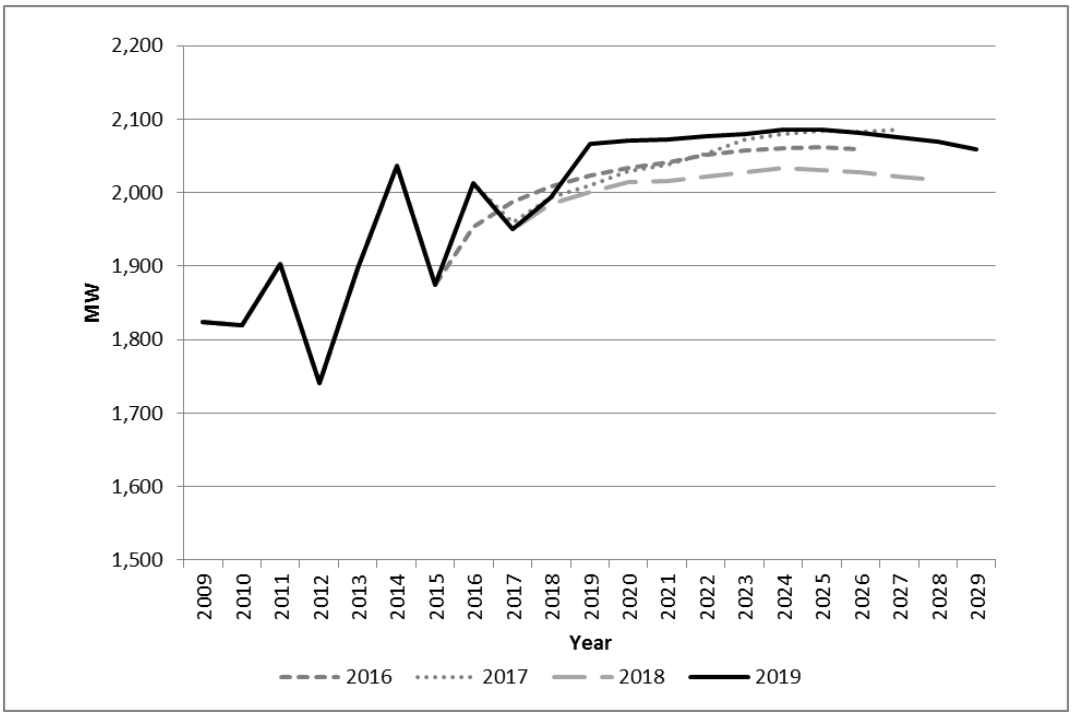
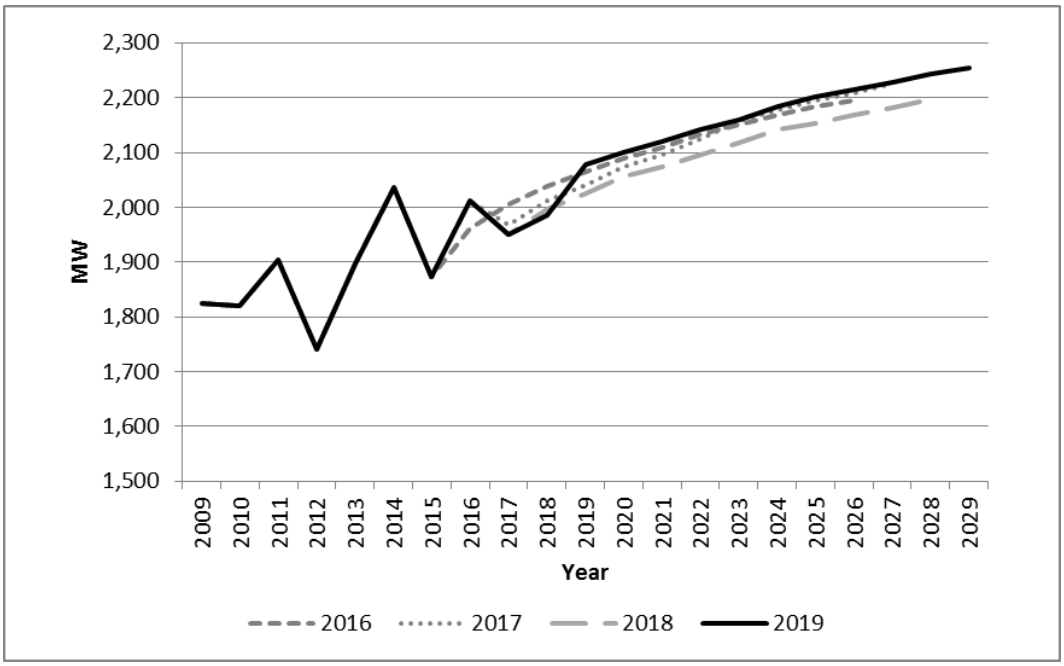


Figure C6: Firm Peak Demand before DSM



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

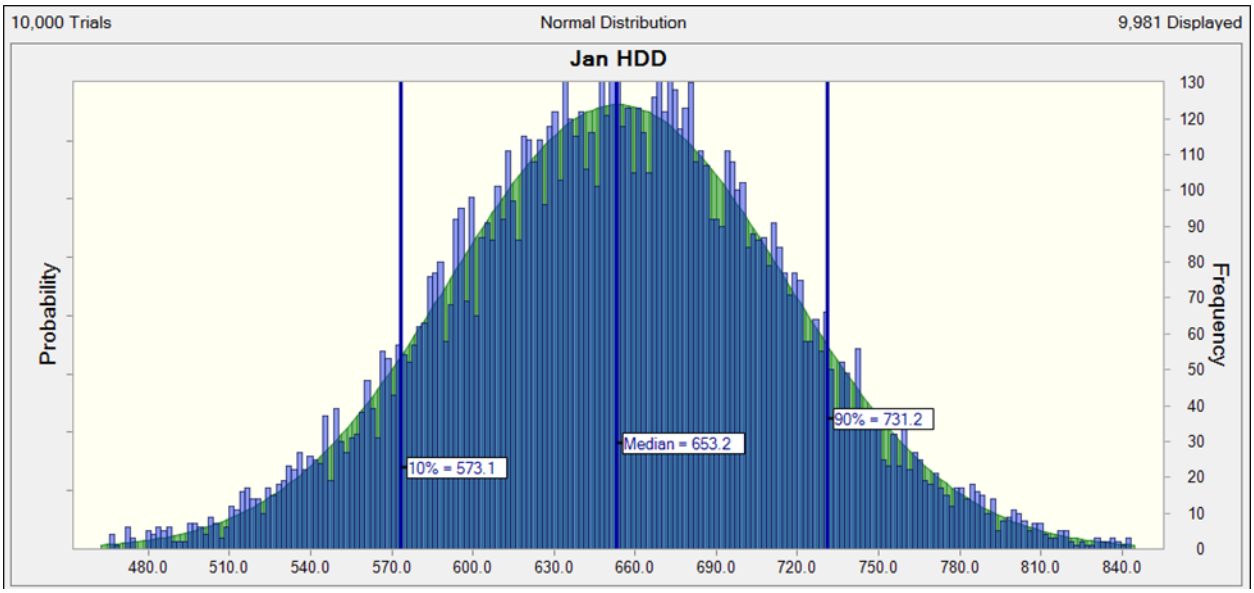
1. Once the deterministic SAE regression models is complete, the regression coefficients are exported into the Monte Carlo tool, called Oracle Crystal Ball (MS Excel add-on).

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 2019 the historical variation of weather (20 years of hourly temperatures expressed in HDDs and CDDs) and economic drivers (as obtained from Conference Board of Canada Economic models) was used.

4. The variation of the weather and economic drivers are treated as Normal distributions (see **Figure D1**).

Figure D1: Distribution of January HDD



5. Since there are high and low DSM scenarios provided by the 2014 IRP, and since a probabilistic DSM forecast would be very difficult to produce given the consistency of prior activity, DSM scenarios have been added outside the Monte Carlo simulation.

6. Oracle's Crystal Ball runs about 10,000 trials, taking a random set of numbers from the aforementioned 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.

7. 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.

8. 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)

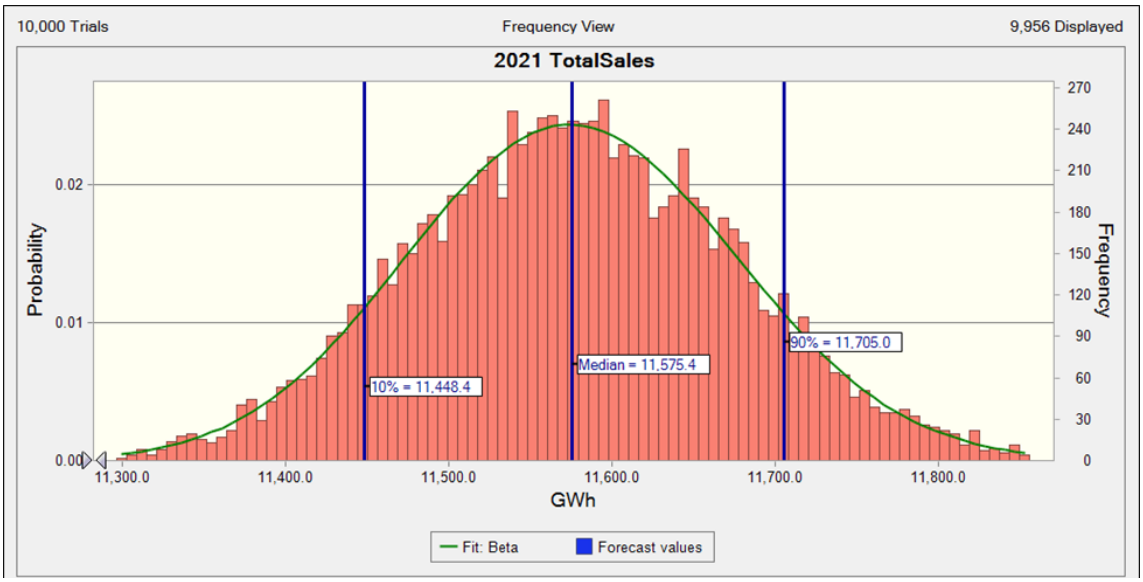
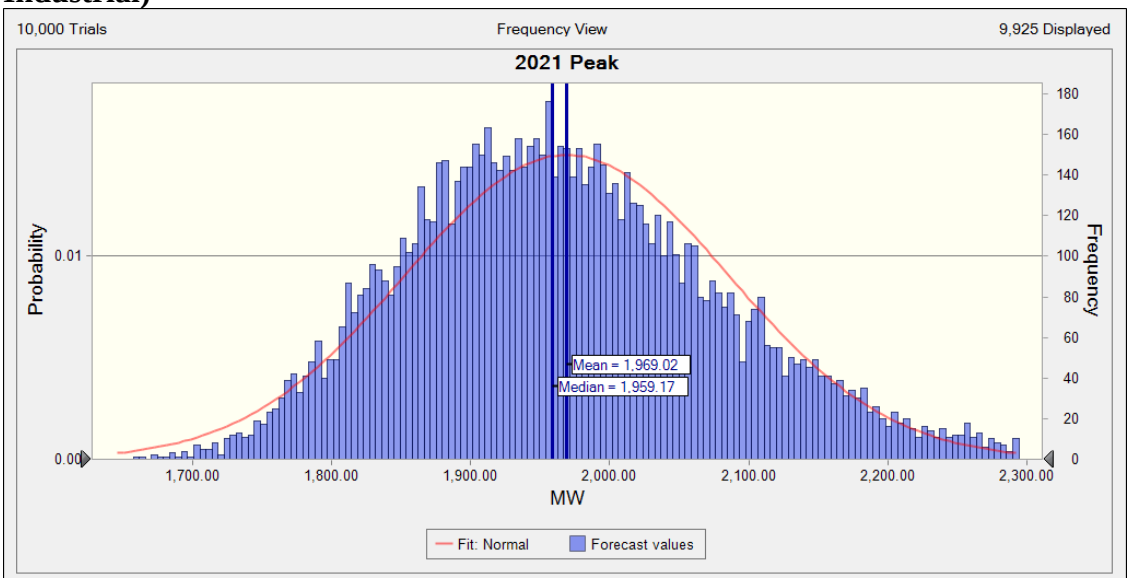
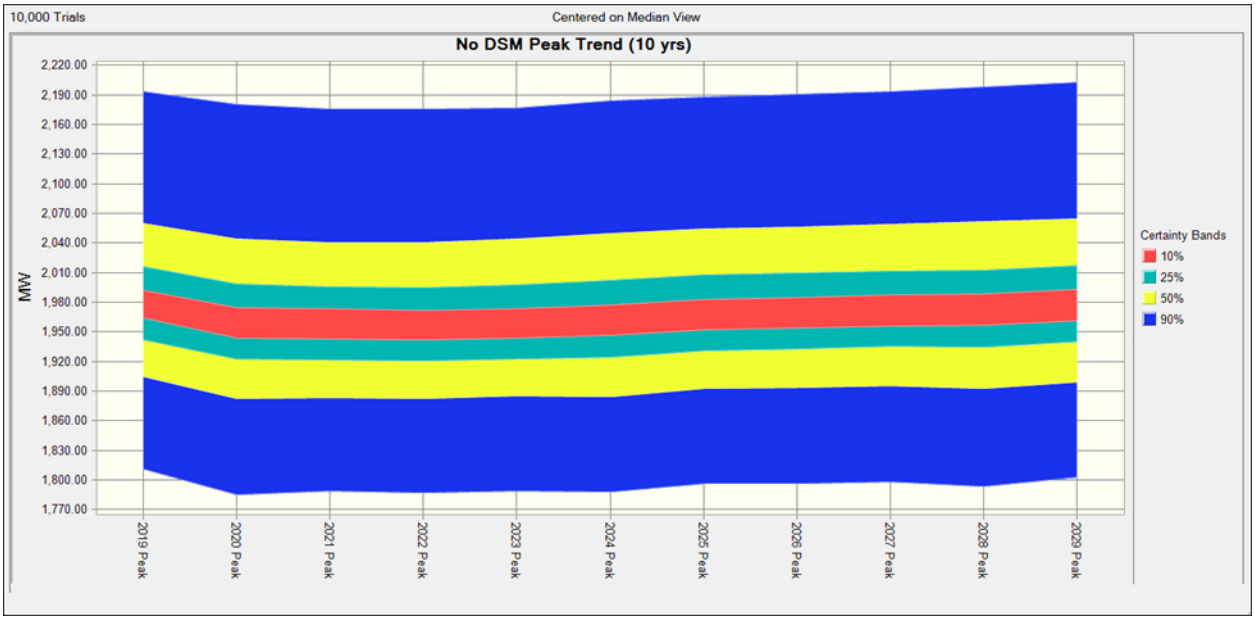


Figure D3: Distribution of Peak (Residential, Commercial and Small and Medium Industrial)



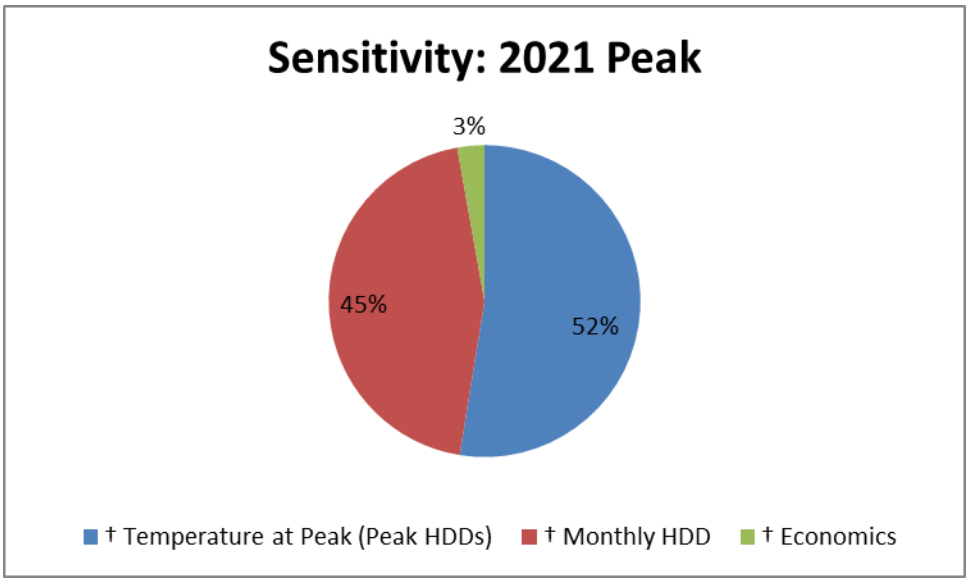
9. From these annual forecast distributions the various probabilistic forecasts can be obtained as well as sensitivity diagrams that show the relative impact of the variables in each year. In **Figure D4** the probabilities of peak forecasts (before DSM) around the median are shown. The area contained 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 gained more importance in 2019 as year-long residential heating had an impact on sales, and therefore, some of that impact (sensitive to monthly variations) 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 start becoming more dominant. This is mainly due to the compounding effect of economics over time, as opposed to weather which will only impact a particular year.

Figure D6 Sensitivity of Energy Forecast (2021)

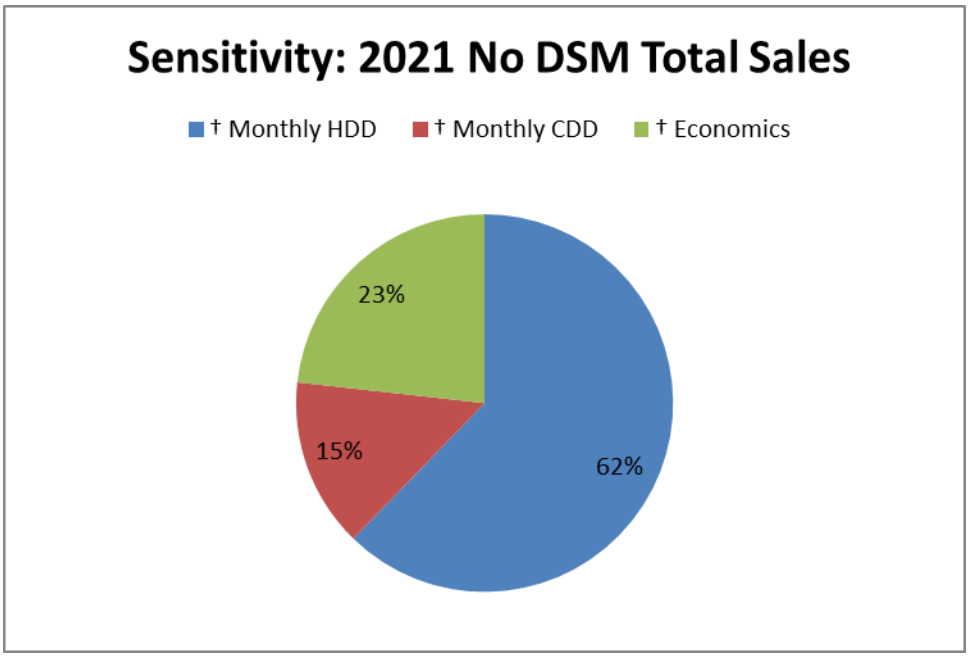
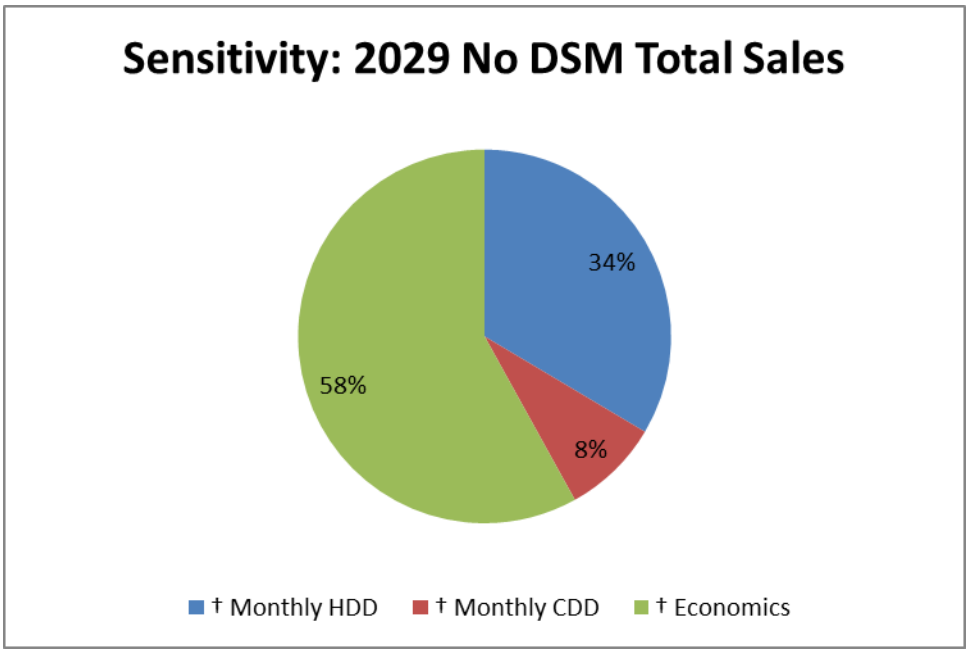


Figure D7 Sensitivity of Energy Forecast (2029)



In terms of relative magnitude of the sensitivities, with the exception of the weather impact on peak, DSM and PHP far outweigh the potential impact from likely changes related to the economy, weather, or underlying end uses. **Figure D8** shows the relative impact of these items.

Figure D8 Relative Impact of Inputs

Item	2021 Energy (GWh)	2021 Peak (MW)	2029 Energy (GWh)	2029 Peak (MW)
Heat Pump Programs	76	46	167	111
EVs	4	1	147	30(1)
Solar PV	-15	0	-178	0
DSM (base case)	-391	-76	-1499	-311
DSM (high case)	-548	-124	-2145	-475
PHP	[redacted]			
Weather/Economics P10/P90	+/-318	+/-297	+/-440	+/-312

(1) This assumes peak mitigation, without mitigation this is estimated to be around 65 MW.

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 2020-2022 Base Cost of Fuel Reset:

- Price strip for Henry Hub from NYMEX
- Algonquin CityGate, AECO, and Dawn Platts basis from [redacted]
- Price strip for WTI from NYMEX
- Price strip for LFO from NYMEX
- CoalDesk, LLC Price Forecast
- Clarksons Platou Futures Limited
- Jacobs' Consultancy "PACE" Index
- Power from [redacted]

Requirement:

Provide the latest detailed fuel forecast for test year in the same format and level of detail as the 2013 rate case (P-893). Identify the date and price of the forward price curve data used for HFO and natural gas forecasts. Also provide the Plexos runs used to compute the fuel and purchased power costs for the test year.

Submission:

Please refer to Confidential Attachments 1, 2, and 3 for the detailed fuel forecasts for 2020, 2021, and 2022, respectively.

Please refer to Confidential Attachment 4 for the PLEXOS runs.

Please refer to Confidential Attachments 5 for the 2019 BCF Refresh fuel forecast denoting annual fuel costs of $653.7M. Note that the 2019 BCF Compliance forecast was ordered to be between $671.1M and $731.8M with the higher amount recognizing the election of the Consumer Advocate and Small Business Advocate to assign a January 1, 2020 start date to the delivery of Maritime Link Nova Scotia Block energy. As a result, high level adjustments were made to the refresh forecast, meaning detailed fuel cost information is not available for the final compliance figures.

The date for the natural gas and HFO forwards is May 17, 2019.

Appendix A OE-01A Attachment 1 has been removed due to confidentiality.

Appendix A OE-01A Attachment 2 has been removed due to confidentiality.

Appendix A OE-01A Attachment 3 has been removed due to confidentiality.

Appendix A OE-01A Attachment 4 has been removed due to confidentiality.

Appendix A OE-01A Attachment 5 has been removed due to confidentiality.

Requirement:

Provide the current forecast of fuel burn levels for each plant for the current year and the test year. Include projections for each fuel type, MMBtu consumed, % sulphur in the fuel, tonnes of SO_2 emitted, $ (dollars) for each fuel type, and $/MMBtu for each fuel type. Provide additional information to indicate the future solid fuel requirements for 3 years beyond the test year.

Submission:

For the 2019 BCF compliance forecast, please refer to Confidential Attachment OE-01A Attachment 5.

For the 2019 BCF Compliance filing year, the forecast for tonnes of SO_2 emission is 55,500 ktonnes.

For 2020-2022, NS Power forecasts it will emit 60,900, 45,000 and 45,000 ktonnes of SO_2 respectively.

Please refer to OE-01A Confidential Attachment 1-3 (summary and plant Station Fuel Cost pages) for test year fuel burn levels.

Please refer to OP-07 for the percent of sulphur in the fuels.

Please refer to OE-01E Confidential Attachment 1 for future solid fuel requirements.

Requirement:

Provide fuel costs per MWh for the past year (actual), current year (forecast) and test year. Provide the substantiating detail for the fuel costs for each of these years; such detail should include all of the individual fuel cost components as follows, on a cost per MWh basis, and a total dollar basis:

(i) Costs for import coal
(ii) Costs for domestic coal
(iii) Costs for petcoke
(iv) Costs for oil
(v) Costs for natural gas used
(vi) Costs for biomass
(vii) Credits from the sale of natural gas
(viii) Costs for purchased power, and
(ix) Solid fuel transportation costs

Submission:

Please refer to Confidential Attachments 1 and 2.

Appendix A OE-01C Attachment 1 has been removed due to confidentiality.

Appendix A OE-01C Attachment 2 has been removed due to confidentiality.

Requirement:

Provide, for the last two years, the history of fossil fuel use, by fuel type, by fuel qualities, by MMBtu contribution, and by cost of fuel.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01D Attachment 1 has been removed due to confidentiality.

Requirement:

Provide a summary of the current fuel contract status for each fuel (domestic coal, petcoke, low sulphur coal, mid sulphur coal, high sulphur coal, heavy fuel oil, natural gas, biomass), and by fuel supplier, for the next five years. Show for each fuel both the amount of fuel already under contract for each year, as well as the balance of open or un-contracted fuel for each year. Include the sulphur content of the fuels as appropriate.

Submission:

Please refer to Confidential Attachment 1.

There are currently no HFO or natural gas contracts for 2020-2024.

Appendix A OE-01E Attachment 1 has been removed due to confidentiality.

Requirement:

Provide a copy of the latest Fuel Manual.

Submission:

This confidential document is available for viewing on NS Power's secure FTP FAM Data Cart site.

Requirement:

Provide the test year monthly quantities of fossil fuels projected to replace the natural gas under contract that is assumed to be sold, rather than used by NS Power. Provide the calculations that support NS Power's fuel cost savings of buying these replacement fuels, as compared to NS Power using the quantities of natural gas under contract using Plexos reports.

Submission:

This Standardized Filing Component was originally completed prior to 2010 when NS Power had a long-term gas supply agreement in place and gas was often resold and other, more economic fuels, were consumed instead. NS Power no longer has excess gas supply that is sold rather than used on a planned basis. This practice ceased with the expiry of a long-term supply agreement in November 2010.

Requirement:

For the test year forecast (proposed rates) provide the solid fuel commodity costs, transportation costs to move the solid fuel to Nova Scotia, foreign exchange, and the costs to move the solid fuels within Nova Scotia to each of the generating stations. Show each cost component separately for the various solid fuels used at each NS Power generating plant. Include in the response a calculation of the fuel price in $/MMBtu for each component of the fuel price, so that the final plant-delivered cost is that used as input to the Plexos run. Include sources used to derive the requested data, and the date the forecast was prepared.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01H Attachment 1 has been removed due to confidentiality.

Requirement:

Provide a summary of the current fuel transportation contract status for each fuel, and by transportation provider, for the next five years. Show for each fuel both the amount of fuel transportation already under contract for each year, as well as the balance of open or un-contracted fuel transportation for each year.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01I Attachment 1 has been removed due to confidentiality.

Requirement:

For each fuel, describe (qualitatively and quantitatively) any hedging program in place, current year hedge positions, and any hedging programs planned for the test year.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01J Attachment 1 has been removed due to confidentiality.

Appendix A OE-01J NS Power Hedging has been removed due to confidentiality.

Requirement:

Provide forecasted price calculations for uncommitted tonnages of solid fuels for the test year.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01K Attachment 1 has been removed due to confidentiality.

Requirement:

Provide data showing how much gas was contracted to be supplied, how much was used (show separately the volumes burned in the combustion turbines at Tufts Cove, and those volumes burned in the steam units and biomass plant), how much was available for sale, and how much was sold, by month for the past year (actual), present year (forecast), and test year.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01L Attachment 1 has been removed due to confidentiality.

Requirement:

Provide information on all actual fuel and power-related Affiliate Transactions for the last two years.

Submission:

2017 Fuel and Power Affiliate Transactions

Provider	Receiver	2017 USD	2017 CAD	Description
Emera Energy	NS Power	[redacted]	[redacted]	Gas purchases
Emera Energy	NS Power	[redacted]	[redacted]	Power sale fees
Emera Energy	NS Power	[redacted]	[redacted]	Power sale fees
Emera Energy	NS Power	[redacted]	[redacted]	REC Transaction fees
Emera Energy	NS Power	[redacted]	[redacted]	REC Transaction fees
Brooklyn Power	NS Power	[redacted]	[redacted]	Power purchases
NSPML	NS Power	[redacted]	[redacted]	Power purchases
NS Power	Emera Energy	[redacted]	[redacted]	Gas sales
NS Power	Emera Energy	[redacted]	[redacted]	Imbalance Penalties
NS Power	Emera Energy	[redacted]	[redacted]	Power Sales
NS Power	Emera Energy	[redacted]	[redacted]	Renewable Energy Credit (REC) Sales

2018 Fuel and Power Affiliate Transactions

Provider	Receiver	2018 USD[1]	2018 CAD	Description
Brooklyn Power	NS Power	[redacted]	[redacted]	Power purchases
Emera Energy	NS Power	[redacted]	[redacted]	Gas purchases
Emera Energy	NS Power	[redacted]	[redacted]	Power purchases
Emera Energy	NS Power	[redacted]	[redacted]	Power purchase fees
NS Power	Emera Energy	[redacted]	[redacted]	Power sales fees
Emera Energy	NS Power	[redacted]	[redacted]	Renewable Energy Credit fees
NSPML	NS Power	[redacted]	[redacted]	Power purchases
NS Power	Emera Energy	[redacted]	[redacted]	Gas sales
NS Power	Emera Energy	[redacted]	[redacted]	Power sales
NS Power	Emera Energy	[redacted]	[redacted]	Renewable Energy Credits (REC) Sales
NS Power	NSPML	[redacted]	[redacted]	Power sales

[1] USD purchases have been converted to CAD dollars, consistent with the 2018 Affiliate Code Annual Report.

Requirement:

Provide a copy of the latest Fuel Supply or Transportation Studies conducted since the last rate filing.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01N Attachment 1 has been removed due to confidentiality.

Requirement:

Provide details on Import and Export Power Calculations over the standard financial timeframes.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01O Attachment 1 has been removed due to confidentiality.

Appendix A OE-01P has been removed due to confidentiality.

Requirement:

Provide a table showing the calculation of the cost and recoveries for Fuel for Resale for the current year, test year, and the most recent five years of data. In the table, address each of the key elements in the calculation.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-01Q Attachment 1 has been removed due to confidentiality.

Requirement:

Provide information about foreign exchange hedging.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OE-12 Attachment 1 has been removed due to confidentiality.

Requirement:

Provide test year Power Production maintenance schedule of all units including hydro, biomass and tidal, submitted as a Gantt chart.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OP-05 Attachment 1 has been removed due to confidentiality.

Requirement:

Provide a breakdown of generating units by type showing in-service date, net capacity, fuel type, heat rate, contribution to system peak, contributions towards annual energy (include IPP and purchased power).

Submission:

Please refer to Partially Confidential Attachment 1 and Confidential Attachment 2.

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2020 (With PHP)

	Fuel Type	In Service Year	Firm Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2020 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	78	[redacted]	5.2
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	9.4
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	125.1
Trenton 5	Coal / Petcoke	1969	150	[redacted]	215.6
Trenton 6	Coal / Petcoke	1991	154	[redacted]	404.1
Pt. Tupper 2	Coal / Petcoke	1973	150	[redacted]	1128.7
		Coal Conv. 1987			
Lingan 1	Coal / Petcoke	1979	153	[redacted]	902.7
Lingan 2	Coal / Petcoke	1980	153	[redacted]	280.9
Lingan 3	Coal / Petcoke	1983	153	[redacted]	875.0
Lingan 4	Coal / Petcoke	1984	153	[redacted]	855.6
Pt. Aconi 1	Petcoke / Coal	1994	168	[redacted]	1116.7
Point Tupper Biomass	Biomass	2013	43	[redacted]	188.3
		Total Thermal	**1595**	[redacted]	**6,107.4**
Combustion Turbines					
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2010	144	[redacted]	495.4
Tusket 1	Light Oil	1971	0	[redacted]	0.0
Burnside 1	Light Oil	1976	33	[redacted]	1.0
Burnside 2	Light Oil	1976	33	[redacted]	0.8
Burnside 3	Light Oil	1976	33	[redacted]	0.5
Burnside 4	Light Oil	1976	33	[redacted]	0.7
Victoria Junction 1	Light Oil	1976	33	[redacted]	0.09
Victoria Junction 2	Light Oil	1975	33	[redacted]	0.09
		Total CT's	**342**		**498.5**

Hydro Systems	**Installed Capacity (MW)**		**Firm Capacity* (MW)**	**Energy (GWh)**
Wreck Cove		1978	212	299.0
Annapolis Tidal		1984	3.5	23.7
Other Hydro			161.6	637.8
Wind Systems				
Digby	30		5.1	120.3
Nuttby Mountain	50.6		8.6	143.4
Sable	13.8		2.3	44.9
South Canoe	102		17.3	312.2
Total Hydro/ Wind			**410**	**1581.2**

Independent Power Producers	**Installed Capacity (MW)**	**Firm Capacity (MW)**	**Energy (GWh)**
Independent Power Producers - Other	30.4	33.9	97.8
Independent Power Producers - Wind	247.1	41.7	750.0
COMFIT	160.6	25.6	578.2

Imported Power		**Energy (GWh)**
NB Imports		479.2
Maritime Link - Surplus		584.4
Maritime Link - NS Block	153	520.3
Maritime Link - Supplemental Block		105.0
		1688.9
Exported Power		1.9
NSPI Total Firm Capacity (MW)	**2449**	**Total Purchases** **3113.0**
		Total Annual Energy **11,300**

* Firm capacity contribution of 17% is applied to NRIS interconnected wind resources, consistent with 2014 IRP capacity assumptions

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2021 (With PHP)

	Fuel Type	In Service Year	Firm Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2021 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	78	[redacted]	23.5
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	6.8
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	34.9
Trenton 5	Coal / Petcoke	1969	150	[redacted]	188.5
Trenton 6	Coal / Petcoke	1991	154	[redacted]	251.6
Pt. Tupper 2	Coal / Petcoke	1973	150	[redacted]	763.5
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	576.0
Lingan 2	Coal / Petcoke	1980		[redacted]	-
Lingan 3	Coal / Petcoke	1983	153	[redacted]	652.4
Lingan 4	Coal / Petcoke	1984	153	[redacted]	645.7
Pt. Aconi 1	Petcoke / Coal	1994	168	[redacted]	1083.9
Point Tupper Biomass	Biomass	2013	43	[redacted]	161.6
		Total Thermal	**1442**	[redacted]	**4,388.4**
Combustion Turbines					
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2010	144	[redacted]	481.3
Tusket 1	Light Oil	1971	0	[redacted]	0.0
Burnside 1	Light Oil	1976	33	[redacted]	1.1
Burnside 2	Light Oil	1976	33	[redacted]	1.2
Burnside 3	Light Oil	1976	33	[redacted]	1.0
Burnside 4	Light Oil	1976	33	[redacted]	1.1
Victoria Junction 1	Light Oil	1976	33	[redacted]	0.0
Victoria Junction 2	Light Oil	1975	33	[redacted]	0.0
		Total CT's	**342**	[redacted]	**485.8**

Hydro Systems	**Installed Capacity (MW)**		**Firm Capacity* (MW)**	**Energy (GWh)**
Wreck Cove		1978	212	292.9
Annapolis Tidal		1984	3.5	23.7
Other Hydro			161.6	635.4
Wind Systems				
Digby	30		5.1	120.3
Nuttby Mountain	50.6		8.6	143.4
Sable	13.8		2.3	312.2
South Canoe	102		17.3	44.9
Total Hydro/ Wind			**410**	**1572.7**

Independent Power Producers	**Installed Capacity (MW)**	**Firm Capacity (MW)**	**Energy (GWh)**
Independent Power Producers - Other	31.4	33.9	98.1
Independent Power Producers - Wind	247.1	41.7	750.0
COMFIT	160.6	25.6	578.2

Imported Power			**Energy (GWh)**
NB Imports			451.3
Maritime Link - Surplus			1847.9
Maritime Link - NS Block		153	893.5
Maritime Link - Supplemental Block			240.0
			3432.7
Exported Power			2.4
NSPI Total Firm Capacity (MW)		**2449**	**Total Purchases** **4856.6**
			Total Annual Energy **11,303**

* Firm capacity contribution of 17% is applied to NRIS interconnected wind resources, consistent with 2014 IRP capacity assumptions

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2022 (With PHP)

	Fuel Type	In Service Year	Firm Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2022 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	78	[redacted]	50.8
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	7.5
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	60.9
Trenton 5	Coal / Petcoke	1969	150	[redacted]	209.1
Trenton 6	Coal / Petcoke	1991	154	[redacted]	244.9
Pt. Tupper 2	Coal / Petcoke	1973	150	[redacted]	714.3
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	677.5
Lingan 2	Coal / Petcoke	1980		[redacted]	-
Lingan 3	Coal / Petcoke	1983	153	[redacted]	572.1
Lingan 4	Coal / Petcoke	1984	153	[redacted]	551.9
Pt. Aconi 1	Petcoke / Coal	1994	168	[redacted]	973.5
Point Tupper Biomass	Biomass	2013	43	[redacted]	141.6
		Total Thermal	**1442**	[redacted]	**4,203.9**
Combustion Turbines				[redacted]	
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2010	144	[redacted]	709.6
Tusket 1	Light Oil	1971	0	[redacted]	0.0
Burnside 1	Light Oil	1976	33	[redacted]	0.38
Burnside 2	Light Oil	1976	33	[redacted]	0.1
Burnside 3	Light Oil	1976	33	[redacted]	0.2
Burnside 4	Light Oil	1976	33	[redacted]	0.2
Victoria Junction 1	Light Oil	1976	33	[redacted]	0.0
Victoria Junction 2	Light Oil	1975	33	[redacted]	0.0
		Total CT's	**342**		**710.5**

Hydro Systems	**Installed Capacity (MW)**		**Firm Capacity* (MW)**	**Energy (GWh)**
Wreck Cove		1978	212	299.1
Annapolis Tidal		1984	3.5	23.7
Other Hydro			161.6	632.4
Wind Systems				
Digby	30		5.1	120.3
Nuttby Mountain	50.6		8.6	143.4
Sable	13.8		2.3	312.2
South Canoe	102		17.3	44.9
Total Hydro/ Wind			**410**	**1575.9**

Independent Power Producers	**Installed Capacity (MW)**	**Firm Capacity (MW)**	**Energy (GWh)**
Independent Power Producers - Other	31.4	33.9	99.4
Independent Power Producers - Wind	247.1	41.7	750.0
COMFIT	160.6	25.6	578.2

Imported Power		**Energy (GWh)**
NB Imports		436.2
Maritime Link - Surplus		1792.1
Maritime Link - NS Block	153	893.5
Maritime Link - Supplemental Block		240.0
		3361.8
Exported Power		1.6
NSPI Total Firm Capacity (MW)	**2449**	**Total Purchases** **4787.8**
		Total Annual Energy **11,278**

* Firm capacity contribution of 17% is applied to NRIS interconnected wind resources, consistent with 2014 IRP capacity assumptions

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2020 (No PHP)

	Fuel Type	In Service Year	Firm Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2020 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	78	[redacted]	6.2
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	3.3
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	71.3
Trenton 5	Coal / Petcoke	1969	150	[redacted]	163.6
Trenton 6	Coal / Petcoke	1991	154	[redacted]	524.0
Pt. Tupper 2	Coal / Petcoke	1973	150	[redacted]	933.9
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	769.7
Lingan 2	Coal / Petcoke	1980	153	[redacted]	256.2
Lingan 3	Coal / Petcoke	1983	153	[redacted]	763.8
Lingan 4	Coal / Petcoke	1984	153	[redacted]	732.9
Pt. Aconi 1	Petcoke / Coal	1994	168	[redacted]	1039.8
Point Tupper Biomass	Biomass	2013	43	[redacted]	93.2
		Total Thermal	**1595**	[redacted]	**5,357.9**
Combustion Turbines					
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2010	144	[redacted]	335.4
Tusket 1	Light Oil	1971	0	[redacted]	0.0
Burnside 1	Light Oil	1976	33	[redacted]	0.3
Burnside 2	Light Oil	1976	33	[redacted]	0.1
Burnside 3	Light Oil	1976	33	[redacted]	0.3
Burnside 4	Light Oil	1976	33	[redacted]	0.4
Victoria Junction 1	Light Oil	1976	33	[redacted]	0.00
Victoria Junction 2	Light Oil	1975	33	[redacted]	0.05
		Total CT's	**342**		**336.6**

Hydro Systems	**Installed Capacity (MW)**		**Firm Capacity* (MW)**	**Energy (GWh)**
Wreck Cove		1978	212	299.0
Annapolis Tidal		1984	3.5	23.7
Other Hydro			161.6	637.9
Wind Systems				
Digby	30		5.1	120.3
Nuttby Mountain	50.6		8.6	143.4
Sable	13.8		2.3	44.9
South Canoe	102		17.3	312.2
Total Hydro/ Wind			**410**	**1581.3**

Independent Power Producers	**Installed Capacity (MW)**	**Firm Capacity (MW)**	**Energy (GWh)**
Independent Power Producers - Other	30.4	33.9	98.0
Independent Power Producers - Wind	247.1	41.7	750.0
COMFIT	160.6	25.6	578.2

Imported Power		**Energy (GWh)**
NB Imports		289.8
Maritime Link - Surplus		568.1
Maritime Link - NS Block	153	520.3
Maritime Link - Supplemental Block		105.0
		1483.2
Exported Power		17.1
NSPI Total Firm Capacity (MW)	**2444**	**Total Purchases** **2892.3**
		Total Annual Energy **10,168**

* Firm capacity contribution of 17% is applied to NRIS interconnected wind resources, consistent with 2014 IRP capacity assumptions

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2021 (No PHP)

	Fuel Type	In Service Year	Firm Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2021 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	78	[redacted]	9.8
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	8.8
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	26.0
Trenton 5	Coal / Petcoke	1969	150	[redacted]	193.1
Trenton 6	Coal / Petcoke	1991	154	[redacted]	239.9
Pt. Tupper 2	Coal / Petcoke	1973	150	[redacted]	690.9
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	568.1
Lingan 2	Coal / Petcoke	1980		[redacted]	-
Lingan 3	Coal / Petcoke	1983	153	[redacted]	616.4
Lingan 4	Coal / Petcoke	1984	153	[redacted]	552.0
Pt. Aconi 1	Petcoke / Coal	1994	168	[redacted]	1021.0
Point Tupper Biomass	Biomass	2013	43	[redacted]	94.8
		Total Thermal	**1442**	[redacted]	**4,020.8**
Combustion Turbines					
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2010	144	[redacted]	312.2
Tusket 1	Light Oil	1971	0	[redacted]	0.0
Burnside 1	Light Oil	1976	33	[redacted]	0.6
Burnside 2	Light Oil	1976	33	[redacted]	0.6
Burnside 3	Light Oil	1976	33	[redacted]	0.8
Burnside 4	Light Oil	1976	33	[redacted]	0.5
Victoria Junction 1	Light Oil	1976	33	[redacted]	0.0
Victoria Junction 2	Light Oil	1975	33	[redacted]	0.0
		Total CT's	**342**	[redacted]	**314.7**

Hydro Systems	**Installed Capacity (MW)**		**Firm Capacity* (MW)**	**Energy (GWh)**
Wreck Cove		1978	212	283.8
Annapolis Tidal		1984	3.5	23.7
Other Hydro			161.6	631.8
Wind Systems				
Digby	30		5.1	120.3
Nuttby Mountain	50.6		8.6	143.4
Sable	13.8		2.3	312.2
South Canoe	102		17.3	44.9
Total Hydro/ Wind			**410**	**1560.1**

Independent Power Producers	**Installed Capacity (MW)**	**Firm Capacity (MW)**	**Energy (GWh)**
Independent Power Producers - Other	31.4	33.9	95.3
Independent Power Producers - Wind	247.1	41.7	750.0
COMFIT	160.6	25.6	578.2

Imported Power			**Energy (GWh)**
NB Imports			185.9
Maritime Link - Surplus			1543.7
Maritime Link - NS Block	153		893.5
Maritime Link - Supplemental Block			240.0
			2863.1
Exported Power			10.8
NSPI Total Firm Capacity (MW)	**2449**	**Total Purchases**	**4275.8**
		Total Annual Energy	**10,171**

* Firm capacity contribution of 17% is applied to NRIS interconnected wind resources, consistent with 2014 IRP capacity assumptions

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Standardized Filing Requirements for Fuel - Generating Units by Type
Year 2022 (No PHP)

	Fuel Type	In Service Year	Firm Capacity (MW)	Net Avg. Heat Rate (Btu/kwh)	2022 Annual Energy (GWh)
Thermal Units					
Tufts Cove 1	Oil / Natural Gas	1965	78	[redacted]	30.1
Tufts Cove 2	Oil / Natural Gas	1972	93	[redacted]	4.5
Tufts Cove 3	Oil / Natural Gas	1976	147	[redacted]	63.6
Trenton 5	Coal / Petcoke	1969	150	[redacted]	173.0
Trenton 6	Coal / Petcoke	1991	154	[redacted]	226.8
Pt. Tupper 2	Coal / Petcoke	1973	150	[redacted]	670.6
		Coal Conv. 1987		[redacted]	
Lingan 1	Coal / Petcoke	1979	153	[redacted]	617.8
Lingan 2	Coal / Petcoke	1980		[redacted]	-
Lingan 3	Coal / Petcoke	1983	153	[redacted]	523.6
Lingan 4	Coal / Petcoke	1984	153	[redacted]	508.8
Pt. Aconi 1	Petcoke / Coal	1994	168	[redacted]	879.3
Point Tupper Biomass	Biomass	2013	43	[redacted]	62.6
		Total Thermal	**1442**	[redacted]	**3,760.8**
Combustion Turbines				[redacted]	
Tufts Cove 4	Natural Gas	2003	49	[redacted]	
Tufts Cove 5	Natural Gas	2005	49	[redacted]	
Tufts Cove 6	Natural Gas Combined Cycle	2010	144	[redacted]	638.7
Tusket 1	Light Oil	1971	0	[redacted]	0.0
Burnside 1	Light Oil	1976	33	[redacted]	0.17
Burnside 2	Light Oil	1976	33	[redacted]	0.0
Burnside 3	Light Oil	1976	33	[redacted]	0.2
Burnside 4	Light Oil	1976	33	[redacted]	0.2
Victoria Junction 1	Light Oil	1976	33	[redacted]	0.0
Victoria Junction 2	Light Oil	1975	33	[redacted]	0.0
		Total CT's	**342**		**639.3**

Hydro Systems	**Installed Capacity (MW)**		**Firm Capacity* (MW)**	**Energy (GWh)**
Wreck Cove		1978	212	299.2
Annapolis Tidal		1984	3.5	23.7
Other Hydro			161.6	631.8
Wind Systems				
Digby	30		5.1	120.3
Nuttby Mountain	50.6		8.6	143.4
Sable	13.8		2.3	312.2
South Canoe	102		17.3	44.9
Total Hydro/ Wind			**410**	**1575.4**

Independent Power Producers	**Installed Capacity (MW)**	**Firm Capacity (MW)**	**Energy (GWh)**
Independent Power Producers - Other	31.4	33.9	99.1
Independent Power Producers - Wind	247.1	41.7	750.0
COMFIT	160.6	25.6	578.2

Imported Power		**Energy (GWh)**
NB Imports		144.4
Maritime Link - Surplus		1476.9
Maritime Link - NS Block	153	893.5
Maritime Link - Supplemental Block		240.0
		2754.8
Exported Power		11.5
NSPI Total Firm Capacity (MW)	**2449**	**Total Purchases** **4170.6**
		Total Annual Energy **10,146**

* Firm capacity contribution of 17% is applied to NRIS interconnected wind resources, consistent with 2014 IRP capacity assumptions

Appendix A OP-06 Attachment 2 has been removed due to confidentiality.

Requirement:

Provide physical, chemical specification sheets for all fuels.

Submission:

Please refer to Attachment 1.

TECHNICAL SPECIFICATION - MID COAL

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	12%	D3302
Free Moisture	-	-	3%	D3302
Ash	7%	-	12%	D3172
Sulphur	-	-	3.5%	D4239
Volatile Matter	35%	30%	-	D3175
Calorific Value (Btu/lb.)	-	12,800	-	D5865
Grindability (HGI)	50-60	50	65	D409
Size (Topsize)	-	-	2” x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Mercury		Indicate typical level in bid		D6414 or D6722
Chlorine			1100 ppm	D4208-02

Terminal Specifications

Terminal	Maximum Draft	Pier Type	Vessel Requirements	Unloading Rate
International Pier	38 feet	Dolphin	Belted Self-Unloader	2,500 MT/Hour
Point Tupper Marine Coal Terminal	54 feet	Dolphin	Belted Self-Unloader	3,000 MT/Hour
Point Tupper Marine Coal Terminal	54 feet	Dolphin	Gearless Panamax	19,000 MT/Day

TECHNICAL SPECIFICATION - LOW SULPHUR COAL

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	15%	D3302
Free Moisture	-	-	3%	D3302
Ash	7%	-	9%	D3172
Sulphur	0.65%	-	1.1%	D4239
Volatile Matter	34%	30%	-	D3175
Calorific Value (Btu/lb.)	-	10,800	13,400	D5865
Grindability (HGI)	45-55	42	65	D409
Size (Topsize)	-	-	2” x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Mercury		Indicate typical level in bid		D6414 or D6722
Chlorine			1100 ppm	D4208-02

Terminal Specifications

Terminal	Maximum Draft	Pier Type	Vessel Requirements	Unloading Rate
International Pier	38 feet	Dolphin	Belted Self-Unloader	2,500 MT/Hour
Point Tupper Marine Coal Terminal	54 feet	Dolphin	Belted Self-Unloader	3,000 MT/Hour
Point Tupper Marine Coal Terminal	54 feet	Dolphin	Gearless Panamax	800 MT/ Hour

TECHNICAL SPECIFICATION - PETROLEUM COKE

Type: Delayed Petroleum Coke, Shot Coke only.

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	9%	D3302
Ash	0.5%	0.2%	1.0%	D3172
Sulphur	4-6%	-	6%	D4239
Volatile Matter	10%	8%	-	D3175
Calorific Value (Btu/lb.)	14,000	13,900	-	D5865
Grindability (HGI)	45-50	40		D409
Size (Topsize)	-	-	2” x 0	D4749
Size (Fines < 0.5 mm)	-	-	12%	D4749
Vanadium, ppm	800		1900	D5056
Nickel, ppm	100		750	D5056
Mercury	Indicate typical level in bid			D6414 or D6722
Chlorine			1100 ppm	D4208-02

Terminal Specifications

Terminal	Maximum Draft	Pier Type	Vessel Requirements	Unloading Rate
International Pier	38 feet	Dolphin	Belted Self-Unloader	2,500 MT/Hour
Point Tupper Marine Coal Terminal	54 feet	Dolphin	Belted Self-Unloader	3,000 MT/Hour
Point Tupper Marine Coal Terminal	54 feet	Dolphin	Gearless Panamax	800 MT/ Hour

TECHNICAL SPECIFICATIONS FOR HEAVY FUEL OIL

Vessel Requirements

Cargo Size (± 10 % for vessel capacity):	Up to 250,000 bbl.
Length Overall:	236 m (775 ft) max.
Manifold Position:	Approximately Amidships
Arrival Draft:	12.2 m (40 ft) max.
Manifold Above Water Level:	15.0 m (49 ft) max.
Discharge Pressure:	862 kPa (125 psi) max.
Average Discharge Pressure: (Note 1)	690 kPa (100 psi)
Cargo Temperature prior to Discharge:	120-135 F
Vessel Dead Weight:	65,000 tonnes max.
Displacement:	60,000 tonnes max.
Maximum Airdraft	47 m

Note 1: The average discharge pressure requirement applies to bulk discharge. Stripping is excepted unless performed during bulk discharge.

HFO QUALITY SPECIFICATION

Property	Requirement	ASTM Test
Gravity, ^{0}API- Apr 1 to Dec 31 Gravity, ^{0}API- Jan 1 to Mar 31	min. 9.0 min. 9.5	D1298 D1298
Saybolt Viscosity, Furol @ 50 ^{0}C	min. 150 max. 300	D445, D2161
Flash Point, ^{0}C (^{0}F)	min. 66 (150)	D93
Sulphur, wt. %	max. 2.2 (or 1.0)	D4294
Water by Distillation, vol. %	max. 1.0	D95
Compatibility, spot	max. 1	D4740
Hydrogen Sulphide, vol. ppm	200	Exxon AM-S90-003
Gross Heat of Combustion, MMBtu/bbl	6.325	D240
Ash, wt. %	max. 0.10	D482
Sediment by Extraction, wt. %	max. 0.25	D473
Sediment by Hot Filtration, wt. %	max. 0.1	D4870
(1) Vanadium, wt. ppm	max. 300	D5863A/B (1)
Sodium, wt. ppm	max. 50	D5863B
Asphaltenes, wt. %	max. 10	IP143
Pour Point, ^{0}C (^{0}F)	max. 21 (70)	D97

Notes: (1) Test method ASTM-D-5863(B) will be used at discharge port to determine if discharge should be delayed while test method 5863(A) is performed. Test method ASTM-D-5863(A) will be used for pricing calculations at discharge port, and will be binding in the event of a dispute.

TECHNICAL SPECIFICATIONS FOR LIGHT FUEL OIL[1]

Distillate Specification for LFO Delivered December 1 – February 29

Property	Min / Max	ASTM Test Method
Appearance	Clear and Bright	Visual
Density, kg/m^3	0.850 max	D1298
Distillation 90% Recovered	290.0 max	D86
Cloud Point, Degree °C	-34 max	D2500
Pour Point, Degrees C	Report	D97
Viscosity @ 40°C	1.1 min – 1.8 max	D445
Cetane Number	40 min	D613
Sulphur, wt%	0.1 max	D1552
Corrosion – Copper – 3 hours @ 50°C	No. 1 max	D130
Micro Carbon Residue 10% Bottoms % Mass	0.1 max	D4530
Flash, Degrees C	40 min	D93
Water and Sediment, Vol. %	0.05 max	D1796
Ash, wt%	0.01 max	D482
Trace Metals, ppm by wt %		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

[1] For LFO, the appendix includes the OEM specification. Refiners provide specifications based on what they are permitted to produce in meeting environmental regulations that are subject to change from time to time. In the event of the Refiner's specification varying from the OEM specification, the Refiner's specification must be reviewed and approved by NS Power's management.

Distillate Specification for LFO Delivered March 1 – November 30

Property	Min / Max	ASTM Test Method
Appearance	Clear and Bright	Visual
Density, kg/m^3	0.881 max	D1298
Distillation 90% Recovered	360.0 max	D86
Cloud Point, Degree °C	Report (note 1)	D2500
Pour Point, Degrees C	Report (note 1)	D97
Viscosity @ 40°C, cst	1.3 min – 3.6 max	D445
Octane Number	40 min	D613
Sulphur, wt%	0.1 max	D1552
Corrosion – Copper – 3 hours @ 50°C	No. 1 max	D130
Micro Carbon Residue 10% Bottoms % Mass	0.1 max	D4530
Flash, Degrees C	40 min	D93
Water and Sediment, Vol. %	0.05 max	D1796
Ash, wt%	0.01 max	D482
Trace Metals, ppm by wt %		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

Note 1: Operability of the fuel shall meet seasonal conditions. An operability schedule must be submitted with the tender.

FUEL SPECIFICATIONS FOR NATURAL GAS

Total Heating Value

a) Natural gas received or delivered shall have a Total Heating Value below 36 MJ/m^3 or above 41 MJ/m^3

b) The Total Heating Value shall be determined by gas chromatographic analysis using most recent AGA standards (or any revision), or by other methods agreed upon by the customer and the pipeline

Composition

c) Merchantability. The gas shall be commercially free, under continuous gas flow conditions, from objectionable odors (except those required by regulations), solid matter, dust, gums, and gum-forming constituents which might interfere with its merchantability or cause injury to or interference with proper operations of the pipelines, compressor stations, meters, regulators or other appliances through which it flows.

d) Oxygen. The gas shall not have an uncombined oxygen content in excess of two-tenths (0.2) of one percent (1%) by volume, and both parties shall make every reasonable effort to keep the gas free from oxygen.

e) Non-Hydrocarbon Gases. The gas shall not contain more than four percent (4%) by volume, of a combined total of non-hydrocarbon gases (including carbon dioxide and nitrogen); it being understood, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume.

f) Liquids. The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is received and delivered.

g) Hydrogen Sulphide. The gas shall not contain more than six (6) milligrams of hydrogen sulphide per one (1) Cubic Metre.

h) Total Sulphur. The gas shall not contain more than four-hundred and sixty (460) milligrams of total sulphur, excluding any mercaptan sulphur, per one (1) Cubic Metre.

i) Temperature. The gas shall not have a temperature of more than forty-nine degrees (49°) Celsius.

j) Water Vapor. The gas shall not contain in excess of eighty (80) milligrams of water vapor per one (1) Cubic Metre.

k) Liquefiable Hydrocarbons. The gas shall not contain liquid hydrocarbons or hydrocarbons liquefiable at temperatures warmer than minus nine degrees (-9°) Celsius and normal pipeline operating pressures of between 690 and 9930 kPag.

l) Microbiological Agents. The gas shall not contain any microbiological organism, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems. Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (APB). Tests for bacteria or bacterial agents shall be conducted on samples taken from the meter run or the appurtenant piping using American Petroleum Institute (API) test method API-RP38 or any other test method acceptable to Pipeline and Customer which is currently available or may become available at any time.

TECHNICAL SPECIFICATIONS FOR BIOMASS

Biomass Fuel shall be delivered as chips or hogged material commuted to a nominal size of thirty-five (35) to thirty-seven (37) millimetres or smaller and shall not contain pieces greater than one hundred fifty (150) millimetres in length. The percentage of Biomass Fuel less than six (6) millimetres sieve size shall not exceed twenty-five percent (25%) of the total quantity.

All Biomass Fuel shall be substantially free of extraneous material including, but not limited to, rock, iron, steel, wire, construction debris, gravel, soil, metal, plastic and industrial waste. In the event that extraneous materials are discovered during the unloading of the Biomass Fuel at the Designated Delivery Point, NSPI shall provide written notice to the supplier and the supplier shall take immediate action to remove the extraneous material failing which the supplier shall reimburse NSPI for all expenses incurred as the result of NSPI removing the extraneous materials from the Biomass Fuel.

All Biomass Fuel shall be comprised of natural, untreated and uncoated wood and wood waste, which, at no stage in its lifecycle, has been treated with organic and/or inorganic substances to change, protect or supplement the physical properties of the materials.

Moisture specifications are determined based on the nature of the fuel being sourced (primary vs secondary) and will vary seasonally.

Requirement:

Provide IPP contract details.

Submission:

Please refer to Confidential Attachment 1.

Appendix A OP-08 Attachment 1 has been removed due to confidentiality.

Requirement:

Provide reliability statistics for fossil fleet, and customer outage indices for NS Power and comparison to latest CEA all-Canada values.

Submission:

Please refer to Attachment 1.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Performance Factor:	**Availability**							
Annual Hours:	**8784**	**8760**	**8760**	**8760**	**8784**	**8760**	**8760**	
Year:	**2012 (actual)**	**2013 (actual)**	**2014 (actual)**	**2015 (actual)**	**2016 (actual)**	**2017 (actual)**	**2018 (actual)**	**NERC 2013-2017 Fossil Units (100-199 MW)**
Plant								
Pt. Aconi	83.19%	88.45%	81.14%	88.00%	85.30%	86.53%	87.25%	
Tufts Cove #1	85.26%	99.98%	88.53%	74.00%	43.33%	86.02%	75.01%	
Tufts Cove #2	74.01%	70.97%	95.56%	92.00%	85.12%	76.57%	49.15%	
Tufts Cove #3	76.96%	82.25%	57.86%	82.00%	91.60%	66.55%	89.68%	
Tufts Cove #4	-	-	84.05%	87.00%	87.43%	94.61%	92.05%	
Tufts Cove #5	-	-	90.35%	88.00%	90.45%	82.68%	91.81%	
Tufts Cove #6	-	-	81.41%	97.00%	88.42%	89.87%	87.23%	
PT. Tupper #2	96.25%	77.59%	96.23%	91.00%	94.30%	85.91%	92.88%	
Trenton #5	35.42%	85.11%	86.96%	90.00%	77.60%	88.68%	69.50%	
Trenton #6	92.12%	86.17%	91.29%	86.00%	92.50%	74.99%	86.72%	
Lingan #1	93.54%	86.00%	91.81%	92.00%	98.61%	85.15%	68.46%	
Lingan #2	64.54%	91.05%	93.21%	96.00%	98.87%	73.45%	61.79%	
Lingan #3	88.55%	94.07%	99.61%	74.00%	98.02%	97.06%	76.83%	
Lingan #4	94.13%	94.23%	92.70%	92.00%	64.23%	90.55%	87.71%	
PHB	-	-	85.78%	90.00%	92.50%	81.59%	91.05%	
Fossil Fleet Availability								**85.01%**

Definition: Availability is not a reported CEA measure. It is comparable to the Capability Factor CbF (%), which is the complement of the Incapability Factor. CEA Availability is calculated here as (100% - ICbF). Availability is now a CEA measure. Availability for 2016 onwards is calculated as: (operating hours + available hours) / unit hours.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Performance Factor:	**ICbF**						
Annual Hours:	**8784**	**8760**	**8760**	**8760**	**8784**	**8760**	**8760**
Year:	**2012 (actual)**	**2013 (actual)**	**2014 (actual)**	**2015 (actual)**	**2016 (actual)**	**2017 (actual)**	**2018 (actual)**
Plant							
Pt. Aconi	11.81%	7.60%	18.18%	11.30%	14.50%	11.55%	11.65%
Tufts Cove #1	15.00%	0.00%	11.33%	26.30%	56.63%	13.98%	22.00%
Tufts Cove #2	25.13%	26.86%	4.13%	7.80%	15.02%	19.12%	50.85%
Tufts Cove #3	23.29%	16.40%	42.06%	17.70%	8.71%	33.45%	8.88%
Tufts Cove #4	16.13%	12.20%	17.03%	13.30%	15.64%	5.16%	7.76%
Tufts Cove #5	7.61%	9.49%	9.66%	11.60%	15.77%	17.02%	8.06%
Tufts Cove #6	-	15.39%	18.41%	3.20%	11.05%	9.93%	12.41%
PT. Tupper #2	3.94%	22.39%	3.33%	8.40%	8.34%	13.73%	7.04%
Trenton #5	64.84%	14.87%	11.38%	10.20%	22.99%	11.31%	24.10%
Trenton #6	8.13%	13.81%	8.19%	13.70%	10.85%	23.08%	9.36%
Lingan #1	6.41%	13.98%	7.57%	8.10%	1.25%	14.82%	21.75%
Lingan #2	35.71%	8.93%	6.47%	4.20%	0.94%	26.55%	2.51%
Lingan #3	11.70%	5.91%	0.07%	25.70%	6.27%	2.88%	12.30%
Lingan #4	6.13%	5.75%	6.97%	7.80%	34.53%	1.50%	9.19%
PHB	-	-	13.90%	9.40%	7.33%	17.69%	11.65%
Fossil Fleet ICbF	**21.44%**	**15.78%**	**11.91%**	**11.91%**	**15.32%**	**14.79%**	**14.63%**

Definition: ICbF (%) - the Incapability Factor is the ratio of Total Equivalent Outage Time, in hours, to the number of Unit Hours times 100.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Performance Factor:	**MOF**							
Annual Hours:	**8784**	**8760**	**8760**	**8760**	**8784**	**8760**	**8760**	
Year:	**2012 (actual)**	**2013 (actual)**	**2014 (actual)**	**2015 (actual)**	**2016 (actual)**	**2017 (actual)**	**2018 (actual)**	**NERC 2013-2017 Fossil Units (100-199 MW)**
Plant								
Pt. Aconi	0.00%	0.00%	0.55%	0.50%	0.80%	1.08%	2.02%	
Tufts Cove #1	4.60%	0.00%	1.75%	11.80%	10.27%	7.27%	5.41%	
Tufts Cove #2	5.70%	3.69%	3.34%	0.70%	5.65%	0.90%	6.16%	
Tufts Cove #3	2.08%	2.13%	3.11%	7.80%	0.00%	1.58%	1.09%	
Tufts Cove #4	0.57%	3.40%	0.46%	1.10%	0.28%	1.59%	0.64%	
Tufts Cove #5	4.55%	0.11%	0.31%	0.30%	1.04%	0.30%	1.09%	
Tufts Cove #6	-	0.00%	0.23%	0.00%	0.66%	0.83%	0.46%	
PT. Tupper #2	0.00%	0.00%	0.00%	0.50%	1.61%	2.92%	0.00%	
Trenton #5	0.03%	0.12%	0.00%	0.80%	1.44%	1.37%	0.83%	
Trenton #6	0.35%	0.00%	0.00%	0.60%	1.50%	0.25%	2.37%	
Lingan #1	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	2.96%	
Lingan #2	0.00%	0.60%	0.00%	0.00%	0.83%	26.04%	1.08%	
Lingan #3	1.63%	0.00%	0.00%	0.00%	0.22%	0.72%	0.01%	
Lingan #4	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.40%	
PHB	-	-	0.75%	0.20%	0.96%	1.13%	0.00%	
Fossil Fleet MOF	**1.77%**	**0.91%**	**0.70%**	**1.62%**	**1.68%**	**3.07%**	**1.63%**	**3.04%**

Definition: MOF (%) - the Maintenance Outage Factor is computed by dividing the number of maintenance outage hours by the number of Unit Hours times 100.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Performance Factor:	**DAFOR**							
Annual Hours:	**8784**	**8760**	**8760**	**8760**	**8784**	**8760**	**8760**	
Year:	**2012 (actual)**	**2013 (actual)**	**2014 (actual)**	**2015 (actual)**	**2016 (actual)**	**2017 (actual)**	**2018 (actual)**	**NERC (EFOR) 2013-2017 Fossil Units (100-199 MW)**
Plant								
Pt. Aconi	2.96%	2.94%	5.09%	5.40%	3.20%	1.22%	1.31%	
Tufts Cove #1	7.68%	0.00%	4.69%	13.00%	75.70%	7.24%	25.20%	
Tufts Cove #2	7.77%	12.04%	1.26%	0.70%	14.40%	6.25%	36.65%	
Tufts Cove #3	1.15%	10.77%	38.38%	2.30%	0.60%	1.35%	4.14%	
Tufts Cove #4	-	-	8.22%	14.80%	5.30%	1.50%	1.81%	
Tufts Cove #5	-	-	7.67%	11.40%	6.30%	8.27%	0.83%	
Tufts Cove #6	-	-	9.71%	2.40%	1.40%	2.21%	1.07%	
PT. Tupper #2	3.37%	1.13%	4.04%	0.00%	2.90%	2.18%	0.71%	
Trenton #5	18.03%	14.01%	10.01%	6.10%	6.40%	1.83%	12.03%	
Trenton #6	6.80%	3.63%	4.20%	1.80%	5.10%	5.21%	2.85%	
Lingan #1	3.89%	7.31%	1.95%	2.50%	1.50%	0.48%	3.00%	
Lingan #2	2.98%	2.03%	0.28%	1.10%	0.30%	1.52%	3.16%	
Lingan #3	2.91%	0.06%	0.42%	3.10%	6.90%	2.56%	3.03%	
Lingan #4	0.34%	0.17%	2.43%	0.20%	5.00%	2.66%	7.47%	
PHB	-	-	6.15%	2.40%	0.60%	1.70%	1.32%	
Fossil Fleet DAFOR	**5.64%**	**5.38%**	**6.46%**	**5.83%**	**5.60%**	**3.00%**	**5.80%**	**10.35%**

Definition: DAFOR (%) - the Derated Adjusted Forced Outage Rate is the ratio of Equivalent Forced Outage Time to Equivalent Forced Outage Time plus Total Equivalent Operating Time.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Customer Outage Indices

	NSPI All-In Data			CEA REGION 2		
YEAR	NSPI SAIFI	NSPI SAIDI	NSPI CAIDI	CEA SAIFI	CEA SAIDI	CEA CAIDI
2007	3.98	14.17	3.56	2.68	7.29	2.72
2008	4.15	11.29	2.72	2.76	8.56	3.10
2009	2.86	5.80	2.03	2.31	5.31	2.30
2010	4.34	17.65	4.07	2.54	7.01	2.76
2011	3.75	7.93	2.12	2.97	7.50	2.52
2012	1.86	3.06	1.64	2.83	5.61	1.98
2013	2.50	6.24	2.50	2.94	9.83	3.34
2014	3.07	17.08	5.57	2.67	7.81	2.93
2015	2.39	4.86	2.03	2.60	6.28	2.41
2016	3.42	11.90	3.48	3.69	7.09	1.92
2017	2.81	8.57	3.05	2.81	9.88	3.51
2018	4.56	16.26	3.57	3.23	10.05	3.11

NOTE:
SAIFI - System Average Interruption Duration Index
SAIDI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index

Requirement:

Applicable emissions targets legislated and compliance accomplished for past year and current year, and how compliance is planned for the test year and five years into the future.

Submission:

NS Power is required to manage air emissions within annual limits. The air emission compliance limits specified in the provincial *Air Quality Regulations*, as amended November 21, 2014 and October 12, 2017 for future years are shown in **Figure 1**.

Figure 1 – Annual Emission Caps for SO_2, NOx and Hg

Year(s)	SO_2 Tonnes			NOx Tonnes		Mercury Kg[1]
	Unit Maximum	Annual	Cumulative	Annual	Cumulative	Annual
2014		72,500		21,365		65
2015-2019	42,775	72,500	304,500	21,365	96,140	65
2020	17,760	36,250		14,955		35
2021-2024	17,760	36,250	136,000	14,955	56,000	35
2025	13,720	28,000		11,500		35
2026-2029	13,760	28,000	104,000	11,500	44,000	35
2030	9,800	20,000		8,800		30

1. The annual emissions of mercury which exceed 65 kg in the years 2010-2013 must be compensated for by reducing annual emissions to a level below 65 kg and/or the use of credits obtained via the Mercury Diversion Program so that the total reduced emissions/credits equals or exceeds the excess emissions above 65 kg by year 2020.

The proposed amendments to the *Air Quality Regulations* provide more relief with respect to SO_2 emissions and mercury (Hg). The revised compliance targets are shown in **Figure 2**.

Figure 2 – Revised Annual Emission Caps for Sulphur Dioxide and Mercury

Year(s)	SO_2 Tonnes			NOx Tonnes		Hg Kg[2]
	Unit Maximum	Annual	Cumulative	Annual	Cumulative	Annual
2014		72,500		21,365		65
2015-2019	42,775	72,500	304,500	21,365	96,140	65
2020[2]	TBD	60,900	TBD	14,955		35
2021-2022[2]	TBD	90,000	TBD	14,955	56,000	35
2023-2024[2]	TBD	68,000	TBD	11,500		35
2025	13,760	28,000	104,000	11,500	44,000	35

1. Mercury diversion credits can be used to account for the difference between the regulated cap of 35 kg and actual emissions. NSE has indicated NS Power can use up to 30kg of diversion credits in 2020 up to 10kg of diversion credits in subsequent years.
2. Annual maximum caps were not defined in the 2019 proposed amendments to the *Air Quality Regulations*; however, NSE has indicated new regulations will be adjusted accordingly.

Greenhouse Gas (GHG) emissions are governed by multi-year cumulative allowances under the *Greenhouse Gas Emission Regulations*, as shown in **Figure 3**. The *Cap and Trade Program Regulations*, effective November 13, 2018, include the annual free allowances for GHG emissions for NS Power, as shown in **Figure 4**.

In 2018 greenhouse gas emissions are estimated at 6,920,866 tonnes subject to third party verification before finalized.

Figure 3 – Greenhouse Gas Emission Caps

Year	GHG Cumulative Million tonnes
2014-2016	26.32
2017-2019	24.06
2020	7.5 (annual)
2021-2024	27.5
2025	6 (annual)
2026-2029	21.5
2030	4.5 (annual)

Figure 4 – Greenhouse Gas Free Allowances

Year	GHG Free Allowances Million tonnes[1]
2019	6.334
2020	5.517
2021	5.120
2022	5.087

NS Power will continue to manage its actual air emissions by purchasing and combusting specific quality fuels, procuring power from other sources (Imports and Independent Power Producers), and by utilizing emission control equipment. Emission control equipment includes Low NOx Combustion Firing Systems (LNCFS) at Lingan, Point Tupper and Trenton; baghouse technology at Trenton 5 and Point Aconi; fluidized bed technology at Point Aconi, and seven mercury abatement systems (Calcium Chloride at the front end and powdered activated carbon – at the back end) at Trenton, Point Tupper and Lingan. In addition, NS Power continues to add renewable energy and manage load through energy conservation and efficiency programs.

In addition to these fleet-wide caps, each generating facility operates within a permit which requires ground-level ambient air quality to be maintained, plume visibility to be within limits and, in some cases, specific emission standards to be met. This is accomplished by maintaining the plant equipment in good working order and operating the plant within the specified limits.

Performance is reviewed on regular basis. Compliance is projected to be achievable.

[1] *Greenhouse Gas Emissions Regulations*, N.S. Reg. 260/2009 as amended, made under ss. 28(6) and 112 of the *Environment Act*, S.N.S. 1994-95, c. 1.

Requirement:

Provide monthly data for the last two years for NSPI's sales of natural gas: quantities sold, prices received, buyer, and location of title transfer. For transportation paid for by NSPI, provide the name of the transporter, nature of the transportation service (firm, interruptible, released firm, etc.), and price paid. Also, provide summaries of the associated contracts that were in place over the last two years.

Submission:

For sales of natural gas, please refer to Confidential Attachment 1.

There were no sales contracts in place.

Appendix A OR-08 Attachment 1 has been removed due to confidentiality.

NOVA SCOTIA
Environment
Office of the Minister

PO Box 442, Halifax, Nova Scotia, Canada B3J 2P8 • www.novascotia.ca/nse

Our File number:
10700-40-54672

MAY 16 2019

Karen Hutt
President and CEO
Nova Scotia Power Inc.
PO Box 910
Halifax, NS B3J 2W5

Dear Karen Hutt:

Thank you for your presentations updating our department and others at the Province of Nova Scotia about potential rate pressures you are currently facing, particularly related to the delay in the Muskrat Falls hydropower project being fully operational until June 2020. All Nova Scotians are impacted by both electricity rates and the health of our environment. Therefore, we must work together to find a balance between electrical rate stability and environmental protection.

In order to address these issues, we are intending to propose amendments to the *Air Quality Regulations* which would lessen the reduction in the sulphur dioxide (SO_2) cap for a three-year period from 2020 to 2022. The current regulations include an SO_2 cap step-down in 2020 to 36,250 tonnes. There is then a multi-year cap of 136,000 tonnes for 2021-2024, before a 2025 step-down to 28,000 tonnes. Our proposal will include an annual SO_2 cap of 60,900 tonnes for 2020, a multi-year SO_2 cap of 90,000 tonnes for 2021 and 2022, and a multi-year SO_2 cap of 68,000 tonnes for 2023 and 2024. Annual maximum caps for the years 2021-2024 will be adjusted accordingly. The cap in 2025 will remain unchanged at 28,000 tonnes.

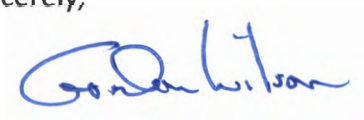
It is critical that we continue to protect the health of Nova Scotians and our environment. To do so, our proposed amendments to the regulations would balance the changes to the SO_2 cap with clarification of the mercury (Hg) diversion program. We will be proposing that actual Hg emissions be capped at 65 kg in 2020 and 45 kg in subsequent years. Mercury diversion credits can be used to account for the difference between the regulated cap of 35 kg and actual emissions. The proposed amendments will not change NSP's obligation to meet ambient air quality and emission requirements at individual facilities.

.../2

Karen Hutt
Page 2

As both the main provider of electricity to Nova Scotians and the largest source of air emissions in our province, NSP has a responsibility to meet our regulations while also achieving competitive rates. We expect NSP to begin preparing now to meet the 2025 SO_2 step-down and other regulatory targets. Consideration of further regulatory changes in reduction targets should be excluded from your rate stability planning. Our regulations have been carefully designed to balance the needs of multiple stakeholders and it would be imprudent to adopt further changes.

Sincerely,



Gordon Wilson, MLA
Minister of Environment

c: Hon. Derek Mombourquette, Minister of Energy and Mines
Frances Marin, Deputy Minister of Environment
Simon d'Entremont, Deputy Minister of Energy and Mines

2018 FAM AA Amounts

FOR THE YEAR ENDING DECEMBER 31, 2017

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M		N	O	P
3	FORMULA			A - B	C /B				F-G	E + H	I / I (Line 29)	J x K (Line 29)	I + K	J x M (Line 29)		L + M		N - O
9	**FAM Rate Class**	**Variance in 2017 GWh Energy Requirement**				**2017 Beginning BCF Balance**	**Variance in 2017 Fuel Cost Recovery before Interest and Incentive**			**Variance in Fuel Costs before Incentive**				**Variance in Fuel Costs**			**2017 FAM AA Rider Calculation**	
11		**Actual**	**Test Year**	**Var**	**% Var**		**Actual Fuel Costs**	**Recovered Fuel Costs**	**Variance (debit/credit)**	**Total Amount owed to Customers before Interest**	**Relative Share**	**Interest Amount**	**Adjustment after 2017 Beginning balance and interest**	**NSPI Incentive Amount(1)**	**Adjustment to reconcile with FAM Model**	**Adjustment after Incentive**	**Amount owed by departing load to non-FAM classes**	**Amount to be paid or credited through riders**
13	Residential Subtotal	4,785.6	4,778.5	7.12	0.1%	($35,618,021)	$207,506,072	$252,835,349	($45,329,278)	($80,947,299)	54.8%	($4,495,688)	($85,442,987)	$0	$322	($85,442,664)		($85,442,664)
14	Small General	304.7	304.5	0.21	0.1%	($1,536,761)	$13,619,542	$16,267,531	($2,647,989)	($4,184,750)	2.8%	($232,415)	($4,417,165)	$0	$17	($4,417,148)		($4,417,148)
15	General Demand	2,532.6	2,528.7	3.86	0.2%	($17,048,332)	$110,768,386	$132,102,776	($21,334,390)	($38,382,722)	26.0%	($2,131,717)	($40,514,439)	$0	$153	($40,514,286)		($40,514,286)
16	Large General	425.3	424.6	0.65	0.2%	$210,677	$17,798,775	$21,620,606	($3,821,832)	($3,611,154)	2.4%	($200,558)	($3,811,712)	$0	$14	($3,811,698)		($3,811,698)
17	Small Industrial	260.9	260.7	0.22	0.1%	($1,790,421)	$11,392,187	$13,390,347	($1,998,160)	($3,788,581)	2.6%	($210,412)	($3,998,993)	$0	$15	($3,998,978)		($3,998,978)
18	Medium Industrial	493.0	492.1	0.85	0.2%	($1,825,368)	$20,453,803	$23,971,151	($3,517,348)	($5,342,717)	3.6%	($296,726)	($5,639,443)	$0	$21	($5,639,422)		($5,639,422)
19	Large Industrial	743.2	742.0	1.24	0.2%	($2,447,580)	$30,262,565	$35,876,847	($5,614,282)	($8,061,863)	5.5%	($447,743)	($8,509,606)	$0	$32	($8,509,574)		($8,509,574)
20	**Municipal**																	
21	Customers staying on the rate	50.8	50.2	0.58	1.1%	($247,676)	$2,133,802	2,569,095.01	($435,293)	($682,969)	0.5%	($37,931)	($720,900)	$0	$3	($720,897)		($720,897)
22	Customers migrating to OATT in 2015																	
23	Customer A	60.9	62.2	- 1.31	-2.1%	$296,790.54	$2,601,030	3,078,552.57	($477,522)	($774,313)	0.5%	($43,004)	($817,317)	$0	$3	($817,314)	$177,535	($639,779)
24	Customer B	23.8	22.5	1.22	5.4%	$115,747.66	$1,002,989	1,200,628.75	($197,639)	($313,387)	0.2%	($17,405)	($330,792)	$0	$1	($330,791)	$71,854	($258,937)
25	Customer C	8.9	8.4	0.46	5.4%	($43,349)	$382,311	449,649.44	($67,338)	($110,687)	0.1%	($6,147)	($116,835)	$0	$0	($116,834)	$25,378	($91,456)
26	Customer D	5.8	5.6	0.19	3.3%	($28,178)	$254,770	292,285.39	($37,515)	($65,694)	0.0%	($3,649)	($69,342)	$0	$0	($69,342)	$15,062	($54,280)
27	**Municipal - Total**	150.1	149.0	1.13	0.8%	($731,741)	$6,374,903	$7,590,211	($1,215,309)	($1,947,049)	0.9%	($108,136)	($2,055,186)	$0	$8	($2,055,178)	($289,829)	($1,765,349)
28	Unmetered	89.9	83.9	6.04	7.2%	($1,006,154)	$3,886,102	$4,450,032	($563,930)	($1,570,084)	1.1%	($87,200)	($1,657,284)	$0	$6	($1,657,278)	-	($1,657,278)
29	**FAM Class Total / Average**	9,785.4	9,764.1	21.3	0.2%	($61,793,701)	$422,062,333	$508,104,851	($86,042,518)	($147,836,219)	100.0%	($8,210,595)	($156,046,814)	$0	$589	($156,046,225)	($289,829)	($155,756,396)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	2016							2017		
	Rate Stability Fund[1]								Actual	
	Year-beginning	Contribution from BCF Recovery	Deferred FAM	DSM RSA Adjustment	Additional Cash Taxes	Year-end bfr Interest	Interest	Year Beginning BCF Balance - Forecast as per 2017-2019 RSP	Adjustment for Deferred FAM Amount	Year Beginning BCF Balance
Residential	**-$25,304,326**	**$0**	**$0**	**$0**	**-$8,250,676**	**-$33,555,002**	**-$2,063,019**	**-$35,618,021**	**$0**	-$35,618,021
Small General	-$1,263,169	$0	$0	$233,088	-$411,866	-$1,441,946	-$94,814	-$1,536,761	$0	-$1,536,761
General Demand	-$11,230,110	$0	$0	-$1,198,960	-$3,661,666	-$16,090,736	-$957,596	-$17,048,332	$0	-$17,048,332
Large General	-$519,976	$0	$1,054,467	$1,291,856	-$468,613	$1,357,734	$29,363	$1,387,098	-$1,176,420	$210,677
Total Commercial	**-$13,013,254**	**$0**	**$1,054,467**	**$325,985**	**-$4,542,146**	**-$16,174,948**	**-$1,023,047**	**-$17,197,995**	**-$1,176,420**	-$18,374,415
Small Industrial	-$1,125,496	$0	$0	-$199,206	-$366,977	-$1,691,679	-$98,742	-$1,790,421	$0	-$1,790,421
Medium Industrial	-$904,731	$0	$941,887	-$106,373	-$648,466	-$717,683	-$56,866	-$774,548	-$1,050,820	-$1,825,368
Large Industrial Total										
Firm	-$212,894	$0	$207,885	$0	-$146,541	-$151,550	-$12,774	-$164,324	-$231,927	-$396,251
Interruptible	-$1,091,677	$0	$1,307,109	$0	-$751,430	-$535,998	-$57,050	-$593,048	-$1,458,281	-$2,051,329
Large Industrial Total	-$1,304,571	$0	$1,514,994	$0	-$897,970	-$687,548	-$69,824	-$757,372	-$1,690,209	**-$2,447,580**
Total Industrial	**-$3,334,798**	**$0**	**$2,456,881**	**-$305,580**	**-$1,913,413**	**-$3,096,910**	**-$225,431**	**-$3,322,341**	**-$2,741,029**	**-$6,063,370**
Municipal[2]	-$433,687	$0	$0	$0	-$258,589	-$692,276	-$39,465	-$731,741	$0	-$731,741
Unmetered	-$699,803	$0	$0	-$20,405	-$228,176	-$948,385	-$57,769	-$1,006,154	$0	-$1,006,153.67
Total Other	**-$1,133,490**	**$0**	**$0**	**-$20,405**	**-$486,765**	**-$1,640,661**	**-$97,234**	**-$1,737,895**	**$0**	**-$1,737,895**
Total FAM Classes	**-$42,785,869**	**$0**	**$3,511,348**	**$0**	**-$15,193,000**	**-$54,467,521**	**-$3,408,731**	**-$57,876,252**	**-$3,917,449**	-$61,793,701
									-$3,917,449	**-$61,793,701**

Footnotes

(1) Source: 2017 - 2019 Fuel Stability Plan Application - Compliance Filing, Appendix E-1B, tab Appendix H Rate Stability Fund

Allocation of Actual Fuel-related Costs among Rate Classes

FOR THE YEAR ENDING DECEMBER 31, 2017

Line #	COLUMN	A	B	C	D	E	F	G														R	S	T	U	V	W	X	Y	Z
	FORMULA			B / B (Line 41)		D/ D (Line 41)																G+L+Q	E x S (line 41)	E x T (line 41)	E x W (line 41)	R+S+T+U	VxA	W / W (line 41)	X x V(line 39)	Y x F (line 39)
		Cost Allocation Factors						Fuel-related Costs from COS																			Fuel Costs used for FAM purposes			
			3 CP Demands		Energy Requirement					Purchased Power- Biomass				Purchased Power other than Biomass and Wind			Purchased Power - Wind													
																Total		NRIS												
	Rate Class	R/C Ratio as per 2013 CF for the 2014 Test Year	KW Demand	Relative Shares	KWh Energy	Relative Shares	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		ERIS	Energy-related	Demand-related	Total	Total	Total Fuel-related costs before Exports, OM&G and Foreign Exchange	Export Revenues	OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh
15	**FAM Rate Classes (ATL)**																													
16	Residential non ETS						4,121,998,915																							
17	Residential ETS						251,558,418																							
18	Residential Subtotal	98.85%	3,535,616	62.2%	4,785,635,857	48.9%	4,373,557,333	$116,176,925	$10,965,693	$969,939	$5,060,226	$3,702,768	$9,732,932	$471,396	$344,939	$816,334	$18,584,118	$44,853,451	$11,682,860	$56,536,311	$75,120,429	$212,812,314	$2,781,319.77	$0.00	-$111	$210,030,884	$207,615,528	49.2%	$207,506,072	**4.745**
19																														
20	Small General	104.64%	151,256	2.7%	304,723,389	3.1%	280,136,575	$7,357,780	$706,496	$62,300	$322,208	$158,406	$542,915	$30,016	$14,757	$44,773	$1,183,336	$2,856,025	$499,799	$3,355,824	$4,539,160	$13,191,124	$168,633.91	$0.00	-$7	$13,022,483	$13,626,726	3.2%	$13,619,542	**4.862**
21	General Demand	102.92%	1,142,508	20.1%	2,532,595,156	25.9%	2,378,944,281	$60,809,273	$6,213,199	$522,383	$2,677,910	$1,196,522	$4,396,815	$249,466	$111,464	$360,931	$9,834,858	$23,736,790	$3,775,229	$27,512,019	$37,346,877	$109,127,095	$1,444,549.97	$0.00	-$59	$107,682,486	$110,826,815	26.2%	$110,768,386	**4.656**
22	Large General	99.35%	161,919	2.8%	425,287,987	4.3%	400,604,157	$10,137,579	$1,081,835	$88,640	$449,690	$169,574	$707,904	$41,892	$15,797	$57,689	$1,651,526	$3,986,019	$535,035	$4,521,054	$6,172,580	$18,157,586	$232,902.77	$0.00	-$10	$17,924,674	$17,808,163	4.2%	$17,798,775	**4.443**
23	Small Industrial	102.46%	120,558	2.1%	260,869,305	2.7%	246,417,863	$6,279,245	$641,416	$53,684	$275,837	$126,258	$455,780	$25,696	$11,762	$37,458	$1,013,037	$2,445,002	$398,365	$2,843,367	$3,856,404	$11,270,302	$145,763.57	$0.00	-$6	$11,124,533	$11,398,196	2.7%	$11,392,187	**4.623**
24	Medium Industrial	98.46%	185,237	3.3%	492,979,427	5.0%	466,455,555	$11,783,324	$1,255,794	$102,136	$521,266	$193,995	$817,396	$48,560	$18,072	$66,632	$1,914,393	$4,620,458	$612,087	$5,232,545	$7,146,938	$21,070,083	$285,395.79	$0.00	-$11	$20,784,676	$20,464,592	4.8%	$20,453,803	**4.385**
25	**Large Industrial**																													
26	Large Industrial - Firm																													
27	Large Industrial - Interruptible																													
28	**Large Industrial Total**	97.44%	233,693	4.1%	743,201,325	7.6%	709,344,434	$17,641,813	$1,928,414	$154,972	$785,845	$244,741	$1,185,558	$73,207	$22,799	$96,006	$2,886,083	$6,965,667	$772,199	$7,737,866	$10,623,948	$31,475,739	$401,698.85	$0.00	-$17	$31,074,023	$30,278,528	7.2%	$30,262,565	**4.266**
29	ELI 2P-RTP (base rate)		-	0.0%	-	0.0%	-																$0.00							**N/A**
30	Municipal																						$0.00							
31	Customers staying on in 2015	97.67%	28,675	0.5%	50,812,651	0.5%	48,236,857	$1,223,457	$121,417	$10,400	$53,728	$30,031	$94,159	$5,005	$2,798	$7,803	$197,321	$476,242	$94,753	$570,995	$768,317	$2,215,152	$29,292.33	$0.00	-$1	$2,185,858	$2,134,928	0.5%	$2,133,802	**4.424**
32	Customers migrating to OATT in 2015												$0										$0.00							
33	Customer A	97.67%	43,101	0.8%	60,887,011	0.6%	57,802,339	$1,472,152	$143,911	$12,440	$64,381	$45,138	$121,958	$5,998	$4,205	$10,202	$236,443	$570,665	$142,419	$713,084	$949,527	$2,697,751	$33,264.54	$0.00	-$1	$2,664,485	$2,602,402	0.6%	$2,601,030	**4.500**
34	Customer B	97.67%	13,981	0.2%	23,761,168	0.2%	22,542,785	$572,134	$58,839	$4,888	$25,125	$14,642	$44,654	$2,341	$1,364	$3,705	$92,272	$222,702	$46,199	$268,901	$361,173	$1,040,504	$13,045.67	$0.00	-$1	$1,027,458	$1,003,518	0.2%	$1,002,989	**4.449**
35	Customer C	97.67%	6,644	0.1%	8,898,239	0.1%	8,442,535	$216,715	$20,375	$1,801	$9,409	$6,958	$18,168	$876	$648	$1,525	$34,555	$83,399	$21,953	$105,352	$139,906	$396,689	$5,050.54	$0.00	-$0	$391,638	$382,513	0.1%	$382,311	**4.528**
36	Customer D	97.67%	5,526	0.1%	5,787,444	0.1%	5,487,897	$142,825	$12,535	$1,164	$6,120	$5,787	$13,070	$570	$539	$1,109	$22,474	$54,243	$18,259	$72,502	$94,977	$264,517	$3,531.39	$0.00	-$0	$260,985	$254,904	0.1%	$254,770	**4.642**
37	**Municipal Total**	97.67%	97,927	1.7%	150,146,514	1.5%	142,512,414	$3,627,283	$357,077	$30,692	$158,762	$102,556	$292,009	$14,790	$9,554	$24,344	$583,066	$1,407,251	$323,582	$1,730,833	$2,313,899	$6,614,612	$84,184.48	$0.00	-$3	$6,530,424	$6,378,265	1.5%	$6,374,903	**4.473**
38	Unmetered	100.00%	56,161	1.0%	89,945,548	0.9%	82,225,284	$2,151,910	$221,661	$18,605	$95,106	$58,816	$172,527	$8,860	$5,479	$14,339	$349,287	$843,016	$185,573	$1,028,589	$1,377,876	$3,938,312	$50,158.40	$0.00	-$2	$3,888,152	$3,888,152	0.9%	$3,886,102	**4.726**
39	ATL Subtotal / Average	100.00%	5,684,874	100.0%	9,785,384,508	100.0%	9,080,197,895	$235,965,130	$23,371,585	$2,003,350	$10,346,850	$5,953,636	$18,303,836	$963,882	$554,623	$1,518,505	$37,999,703	$91,713,679	$18,784,729	$110,498,408	$148,498,111	$427,657,167	-$5,594,608	$0.00	-$226	$422,062,333	$422,284,965	100.0%	$422,062,333	**4.648**
40																														
41	Purchased Power Allocation Factors.									10.9%	56.5%	32.5%	100.0%	63.5%	36.5%	100.0%	$37,999,703	83%	17%	100%										
42																														
43	**Non-FAM Rate Classes**																													
44	[redacted]																													
45																														
46																														
47																														
49																														
50	**In Province Total**		**5,684,874**		**10,873,274,091**		**10,144,296,352**	**285,247,729**	**23,371,585**	**2,003,350**	**10,346,850**	**5,953,636**	**18,303,836**	**$963,882**	**$554,623**	**$1,518,505**	**$37,999,703**	**$91,713,679**	**$18,784,729**	**$110,498,408**		**$476,939,766**	**-$5,594,608**	**$0**	**-$226**	**$471,344,932**	**$471,567,564**	**100.0%**	**$471,344,932**	**9.280**
53	**Exports**				103,355,000		100,351,000																							
54																														
55	**Non-FAM Categories**				1,191,244,583		1,164,449,457	49,282,599	-	0	0	0	0	0	0	0	0													
56																														
57	**Grand Total**				**10,976,629,091**		**10,244,647,352**	**$285,247,729**	**$23,371,585**	**$2,003,350**	**$10,346,850**	**$5,953,636**	**$18,303,836**	**$963,882**	**$554,623**	**$1,518,505**	**$37,999,703**	**$91,713,679**	**$18,784,729**	**$110,498,408**	**$148,498,111**	**$476,939,766**	**-$5,594,608**	**$0**	**$226**	**$471,344,932**	**$471,567,564**	**100%**	**$471,344,932**	**4.601**
58																														

Monthly Fuel Cost Allocation

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Purchased Power													
Imports	$1,317,680	$890,218	$1,492,890	$479,704	$794,217	$261,331	$2,008,296	$1,306,714	$3,213,005	$4,319,124	$5,565,132	$1,723,273	**$23,371,585**
Biomass													
IPP	$1,424,603	$1,227,499	$1,340,266	$1,181,977	$825,955	$759,356	$1,160,727	$1,197,205	$1,093,442	$1,226,857	$1,191,830	$1,268,786	**$13,898,503**
Comfit	$377,858	$449,586	$415,020	$371,884	$369,725	$331,410	$416,504	$363,370	$294,348	$362,543	$265,240	$387,846	**$4,405,333**
Total	**$1,802,461**	**$1,677,085**	**$1,755,285**	**$1,553,861**	**$1,195,680**	**$1,090,766**	**$1,577,231**	**$1,560,575**	**$1,387,789**	**$1,589,399**	**$1,457,070**	**$1,656,632**	**$18,303,836**
Regular other than biomass and wind													
IPP	$127,853	$127,273	$163,847	$105,682	$126,724	$70,278	$70,887	$59,797	$91,606	$118,163	$45,290	$154,427	**$1,261,828**
Comfit	$9,694	($7,395)	$9,992	$14,443	$16,128	$21,299	$12,590	$17,550	$13,546	$18,990	$108,502	$21,338	**$256,676**
Total	**$137,548**	**$119,878**	**$173,839**	**$120,125**	**$142,852**	**$91,576**	**$83,477**	**$77,347**	**$105,152**	**$137,154**	**$153,792**	**$175,764**	**$1,518,505**
Wind NRIS													
IPP	$4,219,217	$3,903,290	$4,874,703	$3,228,935	$3,584,380	$3,446,742	$1,929,194	$2,641,250	$2,946,153	$4,244,585	$4,628,812	$4,223,707	**$43,870,970**
Comfit	$6,000,468	$5,105,465	$7,295,838	$5,124,164	$6,048,158	$5,022,444	$3,275,529	$3,927,126	$4,643,795	$6,508,073	$7,001,623	$6,674,755	**$66,627,438**
Total	**$10,219,685**	**$9,008,756**	**$12,170,541**	**$8,353,100**	**$9,632,538**	**$8,469,187**	**$5,204,724**	**$6,568,376**	**$7,589,948**	**$10,752,658**	**$11,630,435**	**$10,898,461**	**$110,498,408**
Wind ERIS													
IPP	$3,654,433	$3,299,589	$4,197,649	$2,817,569	$3,316,523	$2,870,125	$1,832,564	$2,134,125	$2,565,708	$3,736,215	$3,883,347	$3,691,857	**$37,999,703**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$3,654,433**	**$3,299,589**	**$4,197,649**	**$2,817,569**	**$3,316,523**	**$2,870,125**	**$1,832,564**	**$2,134,125**	**$2,565,708**	**$3,736,215**	**$3,883,347**	**$3,691,857**	**$37,999,703**
Grand Total	**$17,131,808**	**$14,995,526**	**$19,790,205**	**$13,324,360**	**$15,081,810**	**$12,782,985**	**$10,706,291**	**$11,647,136**	**$14,861,601**	**$20,534,551**	**$22,689,777**	**$18,145,988**	**$191,692,037**
Plant Fuel Costs													
Plant Fuel Costs	$34,707,544	$26,334,158	$26,190,281	$21,125,925	$18,667,197	$16,393,032	$20,893,421	$23,494,792	$17,982,809	$17,396,686	$25,271,296	$36,790,587	**$285,247,729**
BTL Class Fuel-related costs													
GRLF	$56,573	$153,631	$27,077	$25,593	$82,152	$78,173	$56,084	$68,912	$76,128	$117,593	$431,398	$73,645	**$1,246,959**
1P - RTP	$31,749	$4,936	$5,452	$7,089	$37,831	$61,809	($8,629)	$53,066	$58,449	$55,704	$56,169	$57,708	**$421,334**
LRT	$3,886,608	$3,650,458	$3,164,967	$3,741,922	$3,097,360	$3,218,684	$2,393,422	$4,097,413	$3,623,577	$4,347,024	$5,392,414	$5,996,215	**$46,610,064**
Shore Power	$0	$0	$0	$1,327	$2,099	$1,400	$2,422	$9,079	$13,212	$18,775	$0	$0	**$48,315**
BUTU	$63,211	$58,681	$55,936	$81,182	$84,594	$78,796	$78,161	$144,534	$99,164	$61,136	$56,769	$93,762	**$955,927**
Total	$4,038,140	$3,867,707	$3,253,432	$3,857,114	$3,304,036	$3,438,861	$2,521,460	$4,373,005	$3,870,530	$4,600,233	$5,936,751	$6,221,330	**$49,282,599**

Monthly Fuel Cost Allocation

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
ATL-related Fuel costs (net of BTL)	$30,669,404	$22,466,451	$22,936,849	$17,268,812	$15,363,161	$12,954,171	$18,371,961	$19,121,788	$14,112,279	$12,796,453	$19,334,545	$30,569,256	**$235,965,130**
Fuel costs before PP													
Domestic	$16,787,640	$12,525,634	$12,722,692	$8,610,223	$7,437,226	$5,394,266	$7,619,555	$7,827,037	$5,810,621	$5,531,059	$9,372,154	$16,538,819	$116,176,925
Small General	$1,057,729	$718,938	$732,502	$528,292	$518,629	$391,964	$602,718	$597,327	$424,315	$380,634	$537,986	$866,746	$7,357,780
General	$7,263,463	$5,270,074	$5,276,903	$4,466,056	$3,843,406	$3,788,130	$5,314,542	$5,486,042	$4,049,352	$3,621,300	$4,963,726	$7,466,278	$60,809,273
Large General	$1,053,362	$760,929	$830,174	$718,646	$685,313	$665,320	$1,001,993	$1,092,779	$777,954	$671,854	$818,913	$1,060,343	$10,137,579
Small Industrial	$793,551	$494,860	$536,170	$418,073	$443,673	$398,818	$628,736	$539,561	$463,805	$292,225	$556,505	$713,267	$6,279,245
Medium Industrial	$1,238,420	$874,014	$881,374	$835,472	$797,115	$806,577	$1,077,810	$1,153,898	$859,217	$762,172	$1,035,068	$1,462,187	$11,783,324
Large Industrial													
Customers staying on the rate	$254,495	$174,117	$202,401	$181,339	$154,410	$137,180	$193,612	$213,896	$150,833	$144,204	$188,005	$248,596	$2,243,088
Customer A moving some of its load to a BTL rate	$1,488,583	$1,094,864	$1,198,122	$1,088,047	$1,114,893	$1,044,945	$1,459,187	$1,719,572	$1,219,369	$1,079,178	$1,376,135	$1,515,829	$15,398,725
Large Industrial	$1,743,079	$1,268,981	$1,400,523	$1,269,387	$1,269,302	$1,182,124	$1,652,800	$1,933,468	$1,370,202	$1,223,382	$1,564,140	$1,764,426	$17,641,813
ELI 2P-RTP													
Municipal													
Customers staying on in 2015	$152,314	$112,615	$123,585	$90,177	$78,820	$70,439	$94,731	$100,701	$72,278	$66,684	$101,297	$159,816	$1,223,457
Customers migrating to OATT in 2015													
Customer A	$219,027	$160,356	$165,031	$108,899	$78,043	$73,469	$106,255	$102,428	$81,799	$76,164	$125,154	$175,527	$1,472,152
Customer B	$72,906	$56,801	$61,553	$38,601	$31,624	$29,516	$43,036	$48,763	$35,206	$33,084	$52,296	$68,748	$572,134
Customer C	$33,650	$25,296	$25,994	$15,833	$11,779	$9,050	$12,871	$13,698	$9,855	$9,886	$18,704	$30,099	$216,715
Customer D	$23,905	$16,203	$17,881	$11,191	$6,732	$5,078	$7,817	$8,675	$5,097	$5,059	$11,415	$23,771	$142,825
Municipal	$501,801	$371,271	$394,045	$264,701	$206,999	$187,552	$264,710	$274,265	$204,234	$190,877	$308,866	$457,961	$3,627,283
Unmetered	$230,359	$181,751	$162,466	$157,962	$161,498	$139,419	$209,095	$217,410	$152,579	$122,950	$177,189	$239,231	$2,151,910
Total	**$30,669,404**	**$22,466,451**	**$22,936,849**	**$17,268,812**	**$15,363,161**	**$12,954,171**	**$18,371,961**	**$19,121,788**	**$14,112,279**	**$12,796,453**	**$19,334,545**	**$30,569,256**	**$235,965,130**
BTL Fuel-related costs													
[redacted]													
Subtotal before PP	$4,038,140	$3,867,707	$3,253,432	$3,857,114	$3,304,036	$3,438,861	$2,521,460	$4,373,005	$3,870,530	$4,600,233	$5,936,751	$6,221,330	$49,282,599

Monthly Fuel Cost Allocation

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Exports	**($289,176)**	**($181,976)**	**($321,896)**	**($411,262)**	**($276,992)**	**($800,355)**	**($242,482)**	**($301,414)**	**($227,586)**	**($141,940)**	**($117,419)**	**($2,282,109)**	**($5,594,608)**
Domestic	($158,288)	($101,456)	($178,550)	($205,055)	($134,090)	($333,277)	($100,567)	($123,377)	($93,707)	($61,351)	($56,917)	($1,234,685)	($2,781,320)
Small General	($9,973)	($5,823)	($10,280)	($12,581)	($9,351)	($24,217)	($7,955)	($9,416)	($6,843)	($4,222)	($3,267)	($64,706)	($168,634)
General	($68,486)	($42,687)	($74,056)	($106,361)	($69,295)	($234,044)	($70,144)	($86,476)	($65,303)	($40,168)	($30,145)	($557,386)	($1,444,550)
Large General	($9,932)	($6,163)	($11,651)	($17,115)	($12,356)	($41,106)	($13,225)	($17,225)	($12,546)	($7,452)	($4,973)	($79,159)	($232,903)
Small Industrial	($7,482)	($4,008)	($7,525)	($9,957)	($7,999)	($24,640)	($8,298)	($8,505)	($7,480)	($3,241)	($3,380)	($53,248)	($145,764)
Medium Industrial	($11,677)	($7,079)	($12,369)	($19,897)	($14,372)	($49,833)	($14,225)	($18,189)	($13,856)	($8,454)	($6,286)	($109,158)	($285,396)
Large Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Customers staying on the rate	($2,400)	($1,410)	($2,840)	($4,319)	($2,784)	($8,475)	($2,555)	($3,372)	($2,432)	($1,600)	($1,142)	($18,559)	($51,888)
Customer A moving some of its load to a BTL rate	($14,036)	($8,868)	($16,814)	($25,912)	($20,101)	($64,560)	($19,259)	($27,105)	($19,665)	($11,970)	($8,357)	($113,162)	($349,811)
Large Industrial	($16,435)	($10,279)	($19,655)	($30,231)	($22,885)	($73,036)	($21,814)	($30,477)	($22,097)	($13,570)	($9,499)	($131,721)	($401,699)
ELI 2P-RTP	$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	
Customers staying on in 2015	($1,436)	($912)	($1,734)	($2,148)	($1,421)	($4,352)	($1,250)	($1,587)	($1,166)	($740)	($615)	($11,931)	($29,292)
Customers migrating to OATT in 2015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Customer A	($2,065)	($1,299)	($2,316)	($2,593)	($1,407)	($4,539)	($1,402)	($1,615)	($1,319)	($845)	($760)	($13,104)	($33,265)
Customer B	($687)	($460)	($864)	($919)	($570)	($1,824)	($568)	($769)	($568)	($367)	($318)	($5,132)	($13,046)
Customer C	($317)	($205)	($365)	($377)	($212)	($559)	($170)	($216)	($159)	($110)	($114)	($2,247)	($5,051)
Customer D	($225)	($131)	($251)	($267)	($121)	($314)	($103)	($137)	($82)	($56)	($69)	($1,775)	($3,531)
Municipal	($4,731)	($3,007)	($5,530)	($6,304)	($3,732)	($11,588)	($3,494)	($4,323)	($3,294)	($2,117)	($1,876)	($34,189)	($84,184)
Unmetered	($2,172)	($1,472)	($2,280)	($3,762)	($2,912)	($8,614)	($2,760)	($3,427)	($2,461)	($1,364)	($1,076)	($17,859)	($50,158)
Total	($289,176)	($181,976)	($321,896)	($411,262)	($276,992)	($800,355)	($242,482)	($301,414)	($227,586)	($141,940)	($117,419)	($2,282,109)	($5,594,608)
Imports													
Domestic	$721,264	$496,320	$828,082	$239,180	$384,476	$108,821	$832,917	$534,871	$1,322,930	$1,866,871	$2,697,621	$932,339	$10,965,693
Small General	$45,444	$28,487	$47,676	$14,675	$26,811	$7,907	$65,885	$40,819	$96,606	$128,474	$154,850	$48,861	$706,496
General	$312,067	$208,823	$343,458	$124,061	$198,689	$76,420	$580,949	$374,896	$921,934	$1,222,280	$1,428,727	$420,895	$6,213,199
Large General	$45,257	$30,151	$54,034	$19,963	$35,428	$13,422	$109,531	$74,677	$177,120	$226,768	$235,711	$59,774	$1,081,835
Small Industrial	$34,094	$19,608	$34,898	$11,614	$22,936	$8,046	$68,729	$36,872	$105,597	$98,633	$160,181	$40,209	$641,416
Medium Industrial	$53,207	$34,632	$57,366	$23,208	$41,208	$16,271	$117,819	$78,853	$195,622	$257,252	$297,927	$82,427	$1,255,794
Large Industrial													
Customers staying on the rate	$10,934	$6,899	$13,174	$5,037	$7,982	$2,767	$21,164	$14,617	$34,341	$48,672	$54,114	$14,014	$233,717
Customer A moving some of its load to a BTL rate	$63,956	$43,383	$77,982	$30,224	$57,636	$21,080	$159,508	$117,509	$277,619	$364,250	$396,098	$85,451	$1,694,697
Large Industrial	$74,890	$50,283	$91,156	$35,262	$65,618	$23,848	$180,673	$132,126	$311,960	$412,922	$450,212	$99,466	$1,928,414
ELI 2P-RTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Municipal													
Customers staying on in 2015	$6,544	$4,462	$8,044	$2,505	$4,075	$1,421	$10,355	$6,882	$16,456	$22,508	$29,157	$9,009	$121,417
Customers migrating to OATT in 2015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer A	$9,410	$6,354	$10,741	$3,025	$4,035	$1,482	$11,615	$7,000	$18,623	$25,707	$36,023	$9,895	$143,911
Customer B	$3,132	$2,251	$4,006	$1,072	$1,635	$595	$4,704	$3,332	$8,015	$11,167	$15,053	$3,875	$58,839
Customer C	$1,446	$1,002	$1,692	$440	$609	$183	$1,407	$936	$2,244	$3,337	$5,384	$1,697	$20,375
Customer D	$1,027	$642	$1,164	$311	$348	$102	$855	$593	$1,160	$1,708	$3,286	$1,340	$12,535
Municipal	$21,559	$14,711	$25,647	$7,353	$10,701	$3,784	$28,936	$18,742	$46,499	$64,426	$88,902	$25,817	$357,077
Unmetered	$9,897	$7,202	$10,574	$4,388	$8,349	$2,813	$22,857	$14,857	$34,738	$41,499	$51,001	$13,486	$221,661
Total	$1,317,680	$890,218	$1,492,890	$479,704	$794,217	$261,331	$2,008,296	$1,306,714	$3,213,005	$4,319,124	$5,565,132	$1,723,273	$23,371,585

Monthly Fuel Cost Allocation

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total
Purchased Biomass Generation	1,424,603	1,227,499	1,340,266	1,181,977	825,955	759,356	1,160,727	1,197,205	1,093,442	1,226,857	1,191,830	1,268,786	13,898,503
Relative Share	10.3%	8.8%	9.6%	8.5%	5.9%	5.5%	8.4%	8.6%	7.9%	8.8%	8.6%	9.1%	100.0%
Bio-fuel Apportioned	**$205,344**	**$176,933**	**$193,188**	**$170,372**	**$119,054**	**$109,455**	**$167,309**	**$172,567**	**$157,610**	**$176,841**	**$171,792**	**$182,885**	**$2,003,350**
Domestic	$112,400	$98,645	$107,158	$84,947	$57,634	$45,578	$69,389	$70,636	$64,895	$76,437	$83,274	$98,946	$969,939
Small General	$7,082	$5,662	$6,170	$5,212	$4,019	$3,312	$5,489	$5,391	$4,739	$5,260	$4,780	$5,185	$62,300
General	$48,632	$41,504	$44,445	$44,062	$29,784	$32,007	$48,398	$49,509	$45,224	$50,045	$44,104	$44,668	$522,383
Large General	$7,053	$5,993	$6,992	$7,090	$5,311	$5,622	$9,125	$9,862	$8,688	$9,285	$7,276	$6,344	$88,640
Small Industrial	$5,313	$3,897	$4,516	$4,125	$3,438	$3,370	$5,726	$4,869	$5,180	$4,038	$4,945	$4,267	$53,684
Medium Industrial	$8,292	$6,883	$7,423	$8,243	$6,177	$6,815	$9,815	$10,413	$9,596	$10,533	$9,197	$8,748	$102,136
Large Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customers staying on the rate	$1,704	$1,371	$1,705	$1,789	$1,197	$1,159	$1,763	$1,930	$1,685	$1,993	$1,670	$1,487	$19,453
Customer A moving some of its load to a BTL rate	$9,967	$8,623	$10,091	$10,735	$8,640	$8,829	$13,288	$15,518	$13,618	$14,914	$12,227	$9,069	$135,519
Large Industrial	$11,671	$9,994	$11,796	$12,524	$9,836	$9,988	$15,052	$17,449	$15,303	$16,907	$13,898	$10,556	$154,972
ELI 2P-RTP													
Municipal													
Customers staying on in 2015	$1,020	$887	$1,041	$890	$611	$595	$863	$909	$807	$922	$900	$956	$10,400
Customers migrating to OATT in 2015													$0
Customer A	$1,466	$1,263	$1,390	$1,074	$605	$621	$968	$924	$914	$1,053	$1,112	$1,050	$12,440
Customer B	$488	$447	$518	$381	$245	$249	$392	$440	$393	$457	$465	$411	$4,888
Customer C	$225	$199	$219	$156	$91	$76	$117	$124	$110	$137	$166	$180	$1,801
Customer D	$160	$128	$151	$110	$52	$43	$71	$78	$57	$70	$101	$142	$1,164
Municipal	$3,360	$2,924	$3,319	$2,612	$1,604	$1,585	$2,411	$2,475	$2,281	$2,638	$2,744	$2,740	$30,692
Unmetered	$1,542	$1,431	$1,368	$1,558	$1,251	$1,178	$1,904	$1,962	$1,704	$1,699	$1,574	$1,431	$18,605
Total	**$205,344**	**$176,933**	**$193,188**	**$170,372**	**$119,054**	**$109,455**	**$167,309**	**$172,567**	**$157,610**	**$176,841**	**$171,792**	**$182,885**	**$2,003,350**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Monthly Energy Allocators

Rate Class	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 FAM Total	2017 Actuals 3- CP kWs
ATL														
Domestic Total	573,303,556	520,441,005	568,371,276	388,561,885	359,059,983	275,203,185	285,678,528	286,562,510	272,323,055	302,519,448	396,743,229	556,868,197	4,785,635,857	3,535,616
Small General	36,121,786	29,871,916	32,723,684	23,840,725	25,038,769	19,997,114	22,597,596	21,869,278	19,886,112	20,818,677	22,774,078	29,183,657	304,723,389	151,256
General	248,049,709	218,971,962	235,739,438	201,544,065	185,554,848	193,261,786	199,257,117	200,854,297	189,778,649	198,065,824	210,125,097	251,392,365	2,532,595,156	1,142,508
Large General	35,972,665	31,616,637	37,087,050	32,431,050	33,086,044	33,943,094	37,567,514	40,008,683	36,459,936	36,746,856	34,666,318	35,702,141	425,287,987	161,919
Small Industrial	27,100,048	20,561,466	23,952,750	18,866,788	21,419,982	20,346,788	23,573,092	19,754,354	21,736,889	15,983,162	23,558,026	24,015,960	260,869,305	120,558
Medium Industrial	42,292,466	36,315,364	39,374,354	37,703,147	38,483,707	41,149,706	40,410,128	42,246,358	40,268,447	41,686,744	43,816,637	49,232,369	492,979,427	185,237
Large Industrial	59,526,722	52,726,243	62,566,706	57,284,854	61,280,339	60,309,300	61,968,101	70,787,902	64,216,476	66,912,454	66,213,360	59,408,868	743,201,325	233,693
ELI 2P-RTP (Adjusted CBL)														0
Municipal														
Customers staying on in 2015	5,201,561	4,679,147	5,521,013	4,069,491	3,805,334	3,593,656	3,551,740	3,686,859	3,387,392	3,647,263	4,288,135	5,381,059	50,812,651	28,675
Customers migrating to OATT in 2015														
Customer A	7,479,829	6,662,813	7,372,586	4,914,395	3,767,841	3,748,219	3,983,781	3,750,081	3,833,608	4,165,778	5,298,028	5,910,053	60,887,011	43,101
Customer B	2,489,775	2,360,076	2,749,793	1,741,999	1,526,790	1,505,851	1,613,543	1,785,308	1,649,970	1,809,499	2,213,807	2,314,758	23,761,168	13,981
Customer C	1,149,143	1,051,050	1,161,273	714,503	568,690	461,695	482,579	501,491	461,880	540,704	791,772	1,013,458	8,898,239	6,644
Customer D	816,366	673,248	798,830	505,032	325,015	259,062	293,093	317,610	238,868	276,712	483,218	800,391	5,787,444	5,526
Municipal	17,136,673	15,426,333	17,603,495	11,945,420	9,993,670	9,568,483	9,924,738	10,041,349	9,571,718	10,439,955	13,074,960	15,419,719	150,146,514	97,927
Unmetered	7,866,841	7,551,764	7,257,976	7,128,518	7,796,901	7,112,862	7,839,577	7,959,803	7,150,828	6,724,721	7,500,770	8,054,987	89,945,548	56,161
Total	**1,047,370,468**	**933,482,688**	**1,024,676,729**	**779,306,453**	**741,714,242**	**660,892,318**	**688,816,388**	**700,084,533**	**661,392,110**	**699,897,841**	**818,472,475**	**1,029,278,263**	**9,785,384,508**	5,684,874
BTL														
[redacted]														
BTL Total	89,301,467	86,265,260	86,539,802	98,251,564	84,118,183	91,293,156	62,523,264	102,338,406	98,327,244	96,500,597	109,673,477	82,757,164	1,087,889,583	
In-province Total	**1,136,671,935**	**1,019,747,948**	**1,111,216,531**	**877,558,017**	**825,832,425**	**752,185,474**	**751,339,651**	**802,422,939**	**759,719,354**	**796,398,438**	**928,145,952**	**1,112,035,427**	**10,873,274,091**	
													0	
Exports	11,160,000	3,840,000	9,820,000	13,457,000	11,252,000	9,578,000	3,473,000	7,851,000	7,184,000	5,266,000	1,984,000	18,490,000	103,355,000	
NSR simulated	1,153,972,842	1,020,630,990	1,099,351,181	883,276,228	851,161,218	762,621,283	757,021,601	791,085,330	758,839,016	781,919,714	902,318,190	1,094,370,633	10,856,568,226	
NSR actual	1,136,671,935	1,019,747,948	1,111,216,531	877,558,017	825,832,425	752,185,474	751,339,651	802,422,939	759,719,354	796,398,438	928,145,952	1,112,035,427	10,873,274,091	
NSR correction factor	**0.985008**	**0.999135**	**1.010793**	**0.993526**	**0.970242**	**0.986316**	**0.992494**	**1.014332**	**1.001160**	**1.018517**	**1.028624**	**1.016142**	**1.001539**	
Simulated Requirements (kWhs)														
Domestic Total	582,029,619	520,891,676	562,302,320	391,093,774	370,072,575	279,021,350	287,838,950	282,513,605	272,007,496	297,019,569	385,702,950	548,022,290	4,778,516,175	3,535,616
Small General	36,671,583	29,897,783	32,374,267	23,996,072	25,806,723	20,274,553	22,768,488	21,560,283	19,863,068	20,440,188	22,140,337	28,720,072	304,513,418	151,256
General	251,825,192	219,161,579	233,222,259	202,857,336	191,245,931	195,943,097	200,763,983	198,016,383	189,558,739	194,464,937	204,277,891	247,398,972	2,528,736,298	1,142,508
Large General	36,520,194	31,644,015	36,691,041	32,642,373	34,100,813	34,414,020	37,851,615	39,443,391	36,417,687	36,078,789	33,701,649	35,135,009	424,640,597	161,919
Small Industrial	27,512,529	20,579,271	23,696,988	18,989,725	22,076,946	20,629,079	23,751,361	19,475,240	21,711,701	15,692,584	22,902,471	23,634,464	260,652,359	120,558
Medium Industrial	42,936,186	36,346,811	38,953,923	37,948,823	39,664,026	41,720,617	40,715,726	41,649,450	40,221,785	40,928,868	42,597,340	48,450,308	492,133,862	185,237
Large Industrial														
Customers staying on the rate	8,823,380	7,240,836	8,945,479	8,236,806	7,683,340	7,095,688	7,313,961	7,720,500	7,060,802	7,743,777	7,737,185	8,237,366	93,839,120	0
Customer A moving some of its load to a BTL rate	51,609,378	45,531,065	52,953,152	49,421,319	55,476,505	54,050,342	55,122,769	62,067,224	57,081,262	57,952,191	56,633,638	50,227,786	648,126,633	0
Large Industrial - Total	60,432,758	52,771,901	61,898,631	57,658,125	63,159,845	61,146,030	62,436,730	69,787,724	64,142,064	65,695,968	64,370,823	58,465,152	741,965,753	233,693
ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Municipal														
Customers staying on in 2015	5,280,732	4,683,199	5,462,061	4,096,008	3,922,046	3,643,515	3,578,600	3,634,766	3,383,467	3,580,955	4,168,808	5,295,581	50,729,737	28,675
Customers migrating to OATT in 2015														
Customer A	7,593,677	6,668,582	7,293,863	4,946,417	3,883,403	3,800,222	4,013,908	3,697,095	3,829,166	4,090,043	5,150,599	5,816,171	60,783,146	43,101
Customer B	2,527,671	2,362,119	2,720,432	1,753,350	1,573,617	1,526,743	1,625,745	1,760,083	1,648,058	1,776,602	2,152,203	2,277,988	23,704,611	13,981
Customer C	1,166,634	1,051,961	1,148,873	719,159	586,132	468,101	486,229	494,406	461,345	530,874	769,739	997,360	8,880,810	6,644
Customer D	828,791	673,831	790,300	508,323	334,983	262,656	295,310	313,122	238,591	271,681	469,772	787,677	5,775,037	5,526
Municipal Total	17,397,505	15,439,691	17,415,528	12,023,257	10,300,182	9,701,236	9,999,793	9,899,472	9,560,627	10,250,154	12,711,120	15,174,776	149,873,342	97,927
Unmetered	7,986,580	7,558,303	7,180,476	7,174,968	8,036,036	7,211,546	7,898,863	7,847,337	7,142,542	6,602,464	7,292,044	7,927,033	89,858,193	56,161
Total	**1,063,312,147**	**934,291,029**	**1,013,735,433**	**784,384,452**	**764,463,078**	**670,061,528**	**694,025,509**	**690,192,886**	**660,625,710**	**687,173,522**	**795,696,626**	**1,012,928,075**	9,770,889,996	5,684,874

Monthly Energy Allocators

Rate Class	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 FAM Total	2017 Actuals 3- CP kWs
BTL													0	
[redacted]														
BTL Total	90,660,695	86,339,960	85,615,747	98,891,776	86,698,140	92,559,756	62,996,091	100,892,444	98,213,305	94,746,192	106,621,564	81,442,558	1,065,199,928	
NSR	1,153,972,842	1,020,630,990	1,099,351,181	883,276,228	851,161,218	762,621,283	757,021,601	791,085,330	758,839,016	781,919,714	902,318,190	1,094,370,633	10,856,568,226	10,873,274,091
Exports	11,152,463	3,843,259	9,826,703	13,484,397	11,278,234	9,604,025	3,478,315	7,845,280	7,192,710	5,257,678	1,980,392	18,510,119	103,453,575	
ATL														
Fuel Cost Allocators														
Domestic	54.74%	55.75%	55.47%	49.86%	48.41%	41.64%	41.47%	40.93%	41.17%	43.22%	48.47%	54.10%	48.91%	
Small General	3.45%	3.20%	3.19%	3.06%	3.38%	3.03%	3.28%	3.12%	3.01%	2.97%	2.78%	2.84%	3.12%	
General	23.68%	23.46%	23.01%	25.86%	25.02%	29.24%	28.93%	28.69%	28.69%	28.30%	25.67%	24.42%	25.88%	
Large General	3.43%	3.39%	3.62%	4.16%	4.46%	5.14%	5.45%	5.71%	5.51%	5.25%	4.24%	3.47%	4.35%	
Small Industrial	2.59%	2.20%	2.34%	2.42%	2.89%	3.08%	3.42%	2.82%	3.29%	2.28%	2.88%	2.33%	2.67%	
Medium Industrial	4.04%	3.89%	3.84%	4.84%	5.19%	6.23%	5.87%	6.03%	6.09%	5.96%	5.35%	4.78%	5.04%	
Large Industrial														
Customers staying on the rate	0.83%	0.78%	0.88%	1.05%	1.01%	1.06%	1.05%	1.12%	1.07%	1.13%	0.97%	0.81%	0.96%	
Customer A moving some of its load to a BTL rate	4.85%	4.87%	5.22%	6.30%	7.26%	8.07%	7.94%	8.99%	8.64%	8.43%	7.12%	4.96%	6.63%	
Large Industrial - Total	5.68%	5.65%	6.11%	7.35%	8.26%	9.13%	9.00%	10.11%	9.71%	9.56%	8.09%	5.77%	7.59%	
ELI 2P-RTP	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%	
Municipal														
Customers staying on in 2015	0.50%	0.50%	0.54%	0.52%	0.51%	0.54%	0.52%	0.53%	0.51%	0.52%	0.52%	0.52%	0.52%	
Customers migrating to OATT in 2015														
Customer A	0.71%	0.71%	0.72%	0.63%	0.51%	0.57%	0.58%	0.54%	0.58%	0.60%	0.65%	0.57%	0.62%	
Customer B	0.24%	0.25%	0.27%	0.22%	0.21%	0.23%	0.23%	0.26%	0.25%	0.26%	0.27%	0.22%	0.24%	
Customer C	0.11%	0.11%	0.11%	0.09%	0.08%	0.07%	0.07%	0.07%	0.07%	0.08%	0.10%	0.10%	0.09%	
Customer D	0.08%	0.07%	0.08%	0.06%	0.04%	0.04%	0.04%	0.05%	0.04%	0.04%	0.06%	0.08%	0.06%	
Municipal Total	1.64%	1.65%	1.72%	1.53%	1.35%	1.45%	1.44%	1.43%	1.45%	1.49%	1.60%	1.50%	1.53%	
Unmetered	0.75%	0.81%	0.71%	0.91%	1.05%	1.08%	1.14%	1.14%	1.08%	0.96%	0.92%	0.78%	0.92%	
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%	

Monthly Energy Allocators

Rate Class	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 FAM Total		2017 Actuals 3- CP kWs
	Jan-17	**Feb-17**	**Mar-17**	**Apr-17**	**May-17**	**Jun-17**	**Jul-17**	**Aug-17**	**Sep-17**	**Oct-17**	**Nov-17**	**Dec-17**	**Total**	**2016 Test Year**	**3CP kWs**
Sales (MWhs)-Actuals															
ATL Classes															
Domestic Non-TOU	492,710,304	439,935,329	480,210,024	337,511,159	320,989,591	248,865,964	258,293,996	250,815,038	243,567,929	260,828,223	332,510,588	455,760,770	4,121,998,915		
Domestic TOU	34,292,023	31,495,243	32,391,006	22,466,857	18,383,096	11,122,973	9,902,070	10,183,168	10,752,360	13,188,253	21,200,957	36,180,411	251,558,418		
Domestic Total	527,002,328	471,430,572	512,601,030	359,978,017	339,372,687	259,988,937	268,196,066	260,998,206	254,320,289	274,016,476	353,711,545	491,941,181	4,373,557,333		3,068,110
Small General	33,525,547	27,270,883	29,662,780	22,082,604	23,621,436	18,932,172	21,160,188	19,835,054	18,529,511	19,028,052	20,382,393	26,105,954	280,136,575		132,090
General	237,162,123	206,107,255	218,310,334	191,313,700	179,427,919	185,237,010	189,380,975	185,808,121	179,818,138	183,300,529	192,970,557	230,107,619	2,378,944,281		1,062,380
Large General	34,281,835	29,850,128	34,437,289	30,849,772	32,116,023	32,765,569	35,686,148	37,114,311	34,803,202	33,990,831	31,856,592	32,852,457	400,604,157		151,090
Small Industrial	26,104,903	19,439,973	22,292,123	17,935,417	20,755,270	19,611,963	22,613,533	18,388,654	20,714,110	14,834,993	21,665,742	22,061,182	246,417,863		112,070
Medium Industrial	40,903,474	34,470,535	36,808,850	35,960,579	37,286,965	39,685,777	38,778,088	39,361,349	38,372,346	38,770,956	40,499,041	45,557,595	466,455,555		172,410
Large Industrial															226,600
Customers staying on the rate	8,490,705	6,931,815	8,543,165	7,864,453	7,289,552	6,794,975	7,004,919	7,339,004	6,785,234	7,380,647	7,438,171	7,855,049	89,717,690		
Customer A moving some of its load to a BTL rate	49,663,508	43,587,913	50,571,638	47,187,181	52,633,213	51,759,707	52,793,627	59,000,277	54,853,507	55,234,629	54,444,955	47,896,588	619,626,743		
Large Industrial - Total	58,154,213	50,519,728	59,114,803	55,051,634	59,922,765	58,554,682	59,798,546	66,339,281	61,638,741	62,615,277	61,883,126	55,751,637	709,344,434		226,600
ELI 2P-RTP (Adjusted CBL)	0	0	0	0	0	0	0	0	0	0	0	0	0		0
Municipal															
Customers staying on in 2015	5,030,321	4,464,071	5,171,370	3,888,297	3,718,474	3,479,362	3,419,757	3,445,636	3,240,632	3,406,111	3,985,704	4,987,122	48,236,857		27,218
Customers migrating to OATT in 2015															
Customer A	7,233,586	6,356,559	6,905,683	4,695,581	3,681,837	3,629,009	3,835,744	3,504,722	3,667,515	3,890,342	4,924,373	5,477,389	57,802,339		40,910
Customer B	2,407,809	2,251,596	2,575,650	1,664,437	1,491,939	1,457,958	1,553,584	1,668,499	1,578,484	1,689,857	2,057,674	2,145,299	22,542,785		13,271
Customer C	1,111,312	1,002,739	1,087,730	682,690	555,709	447,011	464,647	468,680	441,869	504,953	735,930	939,265	8,442,535		6,306
Customer D	789,490	642,302	748,240	482,545	317,596	250,822	282,202	296,829	228,519	258,416	449,138	741,796	5,487,897		5,245
Municipal Total	16,572,519	14,717,267	16,488,673	11,413,550	9,765,556	9,264,162	9,555,934	9,384,367	9,157,019	9,749,678	12,152,819	14,290,871	142,512,414		92,950
Unmetered	7,281,957	6,905,481	6,593,757	6,605,010	7,304,180	6,578,984	7,189,507	7,149,779	6,597,050	6,116,204	6,719,207	7,184,167	82,225,284		48,750
ATL Total	**980,988,900**	**860,711,821**	**936,309,640**	**731,190,282**	**709,572,801**	**630,619,257**	**652,358,985**	**644,379,121**	**623,950,406**	**642,422,995**	**741,841,024**	**925,852,662**	**9,080,197,895**		5,066,450
BTL															
[redacted]															
BTL Total	88,863,680	84,636,650	83,925,331	96,944,445	84,972,453	90,705,377	61,738,984	98,893,282	96,261,754	92,831,940	104,494,705	79,829,857	1,064,098,457		
In-province Sales	1,069,852,579	945,348,471	1,020,234,970	828,134,727	794,545,254	721,324,634	714,097,969	743,272,404	720,212,160	735,254,936	846,335,729	1,005,682,519	10,144,296,352		
Exports	10,818,000	3,728,000	9,532,000	13,080,000	10,940,000	9,316,000	3,374,000	7,610,000	6,977,000	5,100,000	1,921,000	17,955,000	100,351,000		
Total Sales	**1,080,670,579**	**949,076,471**	**1,029,766,970**	**841,214,727**	**805,485,254**	**730,640,634**	**717,471,969**	**750,882,404**	**727,189,160**	**740,354,936**	**848,256,729**	**1,023,637,519**	**10,244,647,352**		

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Monthly Energy Allocators

Rate Class	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017 FAM Total	2017 Actuals 3- CP kWs
Line Loss Factors from the 2017Test Year (2017-2019 RSP Fillings)														
Domestic Total	10.44%	10.49%	9.70%	8.64%	9.05%	7.32%	7.32%	8.24%	6.95%	8.39%	9.04%	11.40%	9.26%	15.24%
Small General	9.38%	9.63%	9.14%	8.67%	9.25%	7.09%	7.60%	8.70%	7.20%	7.42%	8.62%	10.01%	8.69%	14.51%
General	6.18%	6.33%	6.83%	6.03%	6.59%	5.78%	6.01%	6.57%	5.42%	6.09%	5.86%	7.51%	6.29%	7.54%
Large General	6.53%	6.01%	6.54%	5.81%	6.18%	5.03%	6.07%	6.28%	4.64%	6.14%	5.79%	6.95%	6.00%	7.17%
Small Industrial	5.39%	5.86%	6.30%	5.88%	6.37%	5.19%	5.03%	5.91%	4.82%	5.78%	5.71%	7.13%	5.79%	7.57%
Medium Industrial	4.97%	5.44%	5.83%	5.53%	6.38%	5.13%	5.00%	5.81%	4.82%	5.57%	5.18%	6.35%	5.49%	7.44%
Large Industrial														
Customers staying on the rate	3.92%	4.46%	4.71%	4.73%	5.40%	4.43%	4.41%	5.20%	4.06%	4.92%	4.02%	4.87%	4.59%	3.13%
Customer A moving some of its load to a BTL rate	3.92%	4.46%	4.71%	4.73%	5.40%	4.43%	4.41%	5.20%	4.06%	4.92%	4.02%	4.87%	4.59%	3.13%
Large Industrial - Total	3.92%	4.46%	4.71%	4.73%	5.40%	4.43%	4.41%	5.20%	4.06%	4.92%	4.02%	4.87%	4.59%	3.13%
ELI 2P-RTP	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%
Municipal														
Customers staying on in 2015	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customers migrating to OATT in 2015														
Customer A	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customer B	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customer C	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customer D	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Municipal Total	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Unmetered	9.68%	9.45%	8.90%	8.63%	10.02%	9.61%	9.87%	9.76%	8.27%	7.95%	8.53%	10.34%	9.25%	15.20%
BTL														
[redacted]														
BTL Total														
Exports	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Line Losses from 2017 Compliance Filing-2017-2019 RSP

Rate Class	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017Total	3CP kWs Jan-17	Feb-17	Dec-17	Total
kWh Sales																	
Domestic Total	527,002	471,431	512,601	359,978	339,373	259,989	268,196	260,998	254,320	274,016	353,712	491,941	**4,373,557**	965,750	945,100	1,157,260	3,068,110
Small General	33,526	27,271	29,663	22,083	23,621	18,932	21,160	19,835	18,530	19,028	20,382	26,106	**280,137**	57,850	37,610	36,630	132,090
General	237,162	206,107	218,310	191,314	179,428	185,237	189,381	185,808	179,818	183,301	192,971	230,108	**2,378,944**	377,870	330,470	354,040	1,062,380
Large General	34,282	29,850	34,437	30,850	32,116	32,766	35,686	37,114	34,803	33,991	31,857	32,852	**400,604**	52,400	50,850	47,840	151,090
Small Industrial	26,105	19,440	22,292	17,935	20,755	19,612	22,614	18,389	20,714	14,835	21,666	22,061	**246,418**	52,840	28,950	30,280	112,070
Medium Industrial	40,903	34,471	36,809	35,961	37,287	39,686	38,778	39,361	38,372	38,771	40,499	45,558	**466,456**	68,770	51,640	52,000	172,410
Large Industrial	58,154	50,520	59,115	55,052	59,923	58,555	59,799	66,339	61,639	62,615	61,883	55,752	**709,344**	82,710	79,780	64,110	226,600
ELI 2P-RTP																	
Customers staying on the rate	5,030	4,464	5,171	3,888	3,718	3,479	3,420	3,446	3,241	3,406	3,986	4,987	**48,237**	[redacted]			
Customers migrating to OATT in 2015																	
Customer A	7,234	6,357	6,906	4,696	3,682	3,629	3,836	3,505	3,668	3,890	4,924	5,477	**57,802**				
Customer B	2,408	2,252	2,576	1,664	1,492	1,458	1,554	1,668	1,578	1,690	2,058	2,145	**22,543**				
Customer C	1,111	1,003	1,088	683	556	447	465	469	442	505	736	939	**8,443**				
Customer D	789	642	748	483	318	251	282	297	229	258	449	742	**5,488**				
Municipal	16,573	14,717	16,489	11,414	9,766	9,264	9,556	9,384	9,157	9,750	12,153	14,291	**142,512**	34,700	25,130	33,120	92,950
Unmetered	7,282	6,905	6,594	6,605	7,304	6,579	7,190	7,150	6,597	6,116	6,719	7,184	**82,225**	14,870	14,190	19,690	48,750
ATL Total	**980,989**	**860,712**	**936,310**	**731,190**	**709,573**	**630,619**	**652,359**	**644,379**	**623,950**	**642,423**	**741,841**	**925,853**	**9,080,198**	**1,742,460**	**1,588,850**	**1,828,090**	**5,159,400**
BTL																	
[redacted]																	
BTL Total	88,864	84,637	83,925	96,944	84,972	90,705	61,739	98,893	96,262	92,832	104,495	79,830	**1,032,635**				
In-Province Total Sales	1,069,853	945,348	1,020,235	828,135	794,545	721,325	714,098	743,272	720,212	735,255	846,336	1,005,683	10,112,833				

kWh requirements- Estimated on 2017 Actual Sales

ATL																	
Domestic Non-TOU																	
Domestic TOU																	
Domestic Total	582,030	520,892	562,302	391,094	370,073	279,021	287,839	282,514	272,007	297,020	385,703	548,022	**4,778,516**	1,123,167	1,089,700	1,322,748	3,535,616
Small General	36,672	29,898	32,374	23,996	25,807	20,275	22,768	21,560	19,863	20,440	22,140	28,720	**304,513**	66,585	42,875	41,795	151,256
General	251,825	219,162	233,222	202,857	191,246	195,943	200,764	198,016	189,559	194,465	204,278	247,399	**2,528,736**	407,722	355,255	379,531	1,142,508
Large General	36,520	31,644	36,691	32,642	34,101	34,414	37,852	39,443	36,418	36,079	33,702	35,135	**424,641**	56,120	54,562	51,237	161,919
Small Industrial	27,513	20,579	23,697	18,990	22,077	20,629	23,751	19,475	21,712	15,693	22,902	23,634	**260,652**	56,856	31,121	32,581	120,558
Medium Industrial	42,936	36,347	38,954	37,949	39,664	41,721	40,716	41,649	40,222	40,929	42,597	48,450	**492,134**	73,928	55,410	55,900	185,237
Large Industrial	60,433	52,772	61,899	57,658	63,160	61,146	62,437	69,788	64,142	65,696	64,371	58,465	**741,966**	85,347	82,312	66,033	233,693
ELI 2P-RTP	-	-	-	-	-	-	-	-	-	-	-	-					
Customers staying on the rate	5,281	4,683	5,462	4,096	3,922	3,644	3,579	3,635	3,383	3,581	4,169	5,296	50,237	[redacted]			
Customers migrating to OATT in 2015	-	-	-	-	-	-	-	-	-	-	-	-					
Customer A	7,838	6,893	7,469	5,036	3,963	3,855	4,078	3,752	3,881	4,161	5,280	5,989	**62,195**				
Customer B	2,408	2,252	2,576	1,664	1,492	1,458	1,554	1,668	1,578	1,690	2,058	2,145	**22,543**				
Customer C	1,111	1,003	1,088	683	556	447	465	469	442	505	736	939	**8,443**				
Customer D	806	655	764	492	324	256	288	303	233	264	458	757	**5,600**				
Municipal	17,222	15,373	17,265	11,954	10,293	9,674	9,978	9,872	9,529	10,229	12,641	14,986	**149,017**	36,539	26,512	34,875	97,927
Unmetered	7,431	7,046	6,728	6,740	7,453	6,713	7,336	7,296	6,732	6,241	6,856	7,331	**83,903**	17,294	16,361	22,506	56,161
Total	**1,062,802**	**933,826**	**1,013,226**	**783,897**	**763,837**	**669,521**	**693,426**	**689,569**	**660,172**	**686,762**	**795,251**	**1,012,283**	**9,764,078**	**1,923,558**	**1,754,109**	**2,007,206**	**5,684,874**
BTL																	
[redacted]																	
BTL Total	90,728	86,402	85,683	98,985	86,797	92,639	63,074	101,062	98,307	94,813	106,677	81,567	**1,086,735**				
Total	90,728	86,402	85,683	98,985	86,797	92,639	63,074	101,062	98,307	94,813	106,677	81,567	**1,086,735**				
NSR	1,153,531	1,020,227	1,098,909	882,882	850,634	762,160	756,500	790,631	758,479	781,575	901,928	1,093,850	**10,851,307**				
Exports													**0**				
NSR	1,153,531	1,020,227	1,098,909	882,882	850,634	762,160	756,500	790,631	758,479	781,575	901,928	1,093,850	**10,851,307**				
TSR	1,153,531	1,020,227	1,098,909	882,882	850,634	762,160	756,500	790,631	758,479	781,575	901,928	1,093,850	**10,851,307**				

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Line Losses from 2017 Compliance Filing-2017-2019 RSP

Rate Class	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017Total
Line Losses	Line Losses from 2017-2019 RSP	Compliance Filing-2017 data											
ATL													
Domestic Total	10.4%	10.5%	9.7%	8.6%	9.0%	7.3%	7.3%	8.2%	7.0%	8.4%	9.0%	11.4%	9.3%
Small General	9.4%	9.6%	9.1%	8.7%	9.3%	7.1%	7.6%	8.7%	7.2%	7.4%	8.6%	10.0%	8.7%
General	6.2%	6.3%	6.8%	6.0%	6.6%	5.8%	6.0%	6.6%	5.4%	6.1%	5.9%	7.5%	6.3%
Large General	6.5%	6.0%	6.5%	5.8%	6.2%	5.0%	6.1%	6.3%	4.6%	6.1%	5.8%	6.9%	6.0%
Small Industrial	5.4%	5.9%	6.3%	5.9%	6.4%	5.2%	5.0%	5.9%	4.8%	5.8%	5.7%	7.1%	5.8%
Medium Industrial	5.0%	5.4%	5.8%	5.5%	6.4%	5.1%	5.0%	5.8%	4.8%	5.6%	5.2%	6.3%	5.5%
Large Industrial	3.9%	4.5%	4.7%	4.7%	5.4%	4.4%	4.4%	5.2%	4.1%	4.9%	4.0%	4.9%	4.6%
ELI 2P-RTP	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%
Municipal	5.0%	4.9%	5.6%	5.3%	5.5%	4.7%	4.6%	5.5%	4.4%	5.1%	4.6%	6.2%	5.2%
Unmetered	9.7%	9.5%	8.9%	8.6%	10.0%	9.6%	9.9%	9.8%	8.3%	8.0%	8.5%	10.3%	9.3%
Total	**8.4%**	**8.4%**	**8.2%**	**7.2%**	**7.6%**	**6.2%**	**6.3%**	**7.1%**	**5.8%**	**6.9%**	**7.2%**	**9.3%**	**7.5%**

3CP kWs

	Jan-17	Feb-17	Dec-17	Total
Domestic Total	16.3%	15.3%	14.3%	15.2%
Small General	15.1%	14.0%	14.1%	14.5%
General	7.9%	7.5%	7.2%	7.5%
Large General	7.1%	7.3%	7.1%	7.2%
Small Industrial	7.6%	7.5%	7.6%	7.6%
Medium Industrial	7.5%	7.3%	7.5%	7.4%
Large Industrial	3.2%	3.2%	3.0%	3.1%
ELI 2P-RTP	0.0%	0.0%	0.0%	0.0%
Municipal	5.3%	5.5%	5.3%	5.4%
Unmetered	16.3%	15.3%	14.3%	15.2%
Total	**10.4%**	**10.4%**	**9.8%**	**10.2%**

BTL

[redacted]

BTL Total

Winter kW Peaks-2017 Actuals

ATL Classes													**3CP**	Annual Peak
Domestic Total	1,123,167	1,089,700										1,322,748	3,535,616	1,123,167
Small General	66,585	42,875										41,795	151,256	66,585
General	407,722	355,255										379,531	1,142,508	407,722
Large General	56,120	54,562										51,237	161,919	56,120
Small Industrial	56,856	31,121										32,581	120,558	56,856
Medium Industrial	73,928	55,410										55,900	185,237	73,928
Large Industrial	85,347	82,312										66,033	233,693	85,347
Municipal	36,539	26,512										34,875	97,927	36,539
Unmetered	17,294	16,361										22,506	56,161	17,294
Total	**1,923,558**	**1,754,109**										**2,007,206**	5,684,874	1,923,558
BTL Classes													-	-
[redacted]														
Total	**21,685**	**114,322**										**10,076**	146,083	21,685
Grand Total	**1,945,243**	**1,868,431**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,017,282**	**5,830,957**	**1,945,243**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Category	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual
Plant Fuel Costs	$34,707,544	$26,334,158	$26,190,281	$21,125,925	$18,667,197	$16,393,032	$20,893,421	$23,494,792	$17,982,809	$17,396,686	$25,271,296	$36,790,587	$285,247,729
Non-Wind Purchases													
Purchased Power Regular bfr Biomass	$127,853	$127,273	$163,847	$105,682	$126,724	$70,278	$70,887	$59,797	$91,606	$118,163	$45,290	$154,427	$1,261,828
Purchased Power - Biomass	$1,424,603	$1,227,499	$1,340,266	$1,181,977	$825,955	$759,356	$1,160,727	$1,197,205	$1,093,442	$1,226,857	$1,191,830	$1,268,786	$13,898,503
Non-Wind Purchases	$1,552,457	$1,354,772	$1,504,113	$1,287,659	$952,680	$829,634	$1,231,615	$1,257,002	$1,185,048	$1,345,020	$1,237,121	$1,423,213	$15,160,331
Wind Purchases													
Purchased Power Wind - NRIS	$4,219,217	$3,903,290	$4,874,703	$3,228,935	$3,584,380	$3,446,742	$1,929,194	$2,641,250	$2,946,153	$4,244,585	$4,628,812	$4,223,707	$43,870,970
Purchased Power Wind - ERIS	$3,654,433	$3,299,589	$4,197,649	$2,817,569	$3,316,523	$2,870,125	$1,832,564	$2,134,125	$2,565,708	$3,736,215	$3,883,347	$3,691,857	$37,999,703
Purchased Power Wind	$7,873,650	$7,202,879	$9,072,353	$6,046,505	$6,900,903	$6,316,867	$3,761,758	$4,775,375	$5,511,861	$7,980,800	$8,512,159	$7,915,564	$81,870,673
Comift													
Wind Generatiion (NRIS)	$6,000,468	$5,105,465	$7,295,838	$5,124,164	$6,048,158	$5,022,444	$3,275,529	$3,927,126	$4,643,795	$6,508,073	$7,001,623	$6,674,755	$66,627,438
Wind Generatiion (ERIS)													
Biomass Generation	$377,858	$449,586	$415,020	$371,884	$369,725	$331,410	$416,504	$363,370	$294,348	$362,543	$265,240	$387,846	$4,405,333
Other	$9,694	$7,395	$9,992	$14,443	$16,128	$21,299	$12,590	$17,550	$13,546	$18,990	$108,502	$21,338	$256,676
Total Comfit	$6,388,020	$5,547,656	$7,720,850	$5,510,492	$6,434,011	$5,375,153	$3,704,623	$4,308,046	$4,951,688	$6,889,606	$7,375,365	$7,083,938	$71,289,447
Imports	$1,317,680	$890,218	$1,492,890	$479,704	$794,217	$261,331	$2,008,296	$1,306,714	$3,213,005	$4,319,124	$5,565,132	$1,723,273	$23,371,585
Export Revenues	$289,176	$181,976	$321,896	$411,262	$276,992	$800,355	$242,482	$301,414	$227,586	$141,940	$117,419	$2,282,109	$5,594,608
OM&G (Solid Fuel Handling) recovered in fuels													$0
Foreign Exchange (Fuel-related)	$41,568	$105,858	$6,491	$181,269	$34,690	$300,235	$61,075	$60,950	$121	$68	$89	$189	$226
Total FAM related costs	$51,839,352	$41,329,684	$45,980,487	$34,450,285	$33,749,007	$29,176,017	$31,599,712	$35,141,928	$32,844,410	$37,931,236	$47,961,073	$54,936,575	$476,939,766
Purchased Biomass Generation	$1,424,603	$1,227,499	$1,340,266	$1,181,977	$825,955	$759,356	$1,160,727	$1,197,205	$1,093,442	$1,226,857	$1,191,830	$1,268,786	$13,898,503

BLT Fuel Costs	**Source-2017 Revenue Forecast**													
[redacted]														
Total	$4,038,140	$3,867,707	$3,253,432	$3,857,114	$3,304,036	$3,438,861	$2,521,460	$4,373,005	$3,870,530	$4,600,233	$5,936,751	$6,221,330	$49,282,599	100%
[redacted]														
ERIS	**$3,654,433**	**$3,299,589**	**$4,197,649**	**$2,817,569**	**$3,316,523**	**$2,870,125**	**$1,832,564**	**$2,134,125**	**$2,565,708**	**$3,736,215**	**$3,883,347**	**$3,691,857**	**$37,999,703**	46.41%
NRIS	**$4,219,217**	**$3,903,290**	**$4,874,703**	**$3,228,935**	**$3,584,380**	**$3,446,742**	**$1,929,194**	**$2,641,250**	**$2,946,153**	**$4,244,585**	**$4,628,812**	**$4,223,707**	**$43,870,970**	53.59%
Total	**$7,873,650**	**$7,202,879**	**$9,072,353**	**$6,046,505**	**$6,900,903**	**$6,316,867**	**$3,761,758**	**$4,775,375**	**$5,511,861**	**$7,980,800**	**$8,512,159**	**$7,915,564**	**$81,870,673**	100.00%

Usage Data

Category		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual	
2017-kWh Sales-Actuals															
ATL Classes															
Domestic Non-TOU		492,710,304	439,935,329	480,210,024	337,511,159	320,989,591	248,865,964	258,293,996	250,815,038	243,567,929	260,828,223	332,510,588	455,760,770	4,121,998,915	
Domestic TOU		34,292,023	31,495,243	32,391,006	22,466,857	18,383,096	11,122,973	9,902,070	10,183,168	10,752,360	13,188,253	21,200,957	36,180,411	251,558,418	
Domestic Total		**527,002,328**	**471,430,572**	**512,601,030**	**359,978,017**	**339,372,687**	**259,988,937**	**268,196,066**	**260,998,206**	**254,320,289**	**274,016,476**	**353,711,545**	**491,941,181**	**4,373,557,333**	
Small General		**33,525,547**	**27,270,883**	**29,662,780**	**22,082,604**	**23,621,436**	**18,932,172**	**21,160,188**	**19,835,054**	**18,529,511**	**19,028,052**	**20,382,393**	**26,105,954**	280,136,575	
General		**237,162,123**	**206,107,255**	**218,310,334**	**191,313,700**	**179,427,919**	**185,237,010**	**189,380,975**	**185,808,121**	**179,818,138**	**183,300,529**	**192,970,557**	**230,107,619**	2,378,944,281	
Large General		**34,281,835**	**29,850,128**	**34,437,289**	**30,849,772**	**32,116,023**	**32,765,569**	**35,686,148**	**37,114,311**	**34,803,202**	**33,990,831**	**31,856,592**	**32,852,457**	400,604,157	
Small Industrial		**26,104,903**	**19,439,973**	**22,292,123**	**17,935,417**	**20,755,270**	**19,611,963**	**22,613,533**	**18,388,654**	**20,714,110**	**14,834,993**	**21,665,742**	**22,061,182**	246,417,863	
Medium Industrial		**40,903,474**	**34,470,535**	**36,808,850**	**35,960,579**	**37,286,965**	**39,685,777**	**38,778,088**	**39,361,349**	**38,372,346**	**38,770,956**	**40,499,041**	**45,557,595**	466,455,555	
Large Industrial															
Large Industrial - Firm		8,490,705	6,931,815	8,543,165	7,864,453	7,289,552	6,794,975	7,004,919	7,339,004	6,785,234	7,380,647	7,438,171	7,855,049	89,717,690	13%
Large Industrial - Interruptible		49,663,508	43,587,913	50,571,638	47,187,181	52,633,213	51,759,707	52,793,627	59,000,277	54,853,507	55,234,629	54,444,955	47,896,588	619,626,743	87%
Large Industrial - Total		**58,154,213**	**50,519,728**	**59,114,803**	**55,051,634**	**59,922,765**	**58,554,682**	**59,798,546**	**66,339,281**	**61,638,741**	**62,615,277**	**61,883,126**	**55,751,637**	**709,344,434**	100%
ELI 2P-RTP (Adjusted CBL)														-	
Municipal															
Customers staying on in 2015		5,030,321	4,464,071	5,171,370	3,888,297	3,718,474	3,479,362	3,419,757	3,445,636	3,240,632	3,406,111	3,985,704	4,987,122	48,236,857	
Customers migrating to OATT in 2015															
Customer A		7,233,586	6,356,559	6,905,683	4,695,581	3,681,837	3,629,009	3,835,744	3,504,722	3,667,515	3,890,342	4,924,373	5,477,389	57,802,339	
Customer B		2,407,809	2,251,596	2,575,650	1,664,437	1,491,939	1,457,958	1,553,584	1,668,499	1,578,484	1,689,857	2,057,674	2,145,299	22,542,785	
Customer C		1,111,312	1,002,739	1,087,730	682,690	555,709	447,011	464,647	468,680	441,869	504,953	735,930	939,265	8,442,535	
Customer D		789,490	642,302	748,240	482,545	317,596	250,822	282,202	296,829	228,519	258,416	449,138	741,796	5,487,897	
Municipal Total		**16,572,519**	**14,717,267**	**16,488,673**	**11,413,550**	**9,765,556**	**9,264,162**	**9,555,934**	**9,384,367**	**9,157,019**	**9,749,678**	**12,152,819**	**14,290,871**	**142,512,414**	
Unmetered		**7,281,957**	**6,905,481**	**6,593,757**	**6,605,010**	**7,304,180**	**6,578,984**	**7,189,507**	**7,149,779**	**6,597,050**	**6,116,204**	**6,719,207**	**7,184,167**	82,225,284	
ATL Total		**980,988,900**	**860,711,821**	**936,309,640**	**731,190,282**	**709,572,801**	**630,619,257**	**652,358,985**	**644,379,121**	**623,950,406**	**642,422,995**	**741,841,024**	**925,852,662**	**9,080,197,895**	
BTL Classes															
[redacted]															
BTL Total		**88,863,680**	**84,636,650**	**83,925,331**	**96,944,445**	**84,972,453**	**90,705,377**	**61,738,984**	**98,893,282**	**96,261,754**	**92,831,940**	**104,494,705**	**79,829,857**	1,064,098,457	
In-Province Total Sales		**1,069,852,579**	**945,348,471**	**1,020,234,970**	**828,134,727**	**794,545,254**	**721,324,634**	**714,097,969**	**743,272,404**	**720,212,160**	**735,254,936**	**846,335,729**	**1,005,682,519**	**10,144,296,352**	
Export kWh Sales	**+**	10,818,000	3,728,000	9,532,000	13,080,000	10,940,000	9,316,000	3,374,000	7,610,000	6,977,000	5,100,000	1,921,000	17,955,000	**100,351,000**	
Total Electric Sales		**1,080,670,579**	**949,076,471**	**1,029,766,970**	**841,214,727**	**805,485,254**	**730,640,634**	**717,471,969**	**750,882,404**	**727,189,160**	**740,354,936**	**848,256,729**	**1,023,637,519**	**10,244,647,352**	
In Province Losses		66,819,355	74,399,477	90,981,561	49,423,290	31,287,171	30,860,840	37,241,683	59,150,536	39,507,194	61,143,502	81,810,222	106,352,908	**728,977,739**	
NSR		**1,136,671,935**	**1,019,747,948**	**1,111,216,531**	**877,558,017**	**825,832,425**	**752,185,474**	**751,339,651**	**802,422,939**	**759,719,354**	**796,398,438**	**928,145,952**	**1,112,035,427**	**10,873,274,091**	
Export kWh Losses	**-**	342,000	112,000	288,000	377,000	312,000	262,000	99,000	241,000	207,000	166,000	63,000	535,000	3,004,000	
Total System Requirement		1,147,831,935	1,023,587,948	1,121,036,531	891,015,017	837,084,425	761,763,474	754,812,651	810,273,939	766,903,354	801,664,438	930,129,952	1,130,525,427	10,976,629,091	

Category		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual
2017-BCF Recovered Fuel Costs														
ATL Classes														
Domestic Total		$30,466,005	$27,253,401	$29,633,466	$20,810,329	$19,619,135	$15,029,960	$15,504,415	$15,088,306	$14,702,256	$15,840,892	$20,448,064	$28,439,120	$252,835,349
Small General		$1,946,829	$1,583,620	$1,722,518	$1,282,337	$1,371,697	$1,099,391	$1,228,772	$1,151,822	$1,076,009	$1,104,959	$1,183,606	$1,515,973	16,267,531
General		$13,169,613	$11,445,136	$12,122,773	$10,623,650	$9,963,632	$10,286,211	$10,516,326	$10,317,925	$9,985,301	$10,178,678	$10,715,655	$12,777,876	132,102,776
Large General		$1,850,191	$1,611,011	$1,858,580	$1,664,962	$1,733,302	$1,768,358	$1,925,981	$2,003,059	$1,878,329	$1,834,485	$1,719,300	$1,773,047	21,620,606
Small Industrial		$1,418,540	$1,056,368	$1,211,354	$974,611	$1,127,841	$1,065,714	$1,228,819	$999,239	$1,125,605	$806,134	$1,177,316	$1,198,805	13,390,347
Medium Industrial		$2,102,030	$1,771,441	$1,891,607	$1,848,014	$1,916,177	$2,039,452	$1,992,806	$2,022,780	$1,971,955	$1,992,439	$2,081,246	$2,341,205	23,971,151
Large Industrial														
Large Industrial - Firm		$429,290	$350,473	$431,942	$397,627	$368,560	$343,554	$354,169	$371,060	$343,061	$373,166	$376,074	$397,151	4,536,126
Large Industrial - Interruptible		$2,511,980	$2,204,677	$2,557,913	$2,386,728	$2,662,188	$2,618,006	$2,670,302	$2,984,234	$2,774,490	$2,793,768	$2,753,826	$2,422,609	31,340,721
Large Industrial - Total		$2,941,270	$2,555,149	$2,989,856	$2,784,354	$3,030,748	$2,961,560	$3,024,470	$3,355,294	$3,117,552	$3,166,933	$3,129,900	$2,819,761	35,876,847
ELI 2P-RTP														
Municipal														
Customers staying on in 2015		$267,915	$237,756	$275,427	$207,091	$198,046	$185,311	$182,136	$183,515	$172,596	$181,409	$212,279	$265,614	2,569,095
Customers migrating to OATT in 2015														
Customer A		$385,261	$338,550	$367,797	$250,087	$196,095	$193,281	$204,292	$186,661	$195,332	$207,200	$262,272	$291,726	3,078,553
Customer B		$128,240	$119,920	$137,179	$88,648	$79,461	$77,651	$82,744	$88,864	$84,070	$90,002	$109,592	$114,259	1,200,629
Customer C		$59,188	$53,406	$57,932	$36,360	$29,597	$23,808	$24,747	$24,962	$23,534	$26,894	$39,196	$50,025	449,649
Customer D		$42,048	$34,209	$39,851	$25,700	$16,915	$13,359	$15,030	$15,809	$12,171	$13,763	$23,921	$39,508	292,285
Municipal Total		$882,652	$783,842	$878,187	$607,886	$520,113	$493,409	$508,949	$499,811	$487,703	$519,268	$647,259	$761,132	**7,590,211**
Unmetered		$394,100	$373,725	$356,854	$357,463	$395,302	$356,055	$389,096	$386,946	$357,032	$331,009	$363,643	$388,807	4,450,032
Subtotal		55,171,228.57	48,433,693.19	52,665,194.03	40,953,605.79	39,677,947.82	35,100,110.63	36,319,634.51	35,825,182.83	34,701,741.21	35,774,797.79	41,465,989.89	52,015,724.61	508,104,851
2017-BCF Simulated Collected Fuel Costs														
ATL Classes														
Domestic Non-TOU	**5.781**	$28,483,583	$25,432,661	$27,760,941	$19,511,520	$18,556,408	$14,386,941	$14,931,976	$14,499,617	$14,080,662	$15,078,480	$19,222,437	$26,347,530	238,292,757
Domestic TOU	**5.781**	$1,982,422	$1,820,740	$1,872,524	$1,298,809	$1,062,727	$643,019	$572,439	$588,689	$621,594	$762,413	$1,225,627	$2,091,590	14,542,592
Domestic Total	**5.781**	$30,466,005	$27,253,401	$29,633,466	$20,810,329	$19,619,135	$15,029,960	$15,504,415	$15,088,306	$14,702,256	$15,840,892	$20,448,064	$28,439,120	252,835,349
Small General	**5.807**	$1,946,829	$1,583,620	$1,722,518	$1,282,337	$1,371,697	$1,099,391	$1,228,772	$1,151,822	$1,076,009	$1,104,959	$1,183,606	$1,515,973	16,267,531
General	**5.553**	$13,169,613	$11,445,136	$12,122,773	$10,623,650	$9,963,632	$10,286,211	$10,516,326	$10,317,925	$9,985,301	$10,178,678	$10,715,655	$12,777,876	132,102,776
Large General	**5.397**	$1,850,191	$1,611,011	$1,858,580	$1,664,962	$1,733,302	$1,768,358	$1,925,981	$2,003,059	$1,878,329	$1,834,485	$1,719,300	$1,773,047	21,620,606
Small Industrial	**5.434**	$1,418,540	$1,056,368	$1,211,354	$974,611	$1,127,841	$1,065,714	$1,228,819	$999,239	$1,125,605	$806,134	$1,177,316	$1,198,805	13,390,347
Medium Industrial	**5.139**	$2,102,030	$1,771,441	$1,891,607	$1,848,014	$1,916,177	$2,039,452	$1,992,806	$2,022,780	$1,971,955	$1,992,439	$2,081,246	$2,341,205	23,971,151
Large Industrial														
Large Industrial - Firm	**5.056**	$429,290	$350,473	$431,942	$397,627	$368,560	$343,554	$354,169	$371,060	$343,061	$373,166	$376,074	$397,151	4,536,126
Large Industrial - Interruptible	**5.058**	$2,511,980	$2,204,677	$2,557,913	$2,386,728	$2,662,188	$2,618,006	$2,670,302	$2,984,234	$2,774,490	$2,793,768	$2,753,826	$2,422,609	31,340,721
Large Industrial - Total		$2,941,270	$2,555,149	$2,989,856	$2,784,354	$3,030,748	$2,961,560	$3,024,470	$3,355,294	$3,117,552	$3,166,933	$3,129,900	$2,819,761	35,876,847
ELI 2P-RTP	**-**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-
Municipal														
Customers staying on in 2015	**5.326**	$267,915	$237,756	$275,427	$207,091	$198,046	$185,311	$182,136	$183,515	$172,596	$181,409	$212,279	$265,614	2,569,095
Customers migrating to OATT in 2015														-
Customer A	**5.326**	$385,261	$338,550	$367,797	$250,087	$196,095	$193,281	$204,292	$186,661	$195,332	$207,200	$262,272	$291,726	3,078,553
Customer B	**5.326**	$128,240	$119,920	$137,179	$88,648	$79,461	$77,651	$82,744	$88,864	$84,070	$90,002	$109,592	$114,259	1,200,629
Customer C	**5.326**	$59,188	$53,406	$57,932	$36,360	$29,597	$23,808	$24,747	$24,962	$23,534	$26,894	$39,196	$50,025	449,649
Customer D	**5.326**	$42,048	$34,209	$39,851	$25,700	$16,915	$13,359	$15,030	$15,809	$12,171	$13,763	$23,921	$39,508	292,285
Municipal Total	**5.326**	$882,652	$783,842	$878,187	$607,886	$520,113	$493,409	$508,949	$499,811	$487,703	$519,268	$647,259	$761,132	7,590,211
Unmetered	**5.412**	$394,100	$373,725	$356,854	$357,463	$395,302	$356,055	$389,096	$386,946	$357,032	$331,009	$363,643	$388,807	4,450,032
Subtotal	**-**	$55,171,229	$48,433,693	$52,665,194	$40,953,606	$39,677,948	$35,100,111	$36,319,635	$35,825,183	$34,701,741	$35,774,798	$41,465,990	$52,015,725	$508,104,851

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Category	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Annual
2017-Variance													
ATL Classes													
Domestic Total	$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
ELI 2P-RTP	$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
Customers staying on in 2015													
Customers migrating to OATT in 2015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer A	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer B	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer C	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer D	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unmetered	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Biomass Calculations

($ in millions)	2017 Actuals			
Capital	[redacted]		27.4	89.1%
Fuel				
Operating				
Total	30.8	100.0%		

data came from CA IR-065P Confidential from the COSS Proceeding

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Category	2 January	3 February	4 March	5 April	6 May	7 June	8 July	9 August	10 September	11 October	12 November	13 December	Total		
kWh Sales															
ATL Classes															
Domestic Non-TOU															
Domestic TOU															
Domestic Total	564,679,624	508,852,411	499,342,153	389,638,760	325,216,444	268,039,003	275,453,590	270,038,593	258,588,905	302,223,679	380,211,166	507,089,848	4,549,374,177		
Small General	29,139,800	27,225,124	26,123,529	21,769,608	19,802,474	18,307,453	19,435,276	19,120,535	17,074,716	18,648,423	20,169,673	25,467,818	262,284,429		
General	237,470,350	222,749,119	222,025,124	194,513,315	179,068,089	181,481,406	195,478,642	190,893,340	177,137,436	187,273,365	200,305,275	224,679,772	2,413,075,233		
Large General	34,821,230	32,522,015	34,952,820	32,975,315	33,261,575	33,056,314	37,125,875	38,958,363	35,997,222	32,942,886	32,104,277	33,999,308	412,717,201		
Small Industrial	24,003,549	22,543,354	22,005,388	20,622,046	20,622,046	21,544,274	22,031,005	20,109,697	19,418,025	18,009,066	21,236,864	24,029,166	256,174,479		
Medium Industrial	41,144,782	38,222,975	39,420,437	38,797,757	38,366,671	41,048,985	41,240,579	40,809,492	39,755,726	39,899,422	40,091,015	40,282,609	479,080,450		
Large Industrial	65,569,368	58,938,381	65,785,234	62,359,036	66,254,856	66,603,198	67,327,279	73,429,694	71,337,149	67,032,228	66,176,645	62,522,172			
Large Industrial - Firm													-		
Large Industrial - Interruptible													-		
Large Industrial - Total	65,569,368	58,938,381	65,785,234	62,359,036	66,254,856	66,603,198	67,327,279	73,429,694	71,337,149	67,032,228	66,176,645	62,522,172	793,335,241		
ELI 2P-RTP	-	-	-	-	-	-	-	-	-	-	-	-	-		
Municipal															
Customers staying on in 2018	7,824,087.63	7,148,268.25	6,098,237.23	6,659,525.44	6,309,239.57	5,957,695.92	6,738,881.89	6,982,846.52	6,317,889.15	7,689,780.32	6,860,832.94	9,098,268.73	83,685,554	[redacted]	
Customers migrating to OATT in 2015													Bundled		
Customer A	7,233,586	6,356,559	6,905,683	4,695,581	3,681,837	3,629,009	3,835,744	3,504,722	3,667,515	3,890,342	4,924,373	5,477,389	57,802,339		
Customer B	2,407,809	2,251,596	2,575,650	1,664,437	1,491,939	1,457,958	1,553,584	1,668,499	1,578,484	1,689,857	2,057,674	2,145,299	22,542,785		
Customer C	1,111,312	1,002,739	1,087,730	682,690	555,709	447,011	464,647	468,680	441,869	504,953	735,930	939,265	8,442,535		
Customer D	789,490	642,302	748,240	482,545	317,596	250,822	282,202	296,829	228,519	258,416	449,138	741,796	5,487,897		
Municipal Total	19,366,285	17,401,464	17,415,540	14,184,778	12,356,321	11,742,496	12,875,059	12,921,577	12,234,277	14,033,348	15,027,948	18,402,017	177,961,110		16,519,290
Unmetered	8,716,679	8,451,610	8,716,679	8,726,874	8,767,654	8,237,516	8,451,610	8,706,484	8,472,000	7,829,719	8,706,484	8,155,957	101,939,265		
ATL Total	**1,024,911,666**	**936,906,453**	**935,786,904**	**783,587,489**	**703,716,129**	**650,060,645**	**679,418,915**	**674,987,776**	**640,015,457**	**687,892,136**	**784,029,348**	**944,628,667**	**9,445,941,584**	94,275,557	0.175223468
BTL Classes															
[redacted]															
BTL Total	73,773,961	80,168,724	99,879,868	91,199,443	95,388,388	92,128,503	92,884,302	96,253,371	94,472,345	96,666,032	97,657,841	82,489,452	1,092,962,231		
In-Province Total	**1,098,685,628**	**1,017,075,177**	**1,035,666,772**	**874,786,932**	**799,104,517**	**742,189,148**	**772,303,217**	**771,241,147**	**734,487,801**	**784,558,168**	**881,687,189**	**1,027,118,119**	**10,538,903,815**		
Export kWh Sales	5,000,000	10,000,000	14,500,000	2,000,000	500,000	-	-	500,000	500,000	8,000,000	4,500,000	4,500,000	50,000,000		
Export kWh Losses	-	-	-	-	-	-	-	-	-	-	-	-	-		
In-province Losses	85,336,107	77,849,915	77,318,081	57,931,517	55,443,214	40,942,919	43,228,073	48,786,613	38,915,185	49,699,553	55,928,502	89,625,164	721,004,844		
NSR	1,189,021,734	1,104,925,092	1,127,484,853	934,718,449	855,047,731	783,132,067	815,531,290	820,527,759	773,902,987	842,257,721	942,115,691	1,121,243,284	11,309,908,659		

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Annual Peak of ATL Classes	2,007,206
Annual Energy Requirement of ATL	9,785,384,508
System Coincident Load Factor	**55.7%**
Wind Fixed - Energy Related	**70.0%**

Generation Rate Base		**Initial Classification**			**Further Classification**			**Fully Classified**		
	Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$1,370,532	$1,191,036	$179,496	$0	($662,812)	$662,812	$0	$528,224	$842,308	$ -
Hydro Plant	371,461	366,637	4,824	0	($204,033)	$204,033	0	$162,604	$208,857	$ -
Wind Plant	201,182	30,599	170,583	0	($21,419)	$21,419	0	$9,180	$192,002	$ -
LM6000 Plant	71,417	71,417	0	0	($39,744)	$39,744	0	$31,673	$39,744	$ -
Gas Turbine Plant - Other	6,513	6,513	0	0	$0	$0	0	$6,513	$0	$ -
Total Generation Plant	2,021,105	1,666,202	354,903	0	($928,008)	$928,008	0	$738,194	$1,282,911	$ -
General Property Plant	150,810	124,328	26,482	0	-$69,245.81	$69,246	0	$55,082	$95,728	$ -
Total Plant in Service	2,171,915	1,790,530	381,385	0	($997,254)	$997,254	0	$793,276	$1,378,639	$ -
								36.52%	**63.48%**	

2018 BA Amounts

FOR THE YEAR ENDING DECEMBER 31, 2017

Line #	FAM Classes	2016 kWh Sales[1]	2017 Final BA Amount [1]	Adjustment to reconcile with FAM Model in Appendix A	2017 Final BA Amount-reconciled to FAM Appendix A	Payout Credit Refund in 2017	Variance Before Interest	Fixed Cost Deferral Credit-March to December	Final 2018 BA Amount bfr Interest	Interest	2017 AA owed to customer in 2017 as per 2016 AA Calculations-True Up [2]	AA Credit to customers in 2017 paid under One Time Payout	Variance at the end of 2017 bfr Interest	Interest	FAM BA Total bfr Interest	Interest	FAM 2018 BA Total	Amount owed by departing load to non-FAM classes	Amount to be paid or credited through riders	Amount deferred for recovery through BCF rates in years 2017-2019 (2016 year-end estimate)	2017 kWh Sales
			2017 BA Amount								2017 FAM AA TRUE-UP				2018 FAM BA			2018 BA			
10																					
11	Residential	4,318,379,988	$3,030,987	$46,522	$3,077,509	$3,006,408	$71,102	$7,500,991	$7,572,092	$209,479.81	$15,757,029	$16,259,265	$502,237	$214,972.81	$7,069,856	$424,453	$7,494,308		$7,494,308		4,373,557,333
12	Small General	271,757,767	$221,246	$3,396	$224,641	$205,394	$19,248	$374,443	$393,690	$10,891	$1,089,527	$1,110,812	$21,285	($14,864)	$372,405	$25,756	$398,161		$398,161		280,136,575
13	General Demand	2,378,764,581	$1,290,678	$19,811	$1,310,488	$1,369,132	$58,643	$3,328,955	$3,270,311	$90,472	$7,331,823	$7,404,541	$72,718	($100,028)	$3,197,593	$190,500	$3,388,093		$3,388,093		2,378,944,281
14	Large General	411,371,979	$923,112	$14,169	$937,281	$213,373	$1,150,653	$426,033	$724,620	$20,046	$1,207,435	$1,153,962	($53,473)	($16,473)	$671,147	$3,573	$674,721		$674,721	$1,128,311	400,604,157
15	Small Industrial	248,853,339	$153,231	$2,352	$155,583	$147,556	$8,027	$333,632	$341,659	$9,452	$788,837	$798,012	$9,175	($10,762)	$332,484	$20,214	$352,698		$352,698		246,417,863
16	Medium Industrial	461,809,912	$747,229	$11,469	$758,699	$231,052	$989,750	$589,544	$400,207	$11,072	$1,305,667	$1,249,576	($56,091)	($17,813)	$344,115	$6,742	$337,374		$337,374	$1,007,832	466,455,555
17	**Large Industrial**																				
18	Customers staying on the rate in 2015																				
19	**Firm**	78,817,405	$271,258	$4,164	$275,421	$33,442	$308,863	$103,255	$205,608	$5,688	$213,383.44	$171,718	($41,665)	($2,911)	$163,942	$2,777	$166,719		$166,719	$285,439	89,717,690
20	Interruptible-Less Customer A	652,584,291	$1,059,567	$16,263	$1,076,813	$376,440	$1,453,253	$679,915	$773,339	$21,394	$1,553,367	$1,575,325	$21,958	($21,193)	$795,297	$202	$795,499		$795,499	$1,374,162	593,194,140
21	Subtotal (less Customer A Load)	731,401,696	$1,330,825	$20,427	$1,352,234	$409,882	$1,762,116	$783,170	$978,946	$27,082	$1,766,088	$1,747,043	($19,045)	($24,095)	$959,901	$2,988	$962,218		$962,218	$1,659,602	709,344,434
22	Customer A migrating some of its load to a Non-FAM in August, 2014																				
23	Load staying on the LIR rate		$48,473	$744	$49,217	$9,279	$39,937	$33,208	$73,145	$2,024	$77,133	$50,185	($26,948)	($1,052)	$100,093	$3,076	$103,169		$103,169	$38,521	26,432,603
24	Migrated Load	28,490,608	$36,083	$554	$35,654	$35,647	$7		7.325												
25	Subtotal	28,490,608	$12,389	$190	$13,563	$26,367	$39,930	$33,208	$73,138	$2,024	$77,133	$50,185	($26,948)	($1,052)	$100,093	$3,076	$103,169		$103,169	$38,521	26,432,603
26	**Interruptible**	602,257,494	$1,047,178	$16,073	$1,063,251	$350,073	$1,413,323	$713,122	$700,201	$19,371	$1,630,500	$1,625,511	($4,989)	($22,245)	$695,211	$2,874	$692,337		$692,337	$1,335,641	619,626,743
27	**Large Industrial Total**	681,074,899	$1,318,435	$20,237	$1,338,672	$383,514	$1,722,186	$816,378	$905,808	$25,059	**$1,843,883**	**$1,797,229**	**($46,655)**	**$25,156**	$859,154	$97	$859,056		$859,056	$1,621,080	709,344,434
28																					
29	**Municipal**																				
30	Customers staying on in 2017	49,678,784	$40,885	$628	$41,512	$24,663	$16,849	$57,232	$74,081	$2,049	$183,257	$133,383	($49,875)	($2,500)	$123,956	$4,550	$128,506		$128,506		48,236,857
31	Customers migrating to OATT in 2017																				
32	Customer A	72,304,864	$61,975	$951	$62,926	$30,170	$93,096	$113,072	$19,976	$553	$192,817	$163,165	($29,652)	($2,631)	$49,628	$3,183	$52,811	$7,545	$45,266		57,802,339
33	Customer B	26,678,255	$18,889	$290	$19,179	$13,218	$5,961	$38,513	$44,475	$1,230	$79,671	$71,484	($8,188)	($1,087)	$52,662	$2,317	$54,980	$7,885	$47,094		22,542,785
34	Customer C	9,778,788	$9,852	$151	$10,004	$3,654	$13,658	$15,897	$2,239	$62	$21,531	$19,762	($1,769)	($294)	$4,007	$356	$4,363	$626	$3,737		8,442,535
35	Customer D	6,216,870	$12,943	$199	$13,141	$1,858	$14,999	$10,378	$4,620	$128	$10,860	$10,047	($814)	($148)	$3,807	$20	$3,786	$570	$3,216		5,487,897
36	**Municipal - Total**	164,657,562	$24,996	$384	$25,380	$73,562	$98,942	$235,093	$136,150	$3,767	$488,136	$397,840	($90,296)	($6,660)	$226,447	$10,426	$236,873	$15,486	$221,387		142,512,414
37	Unmetered	87,222,388	$51,580	$792	$52,372	$42,317	$10,055	$207,443	$217,499	$6,017	$285,919	$228,858	($57,061)	($3,901)	$274,560	$9,918	$284,477	$0	$284,477		82,225,284
38	**Above the line Subtotal / Average**	9,023,892,414	$1,733,949	$26,614	$1,760,563	$5,672,307	$3,911,744	$13,812,511	$9,900,767	$273,901.95	**$30,098,256**	**$30,400,095**	**$301,839**	**($410,630)**	**$9,598,928**	$684,532	**$10,283,460**	**$15,486**	$10,267,974	**$3,757,223**	9,080,197,895
39																					

Footnotes.

(1) NSPI to UARB 2016 FAM AA BA Refund IR-2 Attachment 3, tab "2017 BA Calculations", column "AR" labeled as "Final 2017 BA Amount". M07703; Exhibit N-7 and N-7 (C)in Board's depository

(2) NSPI to UARB 2016 FAM AA BA Refund IR-2 Attachment 2, tab "AA Calculation", column "T" labeled as "Adjustment after Incentive". M07704; Exhibit N-7 and N-7 (C)in Board's depository

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2017-kWh Sales		Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017	
ATL Classes															
Domestic Non-TOU		492,710,304	439,935,329	480,210,024	337,511,159	320,989,591	248,865,964	258,293,996	250,815,038	243,567,929	260,828,223	332,510,588	455,760,770	4,121,998,915	
Domestic TOU		34,292,023	31,495,243	32,391,006	22,466,857	18,383,096	11,122,973	9,902,070	10,183,168	10,752,360	13,188,253	21,200,957	36,180,411	251,558,418	
Domestic Total		**527,002,328**	**471,430,572**	**512,601,030**	**359,978,017**	**339,372,687**	**259,988,937**	**268,196,066**	**260,998,206**	**254,320,289**	**274,016,476**	**353,711,545**	**491,941,181**	**4,373,557,333**	
Small General		**33,525,547**	**27,270,883**	**29,662,780**	**22,082,604**	**23,621,436**	**18,932,172**	**21,160,188**	**19,835,054**	**18,529,511**	**19,028,052**	**20,382,393**	**26,105,954**	280,136,575	
General		**237,162,123**	**206,107,255**	**218,310,334**	**191,313,700**	**179,427,919**	**185,237,010**	**189,380,975**	**185,808,121**	**179,818,138**	**183,300,529**	**192,970,557**	**230,107,619**	2,378,944,281	
Large General		**34,281,835**	**29,850,128**	**34,437,289**	**30,849,772**	**32,116,023**	**32,765,569**	**35,686,148**	**37,114,311**	**34,803,202**	**33,990,831**	**31,856,592**	**32,852,457**	400,604,157	
Small Industrial		**26,104,903**	**19,439,973**	**22,292,123**	**17,935,417**	**20,755,270**	**19,611,963**	**22,613,533**	**18,388,654**	**20,714,110**	**14,834,993**	**21,665,742**	**22,061,182**	246,417,863	
Medium Industrial		**40,903,474**	**34,470,535**	**36,808,850**	**35,960,579**	**37,286,965**	**39,685,777**	**38,778,088**	**39,361,349**	**38,372,346**	**38,770,956**	**40,499,041**	**45,557,595**	466,455,555	
Large Industrial															
Customer A		**2,667,647**	**1,102,737**	**1,021,500**	**1,233,368**	**2,385,103**	**2,635,150**	**2,578,521**	**2,646,333**	**2,505,685**	**2,633,620**	**2,359,236**	**2,663,703**	26,432,603	
Large Industrial - Firm		8,490,705	6,931,815	8,543,165	7,864,453	7,289,552	6,794,975	7,004,919	7,339,004	6,785,234	7,380,647	7,438,171	7,855,049	89,717,690	
Large Industrial - Interruptible		49,663,508	43,587,913	50,571,638	47,187,181	52,633,213	51,759,707	52,793,627	59,000,277	54,853,507	55,234,629	54,444,955	47,896,588	619,626,743	
Large Industrial - Total		**58,154,213**	**50,519,728**	**59,114,803**	**55,051,634**	**59,922,765**	**58,554,682**	**59,798,546**	**66,339,281**	**61,638,741**	**62,615,277**	**61,883,126**	**55,751,637**	**709,344,434**	
ELI 2P-RTP (Adjusted CBL)														-	
Municipal															
Customers staying on in 2015		5,030,321	4,464,071	5,171,370	3,888,297	3,718,474	3,479,362	3,419,757	3,445,636	3,240,632	3,406,111	3,985,704	4,987,122	48,236,857	
Customers migrating to OATT in 2015															OATT % Split
Customer A		7,233,586	6,356,559	6,905,683	4,695,581	3,681,837	3,629,009	3,835,744	3,504,722	3,667,515	3,890,342	4,924,373	5,477,389	57,802,339	[redacted]
Customer B		2,407,809	2,251,596	2,575,650	1,664,437	1,491,939	1,457,958	1,553,584	1,668,499	1,578,484	1,689,857	2,057,674	2,145,299	22,542,785	
Customer C		1,111,312	1,002,739	1,087,730	682,690	555,709	447,011	464,647	468,680	441,869	504,953	735,930	939,265	8,442,535	
Customer D		789,490	642,302	748,240	482,545	317,596	250,822	282,202	296,829	228,519	258,416	449,138	741,796	5,487,897	
Municipal Total		**16,572,519**	**14,717,267**	**16,488,673**	**11,413,550**	**9,765,556**	**9,264,162**	**9,555,934**	**9,384,367**	**9,157,019**	**9,749,678**	**12,152,819**	**14,290,871**	**142,512,414**	
Unmetered		**7,281,957**	**6,905,481**	**6,593,757**	**6,605,010**	**7,304,180**	**6,578,984**	**7,189,507**	**7,149,779**	**6,597,050**	**6,116,204**	**6,719,207**	**7,184,167**	82,225,284	
ATL Total		**980,988,900**	**860,711,821**	**936,309,640**	**731,190,282**	**709,572,801**	**630,619,257**	**652,358,985**	**644,379,121**	**623,950,406**	**642,422,995**	**741,841,024**	**925,852,662**	**9,080,197,895**	
BTL Classes															
[redacted]															
BTL Total		**88,863,680**	**84,636,650**	**83,925,331**	**96,944,445**	**84,972,453**	**90,705,377**	**61,738,984**	**98,893,282**	**96,261,754**	**92,831,940**	**104,494,705**	**79,829,857**	1,064,098,457	
In-Province Total Sales		**1,069,852,579**	**945,348,471**	**1,020,234,970**	**828,134,727**	**794,545,254**	**721,324,634**	**714,097,969**	**743,272,404**	**720,212,160**	**735,254,936**	**846,335,729**	**1,005,682,519**	**10,144,296,352**	
Export kWh Sales	+	10,818,000	3,728,000	9,532,000	13,080,000	10,940,000	9,316,000	3,374,000	7,610,000	6,977,000	5,100,000	1,921,000	17,955,000	**100,351,000**	
Total Electric Sales		**1,080,670,579**	**949,076,471**	**1,029,766,970**	**841,214,727**	**805,485,254**	**730,640,634**	**717,471,969**	**750,882,404**	**727,189,160**	**740,354,936**	**848,256,729**	**1,023,637,519**	**10,244,647,352**	
In Province Losses		66,819,355	74,399,477	90,981,561	49,423,290	31,287,171	30,860,840	37,241,683	59,150,536	39,507,194	61,143,502	81,810,222	106,352,908	**728,977,739**	
NSR		**1,136,671,935**	**1,019,747,948**	**1,111,216,531**	**877,558,017**	**825,832,425**	**752,185,474**	**751,339,651**	**802,422,939**	**759,719,354**	**796,398,438**	**928,145,952**	**1,112,035,427**	**10,873,274,091**	
Export kWh Losses	-	342,000	112,000	288,000	377,000	312,000	262,000	99,000	241,000	207,000	166,000	63,000	535,000	3,004,000	
Total System Requirement		1,147,831,935	1,023,587,948	1,121,036,531	891,015,017	837,084,425	761,763,474	754,812,651	810,273,939	766,903,354	801,664,438	930,129,952	1,130,525,427	10,976,629,091	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016 FAM AA Payout paid in 2017.

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017
ATL Classes													
Domestic Total		$0	$0	$7,967,031	$7,939,457	$205,012	$124,096	$12,706	$877	$8,669	$422	$566	$429	$16,259,265
Small General		$0	$0	$656,971	$404,576	$24,741	$23,587	$850	$0	$81	$1	$7	$0	$1,110,812
General		$0	$0	$4,946,869	$2,455,136	$1,350	$1,121	$65	$0	$0	$0	$0	$0	$7,404,541
Large General		$0	$0	$1,149,980	$3,982	$0	$0	$0	$0	$0	$0	$0	$0	$1,153,962
Small Industrial		$0	$0	$537,807	$259,246	$952	$6	$0	$0	$0	$0	$0	$0	$798,012
Medium Industrial		$0	$0	$622,032	$627,543	$0	$0	$0	$0	$0	$0	$0	$0	$1,249,576
Large Industrial														
Large Industrial - Firm		$0	$0	$174,077	$2,359	$0	$0	$0	$0	$0	$0	$0	$0	$171,718
Large Industrial - Interruptible		$0	$0	$1,622,652	$2,858	$0	$0	$0	$0	$0	$0	$0	$0	$1,625,511
Large Industrial - Total		$0	$0	$1,796,729	$499	$0	$0	$0	$0	$0	$0	$0	$0	$1,797,229
ELI 2P-RTP														
Municipal														
Customers staying on in 2015		$0	$0	$128,976	$4,407	$0	$0	$0	$0	$0	$0	$0	$0	$133,383
Customers migrating to OATT in 2015														
Customer A		$0	$0	$26,538	$167,367	$2,377	$28,363	$0	$0	$0	$0	$0	$0	$163,165
Customer B		$0	$0	$0	$71,545	$0	$61	$0	$0	$0	$0	$0	$0	$71,484
Customer C		$0	$0	$0	$26,224	$0	$6,462	$0	$0	$0	$0	$0	$0	$19,762
Customer D		$0	$0	$0	$16,672	$0	$6,626	$0	$0	$0	$0	$0	$0	$10,047
Municipal Total		$0	$0	$155,513	$286,216	$2,377	$41,512	$0	$0	$0	$0	$0	$0	**$397,840**
Unmetered		$0	$0	$130,321	$96,615	$1,888	$28	$4	$0	$1	$0	$0	$0	$228,858
Subtotal		$0	$0	$17,963,254	$12,073,270	$231,567	$107,327	$13,624	$878	$8,752	$421	$573	$429	$30,400,095
Customer A-Large Industrial Interruptible		$0	$0	($50,095)	($91)	$0	$0	$0	$0	$0	$0	$0	$0	($50,185)

2016 FAM BA Payout paid in 2017.

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	2017	
ATL Classes														
Domestic Total		$0	$0	$1,473,138	$1,468,040	$37,908	$22,946	$2,349	$162	$1,603	$77	$105	$79	$3,006,408	
Small General		$0	$0	$121,477	$74,808	$4,575	$4,361	$157	$0	$15	$0	$1	$0	$205,394	
General		$0	$0	$914,697	$453,965	$250	$207	$12	$0	$0	$0	$0	$0	$1,369,132	
Large General		$0	$0	$212,636	$736	$0	$0	$0	$0	$0	$0	$0	$0	$213,373	
Small Industrial		$0	$0	$99,443	$47,936	$176	$1	$0	$0	$0	$0	$0	$0	$147,556	
Medium Industrial		$0	$0	$115,016	$116,035	$0	$0	$0	$0	$0	$0	$0	$0	$231,052	
Large Industrial														
Large Industrial - Firm		$0	$0	$32,188	$436	$0	$0	$0	$0	$0	$0	$0	$0	$33,442	-0.018
Large Industrial - Interruptible		$0	$0	$300,035	$529	$0	$0	$0	$0	$0	$0	$0	$0	$350,073	-0.069
Large Industrial - Total		$0	$0	$332,223	$92	$0	$0	$0	$0	$0	$0	$0	$0	$383,514	
ELI 2P-RTP															
Municipal															
Customers staying on in 2015		$0	$0	$23,848	$815	$0	$0	$0	$0	$0	$0	$0	$0	$24,663	
Customers migrating to OATT in 2015															
Customer A		$0	$0	$4,907	$30,947	$440	$5,244	$0	$0	$0	$0	$0	$0	$30,170	
Customer B		$0	$0	$0	$13,229	$0	$11	$0	$0	$0	$0	$0	$0	$13,218	
Customer C		$0	$0	$0	$4,849	$0	$1,195	$0	$0	$0	$0	$0	$0	$3,654	
Customer D		$0	$0	$0	$3,083	$0	$1,225	$0	$0	$0	$0	$0	$0	$1,858	
Municipal Total		$0	$0	$28,755	$52,923	$440	$7,676	$0	$0	$0	$0	$0	$0	**$73,562**	
Unmetered		$0	$0	$24,097	$17,865	$349	$5	$1	$0	$0	$0	$0	$0	$42,317	
Subtotal		$0	$0	$3,321,483	$2,232,400	$42,818	$19,845	$2,519	$162	$1,618	$77	$106	$79	$5,672,307	$5,672,307
Customer A-Large Industrial Interruptible		$0	$0	($9,263)	($17)	$0	$0	$0	$0	$0	$0	$0	$0	($9,279)	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2016-kWh Sales

ATL Classes														
Domestic Non-TOU		496,441,172	415,408,253	425,380,053	358,734,291	312,207,758	242,839,939	244,681,677	255,374,950	247,436,296	273,907,513	341,199,290	444,801,238	4,058,412,430
Domestic TOU		34,015,751	29,377,297	30,159,620	26,011,186	17,299,319	10,037,992	8,868,400	10,485,141	10,601,319	14,353,291	23,415,488	40,180,423	254,805,227
Domestic Total		**530,456,924**	**444,785,550**	**455,539,673**	**384,745,477**	**329,507,078**	**252,877,931**	**253,550,077**	**265,860,091**	**258,037,615**	**288,260,804**	**364,614,778**	**484,981,661**	**4,313,217,658**
Small General		**28,106,778**	**25,763,761**	**26,690,311**	**23,985,810**	**23,743,687**	**18,286,323**	**20,053,094**	**19,656,334**	**19,298,428**	**19,731,376**	**20,278,985**	**25,605,845**	271,200,731
General		**230,002,869**	**216,202,773**	**210,214,602**	**201,244,439**	**179,514,339**	**181,667,417**	**189,461,258**	**185,455,598**	**184,892,732**	**187,778,858**	**201,498,324**	**226,018,000**	2,393,951,208
Large General		**35,220,544**	**33,265,964**	**34,956,874**	**33,370,331**	**33,268,959**	**33,690,408**	**36,829,828**	**38,261,987**	**35,300,791**	**32,963,997**	**32,601,106**	**34,525,464**	414,256,253
Small Industrial		**24,637,427**	**21,097,132**	**22,123,739**	**19,770,154**	**21,246,507**	**21,258,159**	**22,294,514**	**17,475,302**	**21,440,410**	**15,471,134**	**21,255,916**	**24,050,723**	252,121,117
Medium Industrial		**37,203,875**	**36,242,707**	**40,201,023**	**36,301,541**	**37,913,061**	**40,281,302**	**39,859,164**	**40,285,774**	**40,482,353**	**36,439,334**	**39,417,348**	**39,605,722**	464,233,204
Large Industrial														
Large Industrial - Firm		16,886,001	15,563,473	17,184,843	17,377,630	17,380,935	16,946,021	17,622,896	18,002,843	16,631,107	17,880,234	6,168,396	8,073,334	185,717,713
Large Industrial - Interruptible		38,293,821	37,950,972	38,379,687	37,836,735	38,710,398	39,433,900	38,612,979	46,171,520	41,774,424	41,534,475	53,463,720	48,579,410	500,742,042
Large Industrial - Total		**55,179,822**	**53,514,445**	**55,564,530**	**55,214,365**	**56,091,333**	**56,379,921**	**56,235,875**	**64,174,363**	**58,405,531**	**59,414,709**	**59,632,116**	**56,652,743**	**686,459,755**
ELI 2P-RTP (Adjusted CBL)														-
Municipal														
Customers staying on in 2015		5,000,542	4,722,169	4,667,977	4,716,449	3,720,463	3,488,136	3,403,774	3,548,315	3,532,461	3,573,980	3,308,988	6,414,622	50,097,875
Customers migrating to OATT in 2015														
Customer A		8,322,102	7,512,248	7,777,242	6,293,094	4,835,746	4,433,177	4,948,680	4,845,485	5,007,090	5,353,488	7,415,843	7,338,529	74,082,724
Customer B		2,803,825	2,442,393	2,495,006	2,048,086	1,904,657	1,885,660	1,994,486	2,076,080	1,951,589	2,101,674	2,665,296	2,645,854	27,014,607
Customer C		1,215,146	1,064,046	1,040,289	821,646	661,648	558,940	574,681	594,877	576,537	681,346	952,395	1,119,824	9,861,374
Customer D		870,751	701,947	666,946	524,607	381,608	329,045	364,067	377,644	320,043	370,397	583,965	758,947	6,249,966
Municipal Total		**18,212,365**	**16,442,803**	**16,647,459**	**14,403,883**	**11,504,121**	**10,694,958**	**11,285,688**	**11,442,401**	**11,387,719**	**12,080,885**	**14,926,487**	**18,277,776**	**167,306,546**
Unmetered		**8,002,971**	**8,516,537**	**7,246,702**	**7,092,082**	**8,953,885**	**5,038,199**	**9,229,131**	**7,624,522**	**7,353,219**	**6,615,663**	**9,008,831**	**8,439,186**	93,120,928
ATL Total		**967,023,574**	**855,831,672**	**869,184,913**	**776,128,081**	**701,742,970**	**620,174,618**	**638,798,629**	**650,236,373**	**636,598,799**	**658,756,760**	**763,233,891**	**918,157,120**	**9,055,867,400**
BTL Classes														
[redacted]														
BTL Total		**74,619,526**	**66,650,781**	**92,902,876**	**78,780,981**	**100,698,458**	**69,294,566**	**85,931,924**	**97,195,047**	**104,693,520**	**105,869,367**	**97,657,841**	**82,489,452**	1,056,784,339
In-Province Total Sales		**1,041,643,100**	**922,482,452**	**962,087,789**	**854,909,063**	**802,441,428**	**689,469,184**	**724,730,553**	**747,431,420**	**741,292,319**	**764,626,127**	**860,891,733**	**1,000,646,573**	**10,112,651,739**
Export kWh Sales	**+**	-	1,695,000	-	909,000	2,407,000	743,000	772,000	5,646,000	510,000	2,947,000	74,350	-	**15,703,350**
Total Electric Sales		**1,041,643,100**	**924,177,452**	**962,087,789**	**855,818,063**	**804,848,428**	**690,212,184**	**725,502,553**	**753,077,420**	**741,802,319**	**767,573,127**	**860,966,082**	**1,000,646,573**	**10,128,355,089**
In Province Losses		68,864,756	67,580,699	89,577,716	33,168,010	14,420,239	33,098,073	58,156,747	53,312,183	33,683,907	52,030,800	70,321,591	77,410,236	**651,624,959**
NSR		**1,110,507,856**	**990,063,151**	**1,051,665,505**	**888,077,073**	**816,861,667**	**722,567,257**	**782,887,300**	**800,743,603**	**774,976,226**	**816,656,927**	**931,213,324**	**1,078,056,809**	**10,764,276,698**
Export kWh Losses	**-**	-	-	-	-	-	-	-	161,000	14,000	85,000	-	-	260,000
Total System Requirement		1,110,507,856	991,758,151	1,051,665,505	888,986,073	819,268,667	723,310,257	783,659,300	806,550,603	775,500,226	819,688,927	931,287,674	1,078,056,809	10,780,240,048

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Fixed Cost Deferral Credit Allocation as based on 2014 Test

FAM Rate Classes	2014 Usage			2014 Test Year Rate Base ($ thousand)					
	Energy Requirement (kWh)	3CP (kW)	Customers	Energy-related	Demand-related	Customer-related	Total	Relative Share per Rate Base	Non-fuel deferral credit 2017
Residential								54.3%	-$7,500,991
Small General								2.7%	-$374,443
General Demand								24.1%	-$3,328,955
Large General								3.1%	-$426,033
Total Commercial								29.9%	-$4,129,431
Small Industrial								2.4%	-$333,632
Medium Industrial								4.3%	-$589,544
Large Industrial									
Customers staying on the rate	727,263,941	283,351	31	$144,448	$58,608	$60	$203,116	5.7%	-$783,170
Customer A moving some of its load to a Non-FAM rate in 2014	33,705,228	9,264	1	$6,694	$1,916	$2	$8,612	0.2%	-$33,208
Large Industrial Total(2)	**760,969,169**	**292,614**	**32**	**$151,142**	**$60,524**	**$62**	**$211,728**	**5.9%**	**-$816,378**
Total Industrial								12.6%	-$1,739,554
Municipal									
Customers staying on in 2015	51,640,940	29,548	2	$9,049	$5,790	$4	$14,843	0.4%	-$57,232
Customers migrating to OATT in 2015									
Customer A	100,068,911	60,136	3	$17,535	$11,784	$6	$29,326	0.8%	-$113,072
Customer B	35,893,647	18,865	1	$6,290	$3,697	$2	$9,989	0.3%	-$38,513
Customer C	13,351,001	9,090	1	$2,339	$1,781	$2	$4,123	0.1%	-$15,897
Customer D	8,438,932	6,179	1	$1,479	$1,211	$2	$2,692	0.1%	-$10,378
Municipal Total(2)	**209,393,431**	**123,818**	**8**	**$36,692**	**$24,264**	**$16**	**$60,972**	**1.7%**	**-$235,093**
Unmetered								1.5%	-$207,443
Total Other								3.2%	-$442,536
Total FAM Classes								**100.0%**	**-$13,812,511**

(COS Compliance Filing from July 31, 2014)

Class	Rate Base	Relative Share in Rate Base
(1) DOMESTIC	$1,945,386	54.3%
(2) SMALL GENERAL	$97,112	2.7%
(3) GENERAL	$863,366	24.1%
(4) LARGE GENERAL	$110,492	3.1%
(5) SMALL INDUSTRIAL	$86,528	2.4%
(6) MEDIUM INDUSTRIAL	$152,898	4.3%
(7) LARGE INDUSTRIAL	$211,728	5.9%
(9) MUNICIPAL	$60,971	1.7%
(10) UNMETERED	$53,801	1.5%
TOTAL	$3,582,281	100.0%

2019 FAM AA Amounts

FOR THE YEAR ENDING DECEMBER 31, 2018

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P
7	FORMULA			A - B	C /B				F-G	E + H	I / I (Line 29)	J x K (Line 29)	I + K	J x M (Line 29)	L + M		N - O
10	FAM Rate Class	Variance in 2018 GWh Energy Requirement				2018 Beginning BCF Balance	Variance in 2018 Fuel Cost Recovery before Interest and Incentive			Variance in Fuel Costs before Incentive				Variance in Fuel Costs		2019 FAM AA Rider Calculation	
11		Actual	Test Year	Var	% Var		Actual Fuel Costs	Recovered Fuel Costs	Variance (debit/credit)	Total Amount owed to Customers before Interest	Relative Share	Interest Amount	Adjustment after 2018 Beginning balance and interest	NSPI Incentive Amount	Adjustment after Incentive	Amount owed by departing load to non-FAM classes	Amount to be paid to credited through riders
13	Residential Subtotal	4,998.6	4,956.1	42.46	0.9%	$0	$282,060,312	$277,105,336	$4,954,976	$4,954,976	50.4%	($73,255)	$4,881,721	$0	$4,881,721		$4,881,721
14	Small General	316.2	284.1	32.10	11.3%	$0	$18,014,529	$17,754,936	$259,593	$259,593	3.2%	($4,679)	$254,914	$0	$254,914		$254,914
15	General Demand	2,566.5	2,562.7	3.85	0.2%	$0	$143,203,086	$136,609,945	$6,593,141	$6,593,141	25.6%	($37,192)	$6,555,949	$0	$6,555,949		$6,555,949
16	Large General	424.1	437.5	- 13.36	-3.1%	$0	$22,608,452	$23,251,445	($642,994)	($642,994)	4.0%	($5,872)	($648,866)	$0	($648,866)		($648,866)
17	Small Industrial	268.3	270.8	- 2.47	-0.9%	$0	$14,937,094	$14,166,335	$770,758	$770,758	2.7%	($3,879)	$766,879	$0	$766,879		$766,879
18	Medium Industrial	496.5	505.4	- 8.90	-1.8%	$0	$26,040,717	$24,973,690	$1,067,027	$1,067,027	4.7%	($6,763)	$1,060,264	$0	$1,060,264		$1,060,264
19	Large Industrial	782.4	829.8	- 47.35	-5.7%	$0	$40,126,433	$38,786,820	$1,339,613	$1,339,613	7.2%	($10,421)	$1,329,192	$0	$1,329,192		$1,329,192
20	**Municipal**										0.0%						
21	Customers staying on the rate	51.7	72.3	- 20.65	-28.5%	$0	$2,629,600	2,681,421.84	($51,821)	($51,821)	0.5%	($683)	($52,504)	$0	($52,504)		($52,504)
22	Customers migrating to OATT in 2015										0.0%						
23	Customer A	50.4	69.1	- 18.62	-27.0%	$0	$2,976,469	2,615,439.57	$361,029	$361,029	0.5%	($773)	$360,256	$0	$360,256	$0	$360,256
24	Customer B	20.1	27.6	- 7.55	-27.3%	$0	$1,195,414	1,040,515.83	$154,899	$154,899	0.2%	($310)	$154,588	$0	$154,588	$0	$154,588
25	Customer C	8.1	11.1	- 2.92	-26.4%	$0	$486,135	421,667.83	$64,468	$64,468	0.1%	($126)	$64,341	$0	$64,341	$0	$64,341
26	Customer D	5.2	7.0	- 1.81	-25.7%	$0	$323,465	271,120.95	$52,345	$52,345	0.1%	($84)	$52,261	$0	$52,261	$0	$52,261
27	**Municipal - Total**	135.6	187.1	- 51.55	-27.5%	$0	$7,611,085	$7,030,166	$580,919	$580,919	1.4%	($1,977)	$578,942	$0	$578,942	$0	$578,942
28	Unmetered	88.3	111.0	- 22.68	-20.4%	$0	$4,989,810	$4,471,370	$518,441	$518,441	0.9%	($1,296)	$517,145	$0	$517,145	-	$517,145
29	**FAM Class Total / Average**	10,076.6	10,144.5	(67.9)	-0.7%	$0	$559,591,518	$544,150,044	$15,441,473	$15,441,473	100.0%	($145,334)	$15,296,140	$0	$15,296,140	$0	$15,296,140

Allocation of Actual Fuel-related Costs among Rate Classes

FOR THE YEAR ENDING DECEMBER 31, 2018

Line #	COLUMN	A	B	C	D	E	F	G																R	S	T	U	V	W	X	Y	Z
5	FORMULA			B / B (Line 41)		D/ D (Line 41)																		G+L+Q	E x S (line 41)	E x T (line 41)	E x W (line 41)	R+S+T+U	VxA	W / W (line 41)	X x V(line 39)	Y x F (line 39)
10		Cost Allocation Factors						Fuel-related Costs from COS																					Fuel Costs used for FAM purposes			
11			3 CP Demands		Energy Requirement					Purchased Power- Biomass			Maritime Link			Purchased Power other than Biomass and Wind			Purchased Power - Wind												
12													Basic and Supplemental Blocks			Total				NRIS												
13	Rate Class	R/C Ratio as per 2013 CF for the 2014 Test Year	KW Demand	Relative Shares	KWh Energy	Relative Shares	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	Fixed Energy-related	Fixed Demand-related	ERIS	Energy-related	Demand-related	Total	Total	Total Fuel-related costs before Exports, OM&G and Foreign Exchange	Net Margin on Export Sales	OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh
15	**FAM Rate Classes (ATL)**																															
16	Residential non ETS						4,306,482,845																									
17	Residential ETS						274,527,834																									
18	Residential Subtotal	98.85%	3,535,616	62.2%	4,998,573,274	49.6%	4,581,010,679	$126,713,209	$16,468,289	$766,055	$5,375,441	$3,658,729	$9,800,225	$27,701,517	$25,870,776	$53,572,293	$710,417	$483,537	$1,193,954	$18,928,920	$47,281,473	$12,141,490	$59,422,963	$78,351,883	$286,099,853	$682,678.63	$0.00	$0	$285,417,175	$282,134,877	50.4%	$282,060,312	**6.157**
19																$0																
20	Small General	104.64%	151,256	2.7%	316,150,410	3.1%	291,398,915	$8,023,877	$1,063,309	$48,827	$339,987	$156,522	$545,336	$1,752,069	$1,106,766	$2,858,835	$44,933	$20,686	$65,619	$1,197,219	$2,990,465	$519,420	$3,509,884	$4,707,103	$17,264,079	$43,808.35	$0.00	$0	$17,220,270	$18,019,291	3.2%	$18,014,529	**6.182**
21	General Demand	102.92%	1,142,508	20.1%	2,566,532,826	25.5%	2,411,047,394	$65,190,850	$8,948,055	$399,278	$2,760,037	$1,182,291	$4,341,606	$14,223,429	$8,359,948	$22,583,378	$364,766	$156,251	$521,017	$9,719,112	$24,276,818	$3,923,432	$28,200,250	$37,919,362	$139,504,268	$327,292.90	$0.00	$0	$139,176,975	$143,240,943	25.6%	$143,203,086	**5.939**
22	Large General	99.35%	161,919	2.8%	424,119,718	4.2%	399,097,929	$10,801,613	$1,529,353	$67,112	$456,096	$167,557	$690,766	$2,350,423	$1,184,793	$3,535,216	$60,278	$22,144	$82,422	$1,606,084	$4,011,746	$556,039	$4,567,784	$6,173,868	$22,813,238	$50,853.86	$0.00	$0	$22,762,384	$22,614,428	4.0%	$22,608,452	**5.665**
23	Small Industrial	102.46%	120,558	2.1%	268,309,483	2.7%	253,286,884	$6,826,735	$942,671	$41,526	$288,539	$124,756	$454,821	$1,486,940	$882,149	$2,369,089	$38,133	$16,488	$54,621	$1,016,052	$2,537,938	$414,004	$2,951,941	$3,967,993	$14,615,931	$33,613.52	$0.00	$0	$14,582,317	$14,941,042	2.7%	$14,937,094	**5.897**
24	Medium Industrial	98.46%	185,237	3.3%	496,507,889	4.9%	469,606,802	$12,577,870	$1,719,026	$76,885	$533,942	$191,688	$802,515	$2,751,590	$1,355,418	$4,107,007	$70,566	$25,333	$95,899	$1,880,208	$4,696,465	$636,115	$5,332,580	$7,212,788	$26,514,907	$59,898.13	$0.00	$0	$26,455,008	$26,047,601	4.7%	$26,040,717	**5.545**
25	**Large Industrial**																															
26	Large Industrial - Firm																															
27	Large Industrial - Interruptible																															
28	**Large Industrial Total**	97.44%	233,693	4.1%	782,439,856	7.8%	745,866,713	$19,915,086	$2,806,586	$122,454	$841,432	$241,830	$1,205,716	4336191.575	$1,709,974	$6,046,165	$111,203	$31,960	$143,164	$2,962,994	$7,401,094	$802,513	$8,203,607	$11,166,600	$41,283,318	$91,772.96	$0.00	$0	$41,191,545	$40,137,041	7.2%	$40,126,433	**5.380**
29	ELI 2P-RTP (base rate)		-	0.0%	-	0.0%	-																									**NA**
30	Municipal																															
31	Customers staying on in 2015	97.67%	14,092	0.2%	51,691,613	0.5%	49,056,382	$1,312,566	$176,997	$8,013	$55,589	$14,583	$78,184	$286,469	$103,113	$389,582	$7,347	$1,927	$9,274	$195,749	$488,951	$48,392	$537,343	$733,092	$2,699,695	$6,651.76	$0.00	$0	$2,693,043	$2,630,296	0.5%	$2,629,600	**5.360**
32	Customers migrating to OATT in 2015												$0		$0	$0										$0.00						
33	Customer A	97.67%	49,444	0.9%	50,432,571	0.5%	47,849,242	$1,282,111	$167,423	$7,785	$54,235	$51,166	$113,186	$279,491	$361,791	$641,283	$7,168	$6,762	$13,930	$190,981	$477,041	$169,793	$646,835	$837,816	$3,055,748	$7,466.89	$0.00	$0	$3,048,281	$2,977,256	0.5%	$2,976,469	**6.221**
34	Customer B	97.67%	19,458	0.3%	20,098,460	0.2%	19,036,148	$517,103	$72,823	$3,193	$21,614	$20,136	$44,942	$111,383	$142,378	$253,762	$2,856	$2,661	$5,518	$76,110	$190,111	$66,820	$256,931	$333,041	$1,227,189	$2,933.47	$0.00	$0	$1,224,256	$1,195,730	0.2%	$1,195,414	**6.280**
35	Customer C	97.67%	8,510	0.1%	8,135,752	0.1%	7,714,377	$206,821	$26,724	$1,249	$8,749	$8,806	$18,804	$45,087	$62,269	$107,356	$1,156	$1,164	$2,320	$30,809	$76,956	$29,224	$106,180	$136,989	$499,013	$1,149.06	$0.00	$0	$497,864	$486,264	0.1%	$486,135	**6.302**
36	Customer D	97.67%	6,423	0.1%	5,231,493	0.1%	4,960,135	$133,012	$17,001	$800	$5,626	$6,646	$13,072	$28,992	$46,996	$75,988	$744	$878	$1,622	$19,811	$49,485	$22,056	$71,540	$91,351	$332,046	$776.61	$0.00	$0	$331,270	$323,551	0.1%	$323,465	**6.521**
37	**Municipal Total**	97.67%	97,927	1.7%	135,589,889	1.3%	128,616,283	$3,451,612	$460,967	$21,039	$145,813	$101,337	$268,189	$751,424	$716,548	$1,467,971	$19,271	$13,393	$32,663	$513,461	$1,282,544	$336,285	$1,618,829	$2,132,290	$7,813,691	$18,977.78	$0.00	$0	$7,794,714	$7,613,097	1.4%	$7,611,085	**5.918**
38	Unmetered	100.00%	56,161	1.0%	88,329,508	0.9%	80,929,771	$2,242,285	$308,688	$13,744	$94,989	$58,116	$166,850	$489,512	$410,937	$900,449	$12,554	$7,681	$20,234	$334,492	$835,508	$192,858	$1,028,367	$1,362,858	$5,001,364	$10,234.66	$0.00	$0	$4,991,130	$4,991,130	0.9%	$4,989,810	**6.166**
39	ATL Subtotal / Average	100.00%	5,684,874	100.0%	10,076,552,853	100.0%	9,360,861,371	$255,742,937	$34,246,944	$1,556,922	$10,836,276	$5,882,826	$18,276,024	$55,843,095.50	$41,597,308	$97,440,404	$1,432,120	$777,473	$2,209,593	$38,158,542	$95,314,050	$19,522,155	$114,836,205	$152,994,747	$560,910,648	-$1,319,131	$0.00	$0	$559,591,518	$559,739,450	100.0%	$559,591,518	**5.978**
40						1.4														46.2%												
41	Purchased Power Allocation Factors.		107.5		187	1.7				8.5%	59.3%	32.2%	100.0%	57%	42.7%	100.0%	64.8%	35.2%	100.0%	$38,158,542	83%	17%	100%									
42			**98**		**136**																											
43	**Non-FAM Rate Classes**		-9%		-28%																											
44																																
45																																
46																																
47																																
49	**Total Below-the-line before Additional Energy**				1,193,693,416		1,167,133,957	$72,124,823		$0	$0	$0	$0				$0	$0	$0	$0	$0	$0	$0		$72,124,823				$72,124,823	$72,124,823		$72,124,823	**6.180**
50	**In Province Total**		**5,684,874**		**11,270,246,269**		**10,527,995,328**	**327,867,760**	**34,246,944**	**1,556,922**	**10,836,276**	**5,882,826**	**18,276,024**	**55,843,096**	**41,597,308**	**97,440,404**	**$1,432,120**	**$777,473**	**$2,209,593**	**$38,158,542**	**$95,314,050**	**$19,522,155**	**$114,836,205**		**$633,035,471**	**-$1,319,131**	**$0**	**$0**	**$631,716,340**	**$631,864,273**	**100.0%**	**$631,716,340**	**12.158**
53	**Exports**				91,628,000		88,519,119																									
54																																
55	**Non-FAM Categories**				1,285,321,416		1,255,653,076	72,124,823	-	0	0	0	0	0	0	0	0	0	0	0												
56																																
57	**Grand Total**				**11,361,874,269**		**10,616,514,447**	**$327,867,760**	**$34,246,944**	**$1,556,922**	**$10,836,276**	**$5,882,826**	**$18,276,024**	**$55,843,096**	**$41,597,308**	**$97,440,404**	**$1,432,120**	**$777,473**	**$2,209,593**	**$38,158,542**	**$95,314,050**	**$19,522,155**	**$114,836,205**	**$152,994,747**	**$633,035,471**	**-$1,319,131**	**$0**	**$0**	**$631,716,340**	**$631,864,273**	**100%**	**$631,716,340**	**5.950**
58																																

Monthly Fuel Cost Allocation

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Purchased Power													
Imports	$2,080,586	$2,321,236	$1,143,519	$1,180,499	$832,969	$1,377,686	$4,418,660	$5,446,768	$3,134,218	$3,159,239	$3,962,770	$5,188,795	**$34,246,944**
Biomass													
IPP	$1,391,962	$1,026,383	$1,188,251	$1,101,497	$898,291	$919,055	$1,417,856	$1,502,308	$780,057	$1,102,872	$909,703	$1,228,148	**$13,466,384**
Comfit	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	**$4,809,640**
Total	**$1,792,765**	**$1,427,186**	**$1,589,055**	**$1,502,301**	**$1,299,094**	**$1,319,858**	**$1,818,660**	**$1,903,111**	**$1,180,861**	**$1,503,676**	**$1,310,506**	**$1,628,951**	**$18,276,024**
Maritime Link													
ML - NS Block (GWh)	$4,634,247	$9,958,333	$9,125,000	$9,125,000	$9,125,000	$9,125,000	$8,291,667	$8,291,667	$8,291,667	$8,291,667	$8,291,667	$4,889,491	$97,440,404
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$4,634,247**	**$9,958,333**	**$9,125,000**	**$9,125,000**	**$9,125,000**	**$9,125,000**	**$8,291,667**	**$8,291,667**	**$8,291,667**	**$8,291,667**	**$8,291,667**	**$4,889,491**	**$97,440,404**
Regular other than biomass and wind													
IPP	$185,479	$195,882	$243,021	$210,018	$160,000	$151,883	$135,476	$85,802	$126,928	$243,149	$219,492	$220,290	**$2,177,421**
Comfit	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	**$32,172**
Total	**$188,160**	**$198,563**	**$245,702**	**$212,699**	**$162,681**	**$154,564**	**$138,157**	**$88,483**	**$129,609**	**$245,830**	**$222,173**	**$222,971**	**$2,209,593**
Wind NRIS													
IPP	$4,403,687	$3,887,665	$5,455,830	$3,849,299	$3,277,561	$3,352,038	$2,966,137	$1,705,797	$2,816,866	$3,929,206	$4,928,941	$3,847,493	**$44,420,521**
Comfit	$6,907,241	$6,222,947	$7,791,157	$6,225,380	$5,772,008	$5,121,621	$4,817,129	$3,407,029	$4,446,621	$6,761,440	$7,011,886	$5,931,226	**$70,415,684**
Total	**$11,310,928**	**$10,110,612**	**$13,246,987**	**$10,074,678**	**$9,049,569**	**$8,473,660**	**$7,783,266**	**$5,112,826**	**$7,263,487**	**$10,690,646**	**$11,940,827**	**$9,778,719**	**$114,836,205**
Wind ERIS													
IPP	$3,647,660	$3,357,190	$3,629,479	$3,531,950	$3,192,602	$2,814,493	$2,462,303	$1,874,547	$2,342,428	$3,579,588	$4,186,830	$3,539,472	**$38,158,542**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$3,647,660**	**$3,357,190**	**$3,629,479**	**$3,531,950**	**$3,192,602**	**$2,814,493**	**$2,462,303**	**$1,874,547**	**$2,342,428**	**$3,579,588**	**$4,186,830**	**$3,539,472**	**$38,158,542**
Grand Total	**$23,654,345**	**$27,373,121**	**$28,979,743**	**$25,627,127**	**$23,661,916**	**$23,265,259**	**$24,912,713**	**$22,717,401**	**$22,342,270**	**$27,470,646**	**$29,914,773**	**$25,248,398**	**$305,167,711**
Plant Fuel Costs													
Plant Fuel Costs	$34,782,431	$27,420,334	$29,339,325	$22,993,717	$21,289,009	$18,568,156	$25,700,039	$29,051,723	$23,488,537	$26,056,456	$31,813,113	$37,364,921	**$327,867,760**
BTL Class Fuel-related costs													
[redacted]													
Total	$6,473,270	$5,585,585	$5,474,831	$5,229,893	$4,482,007	$4,436,589	$6,061,162	$7,764,522	$5,512,404	$6,093,040	$6,776,245	$8,235,275	**$72,124,823**

Monthly Fuel Cost Allocation

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
ATL-related Fuel costs (net of BTL)	$28,309,161	$21,834,749	$23,864,494	$17,763,824	$16,807,002	$14,131,566	$19,638,877	$21,287,201	$17,976,133	$19,963,417	$25,036,868	$29,129,646	**$255,742,937**
Fuel costs before PP													
Domestic	$16,065,308	$11,837,990	$12,953,286	$9,124,710	$7,967,488	$5,825,157	$8,284,773	$9,014,626	$7,445,591	$8,897,297	$12,904,550	$16,392,433	$126,713,209
Small General	$997,285	$711,372	$760,103	$500,357	$569,446	$424,180	$623,415	$663,031	$569,070	$612,858	$740,368	$852,391	$8,023,877
General	$6,343,686	$5,332,994	$5,553,224	$4,419,420	$4,223,592	$4,110,868	$5,597,305	$5,958,915	$5,101,348	$5,585,305	$6,130,319	$6,833,874	$65,190,850
Large General	$926,943	$746,811	$884,857	$720,458	$737,088	$717,646	$1,060,870	$1,219,345	$983,722	$934,271	$907,642	$961,960	$10,801,613
Small Industrial	$661,151	$498,178	$557,947	$415,877	$514,901	$440,211	$667,793	$608,563	$596,862	$493,844	$713,099	$658,309	$6,826,735
Medium Industrial	$1,125,796	$920,976	$1,081,805	$889,694	$915,549	$916,071	$1,138,663	$1,150,357	$1,050,254	$1,074,499	$1,166,225	$1,147,782	$12,577,670
Large Industrial													
Customers staying on the rate	$218,069	$171,037	$222,414	$178,980	$192,723	$204,259	$266,599	$323,727	$231,872	$287,261	$280,410	$319,615	$2,896,966
Customer A moving some of its load to a BTL rate	$1,335,430	$1,148,936	$1,325,680	$1,117,635	$1,337,829	$1,191,084	$1,548,972	$1,859,198	$1,578,688	$1,632,101	$1,616,007	$1,326,559	$17,018,120
Large Industrial	$1,553,499	$1,319,973	$1,548,094	$1,296,616	$1,530,552	$1,395,343	$1,815,571	$2,182,925	$1,810,559	$1,919,362	$1,896,417	$1,646,174	$19,915,086
ELI 2P-RTP													
Municipal													
Customers staying on in 2015	$144,210	$108,639	$118,134	$93,173	$85,830	$73,361	$103,265	$114,204	$92,660	$99,810	$129,147	$150,134	$1,312,566
Customers migrating to OATT in 2015													
Customer A	$175,012	$134,303	$135,873	$87,329	$59,134	$48,672	$79,995	$90,740	$74,317	$93,371	$135,732	$167,631	$1,282,111
Customer B	$65,712	$46,820	$45,170	$24,228	$19,816	$18,524	$40,735	$48,912	$38,230	$46,671	$53,434	$68,851	$517,103
Customer C	$29,415	$20,532	$22,356	$14,245	$8,951	$8,082	$11,147	$12,831	$9,409	$14,465	$23,030	$32,357	$206,821
Customer D	$21,255	$13,760	$13,820	$9,282	$5,001	$4,689	$6,026	$7,505	$5,556	$8,517	$15,063	$22,539	$133,012
Municipal	$435,604	$324,055	$335,353	$228,257	$178,733	$153,327	$241,169	$274,193	$220,172	$262,833	$356,405	$441,512	$3,451,612
Unmetered	$199,889	$142,399	$189,826	$168,435	$169,654	$148,763	$209,317	$215,246	$198,554	$183,147	$221,843	$195,211	$2,242,285
Total	**$28,309,161**	**$21,834,749**	**$23,864,494**	**$17,763,824**	**$16,807,002**	**$14,131,566**	**$19,638,877**	**$21,287,201**	**$17,976,133**	**$19,963,417**	**$25,036,868**	**$29,129,646**	**$255,742,937**
BTL Fuel-related costs													
[redacted]													
Subtotal before PP	$6,473,270	$5,585,585	$5,474,831	$5,229,893	$4,482,007	$4,436,589	$6,061,162	$7,764,522	$5,512,404	$6,093,040	$6,776,245	$8,235,275	$72,124,823

Monthly Fuel Cost Allocation

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Exports	**($398,476)**	**($582,179)**	**$7,063**	**$60,395**	**($21,639)**	**($3,618)**	**$35,000**	**$832**	**($300,809)**	**($70,450)**	**($49,050)**	**$3,801**	**($1,319,131)**
Domestic	($226,133)	($315,636)	$3,834	$31,023	($10,258)	($1,491)	$14,765	$352	($124,593)	($31,398)	($25,282)	$2,139	($682,679)
Small General	($14,038)	($18,967)	$225	$1,701	($733)	($109)	$1,111	$26	($9,523)	($2,163)	($1,450)	$111	($43,808)
General	($89,293)	($142,193)	$1,643	$15,026	($5,438)	($1,052)	$9,975	$233	($85,365)	($19,710)	($12,010)	$892	($327,293)
Large General	($13,048)	($19,912)	$262	$2,449	($949)	($184)	$1,891	$48	($16,461)	($3,297)	($1,778)	$126	($50,854)
Small Industrial	($9,306)	($13,283)	$165	$1,414	($663)	($113)	$1,190	$24	($9,988)	($1,743)	($1,397)	$86	($33,614)
Medium Industrial	($15,847)	($24,556)	$320	$3,025	($1,179)	($235)	$2,029	$45	($17,575)	($3,792)	($2,285)	$150	($59,898)
Large Industrial													
Customers staying on the rate	($3,070)	($4,560)	$66	$609	($248)	($52)	$475	$13	($3,880)	($1,014)	($549)	$42	($12,170)
Customer A moving some of its load to a BTL rate	($18,797)	($30,634)	$392	$3,800	($1,722)	($305)	$2,761	$73	($26,417)	($5,760)	($3,166)	$173	($79,603)
Large Industrial	($21,867)	($35,194)	$458	$4,408	($1,971)	($357)	$3,236	$85	($30,298)	($6,773)	($3,715)	$215	($91,773)
ELI 2P-RTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Municipal													
Customers staying on in 2015	($2,030)	($2,897)	$35	$317	($111)	($19)	$184	$4	($1,551)	($352)	($253)	$20	($6,652)
Customers migrating to OATT in 2015													
Customer A	($2,463)	($3,581)	$40	$297	($76)	($12)	$143	$4	($1,244)	($330)	($266)	$22	($7,467)
Customer B	($925)	($1,248)	$13	$82	($26)	($5)	$73	$2	($640)	($165)	($105)	$9	($2,933)
Customer C	($414)	($547)	$7	$48	($12)	($2)	$20	$1	($157)	($51)	($45)	$4	($1,149)
Customer D	($299)	($367)	$4	$32	($6)	($1)	$11	$0	($93)	($30)	($30)	$3	($777)
Municipal	($6,132)	($8,640)	$99	$776	($230)	($39)	$430	$11	($3,684)	($928)	($698)	$58	($18,978)
Unmetered	($2,814)	($3,797)	$56	$573	($218)	($38)	$373	$8	($3,323)	($646)	($435)	$25	($10,235)
Total	($398,476)	($582,179)	$7,063	$60,395	($21,639)	($3,618)	$35,000	$832	($300,809)	($70,450)	($49,050)	$3,801	($1,319,131)
Imports													
Domestic	$1,180,722	$1,258,488	$620,685	$606,385	$394,875	$567,894	$1,864,037	$2,306,577	$1,298,172	$1,408,010	$2,042,498	$2,919,945	$16,468,289
Small General	$73,296	$75,625	$36,422	$33,251	$28,222	$41,353	$140,266	$169,650	$99,220	$96,986	$117,184	$151,834	$1,063,309
General	$466,230	$566,947	$266,095	$293,693	$209,325	$400,768	$1,259,369	$1,524,711	$889,443	$883,882	$970,291	$1,217,302	$8,948,055
Large General	$68,126	$79,393	$42,400	$47,878	$36,531	$69,963	$238,691	$311,994	$171,516	$147,850	$143,659	$171,352	$1,529,353
Small Industrial	$48,591	$52,961	$26,735	$27,637	$25,519	$42,916	$150,250	$155,713	$104,066	$78,152	$112,867	$117,263	$942,671
Medium Industrial	$82,741	$97,908	$51,837	$59,125	$45,375	$89,308	$256,194	$294,342	$183,116	$170,041	$184,587	$204,452	$1,719,026
Large Industrial													
Customers staying on the rate	$16,027	$18,183	$10,657	$11,894	$9,552	$19,913	$59,984	$82,832	$40,428	$45,459	$44,383	$56,932	$416,244
Customer A moving some of its load to a BTL rate	$98,148	$122,143	$63,523	$74,273	$66,304	$116,119	$348,512	$475,714	$275,251	$258,282	$255,777	$236,297	$2,390,342
Large Industrial	$114,175	$140,325	$74,180	$86,167	$75,855	$136,032	$408,495	$558,546	$315,679	$303,742	$300,160	$293,229	$2,806,586
ELI 2P-RTP	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Municipal													
Customers staying on in 2015	$10,599	$11,549	$5,661	$6,192	$4,254	$7,152	$23,234	$29,222	$16,156	$15,795	$20,441	$26,743	$176,997
Customers migrating to OATT in 2015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer A	$12,863	$14,278	$6,511	$5,803	$2,931	$4,745	$17,999	$23,218	$12,958	$14,776	$21,483	$29,860	$167,423
Customer B	$4,830	$4,977	$2,164	$1,610	$982	$1,806	$9,165	$12,515	$6,666	$7,386	$8,457	$12,264	$72,823
Customer C	$2,162	$2,183	$1,071	$947	$444	$788	$2,508	$3,283	$1,641	$2,289	$3,645	$5,764	$26,724
Customer D	$1,562	$1,463	$662	$617	$248	$457	$1,356	$1,920	$969	$1,348	$2,384	$4,015	$17,001
Municipal	$32,015	$34,450	$16,069	$15,169	$8,858	$14,948	$54,262	$70,158	$38,388	$41,594	$56,411	$78,645	$460,967
Unmetered	$14,691	$15,138	$9,096	$11,193	$8,408	$14,503	$47,095	$55,075	$34,619	$28,983	$35,113	$34,773	$308,688
Total	$2,080,586	$2,321,236	$1,143,519	$1,180,499	$832,969	$1,377,686	$4,418,660	$5,446,768	$3,134,218	$3,159,239	$3,962,770	$5,188,795	$34,246,944

Monthly Fuel Cost Allocation

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total
Purchased Biomass Generation	13,337,282	7,948,960	10,368,011	9,336,396	4,473,980	4,724,449	12,760,346	13,585,412	4,912,526	9,925,177	8,026,979	11,396,849	110,796,367
Relative Share	12.0%	7.2%	9.4%	8.4%	4.0%	4.3%	11.5%	12.3%	4.4%	9.0%	7.2%	10.3%	100.0%
Bio-fuel Apportioned	**$187,417**	**$111,700**	**$145,692**	**$131,196**	**$62,869**	**$66,388**	**$179,310**	**$190,904**	**$69,031**	**$139,470**	**$112,796**	**$160,150**	**$1,556,922**
Domestic	$106,358	$60,559	$79,080	$67,391	$29,803	$27,366	$75,643	$80,843	$28,592	$62,159	$58,137	$90,123	$766,055
Small General	$6,602	$3,639	$4,640	$3,695	$2,130	$1,993	$5,692	$5,946	$2,185	$4,282	$3,336	$4,686	$48,827
General	$41,997	$27,282	$33,902	$32,640	$15,799	$19,312	$51,105	$53,440	$19,590	$39,020	$27,618	$37,571	$399,278
Large General	$6,137	$3,820	$5,402	$5,321	$2,757	$3,371	$9,686	$10,935	$3,778	$6,527	$4,089	$5,289	$67,112
Small Industrial	$4,377	$2,549	$3,406	$3,071	$1,926	$2,068	$6,097	$5,458	$2,292	$3,450	$3,213	$3,619	$41,526
Medium Industrial	$7,453	$4,711	$6,604	$6,571	$3,425	$4,304	$10,396	$10,316	$4,033	$7,507	$5,254	$6,310	$76,885
Large Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customers staying on the rate	$1,444	$875	$1,358	$1,322	$721	$960	$2,434	$2,903	$890	$2,007	$1,263	$1,757	$17,934
Customer A moving some of its load to a BTL rate	$8,841	$5,878	$8,093	$8,254	$5,004	$5,596	$14,143	$16,673	$6,062	$11,402	$7,280	$7,293	$104,520
Large Industrial	$10,285	$6,753	$9,451	$9,576	$5,725	$6,555	$16,577	$19,576	$6,953	$13,409	$8,544	$9,050	$122,454
ELI 2P-RTP													
Municipal													
Customers staying on in 2015	$955	$556	$721	$688	$321	$345	$943	$1,024	$356	$697	$582	$825	$8,013
Customers migrating to OATT in 2015													$0
Customer A	$1,159	$687	$830	$645	$221	$229	$730	$814	$285	$652	$611	$922	$7,785
Customer B	$435	$240	$276	$179	$74	$87	$372	$439	$147	$326	$241	$379	$3,193
Customer C	$195	$105	$136	$105	$33	$38	$102	$115	$36	$101	$104	$178	$1,249
Customer D	$141	$70	$84	$69	$19	$22	$55	$67	$21	$60	$68	$124	$800
Municipal	$2,884	$1,658	$2,047	$1,686	$669	$720	$2,202	$2,459	$845	$1,836	$1,606	$2,427	$21,039
Unmetered	$1,323	$728	$1,159	$1,244	$635	$699	$1,911	$1,930	$762	$1,280	$999	$1,073	$13,744
Total	**$187,417**	**$111,700**	**$145,692**	**$131,196**	**$62,869**	**$66,388**	**$179,310**	**$190,904**	**$69,031**	**$139,470**	**$112,796**	**$160,150**	**$1,556,922**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Monthly Energy Allocators

Rate Class	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total	2018 3- CP kWs
ATL														
Domestic Total	632,462,782	504,585,359	521,280,823	425,437,751	340,317,864	271,070,480	309,892,887	312,392,261	273,464,645	337,129,944	465,597,576	604,940,902	4,998,573,274	3,535,616
Small General	39,261,335	30,321,704	30,588,940	23,329,057	24,322,924	19,738,962	23,318,925	22,976,623	20,901,043	23,221,990	26,712,567	31,456,341	316,150,410	151,256
General	249,739,718	227,314,847	223,479,132	206,054,539	180,403,656	191,296,977	209,367,848	206,499,848	187,364,343	211,634,330	221,182,565	252,195,024	2,566,532,826	1,142,508
Large General	36,492,121	31,832,249	35,609,407	33,591,219	31,483,480	33,395,260	39,681,950	42,255,096	36,130,550	35,400,721	32,747,812	35,499,851	424,119,718	161,919
Small Industrial	26,028,355	21,234,460	22,453,527	19,390,168	21,993,117	20,484,984	24,978,865	21,089,118	21,921,790	18,712,391	25,728,699	24,294,009	268,309,483	120,558
Medium Industrial	44,320,592	39,255,908	43,535,229	41,481,798	39,106,128	42,628,839	42,591,821	39,864,383	38,574,155	40,714,146	42,077,515	42,357,373	496,507,889	185,237
Large Industrial	61,158,510	56,262,870	62,300,163	60,454,433	65,374,944	64,931,506	67,911,649	75,646,952	66,498,946	72,727,092	68,422,930	60,749,860	782,439,856	233,693
ELI 2P-RTP (Adjusted CBL)														
Municipal														
Customers staying on in 2015	5,677,295	4,630,648	4,754,077	4,344,165	3,666,080	3,413,799	3,862,655	3,957,628	3,403,243	3,781,914	4,659,622	5,540,488	51,691,613	14,092
Customers migrating to OATT in 2015														
Customer A	6,889,905	5,724,585	5,467,962	4,071,712	2,525,830	2,264,925	2,992,235	3,144,504	2,729,551	3,537,939	4,897,216	6,186,206	50,432,571	49,444
Customer B	2,586,984	1,995,684	1,817,780	1,129,619	846,409	861,996	1,523,682	1,694,998	1,404,117	1,768,433	1,927,920	2,540,838	20,098,460	19,458
Customer C	1,158,003	875,167	899,674	664,166	382,335	376,090	416,958	444,656	345,579	548,095	830,921	1,194,108	8,135,752	8,510
Customer D	836,769	586,501	556,149	432,765	213,615	218,184	225,420	260,075	204,061	322,716	543,465	831,773	5,231,493	6,423
Municipal	17,148,957	13,812,585	13,495,643	10,642,426	7,634,269	7,134,994	9,020,950	9,501,861	8,086,551	9,959,097	12,859,143	16,293,413	135,589,889	97,927
Unmetered	7,869,284	6,069,661	7,639,177	7,853,244	7,246,489	6,922,620	7,829,529	7,459,125	7,292,589	6,939,664	8,004,119	7,204,008	88,329,508	56,161
Total	**1,114,481,653**	**930,689,644**	**960,382,040**	**828,234,636**	**717,882,872**	**657,604,622**	**734,594,424**	**737,685,267**	**660,234,613**	**756,439,374**	**903,332,926**	**1,074,990,781**	**10,076,552,853**	5,684,874

BTL

[redacted]

In-province Total	**1,189,626,716**	**1,023,133,034**	**1,063,264,891**	**923,952,447**	**822,014,307**	**747,617,111**	**836,327,828**	**844,484,513**	**765,130,944**	**866,784,445**	**1,004,263,552**	**1,183,646,482**	**11,270,246,269**	
														0
Exports	16,693,000	30,203,000	3,300,000	4,840,000	4,393,000	8,474,000	2,113,000	363,000	6,429,000	9,585,000	3,657,000	1,578,000	91,628,000	
NSR simulated	1,187,057,123	1,046,254,037	1,062,159,182	943,987,434	843,713,974	743,054,719	838,777,120	839,380,483	752,341,473	841,347,759	977,311,303	1,171,839,392	11,247,223,998	
NSR actual	1,189,626,716	1,023,133,034	1,063,264,891	923,952,447	822,014,307	747,617,111	836,327,828	844,484,513	765,130,944	866,784,445	1,004,263,552	1,183,646,482	11,270,246,269	
NSR correction factor	**1.002165**	**0.977901**	**1.001041**	**0.978776**	**0.974281**	**1.006140**	**0.997080**	**1.006081**	**1.017000**	**1.030233**	**1.027578**	**1.010076**	**1.002047**	
Simulated Requirements (kWhs)														
Domestic Total	631,096,663	515,988,099	520,738,733	434,662,944	349,301,631	269,416,251	310,800,448	310,504,175	268,893,574	327,236,518	453,101,950	598,906,506	4,990,647,490	3,535,616
Small General	39,176,530	31,006,922	30,557,130	23,834,925	24,965,004	19,618,503	23,387,218	22,837,753	20,551,674	22,540,517	25,995,659	31,142,558	315,614,392	151,256
General	249,200,280	232,451,761	223,246,732	210,522,626	185,165,981	190,129,572	209,981,008	205,251,772	184,232,473	205,423,702	215,246,506	249,679,332	2,560,531,745	1,142,508
Large General	36,413,298	32,551,602	35,572,376	34,319,611	32,314,586	33,191,462	39,798,164	41,999,708	35,526,614	34,361,850	31,868,932	35,145,734	423,063,938	161,919
Small Industrial	25,972,133	21,714,322	22,430,177	19,810,625	22,573,695	20,359,973	25,052,019	20,961,656	21,555,358	18,163,256	25,038,197	24,051,672	267,683,082	120,558
Medium Industrial	44,224,859	40,143,023	43,489,956	42,381,290	40,138,458	42,368,694	42,716,557	39,623,445	37,929,373	39,519,347	40,948,246	41,934,851	495,418,097	185,237
Large Industrial														
Customers staying on the rate	8,566,429	7,455,089	8,941,324	8,525,870	8,449,143	9,447,068	10,001,369	11,150,617	8,373,921	10,565,270	9,845,697	11,677,323	112,999,119	0
Customer A moving some of its load to a BTL rate	52,459,979	50,079,222	53,294,051	53,239,457	58,651,580	55,088,189	58,109,167	64,039,128	57,013,469	60,027,570	56,740,911	48,466,547	667,209,271	0
Large Industrial - Total	61,026,408	57,534,311	62,235,376	61,765,327	67,100,723	64,535,257	68,110,536	75,189,745	65,387,390	70,592,840	66,586,607	60,143,869	780,208,390	233,693
ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Municipal														
Customers staying on in 2015	5,665,032	4,735,292	4,749,133	4,438,364	3,762,858	3,392,966	3,873,967	3,933,708	3,346,357	3,670,929	4,534,568	5,485,221	51,588,395	14,092
Customers migrating to OATT in 2015														
Customer A	6,875,023	5,853,950	5,462,276	4,160,003	2,592,507	2,251,103	3,000,998	3,125,499	2,683,926	3,434,114	4,765,785	6,124,498	50,329,683	49,444
Customer B	2,581,397	2,040,783	1,815,890	1,154,113	868,752	856,736	1,528,144	1,684,753	1,380,646	1,716,537	1,876,179	2,515,493	20,019,423	19,458
Customer C	1,155,502	894,944	898,739	678,568	392,428	373,795	418,180	441,968	339,803	532,010	808,620	1,182,196	8,116,753	8,510
Customer D	834,962	599,755	555,571	442,149	219,254	216,852	226,080	258,503	200,650	313,246	528,879	823,476	5,219,377	6,423
Municipal Total	17,111,915	14,124,725	13,481,609	10,873,196	7,835,799	7,091,452	9,047,369	9,444,432	7,951,381	9,666,837	12,514,032	16,130,884	135,273,631	97,927
Unmetered	7,852,287	6,206,824	7,631,233	8,023,534	7,437,783	6,880,374	7,852,458	7,414,042	7,170,690	6,736,012	7,789,306	7,132,146	88,126,690	56,161
Total	**1,112,074,373**	**951,721,589**	**959,383,321**	**846,194,078**	**736,833,661**	**653,591,538**	**736,745,777**	**733,226,727**	**649,198,526**	**734,240,879**	**879,089,436**	**1,064,267,552**	10,056,567,457	5,684,874

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Monthly Energy Allocators

Rate Class	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total	2018 3- CP kWs
BTL														0
[redacted]														
NSR	1,187,057,123	1,046,254,037	1,062,159,182	943,987,434	843,713,974	743,054,719	838,777,120	839,380,483	752,341,473	841,347,759	977,311,303	1,171,839,392	11,247,223,998	
Exports	16,715,292	29,887,321	3,292,750	4,831,909	4,404,078	8,453,644	2,116,473	365,976	6,452,511	9,521,552	3,656,663	1,557,716	91,255,885	
ATL														
Fuel Cost Allocators														
Domestic	56.75%	54.22%	54.28%	51.37%	47.41%	41.22%	42.19%	42.35%	41.42%	44.57%	51.54%	56.27%	49.63%	
Small General	3.52%	3.26%	3.19%	2.82%	3.39%	3.00%	3.17%	3.11%	3.17%	3.07%	2.96%	2.93%	3.14%	
General	22.41%	24.42%	23.27%	24.88%	25.13%	29.09%	28.50%	27.99%	28.38%	27.98%	24.49%	23.46%	25.46%	
Large General	3.27%	3.42%	3.71%	4.06%	4.39%	5.08%	5.40%	5.73%	5.47%	4.68%	3.63%	3.30%	4.21%	
Small Industrial	2.34%	2.28%	2.34%	2.34%	3.06%	3.12%	3.40%	2.86%	3.32%	2.47%	2.85%	2.26%	2.66%	
Medium Industrial	3.98%	4.22%	4.53%	5.01%	5.45%	6.48%	5.80%	5.40%	5.84%	5.38%	4.66%	3.94%	4.93%	
Large Industrial														
Customers staying on the rate	0.77%	0.78%	0.93%	1.01%	1.15%	1.45%	1.36%	1.52%	1.29%	1.44%	1.12%	1.10%	1.12%	
Customer A moving some of its load to a BTL rate	4.72%	5.26%	5.56%	6.29%	7.96%	8.43%	7.89%	8.73%	8.78%	8.18%	6.45%	4.55%	6.63%	
Large Industrial - Total	5.49%	6.05%	6.49%	7.30%	9.11%	9.87%	9.24%	10.25%	10.07%	9.61%	7.57%	5.65%	7.76%	
ELI 2P-RTP	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%	
Municipal														
Customers staying on in 2015	0.51%	0.50%	0.50%	0.52%	0.51%	0.52%	0.53%	0.54%	0.52%	0.50%	0.52%	0.52%	0.51%	
Customers migrating to OATT in 2015														
Customer A	0.62%	0.62%	0.57%	0.49%	0.35%	0.34%	0.41%	0.43%	0.41%	0.47%	0.54%	0.58%	0.50%	
Customer B	0.23%	0.21%	0.19%	0.14%	0.12%	0.13%	0.21%	0.23%	0.21%	0.23%	0.21%	0.24%	0.20%	
Customer C	0.10%	0.09%	0.09%	0.08%	0.05%	0.06%	0.06%	0.06%	0.05%	0.07%	0.09%	0.11%	0.08%	
Customer D	0.08%	0.06%	0.06%	0.05%	0.03%	0.03%	0.03%	0.04%	0.03%	0.04%	0.06%	0.08%	0.05%	
Municipal Total	1.54%	1.48%	1.41%	1.28%	1.06%	1.08%	1.23%	1.29%	1.22%	1.32%	1.42%	1.52%	1.35%	
Unmetered	0.71%	0.65%	0.80%	0.95%	1.01%	1.05%	1.07%	1.01%	1.10%	0.92%	0.89%	0.67%	0.88%	
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%	

Monthly Energy Allocators

Rate Class	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total	2018 3- CP kWs
	Jan-18	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Total**	**3CP kWs**
Sales (MWhs)-Actuals														
ATL Classes														
Domestic Non-TOU	536,265,495	436,427,593	442,448,444	374,351,339	303,902,965	240,934,327	278,652,663	275,706,533	242,024,054	287,471,601	390,063,983	498,233,847	4,306,482,845	
Domestic TOU	37,100,969	32,198,498	33,789,543	26,823,414	17,303,538	10,664,973	11,591,345	11,855,068	9,899,793	15,202,472	26,702,203	41,396,017	274,527,834	
Domestic Total	573,366,464	468,626,091	476,237,987	401,174,753	321,206,503	251,599,300	290,244,009	287,561,601	251,923,847	302,674,073	416,766,186	539,629,864	4,581,010,679	3,068,110
Small General	35,955,548	28,395,767	28,104,635	22,013,951	22,939,125	18,374,757	21,805,095	21,086,860	19,230,463	21,049,256	24,018,127	28,425,332	291,398,915	132,090
General	234,895,343	218,801,428	209,173,371	198,712,520	173,884,960	179,888,656	198,244,118	192,775,819	174,900,462	193,797,139	203,501,103	232,472,476	2,411,047,394	1,062,380
Large General	34,181,491	30,706,264	33,387,338	32,434,903	30,433,761	31,601,573	37,521,336	39,519,681	33,951,632	32,373,255	30,124,210	32,862,485	399,097,929	151,090
Small Industrial	24,663,893	20,530,718	21,120,830	18,727,693	21,243,016	19,371,698	23,870,526	19,810,159	20,580,369	17,185,957	23,707,012	22,475,011	253,286,884	112,070
Medium Industrial	42,131,138	38,070,781	41,095,098	40,160,817	37,732,964	40,302,245	40,683,700	37,446,646	36,185,341	37,435,749	38,931,181	39,431,141	469,606,802	172,410
Large Industrial														226,600
Customers staying on the rate	8,250,939	7,145,524	8,549,887	8,151,102	8,027,297	9,039,928	9,570,803	10,590,008	8,041,475	10,061,426	9,458,602	11,125,657	108,012,648	
Customer A moving some of its load to a BTL rate	50,527,952	47,999,734	50,960,920	50,899,234	55,723,247	52,714,055	55,607,524	60,819,496	54,750,025	57,164,932	54,510,078	46,176,867	637,854,065	
Large Industrial - Total	58,778,891	55,145,258	59,510,807	59,050,336	63,750,544	61,753,983	65,178,327	71,409,504	62,791,500	67,226,358	63,968,680	57,302,524	745,866,713	226,600
ELI 2P-RTP (Adjusted CBL)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Municipal														
Customers staying on in 2015	5,396,397	4,513,728	4,496,384	4,213,291	3,567,548	3,240,101	3,702,014	3,729,023	3,205,088	3,491,692	4,335,400	5,165,716	49,056,382	13,376
Customers migrating to OATT in 2015														
Customer A	6,549,011	5,580,043	5,171,573	3,949,046	2,457,944	2,149,683	2,867,794	2,962,868	2,570,622	3,266,440	4,556,461	5,767,756	47,849,242	46,931
Customer B	2,458,987	1,945,295	1,719,248	1,095,587	823,660	818,137	1,460,315	1,597,089	1,322,361	1,632,725	1,793,773	2,368,969	19,036,148	18,469
Customer C	1,100,708	853,070	850,908	644,157	372,059	356,955	399,618	418,971	325,458	506,034	773,104	1,113,335	7,714,377	8,077
Customer D	795,368	571,692	526,003	419,727	207,874	207,082	216,045	245,052	192,179	297,951	505,650	775,510	4,960,135	6,096
Municipal Total	16,300,472	13,463,828	12,764,117	10,321,809	7,429,086	6,771,958	8,645,786	8,953,004	7,615,708	9,194,842	11,964,388	15,191,287	128,616,283	92,950
Unmetered	7,183,765	5,689,536	7,029,662	7,408,689	6,784,053	6,298,001	7,171,916	6,778,055	6,642,461	6,257,552	7,199,046	6,487,035	80,929,771	48,750
ATL Total	**1,027,457,004**	**879,429,671**	**888,423,846**	**790,005,472**	**685,404,011**	**615,962,173**	**693,364,813**	**685,341,330**	**613,821,784**	**687,194,181**	**820,179,933**	**974,277,155**	**9,360,861,371**	5,066,450
BTL														
[redacted]														
In-province Sales	1,100,967,377	972,100,668	989,157,940	885,873,953	790,170,948	703,655,562	793,381,329	789,407,112	714,931,739	792,169,385	916,453,662	1,079,725,654	10,527,995,328	
Exports	16,214,000	28,991,000	3,194,000	4,687,000	4,272,000	8,200,119	2,053,000	355,000	6,259,000	9,236,000	3,547,000	1,511,000	88,519,119	
Total Sales	**1,117,181,377**	**1,001,091,668**	**992,351,940**	**890,560,953**	**794,442,948**	**711,855,681**	**795,434,329**	**789,762,112**	**721,190,739**	**801,405,385**	**920,000,662**	**1,081,236,654**	**10,616,514,447**	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Monthly Energy Allocators

Rate Class	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Total	2018 3- CP kWs
Line Loss Factors from the 2018 Test Year (2017-2019 RSP Fillings)														
Domestic Total	10.07%	10.11%	9.34%	8.35%	8.75%	7.08%	7.08%	7.98%	6.74%	8.12%	8.72%	10.98%	8.94%	15.24%
Small General	8.96%	9.20%	8.73%	8.27%	8.83%	6.77%	7.26%	8.30%	6.87%	7.08%	8.23%	9.56%	8.30%	14.51%
General	6.09%	6.24%	6.73%	5.94%	6.49%	5.69%	5.92%	6.47%	5.34%	6.00%	5.77%	7.40%	6.20%	7.54%
Large General	6.53%	6.01%	6.54%	5.81%	6.18%	5.03%	6.07%	6.28%	4.64%	6.14%	5.79%	6.95%	6.00%	7.17%
Small Industrial	5.30%	5.77%	6.20%	5.78%	6.26%	5.10%	4.95%	5.81%	4.74%	5.69%	5.62%	7.02%	5.70%	7.57%
Medium Industrial	4.97%	5.44%	5.83%	5.53%	6.38%	5.13%	5.00%	5.81%	4.82%	5.57%	5.18%	6.35%	5.49%	7.44%
Large Industrial														
Customers staying on the rate	3.82%	4.33%	4.58%	4.60%	5.26%	4.50%	4.50%	5.29%	4.13%	5.01%	4.09%	4.96%	4.59%	3.13%
Customer A moving some of its load to a BTL rate	3.82%	4.33%	4.58%	4.60%	5.26%	4.50%	4.50%	5.29%	4.13%	5.01%	4.09%	4.96%	4.59%	3.13%
Large Industrial - Total	3.82%	4.33%	4.58%	4.60%	5.26%	4.50%	4.50%	5.29%	4.13%	5.01%	4.09%	4.96%	4.59%	3.13%
ELI 2P-RTP	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%
Municipal														
Customers staying on in 2015	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customers migrating to OATT in 2015														
Customer A	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customer B	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customer C	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Customer D	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Municipal Total	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.35%
Unmetered	9.31%	9.09%	8.56%	8.30%	9.64%	9.25%	9.49%	9.38%	7.95%	7.65%	8.20%	9.94%	8.90%	15.20%
All													7.4%	
BTL														
[redacted]														
BTL Total														
Exports	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Line Losses ,Sales and Energy Requirement data from 2018 Compliance Filing-2018-2019 RSP

Rate Class-	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018Total
kWh Sales													
Domestic Total	564,680	508,852	499,342	389,639	325,216	268,039	275,454	270,039	258,589	302,224	380,211	507,090	**4,549,374**
Small General	29,140	27,225	26,124	21,770	19,802	18,307	19,435	19,121	17,075	18,648	20,170	25,468	**262,284**
General	237,470	222,749	222,025	194,513	179,068	181,481	195,479	190,893	177,137	187,273	200,305	224,680	**2,413,075**
Large General	34,821	32,522	34,953	32,975	33,262	33,056	37,126	38,958	35,997	32,943	32,104	33,999	**412,717**
Small Industrial	24,004	22,543	22,005	20,622	20,622	21,544	22,031	20,110	19,418	18,009	21,237	24,029	**256,174**
Medium Industrial	41,145	38,223	39,420	38,798	38,367	41,049	41,241	40,809	39,756	39,899	40,091	40,283	**479,080**
Large Industrial	65,569	58,938	65,785	62,359	66,255	66,603	67,327	73,430	71,337	67,032	66,177	62,522	**793,335**
ELI 2P-RTP													
Customers staying on the rate	6,411	5,834	6,135	5,790	5,934	5,618	5,513	5,382	5,149	5,329	5,446	6,258	**68,798**
Customers migrating to OATT in 2015													
Customer A	7,781	7,212	7,056	5,427	4,088	3,728	4,271	4,276	4,130	4,985	5,723	6,987	**65,663**
Customer B	2,921	2,514	2,346	1,506	1,370	1,419	2,175	2,305	2,124	2,492	2,253	2,870	**26,294**
Customer C	1,308	1,103	1,161	885	619	619	595	605	523	772	971	1,349	**10,509**
Customer D	945	739	718	577	346	359	322	354	309	455	635	939	**6,697**
Municipal	19,366	17,401	17,416	14,185	12,356	11,742	12,875	12,922	12,234	14,033	15,028	18,402	**177,961**
Unmetered	8,717	8,452	8,717	8,727	8,768	8,238	8,452	8,706	8,472	7,830	8,706	8,156	**101,939**
ATL Total	**1,024,912**	**936,906**	**935,787**	**783,587**	**703,716**	**650,061**	**679,419**	**674,988**	**640,015**	**687,892**	**784,029**	**944,629**	**9,445,942**
BTL													
[redacted]													
In-Province Total Sales	**1,098,686**	**1,017,075**	**1,035,667**	**874,787**	**799,105**	**742,189**	**772,303**	**771,241**	**734,488**	**784,558**	**881,687**	**1,027,118**	**10,538,904**

3CP kWs (2017 Actuals-Sales), 2018 Actuals for Munis

	Jan-18	Feb-18	Dec-18	Total
Domestic Total	965,750	945,100	1,157,260	3,068,110
Small General	57,850	37,610	36,630	132,090
General	377,870	330,470	354,040	1,062,380
Large General	52,400	50,850	47,840	151,090
Small Industrial	52,840	28,950	30,280	112,070
Medium Industrial	68,770	51,640	52,000	172,410
Large Industrial	82,710	79,780	64,110	226,600
[redacted]				
Municipal	34,700	25,130	33,120	92,950
Unmetered	14,870	14,190	19,690	48,750
ATL Total	**1,742,460**	**1,588,850**	**1,828,090**	**5,159,400**

kWh requirements- 2018 Test Year (2017-2018 RSP)

	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018Total
ATL													
Domestic Non-TOU													
Domestic TOU													
Domestic Total	621,535	560,280	546,002	422,164	353,662	287,020	294,963	291,583	276,008	326,750	413,360	562,792	**4,956,118**
Small General	31,750	29,729	28,403	23,570	21,551	19,547	20,845	20,708	18,248	19,970	21,830	27,902	**284,054**
General	251,932	236,646	236,963	206,074	190,685	191,813	207,052	203,247	186,589	198,509	211,866	241,310	**2,562,686**
Large General	37,095	34,476	37,240	34,891	35,317	34,719	39,379	41,403	37,667	34,966	33,964	36,362	**437,480**
Small Industrial	25,277	23,843	23,370	21,815	21,914	22,643	23,121	21,279	20,338	19,033	22,429	25,715	**270,776**
Medium Industrial	43,189	40,304	41,718	40,943	40,813	43,154	43,301	43,182	41,672	42,120	42,168	42,840	**505,403**
Large Industrial	68,077	61,492	68,797	65,226	69,737	69,603	70,356	77,317	74,286	70,389	68,885	65,622	**829,787**
ELI 2P-RTP													
Customers staying on the rate	6,731	6,120	6,480	6,099	6,259	5,883	5,769	5,677	5,376	5,603	5,696	6,645	72,337
Customers migrating to OATT in 2015													
Customer A	8,168	7,566	7,453	5,717	4,312	3,903	4,469	4,511	4,312	5,241	5,986	7,419	**69,057**
Customer B	3,067	2,638	2,478	1,586	1,445	1,486	2,276	2,432	2,218	2,620	2,357	3,047	**27,647**
Customer C	1,373	1,157	1,226	933	653	648	623	638	546	812	1,016	1,432	**11,055**
Customer D	992	775	758	608	365	376	337	373	322	478	664	998	**7,046**
Municipal	20,330	18,256	18,394	14,943	13,033	12,296	13,473	13,631	12,774	14,754	15,718	19,540	**187,142**
Unmetered	9,528	9,220	9,463	9,451	9,613	8,999	9,254	9,523	9,146	8,428	9,420	8,967	**111,012**
Total	**1,108,713**	**1,014,245**	**1,010,350**	**839,077**	**756,325**	**689,795**	**721,744**	**721,873**	**676,727**	**734,919**	**839,641**	**1,031,051**	**10,144,459**
BTL													
[redacted]													
BTL Total	75,281	81,805	101,920	93,062	97,351	94,030	94,803	98,242	96,424	98,662	99,676	84,192	**1,115,450**
Total	75,281	81,805	101,920	93,062	97,351	94,030	94,803	98,242	96,424	98,662	99,676	84,192	**1,115,450**
NSR	1,183,995	1,096,050	1,112,269	932,139	853,675	783,825	816,547	820,115	773,151	833,581	939,318	1,115,243	**11,259,909**
Exports													
NSR	1,183,995	1,096,050	1,112,269	932,139	853,675	783,825	816,547	820,115	773,151	833,581	939,318	1,115,243	**11,259,909**
TSR	1,183,995	1,096,050	1,112,269	932,139	853,675	783,825	816,547	820,115	773,151	833,581	939,318	1,115,243	**11,259,909**

3CP kWs (2017 Actuals-Sales), 2018 Actuals for Munis

	Jan-18	Feb-18	Dec-18	Total
Domestic Total	1,123,167	1,089,700	1,322,748	3,535,616
Small General	66,585	42,875	41,795	151,256
General	407,722	355,255	379,531	1,142,508
Large General	56,120	54,562	51,237	161,919
Small Industrial	56,856	31,121	32,581	120,558
Medium Industrial	73,928	55,410	55,900	185,237
Large Industrial	85,347	82,312	66,033	233,693
ELI 2P-RTP	-	-	-	-
[redacted]				
Municipal	36,539	26,512	34,875	97,927
Unmetered	17,294	16,361	22,506	56,161
Total	**1,923,558**	**1,754,109**	**2,007,206**	**5,684,874**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Rate Class-	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	2018Total	Jan-18	Feb-18	Dec-18	Total
Line Losses	Line Losses from 2017-2019 RSP Compliance Filing-2018 data																
ATL																	
Domestic Total	10.1%	10.1%	9.3%	8.3%	8.7%	7.1%	7.1%	8.0%	6.7%	8.1%	8.7%	11.0%	8.94%	16.3%	15.3%	14.3%	15.2%
Small General	9.0%	9.2%	8.7%	8.3%	8.8%	6.8%	7.3%	8.3%	6.9%	7.1%	8.2%	9.6%	8.3%	15.1%	14.0%	14.1%	14.5%
General	6.1%	6.2%	6.7%	5.9%	6.5%	5.7%	5.9%	6.5%	5.3%	6.0%	5.8%	7.4%	6.2%	7.9%	7.5%	7.2%	7.5%
Large General	6.5%	6.0%	6.5%	5.8%	6.2%	5.0%	6.1%	6.3%	4.6%	6.1%	5.8%	6.9%	6.0%	7.1%	7.3%	7.1%	7.2%
Small Industrial	5.3%	5.8%	6.2%	5.8%	6.3%	5.1%	4.9%	5.8%	4.7%	5.7%	5.6%	7.0%	5.7%	7.6%	7.5%	7.6%	7.6%
Medium Industrial	5.0%	5.4%	5.8%	5.5%	6.4%	5.1%	5.0%	5.8%	4.8%	5.6%	5.2%	6.3%	5.5%	7.5%	7.3%	7.5%	7.4%
Large Industrial	3.8%	4.3%	4.6%	4.6%	5.3%	4.5%	4.5%	5.3%	4.1%	5.0%	4.1%	5.0%	4.6%	3.2%	3.2%	3.0%	3.1%
ELI 2P-RTP														0.0%	0.0%	0.0%	0.0%
Municipal	5.0%	4.9%	5.6%	5.3%	5.5%	4.7%	4.6%	5.5%	4.4%	5.1%	4.6%	6.2%	5.2%	5.3%	5.5%	5.3%	5.4%
Unmetered	9.3%	9.1%	8.6%	8.3%	9.6%	9.2%	9.5%	9.4%	8.0%	7.6%	8.2%	9.9%	8.9%	16.3%	15.3%	14.3%	15.2%
Total	**8.2%**	**8.3%**	**8.0%**	**7.1%**	**7.5%**	**6.1%**	**6.2%**	**6.9%**	**5.7%**	**6.8%**	**7.1%**	**9.1%**	**7.4%**	**10.4%**	**10.4%**	**9.8%**	**10.2%**

BTL

[redacted]

BTL Total

Winter kW Peaks-2018 Actuals

ATL Classes													**3CP**	Annual Peak
Domestic Total	1,123,167	1,089,700										1,322,748	3,535,616	1,322,748
Small General	66,585	42,875										41,795	151,256	41,795
General	407,722	355,255										379,531	1,142,508	379,531
Large General	56,120	54,562										51,237	161,919	51,237
Small Industrial	56,856	31,121										32,581	120,558	32,581
Medium Industrial	73,928	55,410										55,900	185,237	55,900
Large Industrial	85,347	82,312										66,033	233,693	66,033
Municipal	36,539	26,512										34,875	97,927	34,875
Unmetered	17,294	16,361										22,506	56,161	22,506
Total	**1,923,558**	**1,754,109**										**2,007,206**	5,684,874	2,007,206
BTL Classes														
[redacted]														
Total	**21,685**	**114,322**										**10,076**	146,083	10,076
Grand Total	**1,945,243**	**1,868,431**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**2,017,282**	**5,830,957**	**2,017,282**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Data Inputs

2018 Actuals

Category	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual	
Plant Fuel Costs	$34,782,431	$27,420,334	$29,339,325	$22,993,717	$21,289,009	$18,568,156	$25,700,039	$29,051,723	$23,488,537	$26,056,456	$31,813,113	$37,364,921	$327,867,760	
Maritime Link														
ML - NS Block	$4,634,247	$9,958,333	$9,125,000	$9,125,000	$9,125,000	$9,125,000	$8,291,667	$8,291,667	$8,291,667	$8,291,667	$8,291,667	$4,889,491	$97,440,404	$3,402,178
ML - Supp Block														
ML - Surplus														
Total	**$4,634,247**	**$9,958,333**	**$9,125,000**	**$9,125,000**	**$9,125,000**	**$9,125,000**	**$8,291,667**	**$8,291,667**	**$8,291,667**	**$8,291,667**	**$8,291,667**	**$4,889,491**	**$97,440,404**	
Non-Wind Purchases														
Purchased Power Regular bfr Biomass	$185,479	$195,882	$243,021	$210,018	$160,000	$151,883	$135,476	$85,802	$126,928	$243,149	$219,492	$220,290	$2,177,421	
Purchased Power - Biomass	$1,391,962	$1,026,383	$1,188,251	$1,101,497	$898,291	$919,055	$1,417,856	$1,502,308	$780,057	$1,102,872	$909,703	$1,228,148	$13,466,384	
Non-Wind Purchases	$1,577,441	$1,222,265	$1,431,272	$1,311,516	$1,058,291	$1,070,937	$1,553,332	$1,588,110	$906,986	$1,346,022	$1,129,196	$1,448,437	$15,643,805	
Wind Purchases														
Purchased Power Wind - NRIS	$4,403,687	$3,887,665	$5,455,830	$3,849,299	$3,277,561	$3,352,038	$2,966,137	$1,705,797	$2,816,866	$3,929,206	$4,928,941	$3,847,493	$44,420,521	
Purchased Power Wind - ERIS	$3,647,660	$3,357,190	$3,629,479	$3,531,950	$3,192,602	$2,814,493	$2,462,303	$1,874,547	$2,342,428	$3,579,588	$4,186,830	$3,539,472	$38,158,542	
Purchased Power Wind	$8,051,347	$7,244,855	$9,085,309	$7,381,248	$6,470,164	$6,166,531	$5,428,440	$3,580,344	$5,159,294	$7,508,795	$9,115,771	$7,386,965	$82,579,063	
Comfit														
Wind Generation (NRIS)	$6,907,241	$6,222,947	$7,791,157	$6,225,380	$5,772,008	$5,121,621	$4,817,129	$3,407,029	$4,446,621	$6,761,440	$7,011,886	$5,931,226	$70,415,684	
Wind Generation (ERIS)														
Biomass Generation	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$400,803	$4,809,640	
Other	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$2,681	$32,172	
Total Comfit	$7,310,725	$6,626,431	$8,194,641	$6,628,864	$6,175,492	$5,525,106	$5,220,614	$3,810,513	$4,850,105	$7,164,924	$7,415,370	$6,334,710	$75,257,496	
Imports	$2,080,586	$2,321,236	$1,143,519	$1,180,499	$832,969	$1,377,686	$4,418,660	$5,446,768	$3,134,218	$3,159,239	$3,962,770	$5,188,795	$34,246,944	
Export Revenues	$398,476	$582,179	$7,063	$60,395	$21,639	$3,618	$35,000	$832	$300,809	$70,450	$49,050	$3,801	$1,319,131	
OM&G (Solid Fuel Handling) recovered in fuels													$0	
Foreign Exchange (Fuel-related)	$49	$49	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total FAM Cal Model	**$58,038,299**	**$54,793,454**	**$58,319,068**	**$48,620,844**	**$44,950,924**	**$41,833,415**	**$50,612,751**	**$51,769,124**	**$45,830,807**	**$53,527,102**	**$61,727,886**	**$62,613,319**	**$632,636,995**	
Purchased Biomass Generation Units	13,337,281.7	7,948,960.4	10,368,011.0	9,336,396.0	4,473,980	4,724,449	12,760,346	13,585,412	4,912,526	9,925,177	8,026,979	11,396,849	110,796,367.48	

Source-2018

[redacted]															2%
															1%
															95%
															0%
															2%
Total	$6,473,270	$5,585,585	$5,474,831	$5,229,893	$4,482,007	$4,436,589	$6,061,162	$7,764,522	$5,512,404	$6,093,040	$6,776,245	$8,235,275	$72,124,825	100%	$72,115,585
[redacted]															
											$0				
															2013 Compliance Fillings
ERIS	**$3,647,660**	**$3,357,190**	**$3,629,479**	**$3,531,950**	**$3,192,602**	**$2,814,493**	**$2,462,303**	**$1,874,547**	**$2,342,428**	**$3,579,588**	**$4,186,830**	**$3,539,472**	**$38,158,542**	46.21%	47.42%
NRIS	**$4,403,687**	**$3,887,665**	**$5,455,830**	**$3,849,299**	**$3,277,561**	**$3,352,038**	**$2,966,137**	**$1,705,797**	**$2,816,866**	**$3,929,206**	**$4,928,941**	**$3,847,493**	**$44,420,521**	53.79%	52.58%
Total	**$8,051,347**	**$7,244,855**	**$9,085,309**	**$7,381,248**	**$6,470,164**	**$6,166,531**	**$5,428,440**	**$3,580,344**	**$5,159,294**	**$7,508,795**	**$9,115,771**	**$7,386,965**	**$82,579,063**	100.00%	100.00%

Usage Data

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Data Inputs

Category		Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual		
								2018 Actuals								
2018-kWh Sales-Actuals																
ATL Classes																
Domestic Non-TOU		536,265,495	436,427,593	442,448,444	374,351,339	303,902,965	240,934,327	278,652,663	275,706,533	242,024,054	287,471,601	390,063,983	498,233,847	4,306,482,845		
Domestic TOU		37,100,969	32,198,498	33,789,543	26,823,414	17,303,538	10,664,973	11,591,345	11,855,068	9,899,793	15,202,472	26,702,203	41,396,017	274,527,834		
Domestic Total		**573,366,464**	**468,626,091**	**476,237,987**	**401,174,753**	**321,206,503**	**251,599,300**	**290,244,009**	**287,561,601**	**251,923,847**	**302,674,073**	**416,766,186**	**539,629,864**	**4,581,010,679**		3,068,110
Small General		**35,955,548**	**28,395,767**	**28,104,635**	**22,013,951**	**22,939,125**	**18,374,757**	**21,805,095**	**21,086,860**	**19,230,463**	**21,049,256**	**24,018,127**	**28,425,332**	291,398,915		132,090
General		**234,895,343**	**218,801,428**	**209,173,371**	**198,712,520**	**173,884,960**	**179,888,656**	**198,244,118**	**192,775,819**	**174,900,462**	**193,797,139**	**203,501,103**	**232,472,476**	2,411,047,394		1,062,380
Large General		**34,181,491**	**30,706,264**	**33,387,338**	**32,434,903**	**30,433,761**	**31,601,573**	**37,521,336**	**39,519,681**	**33,951,632**	**32,373,255**	**30,124,210**	**32,862,485**	399,097,929		151,090
Small Industrial		**24,663,893**	**20,530,718**	**21,120,830**	**18,727,693**	**21,243,016**	**19,371,698**	**23,870,526**	**19,810,159**	**20,580,369**	**17,185,957**	**23,707,012**	**22,475,011**	253,286,884		112,070
Medium Industrial		**42,131,138**	**38,070,781**	**41,095,098**	**40,160,817**	**37,732,964**	**40,302,245**	**40,683,700**	**37,446,646**	**36,185,341**	**37,435,749**	**38,931,181**	**39,431,141**	469,606,802		172,410
Large Industrial																
Large Industrial - Firm		8,250,939	7,145,524	8,549,887	8,151,102	8,027,297	9,039,928	9,570,803	10,590,008	8,041,475	10,061,426	9,458,602	11,125,657	108,012,648	14%	
Large Industrial - Interruptible		50,527,952	47,999,734	50,960,920	50,899,234	55,723,247	52,714,055	55,607,524	60,819,496	54,750,025	57,164,932	54,510,078	46,176,867	637,854,065	86%	
Large Industrial - Total		**58,778,891**	**55,145,258**	**59,510,807**	**59,050,336**	**63,750,544**	**61,753,983**	**65,178,327**	**71,409,504**	**62,791,500**	**67,226,358**	**63,968,680**	**57,302,524**	**745,866,713**	100%	226,600
ELI 2P-RTP (Adjusted CBL)														-		
Municipal																
Customers staying on in 2015		5,396,397	4,513,728	4,496,384	4,213,291	3,567,548	3,240,101	3,702,014	3,729,023	3,205,088	3,491,692	4,335,400	5,165,716	49,056,382		3,109
Customers migrating to OATT in 2015																
Customer A		6,549,011	5,580,043	5,171,573	3,949,046	2,457,944	2,149,683	2,867,794	2,962,868	2,570,622	3,266,440	4,556,461	5,767,756	47,849,242		57,310
Customer B		2,458,987	1,945,295	1,719,248	1,095,587	823,660	818,137	1,460,315	1,597,089	1,322,361	1,632,725	1,793,773	2,368,969	19,036,148		17,979
Customer C		1,100,708	853,070	850,908	644,157	372,059	356,955	399,618	418,971	325,458	506,034	773,104	1,113,335	7,714,377		8,663
Customer D		795,368	571,692	526,003	419,727	207,874	207,082	216,045	245,052	192,179	297,951	505,650	775,510	4,960,135		5,889
Municipal Total		**16,300,472**	**13,463,828**	**12,764,117**	**10,321,809**	**7,429,086**	**6,771,958**	**8,645,786**	**8,953,004**	**7,615,708**	**9,194,842**	**11,964,388**	**15,191,287**	**128,616,283**		92,950
Unmetered		**7,183,765**	**5,689,536**	**7,029,662**	**7,408,689**	**6,784,053**	**6,298,001**	**7,171,916**	**6,778,055**	**6,642,461**	**6,257,552**	**7,199,046**	**6,487,035**	80,929,771		48,750
ATL Total		**1,027,457,004**	**879,429,671**	**888,423,846**	**790,005,472**	**685,404,011**	**615,962,173**	**693,364,813**	**685,341,330**	**613,821,784**	**687,194,181**	**820,179,933**	**974,277,155**	**9,360,861,371**		5,066,450
Check																
BTL Classes																
[redacted]																
In-Province Total Sales		**1,100,967,377**	**972,100,668**	**989,157,940**	**885,873,953**	**790,170,948**	**703,655,562**	**793,381,329**	**789,407,112**	**714,931,739**	**792,169,385**	**916,453,662**	**1,079,725,654**	**10,527,995,328**		
Export kWh Sales	+	16,214,000	28,991,000	3,194,000	4,687,000	4,272,000	8,200,119	2,053,000	355,000	6,259,000	9,236,000	3,547,000	1,511,000	**88,519,119**		
Total Electric Sales		**1,117,181,377**	**1,001,091,668**	**992,351,940**	**890,560,953**	**794,442,948**	**711,855,681**	**795,434,329**	**789,762,112**	**721,190,739**	**801,405,385**	**920,000,662**	**1,081,236,654**	**10,616,514,447**		
In Province Losses		88,659,339	51,032,366	74,106,951	38,078,494	31,843,359	43,961,549	42,946,499	55,077,401	50,199,205	74,615,060	87,809,890	103,920,828	**742,250,941**		
NSR		**1,189,626,716**	**1,023,133,034**	**1,063,264,891**	**923,952,447**	**822,014,307**	**747,617,111**	**836,327,828**	**844,484,513**	**765,130,944**	**866,784,445**	**1,004,263,552**	**1,183,646,482**	**11,270,246,269**		
Export kWh Losses	-	479,000	1,212,000	106,000	153,000	121,000	273,881	60,000	8,000	170,000	349,000	110,000	67,000	3,108,881		
Total System Requirement		**1,206,319,716**	**1,053,336,034**	**1,066,564,891**	**928,792,447**	**826,407,307**	**756,091,111**	**838,440,828**	**844,847,513**	**771,559,944**	**876,369,445**	**1,007,920,552**	**1,185,224,482**	**11,361,874,269**		

Data Inputs

Category	Jan-18	Feb-18	Mar-18	Apr-18	May-18	Jun-18	Jul-18	Aug-18	Sep-18	Oct-18	Nov-18	Dec-18	Annual
						2018 Actuals							
2018-BCF Recovered Fuel Costs													
ATL Classes													
Domestic Total	$34,682,937	$28,347,192	$28,807,636	$24,267,061	$19,429,781	$15,219,242	$17,556,860	$17,394,601	$15,238,874	$18,308,755	$25,210,187	$32,642,210	$277,105,336
Small General	$2,190,772	$1,730,154	$1,712,415	$1,341,310	$1,397,681	$1,119,574	$1,328,584	$1,284,822	$1,171,712	$1,282,531	$1,463,424	$1,731,955	17,754,936
General	$13,309,170	$12,397,289	$11,851,763	$11,259,051	$9,852,322	$10,192,491	$11,232,512	$10,922,678	$9,909,860	$10,980,546	$11,530,372	$13,171,890	136,609,945
Large General	$1,991,414	$1,788,947	$1,945,146	$1,889,657	$1,773,071	$1,841,108	$2,185,993	$2,302,417	$1,978,022	$1,886,066	$1,755,036	$1,914,568	23,251,445
Small Industrial	$1,379,452	$1,148,283	$1,181,288	$1,047,440	$1,188,122	$1,083,459	$1,335,079	$1,107,982	$1,151,060	$961,211	$1,325,933	$1,257,027	14,166,335
Medium Industrial	$2,240,534	$2,024,604	$2,185,437	$2,135,752	$2,006,639	$2,143,273	$2,163,559	$1,991,413	$1,924,336	$1,990,833	$2,070,360	$2,096,948	24,973,690
Large Industrial													
Large Industrial - Firm	$427,234	$369,995	$442,713	$422,064	$415,653	$468,087	$495,576	$548,351	$416,388	$520,981	$489,766	$576,087	5,592,895
Large Industrial - Interruptible	$2,629,475	$2,497,906	$2,652,006	$2,648,796	$2,899,838	$2,743,239	$2,893,816	$3,165,047	$2,849,191	$2,974,863	$2,836,704	$2,403,044	33,193,926
Large Industrial - Total	$3,056,708	$2,867,901	$3,094,719	$3,070,860	$3,315,491	$3,211,327	$3,389,392	$3,713,397	$3,265,579	$3,495,844	$3,326,471	$2,979,131	38,786,820
ELI 2P-RTP													
Municipal													
Customers staying on in 2015	$294,967	$246,720	$245,772	$230,299	$195,002	$177,104	$202,352	$203,828	$175,190	$190,856	$236,973	$282,358	2,681,422
Customers migrating to OATT in 2015													
Customer A	$357,969	$305,005	$282,678	$215,855	$134,351	$117,502	$156,754	$161,950	$140,510	$178,544	$249,056	$315,266	2,615,440
Customer B	$134,408	$106,330	$93,974	$59,885	$45,021	$44,719	$79,821	$87,297	$72,280	$89,245	$98,048	$129,488	1,040,516
Customer C	$60,165	$46,629	$46,511	$35,210	$20,337	$19,511	$21,843	$22,901	$17,790	$27,660	$42,258	$60,855	421,668
Customer D	$43,475	$31,249	$28,751	$22,942	$11,362	$11,319	$11,809	$13,395	$10,505	$16,286	$27,639	$42,389	271,121
Municipal Total	$890,984	$735,933	$697,687	$564,190	$406,074	$370,155	$472,579	$489,371	$416,275	$502,590	$653,973	$830,356	**7,030,166**
Unmetered	$396,903	$314,347	$388,389	$409,330	$374,819	$347,965	$396,248	$374,488	$366,996	$345,730	$397,747	$358,409	4,471,370
Subtotal	60,138,873.21	51,354,650.46	51,864,481.04	45,984,652.18	39,743,999.83	35,528,593.72	40,060,805.74	39,581,168.93	35,422,713.82	39,754,104.80	47,733,505.04	56,982,495.36	544,150,044

2018-BCF Simulated Collected Fuel Costs

ATL Classes														
Domestic Non-TOU	**6.049**	$32,438,700	$26,399,505	$26,763,706	$22,644,513	$18,383,090	$14,574,117	$16,855,700	$16,677,488	$14,640,035	$17,389,157	$23,594,970	$30,138,165	260,499,147
Domestic TOU	**6.049**	$2,244,238	$1,947,687	$2,043,929	$1,622,548	$1,046,691	$645,124	$701,160	$717,113	$598,838	$919,598	$1,615,216	$2,504,045	16,606,189
Domestic Total	**6.049**	$34,682,937	$28,347,192	$28,807,636	$24,267,061	$19,429,781	$15,219,242	$17,556,860	$17,394,601	$15,238,874	$18,308,755	$25,210,187	$32,642,210	277,105,336
Small General	**6.093**	$2,190,772	$1,730,154	$1,712,415	$1,341,310	$1,397,681	$1,119,574	$1,328,584	$1,284,822	$1,171,712	$1,282,531	$1,463,424	$1,731,955	17,754,936
General	**5.666**	$13,309,170	$12,397,289	$11,851,763	$11,259,051	$9,852,322	$10,192,491	$11,232,512	$10,922,678	$9,909,860	$10,980,546	$11,530,372	$13,171,890	136,609,945
Large General	**5.826**	$1,991,414	$1,788,947	$1,945,146	$1,889,657	$1,773,071	$1,841,108	$2,185,993	$2,302,417	$1,978,022	$1,886,066	$1,755,036	$1,914,568	23,251,445
Small Industrial	**5.593**	$1,379,452	$1,148,283	$1,181,288	$1,047,440	$1,188,122	$1,083,459	$1,335,079	$1,107,982	$1,151,060	$961,211	$1,325,933	$1,257,027	14,166,335
Medium Industrial	**5.318**	$2,240,534	$2,024,604	$2,185,437	$2,135,752	$2,006,639	$2,143,273	$2,163,559	$1,991,413	$1,924,336	$1,990,833	$2,070,360	$2,096,948	24,973,690
Large Industrial														
Large Industrial - Firm	**5.178**	$427,234	$369,995	$442,713	$422,064	$415,653	$468,087	$495,576	$548,351	$416,388	$520,981	$489,766	$576,087	5,592,895
Large Industrial - Interruptible	**5.204**	$2,629,475	$2,497,906	$2,652,006	$2,648,796	$2,899,838	$2,743,239	$2,893,816	$3,165,047	$2,849,191	$2,974,863	$2,836,704	$2,403,044	33,193,926
Large Industrial - Total		$3,056,708	$2,867,901	$3,094,719	$3,070,860	$3,315,491	$3,211,327	$3,389,392	$3,713,397	$3,265,579	$3,495,844	$3,326,471	$2,979,131	38,786,820
ELI 2P-RTP	**-**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-
Municipal														
Customers staying on in 2015	**5.466**	$294,967	$246,720	$245,772	$230,299	$195,002	$177,104	$202,352	$203,828	$175,190	$190,856	$236,973	$282,358	2,681,422
Customers migrating to OATT in 2015														-
Customer A	**5.466**	$357,969	$305,005	$282,678	$215,855	$134,351	$117,502	$156,754	$161,950	$140,510	$178,544	$249,056	$315,266	2,615,440
Customer B	**5.466**	$134,408	$106,330	$93,974	$59,885	$45,021	$44,719	$79,821	$87,297	$72,280	$89,245	$98,048	$129,488	1,040,516
Customer C	**5.466**	$60,165	$46,629	$46,511	$35,210	$20,337	$19,511	$21,843	$22,901	$17,790	$27,660	$42,258	$60,855	421,668
Customer D	**5.466**	$43,475	$31,249	$28,751	$22,942	$11,362	$11,319	$11,809	$13,395	$10,505	$16,286	$27,639	$42,389	271,121
Municipal Total	**5.466**	$890,984	$735,933	$697,687	$564,190	$406,074	$370,155	$472,579	$489,371	$416,275	$502,590	$653,973	$830,356	7,030,166
Unmetered	**5.525**	$396,903	$314,347	$388,389	$409,330	$374,819	$347,965	$396,248	$374,488	$366,996	$345,730	$397,747	$358,409	4,471,370
Subtotal	**-**	$60,138,873	$51,354,650	$51,864,481	$45,984,652	$39,744,000	$35,528,594	$40,060,806	$39,581,169	$35,422,714	$39,754,105	$47,733,505	$56,982,495	$544,150,044

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Data Inputs

	2018 Actuals												
Category	**Jan-18**	**Feb-18**	**Mar-18**	**Apr-18**	**May-18**	**Jun-18**	**Jul-18**	**Aug-18**	**Sep-18**	**Oct-18**	**Nov-18**	**Dec-18**	**Annual**
2018-Variance													
ATL Classes													
Domestic Total	$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
ELI 2P-RTP	$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
Customers staying on in 2015													
Customers migrating to OATT in 2015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer A	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer B	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer C	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer D	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unmetered	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Biomass Calculations

($ in millions)	2018 Actuals	
Capital	[redacted]	
Fuel		
Operating		
Total	30.6	100.0%

data came from CA IR-065P Confidential from the COSS Proceeding

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Category	2 January	3 February	4 March	5 April	6 May	7 June	8 July	9 August	10 September	11 October	12 November	13 December	Total
kWh Sales													
ATL Classes													
Domestic Non-TOU	525,078,886	472,405,598	463,004,424	361,104,491	305,307,579	255,684,531	264,566,718	258,923,908	246,758,630	285,741,578	356,213,968	465,331,518	4,260,121,829
Domestic TOU	44,471,041	41,338,368	41,080,003	31,455,914	21,767,234	13,564,152	12,143,146	12,143,146	12,692,171	18,182,423	27,289,782	46,828,620	322,956,000
Domestic Total	569,549,927	513,743,966	504,084,427	392,560,405	327,074,814	269,248,683	276,709,864	271,067,054	259,450,801	303,924,001	383,503,750	512,160,138	4,583,077,829
Small General	29,118,687	27,205,398	26,104,602	21,753,835	19,788,127	18,294,189	19,421,195	19,106,681	17,062,345	18,634,911	20,155,059	25,449,366	262,094,393
General	236,642,908	221,972,971	221,251,499	193,835,552	178,444,144	180,849,051	194,797,515	190,228,191	176,520,218	186,620,830	199,607,331	223,896,897	2,404,667,106
Large General	34,581,251	32,297,882	34,711,934	32,748,058	33,032,345	32,828,498	36,870,013	38,689,872	35,749,139	32,715,853	31,883,023	33,764,994	409,872,862
Small Industrial	23,990,072	22,530,697	21,993,032	20,610,467	20,610,467	21,532,177	22,018,636	20,098,406	19,407,123	17,998,954	21,224,941	24,015,675	256,030,646
Medium Industrial	41,361,008	38,423,847	39,627,601	39,001,649	38,568,297	41,264,708	41,457,308	41,023,957	39,964,653	40,109,103	40,301,704	40,494,305	481,598,140
Large Industrial	65,308,542	58,911,460	65,755,544	62,334,338	66,186,333	66,529,250	67,129,250	73,291,892	71,249,891	66,969,782	66,107,939	62,441,664	792,215,885
Large Industrial - Firm													-
Large Industrial - Interruptible													-
Large Industrial - Total	65,308,542	58,911,460	65,755,544	62,334,338	66,186,333	66,529,250	67,129,250	73,291,892	71,249,891	66,969,782	66,107,939	62,441,664	792,215,885
ELI 2P-RTP													
Municipal													
Customers staying on in 2018	7,827,923	7,881,427.81	8,577,410.76	7,611,678.18	8,090,087.26	7,826,047.71	7,509,600.76	7,274,386.68	7,422,957.17	7,870,575.37	6,906,761.85	7,773,740.22	92,572,597
Customers migrating to OATT in 2015													Bundled
Customer A	6,549,011	5,580,043	5,171,573	3,949,046	2,457,944	2,149,683	2,867,794	2,962,868	2,570,622	3,266,440	4,556,461	5,767,756	47,849,242
Customer B	2,458,987	1,945,295	1,719,248	1,095,587	823,660	818,137	1,460,315	1,597,089	1,322,361	1,632,725	1,793,773	2,368,969	19,036,148
Customer C	1,100,708	853,070	850,908	644,157	372,059	356,955	399,618	418,971	325,458	506,034	773,104	1,113,335	7,714,377
Customer D	795,368	571,692	526,003	419,727	207,874	207,082	216,045	245,052	192,179	297,951	505,650	775,510	4,960,135
Municipal Total	18,731,997	16,831,528	16,845,144	13,720,196	11,951,625	11,357,904	12,453,372	12,498,367	11,833,578	13,573,726	14,535,750	17,799,311	172,132,498
Unmetered	8,624,329	8,362,069	8,624,329	8,634,416	8,674,764	8,150,243	8,362,069	8,614,242	8,382,243	7,746,766	8,614,242	8,069,548	100,859,263
ATL Total	**1,027,908,721**	**940,279,818**	**938,998,112**	**785,198,916**	**704,330,916**	**650,054,704**	**679,219,223**	**674,618,663**	**639,619,990**	**688,293,926**	**785,933,738**	**948,091,897**	**9,462,548,623**
BTL Classes													
BTL Total	73,773,961	80,168,724	99,879,868	91,199,443	95,388,388	92,128,503	92,884,302	96,253,371	94,472,345	96,666,032	97,657,841	82,489,452	1,092,962,231
In-Province Total	**1,101,682,683**	**1,020,448,541**	**1,038,877,980**	**876,398,359**	**799,719,304**	**742,183,207**	**772,103,525**	**770,872,034**	**734,092,334**	**784,959,957**	**883,591,579**	**1,030,581,349**	**10,555,510,853**
Export kWh Sales	5,000,000	10,000,000	14,500,000	2,000,000	500,000	-	-	500,000	500,000	8,000,000	4,500,000	4,500,000	50,000,000
Export kWh Losses	-	-	-	-	-	-	-	-	-	-	-	-	-
In-province Losses	86,031,669	78,475,414	77,927,008	58,349,602	55,812,112	41,074,376	43,367,591	48,999,847	39,033,512	49,953,230	56,210,990	90,351,911	725,587,262
NSR	1,192,714,351	1,108,923,955	1,131,304,988	936,747,961	856,031,416	783,257,582	815,471,116	820,371,881	773,625,846	842,913,188	944,302,569	1,125,433,260	11,331,098,115

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	2018 Peak	2018 Energy Requirement
Annual Peak of ATL Classes	2,007,206	
Annual Energy Requirement of ATL		10,076,552,853
System Coincident Load Factor	**57.31%**	
Wind Fixed - Energy Related	**0.7000**	

Generation Rate Base		**Initial Classification**			**Further Classification**			**Fully Classified**		
	Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$1,370,532	$1,191,036	$179,496	$0	($682,583)	$682,583	$0	$508,453	$862,079	$ -
Hydro Plant	371,461	366,637	4,824	0	($210,120)	$210,120	0	$156,517	$214,944	$ -
Wind Plant	201,182	30,599	170,583	0	($21,419)	$21,419	0	$9,180	$192,002	$ -
LM6000 Plant	71,417	71,417	0	0	($40,929)	$40,929	0	$30,488	$40,929	$ -
Gas Turbine Plant - Other	6,513	6,513	0	0	$0	$0	0	$6,513	$0	$ -
Total Generation Plant	2,021,105	1,666,202	354,903	0	($955,051)	$955,051	0	$711,151	$1,309,954	$ -
General Property Plant	150,810	124,328	26,482	0	-$71,263.69	$71,264	0	$53,064	$97,746	$ -
Total Plant in Service	2,171,915	1,790,530	381,385	0	($1,026,314)	$1,026,314	0	$764,216	$1,407,700	$ -
								35.19%	**64.81%**	

Fixed Cost Deferral Credit Allocation as based on 2014 Test

FAM Rate Classes	2014 Usage			2014 Test Year Rate Base ($ thousand)					
	Energy Requirement (kWh)	3CP (kW)	Customers	Energy-related	Demand-related	Customer-related	Total	Relative Share per Rate Base	Non-fuel deferral credit 2017
Residential								54.3%	$0
Small General								2.7%	$0
General Demand								24.1%	$0
Large General								3.1%	$0
Total Commercial								29.9%	$0
Small Industrial								2.4%	$0
Medium Industrial								4.3%	$0
Large Industrial									
Customers staying on the rate	727,263,941	283,351	31	$144,448	$58,608	$60	$203,116	5.7%	$0
Customer A moving some of its load to a Non-FAM rate in 2014	33,705,228	9,264	1	$6,694	$1,916	$2	$8,612	0.2%	$0
Large Industrial Total(2)	**760,969,169**	**292,614**	**32**	**$151,142**	**$60,524**	**$62**	**$211,728**	**5.9%**	**$0**
Total Industrial								12.6%	$0
Municipal									
Customers staying on in 2015	51,640,940	29,548	2	$9,049	$5,790	$4	$14,843	0.4%	$0
Customers migrating to OATT in 2015									
Customer A	100,068,911	60,136	3	$17,535	$11,784	$6	$29,326	0.8%	$0
Customer B	35,893,647	18,865	1	$6,290	$3,697	$2	$9,989	0.3%	$0
Customer C	13,351,001	9,090	1	$2,339	$1,781	$2	$4,123	0.1%	$0
Customer D	8,438,932	6,179	1	$1,479	$1,211	$2	$2,692	0.1%	$0
Municipal Total(2)	**209,393,431**	**123,818**	**8**	**$36,692**	**$24,264**	**$16**	**$60,972**	**1.7%**	**$0**
Unmetered								1.5%	$0
Total Other								3.2%	$0
Total FAM Classes								**100.0%**	**$0**

(COS Compliance Filing from July 31, 2014)

Class	Rate Base	Relative Share in Rate Base
(1) DOMESTIC	$1,945,386	54.3%
(2) SMALL GENERAL	$97,112	2.7%
(3) GENERAL	$863,366	24.1%
(4) LARGE GENERAL	$110,492	3.1%
(5) SMALL INDUSTRIAL	$86,528	2.4%
(6) MEDIUM INDUSTRIAL	$152,898	4.3%
(7) LARGE INDUSTRIAL	$211,728	5.9%
(9) MUNICIPAL	$60,971	1.7%
(10) UNMETERED	$53,801	1.5%
TOTAL	$3,582,281	100.0%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

6.96%

Line #

3

5 7%

7

2019 BA Amounts

FOR THE YEAR ENDING DECEMBER 31, 2018

8		2018 BA Amount - Year end 2017					2019 BA - Items from 2019 before interest				2019 BA Interest Allocation		2018 FAM AA TRUE-UP				2019 FAM BA			2019 FAM BA		
9	FAM Classes	2018 BA Amount [1]	2017 DSM RSA Adjustment	Fixed Cost Deferral Credit- Year End 2017	Fixed Cost Deferral Credit- Year End 2017 Interest	2018 BA Amount with 2017 Year End EE	BA Credit to customers in 2018 paid under One Time Payout	2018 DSM RSA Adjustment	Fixed Cost Deferral Credit- Year End 2018	Final 2018 BA Amount bfr Interest	Amount	Interest	2018 Beginning AA Balance [2]	AA Credit to customers in 2018 paid under One Time Payout	Total Before Interest	Interest	FAM BA Total bfr Interest	Interest	FAM 2019 BA Total	Amount owed by departing load to non-FAM classes	Amount to be paid/credited through riders	Amount deferred for recovery through BCF rates in years 2017-2019 (2016 year-end estimate)
10																						
11	Residential	($7,494,308)	$0	($5,601,163)	($32,487)	($13,127,958)	$2,482	$0	($2,983,511)	($2,981,029)	($16,108,987)	($936,541)	($85,442,664)	$9,240,427	($76,202,237)	($5,386,632)	($92,311,224)	($6,323,173)	($98,634,396)		($98,634,396)	
12	Small General	($398,161)	$233,088	($279,605)	($1,622)	($446,299)	$4	$233,088	($148,934)	$84,158	($362,141)	($21,054)	($4,417,148)	$483,636	($3,933,512)	($278,055)	($4,295,653)	($299,109)	($4,594,761)		($4,594,761)	
13	General Demand	($3,388,093)	($1,198,960)	($2,485,807)	($14,418)	($7,087,278)	$147	($1,198,960)	($1,324,088)	($2,522,901)	($9,610,179)	($558,714)	($40,514,286)	$4,084,726	($36,429,560)	($2,575,156)	($46,039,739)	($3,133,870)	($49,173,609)		($49,173,609)	$1,207,293
14	Large General	$674,721	$1,291,856	($318,129)	($1,845)	$1,646,603	$0	$1,291,856	($169,454)	$1,122,402	$2,769,004	$160,984	($3,811,698)	$644,397	($3,167,301)	($223,892)	($398,297)	($62,908)	($461,205)		($461,205)	
15	Small Industrial	($352,698)	($199,206)	($249,131)	($1,445)	($802,480)	$0	($199,206)	($132,702)	($331,908)	($1,134,388)	($65,951)	($3,998,978)	$415,923	($3,583,055)	($253,281)	($4,717,443)	($319,232)	($5,036,675)		($5,036,675)	
16	Medium Industrial	$337,374	($106,373)	($440,226)	($2,553)	($211,779)	$0	($106,373)	($234,490)	($340,864)	($552,642)	($32,129)	($5,639,422)	$715,357	($4,924,065)	($348,075)	($5,476,707)	($380,205)	($5,856,912)		($5,856,912)	$1,078,380
17	**Firm**	$166,719	0	($88,280)	($512)	$77,927	$0	0	($47,023)	($47,023)	$30,903	$1,797	($1,232,314)	$129,037	($1,103,276)	($77,989)	($1,072,373)	($76,192)	($1,148,565)		($1,148,565)	$283,063.94
18	**Interruptible**	$692,337	0	($521,328)	($3,024)	$167,986	$0	0	($277,690)	($277,690)	($109,704)	$6,377.94	($7,277,261)	$882,867	($6,394,394)	($452,011)	($6,504,097)	($458,389)	($6,962,486)		($6,962,486)	$1,451,492
19	**Large Industrial Total**	$859,056	$0	($609,608)	($3,536)	$245,913	$0	$0	($324,713)	($324,713)	($78,801)	($4,581)	($8,509,574)	**$1,011,904**	($7,497,670)	($530,000)	($7,576,470)	($534,581)	($8,111,052)		($8,111,052)	$1,734,556
21	**Municipal**																					
22	Customers staying	($128,506)	$0	($42,737)	($248)	($171,490)	$0	$0	($22,764)	($22,764)	($194,254)	($11,294)	($720,897)	$79,485	($641,412)	($45,341)	($835,667)	($56,634)	($892,301)		($892,301)	
23	Customers migrating to OATT		$0					$0														
24	Customer A	($52,811)	$0	($84,433)	($490)	($137,734)	$0	$0	($44,974)	($44,974)	($182,708)	($10,622)	($817,314)	$113,496	($703,818)	($49,752)	($886,526)	($60,374)	($946,900)	($298,790)	($648,110)	
25	Customer B	($54,980)	$0	($28,759)	($167)	($83,905)	$0	$0	($15,319)	($15,319)	($99,224)	($5,769)	($330,791)	$39,514	($291,277)	($20,590)	($390,501)	($26,359)	($416,859)	($131,538)	($285,321)	
26	Customer C	($4,363)	$0	($11,870)	($69)	($16,302)	$0	$0	($6,323)	($6,323)	($22,625)	($1,315)	($116,834)	$17,771	($99,063)	($7,003)	($121,688)	($8,318)	($130,006)	($41,023)	($88,983)	
27	Customer D	$3,786	$0	($7,750)	($45)	($4,008)	$0	$0	($4,128)	($4,128)	($8,136)	($473)	($69,342)	$11,729	($57,613)	($4,073)	($65,749)	($4,546)	($70,295)	($22,181)	($48,114)	
28	**Municipal - Total**	($236,873)	$0	($175,549)	($1,018)	($413,440)	$0	$0	($93,508)	($93,508)	($506,948)	($29,473)	($2,055,178)	$261,995	($1,793,182)	($126,758)	($2,300,130)	($156,230)	($2,456,361)	($493,533)	($1,962,828)	
29	Unmetered	($284,477)	($20,405)	($154,903)	($898)	($460,684)	$522	($20,405)	($82,510)	($102,393)	($563,077)	($32,736)	($1,657,278)	$73,708	($1,583,569)	($111,940)	($2,146,647)	($144,676)	($2,291,323)		($2,291,323)	
30	**Above the line Subtotal / Average**	($10,283,460)	$0	($10,314,120)	($59,822)	($20,657,402)	$3,154	$0	($5,493,911)	($5,490,757)	($26,148,158)	($1,520,196)	($156,046,225)	**$16,932,074**	**($139,114,151)**	**($9,833,789)**	($165,262,310)	($11,353,985)	($176,616,295)	($493,533)	($176,122,762)	$4,020,229
31																						

Footnotes.

(1) NSPI to UARB 2018 FAM AA BA Evidence , APPENDIX B1-part 2 FAM BA COS (Partially Confidential)

(2) NSPI to UARB 2018 FAM AA BA Evidence , APPENDIX B1-part 1 FAM AA COS (Partially Confidential)

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2018-kWh Sales		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2018	
ATL Classes															
Domestic Non-TOU		536,265,495	436,427,593	442,448,444	374,351,339	303,902,965	240,934,327	278,652,663	275,706,533	242,024,054	287,471,601	390,063,983	498,233,847	4,306,482,845	
Domestic TOU		37,100,969	32,198,498	33,789,543	26,823,414	17,303,538	10,664,973	11,591,345	11,855,068	9,899,793	15,202,472	26,702,203	41,396,017	274,527,834	
Domestic Total		**573,366,464**	**468,626,091**	**476,237,987**	**401,174,753**	**321,206,503**	**251,599,300**	**290,244,009**	**287,561,601**	**251,923,847**	**302,674,073**	**416,766,186**	**539,629,864**	**4,581,010,679**	
Small General		**35,955,548**	**28,395,767**	**28,104,635**	**22,013,951**	**22,939,125**	**18,374,757**	**21,805,095**	**21,086,860**	**19,230,463**	**21,049,256**	**24,018,127**	**28,425,332**	291,398,915	
General		**234,895,343**	**218,801,428**	**209,173,371**	**198,712,520**	**173,884,960**	**179,888,656**	**198,244,118**	**192,775,819**	**174,900,462**	**193,797,139**	**203,501,103**	**232,472,476**	2,411,047,394	
Large General		**34,181,491**	**30,706,264**	**33,387,338**	**32,434,903**	**30,433,761**	**31,601,573**	**37,521,336**	**39,519,681**	**33,951,632**	**32,373,255**	**30,124,210**	**32,862,485**	399,097,929	
Small Industrial		**24,663,893**	**20,530,718**	**21,120,830**	**18,727,693**	**21,243,016**	**19,371,698**	**23,870,526**	**19,810,159**	**20,580,369**	**17,185,957**	**23,707,012**	**22,475,011**	253,286,884	
Medium Industrial		**42,131,138**	**38,070,781**	**41,095,098**	**40,160,817**	**37,732,964**	**40,302,245**	**40,683,700**	**37,446,646**	**36,185,341**	**37,435,749**	**38,931,181**	**39,431,141**	469,606,802	
Large Industrial															
Customer A															
Large Industrial - Firm		8,250,939	7,145,524	8,549,887	8,151,102	8,027,297	9,039,928	9,570,803	10,590,008	8,041,475	10,061,426	9,458,602	11,125,657	108,012,648	
Large Industrial - Interruptible		50,527,952	47,999,734	50,960,920	50,899,234	55,723,247	52,714,055	55,607,524	60,819,496	54,750,025	57,164,932	54,510,078	46,176,867	637,854,065	
Large Industrial - Total		**58,778,891**	**55,145,258**	**59,510,807**	**59,050,336**	**63,750,544**	**61,753,983**	**65,178,327**	**71,409,504**	**62,791,500**	**67,226,358**	**63,968,680**	**57,302,524**	**745,866,713**	
ELI 2P-RTP (Adjusted CBL)														-	
Municipal															
Customers staying on in 2015		5,396,397	4,513,728	4,496,384	4,213,291	3,567,548	3,240,101	3,702,014	3,729,023	3,205,088	3,491,692	4,335,400	5,165,716	49,056,382	
Customers migrating to OATT in 2015															OATT % Split
Customer A		6,549,011	5,580,043	5,171,573	3,949,046	2,457,944	2,149,683	2,867,794	2,962,868	2,570,622	3,266,440	4,556,461	5,767,756	47,849,242	[redacted]
Customer B		2,458,987	1,945,295	1,719,248	1,095,587	823,660	818,137	1,460,315	1,597,089	1,322,361	1,632,725	1,793,773	2,368,969	19,036,148	
Customer C		1,100,708	853,070	850,908	644,157	372,059	356,955	399,618	418,971	325,458	506,034	773,104	1,113,335	7,714,377	
Customer D		795,368	571,692	526,003	419,727	207,874	207,082	216,045	245,052	192,179	297,951	505,650	775,510	4,960,135	
Municipal Total		**16,300,472**	**13,463,828**	**12,764,117**	**10,321,809**	**7,429,086**	**6,771,958**	**8,645,786**	**8,953,004**	**7,615,708**	**9,194,842**	**11,964,388**	**15,191,287**	**128,616,283**	
Unmetered		**7,183,765**	**5,689,536**	**7,029,662**	**7,408,689**	**6,784,053**	**6,298,001**	**7,171,916**	**6,778,055**	**6,642,461**	**6,257,552**	**7,199,046**	**6,487,035**	80,929,771	
ATL Total		**1,027,457,004**	**879,429,671**	**888,423,846**	**790,005,472**	**685,404,011**	**615,962,173**	**693,364,813**	**685,341,330**	**613,821,784**	**687,194,181**	**820,179,933**	**974,277,155**	**9,360,861,371**	
BTL Classes															
[redacted]															
BTL Total		**73,510,373**	**92,670,997**	**100,734,093**	**95,868,481**	**104,766,937**	**87,693,389**	**100,016,516**	**104,065,782**	**101,109,956**	**104,975,203**	**96,273,729**	**105,448,499**	1,167,133,957	
In-Province Total Sales		**1,100,967,377**	**972,100,668**	**989,157,940**	**885,873,953**	**790,170,948**	**703,655,562**	**793,381,329**	**789,407,112**	**714,931,739**	**792,169,385**	**916,453,662**	**1,079,725,654**	**10,527,995,328**	
		(10)	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**68**	**-**	**80**	
Export kWh Sales	**+**	16,214,000	28,991,000	3,194,000	4,687,000	4,272,000	8,200,119	2,053,000	355,000	6,259,000	9,236,000	3,547,000	1,511,000	**88,519,119**	
Total Electric Sales		**1,117,181,377**	**1,001,091,668**	**992,351,940**	**890,560,953**	**794,442,948**	**711,855,681**	**795,434,329**	**789,762,112**	**721,190,739**	**801,405,385**	**920,000,662**	**1,081,236,654**	**10,616,514,447**	
In Province Losses		88,659,339	51,032,366	74,106,951	38,078,494	31,843,359	43,961,549	42,946,499	55,077,401	50,199,205	74,615,060	22,154,632	35,442,394	**608,117,250**	
NSR		**1,189,626,716**	**1,023,133,034**	**1,063,264,891**	**923,952,447**	**822,014,307**	**747,617,111**	**836,327,828**	**844,484,513**	**765,130,944**	**866,784,445**	**938,608,294**	**1,115,168,049**	**11,136,112,578**	
Export kWh Losses	**-**	479,000	1,212,000	106,000	153,000	121,000	273,881	60,000	8,000	170,000	349,000	110,000	67,000	3,108,881	
Total System Requirement		1,206,319,716	1,053,336,034	1,066,564,891	928,792,447	826,407,307	756,091,111	838,440,828	844,847,513	771,559,944	876,369,445	942,265,294	1,116,746,049	11,227,740,578	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2017 ML Payout paid in 2018-AA. **Rate Before Interest**

		18-Jan	18-Feb	18-Mar	18-Apr	18-May	18-Jun	18-Jul	18-Aug	18-Sep	18-Oct	18-Nov	18-Dec	2018
ATL Classes														
Domestic Total		$0	$0	$4,476,720	$4,490,624	$50,916	$1,796	$69,054	$96,176	$13,023	$11,045	$15,808	$15,265	$9,240,427
Small General		$0	$0	$282,223	$176,369	$2,596	$44	$7,417	$12,246	$581	$908	$1,237	$15	$483,636
General		$0	$0	$2,728,120	$1,351,976	$49	$72	$52	$281	$4,035	$0	$0	$141	$4,084,726
Large General		$644,397	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$644,397
Small Industrial		$0	$0	$274,008	$141,365	$276	$0	$0	$100	$174	$0	$0	$0	$415,923
Medium Industrial		$0		$295,177	$418,123	$2,057	$0	$0	$0	$0	$0	$0	$0	$715,357
Large Industrial														$0
Large Industrial - Firm	($0.1443)	$1,805,274	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$151,536
Large Industrial - Interruptible	($0.1446)	$884,384	$91,014	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$896,889
Large Industrial - Total														$0
ELI 2P-RTP														$0
Municipal														$0
Customers staying on in 2015		$22,400	$57,085	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$88,679
Customers migrating to OATT in 2015														$0
Customer A		$32,211	$81,285	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$113,496
Customer B		$10,722	$28,792	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$39,514
Customer C		$4,949	$12,823	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$17,771
Customer D		$3,516	$8,213	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$11,729
Municipal Total		$73,798	$188,198	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$261,995
Unmetered		$0	$0	$71,874	$0	$0	$0	$1,835	$0	$0	$0	$0	$0	$73,708
Subtotal		$1,639,084	$279,212	$8,128,120	$6,578,456	$55,895	$1,912	$78,358	$108,804	$17,813	$11,953	$17,045	$15,421	$16,968,595

2017 ML Payout paid in 2018-BA.

	18-Jan	18-Feb	18-Mar	18-Apr	18-May	18-Jun	18-Jul	18-Aug	18-Sep	18-Oct	18-Nov	18-Dec	2018
ATL Classes													
Domestic Total	$218	$159	$130	$237	$222	$310	$146	$183	$195	$83	$141	$458	$2,482
Small General	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$4	$4
General	$0	$0	$0	$0	$0	$39	$0	$0	$104	$0	$3	$0	$147
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													
Large Industrial - Firm	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large Industrial - Interruptible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large Industrial - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ELI 2P-RTP													
Municipal													
Customers staying on in 2015													
Customers migrating to OATT in 2015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer A	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer B	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer C	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer D	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Unmetered	$0	$0	$35	$0	$0	$0	$488	$0	$0	$0	$0	$0	$522
Subtotal	$218.0111	$159	$164	$237	$222	$349	$633	$183	$299	$83	$144	$462	$3,154
											$0	$0	

2017- Sales

2017-kWh Sales-Actuals

ATL Classes														
Domestic Non-TOU		492,710,304	439,935,329	480,210,024	337,511,159	320,989,591	248,865,964	258,293,996	250,815,038	243,567,929	260,828,223	332,510,588	455,760,770	4,121,998,915
Domestic TOU		34,292,023	31,495,243	32,391,006	22,466,857	18,383,096	11,122,973	9,902,070	10,183,168	10,752,360	13,188,253	21,200,957	36,180,411	251,558,418
Domestic Total		**527,002,328**	**471,430,572**	**512,601,030**	**359,978,017**	**339,372,687**	**259,988,937**	**268,196,066**	**260,998,206**	**254,320,289**	**274,016,476**	**353,711,545**	**491,941,181**	**4,373,557,333**
Small General		**33,525,547**	**27,270,883**	**29,662,780**	**22,082,604**	**23,621,436**	**18,932,172**	**21,160,188**	**19,835,054**	**18,529,511**	**19,028,052**	**20,382,393**	**26,105,954**	280,136,575
General		**237,162,123**	**206,107,255**	**218,310,334**	**191,313,700**	**179,427,919**	**185,237,010**	**189,380,975**	**185,808,121**	**179,818,138**	**183,300,529**	**192,970,557**	**230,107,619**	2,378,944,281
Large General		**34,281,835**	**29,850,128**	**34,437,289**	**30,849,772**	**32,116,023**	**32,765,569**	**35,686,148**	**37,114,311**	**34,803,202**	**33,990,831**	**31,856,592**	**32,852,457**	400,604,157
Small Industrial		**26,104,903**	**19,439,973**	**22,292,123**	**17,935,417**	**20,755,270**	**19,611,963**	**22,613,533**	**18,388,654**	**20,714,110**	**14,834,993**	**21,665,742**	**22,061,182**	246,417,863
Medium Industrial		**40,903,474**	**34,470,535**	**36,808,850**	**35,960,579**	**37,286,965**	**39,685,777**	**38,778,088**	**39,361,349**	**38,372,346**	**38,770,956**	**40,499,041**	**45,557,595**	466,455,555
Large Industrial														
Large Industrial - Firm		8,490,705	6,931,815	8,543,165	7,864,453	7,289,552	6,794,975	7,004,919	7,339,004	6,785,234	7,380,647	7,438,171	7,855,049	89,717,690
Large Industrial - Interruptible		49,663,508	43,587,913	50,571,638	47,187,181	52,633,213	51,759,707	52,793,627	59,000,277	54,853,507	55,234,629	54,444,955	47,896,588	619,626,743
Large Industrial - Total		**58,154,213**	**50,519,728**	**59,114,803**	**55,051,634**	**59,922,765**	**58,554,682**	**59,798,546**	**66,339,281**	**61,638,741**	**62,615,277**	**61,883,126**	**55,751,637**	**709,344,434**
ELI 2P-RTP (Adjusted CBL)														-
Municipal														
Customers staying on in 2015		5,030,321	4,464,071	5,171,370	3,888,297	3,718,474	3,479,362	3,419,757	3,445,636	3,240,632	3,406,111	3,985,704	4,987,122	48,236,857
Customers migrating to OATT in 2015														
Customer A		7,233,586	6,356,559	6,905,683	4,695,581	3,681,837	3,629,009	3,835,744	3,504,722	3,667,515	3,890,342	4,924,373	5,477,389	57,802,339
Customer B		2,407,809	2,251,596	2,575,650	1,664,437	1,491,939	1,457,958	1,553,584	1,668,499	1,578,484	1,689,857	2,057,674	2,145,299	22,542,785
Customer C		1,111,312	1,002,739	1,087,730	682,690	555,709	447,011	464,647	468,680	441,869	504,953	735,930	939,265	8,442,535
Customer D		789,490	642,302	748,240	482,545	317,596	250,822	282,202	296,829	228,519	258,416	449,138	741,796	5,487,897
Municipal Total		**16,572,519**	**14,717,267**	**16,488,673**	**11,413,550**	**9,765,556**	**9,264,162**	**9,555,934**	**9,384,367**	**9,157,019**	**9,749,678**	**12,152,819**	**14,290,871**	**142,512,414**
Unmetered		**7,281,957**	**6,905,481**	**6,593,757**	**6,605,010**	**7,304,180**	**6,578,984**	**7,189,507**	**7,149,779**	**6,597,050**	**6,116,204**	**6,719,207**	**7,184,167**	82,225,284
ATL Total		**980,988,900**	**860,711,821**	**936,309,640**	**731,190,282**	**709,572,801**	**630,619,257**	**652,358,985**	**644,379,121**	**623,950,406**	**642,422,995**	**741,841,024**	**925,852,662**	**9,080,197,895**
BTL Classes														
[redacted]														
BTL Total		**88,863,680**	**84,636,650**	**83,925,331**	**96,944,445**	**84,972,453**	**90,705,377**	**61,738,984**	**98,893,282**	**96,261,754**	**92,831,940**	**104,494,705**	**79,829,857**	1,064,098,457
In-Province Total Sales		**1,069,852,579**	**945,348,471**	**1,020,234,970**	**828,134,727**	**794,545,254**	**721,324,634**	**714,097,969**	**743,272,404**	**720,212,160**	**735,254,936**	**846,335,729**	**1,005,682,519**	**10,144,296,352**
Export kWh Sales	**+**	10,818,000	3,728,000	9,532,000	13,080,000	10,940,000	9,316,000	3,374,000	7,610,000	6,977,000	5,100,000	1,921,000	17,955,000	**100,351,000**
Total Electric Sales		**1,080,670,579**	**949,076,471**	**1,029,766,970**	**841,214,727**	**805,485,254**	**730,640,634**	**717,471,969**	**750,882,404**	**727,189,160**	**740,354,936**	**848,256,729**	**1,023,637,519**	**10,244,647,352**
In Province Losses		66,819,355	74,399,477	90,981,561	49,423,290	31,287,171	30,860,840	37,241,683	59,150,536	39,507,194	61,143,502	81,810,222	106,352,908	**728,977,739**
NSR		**1,136,671,935**	**1,019,747,948**	**1,111,216,531**	**877,558,017**	**825,832,425**	**752,185,474**	**751,339,651**	**802,422,939**	**759,719,354**	**796,398,438**	**928,145,952**	**1,112,035,427**	**10,873,274,091**
Export kWh Losses	**-**	342,000	112,000	288,000	377,000	312,000	262,000	99,000	241,000	207,000	166,000	63,000	535,000	3,004,000

Fixed Cost Deferral Credit Allocation as based on 2014 Test

FAM Rate Classes	2014 Usage			2014 Test Year Rate Base ($ thousand)					
	Energy Requirement (kWh)	3CP (kW)	Customers	Energy-related	Demand-related	Customer-related	Total	Relative Share per Rate Base	Non-fuel deferral credit 2017
Residential								54.3%	-$5,601,163
Small General								2.7%	-$279,605
General Demand								24.1%	-$2,485,807
Large General								3.1%	-$318,129
Total Commercial								29.9%	-$3,083,541
Small Industrial								2.4%	-$249,131
Medium Industrial								4.3%	-$440,226
Large Industrial									
Customers staying on the rate	727,263,941	283,351	31	$144,448	$58,608	$60	$203,116	5.7%	-$584,811
Customer A moving some of its load to a Non-FAM rate in 2014	33,705,228	9,264	1	$6,694	$1,916	$2	$8,612	0.2%	-$24,797
Large Industrial Total(2)	**760,969,169**	**292,614**	**32**	**$151,142**	**$60,524**	**$62**	**$211,728**	**5.9%**	**-$609,608**
Total Industrial								12.6%	-$1,298,965
Municipal									
Customers staying on in 2015	51,640,940	29,548	2	$9,049	$5,790	$4	$14,843	0.4%	-$42,737
Customers migrating to OATT in 2015									
Customer A	100,068,911	60,136	3	$17,535	$11,784	$6	$29,326	0.8%	-$84,433
Customer B	35,893,647	18,865	1	$6,290	$3,697	$2	$9,989	0.3%	-$28,759
Customer C	13,351,001	9,090	1	$2,339	$1,781	$2	$4,123	0.1%	-$11,870
Customer D	8,438,932	6,179	1	$1,479	$1,211	$2	$2,692	0.1%	-$7,750
Municipal Total(2)	**209,393,431**	**123,818**	**8**	**$36,692**	**$24,264**	**$16**	**$60,972**	**1.7%**	**-$175,549**
Unmetered								1.5%	-$154,903
Total Other								3.2%	-$330,452
Total FAM Classes								**100.0%**	**-$10,314,120**

(COS Compliance Filing from July 31, 2014)

Class	Rate Base	Relative Share in Rate Base
(1) DOMESTIC	$1,945,386	54.3%
(2) SMALL GENERAL	$97,112	2.7%
(3) GENERAL	$863,366	24.1%
(4) LARGE GENERAL	$110,492	3.1%
(5) SMALL INDUSTRIAL	$86,528	2.4%
(6) MEDIUM INDUSTRIAL	$152,898	4.3%
(7) LARGE INDUSTRIAL	$211,728	5.9%
(9) MUNICIPAL	$60,971	1.7%
(10) UNMETERED	$53,801	1.5%
TOTAL	$3,582,281	100.0%

Fixed Cost Deferral Credit Allocation as based on 2014 Test

FAM Rate Classes	2014 Usage			2014 Test Year Rate Base ($ thousand)					
	Energy Requirement (kWh)	3CP (kW)	Customers	Energy-related	Demand-related	Customer-related	Total	Relative Share per Rate Base	Non-fuel deferral credit 2017
Residential								54.3%	-$2,983,511
Small General								2.7%	-$148,934
General Demand								24.1%	-$1,324,088
Large General								3.1%	-$169,454
Total Commercial								29.9%	-$1,642,476
Small Industrial								2.4%	-$132,702
Medium Industrial								4.3%	-$234,490
Large Industrial									
Customers staying on the rate	727,263,941	283,351	31	$144,448	$58,608	$60	$203,116	5.7%	-$311,505
Customer A moving some of its load to a Non-FAM rate in 2014	33,705,228	9,264	1	$6,694	$1,916	$2	$8,612	0.2%	-$13,208
Large Industrial Total(2)	**760,969,169**	**292,614**	**32**	**$151,142**	**$60,524**	**$62**	**$211,728**	**5.9%**	**-$324,713**
Total Industrial								12.6%	-$691,905
Municipal									
Customers staying on in 2015	51,640,940	29,548	2	$9,049	$5,790	$4	$14,843	0.4%	-$22,764
Customers migrating to OATT in 2015									
Customer A	100,068,911	60,136	3	$17,535	$11,784	$6	$29,326	0.8%	-$44,974
Customer B	35,893,647	18,865	1	$6,290	$3,697	$2	$9,989	0.3%	-$15,319
Customer C	13,351,001	9,090	1	$2,339	$1,781	$2	$4,123	0.1%	-$6,323
Customer D	8,438,932	6,179	1	$1,479	$1,211	$2	$2,692	0.1%	-$4,128
Municipal Total(2)	**209,393,431**	**123,818**	**8**	**$36,692**	**$24,264**	**$16**	**$60,972**	**1.7%**	**-$93,508**
Unmetered								1.5%	-$82,510
Total Other								3.2%	-$176,018
Total FAM Classes								**100.0%**	**-$5,493,911**

(COS Compliance Filing from July 31, 2014)

Class	Rate Base	Relative Share in Rate Base
(1) DOMESTIC	$1,945,386	54.3%
(2) SMALL GENERAL	$97,112	2.7%
(3) GENERAL	$863,366	24.1%
(4) LARGE GENERAL	$110,492	3.1%
(5) SMALL INDUSTRIAL	$86,528	2.4%
(6) MEDIUM INDUSTRIAL	$152,898	4.3%
(7) LARGE INDUSTRIAL	$211,728	5.9%
(9) MUNICIPAL	$60,971	1.7%
(10) UNMETERED	$53,801	1.5%
TOTAL	$3,582,281	100.0%

2020 FAM AA Amounts

FOR THE YEAR ENDING DECEMBER 31, 2019

Line #	COLUMN	A	B	C	D	E	F	G	H	I	J	K	L	M
6	FORMULA					C-D	G + E	F / F (Line 29)	G x H (Line 30)	F + H	G x J (Line 29)	I + J		K / L * 100
10	FAM Rate Class	2019 GWh Energy Requirement	2019 Beginning BCF Balance	2019 Variance in Fuel Cost Recovery before Interest and Incentive			2019 Variance in Fuel Cost Recovery before Incentive				2019 Variance in Fuel Costs		2020 FAM AA Riders	
11				Actual Fuel Costs	Recovered Fuel Costs	Variance (debit/credit)	Total Amount owed by Customers to NS Power before Interest	Relative Share	Interest Amount	Variance (debit/credit)	NSPI Incentive Amount[1]	Adjustment after Incentive	Forecast kWh Sales in 2020	Cents per KWh
13	Residential Subtotal	5,036.8	$0	$308,538,751	$292,051,481	$16,487,270	$16,487,270	38.1%	$225,961	$16,713,231	$0	$16,713,231	4,493,317,762	0.372
14	Small General	320.2	$0	$19,665,802	$18,867,632	$798,171	$798,171	1.8%	$10,939	$809,110	$0	$809,110	286,830,917	0.282
15	General Demand	2,594.3	$0	$157,295,506	$140,995,277	$16,300,229	$16,300,229	37.7%	$223,397	$16,523,626	$0	$16,523,626	2,392,958,563	0.691
16	Large General	418.9	$0	$24,274,493	$24,741,745	($467,252)	($467,252)	-1.1%	($6,404)	($473,656)	$0	($473,656)	392,840,580	(0.121)
17	Small Industrial	279.2	$0	$16,742,729	$15,148,564	$1,594,165	$1,594,165	3.7%	$21,848	$1,616,014	$0	$1,616,014	250,444,410	0.645
18	Medium Industrial	492.9	$0	$28,244,896	$25,627,619	$2,617,277	$2,617,277	6.1%	$35,870	$2,653,147	$0	$2,653,147	474,373,865	0.559
19	Large Industrial	849.5	$0	$47,626,138	$43,246,677	$4,379,462	$4,379,462	10.1%	$60,021	$4,439,483	$0	$4,439,483	861,915,417	0.515
20	Municipal													
21	Full Service Requirement Customers	52.8	$0	$2,787,647	$2,811,683	($24,037)	($24,037)	-0.1%	($329)	($24,366)	$0	($24,366)		
22	Partial Service Requirement Customers													
23	Customer A	45.9	$0	$2,923,472	$2,446,166	$477,306	$477,306	1.1%	$6,542	$483,847	$0	$483,847		
24	Customer B	19.5	$0	$1,196,240	$1,038,339	$157,902	$157,902	0.4%	$2,164	$160,066	$0	$160,066		
25	Customer C	8.3	$0	$507,854	$442,166	$65,688	$65,688	0.2%	$900	$66,589	$0	$66,589		
26	Customer D	5.5	$0	$348,307	$291,720	$56,586	$56,586	0.1%	$776	$57,362	$0	$57,362		
27	Subtotal	79.2	$0	$4,975,873	$4,218,391	$757,482	$757,482	1.8%	$10,381	$767,864	$0	$767,864		
28	Municipal Total	131.9	$0	$7,763,520	$7,030,074	$733,446	$733,446	1.7%	$10,052	$743,498	$0	$743,498	124,819,979	0.596
29	Unmetered	88.9	$0	$5,380,478	$4,587,629	$792,849	$792,849	1.8%	$10,866	$803,715	$0	$803,715	81,034,159	0.992
30	**FAM Class Total / Average**	10,212.5	$0	$615,532,313	$572,296,697	$43,235,616	$43,235,616	100.0%	$592,551	$43,828,167	$0	$43,828,167	9,358,535,650	

Allocation of Actual Fuel-related Costs among Rate Classes

FOR THE YEAR ENDING DECEMBER 31, 2019

Cost Allocation Factors

Line #	Rate Class	R/C Ratio as per 2013 CF for the 2014 Test Year	3 CP Demands: KW Demand	3 CP Demands: Relative Shares	Energy Requirement: KWh Energy	Energy Requirement: Relative Shares	kWhs Sales	Fuel Costs before Purchased Power	Imports (allocated on monthly energy requirements)
3	COLUMN	A	B	C	D	E	F	G	
5	FORMULA			B / B (Line 41)		D/ D (Line 41)			
15	**FAM Rate Classes (ATL)**								
16	Residential non ETS						4,339,808,424		
17	Residential ETS						280,528,250		
18	Residential Subtotal	98.85%	3,692,482	62.9%	5,036,764,381	49.3%	4,620,336,674	$153,743,601	$12,515,114
20	Small General	104.64%	147,523	2.5%	320,212,636	3.1%	295,499,323	$9,814,650	$803,804
21	General Demand	102.92%	1,165,216	19.9%	2,594,291,298	25.4%	2,438,942,688	$80,485,422	$6,300,729
22	Large General	99.35%	158,368	2.7%	418,895,236	4.1%	394,416,464	$13,107,619	$1,008,355
23	Small Industrial	102.46%	117,764	2.0%	279,215,440	2.7%	263,270,142	$8,638,689	$686,609
24	Medium Industrial	98.46%	187,725	3.2%	492,868,144	4.8%	465,871,997	$15,340,308	$1,179,962
25	**Large Industrial**								
26	Large Industrial - Firm								
27	Large Industrial - Interruptible								
28	**Large Industrial Total**	97.44%	271,294	4.6%	849,472,100	8.3%	809,354,778	$26,547,759	$2,044,067
29	ELI 2P-RTP (base rate)								
30	Municipal								
31	Full Service Requirement Customers	97.67%	5,342	0.1%	52,760,728	0.5%	50,128,069	$1,616,452	$131,874
32	Partial Service Requirement Customers								
33	Customer A	97.67%	43,123	0.7%	45,915,624	0.4%	43,611,452	$1,430,380	$110,462
34	Customer B	97.67%	13,989	0.2%	19,505,526	0.2%	18,512,011	$616,267	$45,419
35	Customer C	97.67%	6,647	0.1%	8,290,162	0.1%	7,883,146	$252,734	$20,425
36	Customer D	97.67%	5,529	0.1%	5,466,801	0.1%	5,200,931	$165,994	$13,603
37	**Municipal Total**	97.67%	74,630	1.3%	131,938,841	1.3%	125,335,609	$4,081,827	$321,783
38	Unmetered	100.00%	51,734	0.9%	88,868,005	0.9%	81,369,792	$2,741,199	$218,587
39	ATL Subtotal / Average	100.00%	5,866,735	100.0%	10,212,526,081	100.0%	9,494,397,468	$314,501,073	$25,079,009
41	Purchased Power Allocation Factors.								
43	**Non-FAM Rate Classes**								
44	GRLF				25,986,726		24,925,000	$1,509,581	
45	1P-RTP				11,718,112		11,149,735	$507,583	
46	LRT				1,079,343,172		1,054,945,756	$60,095,346	
47	Shore Power				1,434,654		1,350,002	$89,816	
	BUTU				20,476,162		20,428,061	$1,265,814	
49	**Total Below-the-line before Additional Energy**				1,138,958,826		1,112,798,554	$63,468,139	
	In Province Total		5,866,735		11,351,484,907		10,607,196,023	377,969,212	25,079,009
53	**Exports**				141,516,048		137,569,048		
55	**Non-FAM Categories**				1,280,474,873		1,250,367,602	63,468,139	-
57	**Grand Total**				11,493,000,955		10,744,765,070	$377,969,212	$25,079,009

Fuel-related Costs from COS

Line #	Rate Class	Purchased Power- Biomass: Bio-fuel Related (allocated on monthly energy requirements)	Purchased Power- Biomass: Energy-related (allocated on annual energy requirements)	Purchased Power- Biomass: Demand-related	Purchased Power- Biomass: Total	Maritime Link (Basic and Supplemental Blocks): Fixed Energy-related	Maritime Link: Fixed Demand-related	Maritime Link: Total	Purchased Power other than Biomass and Wind: Fixed Energy-related	Purchased Power other than Biomass and Wind: Fixed Demand-related	Purchased Power other than Biomass and Wind: Total
18	Residential Subtotal	$768,258	$5,145,885	$3,723,774	$9,637,918	$30,703,751	$30,699,090	$61,402,841	$436,918	$316,172	$753,091
19								$0			
20	Small General	$48,434	$327,150	$148,773	$524,357	$1,951,993	$1,226,500	$3,178,493	$27,777	$12,632	$40,409
21	General Demand	$397,501	$2,650,496	$1,175,091	$4,223,088	$15,814,612	$9,687,540	$25,502,152	$225,044	$99,773	$324,817
22	Large General	$64,278	$427,971	$159,710	$651,958	$2,553,555	$1,316,663	$3,870,218	$36,337	$13,560	$49,898
23	Small Industrial	$42,350	$285,265	$118,762	$446,376	$1,702,077	$979,083	$2,681,160	$24,221	$10,084	$34,304
24	Medium Industrial	$75,140	$503,546	$189,316	$768,002	$3,004,489	$1,560,735	$4,565,224	$42,754	$16,074	$58,828
28	**Large Industrial Total**	$129,958	$867,876	$273,593	$1,271,427	5178320.429	$2,255,525	$7,433,845	$73,688	$23,230	$96,918
31	Full Service Requirement Customers	$7,914	$53,904	$5,387	$67,205	$321,626	$44,414	$366,040	$4,577	$457	$5,034
32	Partial Service Requirement Customers				$0	$0	$0	$0			
33	Customer A	$7,348	$46,910	$43,489	$97,747	$279,898	$358,524	$638,422	$3,983	$3,692	$7,675
34	Customer B	$3,169	$19,928	$14,107	$37,204	$118,904	$116,300	$235,204	$1,692	$1,198	$2,890
35	Customer C	$1,285	$8,470	$6,703	$16,458	$50,536	$55,263	$105,799	$719	$569	$1,288
36	Customer D	$848	$5,585	$5,576	$12,009	$33,325	$45,965	$79,291	$474	$473	$948
37	**Municipal Total**	$20,564	$134,797	$75,262	$230,624	$804,290	$620,467	$1,424,756	$11,445	$6,390	$17,835
38	Unmetered	$13,254	$90,793	$52,172	$156,220	$541,733	$430,112	$971,845	$7,709	$4,430	$12,139
39	ATL Subtotal / Average	$1,559,737	$10,433,780	$5,916,454	$17,909,971	$62,254,819.68	$48,775,713	$111,030,533	$885,894	$502,345	$1,388,239
41	Purchased Power Allocation Factors.	8.7%	58.3%	33.0%	100.0%	56.1%	43.9%	100.0%	63.8%	36.2%	100.0%
44	GRLF	$0	$0	$0	$0				$0	$0	$0
45	1P-RTP	$0	$0	$0	$0				$0	$0	$0
46	LRT	$0	$0	$0	$0				$0	$0	$0
47	Shore Power	$0	$0	$0	$0				$0	$0	$0
	BUTU	$0	$0	$0	$0				$0	$0	$0
49	**Total Below-the-line before Additional Energy**	$0	$0	$0	$0				$0	$0	$0
	In Province Total	1,559,737	10,433,780	5,916,454	17,909,971	62,254,820	48,775,713	111,030,533	$885,894	$502,345	$1,388,239
55	**Non-FAM Categories**	0	0	0	0	0	0	0	0	0	0
57	**Grand Total**	$1,559,737	$10,433,780	$5,916,454	$17,909,971	$62,254,820	$48,775,713	$111,030,533	$885,894	$502,345	$1,388,239

Purchased Power - Wind / Fuel Costs used for FAM purposes

Line #	Rate Class	Wind: ERIS	Wind NRIS: Energy-related	Wind NRIS: Demand-related	Wind NRIS: Total	Wind: Total	Total Fuel-related costs before Exports, OM&G and Foreign Exchange	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
3	COLUMN						R	S	T	U	V	W	X	Y	Z
5	FORMULA						G+L+Q	E x S (line 41)	E x T (line 41)	E x W (line 41)	R+S+T+U	VxA	W / W (line 41)	X x V(line 39)	Y x F (line 39)
18	Residential Subtotal	$19,228,285	$47,999,886	$12,546,265	$60,546,150	$79,774,435	$317,827,000	($5,642,884)	$0.00	$0	$312,184,116	$308,593,999	50.1%	$308,538,751	6.678
20	Small General	$1,222,440	$3,051,596	$501,252	$3,552,848	$4,775,288	$19,137,000	($339,864)	$0.00	$0	$18,797,137	$19,669,324	3.2%	$19,665,802	6.655
21	General Demand	$9,903,932	$24,723,349	$3,959,154	$28,682,504	$38,586,436	$155,422,643	($2,562,488)	$0.00	$0	$152,860,155	$157,323,671	25.6%	$157,295,506	6.449
22	Large General	$1,599,169	$3,992,032	$538,101	$4,530,133	$6,129,302	$24,817,350	($379,665)	$0.00	$0	$24,437,684	$24,278,840	3.9%	$24,274,493	6.155
23	Small Industrial	$1,065,929	$2,660,897	$400,137	$3,061,033	$4,126,962	$16,614,101	($270,428)	$0.00	$0	$16,343,673	$16,745,727	2.7%	$16,742,729	6.360
24	Medium Industrial	$1,881,567	$4,696,987	$637,849	$5,334,836	$7,216,403	$29,128,727	($436,920)	$0.00	$0	$28,691,807	$28,249,953	4.6%	$28,244,896	6.063
28	**Large Industrial Total**	$3,242,933	$8,095,388	$921,800	$9,017,188	$12,260,121	$49,654,137	($767,985)	$0.00	$0	$48,886,152	$47,634,666	7.7%	$47,626,138	5.884
29	ELI 2P-RTP (base rate)														NA
31	Full Service Requirement Customers	$201,419	$502,805	$18,151	$520,956	$722,375	$2,908,980	($54,320)	$0.00	$0	$2,854,660	$2,788,146	0.5%	$2,787,647	5.561
33	Customer A	$175,287	$437,572	$146,523	$584,095	$759,382	$3,044,069	($50,319)	$0.00	$0	$2,993,750	$2,923,995	0.5%	$2,923,472	6.703
34	Customer B	$74,464	$185,886	$47,530	$233,416	$307,880	$1,244,865	($19,868)	$0.00	$0	$1,224,997	$1,196,455	0.2%	$1,196,240	6.462
35	Customer C	$31,648	$79,004	$22,585	$101,590	$133,238	$529,943	($9,881)	$0.00	$0	$520,063	$507,945	0.1%	$507,854	6.442
36	Customer D	$20,870	$52,098	$18,785	$70,883	$91,753	$363,597	($6,918)	$0.00	$0	$356,680	$348,369	0.1%	$348,307	6.697
37	**Municipal Total**	$503,688	$1,257,365	$253,576	$1,510,940	$2,014,628	$8,091,454	($141,305)	$0.00	$0	$7,950,149	$7,764,910	1.3%	$7,763,520	6.194
38	Unmetered	$339,261	$846,904	$175,780	$1,022,684	$1,361,945	$5,461,934	($80,493)	$0.00	$0	$5,381,441	$5,381,441	0.9%	$5,380,478	6.612
39	ATL Subtotal / Average	$38,987,204	$97,324,403	$19,933,914	$117,258,317	$156,245,520	$626,154,345	($10,622,032)	$0.00	$0	$615,532,313	$615,642,531	100.0%	$615,532,313	6.483
41	Purchased Power Allocation Factors.	$38,987,204	83%	17%	100%										
44	GRLF	$0					$1,509,581				$1,509,581	$1,509,581		$1,509,581	6.056
45	1P-RTP	$0					$507,583				$507,583	$507,583		$507,583	4.552
46	LRT	$0					$60,095,346				$60,095,346	$60,095,346		$60,095,346	5.697
47	Shore Power	$0					$89,816				$89,816	$89,816		$89,816	6.653
	BUTU	$0					$1,265,814				$1,265,814	$1,265,814		$1,265,814	6.196
49	**Total Below-the-line before Additional Energy**	$0	$0	$0	$0		$63,468,139				$63,468,139	$63,468,139		$63,468,139	5.703
	In Province Total	$38,987,204	$97,324,403	$19,933,914	$117,258,317		$689,622,484	($10,622,032)	$0	$0	$679,000,452	$679,110,670	100.0%	$679,000,452	12.187
55	**Non-FAM Categories**	0													
57	**Grand Total**	$38,987,204	$97,324,403	$19,933,914	$117,258,317	$156,245,520	$689,622,484	($10,622,032)	$0	$0	$679,000,452	$679,110,670	100%	$679,000,452	6.319

Monthly Fuel Cost Allocation

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Purchased Power													
Imports	$3,982,919	$2,356,940	$4,246,775	$2,268,164	$3,267,898	$2,225,061	$762,205	$920,713	$2,342,542	$1,021,211	$769,655	$914,926	**$25,079,009**
Biomass													
IPP	$935,922	$900,601	$699,622	$500,642	$795,696	$779,672	$1,045,354	$1,028,989	$754,124	$939,383	$1,136,862	$1,325,438	**$10,842,304**
Comfit	$427,248	$334,900	$481,898	$660,923	$612,092	$630,389	$678,684	$680,217	$624,536	$637,981	$652,430	$646,369	**$7,067,667**
Total	**$1,363,170**	**$1,235,502**	**$1,181,520**	**$1,161,565**	**$1,407,788**	**$1,410,060**	**$1,724,038**	**$1,709,206**	**$1,378,660**	**$1,577,364**	**$1,789,292**	**$1,971,807**	**$17,909,971**
Maritime Link													
ML - NS Block (GWh)	$8,558,333	$9,176,052	$10,078,794	$9,057,302	$9,207,231	$9,207,231	$9,207,231	$9,207,231	$9,207,231	$9,207,231	$9,458,333	$9,458,333	$111,030,533
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$8,558,333**	**$9,176,052**	**$10,078,794**	**$9,057,302**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,458,333**	**$9,458,333**	**$111,030,533**
Regular other than biomass and wind													
IPP	$222,795	$265,057	$177,574	$312,770	$52,718	$48,124	$49,991	$53,202	$46,658	$43,386	$42,873	$46,271	**$1,361,418**
Comfit	$1,771	$1,936	$1,964	$2,041	$2,882	$2,504	$1,766	$2,841	$2,147	$2,084	$2,452	$2,435	**$26,821**
Total	**$224,566**	**$266,992**	**$179,537**	**$314,811**	**$55,599**	**$50,628**	**$51,757**	**$56,043**	**$48,805**	**$45,470**	**$45,325**	**$48,706**	**$1,388,239**
Wind NRIS													
IPP	$4,234,668	$4,806,161	$4,025,901	$4,458,893	$3,378,817	$3,353,980	$2,494,285	$2,543,868	$2,976,953	$4,018,222	$4,397,198	$4,242,502	**$44,931,449**
Comfit	$6,815,378	$7,499,528	$6,598,473	$7,151,637	$5,896,761	$5,206,378	$4,430,821	$4,102,970	$5,021,027	$6,383,606	$6,588,546	$6,631,744	**$72,326,868**
Total	**$11,050,045**	**$12,305,689**	**$10,624,374**	**$11,610,531**	**$9,275,578**	**$8,560,357**	**$6,925,106**	**$6,646,838**	**$7,997,980**	**$10,401,828**	**$10,985,744**	**$10,874,247**	**$117,258,317**
Wind ERIS													
IPP	$3,651,471	$4,354,535	$3,485,885	$3,957,031	$3,021,158	$2,846,043	$2,119,709	$2,145,433	$2,578,092	$3,454,352	$3,622,637	$3,750,856	**$38,987,204**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$3,651,471**	**$4,354,535**	**$3,485,885**	**$3,957,031**	**$3,021,158**	**$2,846,043**	**$2,119,709**	**$2,145,433**	**$2,578,092**	**$3,454,352**	**$3,622,637**	**$3,750,856**	**$38,987,204**
Grand Total	**$28,830,505**	**$29,695,710**	**$29,796,885**	**$28,369,403**	**$26,235,252**	**$24,299,381**	**$20,790,046**	**$20,685,464**	**$23,553,310**	**$25,707,455**	**$26,670,987**	**$27,018,875**	**$311,653,272**
Plant Fuel Costs													
Plant Fuel Costs	$39,222,611	$31,700,877	$33,207,791	$22,454,229	$23,333,391	$21,135,273	$32,357,153	$32,813,410	$30,599,401	$31,011,392	$36,554,144	$43,579,540	**$377,969,212**
BTL Class Fuel-related costs													
GRLF	$48,147	$61,539	$52,678	$170,664	$58,632	$21,605	$113,595	$136,115	$42,855	$110,560	$198,061	$495,130	**$1,509,581**
1P - RTP	$17,991	$26,348	$6,231	$13,100	$38,162	$52,764	$66,907	$76,149	$63,882	$49,101	$44,282	$52,667	**$507,583**
LRT	$6,923,690	$3,771,756	$3,751,776	$3,876,309	$5,772,484	$4,878,970	$4,738,386	$5,235,675	$4,997,858	$4,044,775	$6,651,040	$5,452,626	**$60,095,346**
Shore Power	$0	$0	$0	$0	$8,316	$5,655	$17,298	$15,635	$18,296	$24,616	$0	$0	**$89,816**
BUTU	$88,343	$55,927	$109,537	$92,605	$103,240	$95,726	$106,145	$105,329	$101,180	$112,540	$135,039	$160,204	**$1,265,814**
Total	$7,078,171	$3,915,569	$3,920,222	$4,152,678	$5,980,834	$5,054,720	$5,042,331	$5,568,902	$5,224,071	$4,341,592	$7,028,421	$6,160,627	$63,468,139

Monthly Fuel Cost Allocation

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
ATL-related Fuel costs (net of BTL)	$32,144,439	$27,785,307	$29,287,569	$18,301,551	$17,352,557	$16,080,553	$27,314,822	$27,244,508	$25,375,331	$26,669,801	$29,525,723	$37,418,912	**$314,501,073**
Fuel costs before PP													
Domestic	$18,068,810	$15,821,602	$15,957,631	$9,584,747	$8,124,909	$6,708,581	$11,053,509	$11,210,944	$10,367,107	$11,620,852	$14,486,071	$20,738,838	$153,743,601
Small General	$1,152,462	$874,521	$990,625	$570,009	$549,532	$492,070	$864,769	$832,879	$752,441	$791,607	$854,956	$1,088,778	$9,814,650
General	$7,291,828	$6,233,551	$6,947,263	$4,377,184	$4,451,279	$4,601,174	$7,918,317	$7,723,827	$7,234,773	$7,363,594	$7,573,989	$8,768,642	$80,485,422
Large General	$1,026,227	$878,550	$1,004,418	$669,293	$768,970	$783,003	$1,484,792	$1,529,599	$1,345,272	$1,252,167	$1,131,498	$1,233,830	$13,107,619
Small Industrial	$828,611	$624,780	$736,178	$448,553	$517,529	$547,250	$910,782	$798,424	$780,907	$709,731	$808,734	$927,211	$8,638,689
Medium Industrial	$1,130,942	$1,052,977	$1,065,508	$863,305	$922,441	$1,003,665	$1,652,532	$1,559,146	$1,548,616	$1,531,744	$1,498,311	$1,511,122	$15,340,308
Large Industrial													
Customers staying on the rate	$308,012	$233,709	$340,164	$229,656	$261,046	$259,502	$431,798	$442,612	$402,789	$416,291	$366,848	$437,395	$4,129,820
Customer A moving some of its load to a BTL rate	$1,650,922	$1,461,973	$1,660,860	$1,193,467	$1,376,065	$1,321,025	$2,369,410	$2,530,876	$2,340,167	$2,397,388	$2,147,201	$1,968,585	$22,417,939
Large Industrial	$1,958,934	$1,695,682	$2,001,024	$1,423,123	$1,637,111	$1,580,527	$2,801,208	$2,973,487	$2,742,955	$2,813,679	$2,514,049	$2,405,981	$26,547,759
ELI 2P-RTP													
Municipal													
Full Service Requirement Customers	$159,051	$145,650	$152,675	$94,934	$97,264	$93,449	$141,502	$139,120	$137,601	$140,294	$145,577	$169,335	$1,616,452
Partial Service Requirement Customers													
Customer A	$177,004	$160,787	$124,491	$41,737	$68,768	$60,918	$115,194	$110,537	$109,604	$122,175	$153,043	$186,123	$1,430,380
Customer B	$67,659	$58,129	$48,301	$23,563	$23,044	$23,185	$58,658	$59,583	$56,381	$61,069	$60,250	$76,446	$616,267
Customer C	$33,138	$29,964	$27,769	$14,958	$10,409	$10,116	$16,052	$15,631	$13,877	$18,927	$25,967	$35,927	$252,734
Customer D	$23,816	$21,190	$20,101	$10,035	$5,816	$5,868	$8,678	$9,142	$8,194	$11,144	$16,984	$25,025	$165,994
Municipal	$460,667	$415,719	$373,336	$185,227	$205,302	$193,536	$340,084	$334,014	$325,656	$353,609	$401,822	$492,856	$4,081,827
Unmetered	$225,959	$187,925	$211,587	$180,109	$175,485	$170,748	$288,829	$282,187	$277,602	$232,820	$256,294	$251,655	$2,741,199
Total	**$32,144,439**	**$27,785,307**	**$29,287,569**	**$18,301,551**	**$17,352,557**	**$16,080,553**	**$27,314,822**	**$27,244,508**	**$25,375,331**	**$26,669,801**	**$29,525,723**	**$37,418,912**	**$314,501,073**
BTL Fuel-related costs													
[redacted]													
Subtotal before PP	$7,078,171	$3,915,569	$3,920,222	$4,152,678	$5,980,834	$5,054,720	$5,042,331	$5,568,902	$5,224,071	$4,341,592	$7,028,421	$6,160,627	$63,468,139

Monthly Fuel Cost Allocation

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Exports	($370,588)	($1,642,530)	($5,001,008)	($16,116)	($90,462)	($83,442)	($13,817)	($63,428)	($498,274)	($258,255)	($1,433,389)	($1,150,723)	($10,622,032)
Domestic	($208,312)	($935,295)	($2,724,850)	($8,440)	($42,357)	($34,811)	($5,591)	($26,100)	($203,570)	($112,530)	($703,257)	($637,770)	($5,642,884)
Small General	($13,287)	($51,697)	($169,154)	($502)	($2,865)	($2,553)	($437)	($1,939)	($14,775)	($7,665)	($41,506)	($33,483)	($339,864)
General	($84,066)	($368,497)	($1,186,282)	($3,855)	($23,205)	($23,875)	($4,005)	($17,982)	($142,063)	($71,305)	($367,695)	($269,657)	($2,562,488)
Large General	($11,831)	($51,936)	($171,510)	($589)	($4,009)	($4,063)	($751)	($3,561)	($26,416)	($12,125)	($54,931)	($37,943)	($379,665)
Small Industrial	($9,553)	($36,934)	($125,706)	($395)	($2,698)	($2,840)	($461)	($1,859)	($15,334)	($6,873)	($39,262)	($28,514)	($270,428)
Medium Industrial	($13,038)	($62,247)	($181,941)	($760)	($4,809)	($5,208)	($836)	($3,630)	($30,409)	($14,833)	($72,739)	($46,471)	($436,920)
Large Industrial													
Customers staying on the rate	($3,551)	($13,816)	($58,085)	($202)	($1,361)	($1,347)	($218)	($1,030)	($7,909)	($4,031)	($17,809)	($13,451)	($122,811)
Customer A moving some of its load to a BTL rate	($19,033)	($86,425)	($283,601)	($1,051)	($7,174)	($6,855)	($1,199)	($5,892)	($45,952)	($23,215)	($104,240)	($60,539)	($645,175)
Large Industrial	($22,584)	($100,240)	($341,685)	($1,253)	($8,535)	($8,201)	($1,417)	($6,923)	($53,861)	($27,246)	($122,050)	($73,990)	($767,985)
ELI 2P-RTP													
Municipal													
Full Service Requirement Customers	($1,834)	($8,610)	($26,070)	($84)	($507)	($485)	($72)	($324)	($2,702)	($1,359)	($7,067)	($5,207)	($54,320)
Partial Service Requirement Customers													
Customer A	($2,041)	($9,505)	($21,257)	($37)	($358)	($316)	($58)	($257)	($2,152)	($1,183)	($7,430)	($5,724)	($50,319)
Customer B	($780)	($3,436)	($8,248)	($21)	($120)	($120)	($30)	($139)	($1,107)	($591)	($2,925)	($2,351)	($19,868)
Customer C	($382)	($1,771)	($4,742)	($13)	($54)	($52)	($8)	($36)	($272)	($183)	($1,261)	($1,105)	($9,881)
Customer D	($275)	($1,253)	($3,432)	($9)	($30)	($30)	($4)	($21)	($161)	($108)	($825)	($770)	($6,918)
Municipal	($5,311)	($24,575)	($63,749)	($163)	($1,070)	($1,004)	($172)	($778)	($6,395)	($3,424)	($19,507)	($15,157)	($141,305)
Unmetered	($2,605)	($11,109)	($36,130)	($159)	($915)	($886)	($146)	($657)	($5,451)	($2,254)	($12,442)	($7,739)	($80,493)
Total	($370,588)	($1,642,530)	($5,001,008)	($16,116)	($90,462)	($83,442)	($13,817)	($63,428)	($498,274)	($258,255)	($1,433,389)	($1,150,723)	($10,622,032)
Imports													
Domestic	$2,238,851	$1,342,096	$2,313,899	$1,187,866	$1,530,113	$928,264	$308,442	$378,868	$957,047	$444,973	$377,612	$507,083	$12,515,114
Small General	$142,798	$74,183	$143,643	$70,643	$103,490	$68,088	$24,131	$28,147	$69,462	$30,311	$22,286	$26,622	$803,804
General	$903,508	$528,772	$1,007,371	$542,477	$838,281	$636,663	$220,956	$261,022	$667,883	$281,959	$197,433	$214,401	$6,300,729
Large General	$127,157	$74,525	$145,643	$82,947	$144,815	$108,344	$41,432	$51,692	$124,190	$47,947	$29,495	$30,168	$1,008,355
Small Industrial	$102,671	$52,998	$106,748	$55,590	$97,463	$75,723	$25,415	$26,982	$72,090	$27,176	$21,081	$22,671	$686,609
Medium Industrial	$140,132	$89,321	$154,501	$106,992	$173,718	$138,877	$46,113	$52,690	$142,962	$58,652	$39,057	$36,948	$1,179,962
Large Industrial													
Customers staying on the rate	$38,165	$19,825	$49,325	$28,462	$49,161	$35,907	$12,049	$14,958	$37,184	$15,940	$9,563	$10,695	$321,233
Customer A moving some of its load to a BTL rate	$204,561	$124,015	$240,829	$147,910	$259,146	$182,790	$66,117	$85,530	$216,034	$91,798	$55,972	$48,134	$1,722,834
Large Industrial	$242,726	$143,839	$290,154	$176,372	$308,307	$218,697	$78,166	$100,487	$253,218	$107,738	$65,534	$58,828	$2,044,067
ELI 2P-RTP													
Municipal													
Full Service Requirement Customers	$19,708	$12,355	$22,138	$11,765	$18,317	$12,930	$3,949	$4,701	$12,703	$5,372	$3,795	$4,140	$131,874
Partial Service Requirement Customers													
Customer A	$21,932	$13,639	$18,051	$5,173	$12,951	$8,429	$3,214	$3,736	$10,118	$4,678	$3,989	$4,551	$110,462
Customer B	$8,383	$4,931	$7,004	$2,920	$4,340	$3,208	$1,637	$2,014	$5,205	$2,338	$1,571	$1,869	$45,419
Customer C	$4,106	$2,542	$4,027	$1,854	$1,960	$1,400	$448	$528	$1,281	$725	$677	$878	$20,425
Customer D	$2,951	$1,797	$2,915	$1,244	$1,095	$812	$242	$309	$756	$427	$443	$612	$13,603
Municipal	$57,080	$35,264	$54,135	$22,956	$38,663	$26,779	$9,490	$11,288	$30,063	$13,540	$10,474	$12,051	$321,783
Unmetered	$27,998	$15,941	$30,681	$22,321	$33,048	$23,626	$8,060	$9,536	$25,627	$8,915	$6,681	$6,153	$218,587
Total	$3,982,919	$2,356,940	$4,246,775	$2,268,164	$3,267,898	$2,225,061	$762,205	$920,713	$2,342,542	$1,021,211	$769,655	$914,926	$25,079,009

Monthly Fuel Cost Allocation

	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Total
Purchased Biomass Generation	8,251,823	8,120,542	5,485,558	2,384,932	1,816,608	1,827,208	7,500,782	7,291,244	4,781,582	7,793,309	9,118,847	11,915,316	76,287,752
Relative Share	10.8%	10.6%	7.2%	3.1%	2.4%	2.4%	9.8%	9.6%	6.3%	10.2%	12.0%	15.6%	100.0%
Bio-fuel Apportioned	**$168,712**	**$166,028**	**$112,155**	**$48,761**	**$37,141**	**$37,358**	**$153,357**	**$149,073**	**$97,762**	**$159,338**	**$186,439**	**$243,614**	**$1,559,737**
Domestic	$94,835	$94,540	$61,109	$25,537	$17,391	$15,585	$62,059	$61,343	$39,941	$69,428	$91,472	$135,019	$768,258
Small General	$6,049	$5,226	$3,794	$1,519	$1,176	$1,143	$4,855	$4,557	$2,899	$4,729	$5,399	$7,088	$48,434
General	$38,272	$37,248	$26,604	$11,662	$9,528	$10,689	$44,457	$42,262	$27,873	$43,994	$47,826	$57,088	$397,501
Large General	$5,386	$5,250	$3,846	$1,783	$1,646	$1,819	$8,336	$8,369	$5,183	$7,481	$7,145	$8,033	$64,278
Small Industrial	$4,349	$3,733	$2,819	$1,195	$1,108	$1,271	$5,114	$4,369	$3,009	$4,240	$5,107	$6,037	$42,350
Medium Industrial	$5,936	$6,292	$4,080	$2,300	$1,974	$2,332	$9,278	$8,531	$5,966	$9,151	$9,461	$9,838	$75,140
Large Industrial	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customers staying on the rate	$1,617	$1,397	$1,303	$612	$559	$603	$2,424	$2,422	$1,552	$2,487	$2,316	$2,848	$20,138
Customer A moving some of its load to a BTL rate	$8,665	$8,736	$6,360	$3,180	$2,945	$3,069	$13,303	$13,848	$9,016	$14,323	$13,558	$12,816	$109,820
Large Industrial	$10,282	$10,132	$7,663	$3,792	$3,504	$3,672	$15,727	$16,270	$10,568	$16,810	$15,875	$15,664	$129,958
ELI 2P-RTP													
Municipal													
Full Service Requirement Customers	$835	$870	$585	$253	$208	$217	$794	$761	$530	$838	$919	$1,102	$7,914
Partial Service Requirement Customers													$0
Customer A	$929	$961	$477	$111	$147	$142	$647	$605	$422	$730	$966	$1,212	$7,348
Customer B	$355	$347	$185	$63	$49	$54	$329	$326	$217	$365	$380	$498	$3,169
Customer C	$174	$179	$106	$40	$22	$24	$90	$86	$53	$113	$164	$234	$1,285
Customer D	$125	$127	$77	$27	$12	$14	$49	$50	$32	$67	$107	$163	$848
Municipal	$2,418	$2,484	$1,430	$494	$439	$450	$1,909	$1,828	$1,255	$2,113	$2,537	$3,209	$20,564
Unmetered	$1,186	$1,123	$810	$480	$376	$397	$1,622	$1,544	$1,069	$1,391	$1,618	$1,638	$13,254
Total	**$168,712**	**$166,028**	**$112,155**	**$48,761**	**$37,141**	**$37,358**	**$153,357**	**$149,073**	**$97,762**	**$159,338**	**$186,439**	**$243,614**	**$1,559,737**

Monthly Energy Allocators

Rate Class	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2018 FAM Total	2017 Actuals 3- CP kWs
ATL														
Domestic Total	632,348,077	592,444,363	540,585,150	441,070,536	347,411,996	282,526,813	294,405,273	303,772,807	280,158,559	322,245,350	421,717,352	578,078,105	5,036,764,381	3,692,482
Small General	40,332,315	32,746,701	33,558,681	26,230,644	23,497,377	20,723,163	23,032,746	22,567,768	20,333,824	21,951,202	24,889,421	30,348,793	320,212,636	147,523
General	255,189,654	233,417,088	235,347,410	201,429,105	190,331,703	193,774,933	210,900,840	209,285,551	195,511,025	204,191,912	220,493,379	244,418,699	2,594,291,298	1,165,216
Large General	35,914,537	32,897,542	34,025,929	30,799,509	32,880,288	32,975,565	39,546,778	41,446,169	36,354,363	34,722,486	32,940,082	34,391,989	418,895,236	158,368
Small Industrial	28,998,623	23,395,047	24,938,987	20,641,492	22,128,956	23,047,014	24,258,266	21,634,165	21,103,075	19,680,774	23,543,800	25,845,241	279,215,440	117,764
Medium Industrial	39,579,182	39,429,031	36,095,435	39,727,538	39,442,541	42,268,570	44,014,456	42,246,778	41,849,472	42,475,132	43,618,710	42,121,299	492,868,144	187,725
Large Industrial	68,556,147	63,495,285	67,787,233	65,489,198	70,001,032	66,562,685	74,608,931	80,569,897	74,125,056	78,023,098	73,188,797	67,064,741	849,472,100	271,294
ELI 2P-RTP (Adjusted CBL)														0
Municipal														
Full Service Requirement Customers	5,566,250	5,453,914	5,172,054	4,368,659	4,158,921	3,935,520	3,768,835	3,769,621	3,718,502	3,890,333	4,238,038	4,720,081	52,760,728	5,342
Partial Service Requirement Customers														
Customer A	6,194,536	6,020,696	4,217,283	1,920,661	2,940,435	2,565,535	3,068,134	2,995,124	2,961,903	3,387,896	4,455,390	5,188,031	45,915,624	43,123
Customer B	2,367,835	2,176,646	1,636,255	1,084,315	985,344	976,404	1,562,330	1,614,477	1,523,641	1,693,435	1,753,984	2,130,861	19,505,526	13,989
Customer C	1,159,718	1,122,004	940,700	688,338	445,094	426,007	427,535	423,532	374,996	524,850	755,955	1,001,432	8,290,162	6,647
Customer D	833,465	793,460	680,939	461,801	248,679	247,142	231,138	247,720	221,431	309,030	494,433	697,563	5,466,801	5,529
Municipal	16,121,804	15,566,720	12,647,231	8,523,773	8,778,473	8,150,608	9,057,973	9,050,474	8,800,473	9,805,544	11,697,800	13,737,967	131,938,841	74,630
Unmetered	7,907,823	7,036,891	7,167,784	8,288,266	7,503,521	7,190,930	7,692,827	7,646,164	7,501,849	6,456,069	7,461,209	7,014,672	88,868,005	51,734
Total	**1,124,948,162**	**1,040,428,668**	**992,153,840**	**842,200,061**	**741,975,887**	**677,220,280**	**727,518,090**	**738,219,773**	**685,737,697**	**739,551,567**	**859,550,550**	**1,043,021,506**	**10,212,526,081**	5,866,735
BTL														
[redacted]														
BTL Total	92,290,082	66,322,675	69,086,607	85,767,309	106,461,670	88,879,480	101,655,191	105,184,980	104,520,017	108,947,473	100,591,700	109,251,641	1,138,958,826	
In-province Total	**1,217,238,244**	**1,106,751,343**	**1,061,240,447**	**927,967,370**	**848,437,558**	**766,099,760**	**829,173,281**	**843,404,753**	**790,257,715**	**848,499,040**	**960,142,249**	**1,152,273,148**	**11,351,484,907**	
													0	
Exports	4,987,000	16,576,000	58,654,000	1,149,000	4,675,000	4,028,180	579,716	2,763,059	21,059,372	10,526,459	13,539,518	2,978,744	141,516,048	
NSR simulated	1,224,174,452	1,103,544,604	1,088,430,825	930,868,307	855,061,192	765,507,631	826,100,565	841,241,887	770,709,548	831,816,241	941,884,153	1,159,234,494	11,338,573,900	
NSR actual	1,217,238,244	1,106,751,343	1,061,240,447	927,967,370	848,437,558	766,099,760	829,173,281	843,404,753	790,257,715	848,499,040	960,142,249	1,152,273,148	11,351,484,907	
NSR correction factor	**0.994334**	**1.002906**	**0.975019**	**0.996884**	**0.992254**	**1.000774**	**1.003720**	**1.002571**	**1.025364**	**1.020056**	**1.019385**	**0.993995**	**1.001139**	
Simulated Requirements (kWhs)														
Domestic Total	635,951,396	590,727,794	554,435,653	442,449,376	350,124,193	282,308,444	293,314,278	302,993,798	273,228,433	315,909,510	413,697,961	581,570,508	5,036,711,344	3,692,482
Small General	40,562,141	32,651,820	34,418,499	26,312,644	23,680,818	20,707,146	22,947,392	22,509,894	19,830,837	21,519,608	24,416,123	30,532,142	320,089,065	147,523
General	256,643,805	232,740,778	241,377,320	202,058,797	191,817,596	193,625,162	210,119,292	208,748,850	190,674,777	200,177,184	216,300,470	245,895,331	2,590,179,361	1,165,216
Large General	36,119,189	32,802,224	34,897,718	30,895,792	33,136,980	32,950,077	39,400,227	41,339,882	35,455,085	34,039,788	32,313,692	34,599,765	417,950,420	158,368
Small Industrial	29,163,866	23,327,261	25,577,956	20,706,020	22,301,714	23,029,201	24,168,371	21,578,685	20,581,060	19,293,820	23,096,090	26,001,383	278,825,427	117,764
Medium Industrial	39,804,717	39,314,787	37,020,248	39,851,731	39,750,463	42,235,900	43,851,349	42,138,439	40,814,265	41,640,006	42,789,255	42,375,771	491,586,931	187,725
Large Industrial														
Customers staying on the rate	10,840,813	8,725,935	11,818,722	10,601,328	11,249,158	10,920,262	11,458,135	11,962,297	10,615,623	11,316,745	10,476,568	12,265,695	132,251,280	0
Customer A moving some of its load to a BTL rate	58,105,989	54,585,377	57,705,309	55,092,597	59,298,362	55,590,976	62,874,313	68,400,984	61,675,843	65,172,298	61,320,468	55,204,211	715,026,728	0
Large Industrial - Total	68,946,801	63,311,312	69,524,031	65,693,925	70,547,520	66,511,238	74,332,449	80,363,280	72,291,466	76,489,044	71,797,037	67,469,906	847,278,008	271,294
ELI 2P-RTP	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Municipal														
Full Service Requirement Customers	5,597,969	5,438,112	5,304,569	4,382,316	4,191,389	3,932,478	3,754,869	3,759,954	3,626,519	3,813,843	4,157,447	4,748,597	52,708,061	5,342
Partial Service Requirement Customers														
Customer A	6,229,834	6,003,251	4,325,335	1,926,665	2,963,391	2,563,552	3,056,765	2,987,444	2,888,636	3,321,285	4,370,666	5,219,374	45,856,197	43,123
Customer B	2,381,328	2,170,340	1,678,178	1,087,704	993,036	975,649	1,556,541	1,610,337	1,485,952	1,660,139	1,720,630	2,143,734	19,463,567	13,989
Customer C	1,166,326	1,118,753	964,802	690,490	448,569	425,677	425,950	422,446	365,720	514,531	741,580	1,007,482	8,292,328	6,647
Customer D	838,214	791,161	698,386	463,245	250,621	246,951	230,281	247,085	215,954	302,954	485,031	701,777	5,471,659	5,529
Municipal Total	16,213,672	15,521,617	12,971,269	8,550,420	8,847,005	8,144,308	9,024,406	9,027,265	8,582,781	9,612,752	11,475,354	13,820,964	131,791,812	74,630
Unmetered	7,952,884	7,016,502	7,351,432	8,314,176	7,562,100	7,185,372	7,664,319	7,626,556	7,316,280	6,329,132	7,319,326	7,057,050	88,695,131	51,734
Total	**1,131,358,472**	**1,037,414,095**	**1,017,574,128**	**844,832,879**	**747,768,390**	**676,696,848**	**724,822,083**	**736,326,648**	**668,774,985**	**725,010,844**	**843,205,309**	**1,049,322,819**	10,203,107,499	5,866,735
BTL													0	
[redacted]														
BTL Total	92,815,980	66,130,509	70,856,697	86,035,428	107,292,802	88,810,784	101,278,482	104,915,238	101,934,564	106,805,398	98,678,845	109,911,675	1,115,038,340	
NSR	1,224,174,452	1,103,544,604	1,088,430,825	930,868,307	855,061,192	765,507,631	826,100,565	841,241,887	770,709,548	831,816,241	941,884,153	1,159,234,494	11,338,573,900	11,351,484,907
Exports	5,079,329	16,199,833	57,401,471	1,131,947	4,819,538	4,152,720	597,639	2,848,486	21,710,469	10,851,908	13,958,122	3,070,839	141,822,301	
ATL														
Fuel Cost Allocators														
Domestic	56.21%	56.94%	54.49%	52.37%	46.82%	41.72%	40.47%	41.15%	40.86%	43.57%	49.06%	55.42%	49.36%	
Small General	3.59%	3.15%	3.38%	3.11%	3.17%	3.06%	3.17%	3.06%	2.97%	2.97%	2.90%	2.91%	3.14%	
General	22.68%	22.43%	23.72%	23.92%	25.65%	28.61%	28.99%	28.35%	28.51%	27.61%	25.65%	23.43%	25.39%	
Large General	3.19%	3.16%	3.43%	3.66%	4.43%	4.87%	5.44%	5.61%	5.30%	4.70%	3.83%	3.30%	4.10%	
Small Industrial	2.58%	2.25%	2.51%	2.45%	2.98%	3.40%	3.33%	2.93%	3.08%	2.66%	2.74%	2.48%	2.73%	
Medium Industrial	3.52%	3.79%	3.64%	4.72%	5.32%	6.24%	6.05%	5.72%	6.10%	5.74%	5.07%	4.04%	4.82%	
Large Industrial														
Customers staying on the rate	0.96%	0.84%	1.16%	1.25%	1.50%	1.61%	1.58%	1.62%	1.59%	1.56%	1.24%	1.17%	1.30%	
Customer A moving some of its load to a BTL rate	5.14%	5.26%	5.67%	6.52%	7.93%	8.22%	8.67%	9.29%	9.22%	8.99%	7.27%	5.26%	7.01%	
Large Industrial - Total	6.09%	6.10%	6.83%	7.78%	9.43%	9.83%	10.26%	10.91%	10.81%	10.55%	8.51%	6.43%	8.30%	
ELI 2P-RTP	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%	
Municipal														
Full Service Requirement Customers	0.49%	0.52%	0.52%	0.52%	0.56%	0.58%	0.52%	0.51%	0.54%	0.53%	0.49%	0.45%	0.52%	
Partial Service Requirement Customers														
Customer A	0.55%	0.58%	0.43%	0.23%	0.40%	0.38%	0.42%	0.41%	0.43%	0.46%	0.52%	0.50%	0.45%	
Customer B	0.21%	0.21%	0.16%	0.13%	0.13%	0.14%	0.21%	0.22%	0.22%	0.23%	0.20%	0.20%	0.19%	
Customer C	0.10%	0.11%	0.09%	0.08%	0.06%	0.06%	0.06%	0.06%	0.05%	0.07%	0.09%	0.10%	0.08%	
Customer D	0.07%	0.08%	0.07%	0.05%	0.03%	0.04%	0.03%	0.03%	0.03%	0.04%	0.06%	0.07%	0.05%	
Municipal Total	1.43%	1.50%	1.27%	1.01%	1.18%	1.20%	1.25%	1.23%	1.28%	1.33%	1.36%	1.32%	1.29%	
Unmetered	0.70%	0.68%	0.72%	0.98%	1.01%	1.06%	1.06%	1.04%	1.09%	0.87%	0.87%	0.67%	0.87%	
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%	

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Total	2016 Test Year 3CP kWs
Sales (MWhs)-Actuals														
ATL Classes														
Domestic Non-TOU	539,042,332	499,260,210	469,514,634	381,355,254	303,317,310	251,848,705	263,368,494	269,025,643	244,964,421	277,088,456	357,500,335	483,522,631	4,339,808,424	
Domestic TOU	38,466,405	37,040,323	37,341,232	26,804,092	18,451,412	11,652,509	10,408,446	11,407,642	10,875,043	14,948,819	22,875,835	40,256,492	280,528,250	
Domestic Total	577,508,737	536,300,533	506,855,866	408,159,346	321,768,722	263,501,214	273,776,940	280,433,284	255,839,463	292,037,276	380,376,169	523,779,123	4,620,336,674	3,205,400
Small General	37,227,238	29,902,146	31,656,093	24,302,374	21,759,149	19,394,384	21,395,023	20,784,137	18,555,967	20,095,889	22,558,748	27,868,175	295,499,323	130,700
General	241,911,585	219,073,473	226,161,016	190,723,503	180,131,332	183,195,964	198,374,672	196,060,332	181,016,441	188,847,563	204,497,554	228,949,253	2,438,942,688	1,081,900
Large General	34,045,826	30,942,678	32,754,121	29,199,107	31,208,288	31,371,750	37,146,165	38,898,817	33,883,275	32,069,832	30,544,621	32,351,985	394,416,464	149,300
Small Industrial	27,376,384	22,035,830	24,061,579	19,556,423	20,966,582	21,893,747	23,010,565	20,374,741	19,635,419	18,239,423	21,848,906	24,270,542	263,270,142	109,800
Medium Industrial	37,799,717	37,285,300	34,981,657	37,763,788	37,368,222	40,175,929	41,764,488	39,823,474	38,937,583	39,444,599	40,681,503	39,845,736	465,871,997	175,400
Large Industrial														260,500
Customers staying on the rate	10,327,580	8,353,534	11,287,186	10,122,085	10,672,614	10,457,465	10,973,987	11,371,200	10,201,318	10,786,067	10,071,687	11,696,413	126,321,137	
Customer A moving some of its load to a BTL rate	55,355,099	52,255,810	55,110,071	52,602,083	56,259,191	53,235,049	60,217,640	65,021,064	59,268,771	62,116,163	58,950,656	52,642,044	683,033,642	
Large Industrial - Total	65,682,679	60,609,343	66,397,257	62,724,168	66,931,805	63,692,514	71,191,627	76,392,264	69,470,090	72,902,230	69,022,344	64,338,457	809,354,778	260,500
ELI 2P-RTP (Adjusted CBL)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Municipal														
Full Service Requirement Customers	5,332,514	5,183,662	5,022,259	4,160,086	3,973,837	3,755,307	3,588,202	3,564,310	3,473,423	3,627,628	3,974,843	4,471,999	50,128,069	5,068
Partial Service Requirement Customers														
Customer A	5,934,417	5,722,359	4,095,140	1,828,962	2,809,577	2,448,055	2,921,085	2,831,996	2,766,690	3,159,119	4,178,697	4,915,354	43,611,452	40,910
Customer B	2,268,406	2,068,789	1,588,865	1,032,546	941,493	931,693	1,487,451	1,526,545	1,423,221	1,579,081	1,645,056	2,018,865	18,512,011	13,271
Customer C	1,111,019	1,066,407	913,455	655,475	425,286	406,499	407,044	400,465	350,281	489,408	709,008	948,798	7,883,146	6,306
Customer D	798,466	754,142	661,218	439,753	237,612	235,825	220,060	234,228	206,837	288,162	463,727	660,899	5,200,931	5,245
Municipal Total	15,444,822	14,795,359	12,280,938	8,116,822	8,387,805	7,777,379	8,623,842	8,557,544	8,220,453	9,143,398	10,971,331	13,015,916	125,335,609	70,800
Unmetered	7,268,903	6,425,767	6,765,977	7,670,511	6,890,697	6,570,987	6,993,330	6,965,682	6,771,769	5,874,924	6,758,975	6,412,269	81,369,792	44,900
ATL Total	**1,044,265,891**	**957,370,429**	**941,914,505**	**788,216,043**	**695,412,603**	**637,573,868**	**682,276,653**	**688,290,274**	**632,330,460**	**678,655,134**	**787,260,153**	**960,831,456**	**9,494,397,468**	5,228,700
BTL														
[redacted]														
BTL Total	91,000,080	64,791,339	69,467,812	84,283,002	105,158,681	87,072,176	99,257,283	102,825,621	99,912,918	104,648,623	96,759,039	107,621,980	1,112,798,554	
In-province Sales	1,135,265,971	1,022,161,768	1,011,382,316	872,499,045	800,571,283	724,646,044	781,533,937	791,115,895	732,243,378	783,303,757	884,019,192	1,068,453,436	10,607,196,023	
Exports	4,927,000	15,714,000	55,680,000	1,098,000	4,675,000	4,028,180	579,716	2,763,059	21,059,372	10,526,459	13,539,518	2,978,744	137,569,048	
Total Sales	**1,140,192,971**	**1,037,875,768**	**1,067,062,316**	**873,597,045**	**805,246,283**	**728,674,224**	**782,113,653**	**793,878,954**	**753,302,750**	**793,830,216**	**897,558,710**	**1,071,432,180**	**10,744,765,070**	
Line Loss Factors from the 2017Test Year (2017-2019 RSP Fillings)														
Domestic Total	10.12%	10.15%	9.39%	8.40%	8.81%	7.14%	7.14%	8.04%	6.80%	8.17%	8.76%	11.03%	9.00%	15.20%
Small General	8.96%	9.20%	8.73%	8.27%	8.83%	6.77%	7.26%	8.30%	6.87%	7.08%	8.23%	9.56%	8.69%	12.87%
General	6.09%	6.24%	6.73%	5.94%	6.49%	5.69%	5.92%	6.47%	5.34%	6.00%	5.77%	7.40%	6.20%	7.70%
Large General	6.09%	6.01%	6.54%	5.81%	6.18%	5.03%	6.07%	6.28%	4.64%	6.14%	5.79%	6.95%	6.00%	6.07%
Small Industrial	6.53%	5.86%	6.30%	5.88%	6.37%	5.19%	5.03%	5.91%	4.82%	5.78%	5.71%	7.13%	5.79%	7.25%
Medium Industrial	5.30%	5.44%	5.83%	5.53%	6.38%	5.13%	5.00%	5.81%	4.82%	5.57%	5.18%	6.35%	5.49%	7.03%
Large Industrial														
Customers staying on the rate	4.97%	4.46%	4.71%	4.73%	5.40%	4.43%	4.41%	5.20%	4.06%	4.92%	4.02%	4.87%	4.59%	4.14%
Customer A moving some of its load to a BTL rate	4.97%	4.46%	4.71%	4.73%	5.40%	4.43%	4.41%	5.20%	4.06%	4.92%	4.02%	4.87%	4.59%	4.14%
Large Industrial - Total	4.97%	4.46%	4.71%	4.73%	5.40%	4.43%	4.41%	5.20%	4.06%	4.92%	4.02%	4.87%	4.59%	4.14%
ELI 2P-RTP	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%
Municipal														
Full Service Requirement Customers	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.41%
Partial Service Requirement Customers														
Customer A	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.41%
Customer B	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.41%
Customer C	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.41%
Customer D	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.41%
Municipal Total	4.98%	4.91%	5.62%	5.34%	5.47%	4.72%	4.64%	5.49%	4.41%	5.13%	4.59%	6.19%	5.16%	5.41%
Unmetered	9.41%	9.19%	8.65%	8.39%	9.74%	9.35%	9.59%	9.49%	8.04%	7.73%	8.29%	10.06%	9.00%	15.22%
BTL														
[redacted]														
BTL Total														
Exports	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	3.09%	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Line Losses from 2019 Compliance Filing-2018-2019 RSP

Rate Class	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	2019Total	3CP kWs Jan-19	Feb-19	Dec-19	Total
kWh Sales																	
Domestic Total	577,509	536,301	506,856	408,159	321,769	263,501	273,777	280,433	255,839	292,037	380,376	523,779	**4,620,337**	1,090,900	1,050,100	1,064,400	3,205,400
Small General	37,227	29,902	31,656	24,302	21,759	19,394	21,395	20,784	18,556	20,096	22,559	27,868	**295,499**	55,200	40,400	35,100	130,700
General	241,912	219,073	226,161	190,724	180,131	183,196	198,375	196,060	181,016	188,848	204,498	228,949	**2,438,943**	396,900	372,500	312,500	1,081,900
Large General	34,046	30,943	32,754	29,199	31,208	31,372	37,146	38,899	33,883	32,070	30,545	32,352	**394,416**	55,400	48,600	45,300	149,300
Small Industrial	27,376	22,036	24,062	19,556	20,967	21,894	23,011	20,375	19,635	18,239	21,849	24,271	**263,270**	49,600	33,700	26,500	109,800
Medium Industrial	37,800	37,285	34,982	37,764	37,368	40,176	41,764	39,823	38,938	39,445	40,682	39,846	**465,872**	70,900	59,400	45,100	175,400
Large Industrial	65,683	60,609	66,397	62,724	66,932	63,693	71,192	76,392	69,470	72,902	69,022	64,338	**809,355**	91,900	79,700	88,900	260,500
ELI 2P-RTP														-	-	-	-
Full Service Requirement Customers	5,333	5,184	5,022	4,160	3,974	3,755	3,588	3,564	3,473	3,628	3,975	4,472	**50,128**	[redacted]			
Partial Service Requirement Customers																	
Customer A	5,934	5,722	4,095	1,829	2,810	2,448	2,921	2,832	2,767	3,159	4,179	4,915	**43,611**				
Customer B	2,268	2,069	1,589	1,033	941	932	1,487	1,527	1,423	1,579	1,645	2,019	**18,512**				
Customer C	1,111	1,066	913	655	425	406	407	400	350	489	709	949	**7,883**				
Customer D	798	754	661	440	238	236	220	234	207	288	464	661	**5,201**				
Municipal	15,445	14,795	12,281	8,117	8,388	7,777	8,624	8,558	8,220	9,143	10,971	13,016	**125,336**	25,400	25,200	20,200	70,800
Unmetered	7,269	6,426	6,766	7,671	6,891	6,571	6,993	6,966	6,772	5,875	6,759	6,412	**81,370**	16,000	15,100	13,800	44,900
ATL Total	**1,044,266**	**957,370**	**941,915**	**788,216**	**695,413**	**637,574**	**682,277**	**688,290**	**632,330**	**678,655**	**787,260**	**960,831**	**9,494,397**	**1,877,600**	**1,749,900**	**1,672,000**	**5,299,500**
BTL																	
[redacted]																	
BTL Total	91,000	64,791	69,468	84,283	105,159	87,072	99,257	102,826	99,913	104,649	96,759	107,622	**1,079,871**				
In-Province Total Sales	1,135,266	1,022,162	1,011,382	872,499	800,571	724,646	781,534	791,116	732,243	783,304	884,019	1,068,453	10,574,268				

kWh requirements- Estimated on 2019 Budgeted Sales

ATL																	
Domestic Non-TOU																	
Domestic TOU																	
Domestic Total	635,951	590,728	554,436	442,449	350,124	282,308	293,314	302,994	273,228	315,910	413,698	581,571	**5,036,711**	1,262,171	1,210,765	1,219,545	3,692,482
Small General	40,562	32,652	34,418	26,313	23,681	20,707	22,947	22,510	19,831	21,520	24,416	30,532	**320,089**	62,155	46,056	39,312	147,523
General	256,644	232,741	241,377	202,059	191,818	193,625	210,119	208,749	190,675	200,177	216,300	245,895	**2,590,179**	427,064	400,438	337,714	1,165,216
Large General	36,119	32,802	34,898	30,896	33,137	32,950	39,400	41,340	35,455	34,040	32,314	34,600	**417,950**	58,429	52,148	47,792	158,368
Small Industrial	29,164	23,327	25,578	20,706	22,302	23,029	24,168	21,579	20,581	19,294	23,096	26,001	**278,825**	53,022	36,228	28,514	117,764
Medium Industrial	39,805	39,315	37,020	39,852	39,750	42,236	43,851	42,138	40,814	41,640	42,789	42,376	**491,587**	75,650	63,736	48,338	187,725
Large Industrial	68,947	63,311	69,524	65,694	70,548	66,511	74,332	80,363	72,291	76,489	71,797	67,470	**847,278**	95,357	82,223	93,714	271,294
ELI 2P-RTP	-	-	-	-	-	-	-	-	-	-	-	-					
Full Service Requirement Customers	5,598	5,438	5,305	4,382	4,191	3,932	3,755	3,760	3,627	3,814	4,157	4,749	53,438	[redacted]			
Partial Service Requirement Customers	-	-	-	-	-	-	-	-	-	-	-	-					
Customer A	6,422	6,197	4,423	1,959	3,021	2,598	3,104	3,030	2,926	3,376	4,476	5,367	**46,899**				
Customer B	2,268	2,069	1,589	1,033	941	932	1,487	1,527	1,423	1,579	1,645	2,019	**18,512**				
Customer C	1,111	1,066	913	655	425	406	407	400	350	489	709	949	**7,883**				
Customer D	840	777	704	462	245	246	229	243	217	302	474	688	**5,429**				
Municipal	15,987	17,023	12,818	8,733	8,837	8,001	8,962	8,851	8,541	9,589	11,404	13,416	**132,161**	26,755	26,586	21,289	74,630
Unmetered	7,414	6,554	6,901	7,824	7,029	6,702	7,133	7,105	6,907	5,992	6,894	6,541	**82,997**	18,512	17,410	15,811	51,734
Total	**1,130,846**	**1,036,978**	**1,017,087**	**844,284**	**747,212**	**676,184**	**724,249**	**735,737**	**668,327**	**724,621**	**842,767**	**1,048,757**	**10,197,779**	**2,079,116**	**1,935,589**	**1,852,030**	**5,866,735**
BTL																	
[redacted]																	
BTL Total	92,894	66,179	70,955	86,114	107,383	88,883	101,357	105,007	102,006	106,897	98,778	110,070	**1,136,523**				
Total	92,894	66,179	70,955	86,114	107,383	88,883	101,357	105,007	102,006	106,897	98,778	110,070	**1,136,523**				
NSR	1,223,740	1,103,157	1,088,042	930,398	854,595	765,067	825,606	840,745	770,332	831,519	941,545	1,158,826	**11,333,571**				
Exports													**0**				
NSR	1,223,740	1,103,157	1,088,042	930,398	854,595	765,067	825,606	840,745	770,332	831,519	941,545	1,158,826	**11,333,571**				
TSR	1,223,740	1,103,157	1,088,042	930,398	854,595	765,067	825,606	840,745	770,332	831,519	941,545	1,158,826	**11,333,571**				

Line Losses

Line Losses from 2017-2019 RSP Compliance Filing-2019 data

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

ATL

Domestic Total	10.1%	10.1%	9.4%	8.4%	8.8%	7.1%	7.1%	8.0%	6.8%	8.2%	8.8%	11.0%	9.0%	15.7%	15.3%	14.6%	15.2%
Small General	9.0%	9.2%	8.7%	8.3%	8.8%	6.8%	7.3%	8.3%	6.9%	7.1%	8.2%	9.6%	8.7%	12.6%	14.0%	12.0%	12.9%
General	6.1%	6.2%	6.7%	5.9%	6.5%	5.7%	5.9%	6.5%	5.3%	6.0%	5.8%	7.4%	6.2%	7.6%	7.5%	8.1%	7.7%
Large General	6.1%	6.0%	6.5%	5.8%	6.2%	5.0%	6.1%	6.3%	4.6%	6.1%	5.8%	6.9%	6.0%	5.5%	7.3%	5.5%	6.1%
Small Industrial	6.5%	5.9%	6.3%	5.9%	6.4%	5.2%	5.0%	5.9%	4.8%	5.8%	5.7%	7.1%	5.8%	6.9%	7.5%	7.6%	7.3%
Medium Industrial	5.3%	5.4%	5.8%	5.5%	6.4%	5.1%	5.0%	5.8%	4.8%	5.6%	5.2%	6.3%	5.5%	6.7%	7.3%	7.2%	7.0%
Large Industrial	5.0%	4.5%	4.7%	4.7%	5.4%	4.4%	4.4%	5.2%	4.1%	4.9%	4.0%	4.9%	4.6%	3.8%	3.2%	5.4%	4.1%
ELI 2P-RTP	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%	0.0%	0.0%	0.0%
Municipal	5.0%	4.9%	5.6%	5.3%	5.5%	4.7%	4.6%	5.5%	4.4%	5.1%	4.6%	6.2%	5.2%	5.3%	5.5%	5.4%	5.4%
Unmetered	9.4%	9.2%	8.7%	8.4%	9.7%	9.3%	9.6%	9.5%	8.0%	7.7%	8.3%	10.1%	9.0%	15.7%	15.3%	14.6%	15.2%
Total	**8.2%**	**8.3%**	**8.0%**	**7.1%**	**7.5%**	**6.1%**	**6.3%**	**7.0%**	**5.8%**	**6.9%**	**7.1%**	**9.2%**	**7.4%**	**10.7%**	**10.6%**	**10.8%**	**10.7%**

BTL

[redacted]

BTL Total

Winter kW Peaks-2018 Actuals

ATL Classes													**3CP**	Annual Peak
Domestic Total	1,262,171	1,210,765										1,219,545	3,692,482	1,262,171
Small General	62,155	46,056										39,312	147,523	62,155
General	427,064	400,438										337,714	1,165,216	427,064
Large General	58,429	52,148										47,792	158,368	58,429
Small Industrial	53,022	36,228										28,514	117,764	53,022
Medium Industrial	75,650	63,736										48,338	187,725	75,650
Large Industrial	95,357	82,223										93,714	271,294	95,357
Municipal	26,755	26,586										21,289	74,630	26,755
Unmetered	18,512	17,410										15,811	51,734	18,512
Total	**2,079,116**	**1,935,589**										**1,852,030**	5,866,735	2,079,116
BTL Classes													-	-
GRLF	11,648	1,040.00										1,664.00	14,352	11,648
1P - RTP	-	-										-	-	-
Load Retention (LRT)	66,326	66,326										66,326	198,978	66,326
Shore Power	-	-										-	-	-
Total	**77,974**	**67,366**										**67,990**	213,330	77,974
Grand Total	**2,157,090**	**2,002,955**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**1,920,020**	**6,080,065**	**2,157,090**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Data Inputs
Unreconcile

Category	Jan-19	Feb-19	Mar-19	Apr-19	May-19	Jun-19	Jul-19	Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Annual
	Actual				Reprojection								
Plant Fuel Costs	$39,222,611	$31,700,877	$33,207,791	$22,454,229	$23,333,391	$21,135,273	$32,357,153	$32,813,410	$30,599,401	$31,011,392	$36,554,144	$43,579,540	$377,969,212
Maritime Link													
ML - NS Block	$8,558,333	$9,176,052	$10,078,794	$9,057,302	$9,207,231	$9,207,231	$9,207,231	$9,207,231	$9,207,231	$9,207,231	$9,458,333	$9,458,333	$111,030,533
ML - Supp Block													
ML - Surplus													
Total	**$8,558,333**	**$9,176,052**	**$10,078,794**	**$9,057,302**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,207,231**	**$9,458,333**	**$9,458,333**	**$111,030,533**
Non-Wind Purchases													
Purchased Power Regular bfr Biomass	$222,795	$265,057	$177,574	$312,770	$52,718	$48,124	$49,991	$53,202	$46,658	$43,386	$42,873	$46,271	$1,361,418
Purchased Power - Biomass	$935,922	$900,601	$699,622	$500,642	$795,696	$779,672	$1,045,354	$1,028,989	$754,124	$939,383	$1,136,862	$1,325,438	$10,842,304
Non-Wind Purchases	$1,158,717	$1,165,658	$877,195	$813,412	$848,414	$827,796	$1,095,345	$1,082,191	$800,782	$982,769	$1,179,735	$1,371,709	$12,203,722
Wind Purchases													
Purchased Power Wind - NRIS	$4,234,668	$4,806,161	$4,025,901	$4,458,893	$3,378,817	$3,353,980	$2,494,285	$2,543,868	$2,976,953	$4,018,222	$4,397,198	$4,242,502	$44,931,449
Purchased Power Wind - ERIS	$3,651,471	$4,354,535	$3,485,885	$3,957,031	$3,021,158	$2,846,043	$2,119,709	$2,145,433	$2,578,092	$3,454,352	$3,622,637	$3,750,856	$38,987,204
Purchased Power Wind	$7,886,139	$9,160,696	$7,511,786	$8,415,924	$6,399,975	$6,200,023	$4,613,994	$4,689,302	$5,555,046	$7,472,574	$8,019,836	$7,993,359	$83,918,653
Comift													
Wind Generatiion (NRIS)	$6,815,378	$7,499,528	$6,598,473	$7,151,637	$5,896,761	$5,206,378	$4,430,821	$4,102,970	$5,021,027	$6,383,606	$6,588,546	$6,631,744	$72,326,868
Wind Generatiion (ERIS)													
Biomass Generation	$427,248	$334,900	$481,898	$660,923	$612,092	$630,389	$678,684	$680,217	$624,536	$637,981	$652,430	$646,369	$7,067,667
Other	$1,771	$1,936	$1,964	$2,041	$2,882	$2,504	$1,766	$2,841	$2,147	$2,084	$2,452	$2,435	$26,821
Total Comfit	$7,244,397	$7,836,364	$7,082,335	$7,814,601	$6,511,734	$5,839,270	$5,111,271	$4,786,028	$5,647,710	$7,023,670	$7,243,428	$7,280,548	$79,421,355
Imports	$3,982,919	$2,356,940	$4,246,775	$2,268,164	$3,267,898	$2,225,061	$762,205	$920,713	$2,342,542	$1,021,211	$769,655	$914,926	$25,079,009
Export Revenues	($370,588)	($1,642,530)	($5,001,008)	($16,116)	($90,462)	($83,442)	($13,817)	($63,428)	($498,274)	($258,255)	($1,433,389)	($1,150,723)	($10,622,032)
OM&G (Solid Fuel Handling) recovered in fuels													$0
Foreign Exchange (Fuel-related)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total FAM related costs	**$68,053,115**	**$61,396,587**	**$63,004,676**	**$50,823,632**	**$49,568,643**	**$45,434,654**	**$53,147,200**	**$53,498,874**	**$54,152,712**	**$56,718,847**	**$63,225,131**	**$70,598,415**	**$689,622,484**
Purchased Biomass Generation Units	8,251,823	8,120,542	5,485,558	2,384,932	1,816,608	1,827,208	7,500,782	7,291,244	4,781,582	7,793,309	9,118,847	11,915,316	76,287,752
BLT Fuel Costs	**Source-2019 Revenue Forecast**												
[redacted]													
Total	$7,078,171	$3,915,569	$3,920,222	$4,152,678	$5,980,834	$5,054,720	$5,042,331	$5,568,902	$5,224,071	$4,341,592	$7,028,421	$6,160,627	$63,468,139
[redacted]													
											$2,592,402		
ERIS	**$3,651,471**	**$4,354,535**	**$3,485,885**	**$3,957,031**	**$3,021,158**	**$2,846,043**	**$2,119,709**	**$2,145,433**	**$2,578,092**	**$3,454,352**	**$3,622,637**	**$3,750,856**	**$38,987,204**
NRIS	**$4,234,668**	**$4,806,161**	**$4,025,901**	**$4,458,893**	**$3,378,817**	**$3,353,980**	**$2,494,285**	**$2,543,868**	**$2,976,953**	**$4,018,222**	**$4,397,198**	**$4,242,502**	**$44,931,449**
Total	**$7,886,139**	**$9,160,696**	**$7,511,786**	**$8,415,924**	**$6,399,975**	**$6,200,023**	**$4,613,994**	**$4,689,302**	**$5,555,046**	**$7,472,574**	**$8,019,836**	**$7,993,359**	**$83,918,653**
Usage Data													

kWh Sales

ATL Classes		Actuals												
Domestic Non-TOU		539,042,332	499,260,210	469,514,634	381,355,254	303,317,310	251,848,705	263,368,494	269,025,643	244,964,421	277,088,456	357,500,335	483,522,631	4,339,808,424
Domestic TOU		38,466,405	37,040,323	37,341,232	26,804,092	18,451,412	11,652,509	10,408,446	11,407,642	10,875,043	14,948,819	22,875,835	40,256,492	280,528,250
Domestic Total		**577,508,737**	**536,300,533**	**506,855,866**	**408,159,346**	**321,768,722**	**263,501,214**	**273,776,940**	**280,433,284**	**255,839,463**	**292,037,276**	**380,376,169**	**523,779,123**	**4,620,336,674**
Small General		37,227,238	29,902,146	31,656,093	24,302,374	21,759,149	19,394,384	21,395,023	20,784,137	18,555,967	20,095,889	22,558,748	27,868,175	295,499,323
General		241,911,585	219,073,473	226,161,016	190,723,503	180,131,332	183,195,964	198,374,672	196,060,332	181,016,441	188,847,563	204,497,554	228,949,253	2,438,942,688
Large General		34,045,826	30,942,678	32,754,121	29,199,107	31,208,288	31,371,750	37,146,165	38,898,817	33,883,275	32,069,832	30,544,621	32,351,985	394,416,464
Small Industrial		27,376,384	22,035,830	24,061,579	19,556,423	20,966,582	21,893,747	23,010,565	20,374,741	19,635,419	18,239,423	21,848,906	24,270,542	263,270,142
Medium Industrial		37,799,717	37,285,300	34,981,657	37,763,788	37,368,222	40,175,929	41,764,488	39,823,474	38,937,583	39,444,599	40,681,503	39,845,736	465,871,997
Large Industrial														
Large Industrial - Firm		10,327,580	8,353,534	11,287,186	10,122,085	10,672,614	10,457,465	10,973,987	11,371,200	10,201,318	10,786,067	10,071,687	11,696,413	126,321,137
Large Industrial - Interruptible		55,355,099	52,255,810	55,110,071	52,602,083	56,259,191	53,235,049	60,217,640	65,021,064	59,268,771	62,116,163	58,950,656	52,642,044	683,033,642
Large Industrial - Total		**65,682,679**	**60,609,343**	**66,397,257**	**62,724,168**	**66,931,805**	**63,692,514**	**71,191,627**	**76,392,264**	**69,470,090**	**72,902,230**	**69,022,344**	**64,338,457**	**809,354,778**
ELI 2P-RTP (Adjusted CBL)														-
Municipal														
Full Service Requirement Customers		5,332,514	5,183,662	5,022,259	4,160,086	3,973,837	3,755,307	3,588,202	3,564,310	3,473,423	3,627,628	3,974,843	4,471,999	50,128,069
Partial Service Requirement Customers														
Customer A		5,934,417	5,722,359	4,095,140	1,828,962	2,809,577	2,448,055	2,921,085	2,831,996	2,766,690	3,159,119	4,178,697	4,915,354	43,611,452
Customer B		2,268,406	2,068,789	1,588,865	1,032,546	941,493	931,693	1,487,451	1,526,545	1,423,221	1,579,081	1,645,056	2,018,865	18,512,011
Customer C		1,111,019	1,066,407	913,455	655,475	425,286	406,499	407,044	400,465	350,281	489,408	709,008	948,798	7,883,146
Customer D		798,466	754,142	661,218	439,753	237,612	235,825	220,060	234,228	206,837	288,162	463,727	660,899	5,200,931
Municipal Total		**15,444,822**	**14,795,359**	**12,280,938**	**8,116,822**	**8,387,805**	**7,777,379**	**8,623,842**	**8,557,544**	**8,220,453**	**9,143,398**	**10,971,331**	**13,015,916**	**125,335,609**
Unmetered		**7,268,903**	**6,425,767**	**6,765,977**	**7,670,511**	**6,890,697**	**6,570,987**	**6,993,330**	**6,965,682**	**6,771,769**	**5,874,924**	**6,758,975**	**6,412,269**	81,369,792
ATL Total		**1,044,265,891**	**957,370,429**	**941,914,505**	**788,216,043**	**695,412,603**	**637,573,868**	**682,276,653**	**688,290,274**	**632,330,460**	**678,655,134**	**787,260,153**	**960,831,456**	**9,494,397,468**
Check														
BTL Classes														
[redacted]														
BTL Total		**91,000,080**	**64,791,339**	**69,467,812**	**84,283,002**	**105,158,681**	**87,072,176**	**99,257,283**	**102,825,621**	**99,912,918**	**104,648,623**	**96,759,039**	**107,621,980**	1,112,798,554
In-Province Total Sales		**1,135,265,971**	**1,022,161,768**	**1,011,382,316**	**872,499,045**	**800,571,283**	**724,646,044**	**781,533,937**	**791,115,895**	**732,243,378**	**783,303,757**	**884,019,192**	**1,068,453,436**	**10,607,196,023**
Export kWh Sales	+	4,927,000	15,714,000	55,680,000	1,098,000	4,675,000	4,028,180	579,716	2,763,059	21,059,372	10,526,459	13,539,518	2,978,744	**137,569,048**
Total Electric Sales		**1,140,192,971**	**1,037,875,768**	**1,067,062,316**	**873,597,045**	**805,246,283**	**728,674,224**	**782,113,653**	**793,878,954**	**753,302,750**	**793,830,216**	**897,558,710**	**1,071,432,180**	**10,744,765,070**
In Province Losses		81,972,273	84,589,575	49,858,131	55,468,325	47,866,274	41,453,716	47,639,344	52,288,858	58,014,337	65,195,282	76,123,057	83,819,711	**744,288,884**
NSR		**1,217,238,244**	**1,106,751,343**	**1,061,240,447**	**927,967,370**	**848,437,558**	**766,099,760**	**829,173,281**	**843,404,753**	**790,257,715**	**848,499,040**	**960,142,249**	**1,152,273,148**	**11,351,484,907**
Export kWh Losses	-	60,000	862,000	2,974,000	51,000	-	-	-	-	-	-	-	-	3,947,000
Total System Requirement		1,222,225,244	1,123,327,343	1,119,894,447	929,116,370	853,112,558	770,127,940	829,752,997	846,167,812	811,317,087	859,025,499	973,681,767	1,155,251,892	11,493,000,955

2019-BCF Recovered Fuel Costs

ATL Classes													
Domestic Total	$36,504,327	$33,899,557	$32,038,359	$25,799,752	$20,339,001	$16,655,912	$17,305,440	$17,726,188	$16,171,612	$18,459,676	$24,043,578	$33,108,078	$292,051,481
Small General	$2,376,959	$1,909,252	$2,021,242	$1,551,707	$1,389,322	$1,238,331	$1,366,072	$1,327,067	$1,184,798	$1,283,123	$1,440,376	$1,779,383	18,867,632
General	$13,984,909	$12,664,637	$13,074,368	$11,025,726	$10,413,392	$10,590,559	$11,468,040	$11,334,248	$10,464,560	$10,917,278	$11,822,004	$13,235,556	140,995,277
Large General	$2,135,695	$1,941,034	$2,054,666	$1,831,660	$1,957,696	$1,967,950	$2,330,179	$2,440,123	$2,125,498	$2,011,741	$1,916,064	$2,029,440	24,741,745
Small Industrial	$1,575,237	$1,267,942	$1,384,503	$1,125,277	$1,206,417	$1,259,766	$1,324,028	$1,172,363	$1,129,822	$1,049,496	$1,257,186	$1,396,527	15,148,564
Medium Industrial	$2,079,362	$2,051,064	$1,924,341	$2,077,386	$2,055,626	$2,210,078	$2,297,464	$2,190,689	$2,141,956	$2,169,847	$2,237,889	$2,191,914	25,627,619
Large Industrial													
Large Industrial - Firm	$547,568	$442,904	$598,447	$536,673	$565,862	$554,455	$581,841	$602,901	$540,874	$571,877	$534,001	$620,144	6,697,547
Large Industrial - Interruptible	$2,962,051	$2,796,208	$2,948,940	$2,814,737	$3,010,429	$2,848,607	$3,222,246	$3,479,277	$3,171,472	$3,323,836	$3,154,450	$2,816,876	36,549,130
Large Industrial - Total	$3,509,620	$3,239,113	$3,547,387	$3,351,410	$3,576,291	$3,403,062	$3,804,087	$4,082,178	$3,712,346	$3,895,713	$3,688,450	$3,437,020	43,246,677
ELI 2P-RTP													
Municipal													
Full Service Requirement Customers	[redacted]												2,811,683
Partial Service Requirement Customers													
Customer A	$332,861	$320,967	$229,696	$102,587	$157,589	$137,311	$163,844	$158,847	$155,184	$177,195	$234,383	$275,702	2,446,166
Customer B	$127,235	$116,038	$89,119	$57,916	$52,808	$52,259	$83,431	$85,624	$79,828	$88,571	$92,271	$113,238	1,038,339
Customer C	$62,317	$59,815	$51,236	$36,766	$23,854	$22,801	$22,831	$22,462	$19,647	$27,451	$39,768	$53,218	442,166
Customer D	$44,786	$42,300	$37,088	$24,666	$13,328	$13,227	$12,343	$13,138	$11,601	$16,163	$26,010	$37,070	291,720
Municipal Total	$866,300	$829,872	$688,838	$455,273	$470,472	$436,233	$483,711	$479,993	$461,085	$512,853	$615,382	$730,063	**7,030,074**
Unmetered	$409,821	$362,285	$381,466	$432,463	$388,497	$370,472	$394,284	$392,725	$381,792	$331,228	$381,071	$361,524	4,587,629
Subtotal	63,442,229.83	58,164,755.51	57,115,169.52	47,650,653.49	41,796,714.64	38,132,363.44	40,773,305.74	41,145,573.42	37,773,471.12	40,630,955.29	47,402,000.48	58,269,504.65	572,296,697
			$57,115,170	-									

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2018-BCF **Simulated** Collected Fuel Costs														
ATL Classes														
Domestic Non-TOU	**6.321**	$34,072,866	$31,558,238	$29,678,020	$24,105,466	$19,172,687	$15,919,357	$16,647,523	$17,005,111	$15,484,201	$17,514,761	$22,597,596	$30,563,466	274,319,290
Domestic TOU	**6.321**	$2,431,461	$2,341,319	$2,360,339	$1,694,287	$1,166,314	$736,555	$657,918	$721,077	$687,411	$944,915	$1,445,982	$2,544,613	17,732,191
Domestic Total	**6.321**	$36,504,327	$33,899,557	$32,038,359	$25,799,752	$20,339,001	$16,655,912	$17,305,440	$17,726,188	$16,171,612	$18,459,676	$24,043,578	$33,108,078	292,051,481
Small General	**6.385**	$2,376,959	$1,909,252	$2,021,242	$1,551,707	$1,389,322	$1,238,331	$1,366,072	$1,327,067	$1,184,798	$1,283,123	$1,440,376	$1,779,383	18,867,632
General	**5.781**	$13,984,909	$12,664,637	$13,074,368	$11,025,726	$10,413,392	$10,590,559	$11,468,040	$11,334,248	$10,464,560	$10,917,278	$11,822,004	$13,235,556	140,995,277
Large General	**6.273**	$2,135,695	$1,941,034	$2,054,666	$1,831,660	$1,957,696	$1,967,950	$2,330,179	$2,440,123	$2,125,498	$2,011,741	$1,916,064	$2,029,440	24,741,745
Small Industrial	**5.754**	$1,575,237	$1,267,942	$1,384,503	$1,125,277	$1,206,417	$1,259,766	$1,324,028	$1,172,363	$1,129,822	$1,049,496	$1,257,186	$1,396,527	15,148,564
Medium Industrial	**5.501**	$2,079,362	$2,051,064	$1,924,341	$2,077,386	$2,055,626	$2,210,078	$2,297,464	$2,190,689	$2,141,956	$2,169,847	$2,237,889	$2,191,914	25,627,619
Large Industrial														
Large Industrial - Firm	**5.302**	$547,568	$442,904	$598,447	$536,673	$565,862	$554,455	$581,841	$602,901	$540,874	$571,877	$534,001	$620,144	6,697,547
Large Industrial - Interruptible	**5.351**	$2,962,051	$2,796,208	$2,948,940	$2,814,737	$3,010,429	$2,848,607	$3,222,246	$3,479,277	$3,171,472	$3,323,836	$3,154,450	$2,816,876	36,549,130
Large Industrial - Total		$3,509,620	$3,239,113	$3,547,387	$3,351,410	$3,576,291	$3,403,062	$3,804,087	$4,082,178	$3,712,346	$3,895,713	$3,688,450	$3,437,020	43,246,677
ELI 2P-RTP	**-**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	-
Municipal														
Full Service Requirement Customers	**5.609**	$299,101	$290,752	$281,699	$233,339	$222,892	$210,635	$201,262	$199,922	$194,824	$203,474	$222,949	$250,834	2,811,683
Partial Service Requirement Customers														-
Customer A	**5.609**	$332,861	$320,967	$229,696	$102,587	$157,589	$137,311	$163,844	$158,847	$155,184	$177,195	$234,383	$275,702	2,446,166
Customer B	**5.609**	$127,235	$116,038	$89,119	$57,916	$52,808	$52,259	$83,431	$85,624	$79,828	$88,571	$92,271	$113,238	1,038,339
Customer C	**5.609**	$62,317	$59,815	$51,236	$36,766	$23,854	$22,801	$22,831	$22,462	$19,647	$27,451	$39,768	$53,218	442,166
Customer D	**5.609**	$44,786	$42,300	$37,088	$24,666	$13,328	$13,227	$12,343	$13,138	$11,601	$16,163	$26,010	$37,070	291,720
Municipal Total	**5.466**	$866,300	$829,872	$688,838	$455,273	$470,472	$436,233	$483,711	$479,993	$461,085	$512,853	$615,382	$730,063	7,030,074
Unmetered	**5.638**	$409,821	$362,285	$381,466	$432,463	$388,497	$370,472	$394,284	$392,725	$381,792	$331,228	$381,071	$361,524	4,587,629
Subtotal	**-**	$63,442,230	$58,164,756	$57,115,170	$47,650,653	$41,796,715	$38,132,363	$40,773,306	$41,145,573	$37,773,471	$40,630,955	$47,402,000	$58,269,505	$572,296,697

2018-Variance														
ATL Classes														
Domestic Total		$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
ELI 2P-RTP		$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
Full Service Requirement Customers														
Partial Service Requirement Customers		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer A		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer B		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer C		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer D		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal Total		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Unmetered		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0

Biomass Calculations

($ in millions)	2019 Budget(January to March Actuals)		
Capital	[redacted]	28.2	91.3%
Fuel			
Operating			
Total	30.9	100.0%	

data came from CA IR-065P Confidential from the COSS Proceeding

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Annual Peak of ATL Classes	2,079,116	
Annual Energy Requirement of ATL	10,212,526,081	
System Coincident Load Factor	**0.5607**	0.5605
Wind Fixed - Energy Related	**0.7000**	0.700

Generation Rate Base		**Initial Classification**			**Further Classification**			**Fully Classified**		
	Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$1,370,532	$1,191,036	$179,496	$0	($667,814)	$667,814	$0	$523,222	$847,310	$ -
Hydro Plant	371,461	366,637	4,824	0	($205,573)	$205,573	0	$161,064	$210,397	$ -
Wind Plant	201,182	30,599	170,583	0	($21,419)	$21,419	0	$9,180	$192,002	$ -
LM6000 Plant	71,417	71,417	0	0	($40,044)	$40,044	0	$31,373	$40,044	$ -
Gas Turbine Plant - Other	6,513	6,513	0	0	$0	$0	0	$6,513	$0	$ -
Total Generation Plant	2,021,105	1,666,202	354,903	0	($934,850)	$934,850	0	$731,352	$1,289,753	$ -
General Property Plant	150,810	124,328	26,482	0	-$69,756.36	$69,756	0	$54,572	$96,238	$ -
Total Plant in Service	2,171,915	1,790,530	381,385	0	($1,004,606)	$1,004,606	0	$785,924	$1,385,991	$ -
								36.19%	**63.81%**	

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

6.96%

2020 BA Amounts

FOR THE YEAR ENDING DECEMBER 31, 2019

Line # 3 5 7 8 9 10

7%

FAM Classes	2019 BA Amount	2019 BA - Items from 2019 before interest			2019 BA Interest Allocation		2019 AA				DSM HST Refund (inclusive of E1's interest)			2020 FAM BA			2020 FAM BA Riders			
	2019 BA Amount	BA Credit to customers in 2019 paid under One Time Payout	Fixed Cost Deferral Credit-Year End 2019	Final 2019 BA Amount bfr Interest	Amount	Interest	2020 Beginning AA Balance	AA Credit to customers in 2020 paid under One Time Payout	Total Before Interest	Interest	Norminal Amount before interest [1]	Interest Accured by E1	Total before NS Power's Interest	FAM BA Total bfr Interest	Interest	FAM 2019 BA Total	Amount owed by departing load to non-FAM classes	Amount to be paid or credited through riders	Forecast kWh Sales	Cents per kWh
Residential	($98,634,396)	$1,367	($119,442)	($118,075)	($98,752,471)	($6,916,536)	$4,881,721	$18,762,551	$23,644,272	$1,418,462	($7,598,541)	($697,871)	($8,296,412)	($83,404,611)	($5,498,074)	($88,902,685)		($88,902,685)	4,493,317,762	(1.979)
Small General	($4,594,761)	$82	($5,962)	($5,880)	($4,600,642)	($322,225)	$254,914	$956,420	$1,211,334	$72,670	($1,127,675)	($103,569)	($1,231,244)	($4,620,552)	($249,555)	($4,870,106)		($4,870,106)	286,830,917	(1.698)
General Demand	($49,173,609)	$0	($53,009)	($53,009)	($49,226,618)	($3,447,789)	$6,555,949	$8,383,296	$14,939,245	$896,232	($3,790,082)	($348,092)	($4,138,174)	($38,425,547)	($2,551,557)	($40,977,104)		($40,977,104)	2,392,958,563	(1.712)
Large General	($461,205)	$0	($6,784)	($6,784)	($467,989)	($32,778)	($648,866)	$1,262,699	$613,834	$36,825	($289,120)	($26,554)	($315,674)	($169,829)	$4,047	($165,782)		($165,782)	392,840,580	(0.042)
Small Industrial	($5,036,675)	$0	($5,313)	($5,313)	($5,041,987)	($353,136)	$766,879	$879,997	$1,646,876	$98,799	($350,313)	($32,174)	($382,487)	($3,777,598)	($254,337)	($4,031,935)		($4,031,935)	250,444,410	(1.610)
Medium Industrial	($5,856,912)	$0	($9,388)	($9,388)	($5,866,300)	($410,870)	$1,060,264	$1,429,923	$2,490,188	$149,391	($238,213)	($21,878)	($260,092)	($3,636,204)	($261,480)	($3,897,683)		($3,897,683)	474,373,865	(0.822)
Firm	($1,148,565)	$0	($2,029)	($2,029)	($1,150,594)	($80,587)	$207,455	$315,915	$523,370	$31,398	($56,951.93)	($5,231)	($62,183)	($689,407)	($49,189)	($738,596)		($738,596)	128,040,889	(0.577)
Interruptible	($8,962,486)	$0	($10,971)	($10,971)	($8,973,457)	$488,414.77	$1,121,736	$1,908,636	$3,030,372	$181,797	($307,946)	($28,283)	($336,229)	($4,279,313)	($306,617)	($4,585,930)		($4,585,930)	733,874,528	(0.625)
Large Industrial Total	($8,111,052)	$0	($13,000)	($13,000)	($8,124,051)	($569,001)	$1,329,192	**$2,224,551**	$3,553,742	$213,195	($364,898)	($33,513)	($398,411)	($4,968,720)	($355,806)	($5,324,526)		($5,324,526)	861,915,417	(1.202)
Municipal																				
Customers staying	($892,301)	$0	($911)	($911)	($893,212)	($62,560)	($52,504)	$187,900	$135,395	$8,123	($104,858)	($9,630)	($114,488)	($872,305)	($54,437)	($926,742)		($926,742)		(1.157)
Customers migrating to OATT				$0																
Customer A	($946,900)	$0	($1,801)	($1,801)	($948,701)	($66,446)	$360,256	$163,473	$523,729	$31,419	($102,277)	($9,393)	($111,671)	($536,642)	($35,027)	($571,669)	($235,066)	($336,603)		(1.157)
Customer B	($416,859)	$0	($613)	($613)	($417,472)	($29,239)	$154,588	$69,390	$223,978	$13,437	($40,690)	($3,737)	($44,427)	($237,921)	($15,903)	($253,723)	($103,271)	($150,453)		(1.157)
Customer C	($130,006)	$0	($253)	($253)	($130,259)	($9,123)	$64,341	$29,549	$93,890	$5,633	($16,489)	($1,514)	($18,004)	($54,373)	($3,491)	($57,863)	($28,142)	($29,721)		(1.157)
Customer D	($70,295)	$0	($165)	($165)	($70,460)	($4,935)	$52,261	$19,495	$71,756	$4,305	($10,602)	($974)	($11,576)	($10,280)	($630)	($10,911)	($9,963)	($947)		(1.157)
Municipal - Total	($2,456,361)	$0	($3,743)	($3,743)	($2,460,104)	($172,304)	$578,942	$469,807	$1,048,749	$62,916	($274,916)	($25,249)	($300,165)	($1,711,521)	($109,387)	($1,820,908)	($376,442)	($1,444,466)	124,819,979	(1.157)
Unmetered	($2,291,323)	$0	($3,303)	($3,303)	($2,294,626)	($160,714)	$517,145	$76,427	$593,572	$35,609	($82,379)	($7,566)	($89,945)	($1,790,999)	($125,104)	($1,916,103)		($1,916,103)	81,034,159	(2.365)
Above the line Subtotal / Average	($176,616,295)	$1,450	($219,943)	($218,494)	($176,834,788)	($12,385,352)	$15,296,140	**$34,445,672**	**$49,741,811**	**$2,984,100**	**($14,116,138)**	**($1,296,465)**	**($15,412,604)**	($142,505,581)	($9,401,252)	($151,906,833)	($376,442)	($151,530,392)	9,358,535,650	

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Matter M09096 - EfficiencyOne Stakeholders Consensus Agreement: Issue 8 - Disposition of HST refund and interest;20190228 E1 to UARB 2020-2022 EfficiencyOne DSM Resource Plan Application - Appendix F, Summary Tab, column K

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2019 -kWh Sales(Jan-Feb Actuals		Actual				Reprojection									
		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2,019	
ATL Classes															
Domestic Non-TOU		539,042,332	499,260,210	469,514,634	381,355,254	303,317,310	251,848,705	263,368,494	269,025,643	244,964,421	277,088,456	357,500,335	483,522,631	4,339,808,424	
Domestic TOU		38,466,405	37,040,323	37,341,232	26,804,092	18,451,412	11,652,509	10,408,446	11,407,642	10,875,043	14,948,819	22,875,835	40,256,492	280,528,250	
Domestic Total		**577,508,737**	**536,300,533**	**506,855,866**	**408,159,346**	**321,768,722**	**263,501,214**	**273,776,940**	**280,433,284**	**255,839,463**	**292,037,276**	**380,376,169**	**523,779,123**	**4,620,336,674**	
Small General		**37,227,238**	**29,902,146**	**31,656,093**	**24,302,374**	**21,759,149**	**19,394,384**	**21,395,023**	**20,784,137**	**18,555,967**	**20,095,889**	**22,558,748**	**27,868,175**	295,499,323	
General		**241,911,585**	**219,073,473**	**226,161,016**	**190,723,503**	**180,131,332**	**183,195,964**	**198,374,672**	**196,060,332**	**181,016,441**	**188,847,563**	**204,497,554**	**228,949,253**	2,438,942,688	
Large General		**34,045,826**	**30,942,678**	**32,754,121**	**29,199,107**	**31,208,288**	**31,371,750**	**37,146,165**	**38,898,817**	**33,883,275**	**32,069,832**	**30,544,621**	**32,351,985**	394,416,464	
Small Industrial		**27,376,384**	**22,035,830**	**24,061,579**	**19,556,423**	**20,966,582**	**21,893,747**	**23,010,565**	**20,374,741**	**19,635,419**	**18,239,423**	**21,848,906**	**24,270,542**	263,270,142	
Medium Industrial		**37,799,717**	**37,285,300**	**34,981,657**	**37,763,788**	**37,368,222**	**40,175,929**	**41,764,488**	**39,823,474**	**38,937,583**	**39,444,599**	**40,681,503**	**39,845,736**	465,871,997	
Large Industrial															
Customer A															
Large Industrial - Firm		10,327,580	8,353,534	11,287,186	10,122,085	10,672,614	10,457,465	10,973,987	11,371,200	10,201,318	10,786,067	10,071,687	11,696,413	126,321,137	
Large Industrial - Interruptible		55,355,099	52,255,810	55,110,071	52,602,083	56,259,191	53,235,049	60,217,640	65,021,064	59,268,771	62,116,163	58,950,656	52,642,044	683,033,642	
Large Industrial - Total		**65,682,679**	**60,609,343**	**66,397,257**	**62,724,168**	**66,931,805**	**63,692,514**	**71,191,627**	**76,392,264**	**69,470,090**	**72,902,230**	**69,022,344**	**64,338,457**	**809,354,778**	
ELI 2P-RTP (Adjusted CBL)														-	
Municipal															
Customers staying on in 2015		5,332,514	5,183,662	5,022,259	4,160,086	3,973,837	3,755,307	3,588,202	3,564,310	3,473,423	3,627,628	3,974,843	4,471,999	50,128,069	
															OATT % Split
Customers migrating to OATT in 2015															
Customer A		5,934,417	5,722,359	4,095,140	1,828,962	2,809,577	2,448,055	2,921,085	2,831,996	2,766,690	3,159,119	4,178,697	4,915,354	43,611,452	[redacted]
Customer B		2,268,406	2,068,789	1,588,865	1,032,546	941,493	931,693	1,487,451	1,526,545	1,423,221	1,579,081	1,645,056	2,018,865	18,512,011	
Customer C		1,111,019	1,066,407	913,455	655,475	425,286	406,499	407,044	400,465	350,281	489,408	709,008	948,798	7,883,146	
Customer D		798,466	754,142	661,218	439,753	237,612	235,825	220,060	234,228	206,837	288,162	463,727	660,899	5,200,931	
Municipal Total		**15,444,822**	**14,795,359**	**12,280,938**	**8,116,822**	**8,387,805**	**7,777,379**	**8,623,842**	**8,557,544**	**8,220,453**	**9,143,398**	**10,971,331**	**13,015,916**	**125,335,609**	
Unmetered		**7,268,903**	**6,425,767**	**6,765,977**	**7,670,511**	**6,890,697**	**6,570,987**	**6,993,330**	**6,965,682**	**6,771,769**	**5,874,924**	**6,758,975**	**6,412,269**	81,369,792	
ATL Total		**1,044,265,891**	**957,370,429**	**941,914,505**	**788,216,043**	**695,412,603**	**637,573,868**	**682,276,653**	**688,290,274**	**632,330,460**	**678,655,134**	**787,260,153**	**960,831,456**	**9,494,397,468**	
BTL Classes															
[redacted]															
In-Province Total Sales		**1,135,265,971**	**1,022,161,768**	**1,011,382,316**	**872,499,045**	**800,571,283**	**724,646,044**	**781,533,937**	**791,115,895**	**732,243,378**	**783,303,757**	**884,019,192**	**1,068,453,436**	**10,607,196,023**	
Export kWh Sales	**+**	4,927,000	15,714,000	55,680,000	1,098,000	4,675,000	4,028,180	579,716	2,763,059	21,059,372	10,526,459	13,539,518	2,978,744	**137,569,048**	
Total Electric Sales		**1,140,192,971**	**1,037,875,768**	**1,067,062,316**	**873,597,045**	**805,246,283**	**728,674,224**	**782,113,653**	**793,878,954**	**753,302,750**	**793,830,216**	**897,558,710**	**1,071,432,180**	**10,744,765,070**	
In Province Losses		81,972,273	84,589,575	49,858,131	55,468,325	47,866,274	41,453,716	47,639,344	52,288,858	58,014,337	65,195,282	76,123,057	83,819,711	**744,288,884**	
NSR		**1,217,238,244**	**1,106,751,343**	**1,061,240,447**	**927,967,370**	**848,437,558**	**766,099,760**	**829,173,281**	**843,404,753**	**790,257,715**	**848,499,040**	**960,142,249**	**1,152,273,148**	**11,351,484,907**	
Export kWh Losses	**-**	60,000	862,000	2,974,000	51,000	-	-	-	-	-	-	-	-	3,947,000	
Total System Requirement		1,222,225,244	1,123,327,343	1,119,894,447	929,116,370	853,112,558	770,127,940	829,752,997	846,167,812	811,317,087	859,025,499	973,681,767	1,155,251,892	11,493,000,955	1,171
													11,493,000,955		

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2019 -kWh Sales(Jan-Feb Actuals	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2,019
2018 ML Payout paid in 2019-AA.													
	Jan-19	**Feb-19**	**Mar-19**	**Apr-19**	**May-19**	**Jun-19**	**Jul-19**	**Aug-19**	**Sep-19**	**Oct-19**	**Nov-19**	**Dec-19**	**2018**
ATL Classes													
Domestic Total	$12	$0	$9,407,349	$9,355,190	$0	$0	$0	$0	$0	$0	$0	$0	$18,762,551
Small General	$0	$0	$583,887	$372,533	$0	$0	$0	$0	$0	$0	$0	$0	$956,420
General	$628	$0	$5,536,997	$2,845,671	$0	$0	$0	$0	$0	$0	$0	$0	$8,383,296
Large General	$1,262,419	$280	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,262,699
Small Industrial	$0	$0	$593,777	$286,220	$0	$0	$0	$0	$0	$0	$0	$0	$879,997
Medium Industrial	$38,145	$0	$577,392	$814,385	$0	$0	$0	$0	$0	$0	$0	$0	$1,429,923
Large Industrial													$0
Large Industrial - Firm	$315,834	$81	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$315,915
Large Industrial - Interruptible	$1,908,411	$225	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$1,908,636
Large Industrial - Total													
ELI 2P-RTP													
Municipal													
Customers staying on in 2015													
Customers migrating to OATT in 2015													
Customer A													
Customer B													
Customer C													
Customer D													
Municipal Total	$469,437	$370	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$469,807
Unmetered	$0	$0	$0	$76,427	$0	$0	$0	$0	$0	$0	$0	$0	$76,427
Subtotal	$3,994,886	$956	$16,699,403	$13,750,425	$0	$0	$0	$0	$0	$0	$0	$0	$34,445,672

2018 ML Payout paid in 2019-BA.													
	18-Jan	**18-Feb**	**18-Mar**	**18-Apr**	**18-May**	**18-Jun**	**18-Jul**	**18-Aug**	**18-Sep**	**18-Oct**	**18-Nov**	**18-Dec**	**2018**
ATL Classes													
Domestic Total	$706	$228	$256	$178	$0	$0	$0	$0	$0	$0	$0	$0	$1,367
Small General	$0	$38	$34	$10	$0	$0	$0	$0	$0	$0	$0	$0	$82
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													
Large Industrial - Firm	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large Industrial - Interruptible	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Large Industrial - Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
ELI 2P-RTP													
Municipal													
Customers staying on in 2015													
Customers migrating to OATT in 2015	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer A	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer B	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer C	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Customer D	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Municipal Total	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Unmetered	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal	$706.1600	$265	$289	$189	$0	$0	$0	$0	$0	$0	$0	$0	$1,450
											$0	$0	

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2019 -kWh Sales(Jan-Feb Actuals	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2,019
2018-kWh Sales-Actuals													
ATL Classes													
Domestic Non-TOU	536,265,495	436,427,593	442,448,444	374,351,339	303,902,965	240,934,327	278,652,663	275,706,533	242,024,054	287,471,601	390,063,983	498,233,847	4,306,482,845
Domestic TOU	37,100,969	32,198,498	33,789,543	26,823,414	17,303,538	10,664,973	11,591,345	11,855,068	9,899,793	15,202,472	26,702,203	41,396,017	274,527,834
Domestic Total	**573,366,464**	**468,626,091**	**476,237,987**	**401,174,753**	**321,206,503**	**251,599,300**	**290,244,009**	**287,561,601**	**251,923,847**	**302,674,073**	**416,766,186**	**539,629,864**	**4,581,010,679**
Small General	**35,955,548**	**28,395,767**	**28,104,635**	**22,013,951**	**22,939,125**	**18,374,757**	**21,805,095**	**21,086,860**	**19,230,463**	**21,049,256**	**24,018,127**	**28,425,332**	291,398,915
General	**234,895,343**	**218,801,428**	**209,173,371**	**198,712,520**	**173,884,960**	**179,888,656**	**198,244,118**	**192,775,819**	**174,900,462**	**193,797,139**	**203,501,103**	**232,472,476**	2,411,047,394
Large General	**34,181,491**	**30,706,264**	**33,387,338**	**32,434,903**	**30,433,761**	**31,601,573**	**37,521,336**	**39,519,681**	**33,951,632**	**32,373,255**	**30,124,210**	**32,862,485**	399,097,929
Small Industrial	**24,663,893**	**20,530,718**	**21,120,830**	**18,727,693**	**21,243,016**	**19,371,698**	**23,870,526**	**19,810,159**	**20,580,369**	**17,185,957**	**23,707,012**	**22,475,011**	253,286,884
Medium Industrial	**42,131,138**	**38,070,781**	**41,095,098**	**40,160,817**	**37,732,964**	**40,302,245**	**40,683,700**	**37,446,646**	**36,185,341**	**37,435,749**	**38,931,181**	**39,431,141**	469,606,802
Large Industrial													
Large Industrial - Firm	8,250,939	7,145,524	8,549,887	8,151,102	8,027,297	9,039,928	9,570,803	10,590,008	8,041,475	10,061,426	9,458,602	11,125,657	108,012,648
Large Industrial - Interruptible	50,527,952	47,999,734	50,960,920	50,899,234	55,723,247	52,714,055	55,607,524	60,819,496	54,750,025	57,164,932	54,510,078	46,176,867	637,854,065
Large Industrial - Total	**58,778,891**	**55,145,258**	**59,510,807**	**59,050,336**	**63,750,544**	**61,753,983**	**65,178,327**	**71,409,504**	**62,791,500**	**67,226,358**	**63,968,680**	**57,302,524**	**745,866,713**
ELI 2P-RTP (Adjusted CBL)													-
Municipal													
Customers staying on in 2015	5,396,397	4,513,728	4,496,384	4,213,291	3,567,548	3,240,101	3,702,014	3,729,023	3,205,088	3,491,692	4,335,400	5,165,716	49,056,382
Customers migrating to OATT in 2015													
Customer A	6,549,011	5,580,043	5,171,573	3,949,046	2,457,944	2,149,683	2,867,794	2,962,868	2,570,622	3,266,440	4,556,461	5,767,756	47,849,242
Customer B	2,458,987	1,945,295	1,719,248	1,095,587	823,660	818,137	1,460,315	1,597,089	1,322,361	1,632,725	1,793,773	2,368,969	19,036,148
Customer C	1,100,708	853,070	850,908	644,157	372,059	356,955	399,618	418,971	325,458	506,034	773,104	1,113,335	7,714,377
Customer D	795,368	571,692	526,003	419,727	207,874	207,082	216,045	245,052	192,179	297,951	505,650	775,510	4,960,135
Municipal Total	**16,300,472**	**13,463,828**	**12,764,117**	**10,321,809**	**7,429,086**	**6,771,958**	**8,645,786**	**8,953,004**	**7,615,708**	**9,194,842**	**11,964,388**	**15,191,287**	**128,616,283**
Unmetered	**7,183,765**	**5,689,536**	**7,029,662**	**7,408,689**	**6,784,053**	**6,298,001**	**7,171,916**	**6,778,055**	**6,642,461**	**6,257,552**	**7,199,046**	**6,487,035**	80,929,771
ATL Total	**1,027,457,004**	**879,429,671**	**888,423,846**	**790,005,472**	**685,404,011**	**615,962,173**	**693,364,813**	**685,341,330**	**613,821,784**	**687,194,181**	**820,179,933**	**974,277,155**	**9,360,861,371**
BTL Classes													
[redacted]													
BTL Total	**73,510,373**	**92,670,997**	**100,734,093**	**95,868,481**	**104,766,937**	**87,693,389**	**100,016,516**	**104,065,782**	**101,109,956**	**104,975,203**	**96,273,729**	**105,448,499**	1,167,133,957
In-Province Total Sales	**1,100,967,377**	**972,100,668**	**989,157,940**	**885,873,953**	**790,170,948**	**703,655,562**	**793,381,329**	**789,407,112**	**714,931,739**	**792,169,385**	**916,453,662**	**1,079,725,654**	**10,527,995,328**
Export kWh Sales +	16,214,000	28,991,000	3,194,000	4,687,000	4,272,000	8,200,119	2,053,000	355,000	6,259,000	9,236,000	3,547,000	1,511,000	**88,519,119**
Total Electric Sales	**1,117,181,377**	**1,001,091,668**	**992,351,940**	**890,560,953**	**794,442,948**	**711,855,681**	**795,434,329**	**789,762,112**	**721,190,739**	**801,405,385**	**920,000,662**	**1,081,236,654**	**10,616,514,447**
In Province Losses	88,659,339	51,032,366	74,106,951	38,078,494	31,843,359	43,961,549	42,946,499	55,077,401	50,199,205	74,615,060	22,154,632	35,442,394	**608,117,250**
NSR	**1,189,626,716**	**1,023,133,034**	**1,063,264,891**	**923,952,447**	**822,014,307**	**747,617,111**	**836,327,828**	**844,484,513**	**765,130,944**	**866,784,445**	**938,608,294**	**1,115,168,049**	**11,136,112,578**
Export kWh Losses -	479,000	1,212,000	106,000	153,000	121,000	273,881	60,000	8,000	170,000	349,000	110,000	67,000	3,108,881
Total System Requirement	1,206,319,716	1,053,336,034	1,066,564,891	928,792,447	826,407,307	756,091,111	838,440,828	844,847,513	771,559,944	876,369,445	942,265,294	1,116,746,049	11,227,740,578

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Fixed Cost Deferral Credit Allocation as based on 2014 Test

FAM Rate Classes	2014 Usage			2014 Test Year Rate Base ($ thousand)					
	Energy Requirement (kWh)	3CP (kW)	Customers	Energy-related	Demand-related	Customer-related	Total	Relative Share per Rate Base	Non-fuel deferral credit 2019
Residential								54.3%	-$119,442
Small General								2.7%	-$5,962
General Demand								24.1%	-$53,009
Large General								3.1%	-$6,784
Total Commercial								29.9%	-$65,755
Small Industrial								2.4%	-$5,313
Medium Industrial								4.3%	-$9,388
Large Industrial									
Customers staying on the rate	727,263,941	283,351	31	$144,448	$58,608	$60	$203,116	5.7%	-$12,471
Customer A moving some of its load to a Non-FAM rate in 2014	33,705,228	9,264	1	$6,694	$1,916	$2	$8,612	0.2%	-$529
Large Industrial Total(2)	**760,969,169**	**292,614**	**32**	**$151,142**	**$60,524**	**$62**	**$211,728**	**5.9%**	**-$13,000**
Total Industrial								12.6%	-$27,700
Municipal									
Customers staying on in 2015	51,640,940	29,548	2	$9,049	$5,790	$4	$14,843	0.4%	-$911
Customers migrating to OATT in 2015									
Customer A	100,068,911	60,136	3	$17,535	$11,784	$6	$29,326	0.8%	-$1,801
Customer B	35,893,647	18,865	1	$6,290	$3,697	$2	$9,989	0.3%	-$613
Customer C	13,351,001	9,090	1	$2,339	$1,781	$2	$4,123	0.1%	-$253
Customer D	8,438,932	6,179	1	$1,479	$1,211	$2	$2,692	0.1%	-$165
Municipal Total(2)	**209,393,431**	**123,818**	**8**	**$36,692**	**$24,264**	**$16**	**$60,972**	**1.7%**	**-$3,743**
Unmetered								1.5%	-$3,303
Total Other								3.2%	-$7,047
Total FAM Classes								**100.0%**	**($219,943.48)**

(COS Compliance Filing from July 31, 2014)

Class	Rate Base	Relative Share in Rate Base
(1) DOMESTIC	$1,945,386	54.3%
(2) SMALL GENERAL	$97,112	2.7%
(3) GENERAL	$863,366	24.1%
(4) LARGE GENERAL	$110,492	3.1%
(5) SMALL INDUSTRIAL	$86,528	2.4%
(6) MEDIUM INDUSTRIAL	$152,898	4.3%
(7) LARGE INDUSTRIAL	$211,728	5.9%
(9) MUNICIPAL	$60,971	1.7%
(10) UNMETERED	$53,801	1.5%
TOTAL	$3,582,281	100.0%

Fuel Adjustment Mechanism Plan of Administration in Effect for ~~2017-2019~~2020-2022

~~January 30~~June 27, 2019

NS Power
FUEL ADJUSTMENT MECHANISM
PLAN OF ADMINISTRATION IN EFFECT FOR ~~2017-2019~~2020-2022
~~January 30,~~June 27, 2019

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1.0 GENERAL DESCRIPTION

This document describes the plan for administering Nova Scotia Power Inc.'s (NS Power) Fuel Adjustment Mechanism (FAM), which was approved by the Nova Scotia Utility and Review Board (Board) in its decision letter issued on December 11, 2008. The FAM provides for the recovery of fuel and purchased power costs beginning January 1, 2009.

The Plan of Administration (POA) outlines the application and operation of the FAM. The Base Cost of Fuel will be calculated as set out in Section 2 "FAM COMPONENTS".

The Base Cost of Fuel can be reset in a General Rate Application, every second year as part of the FAM adjustment process, or as directed by legislation or an order of the Board[1]. A forecast of costs and load for each test year will be used to set the Base Cost of Fuel. During the Rate Stability Period, the Base Cost of Fuel is smoothed over three test years: ~~2017~~2020, ~~2018~~ 2021~~2~~ and ~~2019~~2022. The change in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the Cost of Service Study (COSS).

Stakeholders shall have the opportunity (and access to information) to challenge the implementation of the methodology and the contents of any forecast prior to its use in re-setting the Base Cost of Fuel. Both the implementation of the methodology and the forecasts will be the subject of a formal Board proceeding in which stakeholders will have their current rights as in general rate cases.

Stakeholders shall have the opportunity to challenge NS Power's fuel costs (and to secure access to information) at each annual or applicable hearing before the Board consistent with their current rights in general rate cases. The Board will also subject NS Power's FAM accounts to audits as per section 5.0 "Audit and Oversight" and as it deems appropriate.

[1] The Base Cost of Fuel is reset for 2017-2019 under the 2017-2019 Fuel Stability Plan as directed in section 4 of the *Electricity Plan Implementation (2015) Act*, S.N.S. 2015, c. 31.

The FAM will pass through the difference between actual costs and the Base Cost of Fuel to customers calculated on a ¢/kWh basis.

Interest will be added to all over/under-balance amounts and calculated at NS Power's ~~Allowance for Funds Used During Construction (AFUDC)~~Annual Weighted Average Cost of Capital (WACC).

The FAM will recover fuel cost changes resulting from over/under-recovery amounts, including an Actual Adjustment (AA) and a Balancing Adjustment (BA) for each rate class. The FAM adjustment is the difference between actual fuel cost and the Base Cost of Fuel) and will be calculated on a ¢/kWh basis.

2.0 FAM COMPONENTS

Each January 1 through December 31 period shall constitute a distinct FAM year. Under the FAM, an adjustment will normally be calculated once per year to reflect the over/-under recovery. During the Rate Stability Period, the annual effect of fuel cost increases on bundled rates will be smoothed by applying any over or under-recoveries to generate fixed annual percentage increases in class total revenues.

The FAM adjustment will consist of two components designed to provide for the recovery of fuel and purchased power costs. Those components are:

1. The Actual Adjustment Component (AA)

   a. Established at a rate expected to recover the amount of the difference between the prior FAM year's actual fuel and purchased power costs and those recovered through the Base Cost of Fuel Component to the end of September of the prior year and October to December of the year before that, making 12 months of actuals.

2. The Balancing Adjustment Component (BA)

   a. The Balancing Adjustment Component will provide for a correction to ensure that over/under-recovery produced by the Actual Adjustment Component is tracked and refunded to or recovered from customers. ~~will be adjusted to reflect differences in sales volumes between forecasts and actuals.~~

   b. The Balancing Adjustment Component may also include, subject to specific Board approval, deferrals of fuel and purchased power costs existing at the time of FAM adoption or that result from any future Board decision.

3.0 CALCULATION OF THE FAM RATE

NS Power's FAM is a forecasted base fuel rate operating on an annual cycle that includes an over/under recovery mechanism consisting of an Actual Adjustment (AA) and Balance Adjustment (BA).

The following formula will be used to determine the fuel adjustment factor (Fuel Adjustment Factor) for each upcoming FAM period:

Fuel Adjustment Mechanism Formula = AA + BA

Where:

1. AA is the Actual Adjustment that accounts for any differences between revenues collected through the application of the FAM during the previous one year period and actual Fuel Costs for each rate class (adjusted for the FAM incentive on an overall fuel cost basis) for the same one year period.~~; and~~

   The AA rate is calculated for the following year on the basis of the over- or under-recovery of the Base Cost of Fuel at the end of September (year 1). Any over- or under-recovery from October to December will not be included in the rate calculation and will be deferred for recovery until the year subsequent to the following year (year 3). The actual AA starting balance for the following year (year 2) is the over- or under-recovery of the Base Cost of Fuel at the end of December (year 1).

2. BA is the Balance Adjustment that accounts for any over- or under-recovery amounts resulting from prior adjustments. The BA will also be the mechanism used to manage any deferred fuel and purchased power costs approved by the Board for inclusion in the BA.

The BA rate is calculated for the following year (year 2) on the basis of the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of September (year 1). The actual BA starting balance for the following year (year 2) is the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of December (year 1).

Appendix "A" to this Plan of Administration titled "Sample FAM Calculations", provides a step by step detailed calculation of the overall Base Cost of Fuel, Actual Adjustment (AA), and Balancing Adjustment (BA) for a sequence of years starting in 2009. The applicable calculations illustrated in Appendix "A" will be used as outlined in the FAM Tariff in Appendix E.

Calculation of the Actual Adjustment Factor (AA) and Balancing Adjustment Factor (BA) FAM components will follow the fuel-related cost allocation methodology.

Actual (i.e. after the fact) fuel-related costs will be allocated in the same manner as the test year fuel-related costs used in setting base rates. In summary, this procedure will operate as follows:

1. A portion of the total fuel-related costs will be assigned to the following categories of non-FAM classes based on their fuel costing principles:

    a. The below-the-line bundled service rates for Generation Replacement and Load Following (GRLF), 1P-RTP and Shore Power classes.

    b. The Load Retention Tariff (LRT) class.

    c. The unbundled tariffs: Open Access Transmission Tariff (OATT), Wholesale Market Backup/Top-up Service Tariff (BUTU), Energy Balancing Service Tariff (EBS), Renewable to Retail Market Transition Tariff (RTT).

d. All remaining fuel-related costs will be allocated to ATL classes.

2. For ATL classes, NS Power's fuel costs will be classified as 100 percent energy-related. These costs will be allocated to each class based on its relative contribution to monthly energy requirement.

3. Fuel costs assigned to the Wholesale Market Non-Dispatchable Supplier Spill Tariff and Wholesale Market Backup/Top-up tariff will be based on avoidable fuel costs.

4. Purchased power and Import costs will be classified to demand and energy as follows.

   a. In-province purchased power from wind generation will be segregated between Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). Their classification between energy and demand related services will reflect concurrent generation planning practice of NS Power. For the rate setting purposes of the ~~2017~~2020-~~2019~~ 2022 Rate Stability Plan (RSP) the Company attributed to demand 17% of installed wind capacity of NRIS projects and 0% of ERIS projects.

   b. In-province purchased power from biomass generation will be classified between energy and demand in the same proportion as classification of total costs of the Port Hawkesbury biomass plant.

   c. In-province purchased power from all other sources than wind and biomass will be classified to demand and energy in the same manner as to NS Power's fixed cost base load generation.

d. Maritime Link imports under Nova Scotia Block will be classified to energy and demand on the basis of the system load factor associated with the above-the-line (FAM) classes.

e. Non-firm imports will be all classified to energy.

The demand-related portion of these costs will be allocated to each class based upon its relative coincident contribution to the three monthly system peaks (3CP) occurring in December, January and February. The energy portion of these costs, with the exception of the non-firm imports, will be allocated to each class based on its relative contribution to annual energy requirement. Non-firm imports will be allocated to each class based on its relative contribution to monthly energy requirements.

5. Export revenues are allocated to ATL classes based on monthly energy requirements.

6. For the AA and BA cost allocation purposes only, the variance between the budgeted and actual hedges for foreign exchange will be allocated to each ATL class based on its relative contribution to annual energy requirement. This does not apply to other fuel-related foreign exchange costs.

7. In order to ensure that allocated fuel-related costs are aligned with the revenue expected from approved rates for each class, the costs will be scaled up or down using the revenue-to-cost ratio (R/C ratio) for each class. The resultant costs by class will then be reconciled to the total ATL fuel-related costs based on their relative share of the total fuel costs.

8. The interest amount on the over- or under-recovery of fuel costs is apportioned to the individual rate classes at the end of the year on an annual basis using the following approach:

a. In a year where the interest amount owed to customers by NS Power at the end of ~~the year~~September coincides with an over-recovery of fuel costs ~~in~~ to the end of September in that year, or where the interest amount owed by customers to NS Power at the end of ~~the year~~September coincides with an under-recovery of fuel costs ~~in~~ to the end of September in the year, the interest amount will be apportioned to each class based on its relative share of the year-end fuel cost variance during that year.

b. In a year where there is an interest balance owed to customers even though there has been an under-recovery of fuel costs to the end of September, or there is an interest balance owed to NS Power even though there was an over-recovery of fuel costs, NS Power will apportion the outstanding interest balance to each rate class on the basis of the relative class shares in the actual annual fuel cost incurred by NS Power.

The apportioned interest expense or credit is added to the fuel cost variance by class to provide the total fuel and interest (over)/under-recovery amount by class.

In order to determine the factor to be used as the Actual Adjustment (AA) component of the FAM, fuel-related costs allocated to each class in base rates will be subtracted from actual fuel-related costs allocated to each rate class. The difference in costs will be divided by the forecast energy sales (i.e. excluding line losses) to yield a credit or additional charge (in cents/kWh) that would normally be applied to customers' bills for the subsequent year. For the Rate Stability Period, the AA/BA credit or charge (in cents/kWh) will be determined in ~~2016~~ 2019 for the entire Rate Stability Period. Any under/over recovered BCF amounts at the end of ~~2019~~ September 2022 will be used to determine the AA charge or credit for ~~2020~~2023.

The Balance Adjustment (BA) component of the FAM will be set to recover or refund any under or over-recovery due to prior adjustments. These adjustments

include variances in actual and forecasted sales volumes that were applied to the prior year AA that result in an under or over-recovery, any over- or under-recovered BCF amounts from October to December of the prior year, along with the associated interest component. The BA component may also capture other fuel-related factors subject to Board approval.

3.1 Treatment of load migrating to non-FAM classes

When a customer transitions some or all of its load from a FAM-class to a non-FAM class, NS Power shall determine the customer's outstanding fuel cost imbalance at the date of transition. This determined imbalance will be adjusted in accordance with UARB decisions in subsequent FAM proceedings relating to the period in question (i.e. FAM AA/BA proceedings or a FAM Audit proceeding). The adjustments will be subject to UARB approval.

The outstanding balance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB. Where payment is made over time, the transitioning customer shall pay, in addition, any carrying costs such that remaining customers and NS Power are kept whole.

3.2 Allowable Fuel and Purchased-Power Costs

This section of the POA provides a framework for the fuel and purchased-power costs eligible for recovery through the FAM. Those costs will include allowable fuel expenses plus purchased-power expenses, less revenues from exported power and other fuel- and power-sale revenues.

Allowable fuel expenses will include normal, recurring, non-capital expenses that have been prudently incurred. Discrepancies between the value of measured fuel quantities and the book value of each fuel may also be included if those discrepancies are reasonably supported through surveys, tank level readings and pipeline reports. Exceptional or non-

recurring costs appropriately classified as a fuel and purchased power cost will be brought to the attention of the Small Working Group for review for inclusion in the FAM.

NS Power understands that these costs are subject to audit, both internal and external, and to approval by the Nova Scotia Utility and Review Board. Allowable Fuel and Purchased Power Costs will include the following items:

3.2.1 Natural Gas

- Natural Gas Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Pipeline Reservation Fees, Tolls, Penalties (such as imbalance charges)
- Pipeline Losses
- Natural Gas Storage Fees
- GHG Emission Compliance Program costs

~~Costs of this type are normally recorded in Account No. 069 in NS Power's Chart of Accounts.~~

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502050 REG FUEL GAS CONSUMED
502160 REG FUEL GAS SOLD
502100 REG FUEL GAS CONSUMED FX
502200 REG NATURAL GAS PIPELINE TOLL
502150 REG FUEL GAS CONSUMED COMMODITY DERIVATIVES
502170 REG FUEL GAS PIPELINE LOSSES
504410 REG GRID SALES FUEL NATURAL GAS CLEARING
504400 REG GRID SALES FUEL NATURAL GAS

3.2.2 Solid Fuel

Solid fuel costs are collected into three categories: Inventoried Costs, Costs Directly Applied, and Costs Expensed Through Plant Fuel Handling Adjustments. Those categories include the following costs:

- Inventoried costs
  - Commodity Costs - Coal, Petroleum Coke
  - Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
  - Third-party Quality Testing and Sampling
  - Transportation Costs (e.g. by rail, barge, vessel, truck etc.)
    - Includes loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees

- Costs directly applied:
  - Third Party Fuel Handling, Transportation (e.g movement between Long Term Dead Storage/Bear head and plants) and Maintenance related to Coal Piles
  - Storage fees (e.g. lease, handling fees, facility fees)
  - Environmental Compliance Fees (e.g. Provincial Air Emissions Fees)
  - Rail Car Costs (e.g. lease, repair, maintenance)
  - International Pier Operating & Maintenance Costs

- Costs expensed through the Plant Fuel Handling Adjustment:
  - At each thermal coal unit a demarcation point has been defined as the reclaim hoppers. Any solid fuel handling and transportation expenses up until the point of the reclaim hopper are considered a FAM expense. Costs will include the following items:
    - NS Power labour and associated costs for Equipment Operators, Mechanics, Supervisors related to fuel handling and Lab Techs related to testing

- Costs associated with measurement of inventory (e.g. surveys, density testing)
- Non-capital materials for fuel handling (e.g. tools, replacement parts for machines)
- Repair costs for fuel handling equipment and infrastructure
- Heavy Equipment operating costs for fuel handling (e.g. rental and fuel)
- PTMT Pier Operating & Maintenance costs

Costs in all three Solid Fuel categories – inventoried, directly applied and expensed through plant fuel handling adjustments – ~~are normally recorded in Account No. 070 in NS Power's Chart of Accounts.~~ are normally recorded in the following accounts in NS Power's Chart of Accounts:

502250 REG FUEL COAL CONSUMED
502260 REG FUEL COAL CONSUMED IMPORT
502270 REG FUEL COAL CONSUMED DOMESTIC
502290 REG FUEL COAL CONSUMED OTHER
502280 REG FUEL COAL CONSUMED PETCOKE
502350 REG FUEL COAL CONSUMED FUEL TESTING
502300 REG FUEL COAL CONSUMED FX
504050 REG GRID SALES FUEL COAL CONSUMED

3.2.3 Heavy Fuel Oil

- HFO/Bunker Fuel Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Quality Testing and Inventory Measurement Costs
- Standby Emergency Response Services
- Third Party Supervision of Unloading

- Transportation Costs (e.g. rail, barge, vessel, truck etc.)
  - This would include loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees
    - GHG Emission Compliance Program costs

~~Costs of this type are normally recorded in Account No. 071 in NS Power's Chart of Accounts.~~ Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502400 REG FUEL BUNKER C CONSUMED
502460 REG FUEL BUNKER C CONSUMED COMMODITY DERIVATIVES
502450 REG FUEL BUNKER C CONSUMED FX
504100 REG GRID SALES FUEL BUNKER C CONSUMED

3.2.4 Diesel Oil

- Diesel Commodity Consumed
- Transportation Costs
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded ~~in Account No. 072 in NS Power's Chart of Accounts.~~ in the following accounts in NS Power's Chart of Accounts:

502500 REG FUEL DIESEL OIL CONSUMED
504450 REG GRID SALES FUEL DIESEL

3.2.5 Light Starter Oil

- LFO (Light Fuel Oil) Commodity Consumed

- Transportation Cost
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded ~~in Account No. 073 in NS Power's Chart of Accounts.~~ in the following accounts in NS Power's Chart of Accounts:

502550 REG FUEL LIGHT OIL CONSUMED

3.2.6 Fuel – Additives

- Additives - Ultramag, FireShield, etc.
- Transportation Costs

Costs of this type are normally recorded ~~in Account No. 074 in NS Power's Chart of Accounts. Limestone and Mercury Sorbents are included in Accounts 075 and 009, respectively.~~ in the following accounts in NS Power's Chart of Accounts:

502600 REG FUEL ADDITIVES CONSUMED
502650 REG FUEL LIMESTONE CONSUMED
504200 REG GRID SALES MERCURY SORBENT
504250 REG GRID SALES MERCURY SORBENT FX

3.2.7 Fuel – Limestone

- Limestone and related transportation
- Limestone Ash Hauling and Equipment Rentals
- Limestone Royalties
- Water Royalties

Costs of this type are normally recorded ~~in Account No. 075 in NS Power's Chart of Accounts.~~ in the following account in NS Power's Chart of Accounts:

502650 REG FUEL LIMESTONE CONSUMED

3.2.8 Purchased Power

- Independent Power Producer (IPP) Purchases (e.g. Wholesale Market Non-Dispatchable Spill Tariff)IPP and COMFIT production bonuses and penalties
- Community Feed in Tariff (COMFIT) Purchases
- Developmental Tidal Feed in Tariff (Tidal FIT) Purchases
- Import Power Purchases and associated fees (e.g. transmission tariffs and losses)
- Renewable Energy credits
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)

Costs of this type are normally recorded ~~in Account No. 076 in NS Power's Chart of Accounts.~~ in the following accounts in NS Power's Chart of Accounts:

502700 REG PURCHASED POWER
502750 REG PURCHASED POWER FX
502800 REG PURCHASED POWER COMMODITY DERIVATIVES

502850 REG PURCHASED POWER IPP PRE 2001
502950 REG PURCHASED POWER COMFIT SMALL
502900 REG PURCHASED POWER IPP POST 2001
502710 REG PURCHASED POWER INADVERTENT
503050 REG PURCHASED POWER COMFIT LARGE
504300 REG GRID SALES PURCHASED POWER
502720 REG PURCHASED POWER NET METERING

3.2.9 Fuel Biomass

- Biomass Commodity Consumed
- Maintenance and Operating expenses for Fuel Handling (allocation between OM&G and FAM)
- Third Party Quality Testing and Inventory Measurement Costs (e.g. surveys, density testing, sampling)
- Storage fees (e.g. lease, handling fees, facility fees)
- Environmental Compliance including Silviculture Fees and harvest audits
- Transportation Costs (e.g. by barge, truck etc.)
- GHG Emission Compliance Program costs

At the biomass plant a demarcation point has been defined as the bin collecting conveyor. Any fuel handling and transportation expenses related to steam for generation up until the point of the bin collecting conveyor are considered a FAM expense.

Costs of this type are normally recorded ~~in Account No. 077 in NS Power's Chart of Accounts.~~ in the following accounts in NS Power's Chart of Accounts:

502380 REG FUEL BIOMASS CONSUMED

3.2.10 Fuel – Mercury Sorbent

- Additives – Powder Activated Carbon (PAC) and Calcium Chloride
- Transportation Costs
- Costs relating to a Hg (mercury) Diversion Program that has been approved by the Minister of Environment under the *Air Quality Regulations*, N.S. Reg. 28/2005, as amended.

Costs of this type are normally recorded ~~in Account No. 009 in NS Power's Chart of Accounts.~~ in the following accounts in NS Power's Chart of Accounts:

504200 REG GRID SALES MERCURY SORBENT
504250 REG GRID SALES MERCURY SORBENT FX

3.2.11 Grid Sales Revenue

Revenue from power exports net of any transmission tariffs and losses. This includes Renewable Energy Credits arising out of the sale of renewable energy in the New England market.

3.2.12 Natural Gas Revenue

Revenue from the resale of natural gas.

3.2.13 Miscellaneous Revenue and Recoveries

Revenues from joint partnerships in wind farms (including the cost of NS Power's ownership which is applied to purchased power) and any other fuel-related miscellaneous revenues. These revenues include steam sales to Port Hawkesbury Paper and steam sales at the Trenton Generating station.

~~Accounts 170, 172 and 190 are normally used to record revenues from power exports and natural gas resales, revenues from joint partnerships in wind farms, and other miscellaneous revenues related to fuel. These revenues will offset FAM-eligible fuel and purchased-power costs.~~

The following accounts are normally used to record revenues from power exports and natural gas resales, revenues from joint partnerships in wind farms, and other miscellaneous revenues related to fuel.

417300	REG GRID SALES REVENUE
503200	REG NATURAL GAS REVENUE
503250	REG NATURAL GAS REVENUE FX
503300	REG WIND RECEIVABLES PURCHASED POWER
503350	REG WIND RECEIVABLES FUEL FOR GENERATION
535850	MISC REVENUE

These revenues will offset FAM-eligible fuel and purchased-power costs.

At times, revenues may be recorded as credits to related expense accounts, depending on their nature and applicable accounting guidelines. In these events, full explanations will be provided regarding why they were not offset against FAM-eligible fuel costs.

3.2.14 Foreign Exchange

All NS Power Fuel Accounts are subject to adjustments to record expenses or revenues denominated in foreign currencies and include the gain or loss on currency hedges entered into for the purpose of fuel procurement.

3.2.15 Limited-Duration Fuel Testing

These fuel testing costs (including solid fuel, liquid fuel and additives such as PAC) consist of the amounts directly incurred for shipping and handling and for conducting the test (e.g., third party testing and analysis), and only to the extent incurred as part of limited duration test burns occasionally made by the Company. They shall be limited to non-capital costs and they shall be separately identified in the Company's accounting records.

3.2.16 BTL Costs

- Spill energy payments under the Wholesale Market Non-Dispatchable Supplier Spill Tariff
- Fuel cost incurred in providing service under the Wholesale Market Backup/Top-up Service tariff, less revenue received under the Wholesale Market Backup/Top-Up Service tariff net of non-fuel items

3.2.17 GHG Emission Compliance Program Costs

- The cost of emission allowances (credits) under the Nova Scotia Cap-and-Trade program-.
- Transaction fees for purposes of purchasing or selling emission allowances (credits).

Costs of this type are normally recorded in the following account in NS Power's Chart of Accounts:

5XXXXX REG EMISSION ALLOWANCE EXPENSE

3.2.18 GHG Emission Compliance Program Revenue

- The revenue from the sale of emission allowances (credits) under the Nova Scotia Cap-and-Trade program.

Revenues of this type are normally recorded in the following account in NS Power's Chart of Accounts:

5XXXXX REG EMISSION ALLOWANCE REVENUE

3.3 Calculation of Fuel Costs

The fuel costs in the Base Cost of Fuel recovered through the FAM include allowable fuel and purchased power expenses (as noted in section 3.1 above) less revenues from exported power. ~~During the Rate Stability Period, the Base Cost of Fuel also incorporates any 2015-2016 "earnings above the allowed range of return" and any financial benefit resulting from a change in the recognition of tax benefits for South Canoe and Sable wind projects as a direct offset to test year fuel costs.~~

3.4 Deferrals

During the Rate Stability Period, NS Power may include prior FAM deferrals for certain rate classes (Large General, Medium Industrial, and Large Industrial) in order to save additional interest charges which would accrue by further deferring such amounts to the end of the Rate Stability Period.

4.0 FILING AND PROCEDURAL DEADLINES

Annual Filing Requirements for Fuel Adjustment Rider

In 2019 NS Power will submit as required by Appendix "D" a Fuel Adjustment Mechanism Formula filing for the AA and BA, which shall provide a forecast of general system requirements and include a proposed calculation of the Fuel Adjustment Mechanism Formula for the upcoming year.

Annual Filing Requirements for Base Cost of Fuel Forecast

For each year in which NS Power applies to adjust the Base Cost of Fuel, a load forecast, Base Cost of Fuel and net system requirement forecast filing for the upcoming FAM year (January 1 - December 31) will be submitted as per the schedule set out in Appendix "D". A Plexos run Base Cost of Fuel forecast update will be provided as per the schedule set out in Appendix "D". The Board's decision on the Base Cost of Fuel for the succeeding year will take into consideration the fuel forecast update and any stakeholder comments on the update.

NS Power will use the standardized forecasting methods provided in Appendix "B". NS Power will submit the standard templates for all fuel related information, including the Fuel Forecast Standardized Filing consisting of Reports OE-1(A) to (Q) and Report OE-12, as approved in the Board's Order dated May 15, 2007, in support of the Base Cost of Fuel forecast for the upcoming year. The inputs developed as part of the Fuel Forecast Methodology in Appendix B and any explanations and required supporting information will also be provided.

General Annual Filing Requirements

NS Power shall make standardized annual report filings in accord with the structure and templates provided in Appendix "C" on the first Business Day of the third month after the preceding year end.

Quarterly Filing Requirements

NS Power shall make standardized quarterly report filings in accord with the structure and templates provided in Appendix "C" on the first Business Day after the release of NS Power's quarterly financial results. NS Power's quarterly financial results are released in the second month after the preceding quarter end.

Monthly Filing Requirements

NS Power shall provide standardized monthly reports in accord with the structure and templates provided in Appendix "C" on the twenty-first day after the month end (or the next Business Day after the twenty-first day if the twenty-first day falls on a non-Business Day).

Changes to Reporting Information

No changes to the approved reporting templates, including but not limited to designation of information as confidential, shall be made without either agreement of NS Power and stakeholders and Board approval, or Board approval.

Suggested revisions to FAM documents will be submitted to Stakeholders for review and input.

5.0 AUDIT AND OVERSIGHT

The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently. The results of any audit shall form part of the issues for consideration by the Board in a subsequent FAM hearing ~~following the Rate Stability Period (after 2019)~~ to consider the re-setting of the Base Cost of Fuel, or setting of the Fuel Adjustment Factor, or a General Rate Case at the request of NS Power or any interested stakeholder or upon Board order. Following consideration of the audit in any such hearing, the Board may make such adjustments (with interest if appropriate) to existing balances or to already recovered amounts as it may find necessary.

Audit Process

The Board shall provide for the conduct of a Fuel Adjustment Mechanism (FAM) audit during the Rate Stability Period as it deems appropriate. The Board shall have a qualified independent firm conduct the audit. The audit will address the financial and management/performance aspects of NS Power's fuel procurement and recovery under the FAM. The audit will include the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1 to December 31 of the years within the audit period. Audits will normally cover two-year periods or such periods as determined by the Board.

Objectives and Scope of the Audit

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NS Power, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NS Power's procurement as described in the NS Power Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production to determine whether NS Power has, in the period following that covered by the last preceding audit, conformed and may reasonably be expected to continue to conform to good utility practice. The audit will also consider whether NS Power's conduct of fuel and energy procurement, fuel management, and generation production has been consistent with the NS Power Fuel Manual in the following specific areas (without limitation as to other areas determined to be relevant to effective and efficient fuel and energy procurement, management, and production):

- Fuel and purchased power costs
- Review of overall operational availability and capacity factor for the generating fleet
- Conduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring
- Review and analyze the model used for day ahead marketers to determine the correct dispatch of resources
- Review all Fuel and Purchased Power contracts executed by NS Power and NSPEMI for the period under review for prudency and for compliance with the Fuel Manual
- Review of NS Power's use of hedging to appropriate accounting and performance standards
- Review of system sales
- Review of internal and external audit reports on the procurement of fuel and purchased power
- Review of the calculation of Base Cost of Fuel and the FAM adjustments

Prior to setting the final audit scope, the auditor shall meet with NS Power and interested stakeholders.

Timing of the Audit

Audits are expected to commence in February of every second year or at such time as directed by the Board. Final reports will normally be filed by July 2 of every second year or on such other date as directed by the Board. The final report will evolve from a draft report which is provided to NS Power and the Board within 30 days of the filing of the final report. The draft report should contain functional area task reports, a management summary, and include findings of operating effectiveness and efficiency, as well as any recommendations for adjustments in costs or changes in functions and activities.

Significant FAM Changes

Where, in the absence of a General Rate Application, an increase for any customer class of more than 10 percent compared with the rate payable in the prior year is caused by the application of the FAM procedures, the Board should consider appropriate measures to assist customers.

The Board will monitor the operation of the FAM closely and reserves the right to intervene in any circumstance where it believes an increase to a customer class is not acceptable or in the public interest and take such steps as it considers appropriate to assist such customers including deferring a part of the increase for collection in a future time period.

6.0 STAKEHOLDER REVIEW AND DISCOVERY

Monthly, quarterly and annual non-confidential and confidential reporting will be available for access and viewing. NS Power confidential reporting will be available electronically or in a confidential data room. A Confidentiality Agreement or undertaking will be required to access confidential information. NS Power's confidential electronic data cart will be maintained on a rolling basis with complete information related to transactions in place and accessible within 45 days of the transaction date. For the Base Cost of Fuel forecast update, all support documentation available will be provided (e.g. recommendations, evaluations, and confirmations).

The reporting templates identified in Appendix "C" and the standard fuel-related forecast templates for the Base Cost of Fuel will be accessible to stakeholders in an electronic format. The Board's secure document site will be utilized to access the monthly, quarterly and annual reports. Transactional information, copyright information, and all forecasting information not included in the reports will be available in NS Power's confidential electronic data cart.

Appendix "D" provides the generic regulatory calendar and hearing dates for the FAM processes which will be undertaken each year during the Rate Stability Period.

In each hearing to adjust the Base Cost of Fuel, or to approve the AA and BA in a non-Base Cost of Fuel setting year, stakeholders shall have the opportunity (and access to information) to challenge NS Power's fuel costs, the implementation of the methodology, and the contents of the succeeding year's forecast, consistent with their current rights in General Rate Cases. Notwithstanding the foregoing, stakeholders shall not be precluded from reviewing prior years' actual results versus prior forecasts in addressing the propriety of the succeeding year's forecast.

7.0 DEFINITIONS

Actual Adjustment (Refund)/Recovery Rate – AA: is an Actual Adjustment which consists of the difference between fuel-related costs recovered from a rate class through the application of the base rates ~~during the previous calendar year~~ and the actual fuel costs incurred and allocated to the rate class as of the end of September of the prior calendar year.~~for the same time period.~~ The actual fuel costs will include the same cost items as the Base Cost of Fuel.

Actual Amount 'AA' Received/(Refunded) current period: the amount of (over)/under recovery of fuel costs collected or refunded in the current period, a product of the 'Actual Adjustment (Refund)/recovery Rate – AA' and the 'Actual Sales' for the current period.

~~**Allowance for Funds used During Construction (AFUDC):** NS Power's pretax annual weighted cost of capital is used to determine the AFUDC, which is an allowance that recognizes the carrying cost of an asset over a defined period of time, and is calculated as approved by the Board.~~

Annual Weighted Average Cost of Capital (WACC): A calculation of a company's cost of capital in which each category of capital is proportionately weighted All capital sources - common stock, preferred stock (if applicable), and debt are included in the calculation.

Audit: An independent, objective examination and evaluation of the accounts and records of or the performance and cost effectiveness of an organization.

~~**Average Equity:** On a company's balance sheet, equity is the amount of the funds contributed by the owners (common shares) plus the retained earnings (or losses). Average Equity is computed by a simple average of the opening and closing equity in a period.~~

Balance: The net of debits and credits for an account at the end of a reporting period.

Balance Adjustment (Refund)/Recovery Rate – BA: is a Balance Adjustment, expressed in cents per kWh, which accounts for any (over)/under recovery collections which have occurred as a result of prior adjustments.

Balance Amount Received/(Refund) current period: the amount of remaining (over)/under recovery collections which have occurred as a result of prior adjustments, that are collected or refunded in the current period, a product of the 'Balance Adjustment (Refund)/Recovery Rate – BA' and the 'Actual Sales' for the current period.

Base Cost of Fuel Component – B: is the Base Cost of Fuel per kWh (¢/kWh) included in NS Power's "rates".

Business Day: is any day other than a Saturday, Sunday, or municipal, provincial or federal statutory holiday in Halifax, Nova Scotia.

Compliance Filing: A report filed by NS Power with the Board subsequent to a Decision. This report includes financial, cost of service, rates, and other information that may require revision from NS Power's original application in order to comply with the Board's Decision.

Estimated Sales for the Current Year: is a forecast of projected electricity sales for customer groups that are subject to the FAM Formula.

Export Sales Costs: are the costs to generate power to serve sales outside of NS Power's service territory of Nova Scotia.

Export Sales Recoveries: are the proceeds or revenues received from the sale of export power.

Export Sales Generation: are the MWh's generated to serve customers outside of Nova Scotia.

Fuel Costs Recovered Through Base Cost of Fuel Component: the fuel costs recovered through the Base Cost of Fuel component is the product of the current period's sales in GWh multiplied by the Base Cost of Fuel, then divided by 100.

Fuel for Generation: the fuel costs incurred with consumption of a commodity for the purpose of generating power.

General Rate Application: An application filed by NS Power with the Board requesting general changes to the rates and tariffs it applies to its customer classes.

GRLF Revenue: The revenue received from Generation Replacement and Load Following (GRLF) Rate billings.

GRLF Administration Costs: That portion of GRLF Revenue represented by the $5/MWh adder of that tariff.

GRLF Requirements: The energy requirement of the Generation and Load Following (GRLF) Rate, including losses.

Net Generation by Fuel Type: a financial report produced out of Oracle showing the net generation, expressed in MWh, by facility and fuel type.

NSPEMI: NS Power Energy Marketing Inc., a wholly owned subsidiary of NS Power, formed to facilitate fuel and purchased power transactions in the United States.

(Over)/Under Recovery Amount: variance (over/under) between actual fuel costs and those recovered through the Base Cost of Fuel component included in rates.

Prior Year's AA (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment'. The residual balance at the end of ~~December~~ September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the ~~following year.~~subsequent years.

Prior Year's 'AA' and 'BA' (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'. The residual balance at the end of ~~December~~ September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the ~~following year.~~subsequent years.

Prior Year's Accumulated Interest: the interest accumulated over the previous year on the balance in the 'Balancing Account' to be recovered/refunded to or by the customer during the current year through the '~~A~~BA: (Refund)/Recovery Rate'.

Prior Years (Refund)/Recovery Amount Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment'.

Rate Stability Period: years ~~2017~~2020, ~~2018~~ 2021 and ~~2019~~2022, starting on January 1, ~~2017~~ 2020 and ending on December 31, ~~2019~~2022.

Total Balance Account Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'.

Total Purchased Power: the total cost of import, IPP and wind power purchases during the period used to serve the domestic load requirements.

Total System Requirements: the total sales and system losses expressed as GWh~~'s~~ for domestic and export activity.

Two Part Real Time Pricing Decremental and Incremental Charges: The credits paid to Extra Large Industrial Two-Part Real Time Pricing (ELI 2P-RTP) customers associated with decremental load (below the customer baseline load, CBL) or the additional charges to ELI 2P-RTP customers associated with load above the CBL.

Water Royalties: Amounts paid to government associated with environmental aspects of operating hydroelectric systems.

Fuel Adjustment Mechanism Plan of Administration in Effect for 2020-2022

June 27, 2019

NS Power
FUEL ADJUSTMENT MECHANISM
PLAN OF ADMINISTRATION IN EFFECT FOR 2020-2022
June 27, 2019

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1.0 GENERAL DESCRIPTION

This document describes the plan for administering Nova Scotia Power Inc.'s (NS Power) Fuel Adjustment Mechanism (FAM), which was approved by the Nova Scotia Utility and Review Board (Board) in its decision letter issued on December 11, 2008. The FAM provides for the recovery of fuel and purchased power costs beginning January 1, 2009.

The Plan of Administration (POA) outlines the application and operation of the FAM. The Base Cost of Fuel will be calculated as set out in Section 2 "FAM COMPONENTS".

The Base Cost of Fuel can be reset in a General Rate Application, every second year as part of the FAM adjustment process, or as directed by legislation or an order of the Board[1]. A forecast of costs and load for each test year will be used to set the Base Cost of Fuel. During the Rate Stability Period, the Base Cost of Fuel is smoothed over three test years: 2020, 2021 and 2022. The change in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the Cost of Service Study (COSS).

Stakeholders shall have the opportunity (and access to information) to challenge the implementation of the methodology and the contents of any forecast prior to its use in re-setting the Base Cost of Fuel. Both the implementation of the methodology and the forecasts will be the subject of a formal Board proceeding in which stakeholders will have their current rights as in general rate cases.

Stakeholders shall have the opportunity to challenge NS Power's fuel costs (and to secure access to information) at each annual or applicable hearing before the Board consistent with their current rights in general rate cases. The Board will also subject NS Power's FAM accounts to audits as per section 5.0 "Audit and Oversight" and as it deems appropriate.

[1] The Base Cost of Fuel is reset for 2017-2019 under the 2017-2019 Fuel Stability Plan as directed in section 4 of the *Electricity Plan Implementation (2015) Act*, S.N.S. 2015, c. 31.

The FAM will pass through the difference between actual costs and the Base Cost of Fuel to customers calculated on a ¢/kWh basis.

Interest will be added to all over/under-balance amounts and calculated at NS Power's Annual Weighted Average Cost of Capital (WACC).

The FAM will recover fuel cost changes resulting from over/under-recovery amounts, including an Actual Adjustment (AA) and a Balancing Adjustment (BA) for each rate class. The FAM adjustment is the difference between actual fuel cost and the Base Cost of Fuel) and will be calculated on a ¢/kWh basis.

2.0 FAM COMPONENTS

Each January 1 through December 31 period shall constitute a distinct FAM year. Under the FAM, an adjustment will normally be calculated once per year to reflect the over/-under recovery. During the Rate Stability Period, the annual effect of fuel cost increases on bundled rates will be smoothed by applying any over or under-recoveries to generate fixed annual percentage increases in class total revenues.

The FAM adjustment will consist of two components designed to provide for the recovery of fuel and purchased power costs. Those components are:

1. The Actual Adjustment Component (AA)

    a. Established at a rate expected to recover the amount of the difference between the prior FAM year's actual fuel and purchased power costs and those recovered through the Base Cost of Fuel Component to the end of September of the prior year and October to December of the year before that, making 12 months of actuals.

2. The Balancing Adjustment Component (BA)

    a. The Balancing Adjustment Component will provide for a correction to ensure that over/under-recovery produced by the Actual Adjustment Component is tracked and refunded to or recovered from customers.

    b. The Balancing Adjustment Component may also include, subject to specific Board approval, deferrals of fuel and purchased power costs existing at the time of FAM adoption or that result from any future Board decision.

3.0 CALCULATION OF THE FAM RATE

NS Power's FAM is a forecasted base fuel rate operating on an annual cycle that includes an over/under recovery mechanism consisting of an Actual Adjustment (AA) and Balance Adjustment (BA).

The following formula will be used to determine the fuel adjustment factor (Fuel Adjustment Factor) for each upcoming FAM period:

Fuel Adjustment Mechanism Formula = AA + BA

Where:

1. AA is the Actual Adjustment that accounts for any differences between revenues collected through the application of the FAM during the previous one year period and actual Fuel Costs for each rate class (adjusted for the FAM incentive on an overall fuel cost basis) for the same one year period.

   The AA rate is calculated for the following year on the basis of the over- or under-recovery of the Base Cost of Fuel at the end of September (year 1). Any over- or under-recovery from October to December will not be included in the rate calculation and will be deferred for recovery until the year subsequent to the following year (year 3). The actual AA starting balance for the following year (year 2) is the over- or under-recovery of the Base Cost of Fuel at the end of December (year 1).

2. BA is the Balance Adjustment that accounts for any over- or under-recovery amounts resulting from prior adjustments. The BA will also be the mechanism used to manage any deferred fuel and purchased power costs approved by the Board for inclusion in the BA.

The BA rate is calculated for the following year (year 2) on the basis of the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of September (year 1). The actual BA starting balance for the following year (year 2) is the over- or under-recovery of the Actual Adjustment and Balance Adjustment at the end of December (year 1).

Appendix "A" to this Plan of Administration titled "Sample FAM Calculations", provides a step by step detailed calculation of the overall Base Cost of Fuel, Actual Adjustment (AA), and Balancing Adjustment (BA) for a sequence of years starting in 2009. The applicable calculations illustrated in Appendix "A" will be used as outlined in the FAM Tariff in Appendix E.

Calculation of the Actual Adjustment Factor (AA) and Balancing Adjustment Factor (BA) FAM components will follow the fuel-related cost allocation methodology.

Actual (i.e. after the fact) fuel-related costs will be allocated in the same manner as the test year fuel-related costs used in setting base rates. In summary, this procedure will operate as follows:

1. A portion of the total fuel-related costs will be assigned to the following categories of non-FAM classes based on their fuel costing principles:

    a. The below-the-line bundled service rates for Generation Replacement and Load Following (GRLF), 1P-RTP and Shore Power classes.

    b. The Load Retention Tariff (LRT) class.

    c. The unbundled tariffs: Open Access Transmission Tariff (OATT), Wholesale Market Backup/Top-up Service Tariff (BUTU), Energy Balancing Service Tariff (EBS), Renewable to Retail Market Transition Tariff (RTT).

d. All remaining fuel-related costs will be allocated to ATL classes.

2. For ATL classes, NS Power's fuel costs will be classified as 100 percent energy-related. These costs will be allocated to each class based on its relative contribution to monthly energy requirement.

3. Fuel costs assigned to the Wholesale Market Non-Dispatchable Supplier Spill Tariff and Wholesale Market Backup/Top-up tariff will be based on avoidable fuel costs.

4. Purchased power and Import costs will be classified to demand and energy as follows.

   a. In-province purchased power from wind generation will be segregated between Energy Resource Interconnection Service (ERIS) and Network Resource Interconnection Service (NRIS). Their classification between energy and demand related services will reflect concurrent generation planning practice of NS Power. For the rate setting purposes of the 2020-2022 Rate Stability Plan (RSP) the Company attributed to demand 17% of installed wind capacity of NRIS projects and 0% of ERIS projects.

   b. In-province purchased power from biomass generation will be classified between energy and demand in the same proportion as classification of total costs of the Port Hawkesbury biomass plant.

   c. In-province purchased power from all other sources than wind and biomass will be classified to demand and energy in the same manner as to NS Power's fixed cost base load generation.

d. Maritime Link imports under Nova Scotia Block will be classified to energy and demand on the basis of the system load factor associated with the above-the-line (FAM) classes.

e. Non-firm imports will be all classified to energy.

The demand-related portion of these costs will be allocated to each class based upon its relative coincident contribution to the three monthly system peaks (3CP) occurring in December, January and February. The energy portion of these costs, with the exception of the non-firm imports, will be allocated to each class based on its relative contribution to annual energy requirement. Non-firm imports will be allocated to each class based on its relative contribution to monthly energy requirements.

5. Export revenues are allocated to ATL classes based on monthly energy requirements.

6. For the AA and BA cost allocation purposes only, the variance between the budgeted and actual hedges for foreign exchange will be allocated to each ATL class based on its relative contribution to annual energy requirement. This does not apply to other fuel-related foreign exchange costs.

7. In order to ensure that allocated fuel-related costs are aligned with the revenue expected from approved rates for each class, the costs will be scaled up or down using the revenue-to-cost ratio (R/C ratio) for each class. The resultant costs by class will then be reconciled to the total ATL fuel-related costs based on their relative share of the total fuel costs.

8. The interest amount on the over- or under-recovery of fuel costs is apportioned to the individual rate classes at the end of the year on an annual basis using the following approach:

a. In a year where the interest amount owed to customers by NS Power at the end of September coincides with an over-recovery of fuel costs to the end of September in that year, or where the interest amount owed by customers to NS Power at the end of September coincides with an under-recovery of fuel costs to the end of September in the year, the interest amount will be apportioned to each class based on its relative share of the year-end fuel cost variance during that year.

b. In a year where there is an interest balance owed to customers even though there has been an under-recovery of fuel costs to the end of September, or there is an interest balance owed to NS Power even though there was an over-recovery of fuel costs, NS Power will apportion the outstanding interest balance to each rate class on the basis of the relative class shares in the actual annual fuel cost incurred by NS Power.

The apportioned interest expense or credit is added to the fuel cost variance by class to provide the total fuel and interest (over)/under-recovery amount by class.

In order to determine the factor to be used as the Actual Adjustment (AA) component of the FAM, fuel-related costs allocated to each class in base rates will be subtracted from actual fuel-related costs allocated to each rate class. The difference in costs will be divided by the forecast energy sales (i.e. excluding line losses) to yield a credit or additional charge (in cents/kWh) that would normally be applied to customers' bills for the subsequent year. For the Rate Stability Period, the AA/BA credit or charge (in cents/kWh) will be determined in 2019 for the entire Rate Stability Period. Any under/over recovered BCF amounts at the end of September 2022 will be used to determine the AA charge or credit for 2023.

The Balance Adjustment (BA) component of the FAM will be set to recover or refund any under or over-recovery due to prior adjustments. These adjustments include variances in actual and forecasted sales volumes that were applied to the

prior year AA that result in an under or over-recovery, any over- or under-recovered BCF amounts from October to December of the prior year, along with the associated interest component. The BA component may also capture other fuel-related factors subject to Board approval.

3.1 Treatment of load migrating to non-FAM classes

When a customer transitions some or all of its load from a FAM-class to a non-FAM class, NS Power shall determine the customer's outstanding fuel cost imbalance at the date of transition. This determined imbalance will be adjusted in accordance with UARB decisions in subsequent FAM proceedings relating to the period in question (i.e. FAM AA/BA proceedings or a FAM Audit proceeding). The adjustments will be subject to UARB approval.

The outstanding balance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB. Where payment is made over time, the transitioning customer shall pay, in addition, any carrying costs such that remaining customers and NS Power are kept whole.

3.2 Allowable Fuel and Purchased-Power Costs

This section of the POA provides a framework for the fuel and purchased-power costs eligible for recovery through the FAM. Those costs will include allowable fuel expenses plus purchased-power expenses, less revenues from exported power and other fuel- and power-sale revenues.

Allowable fuel expenses will include normal, recurring, non-capital expenses that have been prudently incurred. Discrepancies between the value of measured fuel quantities and the book value of each fuel may also be included if those discrepancies are reasonably supported through surveys, tank level readings and pipeline reports. Exceptional or non-

recurring costs appropriately classified as a fuel and purchased power cost will be brought to the attention of the Small Working Group for review for inclusion in the FAM.

NS Power understands that these costs are subject to audit, both internal and external, and to approval by the Nova Scotia Utility and Review Board. Allowable Fuel and Purchased Power Costs will include the following items:

3.2.1 Natural Gas

- Natural Gas Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Pipeline Reservation Fees, Tolls, Penalties (such as imbalance charges)
- Pipeline Losses
- Natural Gas Storage Fees
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502050	REG FUEL GAS CONSUMED
502160	REG FUEL GAS SOLD
502100	REG FUEL GAS CONSUMED FX
502200	REG NATURAL GAS PIPELINE TOLL
502150	REG FUEL GAS CONSUMED COMMODITY DERIVATIVES
502170	REG FUEL GAS PIPELINE LOSSES
504410	REG GRID SALES FUEL NATURAL GAS CLEARING
504400	REG GRID SALES FUEL NATURAL GAS

3.2.2 Solid Fuel

Solid fuel costs are collected into three categories: Inventoried Costs, Costs Directly Applied, and Costs Expensed Through Plant Fuel Handling Adjustments. Those categories include the following costs:

- Inventoried costs
  - Commodity Costs - Coal, Petroleum Coke
  - Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
  - Third-party Quality Testing and Sampling
  - Transportation Costs (e.g. by rail, barge, vessel, truck etc.)
    - Includes loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees

- Costs directly applied:
  - Third Party Fuel Handling, Transportation (e.g movement between Long Term Dead Storage/Bear head and plants) and Maintenance related to Coal Piles
  - Storage fees (e.g. lease, handling fees, facility fees)
  - Environmental Compliance Fees (e.g. Provincial Air Emissions Fees)
  - Rail Car Costs (e.g. lease, repair, maintenance)
  - International Pier Operating & Maintenance Costs

- Costs expensed through the Plant Fuel Handling Adjustment:
  - At each thermal coal unit a demarcation point has been defined as the reclaim hoppers. Any solid fuel handling and transportation expenses up until the point of the reclaim hopper are considered a FAM expense. Costs will include the following items:

- NS Power labour and associated costs for Equipment Operators, Mechanics, Supervisors related to fuel handling and Lab Techs related to testing
- Costs associated with measurement of inventory (e.g. surveys, density testing)
- Non-capital materials for fuel handling (e.g. tools, replacement parts for machines)
- Repair costs for fuel handling equipment and infrastructure
- Heavy Equipment operating costs for fuel handling (e.g. rental and fuel)
- PTMT Pier Operating & Maintenance costs

Costs in all three Solid Fuel categories – inventoried, directly applied and expensed through plant fuel handling adjustments – are normally recorded in the following accounts in NS Power's Chart of Accounts:

502250	REG FUEL COAL CONSUMED
502260	REG FUEL COAL CONSUMED IMPORT
502270	REG FUEL COAL CONSUMED DOMESTIC
502290	REG FUEL COAL CONSUMED OTHER
502280	REG FUEL COAL CONSUMED PETCOKE
502350	REG FUEL COAL CONSUMED FUEL TESTING
502300	REG FUEL COAL CONSUMED FX
504050	REG GRID SALES FUEL COAL CONSUMED

3.2.3 Heavy Fuel Oil

- HFO/Bunker Fuel Consumed
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)
- Quality Testing and Inventory Measurement Costs

- Standby Emergency Response Services
- Third Party Supervision of Unloading
- Transportation Costs (e.g. rail, barge, vessel, truck etc.)
    - This would include loading, unloading, dispatch, demurrage, port fees, draft surveys, marine service fees
    - GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502400	REG FUEL BUNKER C CONSUMED
502460	REG FUEL BUNKER C CONSUMED COMMODITY DERIVATIVES
502450	REG FUEL BUNKER C CONSUMED FX
504100	REG GRID SALES FUEL BUNKER C CONSUMED

3.2.4 Diesel Oil

- Diesel Commodity Consumed
- Transportation Costs
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502500	REG FUEL DIESEL OIL CONSUMED
504450	REG GRID SALES FUEL DIESEL

3.2.5 Light Starter Oil

- LFO (Light Fuel Oil) Commodity Consumed
- Transportation Cost
- Quality Testing and Inventory Measurement Costs
- GHG Emission Compliance Program costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502550 REG FUEL LIGHT OIL CONSUMED

3.2.6 Fuel – Additives

- Additives - Ultramag, FireShield, etc.
- Transportation Costs

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502600 REG FUEL ADDITIVES CONSUMED
502650 REG FUEL LIMESTONE CONSUMED
504200 REG GRID SALES MERCURY SORBENT
504250 REG GRID SALES MERCURY SORBENT FX

3.2.7 Fuel – Limestone

- Limestone and related transportation
- Limestone Ash Hauling and Equipment Rentals
- Limestone Royalties
- Water Royalties

Costs of this type are normally recorded in the following account in NS Power's Chart of Accounts:

502650 REG FUEL LIMESTONE CONSUMED

3.2.8 Purchased Power

- Independent Power Producer (IPP) Purchases (e.g. Wholesale Market Non-Dispatchable Spill Tariff)IPP and COMFIT production bonuses and penalties
- Community Feed in Tariff (COMFIT) Purchases
- Developmental Tidal Feed in Tariff (Tidal FIT) Purchases
- Import Power Purchases and associated fees (e.g. transmission tariffs and losses)
- Renewable Energy credits
- Financial Instruments used for Hedging (including gains, losses, fees and interest charges)

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502700 REG PURCHASED POWER
502750 REG PURCHASED POWER FX
502800 REG PURCHASED POWER COMMODITY DERIVATIVES

502850 REG PURCHASED POWER IPP PRE 2001
502950 REG PURCHASED POWER COMFIT SMALL
502900 REG PURCHASED POWER IPP POST 2001
502710 REG PURCHASED POWER INADVERTENT
503050 REG PURCHASED POWER COMFIT LARGE
504300 REG GRID SALES PURCHASED POWER
502720 REG PURCHASED POWER NET METERING

3.2.9 Fuel Biomass

- Biomass Commodity Consumed
- Maintenance and Operating expenses for Fuel Handling (allocation between OM&G and FAM)
- Third Party Quality Testing and Inventory Measurement Costs (e.g. surveys, density testing, sampling)
- Storage fees (e.g. lease, handling fees, facility fees)
- Environmental Compliance including Silviculture Fees and harvest audits
- Transportation Costs (e.g. by barge, truck etc.)
- GHG Emission Compliance Program costs

At the biomass plant a demarcation point has been defined as the bin collecting conveyor. Any fuel handling and transportation expenses related to steam for generation up until the point of the bin collecting conveyor are considered a FAM expense.

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

502380 REG FUEL BIOMASS CONSUMED

3.2.10 Fuel – Mercury Sorbent

- Additives – Powder Activated Carbon (PAC) and Calcium Chloride
- Transportation Costs
- Costs relating to a Hg (mercury) Diversion Program that has been approved by the Minister of Environment under the *Air Quality Regulations*, N.S. Reg. 28/2005, as amended.

Costs of this type are normally recorded in the following accounts in NS Power's Chart of Accounts:

504200	REG GRID SALES MERCURY SORBENT
504250	REG GRID SALES MERCURY SORBENT FX

3.2.11 Grid Sales Revenue

Revenue from power exports net of any transmission tariffs and losses. This includes Renewable Energy Credits arising out of the sale of renewable energy in the New England market.

3.2.12 Natural Gas Revenue

Revenue from the resale of natural gas.

3.2.13 Miscellaneous Revenue and Recoveries

Revenues from joint partnerships in wind farms (including the cost of NS Power's ownership which is applied to purchased power) and any other fuel-related miscellaneous revenues. These revenues include steam sales to Port Hawkesbury Paper and steam sales at the Trenton Generating station.

The following accounts are normally used to record revenues from power exports and natural gas resales, revenues from joint partnerships in wind farms, and other miscellaneous revenues related to fuel.

417300	REG GRID SALES REVENUE
503200	REG NATURAL GAS REVENUE
503250	REG NATURAL GAS REVENUE FX
503300	REG WIND RECEIVABLES PURCHASED POWER
503350	REG WIND RECEIVABLES FUEL FOR GENERATION
535850	MISC REVENUE

These revenues will offset FAM-eligible fuel and purchased-power costs.

At times, revenues may be recorded as credits to related expense accounts, depending on their nature and applicable accounting guidelines. In these events, full explanations will be provided regarding why they were not offset against FAM-eligible fuel costs.

3.2.14 Foreign Exchange

All NS Power Fuel Accounts are subject to adjustments to record expenses or revenues denominated in foreign currencies and include the gain or loss on currency hedges entered into for the purpose of fuel procurement.

3.2.15 Limited-Duration Fuel Testing

These fuel testing costs (including solid fuel, liquid fuel and additives such as PAC) consist of the amounts directly incurred for shipping and handling and for conducting the test (e.g., third party testing and analysis), and only to the extent incurred as part of limited duration test burns occasionally made by the Company. They shall be limited to non-capital costs and they shall be separately identified in the Company’s accounting records.

3.2.16 BTL Costs

- Spill energy payments under the Wholesale Market Non-Dispatchable Supplier Spill Tariff
- Fuel cost incurred in providing service under the Wholesale Market Backup/Top-up Service tariff, less revenue received under the Wholesale Market Backup/Top-Up Service tariff net of non-fuel items

3.2.17 GHG Emission Compliance Program Costs

- The cost of emission allowances (credits) under the Nova Scotia Cap-and-Trade program.
- Transaction fees for purposes of purchasing or selling emission allowances (credits).

Costs of this type are normally recorded in the following account in NS Power's Chart of Accounts:

5XXXXX REG EMISSION ALLOWANCE EXPENSE

3.2.18 GHG Emission Compliance Program Revenue

- The revenue from the sale of emission allowances (credits) under the Nova Scotia Cap-and-Trade program.

Revenues of this type are normally recorded in the following account in NS Power's Chart of Accounts:

5XXXXX REG EMISSION ALLOWANCE REVENUE

3.3 Calculation of Fuel Costs

The fuel costs in the Base Cost of Fuel recovered through the FAM include allowable fuel and purchased power expenses (as noted in section 3.1 above) less revenues from exported power.

3.4 Deferrals

During the Rate Stability Period, NS Power may include prior FAM deferrals for certain rate classes (Large General, Medium Industrial, and Large Industrial) in order to save additional interest charges which would accrue by further deferring such amounts to the end of the Rate Stability Period.

4.0 FILING AND PROCEDURAL DEADLINES

Annual Filing Requirements for Fuel Adjustment Rider

In 2019 NS Power will submit as required by Appendix "D" a Fuel Adjustment Mechanism Formula filing for the AA and BA, which shall provide a forecast of general system requirements and include a proposed calculation of the Fuel Adjustment Mechanism Formula for the upcoming year.

Annual Filing Requirements for Base Cost of Fuel Forecast

For each year in which NS Power applies to adjust the Base Cost of Fuel, a load forecast, Base Cost of Fuel and net system requirement forecast filing for the upcoming FAM year (January 1 - December 31) will be submitted as per the schedule set out in Appendix "D". A Plexos run Base Cost of Fuel forecast update will be provided as per the schedule set out in Appendix "D". The Board's decision on the Base Cost of Fuel for the succeeding year will take into consideration the fuel forecast update and any stakeholder comments on the update.

NS Power will use the standardized forecasting methods provided in Appendix "B". NS Power will submit the standard templates for all fuel related information, including the Fuel Forecast Standardized Filing consisting of Reports OE-1(A) to (Q) and Report OE-12, as approved in the Board's Order dated May 15, 2007, in support of the Base Cost of Fuel forecast for the upcoming year. The inputs developed as part of the Fuel Forecast Methodology in Appendix B and any explanations and required supporting information will also be provided.

General Annual Filing Requirements

NS Power shall make standardized annual report filings in accord with the structure and templates provided in Appendix "C" on the first Business Day of the third month after the preceding year end.

Quarterly Filing Requirements

NS Power shall make standardized quarterly report filings in accord with the structure and templates provided in Appendix "C" on the first Business Day after the release of NS Power's quarterly financial results. NS Power's quarterly financial results are released in the second month after the preceding quarter end.

Monthly Filing Requirements

NS Power shall provide standardized monthly reports in accord with the structure and templates provided in Appendix "C" on the twenty-first day after the month end (or the next Business Day after the twenty-first day if the twenty-first day falls on a non-Business Day).

Changes to Reporting Information

No changes to the approved reporting templates, including but not limited to designation of information as confidential, shall be made without either agreement of NS Power and stakeholders and Board approval, or Board approval.

Suggested revisions to FAM documents will be submitted to Stakeholders for review and input.

5.0 AUDIT AND OVERSIGHT

The amounts charged through the FAM shall be subject to periodic audit to assure completeness and accuracy and to assure fuel and purchased power costs were incurred reasonably and prudently. The results of any audit shall form part of the issues for consideration by the Board in a subsequent FAM hearing to consider the re-setting of the Base Cost of Fuel, or setting of the Fuel Adjustment Factor, or a General Rate Case at the request of NS Power or any interested stakeholder or upon Board order. Following consideration of the audit in any such hearing, the Board may make such adjustments (with interest if appropriate) to existing balances or to already recovered amounts as it may find necessary.

Audit Process

The Board shall provide for the conduct of a Fuel Adjustment Mechanism (FAM) audit during the Rate Stability Period as it deems appropriate. The Board shall have a qualified independent firm conduct the audit. The audit will address the financial and management/performance aspects of NS Power's fuel procurement and recovery under the FAM. The audit will include the FAM Formula, actual fuel and purchased power costs, contracts and management performance that affect the audit period from January 1 to December 31 of the years within the audit period. Audits will normally cover two-year periods or such periods as determined by the Board.

Objectives and Scope of the Audit

The overall objective of the FAM audit will be to examine operational and managerial aspects of the fuel and energy procurement, management, and production functions and activities of NS Power, including any fuel or energy related affiliate transactions that involve these functions and activities directly or indirectly. The review will address adherence to good utility practice and consistency with the policies and procedures governing NS Power's procurement as described in the NS Power Fuel Manual.

The Scope of the Audit will include a review of fuel and energy procurement, fuel management, and generation production to determine whether NS Power has, in the period following that covered by the last preceding audit, conformed and may reasonably be expected to continue to conform to good utility practice. The audit will also consider whether NS Power's conduct of fuel and energy procurement, fuel management, and generation production has been consistent with the NS Power Fuel Manual in the following specific areas (without limitation as to other areas determined to be relevant to effective and efficient fuel and energy procurement, management, and production):

- Fuel and purchased power costs
- Review of overall operational availability and capacity factor for the generating fleet
- Conduct on-site inspection for fuel handling, quality control, inventory management and performance monitoring
- Review and analyze the model used for day ahead marketers to determine the correct dispatch of resources
- Review all Fuel and Purchased Power contracts executed by NS Power and NSPEMI for the period under review for prudency and for compliance with the Fuel Manual
- Review of NS Power's use of hedging to appropriate accounting and performance standards
- Review of system sales
- Review of internal and external audit reports on the procurement of fuel and purchased power
- Review of the calculation of Base Cost of Fuel and the FAM adjustments

Prior to setting the final audit scope, the auditor shall meet with NS Power and interested stakeholders.

Timing of the Audit

Audits are expected to commence in February of every second year or at such time as directed by the Board. Final reports will normally be filed by July 2 of every second year or on such other date as directed by the Board. The final report will evolve from a draft report which is provided to NS Power and the Board within 30 days of the filing of the final report. The draft report should contain functional area task reports, a management summary, and include findings of operating effectiveness and efficiency, as well as any recommendations for adjustments in costs or changes in functions and activities.

Significant FAM Changes

Where, in the absence of a General Rate Application, an increase for any customer class of more than 10 percent compared with the rate payable in the prior year is caused by the application of the FAM procedures, the Board should consider appropriate measures to assist customers.

The Board will monitor the operation of the FAM closely and reserves the right to intervene in any circumstance where it believes an increase to a customer class is not acceptable or in the public interest and take such steps as it considers appropriate to assist such customers including deferring a part of the increase for collection in a future time period.

6.0 STAKEHOLDER REVIEW AND DISCOVERY

Monthly, quarterly and annual non-confidential and confidential reporting will be available for access and viewing. NS Power confidential reporting will be available electronically or in a confidential data room. A Confidentiality Agreement or undertaking will be required to access confidential information. NS Power's confidential electronic data cart will be maintained on a rolling basis with complete information related to transactions in place and accessible within 45 days of the transaction date. For the Base Cost of Fuel forecast update, all support documentation available will be provided (e.g. recommendations, evaluations, and confirmations).

The reporting templates identified in Appendix "C" and the standard fuel-related forecast templates for the Base Cost of Fuel will be accessible to stakeholders in an electronic format. The Board's secure document site will be utilized to access the monthly, quarterly and annual reports. Transactional information, copyright information, and all forecasting information not included in the reports will be available in NS Power's confidential electronic data cart.

Appendix "D" provides the generic regulatory calendar and hearing dates for the FAM processes which will be undertaken each year during the Rate Stability Period.

In each hearing to adjust the Base Cost of Fuel, or to approve the AA and BA in a non-Base Cost of Fuel setting year, stakeholders shall have the opportunity (and access to information) to challenge NS Power's fuel costs, the implementation of the methodology, and the contents of the succeeding year's forecast, consistent with their current rights in General Rate Cases. Notwithstanding the foregoing, stakeholders shall not be precluded from reviewing prior years' actual results versus prior forecasts in addressing the propriety of the succeeding year's forecast.

7.0 DEFINITIONS

Actual Adjustment (Refund)/Recovery Rate – AA: is an Actual Adjustment which consists of the difference between fuel-related costs recovered from a rate class through the application of the base rates and the actual fuel costs incurred and allocated to the rate class as of the end of September of the prior calendar year. The actual fuel costs will include the same cost items as the Base Cost of Fuel.

Actual Amount 'AA' Received/(Refunded) current period: the amount of (over)/under recovery of fuel costs collected or refunded in the current period, a product of the 'Actual Adjustment (Refund)/recovery Rate – AA' and the 'Actual Sales' for the current period.

Annual Weighted Average Cost of Capital (WACC): A calculation of a company's cost of capital in which each category of capital is proportionately weighted All capital sources - common stock, preferred stock (if applicable), and debt are included in the calculation.

Audit: An independent, objective examination and evaluation of the accounts and records of or the performance and cost effectiveness of an organization.

Balance: The net of debits and credits for an account at the end of a reporting period.

Balance Adjustment (Refund)/Recovery Rate – BA: is a Balance Adjustment, expressed in cents per kWh, which accounts for any (over)/under recovery collections which have occurred as a result of prior adjustments.

Balance Amount Received/(Refund) current period: the amount of remaining (over)/under recovery collections which have occurred as a result of prior adjustments, that are collected or refunded in the current period, a product of the 'Balance Adjustment (Refund)/Recovery Rate – BA' and the 'Actual Sales' for the current period.

Base Cost of Fuel Component – B: is the Base Cost of Fuel per kWh (¢/kWh) included in NS Power's "rates".

Business Day: is any day other than a Saturday, Sunday, or municipal, provincial or federal statutory holiday in Halifax, Nova Scotia.

Compliance Filing: A report filed by NS Power with the Board subsequent to a Decision. This report includes financial, cost of service, rates, and other information that may require revision from NS Power's original application in order to comply with the Board's Decision.

Estimated Sales for the Current Year: is a forecast of projected electricity sales for customer groups that are subject to the FAM Formula.

Export Sales Costs: are the costs to generate power to serve sales outside of NS Power's service territory of Nova Scotia.

Export Sales Recoveries: are the proceeds or revenues received from the sale of export power.

Export Sales Generation: are the MWh's generated to serve customers outside of Nova Scotia.

Fuel Costs Recovered Through Base Cost of Fuel Component: the fuel costs recovered through the Base Cost of Fuel component is the product of the current period's sales in GWh multiplied by the Base Cost of Fuel, then divided by 100.

Fuel for Generation: the fuel costs incurred with consumption of a commodity for the purpose of generating power.

General Rate Application: An application filed by NS Power with the Board requesting general changes to the rates and tariffs it applies to its customer classes.

GRLF Revenue: The revenue received from Generation Replacement and Load Following (GRLF) Rate billings.

GRLF Administration Costs: That portion of GRLF Revenue represented by the $5/MWh adder of that tariff.

GRLF Requirements: The energy requirement of the Generation and Load Following (GRLF) Rate, including losses.

Net Generation by Fuel Type: a financial report produced out of Oracle showing the net generation, expressed in MWh, by facility and fuel type.

NSPEMI: NS Power Energy Marketing Inc., a wholly owned subsidiary of NS Power, formed to facilitate fuel and purchased power transactions in the United States.

(Over)/Under Recovery Amount: variance (over/under) between actual fuel costs and those recovered through the Base Cost of Fuel component included in rates.

Prior Year's AA (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment'. The residual balance at the end of September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the subsequent years.

Prior Year's 'AA' and 'BA' (Refund)/Recovery Ending Balance: the balance remaining at the end of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'. The residual balance at the end of September will be recovered/refunded to the customer through the 'BA: (Refund)/Recovery Rate' in the subsequent years.

Prior Year's Accumulated Interest: the interest accumulated over the previous year on the balance in the 'Balancing Account' to be recovered/refunded to or by the customer during the current year through the 'BA: (Refund)/Recovery Rate'.

Prior Years (Refund)/Recovery Amount Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment'.

Rate Stability Period: years 2020, 2021 and 2022, starting on January 1, 2020 and ending on December 31, 2022.

Total Balance Account Beginning Balance: the balance remaining at the beginning of the period, on the previous year's 'Actual Adjustment' and the 'Balance Adjustment'.

Total Purchased Power: the total cost of import, IPP and wind power purchases during the period used to serve the domestic load requirements.

Total System Requirements: the total sales and system losses expressed as GWh for domestic and export activity.

Two Part Real Time Pricing Decremental and Incremental Charges: The credits paid to Extra Large Industrial Two-Part Real Time Pricing (ELI 2P-RTP) customers associated with decremental load (below the customer baseline load, CBL) or the additional charges to ELI 2P-RTP customers associated with load above the CBL.

Water Royalties: Amounts paid to government associated with environmental aspects of operating hydroelectric systems.

Appendix B

FAM Fuel

Forecasting Methodology

June 27, 2019

The following methodology governs the processes and assumptions that NS Power will use to produce the FAM fuel forecast required to set the Base Cost of Fuel during the Rate Stability Period.

1.0 General Approach

The production of a fuel forecast for use in the establishment of the Base Fuel Cost used in a FAM shall be performed using the methodology set out below.

2.0 Load Forecast

2.1 Load Forecast Model

NS Power will develop the Residential and Commercial Sector forecasts using a Statistically-Adjusted End-Use (SAE) model and will develop the industrial sector forecasts using customer surveys in conjunction with econometric models. A SAE model combines the bottom up approach to forecasting applied by an end-use model with the statistical approach applied by an economic forecast. A bottom up buildup of the electricity consumption required to heat, cool, and operate major appliances in a home or business will be interacted with economic, building stock, and weather data to develop NS Powers SAE forecast. Historical saturation and energy consumption values for electric heating, electric cooling, and the operation of appliances will be based on Natural Resources Canada Comprehensive Energy Use database and supplemented by other publically available research. Forecasted saturation and efficiency values will be based on the US Energy Information Administrator's forecasts for the New England market Nova Scotia specific forecasts if available. NS Power's economic outlook will be based on the

Conference Board of Canada's long term outlook or an industry accepted alternative. For a complete description of the forecast model, please see the 10-year load forecast as filed with the UARB.

2.2 Residential Energy Sales

Typical home electricity consumption is forecast using an SAE average use model and a sales forecast is generated as the product of the average use and customer forecast. The residential average use SAE model is defined as a function of the three primary end-uses – cooling, heating and other use. The variables for each of these components interact end use characteristics, weather and economic indicators.

2.3 Commercial Energy Sales

Separate commercial forecasts will be developed for each commercial rate class. Small General Service uses an average use model similar to the Residential model, while the General Service model uses an SAE approach based on total sales. The Large General class forecast relies on customer surveys to forecast future load. In the absence of a survey response or any publically available information a large customer's load will be presumed flat for the forecast period.

2.4 Industrial Energy Sales

NS Power produces the small and medium industrial forecasts based on econometric models using provincial economic information and historical load data as inputs. The Large Industrial rate class load forecast relies on customer surveys to forecast future load. In the absence of a survey response or any publically available information a large customer's load will be presumed flat for the forecast period.

2.5 Years of Data

Energy models typically use 10 years of monthly sales data unless otherwise specified in the load forecast report. Weather data uses the most recent ten (10) year period to develop "normal" monthly weather profiles. The peak forecast model is based on a design temperature of -15 degrees Celsius.

2.6 Conservation and Energy Efficiency Effects

Conservation and Energy Efficiency effects will be incorporated into the forecast by reducing the load forecast by Efficiency One's annual projected savings for each sector (i.e. Residential, Commercial, and Industrial.) Projected savings are adjusted to account for double counting within the end use profiles as outlined in the 10 year load forecast report.

2.7 Input into PLEXOS

NS Power will develop the annual load forecast using 8,760 hours of data called "base load shape", which it will input into PLEXOS together with monthly energy and peak load forecast information. The PLEXOS load shaping algorithm will convert the monthly energy and peak load into an hourly load forecast using the base load shape.

The base load shape will be updated annually in order to reflect changes in hourly load patterns. NS Power will consider factors such as weather, load behavior, and data accuracy when updating the base load shape and may decide to delay load shape update if the previous year load pattern is considered to be atypical.

Documented reasons for a delay in updating load shape may include items such as, for example, an unusually warm or cold year (10% above or below the long term [i.e. 10-year] average total annual heating degree days), or data availability.

3.0 Fuel Forecast

3.1 General

NS Power will calculate the cost of fuel used in the forecast through a combination of cost for fuel contracted and fuel yet to be contracted (open positions).

Contracted fuel will be priced as per the terms of the relevant contract. If a contract contains a volume option, that volume option will be forecast in the direction that yields the lowest overall cost to the forecast and customers. For example, if the forecast market price of fuel is lower than the volume option price of fuel, the volume option will be forecast down and the forecast market price will be applied to that volume.

The cost of the fuel yet to be contracted (open positions) will be valued at the forecast market price. The forecast market price will be developed using a specified combination of the following:

a. Fuel Price Forecasts
b. Supplier Bids
c. Forward Price Strips & Indices
d. Broker Quotes

The Fuel Forecast methodology, including the weighting percentages associated with the development of the forecast market price for each fuel type, will be subject to review by the Board, and either NS Power or stakeholders may propose modifications to the Board.

No changes to the Fuel Forecast methodology, including the weighting percentages associated with each of the fuel types, can be made without either agreement of NS Power and stakeholders and Board approval, or Board approval.

3.2 Low Sulphur Coal

The forecast of Low Sulphur Coal will be comprised of the cost for contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost), the cost for unhedged index priced volumes valued at the corresponding current index price for the relevant time period, or at the hedged price to the extent that the indexed volumes are financially hedged, and open volumes valued at the forecast market price.

The forecast market price for open volumes will be developed as follows:

3.2.1 Low Sulphur / Low Btu Colombian

a. Supplier Bids ([redacted] percent): The average price (adjusted to 11,300 Btu/lb), from qualified bidders offering a commercially approved low sulphur, low Btu fuel of Colombian origin, of the two most competitive coal bids received within 60 days of the start of NS Power's Fuel Forecast Development, provided that the bids are of comparable quality (e.g. sulphur content). If only two bids are available and they are from frequent and traditionally competitive suppliers, the two bids will be used.

NS Power shall use reasonable commercial efforts to obtain Supplier Bids.

b. The forward indices and relative weightings are as follows:

- [redacted] plus or minus a basis differential adjusted to Colombian origin (Puerto Nuevo) for Low Sulphur Low Btu coals

API2 is comprised of the 12-month calendar year averages published near the start of NS Power's Fuel Forecast development. The API2 index is from [redacted] and contained within Allegro. BCI7 is comprised of

the calendar-year forecast published near the start of NS Power's Fuel Forecast development, by [redacted].

The [redacted]) basis differential shall be calculated using the most recent Supplier Bids received by NS Power. Specifically, the average of the two most competitive bids for low sulphur coal from the most recent RFP will be adjusted to 11,300 Btu/lb and a FOBT Colombian origin and this price will then be compared with the [redacted]) price for the time period coinciding with that of the bids. The resulting basis differential will then be applied to the ([redacted] published near the start of NS Power's Fuel Forecast development.

3.2.2 Low Sulphur High Btu Colombian

Supplier Bids for Low Sulphur High Btu coal are most commonly based on API4 plus a basis differential or may also be fixed priced. The average of two supplier bids is used to determine the Low Sulphur High Btu price using API4 published near the start of NS Power's fuel forecast development. API4 index is from [redacted] and contained in Allegro.

If only one bid is available and it is from a frequent and traditionally competitive supplier, the single bid will be used.

NS Power shall use reasonable commercial efforts to obtain Supplier Bids.

3.2.3 Low Sulphur Central Appalachian Coal

The price of the CAPP Coal Origin CSX-BSK 1.7#SO2 index will be calculated from Allegro data queried at the start of NS Power's Fuel Forecast Development. The rail transportation estimate will be added to the CAPP Coal Origin price. The rail estimate will be obtained using the data published from [redacted] immediately prior to the start of

NS Power Fuel Forecast Development applying an annual escalator to the timeframe beyond [redacted] pricing period.

3.3 Mid Sulphur Coal

The forecast of Mid Sulphur Coal will be comprised of the cost for contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost), the cost for unhedged index priced volumes valued at the corresponding current index price for the relevant time period, or at the hedged price to the extent that the indexed volumes are financially hedged, and open volumes valued at the forecast market price.

The forecast market price for open volumes will be developed as follows:

a. Supplier Bids ([redacted] percent): The weighted average price (basis MMBtu content and bid quantities), from qualified bidders offering a commercially approved fuel, of the two most competitive coal bids received within 60 days of the start of NS Power's Fuel Forecast Development, provided that the bids are of comparable quality (e.g. sulphur content). If only two bids are available and they are from frequent and traditionally competitive suppliers, the two bids will be used.

   If a minimum of two applicable Supplier Bids are not available at the time of the forecast, then the [redacted] percent weighting from part (a) will be allocated to part (b) for a total part (b) weighting of [redacted] percent.

   NSPI shall use reasonable commercial efforts to obtain Supplier Bids.

b. The price of the NAPP Coal Origin MGA 13000 4.5 #SO2 will be calculated from Allegro data queried at the start of NS Power's Fuel Forecast Development. The rail transportation estimate will be added to the NAPP Coal Origin price. The rail estimate will be obtained using the data published from [redacted]

immediately prior to the start of NS Power Fuel Forecast Development applying an annual escalator to the timeframe beyond [redacted] pricing period.

3.4 Domestic Coal

The forecast of Domestic Coal will be comprised of the cost for contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost). With Domestic Coal the decision whether to exercise volume optionality's upwards or downwards is determined by comparing the delivered cost of the import coal alternative, and selecting the lower cost alternative.

NS Power shall use reasonable commercial efforts to contract for favorably priced Domestic Coal prior to the start of NS Power's Fuel Forecast Update.

3.5 Petroleum Coke

Forward indices similar to those available for coal are not published for Petroleum Coke. Petcoke pricing published by [redacted] is a commonly used basis for supplier bids, but is not a forward price index. In addition the petcoke market tends to be more volatile than coal. The forecast market price will be determined as follows:

a. Supplier Bids ([redacted] percent): The average price (adjusted to 14,000 Btu/lb) from qualified bidders offering a commercially approved fuel, of the two most competitive bids received within 60 days of the start of NS Power's Fuel Forecast Development, provided that the bids are of comparable quality (e.g. sulphur content). If only one bid is available and it is from a frequent and traditionally competitive supplier, the single bid may be used.

   If applicable Supplier Bids are not available at the time of the forecast, then there will be no contribution from this component, and [redacted] of the forecast market price will be based on the [redacted] publication immediately prior to the start of

NS Power's Fuel Forecast Development. A constant escalator expressed as a percentage will be applied to the petcoke price based on [redacted].

NS Power shall use reasonable commercial efforts to obtain Supplier Bids.

3.6 Natural Gas

The forecast of Natural Gas will be comprised of the cost of natural gas under all contracts in place, applicable hedges, and open volumes valued at the forecast market price and the contract or forecast transportation costs to deliver the natural gas to Tufts Cove. The cost of Natural Gas under the in-place contracts will be adjusted for any discount/premium under the contracts.

The forecast market price of Natural Gas will be calculated as the simple average of the forward price strips over a period of 30 days immediately prior to the start of NS Power's Fuel Forecast Development. The source of the data will be the NYMEX for the Henry Hub (HH) component of the gas price. The basis will be derived from the simple average over the same period of 30 days from the InterContinental Exchange (ICE) for Algonquin City Gate, Dawn or any other basis point to match the pricing point(s) where the gas is expected to be priced for the forecast period. The forecast cost of Natural Gas will also be adjusted for any market discount/premium to the basis. This results in the formula: HH + Basis + Market discount/premium + transportation. As there is no published information which can be used as the reason for forecasting the premium or discount that Maritimes consumers pay relative to market basis indices, NS Power will use the historical premium/discount. Given the variability in the natural gas market, the most recent RFP premium/discount results will be most relevant. NS Power will provide the rationale for any deviation from the most recent RFP premium/discount.

3.7 Heavy Fuel Oil 1.0 percent Sulphur

The forecast of Heavy Fuel Oil (HFO) will be comprised of the cost of contracts, secured through a competitive RFP process, hedged volumes, and open volumes valued at a

forecast market price. The source of the forecast market price will be the Chicago Merchantile Exchange (CME) New York Harbor Residual Fuel 1.0% or the InterContinental Exchange (ICE). calculated as the simple average of the forward price strips over a period of 30 days immediately prior to the start of NS Power's Fuel Forecast Development. If the forward strips are not published, or they do not go far enough into the future, the HFO price will be derived from the Brent crude price using the recent historic trading relationship between HFO and Brent.

3.8 Light Fuel Oil

The forecast of Light Fuel Oil (LFO) will be comprised of the cost, if any, of contracts and hedged volumes, and open volumes at the forecast market price.

The forecast market price for LFO will be derived from the simple average of the published NYMEX heating oil forward curves for a period of 30 days immediately prior to the start of NS Power's Fuel Forecast Development.

3.9 Freight (Ocean)

The forecast of ocean freight will be comprised of the cost of contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost), and any open volumes valued at the forecast market price.

The forecast market price will be the most recent broker quote receivable within 60 days of the start of NS Power's Fuel Forecast Development by [redacted] for the relevant time period and remaining open tonnages. NS Power cannot change the independent party supplying this broker quote without first notifying stakeholders and the new party is approved by the Board after receipt of stakeholder comment.

The Bunker Escalator will be forecast based on the Ocean Freight contracts in place, the bunker escalation clauses of the competitive offers and a forward price for bunker

calculated based on the relevant fuel forward curve for the relevant time period, taken from the same 30 day time period immediately prior to the start of NS Power's Fuel Forecast Development.

3.10 Additives

The cost of Additives to be used in the forecast will be based on the expected PAC performance at each plant considering fuel qualities and forecast blends, , as well as the contracts in place, and known changes in the product or service costs. The calculation of this cost will be fully documented.

3.11 Foreign Exchange Rate

The forecast for foreign exchange will be comprised of the cost of contracts and hedged volumes, and open volumes at the forecast market rate.

The forecast foreign exchange market rate used in the Fuel Forecast will be calculated as a simple average of the most recent quotes obtained by NS Power from each of RBC, Scotiabank, CIBC, TD, Bank of America and BMO (quarterly forecast reports provided by banks) within 90 days of the start of NS Power's Fuel Forecast Development. The most recent forecasts obtained will be utilized.

3.12 Fuel Blending Optimization

Optimal fuel blends required to meet emissions requirements and lowest cost of production will be co-optimized simultaneously with dispatch optimization in PLEXOS for the current calendar year.

In order to optimize fuel blends, the following information will be supplied to PLEXOS:

- Fuel types available to each generating unit
- Fuel S, Hg and C content

- Average of the 30 days immediately prior to the start of NS Power's Fuel Forecast Delivered price in $ per MMBtu
- Fuel quantity and blend ratio restrictions for each generating unit

3.13 SO_2 Precipitation Removal

SO_2 stack removal rates are specified to be 5% for all coal burning steam units and 90.5% for Point Aconi circulating fluidized bed boiler, nominally. These values can vary operationally due to electrostatic precipitator (ESP) performance, but are expected to average to nominal values for the purpose of fuel and purchased power forecasting. SO_2 removal rates are assessed by internal subject matter experts by comparing sulphur content of fuel blends with measured and reported SO_2 release. If assessed SO_2 stack removal rates are different from expected values, and the differences cannot be explained by ESP performance, field tests will be initiated periodically to confirm SO_2 stack removal rates capabilities of generating units.

3.14 Hg Precipitation Removal and Diversion Credits Usage Forecast

Mercury removal from flue gas occurs either inherently at the ESP without injection of sorbent, or due to injection of sorbent. Both modes of Mercury removal are modeled in PLEXOS in order for the simulation to be able to optimize sorbent use and be able to revert to inherent Mercury capture when sorbent is not in use. Mercury capture is dependent on sulphur content of fuel blends. Mercury removal rates assumptions are developed by internal subject matter experts based on the fuel blends, as well as on the types and quantity of sorbents used.

3.15 Biomass

Total generation from the Port Hawkesbury Biomass facility is determined by Generation Services in conjunction with the plant manager based on expected steam demands from PHP and seasonal fuel quality operating constraints and subsequently entered into PLEXOS. For plant operating characteristics, NS Power will follow the same forecasting

process used for the other thermal units (i.e. DAFOR and heat rate will be based on the average of the prior three years). The FERM team calculates the fuel requirement of the plant, and develops a blended cost of biomass based on availability and costs of different forms of biomass fuel. There are no published forecast prices for biomass. NS Power will determine the forecast price based upon input from internal and external subject matter experts and will provide reasonably detailed and auditable documentation for pricing.

4.0 Resource Characterization

4.1 Thermal resources

The system operating assumptions described in this section are updated annually, except where otherwise specified for specific assumptions.

4.1.1 Heat Rate

In 2013, dispatch Net Unit Heat Rate (NUHR) vs net power curves were developed to best reflect the magnitude of the annual Aligne Fuel system heat rates from 2009 to 2013. The curve shapes, i.e. the change in heat rate with respect to net power, were determined from previous turbine cycle heat rate tests.

The shapes of the NUHR vs net power curves are verified during specific turbine cycle heat rate tests conducted after major turbine overhauls, which occur approximately at 10 year intervals. If it is not possible to conduct a formal turbine cycle heat rate test, general curve shape can be verified by calculating heat rates at multiple load points using measured fuel input and power output or data from the online performance monitoring system.

The actual Aligne Fuel annual unit heat rates are plotted against the dispatch NUHR vs net power curves to determine deviations from expected performance. The data points from 2009 to the most recent year are analyzed annually to determine if the dispatch curves should be updated to improvement alignment with the actual reported Aligne Fuel

heat rates, potentially caused by changes in unit performance or unit configuration. The actual heat rates, dispatch curves and any proposed changes are reviewed with and approved by NSP management. If any heat rate curve modifications are approved, the associated heat input vs net power equation coefficients are calculated and issued to Marketing and Generation Planning departments to be applied in daily economic dispatch and long term fuel forecasting models.

4.1.2 Maintenance Outages

Maintenance outages will be based on the Annual Thermal Maintenance Schedule produced by NS Power's Integrated Outage Planning Committee. In forecasting the outages, the Committee considers NERC/NPCC requirements for the system as well as the length of the outages requested by the plants. For each forecast outage, a description of the primary work to be performed will be documented and stated in the Planned Outage Standardization Playbook for each facility.

4.1.3 Unit Maximum Capacities

The maximum capacity of a unit will be the values used in the most recent Board approved Base Cost of Fuel for each unit. The maximum capacities of generating units rarely change, but should a major physical modification occur that permanently increases or decreases the maximum capacity of the unit, this will be reflected in the forecast as approved by NS Power's management. Reasons for the change and supporting information will be documented.

4.1.4 Deration Factor

For each of the units, a Deration Factor will be assigned to recognize the times that the unit is not at its maximum capability. The following are considered for each plant:

- Seasonal cooling water temperature fluctuations for thermal plants;
- Ambient air temperature for the gas-fired units;

- Effects of frozen coal in the winter period and high moisture coal during wet seasons for coal plants;
- Economic coal blends for meeting environmental emissions that do not yield full load for coal plants

The Deration Factors for each unit are recommended by NS Power operations and engineering personnel using recorded actual generation effects as well as operational models used to determine MW output on specific fuel blends, and must be approved by NS Power's management. Deration Factors not included in the above list must be identified by NS Power operations and/or engineering personnel and approved by NS Power's management for use in the forecast. Deration Factors and the accompanying reasons are documented.

4.1.5 De-rated Adjusted Forced Outage Rate (DAFOR)

The DAFOR will be calculated based on the simple average of actual results for the last three years, adjusted for the unit's point in the maintenance cycle. Adjustments will be fully documented and stated in the assumptions both in magnitude and reason.

4.1.6 Unit Variable Operation and Maintenance (O&M) Costs

The incremental operating and maintenance costs will be calculated based on variable operating costs and net generation over a five year period.

The variable operating and maintenance costs are calculated by the Enterprise Asset Management Department according to the Variable Operating & Maintenance Cost Rate Calculation Procedure. Variable Operating and Maintenance (VOM) cost rates are calculated for each Nova Scotia Power thermal plant and are applied in both fuel forecasting and daily economic dispatch models. The VOM rates are included in the total generation cost for each particular unit, which is used to optimize unit dispatch across the fleet.

The general equation applied to determine the VOM rates is as follows:

VOM ($/MWh) = [OF*variable operating costs + MF*(materials + contract costs)] / net generation

- VOM = Variable Operating and Maintenance cost rate
- OF = variable operating cost factor
- MF = variable maintenance cost factor

The following principles and factors are applied in the calculation of the plant VOM rates.

1. Equipment sustaining capital costs that are dependent on generation or hours of operation, i.e. variable Major Maintenance (MM) costs that are allocated to capital accounts, are excluded from the VOM rate calculations. Only variable operating and maintenance costs from the OM&G accounts are included in the VOM rate calculations.

2. Total variable O&M costs and total net generation for the previous five years are applied in the VOM rate calculation.

3. If capacity factor for a particular steam cycle unit is less than 20%, apply a net generation equivalent to 20% in the calculation. The capacity factors for the Tusket, Victoria Junction and Burnside gas turbines are close to zero. A combined VOM rate is calculated for these gas turbines by applying a fixed capacity factor of 0.03.

4. Operating costs and maintenance costs that are dependent on the amount of generation from a unit are identified from the list of OM&G accounts provided by the Power Production Business Manager. In general, the accounts included are:

    a. Operating – chemicals, gases, water, lubricants and ash disposal
    b. Maintenance – tools and equipment, materials, contracts associated with general equipment maintenance and annual outages

5. The following variable operating cost factors (OF) are applied to estimate the proportion of the identified variable operating costs that are dependent on the amount of generation:

a.	Coal/biomass	1.00
b.	Conventional gas/oil	1.00
c.	Gas turbines	1.00

6. The following variable maintenance cost factors (MF) are applied to estimate the proportion of the identified variable maintenance costs that are dependent on the amount of generation:

a.	Coal/biomass	0.60
b.	Conventional gas/oil	0.35
c.	Gas turbines	1.00

When NS Power deviates from the VOM calculation procedure set out in the Forecasting Appendix, it shall provide adequate explanation and support for the deviations.

4.1.7 Abatement Technologies

Forecast of the efficiency of mercury abatement via powdered activated carbon will be based on the actual powdered activated carbon consumption and actual kg of mercury removed. Forecasted abatement cost will be based on this observed system performance as well as supply contract pricing. This information will be used in conjunction with the forecast pricing as inputs to PLEXOS.

4.1.8 Steam Generating Unit Minimum Up/Down Times

Minimum up and down time capabilities of thermal generating units are provided by Enterprise Asset Management. The two-shifting capability of generating units is defined in the PLEXOS model by the minimum up and down times.

4.1.9 Generating Unit Start-up Costs and Start-up Times

Generating unit start-up costs and start-up times are provided by Enterprise Asset Management. Large steam unit start-up costs in the PLEXOS model will be split into three categories: hot start, warm start, and cold start. Smaller steam units as well as combustion turbines can be modeled accurately with a single tier of start-up costs, and the information will be supplied by generation services, as such.

4.1.10 Generating Unit Shutdown Penalty

The PLEXOS system model differentiates between costs and penalties applied to operation of the fleet. While costs associated with start-ups do factor into the total cost of fuel and purchased power, penalties do not. Penalties are used to express potential incremental damage mechanisms and costs associated with generating unit cycling. The shutdown penalty assumptions in the PLEXOS model are intended to guide PLEXOS model dispatch to reflect the physical asset limitations reflected in system dispatch decisions. Generating unit shutdown penalties are provided by Enterprise Asset Management and updated periodically when fleet operating conditions and characteristics warrant an update.

4.1.11 Generating Unit Forced Outage Repair Time

Information provided by Enterprise Asset Management includes expected minimum and maximum time to repair a problem associated with a forced outage.

4.1.12 Generating Unit Ramp Rate Capability

Generating unit maximum up and down ramp rates are provided by Enterprise Asset Management and updated by exception.

4.1.13 Minimum and Maximum Sulphur Content of Fuel Blends

Fuel blends will reflect the most current information regarding the minimum and maximum sulphur requirements, by plant.

4.1.14 Minimum Calorific Value of Fuel Blend Requirements

Fuel blends will reflect the most current information regarding the minimum and maximum calorific value requirements, by plant.

4.1.15 Emissions Content of Fuels

Emissions content of fuels are revised to reflect the most current estimate by the solid fuel team.

4.1.16 Generating Unit Minimum Stable Level

The minimum stable operating loads for the generating units are provided by Enterprise Asset Management.

4.2 System Constraints

4.2.1 Reserve Requirements

PLEXOS models four types of reserve; Regulation (Lower), Regulation (Raise), Spinning, and Ten-minute non-spinning replacement reserve. These requirements are provided by the NS Power system operator and are updated on an annual basis or by exception.

4.2.2 System Stability Steam Commitment Requirements

These parameters are updated by internal NS Power System Operator subject matter experts as required.

4.2.3 Metro Dynamic Reserve Requirement

The PLEXOS model incorporates a dynamic requirement for Metro Dynamic Reactive Reserve ("MDRR"), where the hourly reserve requirement in Mvar is calculated based on Onslow South corridor flow and total system load. Linearized unit capability curves for the metro units are in the model to properly reflect the inverse relationship between unit dispatch level and available Mvar. These requirements are updated as required by the NS Power System Planning group as system configurations change.

4.8 Transmission system resources

4.8.1 Transmission System Configuration

NS Power has developed a condensed transmission system model allowing for accurate representation of NS Power transmission system constraints. The number of nodes and interconnecting corridors by which the NS Power transmission system will be represented will be determined by the Planning and Performance department. The transmission system model will be reviewed continuously in order to make sure that the level of detail in the model is sufficient to accurately represent the existing and upcoming changes on the system. All adjustments to the system model such as the number of system nodes and the number of transmission lines or corridors, will be fully documented and stated in the assumptions both in magnitude and reason.

4.8.2 Transmission Corridor energy transfer limits

Transmission corridor energy transfer limits as per the data published on OASIS – Open Access Same-time Information System. All necessary adjustments due to transmission

corridor upgrades or reconfiguration which affect energy transfer limits will be fully documented and stated in the assumptions both in magnitude and reason.

4.8.3 Transmission System Restrictions

Transmission system energy transfer restrictions as they affect generating unit dispatch:

- Cape Breton Export energy transfer levels required to trigger arming of the group SPS targeting generating units for tripping in case of corridor overload.
- Onslow South energy transfer limit required to trigger commitment of Metro Halifax generating units in order to satisfy dynamic reactive reserve requirements.

The PLEXOS model captures transmission limits and conditions which have a material effect on system dispatch. The system planning group will request pertinent corridor limit changes and transmission constraints from the system operator and FERM in advance of each forecast.

4.8.4 Muskrat Energy Modeling

Muskrat Falls Energy is modeled using the latest assumptions from NSP Maritime Link Inc. Nova Scotia base block and Supplemental block are modeled using $0 price. Surplus energy is modeled in accordance with section 7.0.

4.9 IPPs

IPP contracts will be forecast using the pricing structure and volumes set out in the contract. If the volume is not fixed, the simple average of the last three years of production will be used where available. If discrete changes in the capability of an IPP occur they will be reflected through an adjustment to the historical performance (adjustment to be documented and explained). If the IPP has not been in service to

produce a three year average, the best available information will be used to estimate the volume to be received considering production information to date and start up experience with other similar projects.

4.10 Hydro

The hydro generation resource will be calculated using the Board approved methodology of a 23-year rolling average. The energy provided by each unit in the hydro fleet will be calculated from historical production percentages based on the last 23 years. Adjustment to the 23 year average will be made and fully documented both in magnitude and reason if hydro assets are added, decommissioned or unavailable for extended periods during the forecast time frame due to major inspections or overhauls.

4.11 Wind generation profile

Data sources for wind and load hourly shapes will be based on the same year in order to reflect consistent weather pattern influences on system load and wind generation.

To produce IPP, COMFIT, and NS Power wind shapes, NS Power will use actual hourly telemetered wind output where available.

Where hourly wind generation profiles based on actual measured wind generator output are not available, NS Power will use wind generation data from the geographically nearest telemetered wind site to create an hourly wind generation profile that would be consistent with the other wind and load profile data in the model.

The wind generation profiles will be input into PLEXOS together with monthly energy and peak generation forecast information for each wind generator; for IPP wind sites this is determined as per section 4.9. The PLEXOS shaping algorithm will convert the monthly energy and peak generation into an hourly wind generation forecast using the appropriate wind generation profile.

4.12 Variable Energy Curtailment

The optimal level of variable energy curtailment is determined by PLEXOS.

4.13 Tidal flow through

Tidal flow-through monthly energy forecast is developed by using installed and expected capacity based on the interconnection queue. Hourly flow-through tidal profile is developed based on actual data, where available. In the absence of actual data, a generic hourly flow- through tidal profile is developed based on actual tidal heights, and translated into potential flow-through tidal generation.

4.14 Solar

Solar monthly energy forecast is developed by using installed and expected capacity based on the interconnection queue. Hourly solar profile is developed based on actual data where available. In the absence of actual data, a generic hourly solar profile is developed based on the potential solar profile for the region.

5.0 Financial Model Assumptions

5.1 Emission Fees

The Emission Fees for the forecast will be calculated based on the most current estimate of costs available from invoicing and communication with the Provincial or Federal Government, including known increases to be implemented.

5.2 Water Use Fees

The Water Use Fees for the forecast will be based on the most current estimate of costs available from invoicing and communication with the Provincial Government, including known increases to be implemented.

5.3 Solid Fuel Pile Management

The Solid Fuel Pile Management costs will be based on the most current information of fuel movement and management for the forecast year from the fuel delivery schedule. If no new information exists, the average of the last three years will be utilized. Any forecast adjustments from historical values for known changes will be fully documented and stated in the assumptions both in magnitude and reason.

5.4 Fuel Testing

The Fuel Testing costs forecast will consist of the incremental shipping, handling and operational costs associated with the test burn program for the forecast period. The specifics and rationale for the test burn program shall be fully documented. Any forecast adjustments from historical values for known changes will be fully documented and stated in the assumptions both in magnitude and reason.

5.5 Rail Car Lease

The Rail Car Lease costs will be calculated based on current contract prices. If no contracts are in place for the forecast period the average of the two lowest evaluated and compliant bids will be used.

5.6 Trucking and Rail Contract Costs

The price per ton associated with Trucking and Rail which is contracted separately from the solid fuel supply contracts (e.g. rail services from PTMT to Trenton) will be calculated based on forecast trucking and rail contract rates (including fuel surcharges), and the volumes (movement of coal to and from long-term storage) will be derived from inventory projections in the Coal Model. The trucking and rail rates and the volumes derived from the Coal Model will create the total forecast cost.

5.7 Auxiliary Fuel

Auxiliary Fuel will be calculated based on a simple average of usage over the last three years, adjusted for known changes. Any adjustments from historical values for known changes will be fully documented and stated in the assumptions both in magnitude and reason.

6.0 Export Power

The methodology used to forecast the price of power exports from Nova Scotia assumes that all exports are considered dump energy and are nominally priced at $10 per MWh in the dispatch optimization model. The forecast model will also be constrained with respect to Maximum export volumes to be the average three years with consideration given to market changes which may require a modification to the methodology.

7.0 Import Power

The methodology used to forecast the price of power imports into Nova Scotia from New Brunswick for the 2020-2022 Rate Stability Period assumes that all NB to NS imports are purchased from ISO New England, including transmission and losses.

NS Power will pay the Maritime Link Assessment which covers all costs associated with the Maritime Link and the Nova Scotia Block.

The price of Maritime Link Surplus energy will be forecast using both on-peak and off-peak forward prices for the New England Power Pool's Hub, located in western Massachusetts, USA.

The volume of imported power will be determined in PLEXOS, subject to Nova Scotia system constraints based on the forecast import prices and, if necessary, it will be adjusted to be reflective of expected imports availability due to system in New Brunswick and New England as well as actual imports for similar years in terms of

system operating conditions. That basic forecast (forecast volumes times forecast price) shall be adjusted for known changes that could materially affect the volume or price of power imports, but any such adjustment would be fully documented as to price, volume and rationale.

8.0 Process Flow Description

8.1 Assumption Gathering

NS Power will gather input assumptions for PLEXOS as per the Appendix D schedule. Short-term forecasts will be provided within the timeframes noted above. The price strips used in the forecast will be for the 30 days immediately prior to the start date of NS Power's Fuel Forecast Development as stated in Appendix D.

Contracts and financial hedges in existence prior to the start date of NS Power's Fuel Forecast Development will be incorporated into the forecast.

8.2 Initial PLEXOS Run

All system assumptions will be input into PLEXOS and an initial run of the PLEXOS model will be performed. If necessary, coal blending restrictions in PLEXOS will be revised and the model will be run again in order to confirm dispatch and coal blend optimality.

8.3 Final PLEXOS Run

The final PLEXOS run is the run in which the coal blend and dispatch optimization is fully vetted and shows no material unaccounted for discrepancies against the operational requirements.

8.4 Financial Model

The financial model is run to forecast the value of the fuel hedges, the gas resale program, and other non-dispatch based fuel costs. The financial model imports the fuel requirements and costs from PLEXOS then applies the effect of the non-dispatched fuel costs.

8.5 Output of Financial Model into Reporting

The output of the financial model will be exported into the Standardized FAM reporting package, as outlined in the body of the Plan of Administration, and submitted to the Board and stakeholders as per the schedule in Appendix D.

9.0 Base Fuel Forecast Update

NS Power will provide an Updated Fuel Forecast as indicated in the schedule in Appendix D. The Update will require the re-running of the PLEXOS model. The Update will list any new contracts for committed volumes and/or fuel hedges that NS Power has entered into after the start date of the Fuel Forecast Development, and a variance analysis from the initial Fuel Forecast will be provided which indicates what factors caused what changes. The Update will reflect the change in contracts committed, applicable hedges, and updates of market fuel prices.

10.0 Accounting Methodology

The FAM Forecast will follow GAAP.

Inventory will be consumed using a weighted average method, as per the Board's approval letter dated August 10, 2006 or as updated and approved by the Board.

11.0 Schedule of Process timelines

Appendix D provides the schedule for forecasting activities and information requirements related to FAM administration.

Appendix B

FAM Fuel

Forecasting Methodology

~~September 22, 2016~~June 27, 2019

The following methodology governs the processes and assumptions that NS Power will use to produce the FAM fuel forecast required to set the Base Cost of Fuel during the Rate Stability Period.

1.0 General Approach

The production of a fuel forecast for use in the establishment of the Base Fuel Cost used in a FAM shall be performed using the methodology set out below.

2.0 Load Forecast

2.1 Load Forecast Model

NS Power will develop the Residential and Commercial Sector forecasts using a Statistically-Adjusted End-Use (SAE) model and will develop the industrial sector forecasts using customer surveys in conjunction with econometric models. A SAE model combines the bottom up approach to forecasting applied by an end-use model with the statistical approach applied by an economic forecast. A bottom up buildup of the electricity consumption required to heat, cool, and operate major appliances in a home or business will be interacted with economic, building stock, and weather data to develop NS Powers SAE forecast. Historical saturation and energy consumption values for electric heating, electric cooling, and the operation of appliances will be based on Natural Resources Canada Comprehensive Energy Use database and supplemented by other publically available research. Forecasted saturation and efficiency values will be based on the US Energy Information Administrator's forecasts for the New England market Nova Scotia specific forecasts if available. NS Power's economic outlook will be based on the

Conference Board of Canada's long term outlook or an industry accepted alternative. For a complete description of the forecast model, please see the 10-year load forecast as filed with the UARB.

2.2 Residential Energy Sales

Typical home electricity consumption is forecast using an SAE average use model and a sales forecast is generated as the product of the average use and customer forecast. 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). The variables for each of these components interacts end use characteristics, weather and economic indicators.:

$$ResAvgUse_m = b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m$$

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:

$$XHeat = HeatUse \times HeatIndex$$

Where

$$HeatUse = f(HDD, Household\ Income, Household\ Size, and\ Price)$$

$$HeatIndex = g(Heating\ Saturation, Efficiency, Shell\ Integrity, Square\ Footage)$$

The cooling variable is defined as:

$$XCool = CoolUse \times CoolIndex$$

Where

~~CoolUse = f(CDD, Household Income, Household Size, and Price)~~

~~CoolIndex = g(Cooling Saturation, Efficiency, Shell Integrity, Square Footage)~~

~~XOther captures non-weather sensitive end-uses:~~

~~XOther = OtherUse × OtherIndex~~

~~Where~~

~~OtherUse = f(Seasonal Use Pattern, Household Income, Household Size, and Price)~~

~~OtherIndex = g(Other Appliance Saturation and Efficiency Trends)~~

2.3 Commercial Energy Sales

Separate commercial forecasts will be developed for each commercial rate class. Small General Service uses an average use model similar to the Residential model, while the General Service model uses an~~d~~ SAE approach based on total sales. The Large General class ~~using the approaches outlined below:~~

~~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 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 an economic variable(s) (SmlGenVarm), real price (Pricem), monthly HDD and CDD and a variable accounting for the number of days in a given month:~~

~~XHeatm = EIheat × Pricem -.15× SmlGenVarm× HDDm~~

~~XCoolm = EIcool × Pricem -.15× SmlGenVarm× CDDm~~

~~XOtherm = EIother × Pricem -.15 × SmlGenVarm× Daysm~~

~~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 (GenVarm), real price (Pricem), monthly HDD and CDD and a variable accounting for the number of days in a given month:~~

~~XHeatm = EIheat × Pricem -.15× GenVarm× HDDm~~

~~XCoolm = EIcool × Pricem -.15× GenVarm× CDDm~~

~~XOtherm = EIother × Pricem -.15 × GenVarm× Daysm~~

~~Large General Service~~

~~The Large General service~~ forecast relies on customer surveys to forecast future load. In the absence of a survey response or any publically available information ~~the~~ a large customer's load will be presumed flat for the forecast period.

2.4 Industrial Energy Sales

NS P~~I~~ower produces the small and medium ~~will base the~~ industrial forecasts based on ~~an~~ econometric models using provincial economic information and historical load data as

inputs. The Large Industrial rate class load forecast ~~will rely~~ relies on customer surveys to forecast future load. In the absence of a survey response or any publically available information ~~the~~ a large customer's load will be presumed flat for the forecast period.

2.5 Years of Data

Energy models typically use 10 years of monthly sales data unless otherwise specified in the load forecast report. Weather data uses ~~NSPI will use weather data from~~ the most recent ten (10) year period to develop "normal" monthly weather profiles. ~~the monthly energy consumption profile. Additionally, NSPI will base the temperature profiles used in projecting winter peak demand on an examination of the minimum temperatures observed over each of the past 30 years as well as the temperatures on peak days over that period.~~The peak forecast model is based on a design temperature of -15 degrees ~~Celcius~~Celsius.

2.6 Conservation and Energy Efficiency Effects

Conservation and Energy Efficiency effects will be incorporated into the forecast by reducing the load forecast by Efficiency One's annual projected savings for each sector (i.e. Residential, Commercial, and Industrial.) Projected savings are adjusted to account for double counting within the end use profiles as outlined in the 10 year load forecast report.

2.7 Input into ~~Plexos~~PLEXOS

NS Power will develop the annual load forecast using 8,760 hours of data called "base load shape", which it will input into ~~Plexos~~PLEXOS together with monthly energy and peak load forecast information. The ~~Plexos~~PLEXOS load shaping algorithm will convert the monthly energy and peak load into an hourly load forecast using the base load shape.

The base load shape will be updated annually in order to reflect changes in hourly load patterns. NS Power will consider factors such as weather, load ~~behaviour~~behavior, and

data accuracy when updating the base load shape and may decide to delay load shape update if the previous year load pattern is considered to be atypical.

Documented reasons for a delay in updating load shape may include items such as, for example, an unusually warm or cold year (10% above or below the long term [~~ie.~~i.e. 10-year] average total annual heating degree days), or data availability.

3.0 Fuel Forecast

3.1 General

NS Power will calculate the cost of fuel used in the forecast through a combination of cost for fuel contracted and fuel yet to be contracted (open positions).

Contracted fuel will be priced as per the terms of the relevant contract. If a contract contains a volume option, that volume option will be forecast in the direction that yields the lowest overall cost to the forecast and customers. For example, if the forecast market price of fuel is lower than the volume option price of fuel, the volume option will be forecast down and the forecast market price will be applied to that volume.

The cost of the fuel yet to be contracted (open positions) will be valued at the forecast market price. The forecast market price will be developed using a specified combination of the following:

a. Fuel Price Forecasts
b. Supplier Bids
c. Forward Price Strips & Indices
d. Broker Quotes

The Fuel Forecast methodology, including the weighting percentages associated with the development of the forecast market price for each fuel type, will be subject to review by the Board, and either NS Power or stakeholders may propose modifications to the Board.

No changes to the Fuel Forecast methodology, including the weighting percentages associated with each of the fuel types, can be made without either agreement of NS Power and stakeholders and Board approval, or Board approval.

3.2 Low Sulphur Coal

The forecast of Low Sulphur Coal will be comprised of the cost for contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost), the cost for unhedged index priced volumes valued at the corresponding current index price for the relevant time period, or at the hedged price to the extent that the indexed volumes are financially hedged, and open volumes valued at the forecast market price.

The forecast market price for open volumes will be developed as follows:

~~3.2.1 Low~~3.2.1 Low Sulphur / Low Btu Colombian

a. Supplier Bids [redacted] percent): The average price (adjusted to 11,300 Btu/lb), from qualified bidders offering a commercially approved low sulphur, low Btu fuel of Colombian origin, of the two most competitive coal bids received within 60 days of the start of NS Power's Fuel Forecast Development, provided that the bids are of comparable quality (e.g. sulphur content). If only two bids are available and they are from frequent and traditionally competitive suppliers, the two bids will be used.

NS Power shall use reasonable commercial efforts to obtain Supplier Bids.

b. ~~Forward Price Strips & Indices ([redacted] percent):~~ The forward indices and relative weightings are as follows:

- [redacted] plus or minus a basis differential adjusted to Colombian origin (Puerto BolivarNuevo) for Low Sulphur High Btu (LSH) coals
- [redacted] plus or minus a basis differential adjusted to Colombian origin (Puerto BolivarNuevo) for Low Sulphur Low Btu (LSL) coals
- and
- [redacted] plus or minus a basis differential adjusted to Colombian origin (Puerto Bolivar)

API 4, API 2 and BCI 7 are is comprised of the simple 12-month calcandercalendar year averages on the last published nearon the start of NS Power's Fuel Forecast development., date s over a period of 30 days immediately prior to the start ofrequested by NS Power's Fuel Forecast Development Team Leader , The API2 index is from [redacted] andas contained withinpublished by the [redacted] or [redacted] Allegro. o for API 4 and API 2, and BCI 7 is comprised of the calendar-year forecast published- on on near the start of NS Power's Fuel Forecast development, by [redacted]. for BCI 7.

The API 4 basis differential shall be calculated using the most recent Supplier Bids received by NS Power and the API 4 Index at the time of the bids for the relevant period. Specifically, the average of the two most competitive bids for low sulphur coal from the most recent RFP will be adjusted to 11,300 Btu/lb and a FOBT Colombian origin and this price will then be compared with the API 4 price for the time period coinciding with that of the bids. The resulting premium or discount will then be applied to the last published API 4 Coal Index's are comprised of the calander year averages on the last published date simple average of the 30 days immediately prior to the start of NS Power's Fuel Forecast Development as the basis differential.

The [redacted] basis differential shall be calculated using the most recent Supplier Bids received by NS Power. ~~and the~~ [redacted] ~~at the time of the bids for the relevant period.~~ Specifically, the average of the two most competitive bids for low sulphur coal from the most recent RFP will be adjusted to 11,300 Btu/lb and a FOBT Colombian origin and this price will then be compared with the [redacted] price for the time period coinciding with that of the bids. The resulting ~~premium or discount~~basis differential will then be applied to the [redacted] published near~~on~~ the start of NS Power's Fuel Forecast development.~~'s~~ ~~which are comprised of the calcander year averages on the last published on the date requested by~~ ~~simple average of the 30 days immediately prior to the start of NS Power's Fuel Forecast Development Team Leader .as the basis differential.~~

3.2.2 Low Sulphur High Btu Colombian

~~The average of the two most recent~~ Supplier Bids for Low Sulphur High Btu coal are most commonly based on API4 plus a basis differential or may also be fixed priced. ~~from qualified bidders offering a commercially approved Low Sulphur High Btu fuel of Colombian origin ("bids") will be used to determine an adder preto be applied to the calculated price in 3.2.1~~ ~~API4 Coal Indices~~ ~~to determine a Low Sulphur High Btu price. The Low Sulphur High Btu bids may be fixed price or based on API4. API4 index is from Intercontinental Exchange and contained in Allegro.~~ The average of two supplier bids is used to determine the Low Sulphur High Btu price using API4 published near the start of NS Power's fuel forecat development. API4 index is from [redacted] and contained in Allegro. ~~This adder is calculated as the delta between average bid prices Specifically, the average of the two most competitive bids for low sulphur high Btu Colombian coal from the most recent RFP adjusted to FOBT Colombian origin, and the last published API4 Coal Indices on the date(s) the bids were received. The basis differential to~~ [redacted] ~~at the time of the bids is then applied to the calculated as the Low Sulphur High Btu Colombian forecast price minus Low Sulphur Low Btu Colombian price as calculated in 3.2.130 day average~~ [redacted] ~~Coal Indices~~

~~plus or minus the basis differential. The basis differential is calculated as the delta between the average bid prices and API4 Index published on the date of the bids. calculated in 2.1 for the time period coinciding with that of the bids. The resulting premium basis differential will be applied to the forecast market price of Low Sulphur Low Btu Colombian coal.~~

If only one bid is available and it is from a frequent and traditionally competitive supplier, the ~~single bid~~single bid will be used.

NS Power shall use reasonable commercial efforts to obtain Supplier Bids.

~~3.2.3 Low~~3.2.3 Low Sulphur Central Appalachian Coal

The price of the CAPP Coal Origin CSX-BSK 1.7#SO2 ~~[1]~~index will be calculated from Allegro data queried ~~immediately prior to the start of~~~~on~~ ~~on~~at the start of ~~date requested by~~ NS Power's Fuel Forecast Development~~ Team Leader~~. ~~The rail~~The rail transportation estimate will be added to the CAPP Coal Origin price. The rail estimate will be obtained using the data published from [redacted] ~~(NTD: add to footer All CoalDesk references for CAPP and NAPP coals are expressed in short tons and require conversion to metric tonnes (by using a mulitpler of 1.1023).~~ immediately prior to the start of NS Power Fuel Forecast Development applying an annual escalator to the timeframe beyond [redacted] pricing period. ~~The rail data published by CoalDesk is expressed in short tons and must be converted to metric tonnes.~~

3.3 Mid Sulphur Coal

The forecast of Mid Sulphur Coal will be comprised of the cost for contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost), the cost for unhedged index priced volumes valued at the corresponding current index price for the

~~[1] CAPP coals are expressed in short tons and require conversion to metric tonnes by multiplying by 1.1023~~

relevant time period, or at the hedged price to the extent that the indexed volumes are financially hedged, and open volumes valued at the forecast market price.

The forecast market price for open volumes will be developed as follows:

a. Supplier Bids ([redacted] percent): The weighted average price (basis MMBtu content and bid quantities), from qualified bidders offering a commercially approved fuel, of the two most competitive coal bids received within 60 days of the start of NSPI's Fuel Forecast Development, provided that the bids are of comparable quality (e.g. sulphur content). If only two bids are available and they are from frequent and traditionally competitive suppliers, the two bids will be used.

   If a minimum of two applicable Supplier Bids are not available at the time of the forecast, then the [redacted] percent weighting from part (a) will be allocated to part (b) for a total part (b) weighting of [redacted] percent.

   NSPI shall use reasonable commercial efforts to obtain Supplier Bids.

b. The price of the NAPP Coal Origin MGA 13000 4.5 ##SO2[2] will be calculated from Allegro data queried ~~immediately prior to the start of~~on~~at the start of~~date ~~requested by~~ NS Power's Fuel Forecast Development ~~Team Leader~~. ~~The rail~~The rail transportation estimate will be added to the NAPP Coal Origin price. The rail estimate will be obtained using the data published from [redacted] immediately prior to the start of NS Power Fuel Forecast Development ~~applying an~~applying an ~~annual escalator~~annual escalator to the timeframe beyond [redacted] pricing period. ~~The rail data published by~~ [redacted] ~~is expressed in short tons and must be converted to metric tonnes. Mid sulphur pricing as published by~~ [redacted] ~~may also be used, such as when~~ [redacted] ~~is not available, or, if~~ [redacted] ~~pricing alone or averaged with~~ [redacted] ~~provides better representation of market trends observed through supplier bids.~~

[2] ~~NAPP coals are expressed in short tons and require conversion to metric tonnes by multiplying by 1.1023~~

3.4 Domestic Coal

The forecast of Domestic Coal will be comprised of the cost for contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost). With Domestic Coal the decision whether to exercise volume optionalities upwards or downwards is determined by comparing the delivered cost of the import coal alternative, and selecting the lower cost alternative.

NS Power shall use reasonable commercial efforts to contract for favorably priced Domestic Coal prior to the start of NS Power's Fuel Forecast Update.

3.5 Petroleum Coke

~~The forecast of Petroleum Coke will be comprised of the cost for contracted volumes (with options forecast to be exercised to provide the lowest overall fuel cost), the cost for unhedged index priced volumes valued at the corresponding current index price for the relevant time period, or at the hedged price to the extent that the indexed volumes are financially hedged, and and open volumes valued at the forecast market price.~~

Forward indices similar to those available for coal are not published for Petroleum Coke. Petcoke pricing published [redacted] is a commonly used basis for supplier bids, but is not a forward price index. In addition the petcoke market tends to be more volatile than coal. ~~Published forecasts (listed below) will be assessed for reasonability by comparing the current market trends observed through supplier bids and trends~~ [redacted] ~~. The market trends will be compared to the published forecasts for the similar period. A single published forecast or average of two published forecasts, which best represents the observed market trends, will be selected to determine the forecast market price.~~ The forecast market price will be determined as follows:

~~a. Fuel Price Forecast ([redacted] percent): Any of the following forecast publications for Petroleum Coke that are available to NS Power within 90 days of the start of NS Power's Fuel Forecast Development may be used:~~

- ~~the most recent quarterly short term market forecast prepared by [redacted]; or~~
- ~~the most recent market forecast prepared by [redacted]; or~~
- ~~the most recent market forecast prepared by [redacted]; or~~
- ~~the most recent market forecast prepared by [redacted].~~

~~b.~~a. Supplier Bids ([redacted] percent): The average price (adjusted to 14,000 Btu/lb) from qualified bidders offering a commercially approved fuel, of the two most competitive bids received within 60 days of the start of NS Power's Fuel Forecast Development, provided that the bids are of comparable quality (e.g. sulphur content). ~~The bids must be examined to ensure they are representative of the forecast market price before they are used, to avoid the influence of temporary economic factors.~~ If only one bid is available and it is from a frequent and traditionally competitive supplier~~ and it the bid is based off~~ [redacted], the ~~representative of a forecast market price, the~~ single bid may~~will~~ be used.

If applicable Supplier Bids are not available at the time of the forecast, then there will be no contribution from this component, and [redacted] of the forecast market price will be based on the [redacted] publication immediately prior to the start of ~~date requested by the start of~~ NS Power's Fuel Forecast Development~~nt Team Leader.~~~~selected in Part (a).~~ A constant escalator expressed as a percentage will be applied to the petcoke price based on [redacted].

NS Power shall use reasonable commercial efforts to obtain Supplier Bids.

3.6 Natural Gas

The forecast of Natural Gas will be comprised of the cost of natural gas under all contracts in place, applicable hedges, and open volumes valued at the forecast market price and the contract or forecast ~~-~~transportation costs to deliver the natural gas to Tufts Cove. The cost of Natural Gas under the in-place contracts will be adjusted for any discount/premium under the contracts.

The forecast market price of Natural Gas will be calculated as the simple average of the forward price strips over a period of 30 days immediately prior to the start of NS Power's Fuel Forecast Development. The source of the data will be the NYMEX for the Henry Hub (HH) component of the gas price. The basis will be derived from the simple average over the same period of 30 days from the InterContinental Exchange (ICE) for Algonquin City Gate, ~~and~~ Dawn ~~Basis and Platts for Tennessee Zone 6 Basis~~ or any other basis point to match the pricing point(s) where the gas is expected to be ~~purchased~~ priced for the forecast period. The forecast cost of Natural Gas will also be adjusted for any market discount/premium to the basis. This results in the formula: HH + Basis + Market discount/premium ~~+ transportation .~~transportation. As there is no published information which can be used as the reason for forecasting the premium or discount that Maritimes consumers pay relative to market basis indices, NS Power will use the historical premium/discount. Given the variability in the natural gas market, the ~~prior year's~~most recent ~~RFP premium~~RFP premium/~~discount~~ discount ~~historical information~~results will be most relevant. NS Power will provide the rationale for any deviation from the ~~prior year's~~most recent ~~RFP premium~~RFP premium/discount.

3.7 Heavy Fuel Oil 1.0 percent Sulphur

The forecast of Heavy Fuel Oil (HFO) will be comprised of the cost of contracts, secured through a competitive RFP process, hedged volumes, and open volumes valued at a forecast market price. The source of the forecast market price will be the Chicago Merchantile Exchange (CME) New York Harbor Residual Fuel 1.0% or the

InterContinental Exchange (ICE). calculated as the simple average of the forward price strips over a period of 30 days immediately prior to the start of NS Power's Fuel Forecast Development. If the forward strips are not published, or they do not go far enough into the future, the HFO price will be derived from the Brent crude price using the recent historic trading relationship between HFO and Brent.

3.8 Light Fuel Oil

The forecast of Light Fuel Oil (LFO) will be comprised of the cost, if any, of contracts and hedged volumes, and open volumes at the forecast market price.

The forecast market price for LFO will be derived from the simple average of the published NYMEX heating oil forward curves for a period of 30 days immediately prior to the start of NS Power's Fuel Forecast Development.

3.9 Freight (Ocean)

The forecast of ocean freight will be comprised of the cost of contracted volumes (with options forecast to be exercised to produce the lowest overall fuel cost), and any open volumes valued at the forecast market price.

The forecast market price will be the most recent broker quote receivable within 60 days of the start of NS Power's Fuel Forecast Development by [redacted] for the relevant time period and remaining open tonnages. NS Power cannot change the independent party supplying this broker quote without first notifying stakeholders and the new party is approved by the Board after receipt of stakeholder comment.

The Bunker Escalator will be forecast based on the Ocean Freight contracts in place, the bunker escalation clauses of the competitive offers and a forward price for bunker calculated based on the relevant fuel forward curve for the relevant time period, taken

from the same 30 day time period immediately prior to the start of NS Power's Fuel Forecast Development.

3.10 Additives

The cost of Additives to be used in the forecast will be based on the expected PAC performance at each plant considering fuel qualities and forecast blends, , as well as the contracts in place, and known changes in the product or service costs. The calculation of this cost will be fully documented.

3.11 Foreign Exchange Rate

The forecast for foreign exchange will be comprised of the cost of contracts and hedged volumes, and open volumes at the forecast market rate.

The forecasted foreign exchange market rate used in the Fuel Forecast will be calculated as a simple average of the most recent quotes obtained by NS Power from each of RBC, Scotiabank, CIBC, TD, Bank of America and BMO (quarterly forecast reports provided by banks) within 90 days of the start of NS Power's Fuel Forecast Development. The most recent forecasts obtained will be utilized.

3.12 Fuel Blending Optimization

Optimal fuel blends required to meet emissions requirements and lowest cost of production will be co-optimized simultaneously with dispatch optimization in ~~Plexos~~PLEXOS for the current calendar year.

In order to optimize fuel blends, the following information will be supplied to ~~Plexos~~PLEXOS:

- Fuel types available to each generating unit
- Fuel S, Hg and C content

- Average of the 30 days immediately prior to the start of NS Power's Fuel Forecast Delivered price in $ per MMBtu
- Fuel quantity and blend ratio restrictions for each generating unit

3.13 SO_2 Precipitation Removal

SO_2 stack removal rates are specified to be 5% for all coal burning steam units and 90.5% for Point Aconi circulating fluidized bed boiler, nominally. These values can vary operationally due to electrostatic precipitator (ESP) performance, but are expected to average to nominal values for the purpose of fuel and purchased power forecasting. SO_2 removal rates are assessed by internal subject matter experts by comparing sulphur content of fuel blends with measured and reported SO_2 release. If assessed SO_2 stack removal rates are different from expected values, and the differences cannot be explained by ESP performance, field tests will be initiated periodically to confirm SO_2 stack removal rates capabilities of generating units.

3.14 Hg Precipitation Removal and Diversion Credits Usage Forecast

Mercury removal from flue gas occurs either inherently at the ESP without injection of sorbent, or due to injection of sorbent. Both modes of Mercury removal are modeled in PLEXOS in order for the simulation to be able to optimize sorbent use and be able to revert to inherent Mercury capture when sorbent is not in use. Mercury capture is dependent on sulphur content of fuel blends. Mercury removal rates assumptions are developed by internal subject matter experts based on the fuel blends, as well as on the types and quantity of sorbents used.

3.1~~3~~5 Biomass

Total generation from the Port Hawkesbury Biomass facility is determined by Generation Services in conjunction with the plant manager based on expected steam demands from PHP and seasonal fuel quality operating constraints and subsequently entered into

~~Plexos~~PLEXOS. For plant operating characteristics, NS Power will follow the same forecasting process used for the other thermal units (~~ie.~~i.e. DAFOR and heat rate will be based on the average of the prior three years). The FERM team calculates the fuel requirement of the plant, and develops a blended cost of biomass based on availability and costs of different forms of biomass fuel. There are no published forecast prices for biomass. NS Power will determine the forecast price based upon input from internal and external subject matter experts and will provide reasonably detailed and auditable documentation for pricing.

4.0 Resource Characterization

4.1 Thermal resources

The system operating assumptions described in this section are updated annually, except where otherwise specified for specific assumptions.

4.1.1 Heat Rate

In 2013, dispatch Net Unit Heat Rate (NUHR) vs net power curves were developed to best reflect the magnitude of the annual ~~Fuelworx/~~Aligne Fuel system heat rates from 2009 to 2013. The curve shapes, i.e. the change in heat rate with respect to net power, were determined from previous turbine cycle heat rate tests.

The shapes of the NUHR vs net power curves are verified during specific turbine cycle heat rate tests conducted after major turbine overhauls, which occur approximately at 10 year intervals. If it is not possible to conduct a formal turbine cycle heat rate test, general curve shape can be verified by calculating heat rates at multiple load points using measured fuel input and power output or data from the online performance monitoring system.

The actual Aligne Fuel annual unit heat rates are plotted against the dispatch NUHR vs net power curves to determine deviations from expected performance. The data points

from 2009 to the most recent year are analyzed annually to determine if the dispatch curves should be updated to improvement alignment with the actual reported Aligne Fuel heat rates, potentially caused by changes in unit performance or unit configuration. The actual heat rates, dispatch curves and any proposed changes are reviewed with and approved by NSP management. If any heat rate curve modifications are approved, the associated heat input vs net power equation coefficients are calculated and issued to Marketing and Generation Planning departments to be applied in daily economic dispatch and long term fuel forecasting models.

4.1.2 Maintenance Outages

Maintenance outages will be based on the Annual Thermal Maintenance Schedule produced by NS Power's Integrated Outage Planning Committee. In forecasting the outages, the Committee considers NERC/NPCC requirements for the system as well as the length of the outages requested by the plants. For each forecast outage, a description of the primary work to be performed will be documented and stated in the Planned Outage Standardization Playbook for each facility.

4.1.3 Unit Maximum Capacities

The maximum capacity of a unit will be the values used in the most recent Board approved Base Cost of Fuel for each unit. The maximum capacities of generating units rarely change, but should a major physical modification occur that permanently increases or decreases the maximum capacity of the unit, this will be reflected in the forecast as approved by NS Power's management. Reasons for the change and supporting information will be documented.

4.1.4 Deration Factor

For each of the units, a Deration Factor will be assigned to recognize the times that the unit is not at its maximum capability. The following are considered for each plant:

- Seasonal cooling water temperature fluctuations for thermal plants;
- Ambient air temperature for the gas-fired units;
- Effects of frozen coal in the winter period and high moisture coal during wet seasons for coal plants;
- Economic coal blends for meeting environmental emissions that do not yield full load for coal plants

The Deration Factors for each unit are recommended by NS Power operations and engineering personnel using recorded actual generation effects as well as operational models used to determine MW output on specific fuel blends, and must be approved by NS Power's management. Deration Factors not included in the above list must be identified by NS Power operations and/or engineering personnel and approved by NS Power's management for use in the forecast. Deration Factors and the accompanying reasons are documented.

4.1.5 De-rated Adjusted Forced Outage Rate (DAFOR)

The DAFOR will be calculated based on the simple average of actual results for the last three years, adjusted for the unit's point in the maintenance cycle. Adjustments will be fully documented and stated in the assumptions both in magnitude and reason.

4.1.6 Unit Variable Operation and Maintenance (O&M) Costs

The incremental operating and maintenance costs will be calculated based on variable operating costs and net generation over a five year period.

The variable operating and maintenance costs are calculated by the Enterprise ~~Generation~~ Asset Management Department according to the Variable Operating & Maintenance Cost Rate Calculation Procedure. Variable Operating and Maintenance (VOM) cost rates are calculated for each Nova Scotia Power thermal plant and are applied in both fuel forecasting and daily economic dispatch models. The VOM rates are included in the total

generation cost for each particular unit, which is used to optimize unit dispatch across the fleet.

The general equation applied to determine the VOM rates is as follows:

VOM ($/MWh) = [OF*variable operating costs + MF*(materials + contract costs)] / net generation

- VOM = Variable Operating and Maintenance cost rate
- OF = variable operating cost factor
- MF = variable maintenance cost factor

The following principles and factors are applied in the calculation of the plant VOM rates.

1. Equipment sustaining capital costs that are dependent on generation or hours of operation, i.e. variable Major Maintenance (MM) costs that are allocated to capital accounts, are excluded from the VOM rate calculations. Only variable operating and maintenance costs from the OM&G accounts are included in the VOM rate calculations.

2. Total variable O&M costs and total net generation for the previous five years are applied in the VOM rate calculation.

3. If capacity factor for a particular steam cycle unit is less than 20%, apply a net generation equivalent to 20% in the calculation. The capacity factors for the Tusket, Victoria Junction and Burnside gas turbines are close to zero. A combined VOM rate is ~~calculatedfor~~calculated for these gas turbines by applying a fixed capacity ~~fctor~~factor of 0.03.

4. Operating costs and maintenance costs that are dependent on the amount of generation from a unit are identified from the list of OM&G accounts provided by the Power Production Business Manager. In general, the accounts included are:

a. Operating – chemicals, gases, water, lubricants and ash disposal

b. Maintenance – tools and equipment, materials, contracts associated with general equipment maintenance and annual outages

5. The following variable operating cost factors (OF) are applied to estimate the proportion of the identified variable operating costs that are dependent on the amount of generation:

a.	Coal/biomass	1.00
b.	Conventional gas/oil	1.00
c.	Gas turbines	1.00

6. The following variable maintenance cost factors (MF) are applied to estimate the proportion of the identified variable maintenance costs that are dependent on the amount of generation:

a.	Coal/biomass	0.60
b.	Conventional gas/oil	0.35
c.	Gas turbines	1.00

When NS Power deviates from the VOM calculation procedure set out in the Forecasting Appendix, it shall provide adequate explanation and support for the deviations.

4.1.7 Abatement Technologies

Forecast of the efficiency of mercury ~~abatement via~~abatement via powdered activated carbon will be based on the actual powdered activated carbon consumption and actual kg of mercury removed. Forecasted abatement cost will be based on this observed system performance as well as supply contract pricing. This information will be used in conjunction with the forecast pricing as inputs to ~~Plexos~~PLEXOS.

4.1.8 Steam Generating Unit Minimum Up/Down Times

Minimum up and down time capabilities of thermal generating units are provided by Enterprise Asset Management. The two-shifting capability of generating units is defined in the PLEXOS model by the minimum up and down times.

4.1.9 Generating Unit Start-up Costs and Start-up Times

Generating unit start-up costs and start-up times are provided by Enterprise Asset Management. Large steam unit start-up costs in the PLEXOS model will be split into three categories: hot start, warm start, and cold start. Smaller steam units as well as combustion turbines can be modeled accurately with a single tier of start-up costs, and the information will be supplied by generation services, as such.

4.1.10 Generating Unit Shutdown Penalty

The PLEXOS system model differentiates between costs and penalties applied to operation of the fleet. While costs associated with start-ups do factor into the total cost of fuel and purchased power, penalties do not. Penalties are used to express potential incremental damage mechanisms and costs associated with generating unit cycling. The shutdown penalty assumptions in the PLEXOS model are intended to guide PLEXOS model dispatch to reflect the physical asset limitations reflected in system dispatch decisions. Generating unit shutdown penalties are provided by Enterprise Asset Management and updated periodically when fleet operating conditions and characteristics warrant an update.

4.1.11 Generating Unit Forced Outage Repair Time

Information provided by Enterprise Asset Management includes expected minimum and maximum time to repair a problem associated with a forced outage.

4.1.12 Generating Unit Ramp Rate Capability

Generating unit maximum up and down ramp rates are provided by Enterprise Asset Management and updated by exception.

4.1.13 Minimum and Maximum Sulphur Content of Fuel Blends

Fuel blends will reflect the most current information regarding the minimum and maximum sulphur requirements, by plant.

4.1.14 Minimum Calorific Value of Fuel Blend Requirements

Fuel blends will reflect the most current information regarding the minimum and maximum calorific value requirements, by plant.

4.1.15 Emissions Content of Fuels

Emissions content of fuels are revised to reflect the most current estimate by the solid fuel team.

4.1.16 Generating Unit Minimum Stable Level

The minimum stable operating loads for the generating units are provided by Enterprise Asset Management.

4.2 System Constraints

4.2.1 Reserve Requirements

PLEXOS models four types of reserve; Regulation (Lower), Regulation (Raise), Spinning, and Ten-minute non-spinning replacement reserve. These requirements are

provided by the NS Power system operator and are updated on an annual basis or by exception.

4.2.2 System Stability Steam Commitment Requirements

These parameters are updated by internal NS Power System Operator subject matter experts as required.

4.2.3 Metro Dynamic Reserve Requirement

The PLEXOS model incorporates a dynamic requirement for Metro Dynamic Reactive Reserve ("MDRR"), where the hourly reserve requirement in Mvar is calculated based on Onslow South corridor flow and total system load. Linearized unit capability curves for the metro units are in the model to properly reflect the inverse relationship between unit dispatch level and available Mvar. These requirements are updated ~~periodically~~as required by the NS Power System Planning group as system configurations change.

4.8 Transmission system resources

4.8.1 Transmission System Configuration

NS Power has developed a condensed ~~transmisison~~transmission system model allowing for accurate representation of NS Power transmission system constraints. The number of nodes and interconnecting corridors by which the NS Power transmission system will be represented will be determined by the Planning and Performance department. The transmission system model will be reviewed continuously in order to make sure that the level of detail in the model is sufficient to accurately represent the existing and upcoming changes on the system. All adjustments to the system model such as the number of system nodes and the number of transmission lines or corridors, will be fully documented and stated in the assumptions both in magnitude and reason.

4.8.2 Transmission Corridor energy transfer limits

Transmission corridor energy transfer limits as per the data published on OASIS – Open Access Same-time Information System. All necessary adjustments due to transmission corridor upgrades or reconfiguration which affect energy transfer limits will be fully documented and stated in the assumptions both in magnitude and reason.

4.8.3 Transmission System Restrictions

Transmission system energy transfer restrictions as they affect generating unit dispatch:

- Cape Breton Export energy transfer levels required to trigger arming of the group SPS targeting generating units for tripping in case of corridor overload.
- Onslow South energy transfer limit required to trigger commitment of Metro Halifax generating units in order to satisfy dynamic reactive reserve requirements.

The PLEXOS model captures transmission limits and conditions which have a material effect on system dispatch. The system planning group will request pertinent corridor limit changes and transmission constraints from the system operator and FERM in advance of each forecast.

4.8.4 Muskrat Energy Modeling

Muskrat Falls Energy is modeled using the latest assumptions from NSP Maritime Link Inc. Nova Scotia base block and Supplemental block are modeled using $0 price. Surplus energy is modeled in accordance with section 7.0.

4.9 IPPs

IPP contracts will be forecast using the pricing structure and volumes set out in the contract. If the volume is not fixed, the simple average of the last three years of production will be used where available. If discrete changes in the capability of an IPP occur they will be reflected through an adjustment to the historical performance (adjustment to be documented and explained). If the IPP has not been in service to produce a three year average, the best available information will be used to estimate the volume to be received considering production information to date and start up experience with other similar projects.

4.10 Hydro

The hydro generation resource will be calculated using the Board approved methodology of a 23-year rolling average. The energy provided by each unit in the hydro fleet will be calculated from historical production percentages based on the last 23 years. Adjustment to the 23 year average will be made and fully documented both in magnitude and reason if hydro assets are added, decommissioned or unavailable for extended periods during the forecast time frame due to major inspections or overhauls.

4.11 Wind generation profile

Data sources for wind and load hourly shapes will be based on the same year in order to reflect consistent weather pattern influences on system load and wind generation.

To produce IPP, COMFIT, and NS Power wind shapes, NS Power will use actual hourly telemetered wind output where available.

Where hourly wind generation profiles based on actual measured wind generator output are not available, NS Power will use wind generation data from the geographically nearest telemetered wind site to create an hourly wind generation profile that would be consistent with the other wind and load profile data in the model.

The wind generation profiles will be input into ~~Plexos~~PLEXOS together with monthly energy and peak generation forecast information for each wind generator; for IPP wind sites this is determined as per section 4.9. The ~~Plexos~~PLEXOS shaping algorithm will convert the monthly energy and peak generation into an hourly wind generation forecast using the appropriate wind generation profile.

4.12 Variable Energy Curtailment

The optimal level of variable energy curtailment is determined by ~~Plexos~~PLEXOS.

4.13 Tidal flow through

Tidal flow-through monthly energy forecast is developed by using installed and expected capacity based on the interconnection queue. Hourly flow-through tidal profile is developed based on actual data, where available. In the absence of actual data, a generic hourly flow- through tidal profile is developed based on actual tidal heights, and translated into potential flow-through tidal generation.

4.14 Solar

Solar monthly energy forecast is developed by using installed and expected capacity based on the interconnection queue. Hourly solar profile is developed based on actual data where available. In the absence of actual data, a generic hourly solar profile is developed based on the potential solar profile for the region.

5.0 Financial Model Assumptions

5.1 Emission Fees

The Emission Fees for the forecast will be calculated based on the most current estimate of costs available from invoicing and communication with the Provincial or Federal Government, including known increases to be implemented.

5.2 Water Use Fees

The Water Use Fees for the forecast will be based on the most current estimate of costs available from invoicing and communication with the Provincial Government, including known increases to be implemented.

5.3 Solid Fuel Pile Management

The Solid Fuel Pile Management costs will be based on the most current information of fuel movement and management for the forecast year from the fuel delivery schedule. If no new information exists, the average of the last three years will be utilized. Any forecast adjustments from historical values for known changes will be fully documented and stated in the assumptions both in magnitude and reason.

5.4 Fuel Testing

The Fuel Testing costs forecast will consist of the incremental shipping, handling and operational costs associated with the test burn program for the forecast period. The specifics and rationale for the test burn program shall be fully documented. Any forecast adjustments from historical values for known changes will be fully documented and stated in the assumptions both in magnitude and reason.

5.5 Rail Car Lease

The Rail Car Lease costs will be calculated based on current contract prices. If no contracts are in place for the forecast period the average of the two lowest evaluated and compliant bids will be used.

5.6 Trucking and Rail Contract Costs

The price per ton associated with Trucking and Rail which is contracted separately from the solid fuel supply contracts (e.g. rail services from PTMT to Trenton) will be calculated based on forecast trucking and rail contract rates (including fuel surcharges), and the volumes (movement of coal to and from long-term storage) will be derived from inventory projections in the Coal Model. The trucking and rail rates and the volumes derived from the Coal Model will create the total forecast cost.

5.7 Auxiliary Fuel

Auxiliary Fuel will be calculated based on a simple average of usage over the last three years, adjusted for known changes. Any adjustments from historical values for known changes will be fully documented and stated in the assumptions both in magnitude and reason.

6.0 Export Power

The methodology used to forecast the price of power exports from Nova Scotia assumes that all exports are considered dump energy and are nominally priced at $10 per MWh in the dispatch optimization model. The forecast model will also be constrained ~~to limit the export volumes i~~with respect to Maximum export volumes to be ~~n each month to the historical monthly average to~~ the average three years with consideration given to market changes which may require a modification to the methodology.~~for the prior year~~.

7.0 Import Power

The methodology used to forecast the price of power imports into Nova Scotia from New Brunswick for the ~~2017~~2020-~~2019~~ 2022 Rate Stability Period assumes that all NB to NS imports are ~~under the Joint Dispatch Agreement with NB Power~~purchased from ISO New England, including transmission and losses. ~~The pricing assumptions for imports under the Joint Dispatch Agreement with NB Power consider the forecasted marginal cost of~~

~~generation in Nova Scotia and the forecasted price of New Brunswick Power energy. The midpoint between the two is the price of NB to NS imports for the 2017-2019 Rate Stability Period.~~

NS Power will pay the Maritime Link Assessment which covers all costs associated with the Maritime Link and the Nova Scotia Block.

The price of Maritime Link Surplus energy will be forecast using both on-peak and off-peak forward prices for the New England Power Pool's Hub, located in western Massachusetts, USA.

The volume of imported power will be determined in ~~Plexos~~PLEXOS, subject to Nova Scotia system constraints based on the forecast import prices and, if necessary, it will be adjusted to be reflective of expected imports availability due to system ~~conditions (i.e. curtailments)~~ in New Brunswick and New England as well as actual imports for similar years in terms of system operating conditions. That basic forecast (forecast volumes times forecast price) shall be adjusted for known changes that could materially affect the volume or price of power imports, but any such adjustment would be fully documented as to price, volume and rationale.

8.0 Process Flow Description

8.1 Assumption Gathering

NS Power will gather input assumptions for ~~Plexos~~PLEXOS as per the Appendix D schedule. Short-term forecasts will be provided within the timeframes noted above. The price strips used in the forecast will be for the 30 days immediately prior to the start date of NS Power's Fuel Forecast Development as stated in Appendix D.

Contracts and financial hedges in existence prior to the start date of NS Power's Fuel Forecast Development will be incorporated into the forecast.

8.2 Initial ~~Plexos~~PLEXOS Run

All system assumptions will be input into ~~Plexos~~PLEXOS and an initial run of the ~~Plexos~~PLEXOS model will be performed. If necessary, coal blending restrictions in ~~Plexos~~PLEXOS will be revised and the model will be run again in order to confirm dispatch and coal blend optimality.

8.3 Final ~~Plexos~~PLEXOS Run

The final ~~Plexos~~PLEXOS run is the run in which the coal blend and dispatch optimization is fully vetted and shows no material unaccounted for discrepancies against the operational requirements.

8.4 Financial Model

The financial model is run to forecast the value of the fuel hedges, the gas resale program, and other non-dispatch based fuel costs. The financial model imports the fuel requirements and costs from ~~Plexos~~PLEXOS then applies the effect of the non-dispatched fuel costs.

8.5 Output of Financial Model into Reporting

The output of the financial model will be exported into the Standardized FAM reporting package, as outlined in the body of the Plan of Administration, and submitted to the Board and stakeholders as per the schedule in Appendix D.

9.0 Base Fuel Forecast Update

NS Power will provide an Updated Fuel Forecast as indicated in the schedule in Appendix D. The Update will require the re-running of the ~~Plexos~~PLEXOS model. The Update will list any new contracts for committed volumes and/or fuel hedges that NS

Power has entered into after the start date of the Fuel Forecast Development, and a variance analysis from the initial Fuel Forecast will be provided which indicates what factors caused what changes. The Update will reflect the change in contracts committed, applicable hedges, and updates of market fuel prices.

10.0 Accounting Methodology

The FAM Forecast will follow GAAP.

Inventory will be consumed using a weighted average method, as per the Board's approval letter dated August 10, 2006 or as updated and approved by the Board.

11.0 Schedule of Process timelines

Appendix D provides the schedule for forecasting activities and information requirements related to FAM administration.

FAM REPORTING REQUIREMENTS AND TEMPLATES

~~January 30, 2019~~June 27, 2019

MONTHLY

M-1 SUMMARY OF FUEL COSTS (Non-Confidential)

- Summary of Fuel Costs by Type ($Millions)
- Total System Requirements (GWh)
- Adjusted for GRLF, Export Revenues, 1P RTP, Shore Power, Back Up/Top Up, Load Retention Tariff, and Foreign Exchange
- Reporting periods include actual and budge amounts for month and year to date
- Lists full year budget and percent of budget spent

M-2 SUMMARY OF COST RECOVERY

(Non-Confidential)

- Summary of Base Cost of Fuel (BCF) actual and budget amounts for year to date and current month
- Provides running balance to be recovered, forecast (over)/under recovery for remainder of the year, and interest on the BCF balance
- Summary of Actual Adjustment Component (AA) including balance at beginning of year, amounts recovered in the year to date, opening balance in the current month, amount recovered/(refunded) in current month, and closing balance as of end of current month
- Provides forecast for recovery/(refund) for remainder of year, and interest on the AA balance
- Summary of Balancing Adjustment (BA) Component including balance at beginning of year, amounts recovered/(refunded) prior to current month, opening balance in the current month, amount recovered/(refunded) in current month, and closing balance as of end of current month
- Provides forecast for recovery/(refund) for remainder of year, and interest on the BA balance

- Total FAM Deferral (Over)/Under-Recovery represents sum of BCF, AA and BA amounts.

M-3 TOTAL ACCUMULATED UNRECOVERED FAM BALANCE (Non-Confidential)

- Provides actual figures for month to date and forecast for remaining months of the year
- Outstanding AA and BA totals
- BCF Variance to current month and in current month
- Accumulated Interest amounts
- Total Outstanding
- Current month highlighted

M-4 FUEL POLICIES AND ORGANIZATIONAL CHANGES (Non-Confidential)

- Details of Fuel Manual Updates in the month
- Details of POA Updates in the month
- Details of any Organizational Updates or other relevant staff changes within Fuels, Energy and Risk Management or Fuels Finance

M-5 MERCURY ABATEMENT PROGRAM

(Confidential and Non-Confidential Versions)

- Mercury sorbent type (both any necessary oxidizing agent and the actual absorbent), quantity and costs by each generating plant per month
- Mercury Emission Levels estimate, forecast and variance for the month and year to date

M-6 VOLUME AND PRICING SUMMARY

(Confidential and Non-Confidential Versions)

- Per commodity breakdown of total consumption costs, consumption MMBtu, price $/MMBtu and price $/MWh for Solid Fuel, Natural Gas, Biomass, Bunker Oil (Heavy Fuel Oil), Light Fuel Oil, Imports, Non-Wind IPP Purchases, Wind IPP Purchases and COMFIT

- Broken down by actual, budget and percent change in current month, actual and budget amounts for the year to date, and total budget for the year

M-7 VOLUME AND PRICING SUMMARY (Non-Confidential)

- Provides information about categories, variance from budget, and detailed explanation of the reason for the variance
- Information provided for Total Fuel and Purchased Power Expense, Total System Requirements, Total FAM Sales, Net Fuel and Purchased Power Costs, Purchased Power Costs, Solid Fuel Costs, Natural Gas, Biomass Fuel Costs, Heavy Fuel Oil, Mercury Sorbent and Mercury Emissions

M-8 LOAD RETENTION TARIFF REVENUE REPORT

(Confidential and Non-Confidential Versions)

- Provides details per month for costs and MWh for Energy, Line Losses, Environmental Adder, Accrual Booked, Accrual Reversed and LRT Credit which links back to report on M-1
- Breaks down the charges on a calendar week basis for Energy Cost, Energy Used, Line Losses, Environmental Adder, Variable OM&G Costs, Fixed Costs, Variable Capital Costs, Customer Charge and Total Billed

M-9 NS POWER ENERGY MARKETING INC. TRANSACTION REPORTING

(Confidential and Non-Confidential Versions)

- Provides details per month on the purchase and sale of power, fuel or other commodities between NS Power and NS Power Energy Marketing Inc. (NSPEMI).
- Breaks down the transactions by product, buy/sell, date/time volume, price, and cost or revenue.

ADDITIONAL DOCUMENTS:

- FAM Calculation Model
- Detailed Cover Letter explaining variances in fuel and purchased power costs and revenues in the month

QUARTERLY:

Q-1 FUEL PORTFOLIO COMPLIANCE (**Confidential**)

- Hedging Report by commodity
- Including solid fuel and related transportation contract details
- Commentary providing basis for commodity hedges in relevant years

Q-1a SOLID FUEL PORTFOLIO UPDATE (**Confidential)**

- Supplier and contract information

Q-2 FOREIGN CURRENCY EXCHANGE PROGRAM (**Non-Confidential**)

- Hedging summary of foreign exchange
- Including FX rates
- New contract details

Q-3 NEW FUEL CONTRACT SUMMARY (**Confidential**)

- Contract type, supplier, term, volume, price details for new physical contracts with terms less than and greater than one year or one month

Q-4 CONTRACT UPDATE (**Confidential**)

- Commentary on changes in fuel contracts, status on all litigations and force majeure
- Records of procurement approvals and actual supplier contracts are catalogued and available in the electronic FAM Data Cart.

Q-5 SOLID FUEL INVENTORY (**Confidential**)

- Solid fuel inventory levels in tons and number of weeks supply with comparison target levels
- Reporting periods include current quarter, forecast rest of year

Q-6 GENERATION AND PURCHASED POWER STATISTICS (Non-Confidential)

- Generation statistics by unit including station service
- Export Sales
- Purchases
- GRLF, Load Retention, Shore Power, 1PT RTP, Back Up/Top Up and Losses
- Reporting periods include current quarter, year to date, prior period year to date, forecast rest of year

Q-7 NATURAL GAS DETAIL REPORT (Confidential)

- Natural gas purchase quantities by supplier
- Prices paid for quantities purchased
- Cost/benefit of settled hedges applicable to purchases
- Quantities consumed to generate electricity, separating volumes between Tuft's Cove Units 1-3 and LM6000 TUC Units 4-5
- Cost of gas applicable to quantity consumed, separating the cost/benefit of settled hedges
- Quantities sold for resale
- Revenue from sales
- Settlement of gas sale hedges applicable for resale
- Cost of gas purchased
- Net margin on gas sales
- Changes in inventory position and cost of inventory
- Reporting periods includes current quarter, rest of year forecast, 200X + 1 forecast

Q-8 FUEL OIL DETAIL REPORT (Confidential)

- Quantities purchased and cost of purchases
- Quantity forecasted to be purchased for next calendar year.
- Cost of purchases including hedges
- Quantity consumed to generate electricity
- Cost of quantity consumed including hedges
- Changes in inventory position and applicable cost of inventory

- Reporting periods include current quarter, rest of year forecast, 200X + 1forecast

Q-9 IMPORT POWER AND EXPORT DETAIL REPORT (**Confidential**)

- Quantities purchased and sold
- Cost of quantities purchased
- Revenue of quantities sold
- Reporting periods (current quarter)
-

Q-10 HISTORICAL FUEL COST GRAPH SUMMARY (**Confidential**)

- Quarterly Five Year Summary of Fuel costs per MWh (Solid Fuel, Natural Gas, HFO, Diesel)
- Monthly Three Year Summary of natural gas, HFO, and LFO prices
- Monthly Three Year Summary of natural gas, HFO, and LFO volumes
- Quarterly Five Year Summary of natural gas resale margin
- Monthly Three Year Summary of natural gas revenue per mmbtu
- Quarterly Five Year Summary of solid fuel costs per mmbtu
- Five Year Summary of annual generation by fuel type

Q-11 THERMAL PLANT MAINTENANCE SCHEDULE (**Confidential**)

- Updated plant maintenance schedule for the current year

Q-12 MERCURY ABATEMENT PROGRAM

(**Confidential and Non-Confidential Versions**)

- Cumulative quarterly mercury capture costs by each generating plant
- Type and amount of sorbent used (oxidizing agent and absorbent) for each generating unit
- Fuel and fuel mix by each generating plant
- Tracking of emissions compared to mercury emissions cap
- Technical issues related to mercury capture technology and impacts on fuel and fuel mix

Q-13 POWER GENERATION & FUEL REPORT (Confidential)

- Report package referenced in the NSPI Fuel Manual. Report package includes details on net generation by type, solid fuel costs by type, heat rate by plant, natural gas sales, export sales, generation statistics, and fuel costs by plant.
- Q-13a Fuel Summary by Type – per month in the quarter
- Q-13b Net Generation by Fuel Type – per month in the quarter
- Q-13c Power Production Station Fuel Costs – per month in the quarter
- Q-13d Power Production Solid Fuel Costs – per month in the quarter
- Q-13e Power Production Heat Rate Report – per month in the quarter
- Q-13f Natural Gas Report – per month in the quarter
- Q-13g Export Sales Report – per month in the quarter
- Q-13h Generation Statistics – per month in the quarter
- Q-13i Generation Statistics – Renewables – per month in the quarter
- Q-13j Renewables Costs – per month in the quarter
- Q-13k Power Plant Average Thermal Load MW/Hr – per month in the quarter
- Q-13l Lingan Station Fuel Cost – per month in the quarter
- Q-13m Lingan Solid Fuel Cost – per month in the quarter
- Q-13n Lingan Heat Rate Report – per month in the quarter
- Q-13o Point Aconi Station Fuel Cost – per month in the quarter
- Q-13p Point Aconi Solid Fuel Costs – per month in the quarter
- Q-13q Trenton 5 Station Fuel Cost – per month in the quarter
- Q-13r Trenton 5 Solid Fuel Costs – per month in the quarter
- Q-13s Trenton 6 Station Fuel Cost – per month in the quarter
- Q-13t Trenton 6 Solid Fuel Costs – per month in the quarter
- Q-13u Trenton Heat Rate Report – per month in the quarter
- Q-13v Point Tupper Station Fuel Cost – per month in the quarter
- Q-13w Point Tupper Solid Fuel Costs – per month in the quarter
- Q-13x Tufts Cove Station Fuel Cost – per month in the quarter
- Q-13y Tufts Cove Heat Rate Report – per month in the quarter
- Q-13z LM6000 Station Fuel Costs – per month in the quarter
- Q-13aa LM6000 Heat Rate Report – per month in the quarter
- Q-13ab Combustion Turbines Station Fuel Costs – per month in the quarter

- Q-13ac Port Hawkesbury Biomass Station Fuel Costs – per month in the quarter
- Q-13ad Port Hawkesbury Biomass Solid Fuel Costs – per month in the quarter

ADDITIONAL DOCUMENTS:

- FAM Data Cart Index (Non-Confidential)
- Natural Gas Market Update (Confidential – FAM Data Cart)

ANNUAL

A-1 ORGANIZATION CHART - FUELS (**Non-Confidential**)

- Full organizational chart for positions reporting to Director, Fuels, Energy and Risk Management
- Commentary notes on vacant positions and position replacements

A-2 GENERATION UNIT SUMMARY (**Non-Confidential**)

- Breakdown of generating units by type showing in-service date, net capacity, fuel type, and annual energy for the year ended.

A-3 FUEL COST SUMMARY (**Confidential**)

- Fuel costs summary by type per MWh
- Reporting periods include year to date, prior period year to date, forecast next year

A-4 FUEL SPECIFICATIONS SUMMARY (**Non-Confidential**)

- Physical characteristics and chemical specification sheets for all fuels (HFO, Diesel, Mid Sulphur Coal, Low Sulphur Coal, Petroleum Coke, Natural Gas, Biomass)

A-5 IPP CONTRACT SUMMARY (**Confidential**)

- Summary of IPP contracts including installed capacity and annual energy for the year ended.

A-6 PLANT PERFORMANCE (**Confidential/Non-Confidential**)

- Summary of capacity factor (non-confidential), availability factor (non-confidential), heat rate (confidential), and DAFOR (non-confidential) by unit
- Unit Forced Outage & Management Response (confidential)
- Generation Equipment Reporting (confidential)

A-7 PLANT MAINTENANCE (Confidential/Non-Confidential)

- Power Production unit maintenance schedule (confidential) of all units (planned vs actual and budget schedule)
- OM&G and Capital spending by station (non-confidential)
- Reporting periods include year to date, prior period year to date, forecast next year
- Identification of major projects for current year
- NOTE: The first report will provide the baseline of planned and actual plant maintenance schedules for the historical period. The baseline of OM&G and capital spending as well as the identification of major projects will be provided for the historical period with the first report.

A-8 T&D SYSTEM LINE LOSSES (Non-Confidential)

- Total line losses for reporting periods year to date, prior period year to date and forecast next year

A-9 EMISSION COMPLIANCE (Non-Confidential)

- Summary of applicable emissions targets legislated and compliance accomplished for past year and current year, and how compliance is planned for the upcoming year and five years into the future.

A-10 SUMMARY OF PROJECTED FUEL EXPENSE FOR THE NEXT 2 YEARS (Confidential)

- Summary of Fuel Costs by Type ($Millions). Detail will be provided in standardized filing requirement for the next year and high level number for second year.
- Output from Strategist model supporting forecasts
- Solid Fuel summary including projected commodity costs, ocean freight, land transportation and associated foreign exchange costs. Commodity cost details include forecast assumptions for contracted and uncommitted tonnages.
- A-10a Fuel Summary by Type
- A-10b Net Generation by Fuel Type

- A-10c Power Production Thermal Station Fuel Costs
- A-10d Power Production Solid Fuel Costs by Supplier
- A-10e Power Production Heat Rate Report
- A-10f Natural Gas Report
- A-10g Export Sales Report – Monthly Forecast
- A-10h Generation Statistics – MWh
- A-10i Generation Statistics – Renewables
- A-10j Renewables Costs (Monthly)
- A-10k Power Production Average Load Report
- A-10l Lingan Monthly Station Fuel Costs
- A-10m Lingan Solid Fuel Costs by Supplier
- A-10n Lingan Heat Rate Report
- A-10o Point Aconi Monthly Station Fuel Costs
- A-10p Point Aconi Solid Fuel Costs by Supplier
- A-10q Trenton 5 Monthly Station Fuel Costs
- A-10r Trenton 5 Solid Fuel Costs by Supplier
- A-10s Trenton 6 Monthly Station Fuel Costs
- A-10t Trenton 6 Solid Fuel Costs by Supplier
- A-10u Trenton Heat Rate Report
- A-10v Point Tupper Monthly Station Fuel Costs
- A-10w Point Tupper Solid Fuel Costs by Supplier
- A-10x Tufts Cove Thermal Station Fuel Costs
- A-10y Tufts Cove Heat Rate Report
- A-10z LM6000 Thermal Station Fuel Costs
- A-10aa Combustion Turbines Thermal Station Fuel Costs
- A-10ab Port Hawkesbury Biomass Station Fuel Costs
- A-10ac Port Hawkesbury Biomass Solid Fuel Costs by Supplier
- A-10ad Summary of [Year +1] Projected Fuel Expense – PLEXOS Output
- A-10ae Summary of [Year +1] Projected Fuel Expense – Solid Fuel Costs
- A-10af Summary of Projected Fuel Expense – [Year +1] Outlook

A-11 SUMMARY OF SALES BY CUSTOMER CLASS FOR THE NEXT 2 YEARS

(**Confidential**)

A-12 AFFILIATE TRANSACTIONS (**Confidential**)

- Summary of all fuel and power related affiliate transactions for the period

A-13 MERCURY ABATEMENT PROGRAM

(**Confidential and Non-Confidential Versions**)

- A-13a Cumulative quarterly mercury capture costs by each generating plant (non-confidential)
- A-13a Type and amount of sorbent used (oxidizing agent and absorbent) for each generating unit (confidential)
- A-13a Fuel and fuel mix by each generating plant (non-confidential)
- A-13a Tracking of emissions compared to mercury emissions cap (non-confidential)
- A-13bTechnical issues related to mercury capture technology and impacts on fuel and fuel mix (non-confidential)
- A-13b Quantitative and qualitative descriptions of the impact on fuel use (non-confidential)
- A-13c Technical or capital changes that may be required to achieve mercury emissions limits (non-confidential)
- A-13d Estimate of the amount and cost of sorbent (oxidizing agent and absorbent) anticipated for the upcoming year (confidential)

FAM REPORTING REQUIREMENTS AND TEMPLATES

June 27, 2019

MONTHLY

M-1 SUMMARY OF FUEL COSTS (**Non-Confidential**)

- Summary of Fuel Costs by Type ($Millions)
- Total System Requirements (GWh)
- Adjusted for GRLF, Export Revenues, 1P RTP, Shore Power, Back Up/Top Up, Load Retention Tariff, and Foreign Exchange
- Reporting periods include actual and budge amounts for month and year to date
- Lists full year budget and percent of budget spent

M-2 SUMMARY OF COST RECOVERY

(**Non-Confidential**)

- Summary of Base Cost of Fuel (BCF) actual and budget amounts for year to date and current month
- Provides running balance to be recovered, forecast (over)/under recovery for remainder of the year, and interest on the BCF balance
- Summary of Actual Adjustment Component (AA) including balance at beginning of year, amounts recovered in the year to date, opening balance in the current month, amount recovered/(refunded) in current month, and closing balance as of end of current month
- Provides forecast for recovery/(refund) for remainder of year, and interest on the AA balance
- Summary of Balancing Adjustment (BA) Component including balance at beginning of year, amounts recovered/(refunded) prior to current month, opening balance in the current month, amount recovered/(refunded) in current month, and closing balance as of end of current month
- Provides forecast for recovery/(refund) for remainder of year, and interest on the BA balance

- Total FAM Deferral (Over)/Under-Recovery represents sum of BCF, AA and BA amounts.

M-3 TOTAL ACCUMULATED UNRECOVERED FAM BALANCE (Non-Confidential)

- Provides actual figures for month to date and forecast for remaining months of the year
- Outstanding AA and BA totals
- BCF Variance to current month and in current month
- Accumulated Interest amounts
- Total Outstanding
- Current month highlighted

M-4 FUEL POLICIES AND ORGANIZATIONAL CHANGES (Non-Confidential)

- Details of Fuel Manual Updates in the month
- Details of POA Updates in the month
- Details of any Organizational Updates or other relevant staff changes within Fuels, Energy and Risk Management or Fuels Finance

M-5 MERCURY ABATEMENT PROGRAM

(Confidential and Non-Confidential Versions)

- Mercury sorbent type (both any necessary oxidizing agent and the actual absorbent), quantity and costs by each generating plant per month
- Mercury Emission Levels estimate, forecast and variance for the month and year to date

M-6 VOLUME AND PRICING SUMMARY

(Confidential and Non-Confidential Versions)

- Per commodity breakdown of total consumption costs, consumption MMBtu, price $/MMBtu and price $/MWh for Solid Fuel, Natural Gas, Biomass, Bunker Oil (Heavy Fuel Oil), Light Fuel Oil, Imports, Non-Wind IPP Purchases, Wind IPP Purchases and COMFIT

- Broken down by actual, budget and percent change in current month, actual and budget amounts for the year to date, and total budget for the year

M-7 VOLUME AND PRICING SUMMARY (Non-Confidential)

- Provides information about categories, variance from budget, and detailed explanation of the reason for the variance
- Information provided for Total Fuel and Purchased Power Expense, Total System Requirements, Total FAM Sales, Net Fuel and Purchased Power Costs, Purchased Power Costs, Solid Fuel Costs, Natural Gas, Biomass Fuel Costs, Heavy Fuel Oil, Mercury Sorbent and Mercury Emissions

M-8 LOAD RETENTION TARIFF REVENUE REPORT

(Confidential and Non-Confidential Versions)

- Provides details per month for costs and MWh for Energy, Line Losses, Environmental Adder, Accrual Booked, Accrual Reversed and LRT Credit which links back to report on M-1
- Breaks down the charges on a calendar week basis for Energy Cost, Energy Used, Line Losses, Environmental Adder, Variable OM&G Costs, Fixed Costs, Variable Capital Costs, Customer Charge and Total Billed

M-9 NS POWER ENERGY MARKETING INC. TRANSACTION REPORTING

(Confidential and Non-Confidential Versions)

- Provides details per month on the purchase and sale of power, fuel or other commodities between NS Power and NS Power Energy Marketing Inc. (NSPEMI).
- Breaks down the transactions by product, buy/sell, date/time volume, price, and cost or revenue.

ADDITIONAL DOCUMENTS:

- FAM Calculation Model
- Detailed Cover Letter explaining variances in fuel and purchased power costs and revenues in the month

QUARTERLY:

Q-1 FUEL PORTFOLIO COMPLIANCE (**Confidential**)

- Hedging Report by commodity
- Including solid fuel and related transportation contract details
- Commentary providing basis for commodity hedges in relevant years

Q-1a SOLID FUEL PORTFOLIO UPDATE (**Confidential)**

- Supplier and contract information

Q-2 FOREIGN CURRENCY EXCHANGE PROGRAM (**Non-Confidential**)

- Hedging summary of foreign exchange
- Including FX rates
- New contract details

Q-3 NEW FUEL CONTRACT SUMMARY (**Confidential**)

- Contract type, supplier, term, volume, price details for new physical contracts with terms less than and greater than one year or one month

Q-4 CONTRACT UPDATE (**Confidential**)

- Commentary on changes in fuel contracts, status on all litigations and force majeure
- Records of procurement approvals and actual supplier contracts are catalogued and available in the electronic FAM Data Cart.

Q-5 SOLID FUEL INVENTORY (**Confidential**)

- Solid fuel inventory levels in tons and number of weeks supply with comparison target levels
- Reporting periods include current quarter, forecast rest of year

Q-6 GENERATION AND PURCHASED POWER STATISTICS (Non-Confidential)

- Generation statistics by unit including station service
- Export Sales
- Purchases
- GRLF, Load Retention, Shore Power, 1PT RTP, Back Up/Top Up and Losses
- Reporting periods include current quarter, year to date, prior period year to date, forecast rest of year

Q-7 NATURAL GAS DETAIL REPORT (Confidential)

- Natural gas purchase quantities by supplier
- Prices paid for quantities purchased
- Cost/benefit of settled hedges applicable to purchases
- Quantities consumed to generate electricity, separating volumes between Tuft's Cove Units 1-3 and LM6000 TUC Units 4-5
- Cost of gas applicable to quantity consumed, separating the cost/benefit of settled hedges
- Quantities sold for resale
- Revenue from sales
- Settlement of gas sale hedges applicable for resale
- Cost of gas purchased
- Net margin on gas sales
- Changes in inventory position and cost of inventory
- Reporting periods includes current quarter, rest of year forecast, 200X + 1 forecast

Q-8 FUEL OIL DETAIL REPORT (Confidential)

- Quantities purchased and cost of purchases
- Quantity forecasted to be purchased for next calendar year.
- Cost of purchases including hedges
- Quantity consumed to generate electricity
- Cost of quantity consumed including hedges
- Changes in inventory position and applicable cost of inventory

- Reporting periods include current quarter, rest of year forecast, 200X + 1forecast

Q-9 IMPORT POWER AND EXPORT DETAIL REPORT (**Confidential**)

- Quantities purchased and sold
- Cost of quantities purchased
- Revenue of quantities sold
- Reporting periods (current quarter)
-

Q-10 HISTORICAL FUEL COST GRAPH SUMMARY (**Confidential**)

- Quarterly Five Year Summary of Fuel costs per MWh (Solid Fuel, Natural Gas, HFO, Diesel)
- Monthly Three Year Summary of natural gas, HFO, and LFO prices
- Monthly Three Year Summary of natural gas, HFO, and LFO volumes
- Quarterly Five Year Summary of natural gas resale margin
- Monthly Three Year Summary of natural gas revenue per mmbtu
- Quarterly Five Year Summary of solid fuel costs per mmbtu
- Five Year Summary of annual generation by fuel type

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- Updated plant maintenance schedule for the current year

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(**Confidential and Non-Confidential Versions**)

- Cumulative quarterly mercury capture costs by each generating plant
- Type and amount of sorbent used (oxidizing agent and absorbent) for each generating unit
- Fuel and fuel mix by each generating plant
- Tracking of emissions compared to mercury emissions cap
- Technical issues related to mercury capture technology and impacts on fuel and fuel mix

Q-13 POWER GENERATION & FUEL REPORT (Confidential)

- Report package referenced in the NSPI Fuel Manual. Report package includes details on net generation by type, solid fuel costs by type, heat rate by plant, natural gas sales, export sales, generation statistics, and fuel costs by plant.
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- Q-13d Power Production Solid Fuel Costs – per month in the quarter
- Q-13e Power Production Heat Rate Report – per month in the quarter
- Q-13f Natural Gas Report – per month in the quarter
- Q-13g Export Sales Report – per month in the quarter
- Q-13h Generation Statistics – per month in the quarter
- Q-13i Generation Statistics – Renewables – per month in the quarter
- Q-13j Renewables Costs – per month in the quarter
- Q-13k Power Plant Average Thermal Load MW/Hr – per month in the quarter
- Q-13l Lingan Station Fuel Cost – per month in the quarter
- Q-13m Lingan Solid Fuel Cost – per month in the quarter
- Q-13n Lingan Heat Rate Report – per month in the quarter
- Q-13o Point Aconi Station Fuel Cost – per month in the quarter
- Q-13p Point Aconi Solid Fuel Costs – per month in the quarter
- Q-13q Trenton 5 Station Fuel Cost – per month in the quarter
- Q-13r Trenton 5 Solid Fuel Costs – per month in the quarter
- Q-13s Trenton 6 Station Fuel Cost – per month in the quarter
- Q-13t Trenton 6 Solid Fuel Costs – per month in the quarter
- Q-13u Trenton Heat Rate Report – per month in the quarter
- Q-13v Point Tupper Station Fuel Cost – per month in the quarter
- Q-13w Point Tupper Solid Fuel Costs – per month in the quarter
- Q-13x Tufts Cove Station Fuel Cost – per month in the quarter
- Q-13y Tufts Cove Heat Rate Report – per month in the quarter
- Q-13z LM6000 Station Fuel Costs – per month in the quarter
- Q-13aa LM6000 Heat Rate Report – per month in the quarter
- Q-13ab Combustion Turbines Station Fuel Costs – per month in the quarter

- Q-13ac Port Hawkesbury Biomass Station Fuel Costs – per month in the quarter
- Q-13ad Port Hawkesbury Biomass Solid Fuel Costs – per month in the quarter

ADDITIONAL DOCUMENTS:

- FAM Data Cart Index (Non-Confidential)
- Natural Gas Market Update (Confidential – FAM Data Cart)

ANNUAL

A-1 ORGANIZATION CHART - FUELS (**Non-Confidential**)

- Full organizational chart for positions reporting to Director, Fuels, Energy and Risk Management
- Commentary notes on vacant positions and position replacements

A-2 GENERATION UNIT SUMMARY (**Non-Confidential**)

- Breakdown of generating units by type showing in-service date, net capacity, fuel type, and annual energy for the year ended.

A-3 FUEL COST SUMMARY (**Confidential**)

- Fuel costs summary by type per MWh
- Reporting periods include year to date, prior period year to date, forecast next year

A-4 FUEL SPECIFICATIONS SUMMARY (**Non-Confidential**)

- Physical characteristics and chemical specification sheets for all fuels (HFO, Diesel, Mid Sulphur Coal, Low Sulphur Coal, Petroleum Coke, Natural Gas, Biomass)

A-5 IPP CONTRACT SUMMARY (**Confidential**)

- Summary of IPP contracts including installed capacity and annual energy for the year ended.

A-6 PLANT PERFORMANCE (**Confidential/Non-Confidential**)

- Summary of capacity factor (non-confidential), availability factor (non-confidential), heat rate (confidential), and DAFOR (non-confidential) by unit
- Unit Forced Outage & Management Response (confidential)
- Generation Equipment Reporting (confidential)

A-7 PLANT MAINTENANCE (Confidential/Non-Confidential)

- Power Production unit maintenance schedule (confidential) of all units (planned vs actual and budget schedule)
- OM&G and Capital spending by station (non-confidential)
- Reporting periods include year to date, prior period year to date, forecast next year
- Identification of major projects for current year
- NOTE: The first report will provide the baseline of planned and actual plant maintenance schedules for the historical period. The baseline of OM&G and capital spending as well as the identification of major projects will be provided for the historical period with the first report.

A-8 T&D SYSTEM LINE LOSSES (Non-Confidential)

- Total line losses for reporting periods year to date, prior period year to date and forecast next year

A-9 EMISSION COMPLIANCE (Non-Confidential)

- Summary of applicable emissions targets legislated and compliance accomplished for past year and current year, and how compliance is planned for the upcoming year and five years into the future.

A-10 SUMMARY OF PROJECTED FUEL EXPENSE FOR THE NEXT 2 YEARS (Confidential)

- Summary of Fuel Costs by Type ($Millions). Detail will be provided in standardized filing requirement for the next year and high level number for second year.
- Output from Strategist model supporting forecasts
- Solid Fuel summary including projected commodity costs, ocean freight, land transportation and associated foreign exchange costs. Commodity cost details include forecast assumptions for contracted and uncommitted tonnages.
- A-10a Fuel Summary by Type
- A-10b Net Generation by Fuel Type

- A-10c Power Production Thermal Station Fuel Costs
- A-10d Power Production Solid Fuel Costs by Supplier
- A-10e Power Production Heat Rate Report
- A-10f Natural Gas Report
- A-10g Export Sales Report – Monthly Forecast
- A-10h Generation Statistics – MWh
- A-10i Generation Statistics – Renewables
- A-10j Renewables Costs (Monthly)
- A-10k Power Production Average Load Report
- A-10l Lingan Monthly Station Fuel Costs
- A-10m Lingan Solid Fuel Costs by Supplier
- A-10n Lingan Heat Rate Report
- A-10o Point Aconi Monthly Station Fuel Costs
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- A-10q Trenton 5 Monthly Station Fuel Costs
- A-10r Trenton 5 Solid Fuel Costs by Supplier
- A-10s Trenton 6 Monthly Station Fuel Costs
- A-10t Trenton 6 Solid Fuel Costs by Supplier
- A-10u Trenton Heat Rate Report
- A-10v Point Tupper Monthly Station Fuel Costs
- A-10w Point Tupper Solid Fuel Costs by Supplier
- A-10x Tufts Cove Thermal Station Fuel Costs
- A-10y Tufts Cove Heat Rate Report
- A-10z LM6000 Thermal Station Fuel Costs
- A-10aa Combustion Turbines Thermal Station Fuel Costs
- A-10ab Port Hawkesbury Biomass Station Fuel Costs
- A-10ac Port Hawkesbury Biomass Solid Fuel Costs by Supplier
- A-10ad Summary of [Year +1] Projected Fuel Expense – PLEXOS Output
- A-10ae Summary of [Year +1] Projected Fuel Expense – Solid Fuel Costs
- A-10af Summary of Projected Fuel Expense – [Year +1] Outlook

A-11 SUMMARY OF SALES BY CUSTOMER CLASS FOR THE NEXT 2 YEARS

(**Confidential**)

A-12 AFFILIATE TRANSACTIONS (**Confidential**)

- Summary of all fuel and power related affiliate transactions for the period

A-13 MERCURY ABATEMENT PROGRAM

(**Confidential and Non-Confidential Versions**)

- A-13a Cumulative quarterly mercury capture costs by each generating plant (non-confidential)
- A-13a Type and amount of sorbent used (oxidizing agent and absorbent) for each generating unit (confidential)
- A-13a Fuel and fuel mix by each generating plant (non-confidential)
- A-13a Tracking of emissions compared to mercury emissions cap (non-confidential)
- A-13bTechnical issues related to mercury capture technology and impacts on fuel and fuel mix (non-confidential)
- A-13b Quantitative and qualitative descriptions of the impact on fuel use (non-confidential)
- A-13c Technical or capital changes that may be required to achieve mercury emissions limits (non-confidential)
- A-13d Estimate of the amount and cost of sorbent (oxidizing agent and absorbent) anticipated for the upcoming year (confidential)

Nova Scotia Power Inc.
Monthly FAM Reporting
For the Period Ended Month, Day, Year

CONFIDENTIAL

Nova Scotia POWER
An Emera Company

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Nova Scotia Power Inc. **NSPI (FAM) M-1**
Monthly FAM Reporting **NON CONFIDENTIAL**
Summary of Fuel Costs
For the Period Ended Month, Day, Year
(millions of dollars)

	Current Month		Year-to-Date		Year Budget	
	Actual	Budget	Actual	Budget	Full Year Budget	% of Budget Spent
Fuel for Generation - Domestic Load						
Solid Fuel						
Natural Gas						
Biomass						
Bunker C						
Furnace						
Diesel						
Additives						
Subtotal						
Import Purchases						
Non-Wind IPP Purchases						
Wind Purchases						
COMFIT Purchases						
Fuel for Resale Net Margin						
Exports						
Fuel and Purchased Power						
Water Royalties						
Total Fuel and Purchased Power						
Less: Load Retention Revenue						
Total Fuel and Purchased Power Less LRT Revenue						
Less: Export Revenues						
Less: 1PT RTP						
Less: Shore Power						
Less: Back Up / Top Up						
Less: GRLF Fuel Costs						
Loss / (Gain): Foreign exchange - Fuel Other						
Net Fuel and Purchased Power						
Total System Requirements (GWh)						
Less: Export Sales and Attributed Losses						
Less: GRLF Requirements						
Less: Load Retention						
Less: Shore Power						
Less: 1PT RTP						
Less: Back Up / Top Up						
Less: Losses*						
Total FAM Sales						

Figures presented are rounded to one decimal place which may cause $0.1M in rounding differences on some line items.

The FAM Budget reflects the 2016 BCF Compliance filing of $542M.

*Includes losses for all customer classes, with the exception of Export Sales.

Nova Scotia Power Inc.
Monthly FAM Reporting
Summary of Cost Recovery
For the Period Ended Month, Day, Year
(millions of dollars)

NSPI (FAM) M-2
NON CONFIDENTIAL

Base Fuel Component (BCF)

	Actual	Budget
(Over)/Under-recovered Prior to Current Month		
(Over)/Under-recovered in Current Month		
Balance Yet to be Recovered		
(Over)/Under-recovery- Remainder of the Year		
Interest on BCF Balance		

Actual Adjustment Component (AA)

Year Beginning AA Balance		
Recovered Prior to Current Month		
Opening Balance as of Month 1, Year		
Recovered/(Refunded) in Current Month		
Closing Balance as of Month Day, Year		
Recovered/(Refunded) Remainder of the Year		
Interest on AA Balance		

Balancing Adjustment Component (BA)

Year Beginning BA Balance		
Recovered Prior to Current Month		
Opening Balance as of Month 1, Year		
Recovered/(Refunded) in Current Month		
Closing Balance as of Month Day, Year		
Recovered/(Refunded) Remainder of the Year		
Interest on BA Balance		
Total FAM Deferral (Over)/Under-Recovery		

Figures presented are rounded to two decimal place which may cause $0.1M in rounding differences on some line items.

The FAM Budget reflects the XXX budget filed with the Board on Month Day, Year.

Commentary for Month: Please see M1 for explanation of fuel costs included in the BCF. AA/BA amounts collected/refunded during the month were above/below budget due to in/decreased FAM sales.

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Nova Scotia Power Inc. **NSPI (FAM) M-3**
Monthly FAM Reporting **NON CONFIDENTIAL**
2016 Total Accumulated Unrecovered FAM Balance
For the Period Ended Month, Day, Year
(millions of dollars)

Month	BA Total Outstanding	AA Total Outstanding	BCF Variance		Accumulated Interest	Total Outstanding
			To Current Month	Current Month		
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
Novemeber						
December						

Figures presented are rounded to one decimal place which may cause $0.1M in rounding differences on some line items

The highlighted rows reference the XXX budget filed with the Board on Month Day, Year.

Nova Scotia Power Inc. **NSPI (FAM) M-4**
Monthly FAM Reporting **NON CONFIDENTIAL**
Fuel Policies and Organizational Changes
For the Period Ended Month, Day, Year

Fuel Manual Updates

POA Updates

Organizational Updates

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Nova Scotia Power Inc.
Monthly FAM Reporting
Mercury Abatement Program
For the Period Ended Month, Day, Year
(millions of dollars)

NSPI (FAM) M-5
CONFIDENTIAL

		Current Month			Year-to-Date		
Generating Unit	**Additive Type**	**Quantity**	**Cost**	**$/MWh**	**Quantity**	**Cost**	**$/MWh**
Lingan - Unit 1	Powder Activated Carbon	kgs			kgs		
Lingan - Unit 2	Powder Activated Carbon	kgs			kgs		
Lingan - Unit 3	Powder Activated Carbon	kgs			kgs		
Lingan - Unit 4	Powder Activated Carbon	kgs			kgs		
Point Tupper	Powder Activated Carbon	kgs			kgs		
Trenton 5	Powder Activated Carbon	kgs			kgs		
Trenton 6	Powder Activated Carbon	kgs			kgs		
Lingan	Calcium Chloride	L			L		
Point Tupper	Calcium Chloride	L			L		
Trenton	Calcium Chloride	L			L		
Total Costs - Powder Activated Carbon		**kgs**	**$0.000**		**- kgs**	**$0.000**	
Total Costs - Calcium Chloride		**L**	**$0.000**		**- L**	**$0.000**	
Total Mercury Sorbent Costs			**$0.000**			**$0.000**	

[a] Calculated using actual MWh produced by unit.

Commentary for the month:

NSPI Environmental Report for Mercury Emissions (b)

Annual Limit = 65 kg (c)

Month	Reported this month (d)	Reported last month	Variance	Reason for variance	2017 Actuals (e)
Jan					
Feb					
Mar					
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Year to Date (f)					

[b] As reported by NSPI's Environmental Services.

[c] Province of Nova Scotia Air Quality Regulations - Schedule C section 3(2).

[d] This value is an estimate based on incomplete laboratory results and consumption figures. Environmental Services will finalize this result next quarter.

[e] Shown for comparative purposes

f Figures presented are rounded to one decimal place which may cause $0.1M in rounding differences on some line items

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Power Inc.
Monthly FAM Reporting
Mercury Abatement Program
For the Period Ended Month, Day, Year
(millions of dollars)

NSPI (FAM) M-5
CONFIDENTIAL

		Current Month			Year-to-Date		
Generating Unit	**Additive Type**	**Quantity**	**Cost**	**$/MWh**	**Quantity**	**Cost**	**$/MWh**
Lingan - Unit 1	Powder Activated Carbon	kgs			kgs		
Lingan - Unit 2	Powder Activated Carbon	kgs			kgs		
Lingan - Unit 3	Powder Activated Carbon	kgs			kgs		
Lingan - Unit 4	Powder Activated Carbon	kgs			kgs		
Point Tupper	Powder Activated Carbon	kgs			kgs		
Trenton 5	Powder Activated Carbon	kgs			kgs		
Trenton 6	Powder Activated Carbon	kgs			kgs		
Lingan	Calcium Chloride	L			L		
Point Tupper	Calcium Chloride	L			L		
Trenton	Calcium Chloride	L			L		
Total Costs - Powder Activated Carbon		**kgs**	**$0.000**		**- kgs**	**$0.000**	
Total Costs - Calcium Chloride		**L**	**$0.000**		**- L**	**$0.000**	
Total Mercury Sorbent Costs			**$0.000**			**$0.000**	

[a] Calculated using actual MWh produced by unit.

Commentary for the month:

NSPI Environmental Report for Mercury Emissions (b)

Annual Limit = 65 kg (c)

Month	Reported this month (d)	Reported last month	Variance	Reason for variance	2017 Actuals (e)
Jan					
Feb					
Mar					
Apr					
May					
Jun					
Jul					
Aug					
Sep					
Oct					
Nov					
Dec					
Year to Date (f)					

[b] As reported by NSPI's Environmental Services.

[c] Province of Nova Scotia Air Quality Regulations - Schedule C section 3(2).

[d] This value is an estimate based on incomplete laboratory results and consumption figures. Environmental Services will finalize this result next quarter.

[e] Shown for comparative purposes

f Figures presented are rounded to one decimal place which may cause $0.1M in rounding differences on some line items

Nova Scotia Power Inc.
Monthly FAM Reporting
Volume and Pricing Summary
For the Period Ended Month, Day, Year

NSPI (FAM) M-6
CONFIDENTIAL

	Current Month			Year-to-Date		Year Budget
	Actual	Budget	% Change	Actual	Budget	Budget
Solid Fuel						
Solid Fuel Consumption Costs ($)						
Solid Fuel Consumption (MMBtu)						
Solid Fuel Price ($/MMBtu)[1]						
Solid Fuel Price ($/MWh)						
Natural Gas						
Natural Gas Consumption Costs ($)						
Natural Gas Consumption (MMBtu)						
Natural Gas Price ($/MMBtu)[1]						
Natural Gas Price ($/MWh)						
Biomass						
Biomass Consumption Costs ($)						
Biomass Consumption (MMBtu)						
Biomass Price ($/MMBtu)						
Biomass Price ($/MWh)						
Bunker						
Bunker Consumption Costs ($)						
Bunker Consumption (MMBtu)						
Bunker Price ($/MMBtu)						
Bunker Price ($/MWh)						
Light Fuel Oil						
Light Fuel Oil Consumption Costs ($)						
Light Fuel Oil Consumption (MMBtu)						
Light Fuel Oil Price ($/MMBtu)						
Light Fuel Oil Price ($/MWh)						
Imports						
Imported Power Volume (MWh)						
Imported Power Price ($/MWh)						
Non-Wind IPP Purchases						
IPP Purchase Volumes (MWh)						
IPP Purchase Price ($/MWh)						
Wind IPP Purchases						
Wind Purchase Volumes (MWh)						
Wind Purchase Price ($/MWh)						
COMFIT						
COMFIT Purchase Volumes (MWh)						
COMFIT Purchase Price ($/MWh)						

The FAM Budget reflects the Year Compliance filing of $XXXM.
Consumption cost totals above are at the forecasted effective USD rate for the year. These figures do not included the impact of monthly foreign exchange rate variations that are reflected in Summary of Fuel Costs (Report M-1).

[1] Includes impact of commodity hedge settlements.

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Nova Scotia Power Inc.
Monthly FAM Reporting
Volume and Pricing Summary
For the Period Ended Month, Day, Year

NSPI (FAM) M-7
NON CONFIDENTIAL

Category	Variance from budget	Details	Additional Comments
Total Fuel and Purchased Power Expense			
Total System Requirements			
Total FAM Sales			
Net Fuel and Purchased-Power Costs			
Purchased Power Costs			
Solid Fuel Costs			
Natural Gas			
Biomass Fuel Costs			
Heavy Fuel Oil			
Mercury Sorbent			
Mercury Emissions			

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NSPI (FAM) M-8
CONFIDENTIAL

Load Retention Tariff Revenue

	Month
Energy	
Line Losses	
Environmental Adder	
Accrual Booked	
Accrual Reversed	
LRT Credit in Monthly FAM Report	

The calculations in this Report and for the purpose of billing PHP in the report period have all been done consistent with the system differential calculation methodology outlined in Confidential Attachment A of the Synapse Audit Report. The individual components of the PHP bill are contained in the table below.

PHP LRT Report

Week	Energy Cost ($)	Energy (MWh)	Line Losses ($)	Environmental Adder ($)	Var OM&G ($)	Fixed cost ($)	Var Capital ($)	Customer charge ($)	Total Billed ($)
Week 1									
Week 2									
Week 3									
Week 4									
Billing Date									

As of January 10th, 2016 Nova Scotia Power (“NSP”) and Port Hawkesbury Paper (“PHP”) have agreed to settle the blending component of the environmental adder on a "month-after basis” where PHP pays their actual cost of blending. Once environmental compliance has been calculated for the previous month, blending costs are then allocated to PHP using the existing environmental cost calculation method. The cost of powder activated carbon (“PAC”) is now applied to the cost of fuel and charged as part of the weekly billing.

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Nova Scotia Power Inc.
Monthly FAM Reporting
NS Power Energy Marketing Inc. Transaction Reporting
For the Period Ended Month, Day, Year

NSPI (FAM) M-9
CONFIDENTIAL

Product	Buy/Sell	Date/Time	Volume	Price	Cost/(Revenue)	Note

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

CONFIDENTIAL

(Note - Figures presented reflect whole numbers which may cause $0.1M or 1% in rounding differences on some line items.)

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NON-CONFIDENTIAL

(Note - Figures presented reflect whole numbers which may cause $0.1M or 1% in rounding differences on some line items.)

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Point Aconi Station Fuel Cost	Confidential	Q-13o	
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Trenton 5 Station Fuel Cost	Confidential	Q-13q	
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Combustion Turbines Station Fuel Costs	Confidential	Q-13ab
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Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-1
CONFIDENTIAL

Compliance to the fuel portfolio and hedging plan

000s		Option Down	Year Plan	Option Up	Option Down	Year +1 Plan	Option Up	Option Down	Year +2 Plan	Option Up	Option Down	Year +3 Plan	Option Up	Option Down	Year +4 Plan	Option Up
SOLID FUEL	HEDGED MTS															
	OPEN MTS															
	TOTAL MTS															
	HEDGED %															
	OPEN %															
	TOTAL MTS															
	LONG (4 yrs +) Min 30% Max 50%															
	MEDIUM (1-4 yrs) Min 30% Max 50%															
	SHORT (less than 1 yr) Min 0% Max 30%															
	OPEN															
SOLID FUEL TRANSPORT	OCEAN FREIGHT Hedged %															
	Open %															
	LAND TRANSPORT Hedged %															
	Open %															

000s		Year Annual	Year +1 Annual	Year +2 Annual	Year +3 Annual
	HEDGED %				
	HEDGED BBLS				
	OPEN BBLS				
	TOTAL BBLS				

000s		Year Annual	Year +1 Annual	Year +2 Annual	Year Q3	Year Q4	Year +1 Q1	Year +1 Q2	Year +1 Q3	Year +1 Q4	Year +2 Q1	Year +2 Q2	Year +2 Q3	Year +2 Q4
NAT GAS	HENRY HUB HEDGED													
	BASIS HEDGE													
	Henry Hub Hedged %													
	Basis Hedged %													
	TOTAL MMBTUS													

Within Target Pending Rebalance Outside Target

Commentary - Fuel portfolio and hedging plan

Solid Fuel
Year is based on the Q1 Forecast, **including** PHP load. The Positions Required for [Year +1 to Year+4] are from the [BCF/GRA Source] without PHP load.

Fuel Oil Year is based on Q1 [Year] Forecast, including PHP load. [Year +1 to Year +3] is based on [BCF / GRA Source] excluding PHP load.

Natural Gas

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-1
CONFIDENTIAL

Compliance to the fuel portfolio and hedging plan

Summary of Solid Fuel Portfolio Status
(in thousands of metric tonnes)

Product	Supplier	2016	2017	2018	2019	2020
Low Sulphur Positions Required (tonnes)						
LS	Supplier					
LS	Supplier					
LS	Supplier					
LS	Supplier					
LS	Supplier					
LS	Supplier					
LS	Supplier					
LS	Supplier					
LS	Supplier					
	Contracted (tonnes)					
	Open (tonnes)					
Mid & High Sulfur Positions Required						
MS	Supplier					
MS	Supplier					
MS	Supplier					
MS	Supplier					
	Contracted (tonnes)					
	Open (tonnes)					
Domestic Positions Required						
DOM	Supplier					
DOM	Inventory					
	Contracted (tonnes)					
	Open (tonnes)					
Petroleum Coke Positions Required						
PC	Supplier					
PC	Supplier					
PC	Tricon					
	Contracted (tonnes)					
	Open (tonnes)					
Total						

*This portfolio provides all commitments, including contracts remaining to be executed.

		2016	2017	2018	2019	2020
Biomass						
Biomass	Supplier					
Biomass	Supplier					
Biomass	Supplier					
	Contracted (tonnes)					
	Open (tonnes)					

		2016	2017	2018	2019	2020
Solid Fuel Ocean Freight						
Ocean	Supplier					
Ocean	Supplier					
Ocean	Supplier					
Ocean	Delivered					
	Contracted (tonnes)					
	Open (tonnes)					
Solid Fuel Land Transportation						
Land	Supplier					
Land	Supplier					
Land	Delivered					
	Contracted (tonnes)					
	Open (tonnes)					

Small differences in the Solid Fuel Portfolio Status for required Solid Fuel positions and Solid Fuel transportation may exist due to the Solid Fuel positions recognizing vessels when they arrive and the Solid Fuel transportation recognizing vessels when they are loaded and due to Solid Fuel positions incorporating positive and negative open

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-1a
CONFIDENTIAL

Solid Fuel Portfolio Updates

Supplier	Mine Source	Contract Date						Update From Last Quarter: New Commitment or Change	New Agreement Execution Date	New Contract Year and Term (Short, Mid or Long)
	Low Sulphur		**2016**	**2017**	**2018**	**2019**	**2020**			
Supplier	Source		55							
Supplier	Source		159							
Supplier	Source		325	300						
Supplier	Source		50							
Supplier	Source		110							
Supplier	Source		163							
	Mid Sulfur		**2016**	**2017**	**2018**	**2019**	**2020**			
Supplier	Source		210	200	200					
Supplier	Source		3							
	Domestic		**2016**	**2017**	**2018**	**2019**	**2020**			
Supplier	Source		360	221						
	Petroleum Coke		**2016**	**2017**	**2018**	**2019**	**2020**			
Supplier	Source		215							
Supplier	Source			300	300	300				
Supplier	Source		226							
	Biomass		**2016**	**2017**	**2018**	**2019**	**2020**			
Supplier			38	-	-	-				
Supplier			62	-	-					
Supplier			5							

Short-term Contract
Mid-term Contract
Long-term Contract

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-2
NON-CONFIDENTIAL

Foreign Currency Exchange Program

	2016	2017	2018	2019	2020
$US Dollar ($Millions)					
Hedged - $					
Open - $					
Total Requirement					
Hedged - $ Rate					
Open - $ Forecasted Rate					
Total - $ Blended Rate					
Hedge %					
Open %					

*Total requirement is without PHP

Foreign Currency Exchange Program - New Contract Details

Value Date	USD Amount	Rate	CDN Amount	Execution Date

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-3
CONFIDENTIAL

New Fuel Contract Summary

Contract Type	Supplier	Term	Volume Base	Price	Execution Date
CONTRACTS ONE MONTH OR LESS					
CONTRACTS GREATER THAN ONE MONTH AND LESS THAN ONE YEAR					
CONTRACTS OF ONE YEAR AND GREATER					

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

Contract Update

Contract Type	Supplier	Status

Contract Changes

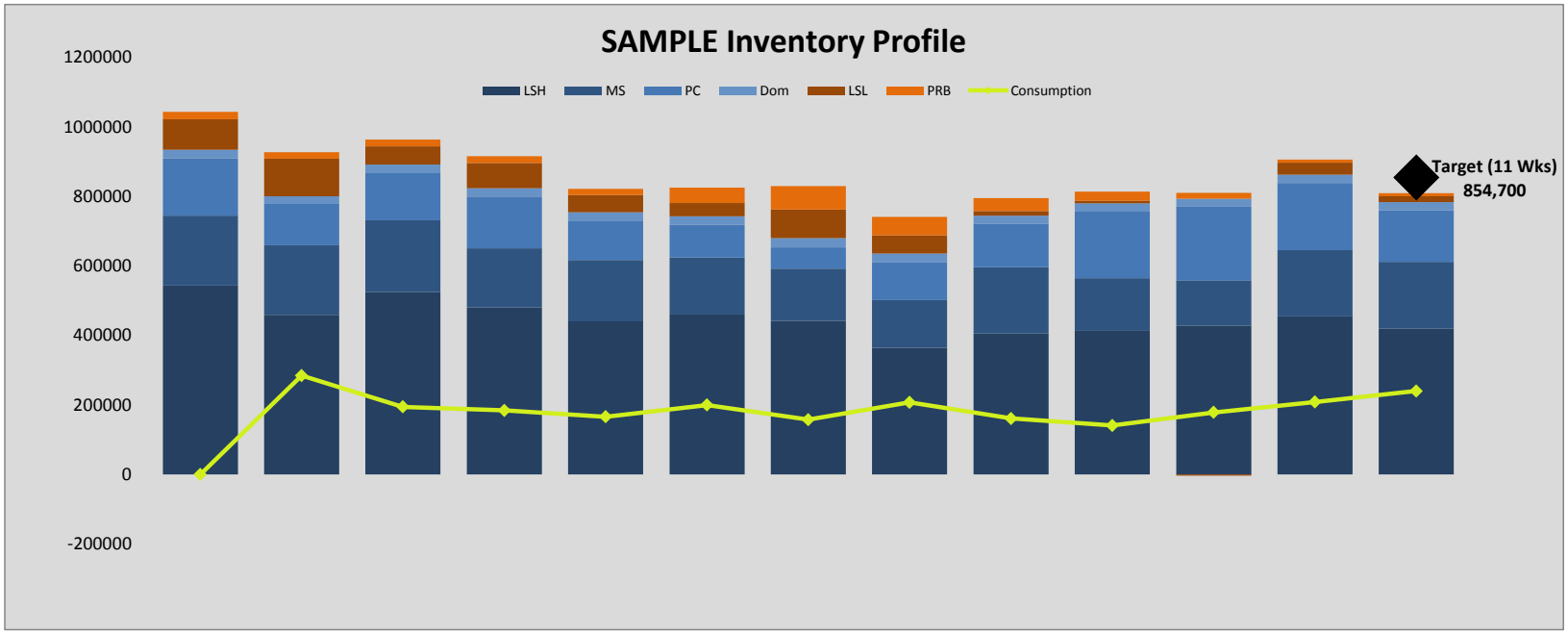
Litigation

Force Majeure

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-5
CONFIDENTIAL

Solid Fuel Inventory



Commentary:

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-6
NON-CONFIDENTIAL

Generation and Purchased Power Statistics

	Q1		Q2		Q3		Q4				
	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Current period Year-to-date	Prior period Year-to-date	Budget* Year-to-date
Net Generation (MWh)											
Lingan											
Unit #1											
Gross											
Station Service											
Net											
Unit #2											
Gross											
Station Service											
Net											
Unit #3											
Gross											
Station Service											
Net											
Unit #4											
Gross											
Station Service											
Net											
Pt. Aconi											
Gross											
Station Service											
Net											
Pt. Tupper											
Gross											
Station Service											
Net											
Trenton											
Unit #5											
Gross											
Station Service											
Net											

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-6
NON-CONFIDENTIAL

Generation and Purchased Power Statistics

	Q1		Q2		Q3		Q4				
	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Current period Year-to-date	Prior period Year-to-date	Budget* Year-to-date
Unit #6											
Gross											
Station Service											
Net											
Point Tupper Biomass											
Gross											
Station Service											
Net											
Tufts Cove											
Unit #1											
Gross											
Station Service											
Net											
Unit #2											
Gross											
Station Service											
Net											
Unit #3											
Gross											
Station Service											
Net											
LM 6000 (Tufts Cove #4)											
Gross											
Station Service											
Net											
LM6000 (Tufts Cove #5)											
Gross											
Station Service											
Net											

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-6
NON-CONFIDENTIAL

Generation and Purchased Power Statistics

	Q1		Q2		Q3		Q4				
	Actual	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Current period Year-to-date	Prior period Year-to-date	Budget* Year-to-date
LM6000 (Tufts Cove #6)											
Gross											
Station Service											
Net											
Total CT's											
Gross											
Station Service											
Net											
Total Hydro											
Gross											
Station Service											
Net											
Total NSPI Wind											
Gross											
Station Service											
Net											
Total Generation											
Gross											
Station Service											
Net											
Purchases											
Imports											
IPP											
Total KWh Available											
Less Export Sales											
Losses (Export Sales)											
Net System Requirement											
Less GRLF requirement											
Less Load Retention											
Less Shore Power											
Less 1PT RTP											
Less Back Up/Top Up											
Less Losses **											
Net Requirement											

Note: LM6000 (Tufts Cove #6) budgeted generation is combined with Tufts Cove # 4 and Tufts Cove #5.
*2016 BCF Compliance Budget
**Includes losses for all customer classes, with the exception of Export Sales.

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-7
CONFIDENTIAL

Natural Gas Details

	Current Quarter Actual	Current Quarter Budget	Year-to-date	Rest of Year Budget	Year+1 Forecast
Purchases					
Supplier (MMBtu)					
Supplier (MMBtu)					
Supplier (MMBtu)					
Supplier (MMBtu)					
Supplier (MMBtu)					
Supplier (MMBtu)					
Supplier (MMBtu)					
Supplier (MMBtu)					
Supplier (MMBtu)					
Spot Gas (MMBtu)					
Cost of purchases (excluding hedges) ($M)					
Settlement of hedges (gain) loss ($M)					
Gas Consumed					
Gas Burn TUC1-3 (mmbtu)					
Gas Burn TUC4-6 (mmbtu)					
Gas Burn PHB (mmbtu)					
Cost of gas consumed (excluding hedges) ($M)					
Settlement of hedges (gain) loss ($M)					
Gas Resale					
Gas sold - mmbtu					
Revenue (excluding hedges) ($M)					
Settlement of hedges (gain) loss ($M)					
Cost of gas resold (excluding hedges) ($M)					
Net Margin ($M)					
Ending inventory					
Gas inventory - mmbtu					
Cost of inventory ($M)					

Figures presented are rounded to one decimal place which may cause $0.1M in rounding differences on some line items
Budget Figures are from [BCF/GRA Source]

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-8
CONFIDENTIAL

Heavy Fuel Oil Details

	Current Quarter Actual	Current Quarter Budget	Year-to-date	Rest of Year Budget	Year+1 Forecast
Purchases					
Purchase quantities (Barrels)					
Cost of purchases (excluding hedges) ($M)					
Settlement of hedges (gain) loss ($M)					
Consumption					
HFO consumed (Barrels)					
Cost of fuel consumed (excluding hedges) ($M)					
Settlement of hedges (gain) loss ($M)					
Ending inventory					
HFO inventory (Barrels)					
Cost of inventory (excluding hedges) ($M)					
Settlement of hedges (gain) loss ($M)					

*[BCF/GRA Source]
**[BCF/GRA Source]

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-8
CONFIDENTIAL

Furnace Oil Details

	Current Quarter Actual	Current Quarter Budget	Year-to-date	Rest of Year Budget	Year+1 Forecast
Purchases					
Purchase quantities (Gallons)					
Cost of purchases ($M)					
Consumption					
Furnace Oil consumed (Gallons)					
Cost of fuel consumed ($M)					
Ending Inventory					
Furnace Oil inventory (Gallons)					
Cost of inventory ($M)					

Diesel Details

	Current Quarter	Current Quarter Budget	Year-to-date	Rest of Year Budget	2017 Forecast
Purchases					
Purchase quantities (Gallons)					
Cost of purchases ($M)					
Consumption					
Diesel consumed (Gallons)					
Cost of fuel consumed ($M)					
Ending Inventory					
Diesel inventory (Gallons)					
Cost of inventory ($M)					

*[BCF/GRA Source]
**[BCF/GRA Source]

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

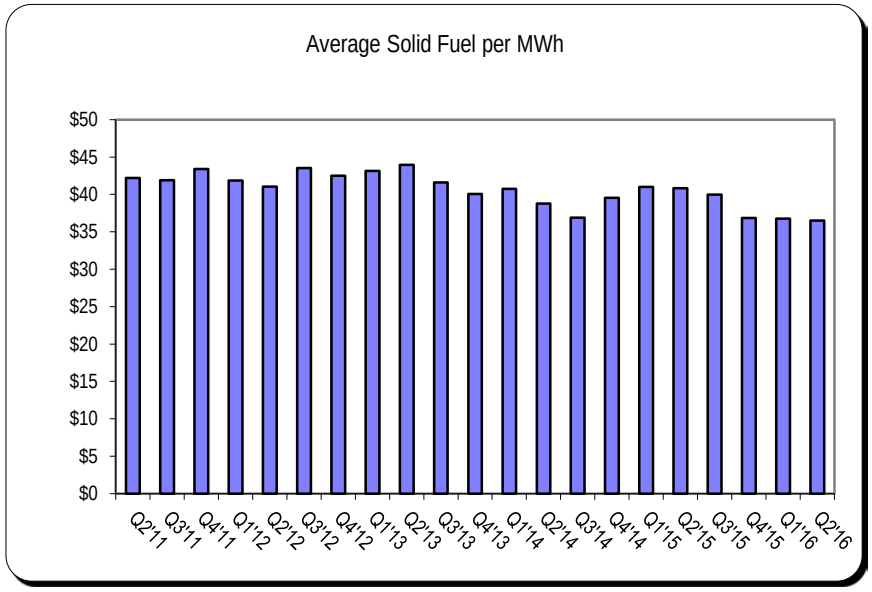
NSPI (FAM) Q-9
CONFIDENTIAL

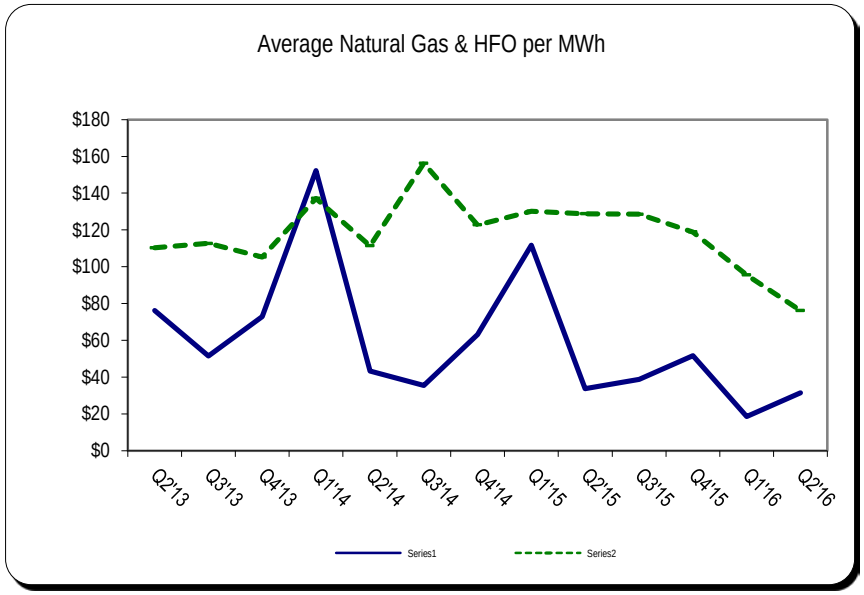
Import Power & Exports

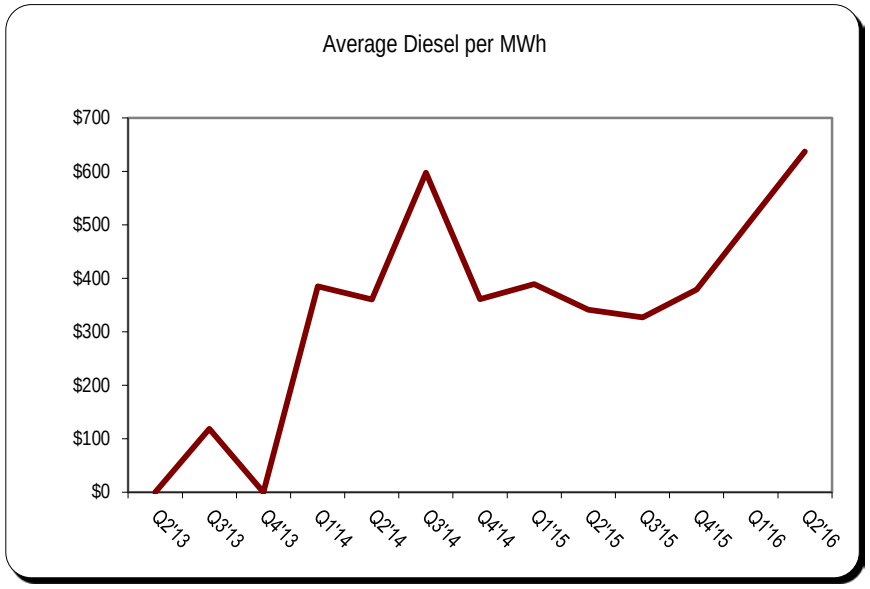
Transaction	Term	Quarterly Volume (MWh)	Weighted Average Price
Imports			
Imports			
Cost/(Benefit) of hedges			
Exports			
Exports			
Cost/(Benefit) of hedges			

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

Fuel Costs per MWh







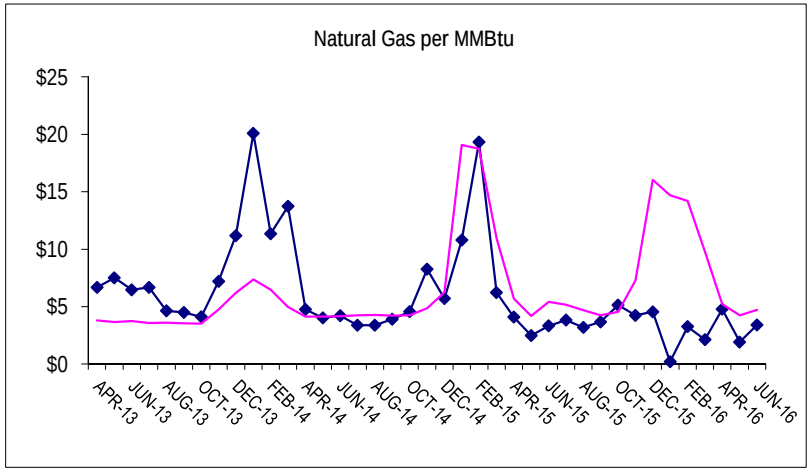
Data points represented as blank reflect values outside of the graph range or station service skewing the $/MWh due to minimal generation.

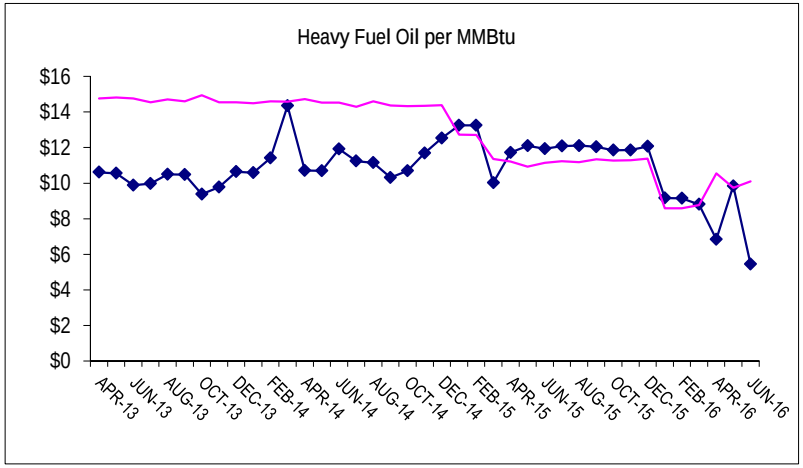
Fuel costs include the effect of hedges.

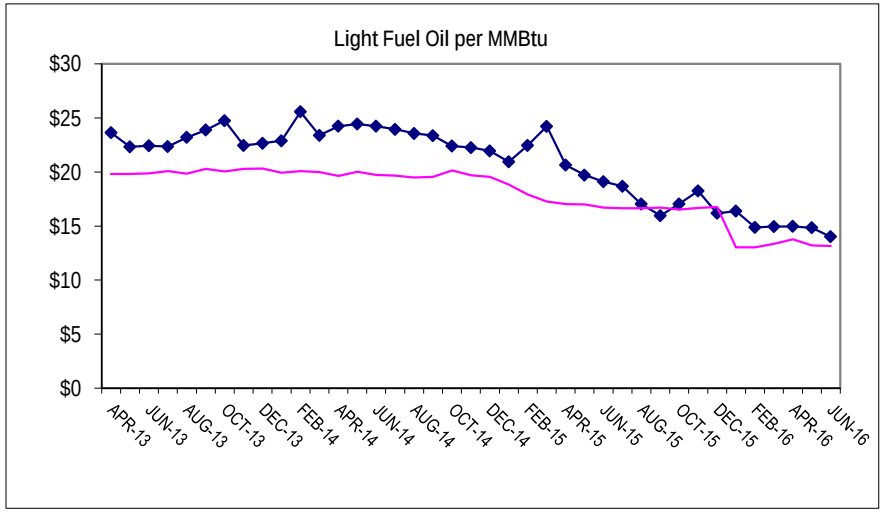
Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-10
CONFIDENTIAL

Fuel Costs per MMBtu
Actual vs. Budget







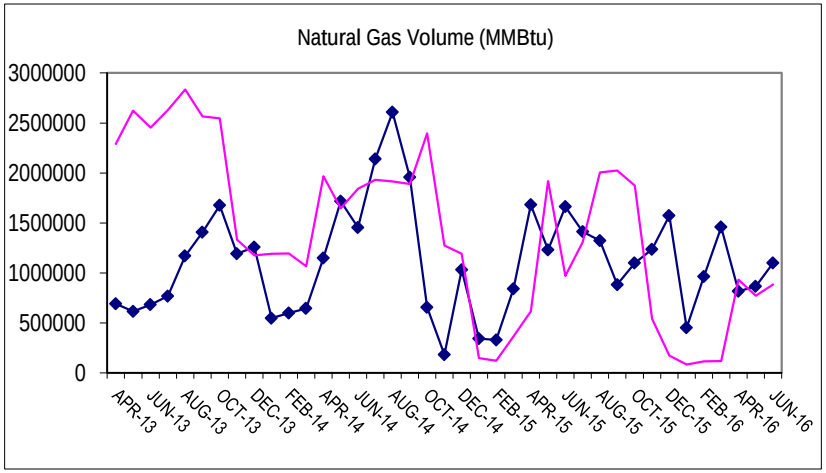
Data points represented as blank reflect values outside of the graph range.

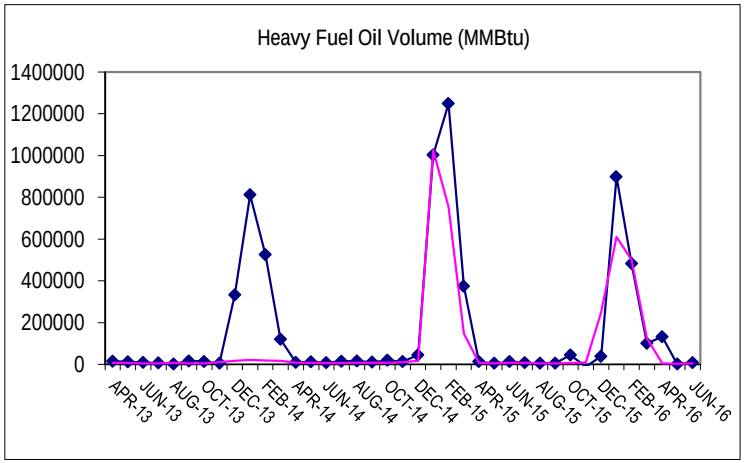
Fuel costs include the effect of hedges.

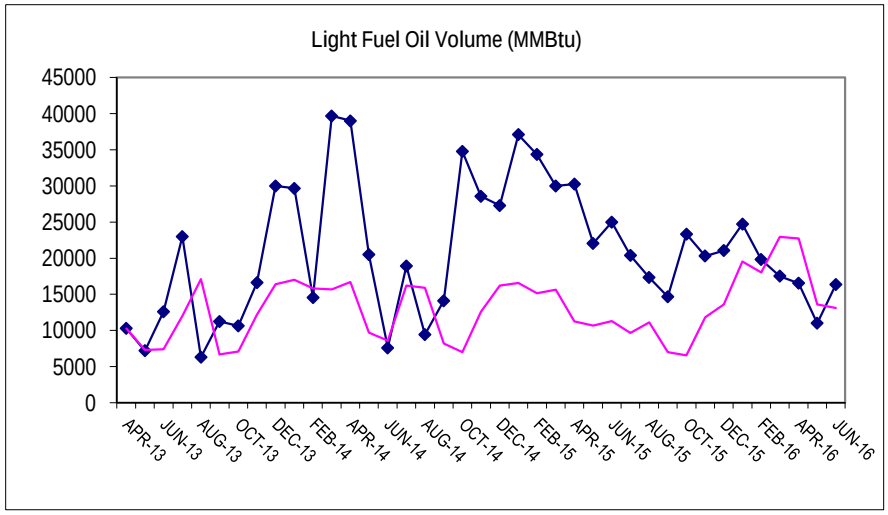
Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-10
CONFIDENTIAL

Fuel Volumes (MMBtu)
Actual vs. Budget





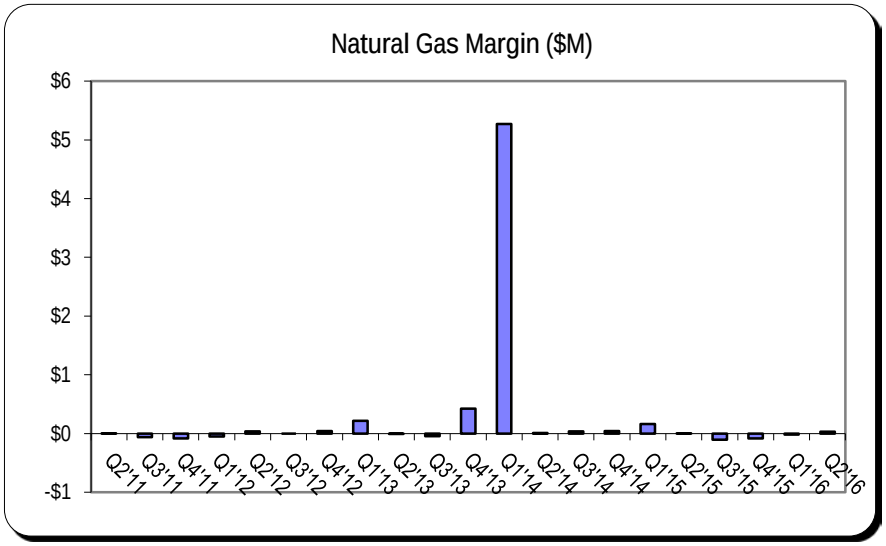


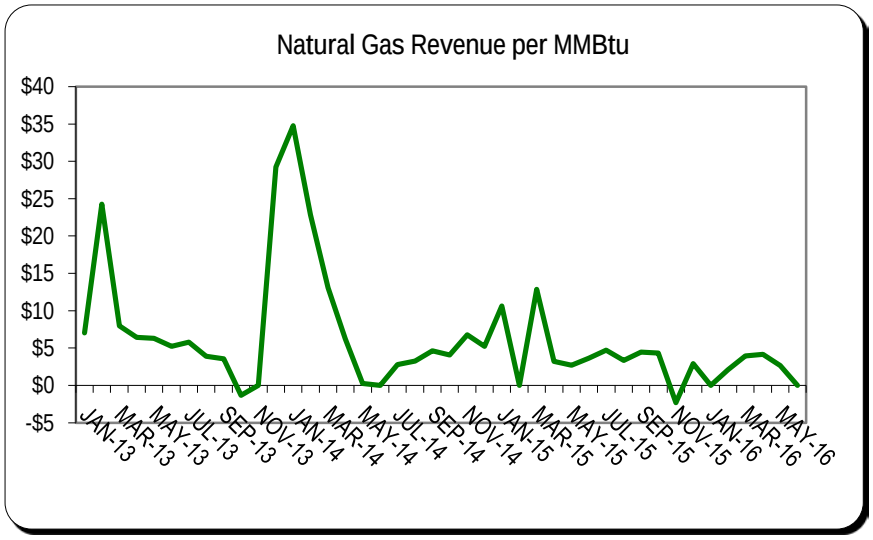
Data points represented as blank reflect values outside of the graph range.

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-10
CONFIDENTIAL

Natural Gas Sales Program



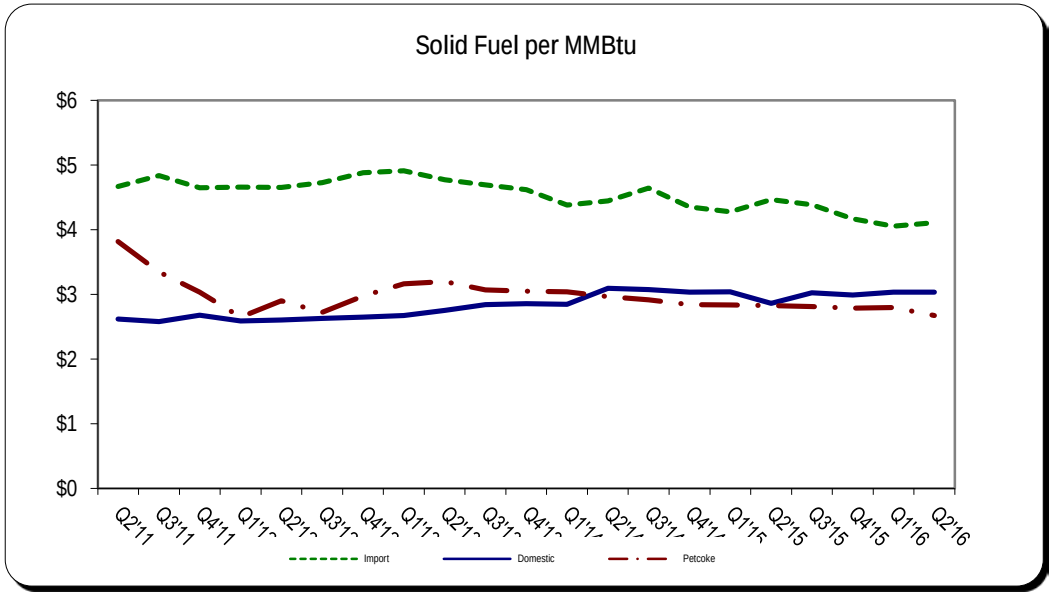


Natural gas margin is calculated using an average cost of natural gas for the month.

Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-10
CONFIDENTIAL

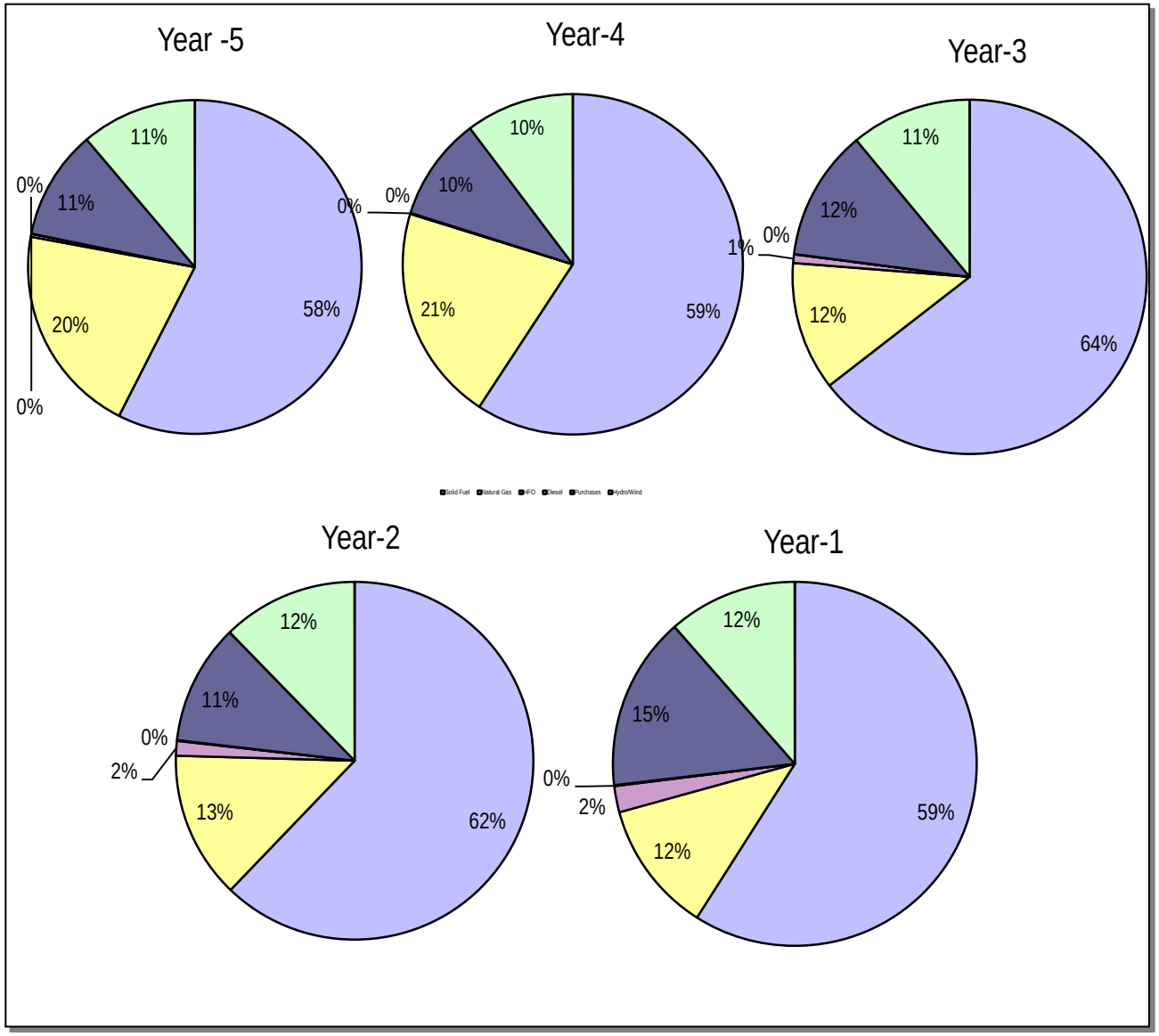
Solid Fuel Program



Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

NSPI (FAM) Q-10
CONFIDENTIAL

Annual Generation by Fuel Type



Nova Scotia Power Inc.
Quarterly FAM Reporting
As at [Month Day, Year]

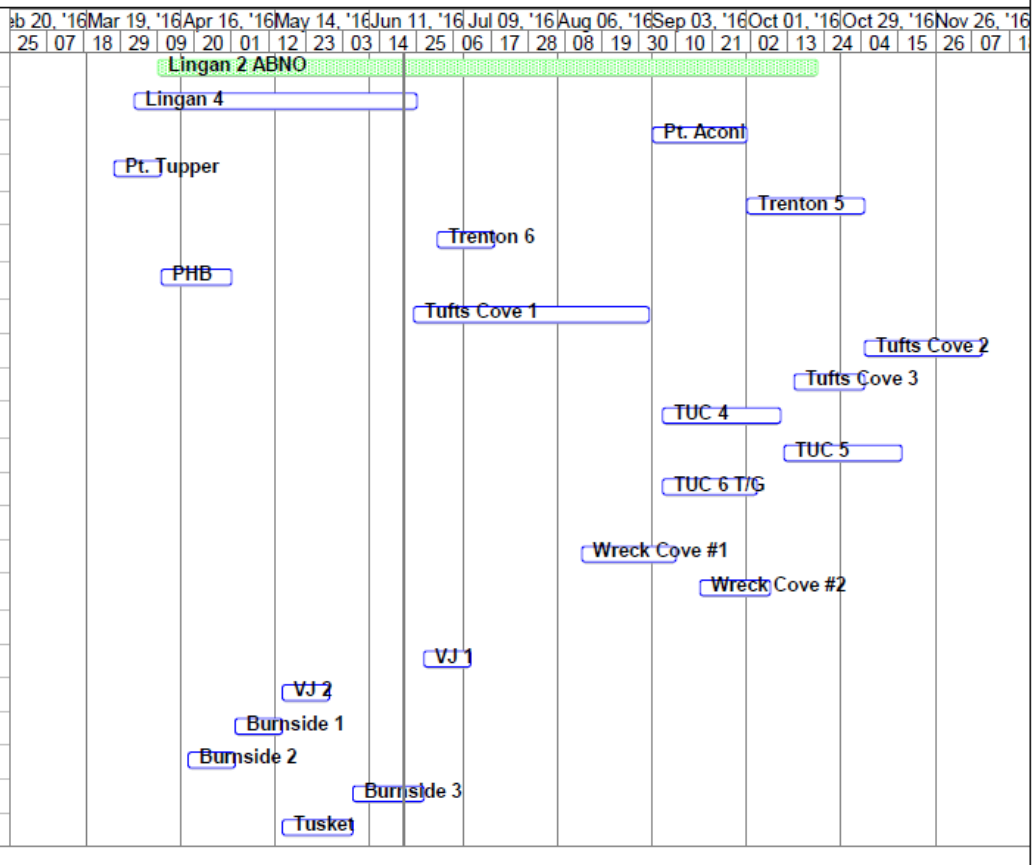
NSPI (FAM) Q-11
CONFIDENTIAL

Thermal Plant Maintenance Schedule

APPROVED

2016 Thermal Maintenance Schedule (As of June 21, 2016)

ID	Task Name	Duration	Start	Finish
1	Lingan 2 ABNO	28 ewks	Sat 04/09/16	Sat 10/22/16
2	Lingan 4	12 ewks	Sat 04/02/16	Sat 06/25/16
3	Pt. Aconi	4 ewks	Sat 09/03/16	Sat 10/01/16
4	Pt. Tupper	2 ewks	Sat 03/26/16	Sat 04/09/16
5	Trenton 5	5 ewks	Sat 10/01/16	Sat 11/05/16
6	Trenton 6	2.4 ewks	Fri 07/01/16	Mon 07/18/16
7	PHB	3 ewks	Sat 04/09/16	Sat 04/30/16
8	Tufts Cove 1	10 ewks	Fri 06/24/16	Fri 09/02/16
9	Tufts Cove 2	5 ewks	Sat 11/05/16	Sat 12/10/16
10	Tufts Cove 3	3 ewks	Sat 10/15/16	Sat 11/05/16
11	TUC 4	5 ewks	Tue 09/06/16	Tue 10/11/16
12	TUC 5	5 ewks	Wed 10/12/16	Wed 11/16/16
13	TUC 6 T/G	4 ewks	Tue 09/06/16	Tue 10/04/16
14				
15	Wreck Cove #1	4 ewks	Sat 08/13/16	Sat 09/10/16
16	Wreck Cove #2	3 ewks	Sat 09/17/16	Sat 10/08/16
17				
18	VJ 1	2 ewks	Mon 06/27/16	Mon 07/11/16
19	VJ 2	2 ewks	Mon 05/16/16	Mon 05/30/16
20	Burnside 1	2 ewks	Mon 05/02/16	Mon 05/16/16
21	Burnside 2	2 ewks	Mon 04/18/16	Mon 05/02/16
22	Burnside 3	3 ewks	Mon 06/06/16	Mon 06/27/16
23	Tusket	3 ewks	Mon 05/16/16	Mon 06/06/16



Commentary:
The above maintenance schedule reflects actual maintenance.
Solid red bars represent actual outages. Solid green bars represent seasonal outages.
Outlined blue bars represent planned outages and oulined red bars represent actual outages.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Nova Scotia Power Inc.
Quarterly FAM Reporting
Mercury Abatement Program
As at [Month Day, Year]

NSPI (FAM) Q-12
CONFIDENTIAL

Mercury Sorbent Details
(Including oxidizing agents)

		~ Quarter ~					~ Year To Date ~				
	Fuel Mix	Type	Quantity		Costs [$]	$/MWh	Type	Quantity		Costs [$]	$/MWh
Generating Plant											
Lingan Unit 1	LS/MS/PC	Powder Activated Carbon		Kg			Powder Activated Carbon		Kg		
Lingan Unit 2	LS/MS/PC	Powder Activated Carbon		Kg			Powder Activated Carbon		Kg		
Lingan Unit 3	LS/MS/PC	Powder Activated Carbon		Kg			Powder Activated Carbon		Kg		
Lingan Unit 4	LS/MS/PC	Powder Activated Carbon		Kg			Powder Activated Carbon		Kg		
Point Tupper	LS/MS	Powder Activated Carbon		Kg			Powder Activated Carbon		Kg		
Trenton 5	DOM/LS/MS/PC	Powder Activated Carbon		Kg			Powder Activated Carbon		Kg		
Trenton 6	LS/MS/PC	Powder Activated Carbon		Kg			Powder Activated Carbon		Kg		
Lingan	LS/MS/PC	Calcium Chloride		L			Calcium Chloride		L		
Point Tupper	DOM/LS/MS/PC	Calcium Chloride		L			Calcium Chloride		L		
Trenton	LS/MS/PC	Calcium Chloride		L			Calcium Chloride		L		
Total Mercury Sorbent Costs (PAC)				Kg					Kg		
Total Mercury Sorbent Costs (Cal. Chl.)				L					L		
Total Mercury Sorbent Costs											

Mercury Emission Levels (kgs)	Estimated Emission	Forecast	Variance	Estimated Emission YTD	Forecast YTD	Variance

Emissions Commentary -

Technical Issues Commentary -

YTD (Forecast)= January to May actuals + June (Forecast).

Fuel Mix Legend -
LS - Low Sulphur
MS - Mid Sulphur
DOM - Domestic
PC - Petcoke

Nova Scotia Power Inc.
Quarterly FAM Reporting
Mercury Abatement Program
As at [Month Day, Year]

NSPI (FAM) Q-12
NON-CONFIDENTIAL

Mercury Sorbent Details
(Including oxidizing agents)

		~ Quarter ~				~ Year To Date ~			
	Fuel Mix	Type	Quantity	Costs [$]	$/MWh	Type	Quantity	Costs [$]	$/MWh
Generating Plant									
Lingan Unit 1	LS/MS/PC	Powder Activated Carbon	[redacted]	[redacted]	[redacted]	Powder Activated Carbon	[redacted]	[redacted]	[redacted]
Lingan Unit 2	LS/MS/PC	Powder Activated Carbon	[redacted]	[redacted]	[redacted]	Powder Activated Carbon	[redacted]	[redacted]	[redacted]
Lingan Unit 3	LS/MS/PC	Powder Activated Carbon	[redacted]	[redacted]	[redacted]	Powder Activated Carbon	[redacted]	[redacted]	[redacted]
Lingan Unit 4	LS/MS/PC	Powder Activated Carbon	[redacted]	[redacted]	[redacted]	Powder Activated Carbon	[redacted]	[redacted]	[redacted]
Point Tupper	LS/MS	Powder Activated Carbon	[redacted]	[redacted]	[redacted]	Powder Activated Carbon	[redacted]	[redacted]	[redacted]
Trenton 5	DOM/LS/MS/PC	Powder Activated Carbon	[redacted]	[redacted]	[redacted]	Powder Activated Carbon	[redacted]	[redacted]	[redacted]
Trenton 6	LS/MS/PC	Powder Activated Carbon	[redacted]	[redacted]	[redacted]	Powder Activated Carbon	[redacted]	[redacted]	[redacted]
Lingan	LS/MS/PC	Calcium Chloride	[redacted]	[redacted]	[redacted]	Calcium Chloride	[redacted]	[redacted]	[redacted]
Point Tupper	DOM/LS/MS/PC	Calcium Chloride	[redacted]	[redacted]	[redacted]	Calcium Chloride	[redacted]	[redacted]	[redacted]
Trenton	LS/MS/PC	Calcium Chloride	[redacted]	[redacted]	[redacted]	Calcium Chloride	[redacted]	[redacted]	[redacted]
Total Mercury Sorbent Costs (PAC)			-	Kg	[redacted]		Kg	[redacted]	
Total Mercury Sorbent Costs (Cal. Chl.)			-	L			L		
Total Mercury Sorbent Costs					[redacted]			[redacted]	

Mercury Emission Levels (kgs)	Estimated Emission	Forecast	Variance	Estimated Emission YTD	Forecast YTD	Variance
	-	-	-	-	-	-

Emissions Commentary -

Technical Issues Commentary -

YTD (Forecast)= January -February Actuals + March (Forecast).

Fuel Mix Legend -
LS - Low Sulphur
MS - Mid Sulphur
DOM - Domestic
PC - Petcoke

FUEL SUMMARY BY TYPE (FAM)

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Fuel & PP (Domestic Load Only)									
Solid Fuel									-29,489,851.00
Natural Gas									-11,845,824.00
Biomass									-284,385.00
Bunker C									-19,181,483.00
Furnace									-238,038.00
Diesel									-1,412,118.00
Additives - Mercury									-1,006,712.00
Additives									-278,998.00
Subtotal									-63,737,410.00
Fuel for Generation									-63,737,410.00
Purchased Power									
Imports									-6,397,058.00
IPP									-10,381.00
Wind Purchases									7,680,993.00
COMFIT									12,288,487.00
Total Purchased Power									13,562,041.00
Fuel & PP (Domestic Load Only)									-50,175,369.00
Fuel for Resale									
Costs									516,125.00
Recoveries									-373,866.00
Net Cost (Benefit)									142,259.00
Export Sales									
Costs									-1,222,329.00
Recoveries									1,526,962.00
Net Cost (Benefit)									304,632.00
Net Fuel and Purchased Power									-49,728,478.00
Water Royalties									25,156.00
Total Fuel and Purchased Power									-51,230,283.00
Total Fuel & PP									-51,230,283.00
FUEL COST PER Mwh:									
$/MWh on Total Generation									-7.60
$/MWh - no gas margin									-7.63
$/Mwh - no export costs									-7.55
$/Mwh - no export costs & no gas margin (Domestic Load Only)									-7.58

exports (which is a revenue line item)**

NET GENERATION BY FUEL TYPE (FAM)

NOVA SCOTIA POWER
Period: MONTH-Year
Submitted: Date

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Net Generation (MWh)									
Lingan									
Solid Fuel									
HFO									
Tufts Cove									
HFO									
Natural Gas									
LM6000 - Natural Gas									
Trenton 5									
Solid Fuel									
HFO									
Trenton 6									
Solid Fuel									
HFO									
Point Tupper									
Solid Fuel									
HFO									
Point Aconi									
Solid Fuel									
Port Hawkesbury Biomass									
Solid Fuel									
Combustion Turbines									
Diesel									
Natural Gas									
Total Thermal Production									
Solid Fuel									
Natural Gas									
HFO									
Diesel									
Subtotal									
Purchases									
Imports									
Maritime Link									
IPP									
Wind Purchases									
COMFIT									
Subtotal									
Renewables									
Total System Requirement									
Net Generation Percentages									
Solid Fuel									
Natural Gas									
HFO									
Diesel									
Purchases									
Hydro & Tidal									

PP STATION FUEL COSTS (FAM)

Q-13c
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NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Natural Gas									
MMBTU									
Costs									
$ per MMBTU									
Biomass									
Green MT									
MMBtu									
Costs									
$ per Green MT									
$ per MMBtu									
Bunker C									
Barrels									
MMBTU									
Costs									
$ per Barrel									
$ per MMBTU									
Diesel									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									
Furnace									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Additives Costs									
Additives - Hg									
Total Consumed Costs									
Purchased Power									
Total Fuel and Purchased Power									
$/Mwh									
FX Adjustment on Consumed Fuel									
Solid Fuel									
Natural Gas									
Bunker C									
Purchased Power									
Additives - Hg									
Total FX Adjustments									
FX Adj'd Fuel & PP									
$/Mwh (FX Adj'd)									
Fuel for Resale									
Costs									
Recoveries									
Net Cost (Benefit)									
FX Adjustment on Revenue									
FX Adj on Costs									
FX Adj'd Cost(Benefit)									
Other Costs									
Adjustments									
MTM on HFO and Natural Gas									
Total Other Costs									
Total Fuel & PP									
Newpage Gas Loss									
Total Fuel and Purchased Power									

PP SOLID FUEL COSTS (FAM)

Q-13d
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=VPP (V.P. POWER PRODUCTION)

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Import									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Domestic									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Pet Coke									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Other									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
All Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Blend Percentages (Tonnes)									
Import									
Domestic									
Pet Coke									
Biomass									

PP HEAT RATE REPORT (FAM)

Q-13e
CONFIDENTIAL

NOVA SCOTIA POWER
Period: APR-16 Currency: CND
Submitted: 08-MAY-16 12:03:27

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Net Generation by Plant (MWh)									
Lingan									
Tufts Cove									
Trenton									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
Combustion Turbines									
LM6000 Combined Cycle (Units 4,5,6)									
Total System									
Fuel Consumption by Plant (MMBTU)									
Lingan									
Tufts Cove									
Trenton									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
Combustion Turbines									
LM6000 Combined Cycle (Units 4,5,6)									
Total System									
Heat Rate by Plant									
Lingan									
Tufts Cove									
Trenton									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
Combustion Turbines									
LM6000 Combined Cycle (Units 4,5,6)									
Total System									
Fuel Cost by Plant (Including Additives, Exclud									
Lingan									
Tufts Cove									
Trenton									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
Combustion Turbines									
LM6000 Combined Cycle (Units 4,5,6)									
Total System									
Fuel Cost per MWh by Plant									
Lingan									
Tufts Cove									
Trenton									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
Combustion Turbines									
LM6000 Combined Cycle (Units 4,5,6)									
Total System									

NATURAL GAS REPORT (FAM)

Q-13f
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Sales (Mmbtu)									
Sales ($$)									
Revenue									
Revenue- Gas Margin Deferral									
Gain/(Loss) on Derivatives									
Total Gas Sales									
Cost of Sales									
Shell Gas									
Newpage Gas									
Market Gas									
Fuel									
Other Costs									
Total Costs									
Net Benefit (Cost) from Gas Sales									
Net Margin/Mmbtu ($/Mmbtu)									
FX Adj. on Gas Margin									
FX Adjusted Natural Gas Margin									
FX Adj. $/Mmbtu									

Export Sales Report

Q-13g
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Sales (Mwh)									
Generation									
Losses									
Sales (Billed)									
Sales ($$)									
Cost of Sales									
Lingan 1/2									
Lingan 3/4									
Trenton									
Pt. Tupper									
Pt. Aconi									
Tufts Cove									
HFO									
Natural Gas									
LM6000									
Combustion Turbines									
Purchased Power									
Total Costs									
Net Margin on Exports									
($/Mwh)									

GENERATION STATISTICS - MWh (FAM)

Q-13h
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year
Submitted: Date

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Lingan									
Tufts Cove									
Trenton									
Point Tupper									
Point Aconi									
Combustion Turbines									
LM6000									
Renewables									
Total Generation									
Purchased Power									
Imports									
IPP									
Wind									
COMFIT									
Total Purchases									
Total MWhs Available									
Domestic Revenue									
Exports									
Total Electric Revenue									
Line and Other Losses									
Export Percentage of Total MWhs									

GEN. STATS - RENEWABLES (FAM)

Q-13h
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year
Submitted: Date

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Renewables - NSPI-owned									
Hydro									
Energy Dispatch & Fuels									
Hydro Production Administ									
Dickie Brook Hydro									
Tusket Hydro									
Bear River Hydro System									
Sissiboo/Weymouth System									
Avon Hydro System									
Lequille Hydro System									
Nictaux/Paradise System									
Paradise System									
Annapolis Tidal Power									
St.Margaret's Hydro Syste									
Sheet Harbour Hydro Syste									
Black River Hydro System									
Mersey Hydro System									
Roseway & Harmony Hydro									
Harmony Hydro System									
Wreck Cove Hydro System									
Wreck Cove Windmill									
Fall River Hydro									
TOTAL									
Wind									
Little Brook Wind Turbine									
Grand Etang Wind Turbine									
203 Nuttby Wind Farm									
Digby Wind Farm									
TOTAL									
Biomass									
Port Hawkesbury Biomass									
Total NSPI Renewables									

Renewables - IPP-owned	
Wind	
Pubnico Point Wind Farm	
Lingan	
Glace Bay 1B	
Port Caledonia (Donkin)	
Gillis Cove	
Tiverton (Londonderry)	
Springhill	
Higgins Mountain	
Goodwood	
Brookfield (Lake Major)	
Fitzpatrick Mountain	
Point Tupper 1	
Digby	
Tatamagouche (Marshville/RJ)	
Amherst	
Dalhousie Mountain	
Glen Dhu North	
Maryvale	
Point Tupper 3	
Watts Section	
Fairmont	
Dunvegan	
Granville Ferry	
Isle Madame	
Creignish Rear	
Irish Mountain	
South Cape Mabou	
Spiddle Hill	
Cape North	
Donkin	
Sable Wind	
South Canoe	
Other	
TOTAL IPP WIND	
COMFIT	
HYDRO COMFIT	
SMALL WIND COMFIT	
LARGE WIND COMFIT	
BIOMASS/BIOGAS COMFIT	
SMALL TIDAL COMFIT	
TOTAL COMFIT	
IPP - Other	
Halifax Renewable Energy	
Black River Hydro	
Brooklyn Power	
Morgan Falls Power Company	
FW Taylor Lumber Company	
Minas Basin Pulp and Paper	
Cape Sharpe Tidal	
TOTAL IPP OTHER	
Total IPP Renewables	
Total Renewables	

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RENEWABLES COSTS (FAM)

Q-13i
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	<----- Actual	-------Period-t Budget	o-date -------- Variance	-> <---------- Actual	- Year-to-date Budget	---------- Variance	Full Year Budget	Prior YTD Actual	C Y	urr/Prior TD Variance
Renewables - NSPI-owned										
Hydro										
Energy Dispatch & Fuels										
402										
TOTAL										
Hydro Production Administratino										
Dickie Brook Hydro										
Tusket Hydro										
Bear River Hydro System										
Sissiboo/Weymouth System										
Avon Hydro System										
Lequille Hydro System										
Nictaux/Paradise System										
Paradise System										
Annapolis Tidal Power										
St. Margaret's Hydro System										
Sheet Harbour Hydro System										
Black River Hydro System										
Mersey Hydro System										
Roseway & Harmony Hydro										
Harmony Hydro System										
Wreck Cove Hydro System										
Wreck Cove Windmill										
Fall River Hydro										
TOTAL										
Wind										
Little Brook Wind Turbines										
Grand Etang Wind Turbine										
Nuttby Wind Farm										
Digby Wind Farm										
TOTAL										

Renewables - IPP-owned	
Wind	
Pubnico Point Wind Farm	
Lingan	
Glace Bay 1B	
Port Caledonia (Donkin)	
Gillis Cove	
Tiverton (Londonderry)	
Springhill	
Higgins Mountain	
Goodwood	
Brookfield (Lake Major)	
Fitzpatrick Mountain	
Point Tupper 1	
Digby	
Tatamagouche (Marshville/RJ)	
Amherst	
Dalhousie Mountain	
Glen Dhu North	
Maryvale	
Point Tupper 3	
Watts Section	
Fairmont	
Dunvegan	
Granville Ferry	
Isle Madame	
Creignish Rear	
Irish Mountain	
South Cape Mabou	
Spiddle Hill	
Cape North	
Lingan II	
Sable Wind	
South Canoe	
Other	
TOTAL IPP WIND	
COMFIT	
HYDRO COMFIT	
SMALL WIND COMFIT	
LARGE WIND COMFIT	
BIOMASS/BIOGAS COMFIT	
SMALL TIDAL COMFIT	
TOTAL COMFIT	
IPP - Other	
Halifax Renewable Energy	
Black River Hydro	
Brooklyn Power	
Morgan Falls Power Company	
FW Taylor Lumber Company	
Minas Basin Pulp and Paper	
Cape Sharpe Tidal	
Other IPP	
TOTAL IPP OTHER	
Total IPP Renewables	
Total Renewables	

ORACLE Applications

PP AVG THML LD MW/HR (FAM)

Q-13j
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year
Submitted: Date

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Net Generation by Unit (MWh)									
Lingan - Unit 1									
Lingan - Unit 2									
Lingan - Unit 3									
Lingan - Unit 4									
Tufts Cove - Unit 1									
Tufts Cove - Unit 2									
Tufts Cove - Unit 3									
LM- Unit 4									
LM- Unit 5									
LM-Unit 6									
Trenton - Unit 5									
Trenton - Unit 6									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
CT- Tusket									
CT-Victoria Junction									
CT- Burnside									
Total Net Generation (MWh)									
Operating Hours									
Lingan - Unit 1									
Lingan - Unit 2									
Lingan - Unit 3									
Lingan - Unit 4									
Tufts Cove - Unit 1									
Tufts Cove - Unit 2									
Tufts Cove - Unit 3									
LM- Unit 4									
LM- Unit 5									
LM-Unit 6									
Trenton - Unit 5									
Trenton - Unit 6									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
CT- Tusket									
CT- Victoria Junction									
CT- Burnside									
Total Operating Hours									
Average Load - MW									
Lingan - Unit 1									
Lingan - Unit 2									
Lingan - Unit 3									
Lingan - Unit 4									
Tufts Cove - Unit 1									
Tufts Cove - Unit 2									
Tufts Cove - Unit 3									
LM- Unit 4									
LM- Unit 5									
LM-Unit 6									
Trenton - Unit 5									
Trenton - Unit 6									
Point Tupper									
Point Aconi									
Port Hawkesbury Biomass									
CT- Tusket									
CT- Victoria Junction									
CT- Burnside									

LIN STATION FUEL COST (FAM)

Q-13k
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=LIN (Lingan)

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Natural Gas									
MMBTU									
Costs									
$ per MMBTU									
Biomass									
Green MT									
MMBtu									
Costs									
$ per Green MT									
$ per MMBtu									
Bunker C									
Barrels									
MMBTU									
Costs									
$ per Barrel									
$ per MMBTU									
Diesel									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Furnace									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Additives Costs									
Additives - Hg									
Total Consumed Costs									
Purchased Power									
Total Fuel and Purchased Power									
$/Mwh									
FX Adjustment on Consumed Fuel									
Solid Fuel									
Natural Gas									
Bunker C									
Purchased Power									
Additives - Hg									
Total FX Adjustments									
FX Adj'd Fuel & PP									
$/Mwh (FX Adj'd)									
Fuel for Resale									
Costs									
Recoveries									
Net Cost (Benefit)									
FX Adjustment on Revenue									
FX Adj on Costs									
FX Adj'd Cost(Benefit)									
Other Costs									
Adjustments									
MTM on HFO and Natural Gas									
Total Other Costs									
Total Fuel & PP									
Newpage Gas Loss									
Total Fuel and Purchased Power									

LINGAN SOLID FUEL COSTS (FAM)

Q-13k
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=LIN (Lingan)

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Import									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Domestic									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Pet Coke									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Other									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
All Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Blend Percentages (Tonnes)									
Import									
Domestic									
Pet Coke									
Biomass									

LIN HEAT RATE REPORT (FAM)

Q-13l
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=LIN (Lingan)

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Net Generation by Unit (MWh)									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Consumption by Unit (MMBTU)									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Heat Rate by Unit									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Cost by Unit (Including Additives, Excludi									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Cost per MWh by Unit									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									

POA STATION FUEL COST (FAM)

Q-13m
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=PTA (Point Aconi)

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Natural Gas									
MMBTU									
Costs									
$ per MMBTU									
Biomass									
Green MT									
MMBtu									
Costs									
$ per Green MT									
$ per MMBtu									
Bunker C									
Barrels									
MMBTU									
Costs									
$ per Barrel									
$ per MMBTU									
Diesel									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Furnace									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Additives Costs									
Additives - Hg									
Total Consumed Costs									
Purchased Power									
Total Fuel and Purchased Power									
$/Mwh									
FX Adjustment on Consumed Fuel									
Solid Fuel									
Natural Gas									
Bunker C									
Purchased Power									
Additives - Hg									
Total FX Adjustments									
FX Adj'd Fuel & PP									
$/Mwh (FX Adj'd)									
Fuel for Resale									
Costs									
Recoveries									
Net Cost (Benefit)									
FX Adjustment on Revenue									
FX Adj on Costs									
FX Adj'd Cost(Benefit)									
Other Costs									
Adjustments									
MTM on HFO and Natural Gas									
Total Other Costs									
Total Fuel & PP									
Newpage Gas Loss	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Fuel and Purchased Power	3,920,237.00	3,701,017.00	219,220.00	15,805,438.00	16,567,235.00	-761,797.00	46,165,687.00	17,141,292.00	-1,335,854.00

POA SOLID FUEL COSTS (FAM)

Q-13n
CONFIDENTIAL

NOVA SCOTIA POWER
Period:MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=PTA (Point Aconi)

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Import									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Domestic									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Pet Coke									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Other									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
All Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Blend Percentages (Tonnes)									
Import									
Domestic									
Pet Coke									
Biomass									

TR5 STATION FUEL COST (FAM)

Q-13o
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Bunker C									
Barrels									
MMBTU									
Costs									
$ Per Barrel									
$ per MMBTU									
Furnace									
Gallons									
Barrels									
MMBTU									
Costs									
$ per Gallon									
$ per Barrel									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Adjustments									
Additives									
Total Fuel & PP									
Generation by Fuel Type (Mwh)									
Solid Fuel									
Bunker C									
Total Generation									

TR5 SOLID FUEL COSTS (FAM)

Q-13p
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CND
Submitted: Date

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Import									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Domestic									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Pet Coke									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Other									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
All Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Blend Percentages (Tonnes)									
Import									
Domestic									
Pet Coke									
Other									

TR6 STATION FUEL COST (FAM)

Q-13p
CONFIDENTIAL

NOVA SCOTIA POWER
Period:MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Bunker C									
Barrels									
MMBTU									
Costs									
$ Per Barrel									
$ per MMBTU									
Furnace									
Gallons									
Barrels									
MMBTU									
Costs									
$ per Gallon									
$ per Barrel									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Additives									
Generation by Fuel Type (MWh)									
Solid Fuel									
Bunker C									
Total Generation									

TR6 SOLID FUEL COSTS (FAM)

Q-13r
CONFIDENTIAL

NOVA SCOTIA POWER
Period:MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Import									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Domestic									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Pet Coke									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Other									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
All Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Blend Percentages (Tonnes)									
Import									
Domestic									
Pet Coke									
Other									

TRE HEAT RATE REPORT (FAM)

Q-13s
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=TRN (Trenton)

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Net Generation by Unit (MWh)									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Consumption by Unit (MMBTU)									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Heat Rate by Unit									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Cost by Unit (Including Additives, Excludi									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Cost per MWh by Unit									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									

TUP STATION FUEL COST (FAM)

Q-13t
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=PTU (Point Tupper)

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Natural Gas									
MMBTU									
Costs									
$ per MMBTU									
Biomass									
Green MT									
MMBtu									
Costs									
$ per Green MT									
$ per MMBtu									
Bunker C									
Barrels									
MMBTU									
Costs									
$ per Barrel									
$ per MMBTU									
Diesel									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Furnace									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Additives Costs									
Additives - Hg									
Total Consumed Costs									
Purchased Power									
Total Fuel and Purchased Power									
$/Mwh									
FX Adjustment on Consumed Fuel									
Solid Fuel									
Natural Gas									
Bunker C									
Purchased Power									
Additives - Hg									
Total FX Adjustments									
FX Adj'd Fuel & PP									
$/Mwh (FX Adj'd)									
Fuel for Resale									
Costs									
Recoveries									
Net Cost (Benefit)									
FX Adjustment on Revenue									
FX Adj on Costs									
FX Adj'd Cost(Benefit)									
Other Costs									
Adjustments									
MTM on HFO and Natural Gas									
Total Other Costs									
Total Fuel & PP									
Newpage Gas Loss									
Total Fuel and Purchased Power									

TUP SOLID FUEL COSTS (FAM)

Q-13u
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=PTU (Point Tupper)

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Import									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Domestic									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Pet Coke									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Other									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
All Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Blend Percentages (Tonnes)									
Import									
Domestic									
Pet Coke									
Biomass									

TFT STATION FUEL COST (FAM)

Q-13v
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CND
Submitted: Date

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Natural Gas									
MMBTU									
Costs									
$ w/o Hedges									
$/MMBTU									
$/MMBTU w/o Hedges									
Bunker C									
Barrels									
MMBTU									
Costs									
Costs w/o Hedges									
$/BBL									
$/BBL w/o Hedges									
$/MMBTU									
$/MMBTU w/o Hedges									
Furnace / Diesel									
Gallons									
Barrels									
MMBTU									
Costs									
$ per Gallon									
$ per Barrel									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Additives Costs									
Total Consumed Costs									
Adjustments									
Pipeline Toll									
Total Fuel Costs									

TFT HEAT RATE REPORT (FAM)

Q-13w
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=TCF (Tufts Cove Fuel)

	---------- Pe Actual	riod-to-date - Forecast	---------> <- Variance	---------- Y Actual	ear-to-date - Forecast	----------> Variance	Full Year Forecast	Prior YTD C Actual	urr/Prior YT Variance
Net Generation by Unit (MWh)									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Consumption by Unit (MMBTU)									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Heat Rate by Unit									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Cost by Unit (Including Additives, Excludi									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									
Fuel Cost per MWh by Unit									
Unit 1									
Unit 2									
Unit 3									
Unit 4									
Unit 5									
Unit 6									
Total Plant									

LM6000 STN FUEL COSTS (FAM)

Q-13x
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Natural Gas									
MMBTU									
Costs									
Costs w/o Hedges									
$/MMBTU									
$/MMBTU w/o Hedges									
Bunker C									
Barrels									
MMBTU									
Costs									
$ per Barrel									
$ per MMBTU									
Furnace / Diesel									
Gallons									
Barrels									
MMBTU									
Costs									
$ per Gallon									
$ per Barrel									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Additives Costs									
Total Consumed Costs									
Adjustments									
Pipeline Toll									
Total Fuel Costs									

LM6000 HEAT RATE REP (FAM)

Q-13y
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	<----- Actual	-------Period-t Budget	o-date -------- Variance	-> <---------- Actual	- Year-to-date Budget	---------- Variance	Full Year Budget	Prior YTD Actual	C Y	urr/Prior TD Variance
Net Generation by Unit (MWh)										
Unit 1										
Unit 2										
Unit 3										
Unit 4										
Unit 5										
Unit 6										
Total Plant										
Fuel Consumption by Unit (MBTU)										
Unit 1										
Unit 2										
Unit 3										
Unit 4										
Unit 5										
Unit 6										
Total Plant										
Heat Rate by Unit										
Unit 1										
Unit 2										
Unit 3										
Unit 4										
Unit 5										
Unit 6										
Total Plant										
Fuel Cost by Unit (Including Additives, Excludi										
Unit 1										
Unit 2										
Unit 3										
Unit 4										
Unit 5										
Unit 6										
Total Plant										
Fuel Cost per MWh by Unit										
Unit 1										
Unit 2										
Unit 3										
Unit 4										
Unit 5										
Unit 6										
Total Plant										

Combustion Turbines Station Fuel Costs

Q-13z
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NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

Cost Centre=CTS (Combustion Turbine)

	---------- Pe	riod-to-date -	---------> <-	---------- Y	ear-to-date -	---------->	Full Year	Prior YTD C	urr/Prior YT
	Actual	Forecast	Variance	Actual	Forecast	Variance	Forecast	Actual	Variance
Solid Fuel									
Tonnes									
MMBTU									
Costs									
$ per Tonne									
$ per MMBTU									
Natural Gas									
MMBTU									
Costs									
$ per MMBTU									
Biomass									
Green MT									
MMBtu									
Costs									
$ per Green MT									
$ per MMBtu									
Bunker C									
Barrels									
MMBTU									
Costs									
$ per Barrel									
$ per MMBTU									
Diesel									
Gallons									
MMBTU									
Costs									
$ per Gallon									
$ per MMBTU									

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Furnace									
MMBTU									
$ per MMBTU									
All Fuels									
MMBTU									
Costs									
$ per MMBTU									
Additives Costs									
Additives - Hg									
Total Consumed Costs									
Purchased Power									
Total Fuel and Purchased Power									
$/Mwh									
FX Adjustment on Consumed Fuel									
Solid Fuel									
Natural Gas									
Bunker C									
Purchased Power									
Additives - Hg									
Total FX Adjustments									
FX Adj'd Fuel & PP									
$/Mwh (FX Adj'd)									
Fuel for Resale									
Costs									
Recoveries									
Net Cost (Benefit)									
FX Adjustment on Revenue									
FX Adj on Costs									
FX Adj'd Cost(Benefit)									
Other Costs									
Adjustments									
MTM on HFO and Natural Gas									
Total Other Costs									
Total Fuel & PP									
Newpage Gas Loss									
Total Fuel and Purchased Power									

Port Hawkesbury Biomass Station Fuel Costs (FAM)

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NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	<----- Actual	-------Period-t Budget	o-date -------- Variance	-> <---------- Actual	- Year-to-date Budget	---------- Variance	Full Year Budget	Prior YTD Actual	C Y	urr/Prior TD Variance
Solid Fuel										
Tonnes										
MMBTU										
Costs										
$ per Tonne										
$ per MMBTU										
Natural Gas										
MMBTU										
Costs										
Costs w/o Hedges										
$ Per MMBTU										
$ per MMBTU w/o Hedges										
Furnace										
Gallons										
Barrels										
MMBTU										
Costs										
$ per Gallon										
$ per Barrel										
$ per MMBTU										
All Fuels										
MMBTU										
Costs										
$ per MMBTU										
Additives										
Generation by Fuel Type (MWh)										
Solid Fuel										
Natural Gas										
Total Generation										

Port Hawkesbury Biomass Solid Fuel Costs (FAM)

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NOVA SCOTIA POWER
Period: MONTH-Year Currency: CAD
Submitted: Date

	<----- Actual	-------Period-to-date Budget	Variance	-> <---------- Actual	- Year-to-date Budget	---------- Variance	Full Year Budget	Prior YTD Actual	CY	urr/Prior TD Variance
Import										
Tonnes										
MMBTU										
Costs										
$ per Tonne										
$ per MMBTU										
Domestic										
Tonnes										
MMBTU										
Costs										
$ per Tonne										
$ per MMBTU										
Pet Coke										
Tonnes										
MMBTU										
Costs										
$ per Tonne										
$ per MMBTU										
Biomass										
Tonnes										
MMBTU										
Costs										
$ per Tonne										
$ per MMBTU										
All Solid Fuel										
Tonnes										
MMBTU										
Costs										
$ per Tonne										
$ per MMBTU										
Blend Percentages (Tonnes)										
Import										
Domestic										
Pet Coke										
Biomass										

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Diesel			NC
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Petroleum Coke			NC
Natural Gas			NC
Biomass			NC
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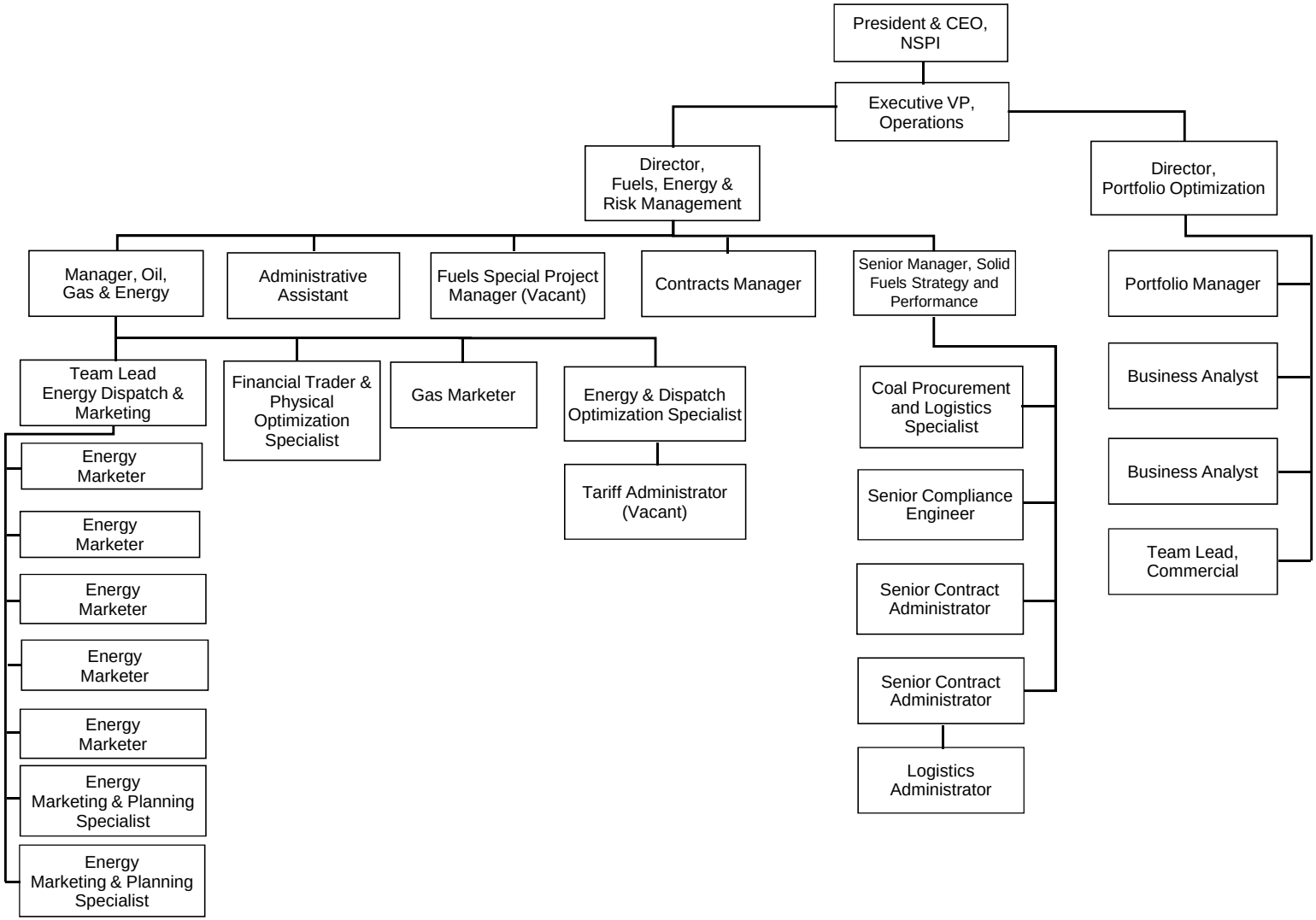
Organization Chart - Fuels



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Organization Chart Commentary

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Generation Unit Summary

Plant	Nameplate Capacity (MW)	In Service Year	Fuel Type	[Year] Annual Energy (GWh)*
Lingan Unit 1	150	1979	Coal / Petcoke	
Lingan Unit 2	150	1980	Coal / Petcoke	
Lingan Unit 3	150	1983	Coal / Petcoke	
Lingan Unit 4	150	1984	Coal / Petcoke	
Tufts Cv Unit 1	100	1965	Oil / Natural Gas	
Tufts Cv Unit 2	100	1972	Oil / Natural Gas	
Tufts Cv Unit 3	150	1976	Oil / Natural Gas	
Tufts Cv Unit 4 (LM 6000)	47	2003	Natural Gas	
Tufts Cv Unit 5 (LM 6000)	47	2005	Natural Gas	
Tufts Cv Unit 6 (LM 6000)	50	2012	Natural Gas	
Pt Tupper	150	1973	Coal / Petcoke	
Pt Aconi	165	1994	Petcoke / Coal	
Trenton Unit 5	150	1969	Coal / Petcoke	
Trenton Unit 6	160	1991	Coal / Petcoke	
Port Hawkesbury Biomass	63	2013	Biomass	
Burnside 1	30	1976	Light Oil	
Burnside 2	30	1976	Light Oil	
Burnside 3	30	1976	Light Oil	
Burnside 4	30	1976	Light Oil	
Victoria Junction 1	30	1976	Light Oil	
Victoria Junction 2	30	1975	Light Oil	
Tusket 1	24	1971	Light Oil	
Hydro System	395	Various		
NSPI Wind	82	Various		
Total	2463			

* Net generation

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Fuel Cost Summary - per MWh

Properties	Actual Year	Actual Year -1	Budget Year +1*
Fuel for Generation - Domestic Load ($M)			
Solid Fuel	$261.3	$273.8	$239.2
Natural Gas	$61.6	$79.2	$41.6
Biomass	$20.0	$24.5	$24.8
Bunker C	$34.9	$18.0	$11.3
Furnace	$2.9	$4.3	$2.0
Diesel	$2.8	$2.3	$0.6
Additives	$13.1	$13.1	$15.0
Subtotal	$396.7	$415.1	$334.5
Purchased Power	$143.3	$100.6	$206.5
Fuel for Resale Net Margin	$0.0	($5.4)	$0.0
Exports	$1.8	$0.5	$0.0
Fuel and Purchased Power	$541.8	$510.8	$541.0
Water Royalties	$1.0	$0.8	$1.0
MTM on HFO and Natural Gas	$0.0	$0.0	$0.0
Total Fuel and Purchased Power	$542.9	$511.7	$542.0
Less: Export Revenues	($1.7)	($0.8)	($0.2)
Less: Load Retention	($55.6)	($58.3)	($50.0)
Less: GRLF Fuel Costs	($1.2)	($0.9)	($0.4)
Less: 1PT RTP	($0.4)	($0.2)	($0.4)
Less: Shore Power	($0.0)	($0.0)	($0.1)
Less: Back Up/Top Up	($0.1)	$0.0	$0.0
Plus / (Less): Foreign exchange - Fuel Other	($0.4)	($0.4)	$0.0
Net Fuel and Purchased Power	$483.5	$451.1	$490.8
Total System Requirements (GWh)	11,129.8	11,046.9	11,199.0
Less: Export Sales and Losses (1)	(31.2)	(9.7)	(2.3)
GRLF Requirements (1)	(25.1)	(19.9)	(10.1)
Load Retention (1)	(1,028.2)	(1,079.1)	(1,079.4)
1PT RTP (1)	(10.1)	(4.5)	(12.0)
Shore Power (1)	(0.5)	-	(3.1)
Back Up/Top Up (1)	(1.6)	-	-
Total	10,033.0	9,933.7	10,092.1
Cost of Fuel per MWh	$48.19	$45.41	$48.63

Figures presented are rounded to one decimal place which may cause $0.1M in rounding differences on some line items
(1) Adjusted for losses
* [Year+1]Budget reflects the [BCF/GRA Source] filing of $XXM.

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Fuel Specifications Summary - HFO

HFO QUALITY SPECIFICATION

Property	Requirement	ASTM Test
Gravity, ^{0}API- Apr 1 to Dec 31 Gravity, ^{0}API- Jan 1 to Mar 31	min. 9.0 min. 9.5	D1298 D1298
Saybolt Viscosity, Furol @ 50 ^{0}C	min. 150 max. 300	D445, D2161
Flash Point, ^{0}C (^{0}F)	min. 66 (150)	D93
Sulphur, wt. %	max. 2.2 (or 1.0)	D4294
Water by Distillation, vol. %	max. 1.0	D95
Compatibility, spot	max. 1	D4740
Hydrogen Sulphide, vol. ppm *(The preceding seven Properties are referenced in Section 13.8 (a))*	200	D5705
Gross Heat of Combustion, MMBtu/Bbl	6.325	D240
Ash, wt. %	max. 0.10	D482
Sediment by Extraction, wt. %	max. 0.25	D473
Sediment by Hot Filtration, wt. %	max. 0.1	D4870
(1) Vanadium, wt. ppm	max. 300	D5863A/B (1)
Sodium, wt. ppm	max. 50	D5863B
Ashphaltenes, wt. %	max. 10	ASTM D6560-00
Pour Point, ^{0}C (^{0}F)	max. 21 (70)	D97

Notes: 1)Test method ASTM-D-5863(B) will be used at discharge port to determine if discharge should be delayed while test method 5863(A) is performed. Test method ASTM-D-5863(A) will be used for pricing calculations at discharge port, and will be binding in the event of a dispute.

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Fuel Specifications Summary - Diesel

Nova Scotia Power Product Specifications	Combustion Turbine	Delivered Dec-Feb 28th
Property	MIN/MAX	ASTM Test Method
Appearance	Clear and Bright	Visual
Density, Kg/M3	0.850	D1298
Distillation 90% Recovered	290.0 MAX	D86
Cloud Point	CP -34 MAX Temp	D2500
Pour Point(Deg C)	Report	D97
Viscosity	1.1 min-1.8 Max	D445
Octane Number	40 MIN	D613
Sulfur, wt. %	0.1max	D1552
Corrosion-Copper-3 hours@ 50c	No.1 Max	D180
Micro Carbon Residue 10% Bottoms % Mass	0.1 Max	D4530
Flash Degrees C	40 min	D93
Water and Sediment, Volume %	0.05 max	D1796
Ash, wt. %	0.01max	D482
Trace Metals ppm by wt.%		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

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NON CONFIDENTIAL

Fuel Specifications Summary - Diesel

Nova Scotia Power	Combustion Turbine	Delivered March 1-Nov 30
Product Specifications		
Property	MIN/MAX	ASTM Test Method
Appearance	Clear and Bright	Visual
Density,Kg/M3	0.881	D1298
Distillation 90% Recovered	360.0 MAX	D86
Cloud Point	note 1	D2500
Pour Point(Deg C)	note 1	D97
Viscosity	1.1 min-3.6 Max	D445
Octane Number	40 MIN	D613
Sulfur, wt. %	0.1max	D1552
Corrosion-Copper-3 hours@ 50c	No.1 Max	D180
Micro Carbon Residue !05 Bottoms % Mass	0.2 Max	D4530
Flash Degrees C	40 min	D93
Water and Sediment, Volume %	0.05 max	D1796
Ash, wt. %	0.01max	D482
Trace Metals ppm by wt.%		D3605
Vanadium	0.2 max	
Sodium plus Potassium	0.6 max	
Calcium	2.0 max	
Lead	0.1 max	

Note: Operatbility of fuel shall meet seasonal conditions

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Fuel Specifications Summary - Mid Sulphur Coal

TECHNICAL SPECIFICATION - LOW MID COAL

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	12%	D3302
Free Moisture	-	-	3%	D3302
Ash	7%	-	12%	D3172
Sulphur	-	-	3.0%	D3177
Volatile Matter	35%	30%	-	D3175
Calorific Value (Btu/lb.)	-	12,800	-	D5865
Grindability (HGI)	50-60	50	65	D409
Size (Topsize)	-	-	2" x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Mercury		Indicate typical level in bid		D6414 or D6722
Chlorine			1100 ppm	D4208-02

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Fuel Specifications Summary - Low Sulphur Coal

TECHNICAL SPECIFICATION - LOW SULPHUR COAL

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	9%	D3302
Free Moisture	-	-	3%	D3302
Ash	7%	-	9%	D3172
Sulphur	0.65%	-	1.10%	D3177
Volatile Matter	34%	30%	-	D3175
Calorific Value (Btu/lb.)	-	10,800	13,400	D5865
Grindability (HGI)	45-55	42	65	D409
Size (Topsize)	-	-	2" x 0	D4749
Size (Fines < 0.5 mm)	-	-	10%	D4749
Chlorine	-	-	1100 ppm	D4208-02
Mercury	Indicate typical level in bid			D6414 or D6722

Penalties/Premiums may be negotiated for Calorific Value, Sulphur, and Moisture with successful bidders.

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Fuel Specifications Summary - Petroleum Coke

TECHNICAL SPECIFICATION - PETROLEUM COKE

Type: Delayed Petroleum Coke, Shot Coke only.

Properties (As Received Basis)	Typical	Minimum	Maximum	Applicable ASTM Standard
Moisture	7%	-	9%	D3302
Ash	0.5%	0.2%	1.0%	D3172
Sulphur	4-6%	-	6.5%	D3177
Volatile Matter	10%	8%	-	D3175
Calorific Value (Btu/lb.)	14,000	13,900	-	D5865
Grindability (HGI)	40	30	55	D409
Size (Topsize)	-	-	2" x 0	D4749
Size (Fines < 0.5 mm)	-	-	12%	D4749
Vanadium, ppm	800		1900	D5056
Nickel, ppm	100		750	D5056
Mercury	Indicate typical level in bid			D6414-01
Chlorine			1100 ppm	D4208-02

Penalties/Premiums may be negotiated for Calorific Value, Sulphur, and Moisture with successful bidders

Fuel Specifications Summary - Natural Gas

Total Heating Value

(a) Natural gas received or delivered hereunder shall have a Total Heating Value below 36 MJ/m^3 or above 41 MJ/m^3.

(b) The Total Heating Value shall be determined by gas chromatographic analysis using most recent AGA standards or any revision thereof, or by other methods mutually agreed upon by Customer and Pipeline.

Composition

(a) Merchantability. The gas shall be commercially free, under continuous gas flow conditions, from objectionable odors (except those required by applicable regulations), solid matter, dust, gums, and gum-forming constituents which might interfere with its merchantability or cause injury to or interference with proper operations of the pipelines, compressor stations, meters, regulators or other appliances through which it flows.

(a) Oxygen. The gas shall not have an uncombined oxygen content in excess of two-tenths (0.2) of one percent (1%) by volume, and both parties shall make every reasonable effort to keep the gas free from oxygen.

(b) Non-Hydrocarbon Gases. The gas shall not contain more than four percent (4%) by volume, of a combined total of non-hydrocarbon gases (including carbon dioxide and nitrogen); it being understood, however, that the total carbon dioxide content shall not exceed three percent (3%) by volume.

(c) Liquids. The gas shall be free of water and hydrocarbons in liquid form at the temperature and pressure at which the gas is received and delivered.

(d) Hydrogen Sulphide. The gas shall not contain more than six (6) milligrams of hydrogen sulphide per one (1) Cubic Metre.

(e) Total Sulphur. The gas shall not contain more than four-hundred and sixty (460) milligrams of total sulphur, excluding any mercaptan sulphur, per one (1) Cubic Metre.

(f) Temperature. The gas shall not have a temperature of more than forty-nine degrees (49^0) Celsius.

(g) Water Vapor. The gas shall not contain in excess of eighty (80) milligrams of water vapor per one (1) Cubic Metre.

(h) Liquefiable Hydrocarbons. The gas shall not contain liquid hydrocarbons or hydrocarbons liquefiable at temperatures warmer than minus nine degrees (-9^0) Celsius and normal pipeline operating pressures of between 690 and 9930 kPag.

(i) Microbiological Agents. The gas shall not contain any microbiological organism, active bacteria or bacterial agent capable of contributing to or causing corrosion and/or operational and/or other problems.

Microbiological organisms, bacteria or bacterial agents include, but are not limited to, sulfate reducing bacteria (SRB) and acid producing bacteria (APB). Tests for bacteria or bacterial agents shall be conducted on samples taken from the meter run or the appurtenant piping using American Petroleum Institute (API) test method API-RP38 or any other test method acceptable to Pipeline and Customer which is currently available or may become available at any time.

Fuel Specifications Summary - Biomass

Biomass Fuel shall be delivered as chips or hogged material commuted to a nominal size of thirty-five (35) to thirty-seven (37) millimeters or smaller and shall not contain more than three percent (3%) by volume of pieces greater than one hundred fifty (150) millimeters in length. The percentage of Biomass Fuel less than six (6) millimeters shall be less than approximately twenty-five percent (25%) of the total quantity.

All Biomass Fuel shall be substantially free of extraneous material including, but not limited to, rock, iron, steel, wire, construction debris, gravel, soil, metal, plastic and industrial waste.

All Biomass Fuel shall be comprised of natural, untreated and uncoated wood and wood waste, which, at no stage in its lifecycle, has been treated with organic and/or inorganic substances to change, protect or supplement the physical properties of the materials.

Biomass Fuel shall meet the following average moisture content requirements (wet basis):

(i) Secondary forest biomass:

(a) November to April deliveries: Monthly average of fifty-five percent (55%) or less with no deliveries exceeding sixty percent (60%);

(b) May to October deliveries: Monthly average of fifty percent (50%) or less with no deliveries exceeding fifty-five percent (55%).

(ii) Primary forest biomass:

(a) November to April deliveries: Monthly average of forty-seven percent (47%) or less with no deliveries exceeding fifty-five percent (55%);

(b) May to October deliveries: Monthly average of forty-three percent (43%) or less with no deliveries exceeding fifty percent (50%).

The Biomass Fuel shall not contain a level of chlorides or metals which, in the sole discretion of NSPI, would cause damage to or interfere with the operation of the boiler or ash management programs.

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IPP Contract Summary

Counterparty	Location	Contract Start Date	Contract End Date	Installed Capacity MW	Actual 2015 $'000s	Actual 2015 MWh	Budget* 2015 MWh
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						

Counterparty	Location	Contract Start Date	Contract End Date	Installed Capacity MW	Actual 2015 $'000s	Actual 2015 MWh	Budget* 2015 MWh
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Total COMFIT							
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Counterparty	Location						
Total Other IPPs							
Total IPP Renewables							

* [Year] Budget reflects the [Year] [Source] forecast of $XXS M presented to SWG in [Month Year]

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Plant Performance

Capacity Factor	Q1	Q2	Q3	Q4	Annual Actual	Year Budget*	Prior Year
Plant							
Lingan Unit 1							
Lingan Unit 2							
Lingan Unit 3							
Lingan Unit 4							
Tufts Cv Unit 1							
Tufts Cv Unit 2							
Tufts Cv Unit 3							
Tufts Cv Unit 4 (LM 6000)							
Tufts Cv Unit 5 (LM 6000)							
Pt Tupper							
Pt Aconi							
Trenton Unit 5							
Trenton Unit 6							

Definition: Capacity factor = Actual Net GWh / (Net Operating Capacity X 8760 hrs)
* [Year][Source] presented to SWG in [Month Year] of $XXX M
(1) This value represents the combined capacity factor for Tufts Cv Unit 4, 5, and 6

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Plant Performance

Availability Factor	Q1	Q2	Q3	Q4	Annual Actual	Year Budget*	Prior Year
Plant							
Lingan Unit 1							
Lingan Unit 2							
Lingan Unit 3							
Lingan Unit 4							
Tufts Cv Unit 1							
Tufts Cv Unit 2							
Tufts Cv Unit 3							
Tufts Cv Unit 4 (LM 6000)							
Tufts Cv Unit 5 (LM 6000)							
Pt Tupper							
Pt Aconi							
Trenton Unit 5							
Trenton Unit 6							

Definition: Availability = (Operating hours + ABNO Outages) / 8760 hrs
* [Year][Source] presented to SWG in [Month Year] of $XXX M

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Plant Performance

Heat Rates	Q1	Q2	Q3	Q4	Annual Actual	Annual Budget*	Prior Year
Plant							
Lingan Unit 1							
Lingan Unit 2							
Lingan Unit 3							
Lingan Unit 4							
Tufts Cv Unit 1							
Tufts Cv Unit 2							
Tufts Cv Unit 3							
Tufts Cv Unit 4, 5, 6 (LM 6000) (1)							
Pt Tupper							
Pt Aconi							
Trenton Unit 5							
Trenton Unit 6							

Note: Heat rates may vary quarterly partly due to inventory and other adjustments.
* [Year][Source] presented to SWG in [Month Year] of $XXX M
(1) Actual and Budget results represent the combined heat rate for Tufts Cv Unit 4, 5, and 6.

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Plant Performance

DAFOR	Q1	Q2	Q3	Q4	Annual Actual	Annual Budget*	Prior Year
Plant							
Lingan Unit 1							
Lingan Unit 2							
Lingan Unit 3							
Lingan Unit 4							
Tufts Cv Unit 1							
Tufts Cv Unit 2							
Tufts Cv Unit 3							
Tufts Cv Unit 4 (LM 6000)							
Tufts Cv Unit 5 (LM 6000)							
Tufts Cv Unit 6 (LM6000)							
Pt Tupper							
Pt Aconi							
Trenton Unit 5							
Trenton Unit 6							

Definition: DAFOR = Equivalent Forced Outage time / (Equivalent Forced Outage Time + Total Equivalent Operating time)
* [Year][Source] presented to SWG in [Month Year] of $XXX M

Plant Performance

Unit Forced Outage & Management Response

Unit forced outages are investigated for root cause. Maintenance is completed to return the unit to service promptly and allow the unit to operate to the next scheduled outage.

Maintenance records are generated when further inspection or repairs are required and applied to all similar equipment where applicable. Operational procedures and training are initiated when enhanced skills or knowledge will improve performance.

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Plant Performance

Unit Forced Outage & Management Response

Plant	Date	Forced Outage Reason / Root Cause	Duration (hrs)	Management Response

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Plant Performance

Generation Equipment Reporting	Q1	Q2	Q3	Q4	Annual Actual
Operating Factor (OF)					
Utilization of Forced Outage Probability (UFOP)					
Forced Outage Rate (FOR)					
Derated Adjusted Forced Outage Rate (DAFOR)					
Incapability Factor (ICBF)					
Maintenance Outage Factor (MO)					
Planned Outage Factor (PO)					
Failure Rate (FR)					
Type and Number of Forced Outages					
Type 21 - 1 *(Forced Outage - Sudden Forced Outage)*					
Type 21 - 2 *(Forced Outage - Immediately Deferrable Forced Outage)*					
Type 21 - 3 *(Forced Outage - Deferrable Forced Outage)*					
Type 21 - 4 *(Forced Outage - Starting Failure Outage)*					
FEMO					
FEPO					
Total:					
Type and Number of Start Type					
Cold					
Warm					
Hot					
Total:					

FEMO: The number of times the generating units were in a forced extension of a maintenance outage state.
FEPO: The number of times the generating units were in a forced extension of a planned outage state.
Note: Pt. Hawksbury Biomass has been included in GM stats for [Year]. [Has this impacted the results?]

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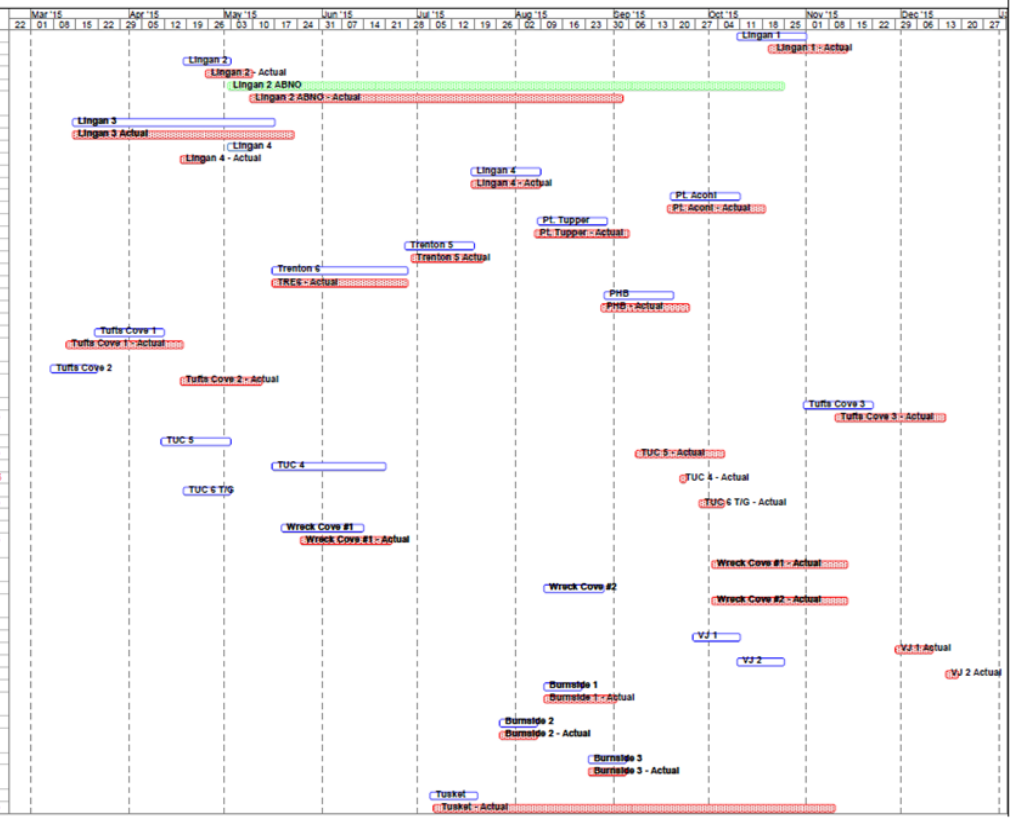
Plant Maintenance

[Year] Thermal Maintenance Schedule - Actual vs. Planned

2015 Thermal Maintenance Schedule
(Planned vs Actuals 2015)

ID	Task Name	Duration	Start	Finish
1	Lingan 1	22 days	Sat 10/10/15	Sat 10/31/15
2	Lingan 1 - Actual	25 days	Tue 10/20/15	Fri 11/13/15
3	Lingan 2	15 days	Sat 04/18/15	Sat 05/02/15
4	Lingan 2 - Actual	15 days	Sat 04/25/15	Sat 05/09/15
5	Lingan 2 ABNO	176 days	Sat 05/02/15	Sat 10/24/15
6	Lingan 2 ABNO - Actual	118 days	Sat 05/09/15	Thu 09/03/15
7	Lingan 3	64 days	Sat 03/14/15	Sat 05/16/15
8	Lingan 3 Actual	70 days	Sat 03/14/15	Fri 05/22/15
9	Lingan 4	8 days	Sat 05/02/15	Sat 05/09/15
10	Lingan 4 - Actual	8 days	Fri 04/17/15	Fri 04/24/15
11	Lingan 4	22 days	Sat 07/18/15	Sat 08/08/15
12	Lingan 4 - Actual	22 days	Sat 07/18/15	Sat 08/08/15
13	Pt. Aconi	22 days	Sat 09/19/15	Sat 10/10/15
14	Pt. Aconi - Actual	31 days	Fri 09/18/15	Sun 10/18/15
15	Pt. Tupper	22 days	Sat 08/08/15	Sat 08/29/15
16	Pt. Tupper - Actual	30 days	Fri 08/07/15	Sat 09/05/15
17	Trenton 5	22 days	Sat 06/27/15	Sat 07/18/15
18	Trenton 5 Actual	23 days	Mon 06/29/15	Tue 07/21/15
19	Trenton 6	43 days	Sat 05/16/15	Sat 06/27/15
20	TRE6 - Actual	43 days	Sat 05/16/15	Sat 06/27/15
21	PHB	22 days	Sat 08/29/15	Sat 09/19/15
22	PHB - Actual	26 days	Fri 08/28/15	Thu 09/24/15
23				
24	Tufts Cove 1	22 days	Sat 03/21/15	Sat 04/11/15
25	Tufts Cove 1 - Actual	37 days	Thu 03/12/15	Fri 04/17/15
26	Tufts Cove 2	15 days	Sat 03/07/15	Sat 03/21/15
27	Tufts Cove 2 - Actual	26 days	Fri 04/17/15	Tue 05/12/15
28	Tufts Cove 3	22 days	Sat 10/31/15	Sat 11/21/15
29	Tufts Cove 3 - Actual	35 days	Tue 11/10/15	Mon 12/14/15
30	TUC 5	22 days	Sat 04/11/15	Sat 05/02/15
31	TUC 5 - Actual	25 days	Tue 09/08/15	Mon 10/05/15
32	TUC 4	36 days	Sat 05/16/15	Sat 06/20/15
33	TUC 4 - Actual	2 days	Tue 09/22/15	Wed 09/23/15
34	TUC 6 T/G	15 days	Sat 04/18/15	Sat 05/02/15
35	TUC 6 T/G - Actual	8 days	Mon 09/28/15	Mon 10/05/15
36				
37	Wreck Cove #1	26 days	Mon 05/18/15	Sat 06/13/15
38	Wreck Cove #1 - Actual	29 days	Mon 05/25/15	Mon 06/22/15
39	Wreck Cove #1 - Actual	43 days	Fri 10/02/15	Fri 11/13/15
40	Wreck Cove #2	19 days	Mon 08/10/15	Fri 08/28/15
41	Wreck Cove #2 - Actual	43 days	Fri 10/02/15	Fri 11/13/15
42				
43	VJ 1	15 days	Sat 09/26/15	Sat 10/10/15
44	VJ 1 Actual	12 days	Sun 11/29/15	Thu 12/10/15
45	VJ 2	15 days	Sat 10/10/15	Sat 10/24/15
46	VJ 2 Actual	4 days	Tue 12/15/15	Fri 12/18/15
47	Burnside 1	12 days	Mon 08/10/15	Fri 08/21/15
48	Burnside 1 - Actual	23 days	Mon 08/10/15	Tue 09/01/15
49	Burnside 2	12 days	Mon 07/27/15	Fri 08/07/15
50	Burnside 2 - Actual	12 days	Mon 07/27/15	Fri 08/07/15
51	Burnside 3	12 days	Mon 08/24/15	Fri 09/04/15
52	Burnside 3 - Actual	12 days	Mon 08/24/15	Fri 09/04/15
53	Tusket	15 days	Sun 07/05/15	Sun 07/19/15
54	Tusket - Actual	127 days	Mon 07/06/15	Mon 11/09/15



Commentary:
NSPI monitors various indicators throughout the year as the Thermal Maintenance Shutdown Schedule unfolds and adjusts the Schedule appropriately in response to changing conditions. The key indicators that NSPI monitors include: Fuel Pricing, Energy Sales / Purchase Opportunity, Analysis of Safety and Cost Risk, Transmission / Distribution Limitations, Availability of Resources (i.e. Critical Parts, Contractors, Construction Resources, Manpower, etc.). Various groups within NSPI, including Power Production, Fuels and the Control Centre, work together and share information on the indicators listed above. Together they make coordinated decisions and take advantage of the changing conditions to reduce outage costs.

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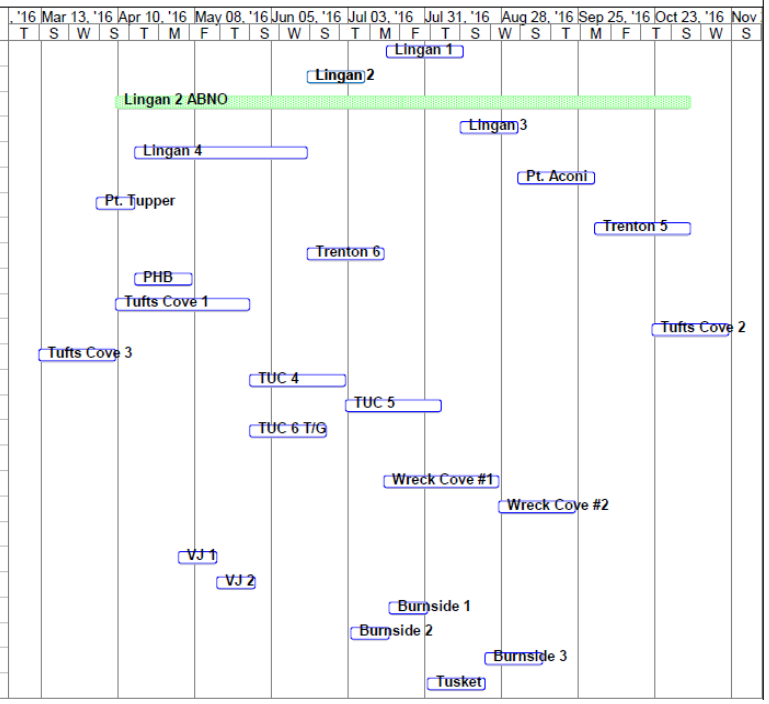
Plant Maintenance

2016 Plant Maintenance Schedule Plan - Budget

2016 Thermal Maintenance Schedule
(As of July 2, 2015)

ID	Task Name	Duration	Start	Finish
1	Lingan 1	4 ewks	Sat 07/16/16	Sat 08/13/16
2	Lingan 2	3 ewks	Sat 06/18/16	Sat 07/09/16
3	Lingan 2 ABNO	30 ewks	Sat 04/09/16	Sat 11/05/16
4	Lingan 3	3 ewks	Sat 08/13/16	Sat 09/03/16
5	Lingan 4	9 ewks	Sat 04/16/16	Sat 06/18/16
6	Pt. Aconi	4 ewks	Sat 09/03/16	Sat 10/01/16
7	Pt. Tupper	2 ewks	Sat 04/02/16	Sat 04/16/16
8	Trenton 5	5 ewks	Sat 10/01/16	Sat 11/05/16
9	Trenton 6	4 ewks	Sat 06/18/16	Sat 07/16/16
10	PHB	3 ewks	Sat 04/16/16	Sat 05/07/16
11	Tufts Cove 1	7 ewks	Sat 04/09/16	Sat 05/28/16
12	Tufts Cove 2	4 ewks	Sat 10/22/16	Sat 11/19/16
13	Tufts Cove 3	4 ewks	Sat 03/12/16	Sat 04/09/16
14	TUC 4	5 ewks	Sat 05/28/16	Sat 07/02/16
15	TUC 5	5 ewks	Sat 07/02/16	Sat 08/06/16
16	TUC 6 T/G	4 ewks	Sat 05/28/16	Sat 06/25/16
17				
18	Wreck Cove #1	6 ewks	Sat 07/16/16	Sat 08/27/16
19	Wreck Cove #2	4 ewks	Sat 08/27/16	Sat 09/24/16
20				
21	VJ 1	2 ewks	Mon 05/02/16	Mon 05/16/16
22	VJ 2	2 ewks	Mon 05/16/16	Mon 05/30/16
23	Burnside 1	2 ewks	Mon 07/18/16	Mon 08/01/16
24	Burnside 2	2 ewks	Mon 07/04/16	Mon 07/18/16
25	Burnside 3	3 ewks	Mon 08/22/16	Mon 09/12/16
26	Tusket	3 ewks	Mon 08/01/16	Mon 08/22/16



Commentary:
NSPI monitors various indicators throughout the year as the Thermal Maintenance Shutdown Schedule unfolds and adjusts the Schedule appropriately in response to changing conditions. The key indicators that NSPI monitors include: Fuel Pricing, Energy Sales / Purchase Opportunity, Analysis of Safety and Cost Risk, Transmission / Distribution Limitations, Availability of Resources (i.e. Critical Parts, Contractors, Construction Resources, Manpower, etc.) Various groups within NSPI, including Power Production, Fuels and the Control Centre, work together and share information on the indicators listed above. Together they make coordinated decisions and take advantage of the changing conditions to reduce outage costs.

*ewks = estimated weeks

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Plant Maintenance

OM&G and Capital Spending	Actual Year	Actual Year -1	Actual Year -2	Actual Year -3	Actual Year -4	Actual Year -5	Actual Year -6	Actual Year -7	Budget Year	Budget Year +1
OM&G Expense by Operating Group										
Lingan										
Tuft's Cove										
Pt Tupper										
Pt. Aconi										
Trenton										
Hydro										
Wind										
Combustion Turbine										
Plant Operations										
Biomass										
Fuel, Energy & Risk Management										
Total										
Capital Spending by Station										
Lingan										
Tuft's Cove										
Pt Tupper										
Pt. Aconi										
Trenton										
Hydro										
Combustion Turbine (Includes LMs)										
PH Biomass										
Wind										
Glace Bay										
Fuel, Energy & Risk Management										
Total										

Commentary:

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Plant Maintenance

Major Projects - [Year]

Project	Station

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Plant Maintenance

Major Projects - [Year +1]

Project	Station

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System Losses

GWh	Actual [Year]	Actual [Year -1]	Budget [Year]*	Budget [Year +1]**
Total System Requirements				
Domestic Electric Sales				
Export Sales				
Net System Losses				
%				

* [Year] [Source] Forecast presented to SWG in [Month Year]
** [Year +1] Budget reflects the [Source] filing of $XXX M.

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Emission Compliance

Commentary

Nova Scotia Power (NSPI) is required to manage air emissions to annual fleet wide limits, as per the NS Air Quality Regulations and the NS Greenhouse Gas (GHG) Emission Regulations. NSPI has been fully compliant with legislated emission targets each year.

The fleet wide limit of sulphur dioxide (SO2) emissions for 2015-2019 inclusive is 304,500 tonnes. This is equivalent to an annual average limit of 60,900 tonnes.

The [Year] limit on annual emissions of mercury (Hg) was [##] kg. NSPI continued the operation of seven (7) sorbent injection systems that were installed in 2009. The mercury emissions were within this limit in [Year] at [##] kg. The [Year +1] emission limit for mercury will remain at [##] kg. Under current regulations, any NSPI emissions of Hg above 65 kg for 2010-2013 must be made up by 2020.

NSPI manages its actual air emissions (SO_2 and to some extent mercury) by purchasing and combusting specific quality fuels and procuring power from other sources (i.e., Imports and Independent Power Producers), and by increasing the amount of renewable generation.

From 2015 to the end of 2019 there is a compliance limit total of 96,140 tonnes for nitrogen oxides (NOx) emissions, which is equivalent to an annual average limit of 19,228 tonnes. The [Year] NOx emissions were [###] tonnes. NSPI continued the operation of the low NO_x Combustion Firing Systems (LNCFS) on all Lingan units, Point Tupper and Trenton 6. These LNCFS additions represent the primary approach to reduce NO_x emissions.

The GHG emission limit for the three-year period of [Years covered] has been set at [##] million tonnes CO2 eq. This equates to the approximate targets of [##] million tonnes in [Year], [##] million tonnes in [Year +1], and [##] million tonnes in [Year +2]. In [Year], NSPI emitted [##] tonnes of CO2 eq. The [Year +1] emissions are estimated at [##] tonnes of CO2 eq. and subject to third party verification before finalized. In addition, NSPI will be applying for a GHG emission credit for [Year +2], related to transmission upgrades to support renewable generation.

In addition to these fleet-wide caps, each generating facility operates within an Industrial Operating Approval which requires ground level ambient air quality to be maintained, plume visibility to be within limits and, in some cases, specific emission standards to be met. This is accomplished by maintaining the plant equipment in good working order and operating the plant within the specified limits.

Fuel Summary by Type

NSPI (FAM) A-10a
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Fuel & PP (Domestic Load On													
Solid Fuel													
Natural Gas													
Biomass													
Bunker C													
Furnace													
Diesel													
Additives - Mercury													
Additives													
Subtotal													
Fuel for Generation													
Purchased Power													
Imports													
IPP													
Wind Purchases													
COMFIT													
Total Purchased Power													
Fuel & PP (Domestic Load On													
Fuel for Resale													
Costs													
Recoveries													
Net Cost (Benefit)													
Export Sales													
Costs													
Recoveries													
Net Cost (Benefit)													
Net Fuel and Purchased Powe													
Water Royalties													
Total Fuel and Purchased Po													
Total Fuel & PP													
FUEL COST PER Mwh:													
$/MWh on Total Generation													
$/MWh - no gas margin													
$/Mwh - no export costs													
$/Mwh - no export costs & n (Domestic Load Onl													

Net Generation by Fuel Type

NSPI (FAM) A-10b
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Net Generation (MWh)													
Lingan													
Solid Fuel													
HFO													
Tufts Cove													
HFO													
Natural Gas													
LM6000 - Natural Gas													
Trenton 5													
Solid Fuel													
HFO													
Trenton 6													
Solid Fuel													
HFO													
Point Tupper													
Solid Fuel													
HFO													
Point Aconi													
Solid Fuel													
Port Hawkesbury Biomass													
Solid Fuel													
Combustion Turbines													
Diesel													
Natural Gas													
Total Thermal Production													
Solid Fuel													
Natural Gas													
HFO													
Diesel													
Subtotal													
Purchases													
Imports													
IPP													
Wind Purchases													
COMFIT													
Subtotal													
Renewables													
Total System Requirement													
Net Generation Percentages													
Solid Fuel													
Natural Gas													
HFO													
Diesel													
Purchases													
Hydro & Tidal													

Power Production Thermal Station Fuel Costs

NSPI (FAM) A-10c
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
$ per MMBTU													
Biomass													
Green MT													
MMBtu													
Costs													
$ per Green MT													
$ per MMBtu													
Bunker C													
Barrels													
MMBTU													
Costs													
$ per Barrel													
$ per MMBTU													
Diesel													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
Furnace													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives Costs													
Additives - Hg													
Total Consumed Costs													
Purchased Power													
Total Fuel and Purchased Po													
$/Mwh													
FX Adjustment on Consumed F													
Solid Fuel													
Natural Gas													
Bunker C													
Purchased Power													
Additives - Hg													
Total FX Adjustments													
FX Adj'd Fuel & PP													
$/Mwh (FX Adj'd)													
Fuel for Resale													
Costs													
Recoveries													
Net Cost (Benefit)													
FX Adjustment on Revenue													
FX Adj on Costs													
FX Adj'd Cost(Benefit)													
Other Costs													
Adjustments													

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

MTM on HFO and Natural Gas													
Total Other Costs													
Total Fuel & PP													
Newpage Gas Loss													
Total Fuel and Purchased Po													

Power Production Solid Fuel Costs by Supplier

NSPI (FAM) A-10d
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Import													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Domestic													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Pet Coke													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Other													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
All Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Blend Percentages (Tonnes)													
Import													
Domestic													
Pet Coke													
Biomass													

Power Production Heat Rate Report

NSPI (FAM) A-10e
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Net Generation by Plant (MW													
Lingan													
Tufts Cove													
Trenton													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
Combustion Turbines													
LM6000 Combined Cycle (Unit													
Total System													
Fuel Consumption by Plant (													
Lingan													
Tufts Cove													
Trenton													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
Combustion Turbines													
LM6000 Combined Cycle (Unit													
Total System													
Heat Rate by Plant													
Lingan													
Tufts Cove													
Trenton													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
Combustion Turbines													
LM6000 Combined Cycle (Unit													
Total System													
Fuel Cost by Plant (Includi													
Lingan													
Tufts Cove													
Trenton													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
Combustion Turbines													
LM6000 Combined Cycle (Unit													
Total System													
Fuel Cost per MWh by Plant													
Lingan													
Tufts Cove													
Trenton													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
Combustion Turbines													
LM6000 Combined Cycle (Unit													
Total System													

Natural Gas Report

NSPI (FAM) A-10f
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Sales (Mmbtu)													
Sales ($$)													
Revenue													
Revenue- Gas Margin Deferra													
Gain/(Loss) on Derivatives													
Cost of Sales													
Shell Gas													
Newpage Gas													
Fuel													
Net Margin/Mmbtu ($/Mmbtu)													
FX Adj. on Gas Margin													
FX Adjusted Natural Gas Mar													
FX Adj. $/Mmbtu													

Export Sales Report - Monthly Forecast

NSPI (FAM) A-10g
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Sales (Mwh)													
Generation													
Losses													
Sales (Billed)													
Sales ($$)													
Cost of Sales													
Lingan 1/2													
Lingan 3/4													
Trenton													
Pt. Tupper													
Pt. Aconi													
Tufts Cove													
HFO													
Natural Gas													
LM6000													
Combustion Turbines													
Purchased Power													
Total Costs													
Net Margin on Exports													
($/Mwh)													

GENERATION STATISTICS - MWh

NSPI (FAM) A-10h
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Lingan													
Tufts Cove													
Trenton													
Point Tupper													
Point Aconi													
Combustion Turbines													
LM6000													
Renewables													
Total Generation													
Purchased Power													
Imports													
IPP													
Wind													
COMFIT													
Total Purchases													
Total MWhs Available													
Domestic Revenue													
Exports													
Total Electric Revenue													
Line and Other Losses													
Export Percentage of Total													

GENERATION STATISTICS - RENEWABLES

NSPI (FAM) A-10i
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year
Submitted: Date

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Renewables - NSPI-owned													
Hydro													
Dickie Brook Hydro													
Tusket Hydro													
Bear River Hydro Syst													
Avon Hydro System													
Lequille Hydro System													
Annapolis Tidal Power													
St.Margaret's Hydro S													
Sheet Harbour Hydro S													
Black River Hydro Sys													
Mersey Hydro System													
Roseway & Harmony Hyd													
Wreck Cove Hydro Syst													
Fall River Hydro													
TOTAL													
Wind													
Grand Etang Wind Turb													
203 Nuttby Wind Farm													
Digby Wind Farm													
TOTAL													
Biomass													
Port Hawkesbury Biomass													
Total NSPI Renewables													
Renewables - IPP-owned													
Wind													
Pubnico Point Wind Farm													
Lingan													
Glace Bay 1B													
Port Caledonia (Donkin)													
Gillis Cove													
Tiverton (Londonderry)													
Springhill													
Higgins Mountain													
Goodwood													
Brookfield (Lake Major)													
Fitzpatrick Mountain													
Point Tupper 1													
Digby													
Tatamagouche (Marshville/R													
Amherst													
Dalhousie Mountain													
Glen Dhu North													
Maryvale													
Point Tupper 3													
Watts Section													
Fairmont													
Dunvegan													
Granville Ferry													
Isle Madame													
Creignish Rear													
Irish Mountain													
South Cape Mabou													
Spiddle Hill													
Cape North													
Donkin													
Sable Wind													
South Canoe													
Other													
TOTAL IPP WIND													
COMFIT													
158- Spiddle Hill (Colchest													
074- Town of New Glasgow													
111-2 District of Guysboro													
072- Spiddle Hill T800N													
271- Windmill Holsteins Bio													
162- Kaizer Meadow													
216- St. Rose													
171- Isle Madame													
222- Little River													
225- Martock Ridge													
277- Barrington													
084- New Glasgow													

212- Cape Breton	
109- Melford	
081- Harbourside Biomass	
264- Hillside Boularderie	
150- Gaetz Brook	
138- District of Shelburne	
077- Pockwock Wind Limited	
143- District of Digby	
375- Barrachois Wind Farm	
226- Nine Mile River	
240- Whynotts	
241- Truro Heights	
242- Truro-Millbrook	
251- Aulds Mountain	
272- North Beaver Bank	
273- Black Pond	
311- Hefler Forest Products	
280- Tatamagouche Wind Fiel	
116- Universite Sainte-Anne	
161- Town of Amherst	
193- Cheticamp	
283- Halifax Water	
198- Celtic Current - Mulgr	
118- Pictou - Riverton Phas	
317- Pictou - Riverton Phas	
181- Affinity - Fitzpatrick	
182- Affinity - Kemptown	
183- Affinity - Greenfield	
184- Affinity - Limerock Mt	
235- Watts Wind - Wedgeport	
086- Ketch Harbour	
139- Avondale	
205- Fundy Tidal	
243- Chebucto Terence Bay	
367- Barrington	
190- Bateston	
192- Point Aconi	
164 - The Northumberland Wi	
180 - Affinity Renewables -	
184 - Affinity Renewables -	
224 - Scotian Wind - Brento	
229 - Scotian Wind - Walton	
230 - Scotian Wind - Badeck	
239 - The Northumberland Wi	
244 - Membertou - Victoria	
284 - Port Hood & District	
286 - Celtic Current - Mulg	
287 - Port Hood & District	
288 - Celtic Current - Mulg	
291 - Town of Mulgrave - Mu	
298 - Halifax Regional Wate	
309 - The Northumberland Wi	
313 - The Northumberland Wi	
391 - Chestico Museum and H	
393 - The Northumberland Wi	
394 - The Northumberland Wi	
395 - Chestico Museum and H	
Add Projects In 2016 - Smal	
Add Projects In 2016 - Larg	
Add Projects In 2016 - Biom	
247 - Watts Wind Porters La	
TOTAL COMFIT	
IPP - Other	
Halifax Renewable Energy	
Black River Hydro	
Brooklyn Power	
Morgan Falls Power Company	
FW Taylor Lumber Company	
Minas Basin Pulp and Paper	
Cape Sharpe Tidal	
TOTAL IPP OTHER	
Total IPP Renewables	
Total Renewables	

RENEWABLES COSTS (MTHLY)

NSPI (FAM) A-10j
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
--- --- --- --- ---	---	---	---	---	---	---	---	---	---	---	---	---	---
Renewables - NSPI-owned													
Hydro													
Energy Dispatch & Fuels													
Hydro Production Administra													
Dickie Brook Hydro													
Tusket Hydro													
Bear River Hydro System													
Sissiboo/Weymouth System													
Avon Hydro System													
Lequille Hydro System													
Nictaux/Paradise System													
Paradise System													
Annapolis Tidal Power													
St. Margaret's Hydro System													
Sheet Harbour Hydro System													
Black River Hydro System													
Mersey Hydro System													
Roseway & Harmony Hydro													
Harmony Hydro System													
Wreck Cove Hydro System													
Wreck Cove Windmill													
Fall River Hydro													
TOTAL													
Wind													
Little Brook Wind Turbines													
Grand Etang Wind Turbine													
Nuttby Wind Farm													
Digby Wind Farm													
TOTAL													
Renewables - IPP-owned													
Wind													
Pubnico Point Wind Farm													
Lingan													
Glace Bay 1B													
Port Caledonia (Donkin)													
Gillis Cove													
Tiverton (Londonderry)													
Springhill													
Higgins Mountain													
Goodwood													
Brookfield (Lake Major)													
Fitzpatrick Mountain													
Point Tupper 1													
Digby													
Tatamagouche (Marshville/R													
Amherst													
Dalhousie Mountain													
Glen Dhu North													
Maryvale													
Point Tupper 3													
Watts Section													
Fairmont													
Dunvegan													
Granville Ferry													
Isle Madame													
Creignish Rear													
Irish Mountain													
South Cape Mabou													
Spiddle Hill													
Cape North													
Lingan II													
Sable Wind													
South Canoe													
Other													
TOTAL IPP WIND													
COMFIT													
158- Spiddle Hill													
074- Town of New Glasgow													
111- District of Guysborou													
072- Spiddle Hill T800N													
271- Windmill Holsteins Bio													
162- Kaizer Meadow													
216- St. Rose													
171- Isle Madame													
222- Little River													

225- Martock Ridge	
277- Barrington	
084- New Glasgow	
212- Cape Breton	
109- Melford	
081- Harbourside Biomass	
264- Hillside-Boularderie	
150- Gaetz Brook	
138- District of Shelburne	
077- Pockwock Wind Limited	
143- District of Digby	
375- Barrachois Wind Farm	
226- Nine Mile River	
240- Whynotts	
241- Truro Heights	
242- Truro-Millbrook	
251- Aulds Mountain	
272- North Beaver Bank	
273- Black Pond	
311- Hefler Forest Products	
280- Tatamagouche Wind Fiel	
116- Universite Sainte Anne	
161- Town of Amherst	
193- Chetitcamp	
283- Halifax Water	
198- Celtic Current - Mulgr	
118- Pictou - Riverton Phas	
317- Pictou - Riverton Phas	
181- Affinity - Fitzpatrick	
182- Affinity - Kemptown	
183- Affinity - Greenfield	
184- Affinity - Limerock Mt	
235- Watts Wind - Wedgeport	
086- Ketch Harbour	
139- Avondale	
205- Fundy Tidal	
243- Chebucto Terrence Bay	
367- Barrington	
190- Bateston	
192- Point Aconi	
164 - The Northumberland Wi	
180 - Affinity Renewables -	
184 - Affinity Renewables -	
224 - Scotian Wind - Brento	
229 - Scotian Wind - Walton	
230 - Scotian Wind - Badeck	
239 - The Northumberland Wi	
244 - Membertou - Victoria	
284 - Port Hood & District	
286 - Celtic Current - Mulg	
287 - Port Hood & District	
288 - Celtic Current - Mulg	
291 - Town of Mulgrave - Mu	
298 - Halifax Regional Wate	
309 - The Northumberland Wi	
313 - The Northumberland Wi	
391 - Chestico Museum and H	
393 - The Northumberland Wi	
394 - The Northumberland Wi	
395 - Chestico Museum and H	
Add Projects In 2016 - Smal	
Add Projects In 2016 - Larg	
Add Projects In 2016 - Biom	
247 - Watts Wind Porters La	
TOTAL COMFIT	
IPP - Other	
Halifax Renewable Energy	
Black River Hydro	
Brooklyn Power	
Morgan Falls Power Company	
FW Taylor Lumber Company	
Minas Basin Pulp and Paper	
Cape Sharpe Tidal	
Other IPP	
TOTAL IPP OTHER	
Total IPP Renewables	
Total Renewables	

Power Production Average Load Report

NSPI (FAM) A-10k
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Net Generation by Unit (MWh													
Lingan - Unit 1													
Lingan - Unit 2													
Lingan - Unit 3													
Lingan - Unit 4													
Tufts Cove - Unit 1													
Tufts Cove - Unit 2													
Tufts Cove - Unit 3													
LM- Unit 4													
LM- Unit 5													
LM-Unit 6													
Trenton - Unit 5													
Trenton - Unit 6													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
CT- Tusket													
CT-Victoria Junction													
CT- Burnside													
Total Net Generation (MWh)													
Operating Hours													
Lingan - Unit 1													
Lingan - Unit 2													
Lingan - Unit 3													
Lingan - Unit 4													
Tufts Cove - Unit 1													
Tufts Cove - Unit 2													
Tufts Cove - Unit 3													
LM- Unit 4													
LM- Unit 5													
LM-Unit 6													
Trenton - Unit 5													
Trenton - Unit 6													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
CT- Tusket													
CT- Victoria Junction													
CT- Burnside													
Average Load - MW													
Lingan - Unit 1													
Lingan - Unit 2													
Lingan - Unit 3													
Lingan - Unit 4													
Tufts Cove - Unit 1													
Tufts Cove - Unit 2													
Tufts Cove - Unit 3													
LM- Unit 4													
LM- Unit 5													
LM-Unit 6													
Trenton - Unit 5													
Trenton - Unit 6													
Point Tupper													
Point Aconi													
Port Hawkesbury Biomass													
CT- Tusket													
CT- Victoria Junction													
CT- Burnside													

Lingan Monthly Station Fuel Costs

NSPI (FAM) A-10I
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=LIN (Lingan)

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
$ per MMBTU													
Biomass													
Green MT													
MMBtu													
Costs													
$ per Green MT													
$ per MMBtu													
Bunker C													
Barrels													
MMBTU													
Costs													
$ per Barrel													
$ per MMBTU													
Diesel													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
Furnace													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives Costs													
Additives - Hg													
Total Consumed Costs													
Purchased Power													
Total Fuel and Purchased Po													
$/Mwh													
FX Adjustment on Consumed F													
Solid Fuel													
Natural Gas													
Bunker C													
Purchased Power													
Additives - Hg													
Total FX Adjustments													
FX Adj'd Fuel & PP													
$/Mwh (FX Adj'd)													
Fuel for Resale													
Costs													
Recoveries													
Net Cost (Benefit)													
FX Adjustment on Revenue													
FX Adj on Costs													
FX Adj'd Cost(Benefit)													
Other Costs													
Adjustments													

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

MTM on HFO and Natural Gas													
Total Other Costs													
Total Fuel & PP													
Newpage Gas Loss													
Total Fuel and Purchased Po													

Lingan Solid Fuel Costs by Supplier

NSPI (FAM) A-10m
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=LIN (Lingan)

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
	---	---	--- -	--- -	--- -	--- -	--- -	--- -	--- -	--- -	--- -	--- -	---
Import													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Domestic													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Pet Coke													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Other													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
All Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Blend Percentages (Tonnes)													
Import													
Domestic													
Pet Coke													
Biomass													

Lingan Heat Rate Report

NSPI (FAM) A-10n
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=LIN (Lingan)

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Net Generation by Unit (MWh													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Consumption by Unit (M													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Heat Rate by Unit													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Cost by Unit (Includin													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Cost per MWh by Unit													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													

Pt. Aconi Monthly Station Fuel Costs

NSPI (FAM) A-10o
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=PTA (Point Aconi)

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
$ per MMBTU													
Biomass													
Green MT													
MMBtu													
Costs													
$ per Green MT													
$ per MMBtu													
Bunker C													
Barrels													
MMBTU													
Costs													
$ per Barrel													
$ per MMBTU													
Diesel													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
Furnace													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives Costs													
Additives - Hg													
Total Consumed Costs													
Purchased Power													
Total Fuel and Purchased Po													
$/Mwh													
FX Adjustment on Consumed F													
Solid Fuel													
Natural Gas													
Bunker C													
Purchased Power													
Additives - Hg													
Total FX Adjustments													
FX Adj'd Fuel & PP													
$/Mwh (FX Adj'd)													
Fuel for Resale													
Costs													
Recoveries													
Net Cost (Benefit)													
FX Adjustment on Revenue													
FX Adj on Costs													
FX Adj'd Cost(Benefit)													
Other Costs													
Adjustments													

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

MTM on HFO and Natural Gas													
Total Other Costs													
Total Fuel & PP													
Newpage Gas Loss													
Total Fuel and Purchased Po													

Pt. Aconi Solid Fuel Costs by Supplier

NSPI (FAM) A-10p
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=PTA (Point Aconi)

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Import													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Domestic													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Pet Coke													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Other													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
All Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Blend Percentages (Tonnes)													
Import													
Domestic													
Pet Coke													
Biomass													

Trenton 5 Monthly Station Fuel Costs

NSPI (FAM) A-10q
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Bunker C													
Barrels													
MMBTU													
Costs													
$ Per Barrel													
$ per MMBTU													
Furnace													
Gallons													
Barrels													
MMBTU													
Costs													
$ per Gallon													
$ per Barrel													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Adjustments													
Additives													
Total Fuel & PP													
Generation by Fuel Type (Mw													
Solid Fuel													
Bunker C													
Total Generation													

Trenton 5 Solid Fuel Costs by Supplier

NSPI (FAM) A-10r
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Import													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Domestic													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Pet Coke													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Other													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
All Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Blend Percentages (Tonnes)													
Import													
Domestic													
Pet Coke													
Other													

Trenton 6 Monthly Station Fuel Costs

NSPI (FAM) A-10s
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Bunker C													
Barrels													
MMBTU													
Costs													
$ Per Barrel													
$ per MMBTU													
Furnace													
Gallons													
Barrels													
MMBTU													
Costs													
$ per Gallon													
$ per Barrel													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives													
Generation by Fuel Type (MW													
Solid Fuel													
Bunker C													
Total Generation													

Trenton 6 Solid Fuel Costs by Supplier

NSPI (FAM) A-10t
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Import													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Domestic													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Pet Coke													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Other													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
All Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Blend Percentages (Tonnes)													
Import													
Domestic													
Pet Coke													
Other													

Trenton Heat Rate Report

NSPI (FAM) A-10u
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=TRN (Trenton)

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Net Generation by Unit (MWh													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Consumption by Unit (M													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Heat Rate by Unit													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Cost by Unit (Includin													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Cost per MWh by Unit													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													

Pt. Tupper Monthly Station Fuel Costs

NSPI (FAM) A-10v
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=PTU (Point Tupper)

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
$ per MMBTU													
Biomass													
Green MT													
MMBtu													
Costs													
$ per Green MT													
$ per MMBtu													
Bunker C													
Barrels													
MMBTU													
Costs													
$ per Barrel													
$ per MMBTU													
Diesel													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
Furnace													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives Costs													
Additives - Hg													
Total Consumed Costs													
Purchased Power													
Total Fuel and Purchased Po													
$/Mwh													
FX Adjustment on Consumed F													
Solid Fuel													
Natural Gas													
Bunker C													
Purchased Power													
Additives - Hg													
Total FX Adjustments													
FX Adj'd Fuel & PP													
$/Mwh (FX Adj'd)													
Fuel for Resale													
Costs													
Recoveries													
Net Cost (Benefit)													
FX Adjustment on Revenue													
FX Adj on Costs													
FX Adj'd Cost(Benefit)													
Other Costs													
Adjustments													

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

MTM on HFO and Natural Gas													
Total Other Costs													
Total Fuel & PP													
Newpage Gas Loss													
Total Fuel and Purchased Po													

Pt. Tupper Solid Fuel Costs by Supplier

NSPI (FAM) A-10w
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=PTU (Point Tupper)

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Import													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Domestic													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Pet Coke													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Other													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
All Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Blend Percentages (Tonnes)													
Import													
Domestic													
Pet Coke													
Biomass													

Tufts Cove Thermal Station Fuel Costs

NSPI (FAM) A-10x
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
$ w/o Hedges													
$/MMBTU													
$/MMBTU w/o Hedges													
Bunker C													
Barrels													
MMBTU													
Costs													
Costs w/o Hedges													
$/BBL													
$/BBL w/o Hedges													
$/MMBTU													
$/MMBTU w/o Hedges													
Furnace / Diesel													
Gallons													
Barrels													
MMBTU													
Costs													
$ per Gallon													
$ per Barrel													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives Costs													
Total Consumed Costs													
Adjustments													
Pipeline Toll													
Total Fuel Costs													

Tufts Cove Heat Rate Report

NSPI (FAM) A-10y
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=312 (Tufts Cove Operations)

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Net Generation by Unit (MWh													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Consumption by Unit (M													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Heat Rate by Unit													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Cost by Unit (Includin													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													
Fuel Cost per MWh by Unit													
Unit 1													
Unit 2													
Unit 3													
Unit 4													
Unit 5													
Unit 6													
Total Plant													

LM6000 Thermal Station Fuel Costs

NSPI (FAM) A-10z
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
Costs w/o Hedges													
$/MMBTU													
$/MMBTU w/o Hedges													
Bunker C													
Barrels													
MMBTU													
Costs													
$ per Barrel													
$ per MMBTU													
Furnace / Diesel													
Gallons													
Barrels													
MMBTU													
Costs													
$ per Gallon													
$ per Barrel													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives Costs													
Total Consumed Costs													
Adjustments													
Pipeline Toll													
Total Fuel Costs													

Combustion Turbines Thermal Station Fuel Costs

NSPI (FAM) A-10aa
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

Cost Centre=CTS (Combustion Turbine)

	JAN-16 Forecast	FEB-16 Forecast	MAR-16 Forecast	APR-16 Forecast	MAY-16 Forecast	JUN-16 Forecast	JUL-16 Forecast	AUG-16 Forecast	SEP-16 Forecast	OCT-16 Forecast	NOV-16 Forecast	DEC-16 Forecast	Total Forecast
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
$ per MMBTU													
Biomass													
Green MT													
MMBtu													
Costs													
$ per Green MT													
$ per MMBtu													
Bunker C													
Barrels													
MMBTU													
Costs													
$ per Barrel													
$ per MMBTU													
Diesel													
Gallons													
MMBTU													
Costs													
$ per Gallon													
$ per MMBTU													
Furnace													
MMBTU													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives Costs													
Additives - Hg													
Total Consumed Costs													
Purchased Power													
Total Fuel and Purchased Po													
$/Mwh													
FX Adjustment on Consumed F													
Solid Fuel													
Natural Gas													
Bunker C													
Purchased Power													
Additives - Hg													
Total FX Adjustments													
FX Adj'd Fuel & PP													
$/Mwh (FX Adj'd)													
Fuel for Resale													
Costs													
Recoveries													
Net Cost (Benefit)													
FX Adjustment on Revenue													
FX Adj on Costs													
FX Adj'd Cost(Benefit)													
Other Costs													
Adjustments													
MTM on HFO and Natural Gas													
Total Other Costs													

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Total Fuel & PP													
Newpage Gas Loss													
Total Fuel and Purchased Po													

Port Hawkesbury Biomass Station Fuel Costs

NSPI (FAM) A-10ab
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Natural Gas													
MMBTU													
Costs													
Costs w/o Hedges													
$ Per MMBTU													
$ per MMBTU w/o Hedges													
Furnace													
Gallons													
Barrels													
MMBTU													
Costs													
$ per Gallon													
$ per Barrel													
$ per MMBTU													
All Fuels													
MMBTU													
Costs													
$ per MMBTU													
Additives													
Generation by Fuel Type (MW													
Solid Fuel													
Natural Gas													
Total Generation													

Port Hawkesbury Biomass Solid Fuel Costs by Supplier

NSPI (FAM) A-10ac
CONFIDENTIAL

NOVA SCOTIA POWER
Period: MONTH-Year $CAD
Submitted: Date

	JAN-16 Forecast	*FEB-16 Forecast*	*MAR-16 Forecast*	*APR-16 Forecast*	*MAY-16 Forecast*	*JUN-16 Forecast*	*JUL-16 Forecast*	*AUG-16 Forecast*	*SEP-16 Forecast*	*OCT-16 Forecast*	*NOV-16 Forecast*	*DEC-16 Forecast*	*Total Forecast*
Import													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Domestic													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Pet Coke													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Biomass													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
All Solid Fuel													
Tonnes													
MMBTU													
Costs													
$ per Tonne													
$ per MMBTU													
Blend Percentages (Tonnes)													
Import													
Domestic													
Pet Coke													
Biomass													

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-10ad
CONFIDENTIAL

Summary of [Year +1] Projected Fuel Expense - Plexos Output

NSPI	Measure	Output
ENERGY REQUIRED	GWh	
THERM GENERATION	GWh	
HYDRO GENERATION	GWh	
NET TRANSACTIONS	GWh	
PEAK LOAD	MW	
FUEL BURNED	MBtu	
TRANS PURCH	GWh	
TRANS SALES	GWh	
PT ACONI 1 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	
LINGAN 1 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBTu/MWh	
GENERATION GWH	GWh	
FUEL BURN	MBtu	
LINGAN 2 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	
LINGAN 3 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	Mbtu	
LINGAN 4 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-10ad
CONFIDENTIAL

Summary of [Year +1] Projected Fuel Expense - Plexos Output

NSPI	Measure	Output
TUPPER 2 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR MBTU/MWH	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	
TRENTON 5 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	
TRENTON 6 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	
TC 1 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	
TC-GAS		
TC-OIL		
TC 2 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	MBtu/MWh	
GENERATION	GWh	
FUEL BURN	MBtu	
TC-GAS		
TC-OIL		
TC 3 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	Mbtu/MWh	
GENERATION	GWh	
FUEL BURN 000	MBTu	
TC-GAS		
TC-OIL		

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-10ad
CONFIDENTIAL

Summary of [Year +1] Projected Fuel Expense - Plexos Output

NSPI	Measure	Output
TC - CC 4/5/6 CAPACITY FACTOR		
CAPACITY	MW	
AVG HR	Mbtu/MWh	
GENERATION	GWh	
FUEL BURN	MBTu	
TUSKET 1 CAPACITY FACTOR		
CAPACITY	MW	
GENERATION	GWh	
VJ 1 CAPACITY FACTOR		
CAPACITY	MW	
GENERATION	GWh	
VJ 2 CAPACITY FACTOR		
CAPACITY	MW	
GENERATION	GWh	
BURNSIDE 1 CAPACITY FACTOR		
CAPACITY	MW	
GENERATION	GWh	
BURNSIDE 2 CAPACITY FACTOR		
CAPACITY	MW	
GENERATION	GWh	
BURNSIDE 3 CAPACITY FACTOR		
CAPACITY	MW	
GENERATION	GWh	
BURNSIDE 4 CAPACITY FACTOR		
CAPACITY	MW	
GENERATION	GWh	

* [Year +1] Budget reflects the [Year, Source] filing of $XXX M.

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-10ae
CONFIDENTIAL

Summary of [Year +1]Projected Fuel Expense - Details of Solid Fuel Costs

Plant	Fuel Type	Opening Inventory			Deliveries											Weighted Average Cost
		Qty MT (000)	Heat Content MMBtu/ MT (000)	Price $/MMBtu	Qty MT (000)	Commodity $CDN/MT	Qty MT (000)	Ocean Freight $CDN/MT	Qty MT (000)	Land Transport $CDN/MT	Qty MT (000)	Sub-total $CDN/MT	FX	Heat Content MMBtu/ MT (000)	Price $/MMBtu	Price $/mBTU
Lingan	LS Import < 12															
	LS Import > 12															
	Mid Sulphur															
	Petcoke															
	PRB															
Pt. Aconi	LS Import < 12															
	Petcoke															
Trenton #5	LS Import < 12															
	LS Import > 12															
	Mid Sulphur															
Trenton #6	LS Import < 12															
	Petcoke															
	Domestic Low Sulphur															
Point Tupper	LS Import < 12															
	LS Import > 12															
	Mid Sulphur															
	Petcoke															
	PRB															

Notes:

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-10af
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Summary of Projected Fuel Expense - [Year +1] Outlook

NSPI is projecting fuel and purchased power expense in the range of $XXX M for [Year +1] which is based on the [Year, BCF/GRA Source] filing.

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-11
CONFIDENTIAL

Summary of Sales Forecast by Customer Class

GWh Sales	[Year +1]*	[Year +2]**
Residential		
General		
Small general		
General		
Large general		
Total General		
Industrial		
Small industrial		
Medium industrial		
Large industrial		
Load Retention		
GRLF		
RTP		
Shore Power		
Total Industrial		
Other		
Municipal		
Unmetered		
Total Other		
Total In-province electric sales		
Export		
Total Electric Sales		

* [Year +1] [Source]
** [Year +2] [Source]

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-12
CONFIDENTIAL

Affiliate Transactions - Fuels and Power

No.	Goods / Service Provider	Goods / Service Receiver	Dollars	Short Description	Pricing Mechanism	Price Paid
1						
2						
3						
4						
5						

Commentary -

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-13a
CONFIDENTIAL

Mercury Abatement Program
Mercury Sorbent Details
(Including oxidising agents)

~ Year To Date ~

	Fuel Mix	Type	Quantity		Capture Costs [$M]	$/MWh*
Generating Plant						
Lingan Unit 1	LS/MS/PC	Powder Activated Carbon		Kg		
Lingan Unit 2	LS/MS/PC	Powder Activated Carbon		Kg		
Lingan Unit 3	LS/MS/PC	Powder Activated Carbon		Kg		
Lingan Unit 4	LS/MS/PC	Powder Activated Carbon		Kg		
Trenton Unit 5	LS/MS	Powder Activated Carbon		Kg		
Trenton Unit 6	DOM/LS/MS/PC	Powder Activated Carbon		Kg		
Point Tupper	LS/MS/PC	Powder Activated Carbon		Kg		
Lingan	LS/MS/PC	Calcium Chloride		L		
Trenton	DOM/LS/MS/PC	Calcium Chloride		L		
Point Tupper	LS/MS/PC	Calcium Chloride		L		
Total Mercury Sorbent Costs (PAC)				Kg		
Total Mercury Sorbent Costs (Cal. Chl.)				L		
Total Mercury Sorbent Costs						

*The value of $/MWh has been calculated using the total sorbent cost for the unit identified and the total MWh produced by that unit.

Mercury Emission Levels (kgs)	Year Actual	Year Forecast	Variance

Emissions Commentary -

Technical Issues Commentary -

PAC [Year]

CaCl [Year]

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-13a
NON-CONFIDENTIAL

Mercury Abatement Program
Mercury Sorbent Details
(Including oxidising agents)

~ Year To Date ~

	Fuel Mix	Type	Quantity		Capture Costs [$M]	$/MWh*
Generating Plant						
Lingan Unit 1	LS/MS/PC	Powder Activated Carbon	[redacted]	Kg	[redacted]	
Lingan Unit 2	LS/MS/PC	Powder Activated Carbon	[redacted]	Kg	[redacted]	
Lingan Unit 3	LS/MS/PC	Powder Activated Carbon	[redacted]	Kg	[redacted]	
Lingan Unit 4	LS/MS/PC	Powder Activated Carbon	[redacted]	Kg	[redacted]	
Trenton Unit 5	LS/MS	Powder Activated Carbon	[redacted]	Kg	[redacted]	
Trenton Unit 6	DOM/LS/MS/PC	Powder Activated Carbon	[redacted]	Kg	[redacted]	
Point Tupper	LS/MS/PC	Powder Activated Carbon	[redacted]	Kg	[redacted]	
Lingan	LS/MS/PC	Calcium Chloride	[redacted]	L	[redacted]	
Trenton	DOM/LS/MS/PC	Calcium Chloride	[redacted]	L	[redacted]	
Point Tupper	LS/MS/PC	Calcium Chloride	[redacted]	L	[redacted]	
Total Mercury Sorbent Costs (PAC)				Kg		
Total Mercury Sorbent Costs (Cal. Chl.)				L		
Total Mercury Sorbent Costs						

*The value of $/MWh has been calculated using the total sorbent cost for the unit identified and the total MWh produced by that unit.

Mercury Emission Levels (kgs)	Year Actual	Year Forecast	Variance

Emissions Commentary -

Technical Issues Commentary -

PAC [Year]

CaCl [Year]

Nova Scotia Power Inc.
Annual FAM Reporting
Year 2015

NSPI (FAM) A-13b
NON-CONFIDENTIAL

Mercury Abatement Program
Impact on Fuel Use

Commentary including quantitative and qualitative descriptions of the impact on fuel use by virtue of the mercury abatement program

PAC 2015
The PAC systems were run to achieve compliance in [Year]. Emissions were closely monitored to optimize injection rates.
Final performance of [##] kg was achieved within the target period.

Testing:
PAC testing was conducted in [Year] as follows:
[Station and detail information]

Calcium Chloride 2015
Calcium chloride systems are installed at each plant. The systems are run as required, based on fuel blend.

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-13c
NON-CONFIDENTIAL

Mercury Abatement Program
Technical / Capital Changes

Option	Description	Anticipated Result

Nova Scotia Power Inc.
Annual FAM Reporting
Year [20XX]

NSPI (FAM) A-13d
CONFIDENTIAL

Mercury Abatement Program
Forecast Mercury Sorbent Use [Year +1]
(Including oxidising agents)

	Year +1			
	Type	Quantity	Capture Costs [$M] (millions of dollars)	$/MWh
Generating Plant				
Lingan Unit 1	Powder Activated Carbon	Kgs		
Lingan Unit 2	Powder Activated Carbon	Kgs		
Lingan Unit 3	Powder Activated Carbon	Kgs		
Lingan Unit 4	Powder Activated Carbon	Kgs		
Trenton Unit 5	Powder Activated Carbon	Kgs		
Trenton Unit 6	Powder Activated Carbon	Kgs		
Point Tupper	Powder Activated Carbon	Kgs		
Lingan	Calcium Chloride	L		
Trenton	Calcium Chloride	L		
Point Tupper	Calcium Chloride	L		
Total Mercury Sorbent Costs				

Commentary -

Suppliers for [Year +1]:

ADA (Powdered Activated Carbon)	100% supply +/-20%
Somavrac/DOW (Calcium Chloride)	100% supply +/-20%

January 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
30	31	1	2	3	4	5
6	7	8	9	10	11	12
13 2016-2017 FAM Audit Hearing	14 2016-2017 FAM Audit Hearing (If Necessary)	15 2016-2017 FAM Audit Hearing (If Necessary)	16	17	18	19
20	**21** FAM Monthly (December 2019) 2019 AA/BA Actuals*	22	23	24	25	26
27	28	29	30	31	1	2
3	4	**NOTES**	*During 2020-2022 Fuel Stability Period, NS Power will continue to report AA/BA for each previous year			

February 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
27	28	29	30	31	1	2
3	4	5	6	7	8	9
10 FAM Quarterly Q4* ML Benefits Report Q4 2019	**11**	12	13	14	15	16
17	18	19	20	**21** FAM Monthly (January 2020)	22	23
24	25	26	27	28	29	1
2	3	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results			

March 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
24	25	26	27	28	29	1
2 2019 FAM Annual	3	4	5	6	7	8
9	10	11	12	13	14	15
16	17	18	19	20	21 FAM Monthly (February 2020)	22
23	24	25	26	27	28	29
30	31	**NOTES**	Anticipated FAM SWG meeting (date TBD)			

April 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
30	31	1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21 FAM Monthly (March 2020)	22	23	24	25	26
27	28	29	30	1	2	3
4	5	NOTES				

May 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
27	28	29	30	1	2	3
4	5	6	7	8	9	10
11 FAM Quarterly Q1* ML Benefits Report Q2 2020	12	13	14	15	16	17
18	19	20	21 FAM Monthly (April 2020)	22	23	24
25	26	27	28	29	30	31
1	2	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results			

June 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
1	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21 FAM Monthly (May 2020)
22	23	24	25	26	27	28
29	30	1	2	3	4	5
6	7	**NOTES**	Anticipated FAM SWG meeting (date TBD)			

July 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
29	30	1 CANADA DAY	2 2018-2019 FAM Audit Report*	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20 NSP IRs to FAM Auditor** Notices of Intervention**	21 FAM Monthly (June 2020)	22	23	24	25	26
27	28	29	30	31	1	2
3	4	NOTES	*Assumes bi-annual FAM Audit in 2020 **TBD by UARB			

August 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
27	28	29	30	31	1	2
3 NATAL DAY	4 FAM Auditor Responses to NSP IRs***	5	6	7	8	9
10 FAM Quarterly Q2* ML Benefits Report Q2**	11	12	13	14	15	16
17	18	19	20	21 FAM Monthly (July 2020)	22	23
24 NSP Reply to FAM Audit***	25	26	27	28	29	30
31	1	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results **Anticipated final ML Quarterly Benefits report (Muskrat Falls forecast June 2020) ***TBD			

September 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
31	1	2	3	4	5	6
7 LABOUR DAY	8 FAM Audit IRS to FAM Auditor and NSP*	9	10	11	12	13
14	15	16	17	18	19	20
21 FAM Monthly (August 2020)	22	23	24	25	26	27
28 FAM Audit IR Responses by NSP and FAM Auditor*	29	30	1	2	3	4
5	6	**NOTES**	Anticipated FAM SWG meeting (date TBD) *TBD			

October 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
28	29	30	1	2	3	4
5	6	7	8	9	10	11
12 FAM Audit Intervenor Evidence*	13	14	15	16	17	18
19	20	21	22	23	24	25
26 FAM Auditor and NSP Rebuttal*	27	28	29 FAM Audit Letters of Comment & Requests to Speak*	30 FAM Audit Opening Statements*	31	1
2	3	**NOTES**	*TBD			

November 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
26	27	28	29	30	31	1
2 2018-2019 FAM Audit Hearing**	3 2018-2019 FAM Audit Hearing (if necessary)**	4 2018-2019 FAM Audit Hearing (if necessary)**	5	6	7	8
9 FAM Quarterly Q3*	10	11	12	13	14	15
16	17	18	19	20	21	22
23 FAM Monthly (October 2020)	24	25	26	27	28	29
30	1	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results **TBD			

December 2020

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
30	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21 FAM Monthly (November 2020)	22	23 NSP to file Natural Gas Report	24	25	26	27
28	29	30	31	1	2	3
4	5	**NOTES**	Anticipated FAM SWG meeting (Date TBD)			

January 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
28	29	30	31	1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21 FAM Monthly (December 2020) 2020 AA/BA Actuals	22	23	24
25	26	27	28	29	30	31
1	2	NOTES				

February 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
1	2	3	4	5	6	7
8	9	10 FAM Quarterly Q4 2020*	11	12	13	14
15	16	17	18	19	20	21
22 FAM Monthly (January 2021) 2020 AABA Actuals	23	24	25	26	27	28
1	2	3	4	5	6	7
8	9	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results			

March 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
1 FAM Annual 2020	2	3	4	5	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22 FAM Monthly (February 2021)	23	24	25	26	27	28
29	30	31	1	2	3	4
5	6	**NOTES**	Anticipated FAM SWG meeting (date TBD)			

April 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
29	30	31	1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21 FAM Monthly (March 2021)	22	23	24	25
26	27	28	29	30	1	2
3	4	NOTES				

May 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
26	27	28	29	30	1	2
3	4	5	6	7	8	9
10 FAM Quarterly Q1*	11	12	13	14	15	16
17	18	19	20	21 FAM Monthly (April 2021)	22	23
24	25	26	27	28	29	30
31	1	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results			

June 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
31	1	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21 FAM Monthly (May 2021)	22	23	24	25	26	27
28	29	30	1	2	3	4
5	6	**NOTES**	Anticipated FAM SWG meeting (date TBD)			

July 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
28	29	30	1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16	17	18
19	20	21 FAM Monthly (June 2021)	22	23	24	25
26	27	28	29	30	31	1
2	3	NOTES				

August 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
26	27	28	29	30	31	1
2	3	4	5	6	7	8
9 FAM Quarterly Q2*	10	11	12	13	14	15
16	17	18	19	20	21	22
23 FAM Monthly (July 2021)	24	25	26	27	28	29
30	31	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results			

September 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
30	31	1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21 FAM Monthly (August 2021)	22	23	24	25	26
27	28	29	30	1	2	3
4	5	**NOTES**	Anticipated FAM SWG meeting (date TBD)			

October 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
27	28	29	30	1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21 FAM Monthly (September 2021)	22	23	24
25	26	27	28	29	30	31
1	2	NOTES				

November 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
1	2	3	4	5	6	7
8	9	10 FAM Quarterly Q3*	11	12	13	14
15	16	17	18	19	20	21
22 FAM Monthly (October 2021)	23	24	25	26	27	28
29	30	1	2	3	4	5
6	7	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results			

December 2021

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
29	30	1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21 FAM Monthly (November 2021)	22	23 NSP to file Natural Gas Report	24	25	26
27	28	29	30	31	1	2
3	4	NOTES	Anticipated FAM SWG meeting (date TBD)			

January 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
27	28	29	30	31	1	2
3	4	5	6	7	8	9
10	11	12	13	14	15	16
17	18	19	20	21 FAM Monthly (December 2021) 2021 AABA Actuals	22	23
24	25	26	27	28	29	30
31	1	NOTES				

February 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
31	1	2	3	4	5	6
7	8	9	10 FAM Quarterly Q4 2021*	11	12	13
14	15	16	17	18	19	20
21 FAM Monthly (January 2022)	22	23	24	25	26	27
28	1	2	3	4	5	6
7	8	NOTES	*Subject to confirmation of release date of NS Power's quarterly financial results			

March 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
28	1 FAM Annual 2021	2	3	4	5	6
7	8	9	10	11	12	13
14	15	16	17	18	19	20
21 FAM Monthly (February 2022)	22	23	24	25	26	27
28	29	30	31	1	2	3
4	5	**NOTES**	Anticipated FAM SWG meeting (date TBD)			

April 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
28	29	30	31	1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21 FAM Monthly (March 2022)	22	23	24
25	26	27	28	29	30	1
2	3	NOTES				

May 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
25	26	27	28	29	30	1
2	3	4	5	6	7	8
9 FAM Quarterly Q1*	10	11	12	13	14	15
16	17	18	19	20	21	22
23 FAM Monthly (April 2022)	24	25	26	27	28	29
30	31	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results			

June 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
30	31	1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21 FAM Monthly (June 2022)	22	23	24	25	26
27	28	29	30	1	2	3
4	5	**NOTES**	Anticipated FAM SWG meeting (date TBD)			

July 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
27	28	29	30	1 CANADA DAY	2	3
4 2020-2021 FAM Audit Report*	5	6	7	8	9	10
11	12	13	14	15	16	17
18 NSP IRs to FAM Auditor** Notices of Intervention**	19	20	21 FAM Monthly (June 2022)	22	23	24
25	26	27	28	29	30	31
1	2	**NOTES**	*Assumes bi-annual FAM Audit in 2022 for 2020-2021 **TBD by UARB			

August 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
1 NATAL DAY	2 FAM Auditor Responses to NSP IRs**	3	4	5	6	7
8	9	10 FAM Quarterly Q2*	11	12	13	14
15	16	17	18	19	20	21
22 FAM Monthly (July 2022)	23	24	25 NSP Reply to FAM Audit**	26	27	28
29	30	31	1	2	3	4
5	6	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results **TBD by UARB			

September 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
29	30	31	1	2	3	4
5 LABOUR DAY	6	7	8 FAM Audit IRs to FAM Auditor and NSP*	9	10	11
12	13	14	15	16	17	18
19	20	21 FAM Monthly (August 2022)	22	23	24	25
26 FAM Audit IR Responses by NSP and FAM Auditor*	27	28	29	30	1	2
3	4	**NOTES**	Anticipated FAM SWG meeting (date TBD) *TBD by UARB			

October 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
26	27	28	29	30	1	2
3 FAM Audit IR Responses by NSP and FAM Auditor*	4	5	6	7	8	9
10	11	12	13 FAM Audit Intervenor Evidence*	14	15	16
17	18	19	20	21 FAM Monthly (September 2022)	22	23
24 NSP Application for AABA rates to be charged in 2023*	25	26	27	28	29	30
31 FAM Auditor and NSP Rebuttal*	1	**NOTES**	*TBD by UARB			

November 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
31	1	2 Intervenor AA/BA IRs to NSP**	3 FAM Audit Letters of Comment & Requests to Speak**	4 FAM Audit Opening Statements**	5	6
7 FAM Audit Hearing**	8	9 FAM Quarterly Q3*	10	11	12	13
14 NSP Responses to AA/BA IRs**	15	16	17	18	19	20
21 FAM Monthly (October 2022) AA/BA Hearing**	22	23	24	25	26	27
28	29	30	1	2	3	4
5	6	**NOTES**	*Subject to confirmation of release date of NS Power's quarterly financial results **TBD by UARB			

December 2022

MONDAY	TUESDAY	WEDNESDAY	THURSDAY	FRIDAY	SATURDAY	SUNDAY
28	29	30	1	2	3	4
5	6	7	8	9	10	11
12	13	14	15	16 AA/BA Decision*	17	18
19 NSP AA/BA Compliance filing*	20	21 FAM Monthly (November 2022)	22 AA/BA Order* NSP to file Natural Gas Report	23	24	25
26	27	28	29	30	31	1
2	3	**NOTES**	Anticipated FAM SWG meeting (date TBD) *TBD by UARB			

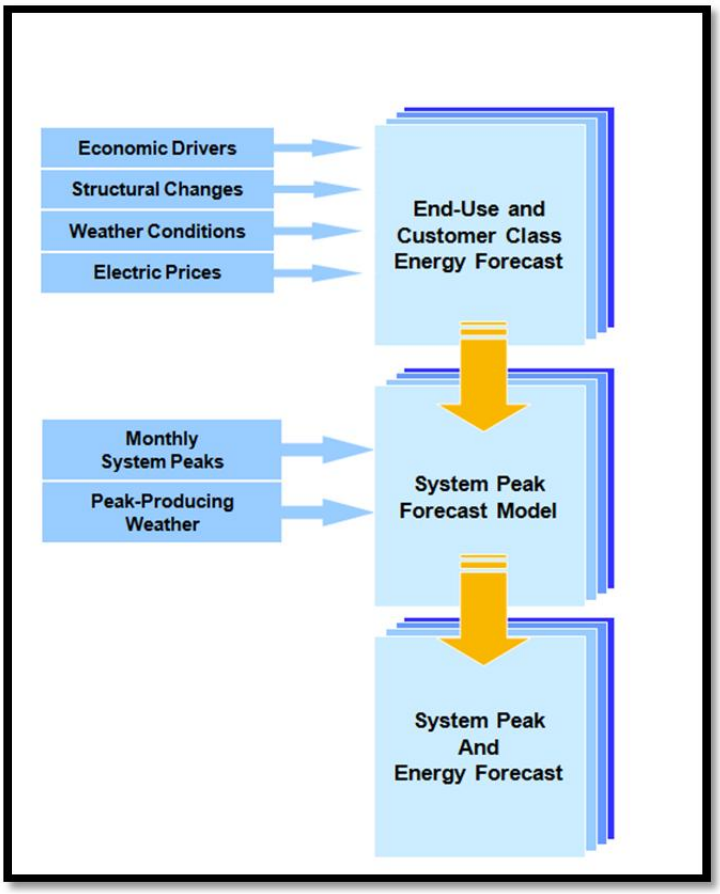
Appendix E
Load Forecast Methodology

Forecasting Approach

In compliance with the revisions to the FAM POA, agreed to during the 2016 FAM BCF proceeding, NS Power has adopted a set of SAE models for the residential and commercial rate classes. 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. The SAE model is a hybrid of the econometric and end-use methodologies, incorporating economic and end-use forecast variables into one model.

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 end-use standards and naturally-occurring efficiency gains. 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 1** shows the general forecast approach used in the SAE models.

Figure 1: Forecast Approach



Discussion of Major Inputs

Historical Class Sales and Energy Data

The load forecast is developed using NS Power "billed" sales rather than "accrued" sales. Billed sales refer to the amount of energy billed to customers in a given time period such as a calendar month or a year. Accrued sales recognize the amount of energy actually 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 will vary from accrued sales.

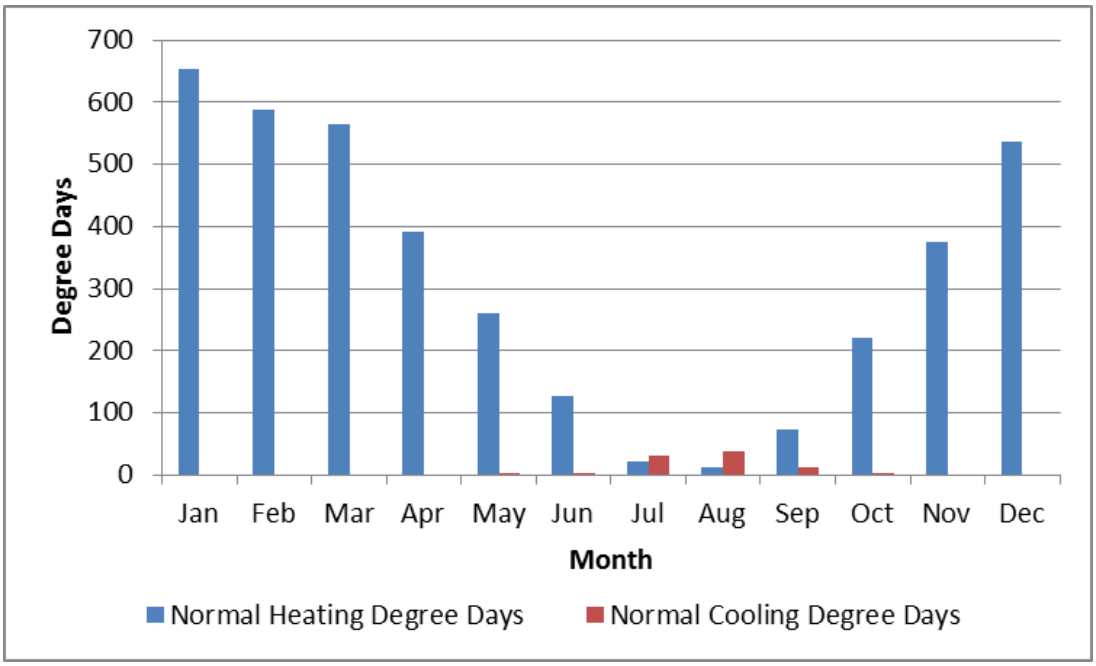
Historical monthly billed sales are the primary dependent variables in the linear regression models used in developing the forecast. For the forecast, the residential and commercial energy forecasts are estimated using monthly billed sales data for the period January 2008 to December

2017. The industrial forecasts use the period January 2005 to December 2017 to improve the model fit.

Weather Data

Weather conditions have the largest single impact on month-to-month variation in electric sales. The impacts of temperature can be captured through constructed heating degree-day (HDD) and cooling degree-day (CDD) variables. HDDs are a common measure of heating requirement based on the degree departure between the daily mean temperature and a given standard temperature. The standard temperature of 18°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. The forecast uses the Environment Canada hourly temperature information for the Shearwater Airport to define the monthly HDD and CDD variables. Normal monthly HDD and CDD are calculated using 10-years of actual weather data covering the period January 2008 to December 2017, and are shown in **Figure 2**.

Figure 2: Normal Monthly HDDs and CDDs



Economic Information

The primary source of economic and other provincial statistics used in the load forecast is the Conference Board of Canada's *Economic Outlook*. 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. For 2018, the variable retail sales (RRTS) was added to the residential model and weighted at 50 percent with the household income (RPDI) variable. The retail sales variable was used in previous forecast models and found to be significant for the residential sector. This variable shows a slight decline in the long run compared to the growth in the household income variable, so weighting the two variables produces a more modest increase from economics and improves the model fit. New housing starts are used in generating residential customer forecasts. In the non-residential models Gross Domestic Product (GDP) and employment (EMP) continue to be used. In the Industrial sector, rate classes are forecast using an Econometric framework, with GDP and manufacturing employment (MANEMP) used as economic variables. **Figures 3, 4, and 5** summarize the economic drivers, on an annual basis, used in the forecast. For financial measures, the variables have been adjusted to constant dollars, eliminating the inflation effects from the series.

Figure 3: Residential Economic Drivers

Year	New Construction	% Change	RPDI (mil $02)	% Change	RRTS (mil $02)	% Change
2008	4,634		18,178		10,437	
2009	3,836	-17.2%	18,924	4.1%	10,460	0.2%
2010	3,960	3.2%	19,460	2.8%	10,699	2.3%
2011	3,662	-7.5%	19,217	-1.2%	10,674	-0.2%
2012	3,963	8.2%	19,416	1.0%	10,584	-0.8%
2013	4,681	18.1%	19,920	2.6%	10,795	2.0%
2014	3,268	-30.2%	19,974	0.3%	10,901	1.0%
2015	3,241	-0.9%	20,426	2.3%	10,874	-0.3%
2016	3,452	6.5%	20,753	1.6%	11,234	3.3%
2017	3,687	6.8%	21,312	2.7%	11,902	6.0%
2018	3,060	-17.0%	21,355	0.2%	12,065	1.4%
2019	2,711	-11.4%	21,383	0.1%	11,963	-0.8%
2020	2,633	-2.9%	21,385	0.0%	11,838	-1.0%
2021	2,541	-3.5%	21,446	0.3%	11,750	-0.7%
2022	2,449	-3.6%	21,551	0.5%	11,686	-0.5%

Figure 4: Commercial Economic Drivers

Year	GDP (mil $07)	% Change	EMP (thou)	% Change
2008	31,496		452	
2009	31,509	0.0	449	-0.5
2010	32,330	2.6	451	0.4
2011	32,426	0.3	453	0.3
2012	32,116	-1.0	457	1.0
2013	32,020	-0.3	453	-1.0
2014	32,243	0.7	448	-1.1
2015	32,560	1.0	448	0.1
2016	32,852	0.9	446	-0.4
2017	33,092	0.7	448	0.4
2018	33,549	1.4	448	0.0
2019	33,931	1.1	449	0.3
2020	34,247	0.9	450	0.1
2021	34,367	0.4	451	0.1
2022	34,961	1.7	451	0.0

Figure 5: Industrial Economic Drivers

Year	GDP (mil $07)	% Change	MANEMP (thou)	% Change
2008	31,496		39	
2009	31,509	0.0	35	-9.2
2010	32,330	2.6	33	-7.7
2011	32,426	0.3	33	1.1
2012	32,116	-1.0	33	-0.8
2013	32,020	-0.3	31	-6.0
2014	32,243	0.7	30	-2.5
2015	32,560	1.0	29	-4.3
2016	32,852	0.9	29	1.2
2017	33,092	0.7	30	5.0
2018	33,549	1.4	32	3.7
2019	33,931	1.1	32	1.1
2020	34,247	0.9	32	-0.3
2021	34,367	0.4	32	1.6
2022	34,961	1.7	33	2.6

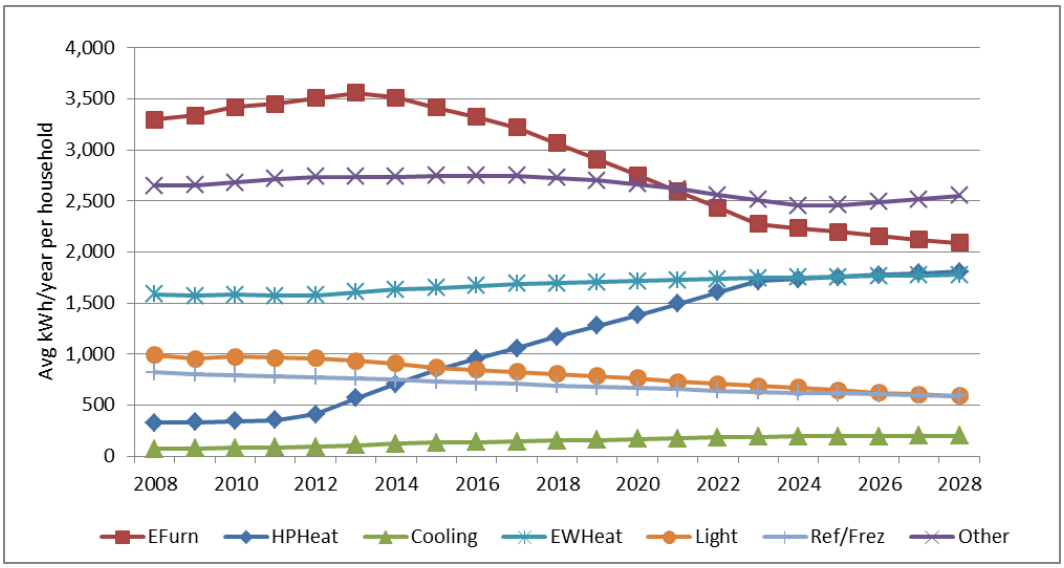
End-Use Intensity Trends

In addition to the economic variables listed above, the SAE model also uses end-use data, in the form of saturations and efficiencies, from Natural Resources Canada (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 general approach to developing the individual end-use intensities is to start with NRCan end-use saturation trends and combine saturation projections with end-use efficiency estimates (both historical and forecast) 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 sales and actual average use derived from NS Power billing data. The forecast for the end use intensities is shown in **Figure 6** below. The end uses listed include:

- EFurn: electric baseboard and electric forced air furnaces as well as secondary heaters
- HPHeat: heat pump electric heat
- Cooling: room and central air conditioners, as well as heat pump cooling
- EWHeat: electric water heaters
- Lights
- 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.

Figure 6: Historical and Projected Residential End-Use Intensities (kWh per household)



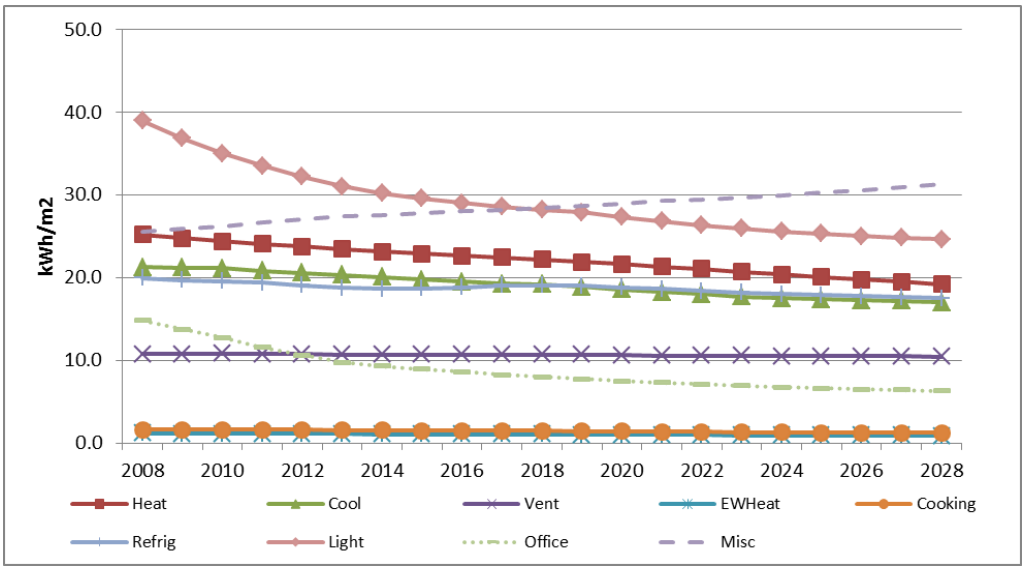
Electric heating is forecasted to increase overall with heat pump market penetration adding to the overall electric heat base and replacing electric baseboards and electric forced air furnaces. The increase in electric heat saturation will be partly offset by the fact that newly installed heat pumps will be more efficient than existing electric heating appliances. Along with the increase in heat pump penetration will come a corresponding increase in electric water heating as customers switch from hot water boilers. In addition, the air conditioning capabilities of heat pumps will increase the overall space cooling intensity in the province. Lighting is forecasted to decline as consumers continue to switch to more efficient bulbs. The largest intensity after electric heating is Other, which contains all other appliances and small plug loads. This end use category will stay relatively stable as more appliance penetration is offset by higher efficiencies.

The end use intensities for the commercial models are done on a per square meter basis, rather than per customer. The forecast for the end use intensities is shown in **Figure 7** below. The end uses listed include:

- Heat: electric heating
- Cool: air conditioning
- Vent: ventilation
- EWHeat: electric water heaters

- Cooking: electric stoves
- Refrig: refrigerators
- Lighting
- Office: computers and printers
- Misc: other loads including motors, servers, escalators, medical equipment, etc.

Figure 7: Historical and Projected Commercial End-Use Intensity (kWh/m^2)

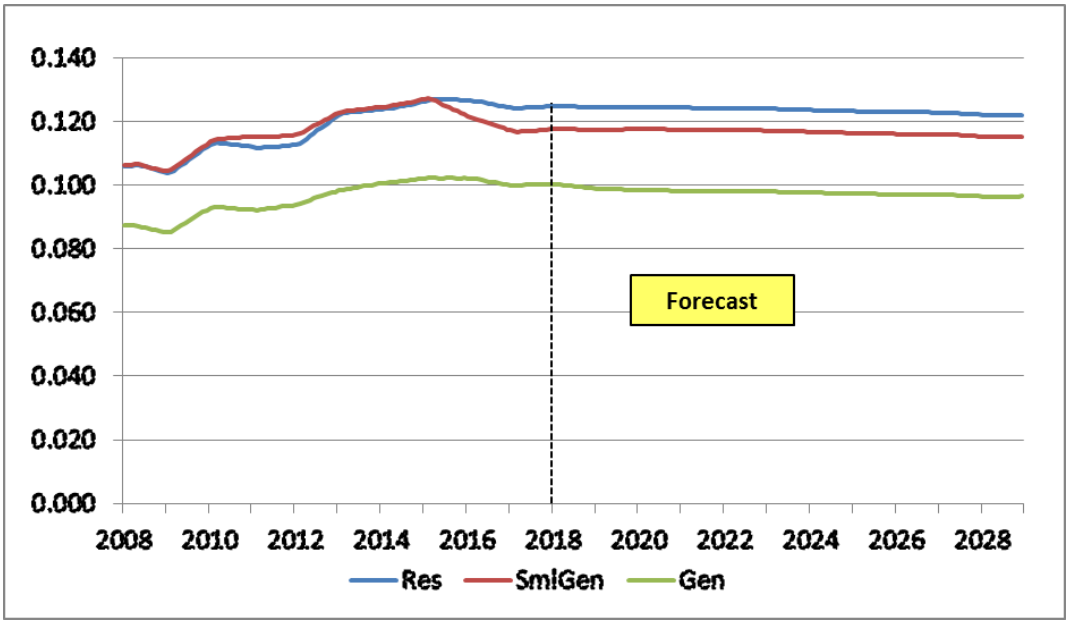


Space heating intensity in the commercial sector has been declining and is expected to continue declining for the forecast due to increased equipment efficiency. Lighting and office equipment intensity will also decline. Cooling, ventilation, electric water heat, and stoves are forecasted to remain at present levels due to minimal forecast changes in efficiency and penetration. The miscellaneous category shows growth over the period, mainly driven by IT equipment and servers.

Price Data

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, smoothes 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 each of the calendar years 2017, 2018 and 2019 is based on the rates included in the Company's Fuel Stability Plan and Base Cost of Fuel Reset dated March 7, 2016.[1] For the period from 2017 to 2019 inclusive, the average nominal price is increased at 1.5 percent per year. Beyond 2019, the nominal price of electricity changes at an average of 1.9 percent per year, or around inflation. **Figure 8** shows the price trends.

Figure 8: Historical and projected real electricity prices (dollars per kWh)



Prices impact the class sales through imposed price elasticities. The SAE models are estimated using a -0.15 price elasticity. This elasticity estimate was provided by Itron during the development of the SAE model and is based on studies and its experience working with other

[1] M07348, 2017-2019 Fuel Stability Plan and Base Cost of Fuel Reset, March 7, 2016.

utilities and developing forecasting models. Though the elasticities are small, relatively strong price increases will have a measurable impact on sales.

Demand Side Management

Demand Side Management and conservation plans continue to play a role in the use of electricity in Nova Scotia. DSM is taken into account in the load forecast by adjusting the forecast for DSM savings. NS Power uses the DSM targets approved by the Board to modify its forecast. In August 2015, the Board approved a DSM plan covering the 2016–2018 period.[2]

2019 DSM savings are at a similar level to 2018 levels in order to best align with Section 20 of the *Electricity Plan Implementation* (2015) *Act* which caps DSM spending for the calendar year 2019 at an amount not greater than $34,050,000. On April 9, 2018, E1 filed its 2019 DSM Plan application with the UARB confirming that the proposal for 2019 reflects a continuation of the 2016-2018 DSM Plan, and projects an incremental annual net energy savings of 127.2 GWh and an incremental annual net demand savings of 20.2 MW. The forecast was prepared before these were released but E1 did provide guidance on reduced 2019 values from previous forecasts and an approximate reduction was included. Beyond 2019, DSM savings equal the base DSM scenario from the 2014 Integrated Resource Plan. The base DSM scenario was chosen as the 2021–2028 DSM forecast, because the average annual savings in the base DSM forecast best match the expected average annual DSM savings from the 2017 to 2019 period.

As with other jurisdictions and utilities with significant DSM activity, NS Power continues to refine how best to address DSM in its forecast. Simply subtracting 100 percent of any future DSM savings results in double-counting the impact of such DSM savings, because the “no DSM” forecast has an inherent level of DSM savings and

[2] Decision 2015 NSUARB 204, M06733, Application for approval of a Supply Agreement for Electricity Efficiency and Conservation Activities between Efficiency One and Nova Scotia Power Inc., August 12, 2015.

therefore is already on a lower trajectory. Past DSM has an influence on many inputs to the load forecast, including sales, price, and overall appliance efficiency. Since the inputs to the regression model are impacted by DSM, the model output is potentially lower than it would be if the inputs had not been impacted by DSM.

In general, the efficiency of appliances used by consumers is improving as a result of several factors, including past investment in DSM, consumer awareness of environmental issues, a cultural shift to making energy efficient behaviour the norm, consumers' awareness of the long-term costs savings associated with energy efficient products, and a natural turnover as equipment stock is replaced with more efficient units even without incentives. For instance, although lighting intensity is expected to continue to decline through natural stock turnover, the portion of DSM savings associated with LED light bulbs is expected to be reduced in the future as E1 moves away from energy savings associated with "Instant Savings" programs[3] (. The outcome of the incentive setting methodology proceeding for DSM (E-ENS-R-16, M07544) may impact future DSM targets.

In 2015, NS Power worked with its forecasting consultant, Itron, to statistically determine what level of DSM is already captured in the load forecast and incorporated this into the 2016 load forecast. The 2018 load forecast uses the same approach to quantify double counting of DSM. The approach taken was to introduce cumulative historical DSM savings to the regression model, as a load modifying variable, and allow the model to determine what level of DSM was already being captured by other variables. To do this, DSM was provided to the model in the same unit of measure, kWh per customer, as the model output. By doing this, the value of the DSM variable coefficient, determined by the regression model, is an indication of the level of double counted DSM. If the coefficient is -1, no DSM is double counted, 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 is double counted. As can be seen in the residential model results, the coefficient on the DSM variable is -0.579

[3] EfficiencyOne 2019 DSM Plan Application, March 28, 2018, Appendix A, page 7, line 6-9.

(similar to the 2017 value) meaning future years in the load forecast should only be adjusted by 58 percent of the forecast DSM amounts. The remaining 42 percent of savings is already accounted for in the forecast.

For the commercial and industrial classes a combined model was created to identify the level of DSM double counting. By creating a combined model for all classes the level of uncertainty around allocating historical DSM savings across rate classes and months of the year is reduced. The model has been revised for 2018 to provide a better overall fit and a more significant DSM variable. This has resulted in an increased DSM variable coefficient with the 2017 value, and the statistics of the model indicate it is a better fit (adjusted R squared of 0.795 vs 0.762) and the DSM variable is more significant than in 2017 (p-value of 3.26 percent vs 20.87 percent). The coefficient is -0.608 meaning future years in the load forecast should only be adjusted by 61 percent of the forecast DSM amounts. **Figure 10** shows the DSM levels incorporated into the BCF forecast for 2017 – 2019.

Figure 10: Annual Forecasted DSM Savings and Load Forecast Modifying GWh

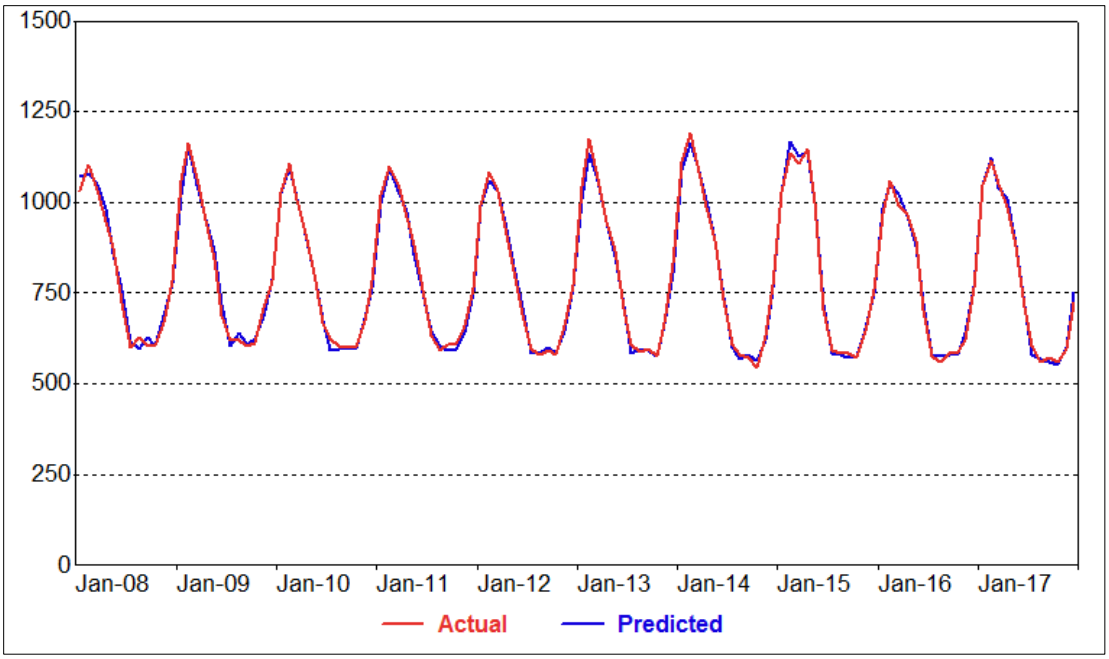
Year	Forecast Residential DSM savings (GWh)	Forecast Commercial and Industrial DSM savings (GWh)	DSM Adjustment for Residential Load Forecast (GWh)	DSM Adjustment for Commercial and Industrial Load Forecast (GWh)
2018	59.3	76.6	34.3	46.6
2019	54.9	71.0	31.8	43.1
2020	58.4	75.5	33.8	45.9
2021	56.8	73.3	32.9	44.6
2022	55.7	71.9	32.2	43.7

Residential Model Details

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRes.WtXHeat	0.816	0.021	38.069	0.00%
MStructRes.WtXCool	0.663	0.278	2.388	1.87%
MStructRes.WtXOther	1.000	0.021	48.339	0.00%
MSales.AvgEESavings	-0.579	0.117	-4.941	0.00%
MBin.Jan	56.354	8.335	6.761	0.00%
MBin.Aug	72.279	11.022	6.558	0.00%
MBin.Sep	87.812	15.074	5.825	0.00%
MBin.Oct	53.864	11.047	4.876	0.00%
MBin.Dec	-31.474	8.515	-3.696	0.04%
MBin.May15	91.377	15.803	5.782	0.00%
MBin.Apr15	97.522	16.013	6.090	0.00%
MA(1)	0.518	0.090	5.753	0.00%
SMA(1)	0.494	0.091	5.417	0.00%

Model Statistics	
Iterations	18
Adjusted Observations	120
Deg. of Freedom for Error	107
R-Squared	0.993
Adjusted R-Squared	0.992
AIC	5.858
BIC	6.159
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-508.72
Model Sum of Squares	4,680,046.42
Sum of Squared Errors	33,803.87
Mean Squared Error	315.92
Std. Error of Regression	17.77
Mean Abs. Dev. (MAD)	13.53
Mean Abs. % Err. (MAPE)	1.74%
Durbin-Watson Statistic	1.941
Durbin-H Statistic	#NA
Ljung-Box Statistic	22.43
Prob (Ljung-Box)	0.5534
Skewness	-0.071
Kurtosis	2.615
Jarque-Bera	0.844
Prob (Jarque-Bera)	0.6556

Model Fit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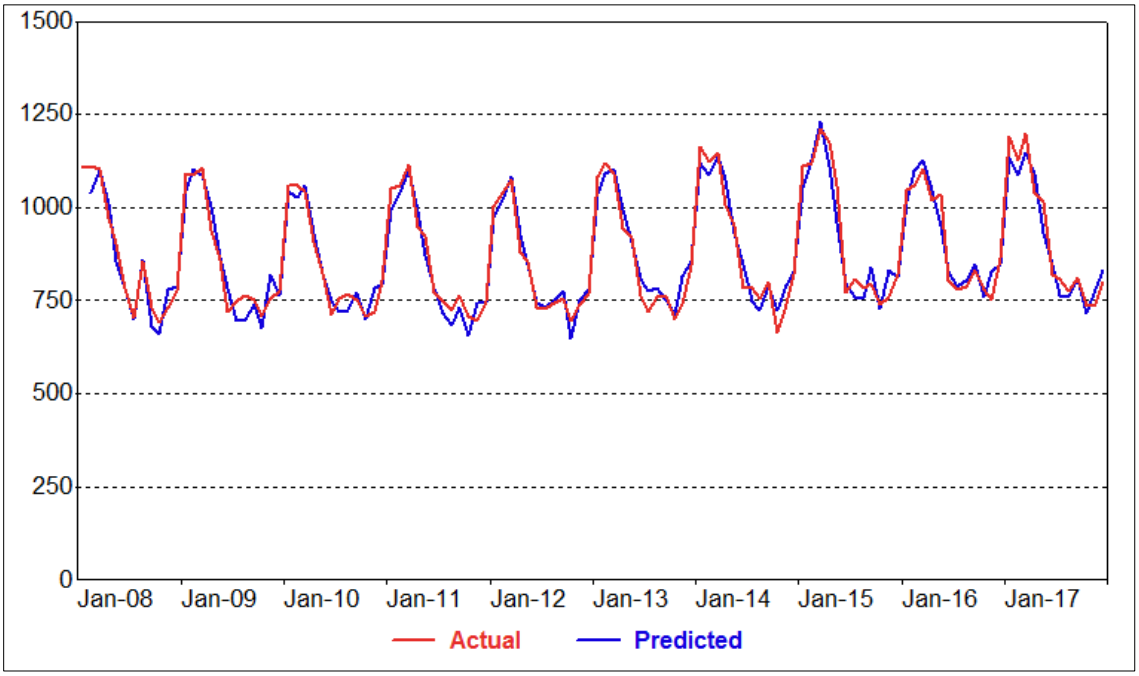
Jan-16
Jan-17
Actual
Predicted

Small General Model Details

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructSmlGen.WtXOther	0.839	0.125	6.735	0.00%
MStructSmlGen.WtXCool	0.177	0.028	6.405	0.00%
MStructSmlGen.WtXHeat	0.928	0.028	32.694	0.00%
MBin.Aug08	223.702	45.223	4.947	0.00%
MBin.Mar	93.748	16.082	5.829	0.00%
MBin.Sep	77.008	16.493	4.669	0.00%
MBin.Dec	-113.247	15.023	-7.538	0.00%
MBin.Aft13	30.789	22.661	1.359	17.71%
AR(1)	0.989	0.005	192.863	0.00%
MA(1)	-1.118	0.067	-16.788	0.00%

Model Statistics	
Iterations	99
Adjusted Observations	119
Deg. of Freedom for Error	109
R-Squared	0.935
Adjusted R-Squared	0.930
AIC	7.511
BIC	7.744
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-605.75
Model Sum of Squares	2,653,869.27
Sum of Squared Errors	183,857.53
Mean Squared Error	1,686.77
Std. Error of Regression	41.07
Mean Abs. Dev. (MAD)	32.65
Mean Abs. % Err. (MAPE)	3.80%
Durbin-Watson Statistic	2.110
Durbin-H Statistic	#NA
Ljung-Box Statistic	89.58
Prob (Ljung-Box)	0.0000
Skewness	-0.038
Kurtosis	2.367
Jarque-Bera	2.015

Model Fit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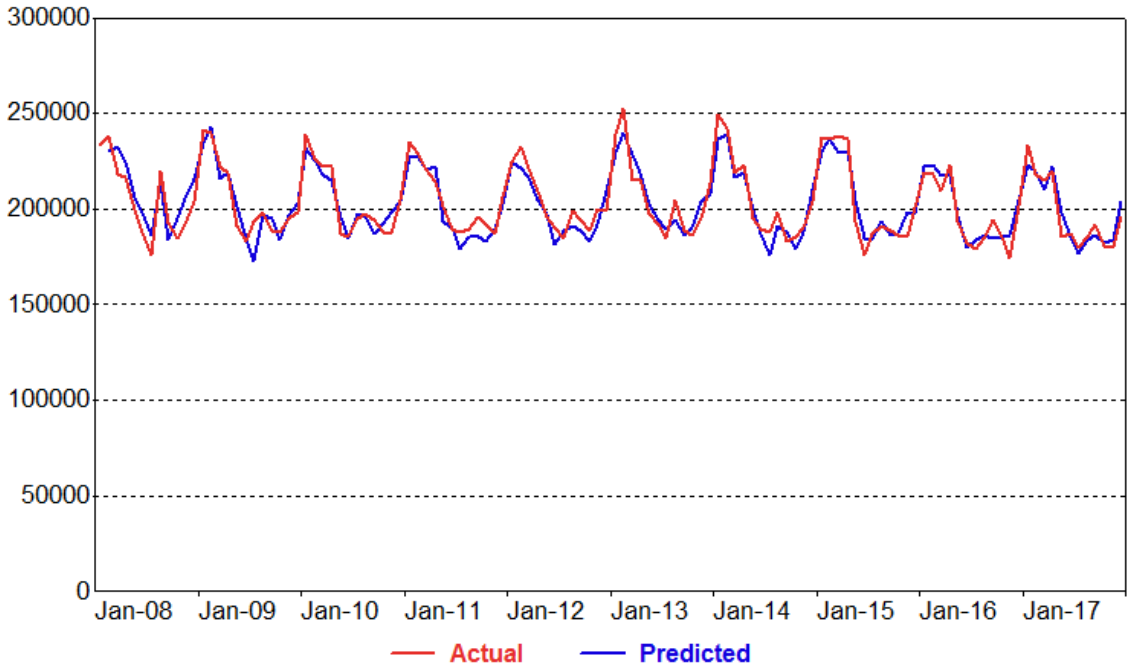
Jan-14
Jan-15
Jan-16
Jan-17
Actual
Predicted

General Demand Model Details

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructGen.WtXHeat	0.805	0.062	12.924	0.00%
MStructGen.WtXCool	0.243	0.057	4.270	0.00%
MStructGen.WtXOther	0.958	0.020	47.873	0.00%
MBin.Aug08	32770.711	5630.297	5.820	0.00%
MBin.Aft13	12818.322	2617.019	4.898	0.00%
AR(1)	0.384	0.089	4.341	0.00%
SMA(1)	0.611	0.080	7.629	0.00%

Model Statistics	
Iterations	15
Adjusted Observations	119
Deg. of Freedom for Error	112
R-Squared	0.861
Adjusted R-Squared	0.853
AIC	17.853
BIC	18.016
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,224.09
Model Sum of Squares	37,039,731,744.02
Sum of Squared Errors	5,995,074,216.09
Mean Squared Error	53,527,448.36
Std. Error of Regression	7,316.25
Mean Abs. Dev. (MAD)	5,895.33
Mean Abs. % Err. (MAPE)	2.92%
Durbin-Watson Statistic	1.859
Durbin-H Statistic	#NA
Ljung-Box Statistic	49.73
Prob (Ljung-Box)	0.0015
Skewness	-0.090
Kurtosis	2.479
Jarque-Bera	1.507
Prob (Jarque-Bera)	0.4707

Model Fit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Jan-08
Jan-09
Jan-10
Jan-11
Jan-12
Jan-13
Jan-14
Jan-15
Jan-16
Jan-17
Actual
Predicted

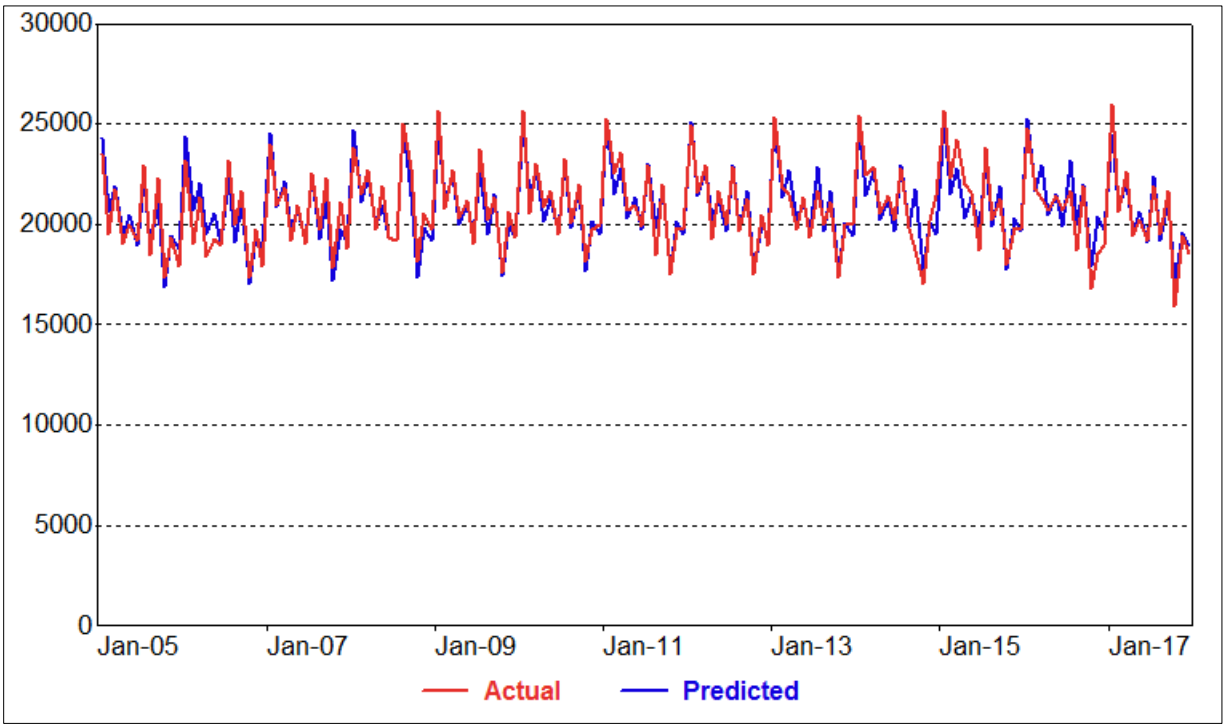
Small Industrial Model Details

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	12686.283	2564.525	4.947	0.00%
MBin.Feb	9023.597	2566.192	3.516	0.06%
MBin.Mar	10310.050	2567.859	4.015	0.01%
MBin.Apr	7802.715	2569.526	3.037	0.29%
MBin.May	8853.659	2571.193	3.443	0.08%
MBin.Jun	7260.758	2572.860	2.822	0.55%
MBin.Jul	10558.581	2577.117	4.097	0.01%
MBin.Aug	7351.379	2578.939	2.851	0.50%
MBin.Sep	9324.279	2577.904	3.617	0.04%
MBin.Oct	5200.260	2579.593	2.016	4.57%
MBin.Nov	7707.863	2581.281	2.986	0.33%
MBin.Dec	7059.016	2582.970	2.733	0.71%
MEcon.GDPIdx	11641.473	2441.981	4.767	0.00%
MBin.Jul08	-3491.929	803.360	-4.347	0.00%
MBin.Aug08	5540.554	803.414	6.896	0.00%
MBin.Aft17	-924.821	255.866	-3.614	0.04%

Model Statistics	
Iterations	1
Adjusted Observations	156
Deg. of Freedom for Error	140
R-Squared	0.874
Adjusted R-Squared	0.861
AIC	13.393
BIC	13.706
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,250.01
Model Sum of Squares	578,104,935.70
Sum of Squared Errors	83,281,068.53
Mean Squared Error	594,864.78
Std. Error of Regression	771.27
Mean Abs. Dev. (MAD)	552.50
Mean Abs. % Err. (MAPE)	2.68%
Durbin-Watson Statistic	1.493
Durbin-H Statistic	#NA
Ljung-Box Statistic	64.49
Prob (Ljung-Box)	0.0000
Skewness	-0.570

Model Statistics	
Kurtosis	4.477
Jarque-Bera	22.631
Prob (Jarque-Bera)	0.0000

Model Fit



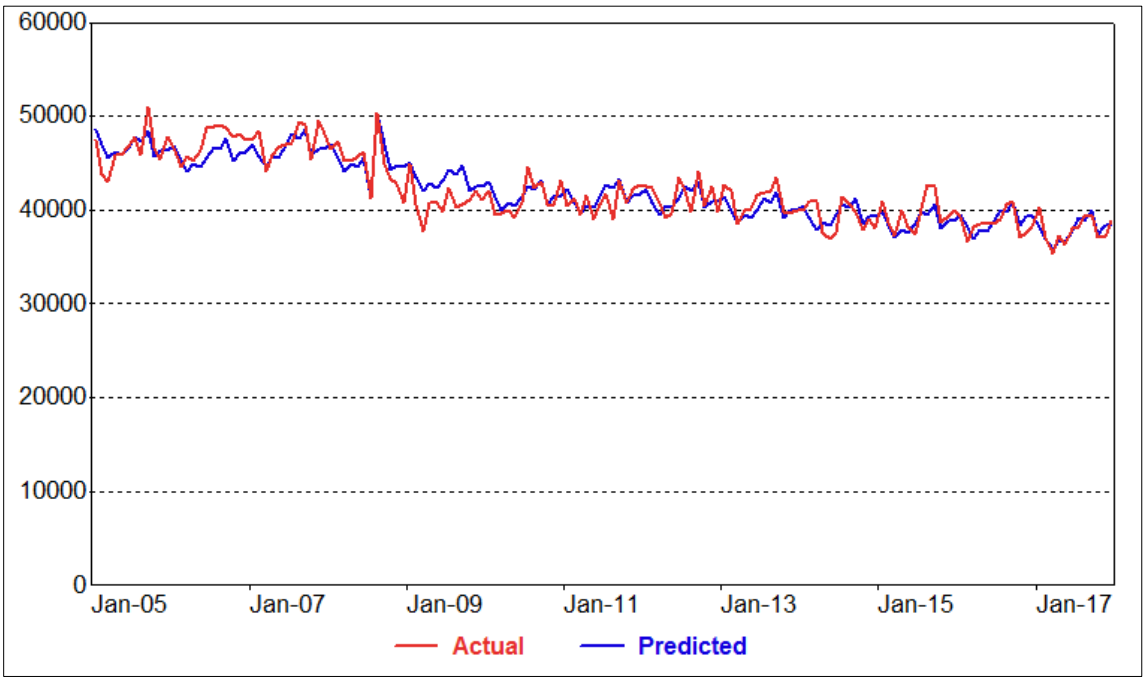
Medium Industrial Model Details

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	20058.247	1156.060	17.351	0.00%
MBin.Feb	18692.109	1153.629	16.203	0.00%
MBin.Mar	17435.093	1151.199	15.145	0.00%
MBin.Apr	18354.927	1148.769	15.978	0.00%
MBin.May	18132.200	1146.340	15.817	0.00%
MBin.Jun	19187.667	1143.912	16.774	0.00%
MBin.Jul	20446.881	1137.746	17.971	0.00%
MBin.Aug	20120.392	1136.694	17.701	0.00%
MBin.Sep	21191.393	1138.229	18.618	0.00%
MBin.Oct	18607.499	1136.601	16.371	0.00%
MBin.Nov	19353.091	1134.974	17.052	0.00%
MBin.Dec	19399.318	1133.347	17.117	0.00%
MBin.Aug08	4138.508	1654.295	2.502	1.35%
MBin.Jul08	-5444.908	1655.021	-3.290	0.13%
MEcon.ManEmpIdx	27516.807	1253.407	21.954	0.00%
MBin.Aft17	-1854.060	491.055	-3.776	0.02%

Model Statistics	
Iterations	1
Adjusted Observations	156
Deg. of Freedom for Error	140
R-Squared	0.824
Adjusted R-Squared	0.805
AIC	14.831
BIC	15.144
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,362.15
Model Sum of Squares	1,639,028,853.36
Sum of Squared Errors	350,706,085.71
Mean Squared Error	2,505,043.47
Std. Error of Regression	1,582.73
Mean Abs. Dev. (MAD)	1,173.50
Mean Abs. % Err. (MAPE)	2.79%
Durbin-Watson Statistic	1.181
Durbin-H Statistic	#NA
Ljung-Box Statistic	146.04
Prob (Ljung-Box)	0.0000
Skewness	-0.324

Model Statistics	
Kurtosis	3.214
Jarque-Bera	3.028
Prob (Jarque-Bera)	0.2200

Model Fit



REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Rate Classes	BCF Rates before Smoothing Adj. (c/kWh)					BCF Rates after Smoothing Adj. (c/kWh)					FAM AA (c/kWh)					FAM BA (c/kWh)				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
FAM Classes																				
Residential	6.321	7.485	7.584	7.568	7.708	6.321	8.170	6.810	7.059	8.230	0.000	0.372	0.000	0.000	0.000	0.000	(1.979)	0.000	0.000	0.000
Small General	6.385	7.322	7.340	7.310	7.399	6.385	7.955	6.695	6.852	7.798	0.000	0.282	0.000	0.000	0.000	0.000	(1.698)	0.000	0.000	0.000
General Demand	5.781	6.998	7.031	7.014	7.088	5.781	7.155	6.495	6.867	7.630	0.000	0.691	0.000	0.000	0.000	0.000	(1.712)	0.000	0.000	0.000
Large General	6.273	6.578	6.600	6.601	6.653	6.273	6.547	6.497	6.611	6.793	0.000	(0.121)	0.000	0.000	0.000	0.000	(0.042)	0.000	0.000	0.000
Total Commercial																				
Small Industrial	5.754	6.908	6.942	6.933	7.002	5.754	7.056	6.438	6.794	7.505	0.000	0.645	0.000	0.000	0.000	0.000	(1.610)	0.000	0.000	0.000
Medium Industrial	5.501	6.530	6.558	6.555	6.611	5.501	6.171	6.333	6.774	7.070	0.000	0.559	0.000	0.000	0.000	0.000	(0.822)	0.000	0.000	0.000
Large Industrial																				
Firm	5.302	6.288	6.298	6.303	6.353	5.302	5.786	6.162	6.617	6.784	0.000	0.515	0.000	0.000	0.000	0.000	(0.577)	0.000	0.000	0.000
Interruptible	5.351	6.288	6.298	6.303	6.353	5.351	5.848	6.141	6.559	6.753	0.000	0.515	0.000	0.000	0.000	0.000	(0.625)	0.000	0.000	0.000
Large Industrial Total																				
Total Industrial																				
Municipal	5.609	6.749	6.795	6.773	6.883	5.609	6.575	6.434	6.870	7.508	0.000	0.596	0.000	0.000	0.000	0.000	(1.157)	0.000	0.000	0.000
Unmetered	5.638	7.119	7.153	7.147	7.203	5.638	7.420	6.463	6.885	7.847	0.000	0.992	0.000	0.000	0.000	0.000	(2.365)	0.000	0.000	0.000

2020 REVENUE ANALYSIS

Rate Classes	2020 Sales (GWh's)	Revenues at 2019 rates				Revenues at 2020 rates				Revenue Variance				Revenue % Var			
		Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total
FAM Classes																	
Residential	**4,493.3**	**$749,540,113**	**$0**	**$0**	**$749,540,113**	**$832,616,435**	**$16,713,231**	**($88,902,685)**	**$760,426,981**	**$83,076,322**	**$16,713,231**	**($88,902,685)**	**$10,886,868**	**11.1%**	**2.2%**	**-11.9%**	**1.5%**
Small General	286.8	$46,312,241	$0	$0	$46,312,241	$50,816,023	$809,110	($4,870,106)	$46,755,026	$4,503,782	$809,110	($4,870,106)	$442,785	9.7%	1.7%	-10.5%	1.0%
General Demand	2,393.0	$318,906,693	$0	$0	$318,906,693	$351,798,679	$16,523,626	($40,977,104)	$327,345,201	$32,891,986	$16,523,626	($40,977,104)	$8,438,508	10.3%	5.2%	-12.8%	2.6%
Large General	392.8	$48,529,955	$0	$0	$48,529,955	$49,608,919	($473,656)	($165,782)	$48,969,481	$1,078,963	($473,656)	($165,782)	$439,526	2.2%	-1.0%	-0.3%	0.9%
Total Commercial	**3,072.6**	**$413,748,890**	**$0**	**$0**	**$413,748,890**	**$452,223,621**	**$16,859,080**	**($46,012,992)**	**$423,069,709**	**$38,474,731**	**$16,859,080**	**($46,012,992)**	**$9,320,819**	**9.3%**	**4.1%**	**-11.1%**	**2.3%**
Small Industrial	250.4	$31,702,850	$0	$0	$31,702,850	$34,964,533	$1,616,014	($4,031,935)	$32,548,611	$3,261,683	$1,616,014	($4,031,935)	$845,761	10.3%	5.1%	-12.7%	2.7%
Medium Industrial	474.4	$48,923,099	$0	$0	$48,923,099	$52,103,669	$2,653,147	($3,897,683)	$50,859,133	$3,180,571	$2,653,147	($3,897,683)	$1,936,034	6.5%	5.4%	-8.0%	4.0%
Large Industrial																	
Firm	128.0	$13,917,061	$0	$0	$13,917,061	$14,535,989	$659,502	($738,596)	$14,456,896	$618,928	$659,502	($738,596)	$539,834	4.4%	4.7%	-5.3%	3.9%
Interruptible	733.9	$72,271,133	$0	$0	$72,271,133	$75,918,111	$3,779,980	($4,585,930)	$75,112,161	$3,646,978	$3,779,980	($4,585,930)	$2,841,028	5.0%	5.2%	-6.3%	3.9%
Large Industrial Total	861.9	$86,188,194	$0	$0	$86,188,194	$90,454,100	$4,439,483	($5,324,526)	$89,569,057	$4,265,906	$4,439,483	($5,324,526)	$3,380,863	4.9%	5.2%	-6.2%	3.9%
Total Industrial	**1,586.7**	**$166,814,143**	**$0**	**$0**	**$166,814,143**	**$177,522,302**	**$8,708,644**	**($13,254,145)**	**$172,976,801**	**$10,708,159**	**$8,708,644**	**($13,254,145)**	**$6,162,658**	**6.4%**	**5.2%**	**-7.9%**	**3.7%**
Municipal	124.8	$16,317,420	$0	$0	$16,317,420	$17,523,454	$743,498	($1,444,466)	$16,822,485	$1,206,034	$743,498	($1,444,466)	$505,065	7.4%	4.6%	-8.9%	3.1%
Unmetered	81.0	$20,379,253	$0	$0	$20,379,253	$21,823,233	$803,715	($1,916,103)	$20,710,844	$1,443,980	$803,715	($1,916,103)	$331,592	7.1%	3.9%	-9.4%	1.6%
Total Other	**205.9**	**$36,696,672**	**$0**	**$0**	**$36,696,672**	**$39,346,687**	**$1,547,213**	**($3,360,570)**	**$37,533,330**	**$2,650,014**	**$1,547,213**	**($3,360,570)**	**$836,657**	**7.2%**	**4.2%**	**-9.2%**	**2.3%**
Total FAM Classes	**9,358.5**	**$1,366,799,818**	**$0**	**$0**	**$1,366,799,818**	**$1,501,709,045**	**$43,828,167**	**($151,530,392)**	**$1,394,006,821**	**$134,909,226**	**$43,828,167**	**($151,530,392)**	**$27,207,002**	**9.9%**	**3.2%**	**-11.1%**	**2.0%**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2021 REVENUE ANALYSIS

Rate Classes	2021 Sales (GWh's)	Revenues at 2020 rates				Revenues at 2021 rates				Revenue Variance				Revenue % Var			
		Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total
FAM Classes																	
Residential	**4,472.7**	**$829,166,905**	**$16,636,687**	**($88,495,522)**	**$757,308,069**	**$768,307,765**	**$0**	**$0**	**$768,307,765**	**($60,859,140)**	**($16,636,687)**	**$88,495,522**	**$10,999,696**	**-8.0%**	**-2.2%**	**11.7%**	**1.5%**
Small General	287.8	$50,991,005	$811,713	($4,885,777)	$46,916,941	$47,365,507	$0	$0	$47,365,507	($3,625,498)	($811,713)	$4,885,777	$448,566	-7.7%	-1.7%	10.4%	1.0%
General Demand	2,360.7	$347,056,568	$16,300,894	($40,424,748)	$322,932,714	$331,477,753	$0	$0	$331,477,753	($15,578,815)	($16,300,894)	$40,424,748	$8,545,040	-4.8%	-5.0%	12.5%	2.6%
Large General	393.6	$49,705,192	($474,575)	($166,104)	$49,064,514	$49,508,881	$0	$0	$49,508,881	($196,312)	$474,575	$166,104	$444,367	-0.4%	1.0%	0.3%	0.9%
Total Commercial	**3,042.1**	**$447,752,765**	**$16,638,032**	**($45,476,630)**	**$418,914,168**	**$428,352,141**	**$0**	**$0**	**$428,352,141**	**($19,400,624)**	**($16,638,032)**	**$45,476,630**	**$9,437,973**	**-4.6%**	**-4.0%**	**10.9%**	**2.3%**
Small Industrial	250.6	$34,983,004	$1,616,867	($4,034,065)	$32,565,806	$33,434,588	$0	$0	$33,434,588	($1,548,415)	($1,616,867)	$4,034,065	$868,783	-4.8%	-5.0%	12.4%	2.7%
Medium Industrial	472.9	$51,941,066	$2,644,867	($3,885,520)	$50,700,414	$52,706,782	$0	$0	$52,706,782	$765,716	($2,644,867)	$3,885,520	$2,006,368	1.5%	-5.2%	7.7%	4.0%
Large Industrial			$0	$0													
Firm	127.9	$14,524,155	$658,966	($737,994)	$14,445,126	$15,005,443	$0	$0	$15,005,443	$481,289	($658,966)	$737,994	$560,318	3.3%	-4.6%	5.1%	3.9%
Interruptible	795.4	$82,283,665	$4,096,923	($4,970,450)	$81,410,138	$84,610,427	$0	$0	$84,610,427	$2,326,762	($4,096,923)	$4,970,450	$3,200,289	2.9%	-5.0%	6.1%	3.9%
Large Industrial Total	923.3	$96,807,820	$4,755,888	($5,708,444)	$95,855,264	$99,615,871	$0	$0	$99,615,871	$2,808,051	($4,755,888)	$5,708,444	$3,760,607	2.9%	-5.0%	6.0%	3.9%
Total Industrial	**1,646.8**	**$183,731,890**	**$9,017,623**	**($13,628,029)**	**$179,121,483**	**$185,757,241**	**$0**	**$0**	**$185,757,241**	**$2,025,351**	**($9,017,623)**	**$13,628,029**	**$6,635,757**	**1.1%**	**-5.0%**	**7.6%**	**3.7%**
Municipal	122.6	$17,352,942	$730,527	($1,419,267)	$16,664,202	$17,180,001	$0	$0	$17,180,001	($172,940)	($730,527)	$1,419,267	$515,799	-1.0%	-4.4%	8.5%	3.1%
Unmetered	81.0	$21,823,233	$803,715	($1,916,103)	$20,710,844	$21,047,832	$0	$0	$21,047,832	($775,401)	($803,715)	$1,916,103	$336,987	-3.7%	-3.9%	9.3%	1.6%
Total Other	**203.7**	**$39,176,175**	**$1,534,242**	**($3,335,370)**	**$37,375,046**	**$38,227,833**	**$0**	**$0**	**$38,227,833**	**($948,342)**	**($1,534,242)**	**$3,335,370**	**$852,786**	**-2.5%**	**-4.1%**	**8.9%**	**2.3%**
Total FAM Classes	**9,365.3**	**$1,499,827,734**	**$43,826,584**	**($150,935,551)**	**$1,392,718,767**	**$1,420,644,979**	**$0**	**$0**	**$1,420,644,979**	**($79,182,755)**	**($43,826,584)**	**$150,935,551**	**$27,926,212**	**-5.7%**	**-3.1%**	**10.8%**	**2.0%**

2022 REVENUE ANALYSIS

Rate Classes	2022 Sales (GWh's)	Revenues at 2021 rates				Revenues at 2022 rates				Revenue Variance				Revenue % Var			
		Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total
FAM Classes																	
Residential	**4,479.1**	**$769,450,910**	**$0**	**$0**	**$769,450,910**	**$780,626,977**	**$0**	**$0**	**$780,626,977**	**$11,176,067**	**$0**	**$0**	**$11,176,067**	**1.5%**	**0.0%**	**0.0%**	**1.5%**
Small General	288.6	$47,512,571	$0	$0	$47,512,571	$47,966,832	$0	$0	$47,966,832	$454,261	$0	$0	$454,261	1.0%	0.0%	0.0%	1.0%
General Demand	2,335.1	$327,876,517	$0	$0	$327,876,517	$336,552,374	$0	$0	$336,552,374	$8,675,856	$0	$0	$8,675,856	2.6%	0.0%	0.0%	2.6%
Large General	390.8	$49,154,638	$0	$0	$49,154,638	$49,599,821	$0	$0	$49,599,821	$445,183	$0	$0	$445,183	0.9%	0.0%	0.0%	0.9%
Total Commercial	**3,014.4**	**$424,543,726**	**$0**	**$0**	**$424,543,726**	**$434,119,026**	**$0**	**$0**	**$434,119,026**	**$9,575,301**	**$0**	**$0**	**$9,575,301**	**2.3%**	**0.0%**	**0.0%**	**2.3%**
Small Industrial	250.9	$33,482,219	$0	$0	$33,482,219	$34,375,450	$0	$0	$34,375,450	$893,231	$0	$0	$893,231	2.7%	0.0%	0.0%	2.7%
Medium Industrial	469.8	$52,366,070	$0	$0	$52,366,070	$54,438,353	$0	$0	$54,438,353	$2,072,283	$0	$0	$2,072,283	4.0%	0.0%	0.0%	4.0%
Large Industrial						$0											
Firm	127.8	$14,990,529	$0	$0	$14,990,529	$15,572,003	$0	$0	$15,572,003	$581,474	$0	$0	$581,474	3.9%	0.0%	0.0%	3.9%
Interruptible	793.3	$84,388,517	$0	$0	$84,388,517	$87,705,888	$0	$0	$87,705,888	$3,317,371	$0	$0	$3,317,371	3.9%	0.0%	0.0%	3.9%
Large Industrial Total	921.1	$99,379,047	$0	$0	$99,379,047	$103,277,891	$0	$0	$103,277,891	$3,898,845	$0	$0	$3,898,845	3.9%	0.0%	0.0%	3.9%
Total Industrial	**1,641.9**	**$185,227,336**	**$0**	**$0**	**$185,227,336**	**$192,091,694**	**$0**	**$0**	**$192,091,694**	**$6,864,358**	**$0**	**$0**	**$6,864,358**	**3.7%**	**0.0%**	**0.0%**	**3.7%**
Municipal	121.1	$17,067,720	$0	$0	$17,067,720	$17,596,009	$0	$0	$17,596,009	$528,289	$0	$0	$528,289	3.1%	0.0%	0.0%	3.1%
Unmetered	81.0	$21,047,832	$0	$0	$21,047,832	$21,390,302	$0	$0	$21,390,302	$342,470	$0	$0	$342,470	1.6%	0.0%	0.0%	1.6%
Total Other	**202.1**	**$38,115,551**	**$0**	**$0**	**$38,115,551**	**$38,986,311**	**$0**	**$0**	**$38,986,311**	**$870,759**	**$0**	**$0**	**$870,759**	**2.3%**	**0.0%**	**0.0%**	**2.3%**
Total FAM Classes	**9,337.5**	**$1,417,337,524**	**$0**	**$0**	**$1,417,337,524**	**$1,445,824,009**	**$0**	**$0**	**$1,445,824,009**	**$28,486,486**	**$0**	**$0**	**$28,486,486**	**2.0%**	**0.0%**	**0.0%**	**2.0%**

2023 REVENUE ANALYSIS

Rate Classes	2023 Sales (GWh's)	Revenues at 2022 rates				Revenues at 2023 rates				Revenue Variance				Revenue % Var			
		Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total	Base Cost Rates	FAM AA	FAM BA	Total
FAM Classes																	
Residential	**4,490.2**	**$782,551,516**	**$0**	**$0**	**$782,551,516**	**$835,104,002**	**$0**	**$0**	**$835,104,002**	**$52,552,485**	**$0**	**$0**	**$52,552,485**	**6.7%**	**0.0%**	**0.0%**	**6.7%**
Small General	288.5	$47,976,673	$0	$0	$47,976,673	$50,706,350	$0	$0	$50,706,350	$2,729,677	$0	$0	$2,729,677	5.7%	0.0%	0.0%	5.7%
General Demand	2,313.3	$333,413,257	$0	$0	$333,413,257	$351,067,419	$0	$0	$351,067,419	$17,654,162	$0	$0	$17,654,162	5.3%	0.0%	0.0%	5.3%
Large General	387.6	$49,190,237	$0	$0	$49,190,237	$49,893,821	$0	$0	$49,893,821	$703,584	$0	$0	$703,584	1.4%	0.0%	0.0%	1.4%
Total Commercial	**2,989.3**	**$430,580,167**	**$0**	**$0**	**$430,580,167**	**$451,667,590**	**$0**	**$0**	**$451,667,590**	**$21,087,423**	**$0**	**$0**	**$21,087,423**	**4.9%**	**0.0%**	**0.0%**	**4.9%**
Small Industrial	251.6	$34,473,468	$0	$0	$34,473,468	$36,261,932	$0	$0	$36,261,932	$1,788,464	$0	$0	$1,788,464	5.2%	0.0%	0.0%	5.2%
Medium Industrial	465.8	$53,973,937	$0	$0	$53,973,937	$55,351,827	$0	$0	$55,351,827	$1,377,889	$0	$0	$1,377,889	2.6%	0.0%	0.0%	2.6%
Large Industrial		$0															
Firm	127.7	$15,563,853	$0	$0	$15,563,853	$15,777,552	$0	$0	$15,777,552	$213,699	$0	$0	$213,699	1.4%	0.0%	0.0%	1.4%
Interruptible	791.3	$87,483,615	$0	$0	$87,483,615	$89,017,946	$0	$0	$89,017,946	$1,534,330	$0	$0	$1,534,330	1.8%	0.0%	0.0%	1.8%
Large Industrial Total	919.1	$103,047,469	$0	$0	$103,047,469	$104,795,498	$0	$0	$104,795,498	$1,748,029	$0	$0	$1,748,029	1.7%	0.0%	0.0%	1.7%
Total Industrial	**1,636.5**	**$191,494,874**	**$0**	**$0**	**$191,494,874**	**$196,409,256**	**$0**	**$0**	**$196,409,256**	**$4,914,382**	**$0**	**$0**	**$4,914,382**	**2.6%**	**0.0%**	**0.0%**	**2.6%**
Municipal	98.7	$15,445,625	$0	$0	$15,445,625	$16,074,981	$0	$0	$16,074,981	$629,356	$0	$0	$629,356	4.1%	0.0%	0.0%	4.1%
Unmetered	81.0	$21,390,302	$0	$0	$21,390,302	$22,169,796	$0	$0	$22,169,796	$779,495	$0	$0	$779,495	3.6%	0.0%	0.0%	3.6%
Total Other	**179.7**	**$36,835,927**	**$0**	**$0**	**$36,835,927**	**$38,244,778**	**$0**	**$0**	**$38,244,778**	**$1,408,851**	**$0**	**$0**	**$1,408,851**	**3.8%**	**0.0%**	**0.0%**	**3.8%**
Total FAM Classes	**9,295.8**	**$1,441,462,485**	**$0**	**$0**	**$1,441,462,485**	**$1,521,425,626**	**$0**	**$0**	**$1,521,425,626**	**$79,963,141**	**$0**	**$0**	**$79,963,141**	**5.5%**	**0.0%**	**0.0%**	**5.5%**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

WACC 6.84%

2014 Rate Base / 2020 FAM Amounts

	2014 Rate Base Amount	%	2019 Actual Sales (GWh)	Year-end FAM AA: 202 ML Depr Credit	Year-end FAM AA: Before 2020 ML Depr Credit	Year-end FAM AA: Total	Year-end FAM BA	Total
Residential	**$1,945,386**	**54.3%**	**4,620.3**	**-$29,479,722**	**$46,192,953**	**$16,713,231**	**-$88,902,685**	**-$72,189,454**
Small General	$97,112	2.7%	295.5	-$1,617,082	$2,426,192	$809,110	-$4,870,106	-$4,060,997
General Demand	$863,366	24.1%	2,438.9	-$12,439,862	$28,963,488	$16,523,626	-$40,977,104	-$24,453,478
Large General	$110,492	3.1%	394.4	-$1,913,976	$1,440,320	-$473,656	-$165,782	-$639,438
Total Commercial	**$1,070,970**	**29.9%**	**3,128.9**	**-$15,970,920**	**$32,830,000**	**$16,859,080**	**-$46,012,992**	**-$29,153,912**
Small Industrial	$86,528	2.4%	263.3	-$1,294,171	$2,910,184	$1,616,014	-$4,031,935	-$2,415,922
Medium Industrial	$152,898	4.3%	465.9	-$2,158,812	$4,811,959	$2,653,147	-$3,897,683	-$1,244,536
Large Industrial Total		0.0%						
Firm	$31,453.01	0.9%	126.3	-$516,661	$1,176,164	$659,502	-$738,596	-$79,093
Interruptible	$180,274.92	5.0%	683.0	-$3,012,240	$6,792,220	$3,779,980	-$4,585,930	-$805,950
Large Industrial Total	$211,728	5.9%	809.4	-$3,528,901	$7,968,384	$4,439,483	-$5,324,526	-$885,043
Total Industrial	**$451,154**	**12.6%**	**1,538.5**	**-$6,981,884**	**$15,690,528**	**$8,708,644**	**-$13,254,145**	**-$4,545,501**
Municipal	$60,971	1.7%	125.3	-$694,660	$1,438,157	$743,498	-$1,444,466	-$700,968
Unmetered	$53,801	1.5%	81.4	-$456,951	$1,260,666	$803,715	-$1,916,103	-$1,112,389
Total Other	**$114,772**	**3.2%**	**206.7**	**-$1,151,611**	**$2,698,824**	**$1,547,213**	**-$3,360,570**	**-$1,813,357**
Total FAM Classes	**$3,582,281**	**100.0%**	**9,494.4**	**-$53,584,137**	**$97,412,304**	**$43,828,167**	**-$151,530,392**	**-$107,702,224**

2020

	Sales (GWh)	BCF Requirement	BCF Recovery at 2019 Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest
Residential	**4,493.3**	**$336,308,159**	**$211,850,947**	**-$72,189,454**	**$124,457,211**	**$52,267,758**	**-$681,322**
Small General	286.8	$21,000,825	$14,251,795	-$4,060,997	$6,749,030	$2,688,033	-$46,955
General Demand	2,393.0	$167,452,595	$113,873,447	-$24,453,478	$53,579,148	$29,125,670	$159,789
Large General	392.8	$25,842,972	$24,001,841	-$639,438	$1,841,130	$1,201,693	$19,229
Total Commercial	**3,072.6**	**$214,296,392**	**$152,127,084**	**-$29,153,912**	**$62,169,308**	**$33,015,396**	**$132,063**
Small Industrial	250.4	$17,300,100	$11,993,799	-$2,415,922	$5,306,301	$2,890,379	$16,226
Medium Industrial	474.4	$30,977,383	$24,849,105	-$1,244,536	$6,128,279	$4,883,742	$124,461
Large Industrial Total							
Firm	128.0	$8,051,636	$6,710,160	-$79,093	$1,341,476	$1,262,382	$40,468
Interruptible	733.9	$46,148,465	$38,465,190	-$805,950	$7,683,275	$6,877,325	$207,641
Large Industrial Total	861.9	$54,200,101	$45,175,351	-$885,043	$9,024,750	$8,139,707	$248,110
Total Industrial	**1,586.7**	**$102,477,584**	**$82,018,254**	**-$4,545,501**	**$20,459,330**	**$15,913,829**	**$388,797**
Municipal	124.8	$8,423,709	$6,299,579	-$700,968	$2,124,130	$1,423,161	$24,699
Unmetered	81.0	$5,768,423	$3,456,098	-$1,112,389	$2,312,325	$1,199,937	$2,994
Total Other	**205.9**	**$14,192,132**	**$9,755,677**	**-$1,813,357**	**$4,436,455**	**$2,623,098**	**$27,693**
Total FAM Classes	**9,358.5**	**$667,274,266**	**$455,751,962**	**-$107,702,224**	**$211,522,305**	**$103,820,081**	**-$132,769**

2021

	Sales (GWh)	BCF Requirement	BCF Recovery at 2019 Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest
Residential	**4,472.7**	**$339,225,419**	**282,739,533**	**$51,586,436**	**$56,485,886**	**$108,072,321**	**$5,460,329**
Small General	287.8	$21,121,735	18,371,719	$2,641,078	$2,750,016	$5,391,094	$274,700
General Demand	2,360.7	$165,983,147	136,462,331	$29,285,459	$29,520,817	$58,806,276	$3,012,737
Large General	393.6	$25,978,950	24,689,099	$1,220,922	$1,289,851	$2,510,772	$127,624
Total Commercial	**3,042.1**	**$213,083,832**	**179,523,149**	**$33,147,459**	**$33,560,683**	**$66,708,142**	**$3,415,062**
Small Industrial	250.6	$17,395,144	14,417,333	$2,906,606	$2,977,811	$5,884,417	$300,653
Medium Industrial	472.9	$31,010,766	26,012,209	$5,008,203	$4,998,557	$10,006,760	$513,512
Large Industrial Total							
Firm	127.9	$8,057,849	6,783,726	$1,302,851	$1,274,123	$2,576,974	$132,690
Interruptible	795.4	$50,097,289	42,563,933	$7,084,966	$7,533,356	$14,618,321	$742,252
Large Industrial Total	923.3	$58,155,138	49,347,659	$8,387,817	$8,807,478	$17,195,295	$874,942
Total Industrial	**1,646.8**	**$106,561,047**	**89,777,200**	**$16,302,626**	**$16,783,847**	**$33,086,472**	**$1,689,107**
Municipal	122.6	$8,333,806	6,878,419	$1,447,860	$1,455,387	$2,903,248	$148,808
Unmetered	81.0	$5,796,528	4,568,486	$1,202,931	$1,228,042	$2,430,973	$124,280
Total Other	**203.7**	**$14,130,335**	**11,446,905**	**$2,650,791**	**$2,683,429**	**$5,334,221**	**$273,087**
Total FAM Classes	**9,365.3**	**$673,000,633**	**563,486,788**	**$103,687,311**	**$109,513,845**	**$213,201,156**	**$10,837,586**

2022

	Sales (GWh)	BCF Requirement	BCF Recovery at 2019 Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest
Residential	**4,479.1**	**$338,965,052**	**283,139,778.6**	**$113,532,651**	**$55,825,274**	**$169,357,925**	**$9,674,858**
Small General	288.6	$21,093,984	18,424,099.7	$5,665,794	$2,669,884	$8,335,678	$478,850
General Demand	2,335.1	$163,774,514	134,979,778.4	$61,819,013	$28,794,736	$90,613,749	$5,213,200
Large General	390.8	$25,794,291	24,512,445.1	$2,638,396	$1,281,846	$3,920,242	$224,305
Total Commercial	**3,014.4**	**$210,662,789**	**$177,916,323**	**$70,123,203**	**$32,746,466**	**$102,869,669**	**$5,916,356**
Small Industrial	250.9	$17,397,587	14,437,871.6	$6,185,070	$2,959,715	$9,144,785	$524,281
Medium Industrial	469.8	$30,797,588	25,844,058.4	$10,520,272	$4,953,530	$15,473,802	$888,997
Large Industrial Total							#DIV/0!
Firm	127.8	$8,055,274	6,776,983.8	$2,709,664	$1,278,291	$3,987,954	$229,059
Interruptible	793.3	$49,999,626	42,452,299.4	$15,360,574	$7,547,327	$22,907,901	$1,308,782
Large Industrial Total	921.1	$58,054,901	$49,229,283	$18,070,237	$8,825,618	$26,895,855	$1,537,840
Total Industrial	**1,641.9**	**$106,250,075**	**$89,511,213**	**$34,775,580**	**$16,738,862**	**$51,514,442**	**$2,951,119**
Municipal	121.1	$8,200,053	6,790,257.4	$3,052,056	$1,409,796	$4,461,852	$256,976
Unmetered	81.0	$5,791,187	4,568,486.4	$2,555,253	$1,222,701	$3,777,953	$216,596
Total Other	**202.1**	**$13,991,240**	**$11,358,744**	**$5,607,308**	**$2,632,497**	**$8,239,805**	**$473,571**
Total FAM Classes	**9,337.5**	**$669,869,157**	**$561,926,059**	**$224,038,742**	**$107,943,098**	**$331,981,840**	**$19,015,904**

2023

	Sales (GWh)	BCF Requirement	BCF Recovery at 2019 Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest	Year Beginning 2024
Residential	**4,490.2**	**$346,115,794**	**283,844,417**	**$179,032,782**	**$62,271,378**	**$241,304,160**	**$14,375,523**	**$255,679,683**
Small General	288.5	$21,345,470	18,419,008	$8,814,529	$2,926,461	$11,740,990	$702,999	$12,443,989
General Demand	2,313.3	$163,972,201	133,720,785	$95,826,949	$30,251,416	$126,078,365	$7,589,162	$133,667,527
Large General	387.6	$25,784,583	24,310,027	$4,144,547	$1,474,556	$5,619,103	$333,917	$5,953,020
Total Commercial	**2,989.3**	**$211,102,254**	**176,449,820**	**$108,786,025**	**$34,652,433**	**$143,438,459**	**$8,626,077**	**$152,064,536**
Small Industrial	251.6	$17,621,461	14,479,040	$9,669,066	$3,142,421	$12,811,487	$768,835	$13,580,322
Medium Industrial	465.8	$30,794,327	25,623,582	$16,362,799	$5,170,746	$21,533,545	$1,296,055	$22,829,599
Large Industrial Total								
Firm	127.7	$8,115,011	6,773,437	$4,217,013	$1,341,573	$5,558,586	$334,325	$5,892,912
Interruptible	791.3	$50,269,067	42,344,713	$24,216,683	$7,924,355	$32,141,037	$1,927,434	$34,068,471
Large Industrial Total	919.1	$58,384,078	49,118,150	$28,433,695	$9,265,928	$37,699,624	$2,261,760	$39,961,383
Total Industrial	**1,636.5**	**$106,799,866**	**89,220,771**	**$54,465,560**	**$17,579,095**	**$72,044,655**	**$4,326,649**	**$76,371,305**
Municipal	98.7	$6,790,846	5,533,726	$4,718,827	$1,257,120	$5,975,947	$365,761	$6,341,709
Unmetered	81.0	$5,836,774	4,568,486	$3,994,549	$1,268,287	$5,262,836	$316,603	$5,579,439
Total Other	**179.7**	**$12,627,620**	**10,102,213**	**$8,713,376**	**$2,525,408**	**$11,238,784**	**$682,364**	**$11,921,147**
Total FAM Classes	**9,295.8**	**$676,645,534**	**559,617,220**	**$350,997,744**	**$117,028,313**	**$468,026,057**	**$28,010,614**	**$496,036,671**

Rate Plan

2014 Rate Base / 2020 FAM Amounts

	2014 Rate Base Amount	%	2019 Actual Sales (GWh)	Year-end FAM AA: 202 ML Depr Credit	Year-end FAM AA: Before 2020 ML Depr Credit	Year-end FAM AA: Total	Year-end FAM BA	Total
Residential	**$1,945,386**	**54.3%**	**4,620.3**	**-$29,479,722**	**$46,192,953**	**$16,713,231**	**-$88,902,685**	**-$72,189,454**
Small General	$97,112	2.7%	295.5	-$1,617,082	$2,426,192	$809,110	-$4,870,106	-$4,060,997
General Demand	$863,366	24.1%	2,438.9	-$12,439,862	$28,963,488	$16,523,626	-$40,977,104	-$24,453,478
Large General	$110,492	3.1%	394.4	-$1,913,976	$1,440,320	-$473,656	-$165,782	-$639,438
Total Commercial	**$1,070,970**	**29.9%**	**3,128.9**	**-$15,970,920**	**$32,830,000**	**$16,859,080**	**-$46,012,992**	**-$29,153,912**
Small Industrial	$86,528	2.4%	263.3	-$1,294,171	$2,910,184	$1,616,014	-$4,031,935	-$2,415,922
Medium Industrial	$152,898	4.3%	465.9	-$2,158,812	$4,811,959	$2,653,147	-$3,897,683	-$1,244,536
Large Industrial Total								
Firm	$31,453.01	0.9%	126.3	-$516,661	$1,176,164	$659,502	-$738,596	-$79,093
Interruptible	$180,274.92	5.0%	683.0	-$3,012,240	$6,792,220	$3,779,980	-$4,585,930	-$805,950
Large Industrial Total	$211,728	5.9%	809.4	-$3,528,901	$7,968,384	$4,439,483	-$5,324,526	-$885,043
Total Industrial	**$451,154**	**12.6%**	**1,538.5**	**-$6,981,884**	**$15,690,528**	**$8,708,644**	**-$13,254,145**	**-$4,545,501**
Municipal	$60,971	1.7%	125.3	-$694,660	$1,438,157	$743,498	-$1,444,466	-$700,968
Unmetered	$53,801	1.5%	81.4	-$456,951	$1,260,666	$803,715	-$1,916,103	-$1,112,389
Total Other	**$114,772**	**3.2%**	**206.7**	**-$1,151,611**	**$2,698,824**	**$1,547,213**	**-$3,360,570**	**-$1,813,357**
Total FAM Classes	**$3,582,281**	**100.0%**	**9,494.4**	**-$53,584,137**	**$97,412,304**	**$43,828,167**	**-$151,530,392**	**-$107,702,224**

2020

	Sales (GWh)	BCF Requirement	BCF Recovery at 2020 Composite BCF Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest
Residential	**4,493.3**	**$336,308,159**	**$294,927,269**	**-$72,189,454**	**$41,380,890**	**-$30,808,564**	**-$3,522,532**
Small General	286.8	$21,000,825	$18,755,577	-$4,060,997	$2,245,248	-$1,815,749	-$200,985
General Demand	2,393.0	$167,452,595	$146,765,433	-$24,453,478	$20,687,162	-$3,766,316	-$965,117
Large General	392.8	$25,842,972	$25,080,805	-$639,438	$762,167	$122,729	-$17,671
Total Commercial	**3,072.6**	**$214,296,392**	**$190,601,814**	**-$29,153,912**	**$23,694,577**	**-$5,459,335**	**-$1,183,773**
Small Industrial	250.4	$17,300,100	$15,255,481	-$2,415,922	$2,044,618	-$371,303	-$95,323
Medium Industrial	474.4	$30,977,383	$28,029,675	-$1,244,536	$2,947,708	$1,703,172	$15,685
Large Industrial Total							
Firm	128.0	$8,051,636	$7,329,088	-$79,093	$722,548	$643,455	$19,301
Interruptible	733.9	$46,148,465	$42,112,169	-$805,950	$4,036,297	$3,230,346	$82,914
Large Industrial Total	861.9	$54,200,101	$49,441,257	-$885,043	$4,758,845	$3,873,801	$102,216
Total Industrial	**1,586.7**	**$102,477,584**	**$92,726,413**	**-$4,545,501**	**$9,751,171**	**$5,205,670**	**$22,578**
Municipal	124.8	$8,423,709	$7,505,613	-$700,968	$918,096	$217,127	-$16,547
Unmetered	81.0	$5,768,423	$4,900,078	-$1,112,389	$868,345	-$244,044	-$46,390
Total Other	**205.9**	**$14,192,132**	**$12,405,691**	**-$1,813,357**	**$1,786,441**	**-$26,916**	**-$62,937**
Total FAM Classes	**9,358.5**	**$667,274,266**	**$590,661,188**	**-$107,702,224**	**$76,613,079**	**-$31,089,146**	**-$4,746,665**

2021

	Sales (GWh)	BCF Requirement	BCF Recovery at 2021 Composite BCF Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest
Residential	**4,472.7**	**$339,225,419**	**304,576,236**	**-$34,331,096**	**$34,649,183**	**$318,086**	**-$1,163,245**
Small General	287.8	$21,121,735	19,264,495.4	-$2,016,733	$1,857,240	-$159,493	-$74,427
General Demand	2,360.7	$165,983,147	153,332,130.6	-$4,731,432	$12,651,017	$7,919,584	$109,035
Large General	393.6	$25,978,950	25,573,845.0	$105,058	$405,105	$510,162	$21,041
Total Commercial	**3,042.1**	**$213,083,832**	**$198,170,471**	**-$6,643,108**	**$14,913,361**	**$8,270,253**	**$55,648**
Small Industrial	250.6	$17,395,144	16,132,322.9	-$466,626	$1,262,821	$796,194	$11,271
Medium Industrial	472.9	$31,010,766	29,948,569.1	$1,718,857	$1,062,197	$2,781,054	$153,897
Large Industrial Total							
Firm	127.9	$8,057,849	7,883,438.6	$662,756	$174,410	$837,166	$51,297
Interruptible	795.4	$50,097,289	48,843,463.8	$3,313,261	$1,253,825	$4,567,086	$269,508
Large Industrial Total	923.3	$58,155,138	$56,726,902	$3,976,017	$1,428,235	$5,404,252	$320,805
Total Industrial	**1,646.8**	**$106,561,047**	**$102,807,794**	**$5,228,247**	**$3,753,253**	**$8,981,500**	**$485,973**
Municipal	122.6	$8,333,806	7,890,472.5	$200,580	$443,334	$643,914	$28,882
Unmetered	81.0	$5,796,528	5,237,065.4	-$290,433	$559,463	$269,029	-$732
Total Other	**203.7**	**$14,130,335**	**$13,127,538**	**-$89,853**	**$1,002,797**	**$912,943**	**$28,150**
Total FAM Classes	**9,365.3**	**$673,000,633**	**$618,682,040**	**-$35,835,810**	**$54,318,593**	**$18,482,783**	**-$593,474**

2022

	Sales (GWh)	BCF Requirement	BCF Recovery at 2022 Composite BCF Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest
Residential	**4,479.1**	**$338,965,052**	**316,183,461**	**-$845,159**	**$22,781,592**	**$21,936,433**	**$721,322**
Small General	288.6	$21,093,984	19,773,682.4	-$233,920	$1,320,302	$1,086,381	$29,154
General Demand	2,335.1	$163,774,514	160,342,158.1	$8,028,619	$3,432,356	$11,460,975	$666,544
Large General	390.8	$25,794,291	25,836,043.8	$531,203	-$41,753	$489,450	$34,906
Total Commercial	**3,014.4**	**$210,662,789**	**$205,951,884**	**$8,325,902**	**$4,710,905**	**$13,036,806**	**$730,605**
Small Industrial	250.9	$17,397,587	17,048,535.7	$807,466	$349,051	$1,156,517	$67,168
Medium Industrial	469.8	$30,797,588	31,827,256.1	$2,934,951	-$1,029,668	$1,905,283	$165,536
Large Industrial Total							
Firm	127.8	$8,055,274	8,457,076.7	$888,464	-$401,802	$486,661	$47,029
Interruptible	793.3	$49,999,626	52,032,731.8	$4,836,593	-$2,033,105	$2,803,488	$261,291
Large Industrial Total	921.1	$58,054,901	$60,489,808	$5,725,057	-$2,434,908	$3,290,149	$308,320
Total Industrial	**1,641.9**	**$106,250,075**	**$109,365,600**	**$9,467,473**	**-$3,115,525**	**$6,351,948**	**$541,024**
Municipal	121.1	$8,200,053	8,317,628.4	$672,796	-$117,575	$555,221	$41,998
Unmetered	81.0	$5,791,187	5,579,535.7	$268,297	$211,651	$479,949	$25,590
Total Other	**202.1**	**$13,991,240**	**$13,897,164**	**$941,093**	**$94,076**	**$1,035,169**	**$67,588**
Total FAM Classes	**9,337.5**	**$669,869,157**	**$645,398,110**	**$17,889,309**	**$24,471,047**	**$42,360,357**	**$2,060,539**

2023

	Sales (GWh)	BCF Requirement	BCF Recovery at 2023 Rates	Rate Stability Fund Year-beginning	Contribution from BCF Recovery	Year-end bfr Interest	Interest	Year Beginning 2024
Residential	**4,490.2**	**$346,115,794**	**369,522,819**	$22,657,754	**-$23,407,024**	**-$749,270**	**$749,270**	**-$0**
Small General	288.5	$21,345,470	22,497,895	$1,115,536	-$1,152,425	-$36,890	$36,890	$0
General Demand	2,313.3	$163,972,201	176,500,765	$12,127,519	-$12,528,564	-$401,045	$401,045	$0
Large General	387.6	$25,784,583	26,326,279	$524,356	-$541,696	-$17,340	$17,340	-$0
Total Commercial	**2,989.3**	**$211,102,254**	**225,324,939**	**$13,767,411**	**-$14,222,686**	**-$455,275**	**$455,275**	**$0**
Small Industrial	251.6	$17,621,461	18,885,611	$1,223,685	-$1,264,151	-$40,466	$40,466	-$0
Medium Industrial	465.8	$30,794,327	32,933,626	$2,070,819	-$2,139,299	-$68,480	$68,480	-$0
Large Industrial Total								
Firm	127.7	$8,115,011	8,666,350	$533,690	-$551,339	-$17,649	$17,649	-$0
Interruptible	791.3	$50,269,067	53,435,196	$3,064,779	-$3,166,128	-$101,349	$101,349	-$0
Large Industrial Total	919.1	$58,384,078	62,101,545	$3,598,469	-$3,717,467	-$118,998	$118,998	-$0
Total Industrial	**1,636.5**	**$106,799,866**	**$113,920,782**	**$6,892,973**	**-$7,120,917**	**-$227,944**	**$227,944**	**-$0**
Municipal	98.7	$6,790,846	7,407,814.5	$597,219	-$616,968	-$19,749	$19,749	-$0
Unmetered	81.0	$5,836,774	6,359,030.3	$505,539	-$522,256	-$16,718	$16,718	-$0
Total Other	**179.7**	**$12,627,620**	**$13,766,845**	**$1,102,758**	**-$1,139,225**	**-$36,467**	**$36,467**	**-$0**
Total FAM Classes	**9,295.8**	**$676,645,534**	**$722,535,385**	**$44,420,895**	**-$45,889,851**	**-$1,468,956**	**$1,468,956**	**-$0**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	GWh Sales				Revenues priced at 2019 base cost rates				Proposed Revenues under Smoothed Rate Increases				Revenues priced at previous year's rates				Variance				% Variance				Composite BCF Rates (c/kWh)				% Var BCF Rates (c/kWh)				Oustanding Balance Year Beginning 2024
	2020	2021	2022	2023	2020	2021	2022	2023	2020	2021	2022	2023	2020	2021	2022	2023	2020	2021	2022	2023	2020	2021	2022	2023	2020	2021	2022	2023	2020	2021	2022	2023	
Residential	**4,493.3**	**4,472.7**	**4,479.1**	**4,490.2**	**$749,540,113**	**$746,471,062**	**$747,583,295**	**$749,425,600**	**$760,426,981**	**$768,307,765**	**$780,626,977**	**$835,104,002**	**$749,540,113**	**$757,308,069**	**$769,450,910**	**$782,551,516**	**$10,886,868**	**$10,999,696**	**$11,176,067**	**$54,477,025**	**1.452%**	**1.452%**	**1.452%**	**6.961%**	6.564	6.810	7.059	8.230	3.8%	3.7%	3.7%	16.6%	**-$0**
Small General	286.8	287.8	288.6	288.5	$46,312,241	$46,472,731	$46,617,249	$46,627,463	$46,755,026	$47,365,507	$47,966,832	$50,706,350	$46,312,241	$46,916,941	$47,512,571	$47,976,673	$442,785	$448,566	$454,261	$2,739,518	0.956%	0.956%	0.956%	5.710%	6.539	6.695	6.852	7.798	2.4%	2.4%	2.4%	13.8%	$0
General Demand	2,393.0	2,360.7	2,335.1	2,313.3	$318,906,693	$314,607,953	$311,189,994	$308,287,439	$327,345,201	$331,477,753	$336,552,374	$351,067,419	$318,906,693	$322,932,714	$327,876,517	$333,413,257	$8,438,508	$8,545,040	$8,675,856	$14,515,046	2.646%	2.646%	2.646%	4.353%	6.133	6.495	6.867	7.630	6.1%	5.9%	5.7%	11.1%	$0
Large General	392.8	393.6	390.8	387.6	$48,529,955	$48,624,135	$48,276,222	$47,877,568	$48,969,481	$49,508,881	$49,599,821	$49,893,821	$48,529,955	$49,064,514	$49,154,638	$49,190,237	$439,526	$444,367	$445,183	$294,000	0.906%	0.906%	0.906%	0.598%	6.384	6.497	6.611	6.793	1.8%	1.8%	1.8%	2.7%	-$0
Total Commercial	**3,072.6**	**3,042.1**	**3,014.4**	**2,989.3**	**$413,748,890**	**$409,704,819**	**$406,083,465**	**$402,792,471**	**$423,069,709**	**$428,352,141**	**$434,119,026**	**$451,667,590**	**$413,748,890**	**$418,914,168**	**$424,543,726**	**$430,580,167**	**$9,320,819**	**$9,437,973**	**$9,575,301**	**$17,548,563**	**2.253%**	**2.253%**	**2.255%**	**4.076%**									**$0**
Small Industrial	250.4	250.6	250.9	251.6	$31,702,850	$31,719,598	$31,764,786	$31,855,360	$32,548,611	$33,434,588	$34,375,450	$36,261,932	$31,702,850	$32,565,806	$33,482,219	$34,473,468	$845,761	$868,783	$893,231	$1,886,482	2.668%	2.668%	2.668%	5.472%	6.091	6.438	6.794	7.505	5.9%	5.7%	5.5%	10.5%	-$0
Medium Industrial	474.4	472.9	469.8	465.8	$48,923,099	$48,770,421	$48,455,156	$48,041,782	$50,859,133	$52,706,782	$54,438,353	$55,351,827	$48,923,099	$50,700,414	$52,366,070	$53,973,937	$1,936,034	$2,006,368	$2,072,283	$913,473	3.957%	3.957%	3.957%	1.692%	5.909	6.333	6.774	7.070	7.4%	7.2%	7.0%	4.4%	-$0
Large Industrial Total																				$0													
Firm	128.0	127.9	127.8	127.7	$13,917,061	$13,905,731	$13,891,910	$13,884,640	$14,456,896	$15,005,443	$15,572,003	$15,777,552	$13,917,061	$14,445,126	$14,990,529	$15,563,853	$539,834	$560,318	$581,474	$205,549	3.879%	3.879%	3.879%	1.321%	5.724	6.162	6.617	6.784	8.0%	7.7%	7.4%	2.5%	-$0
Interruptible	733.9	795.4	793.3	791.3	$72,271,133	$78,330,897	$78,125,456	$77,927,463	$75,112,161	$84,610,427	$87,705,888	$89,017,946	$72,271,133	$81,410,138	$84,388,517	$87,483,615	$2,841,028	$3,200,289	$3,317,371	$1,312,057	3.931%	3.931%	3.931%	1.500%	5.738	6.141	6.559	6.753	7.2%	7.0%	6.8%	3.0%	-$0
Large Industrial Total	861.9	923.3	921.1	919.1	$86,188,194	$92,236,627	$92,017,366	$91,812,102	$89,569,057	$99,615,871	$103,277,891	$104,795,498	$86,188,194	$95,855,264	$99,379,047	$103,047,469	$3,380,863	$3,760,607	$3,898,845	$1,517,607	3.923%	3.923%	3.923%	1.473%									-$0
Total Industrial	**1,586.7**	**1,646.8**	**1,641.9**	**1,636.5**	**$166,814,143**	**$172,726,647**	**$172,237,307**	**$171,709,245**	**$172,976,801**	**$185,757,241**	**$192,091,694**	**$196,409,256**	**$166,814,143**	**$179,121,483**	**$185,227,336**	**$191,494,874**	**$6,162,658**	**$6,635,757**	**$6,864,358**	**$4,317,562**	**3.694%**	**3.705%**	**3.706%**	**2.255%**									**-$0**
Municipal	124.8	122.6	121.1	98.7	$16,317,420	$16,167,948	$16,068,638	$14,200,893	$16,822,485	$17,180,001	$17,596,009	$16,074,981	$16,317,420	$16,664,202	$17,067,720	$15,445,625	$505,065	$515,799	$528,289	-$1,521,028	3.095%	3.095%	3.095%	-9.848%	6.013	6.434	6.870	7.508	7.2%	7.0%	6.8%	9.3%	-$0
Unmetered	81.0	81.0	81.0	81.0	$20,379,253	$20,379,253	$20,379,253	$20,379,253	$20,710,844	$21,047,832	$21,390,302	$22,169,796	$20,379,253	$20,710,844	$21,047,832	$21,390,302	$331,592	$336,987	$342,470	$779,495	1.627%	1.627%	1.627%	3.644%	6.047	6.463	6.885	7.847	7.3%	6.9%	6.5%	14.0%	-$0
Total Other	**205.9**	**203.7**	**202.1**	**179.7**	**$36,696,672**	**$36,547,200**	**$36,447,891**	**$34,580,146**	**$37,533,330**	**$38,227,833**	**$38,986,311**	**$38,244,778**	**$36,696,672**	**$37,375,046**	**$38,115,551**	**$36,835,927**	**$836,657**	**$852,786**	**$870,759**	**-$741,533**	**2.280%**	**2.282%**	**2.285%**	**-2.013%**									**-$0**
Total FAM Classes	**9,358.5**	**9,365.3**	**9,337.5**	**9,295.8**	**$1,366,799,818**	**$1,365,449,728**	**$1,362,351,958**	**$1,358,507,461**	**$1,394,006,821**	**$1,420,644,979**	**$1,445,824,009**	**$1,521,425,626**	**$1,366,799,818**	**$1,392,718,767**	**$1,417,337,524**	**$1,441,462,485**	**$27,207,002**	**$27,926,212**	**$28,486,486**	**$75,601,617**	**1.991%**	**2.005%**	**2.010%**	**5.245%**									**-$0**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

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

FOR THE YEAR ENDING DECEMBER 31, 2020

Line #	COLUMN	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
1		Cost Allocation Factors						Fuel-related Costs from COS																						Fuel Costs used for FAM purposes			
2			3 CP Demands		Energy Requirement					Purchased Power- Biomass				Maritime Link			Purchased Power other than Biomass and Wind			Purchased Power - Wind													
3														Basic and Supplemental Blocks							NRIS													
4	FORMULA																																
14	Rate Class	R/C Ratios	KW Demand	Relative Shares	KWh Energy	Relative Shares	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	Fixed Energy-related	Fixed Demand-related	Total	ERIS	Energy-related	Demand-related	Total	Total	Total Fuel-related costs before Exports, OM&G and Foreign Exchange	Export Revenues	OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh
15	FAM Rate Classes (ATL)																																
16	Residential	98.9%	3,882,961	63.6%	4,944,860,413	48.8%	4,493,317,762	$142,384,798	$27,523,247	$1,928,481	$2,600,951	$2,137,526	$6,666,957	$37,781,957	$42,672,540	$80,454,497	$2,690,088	$2,210,781	$4,900,869	$18,292,277	$47,347,341	$12,627,117	$59,974,458	$78,266,736	$340,197,104	-$24,112	$0	$0	$340,172,992	$336,261,002	50.4%	$336,308,159	7.485
17	Small General	104.6%	154,883	2.5%	312,005,160	3.1%	286,830,917	$8,834,303	$1,875,936	$119,403	$164,112	$85,261	$368,776	$2,383,923	$1,702,116	$4,086,039	$169,736	$88,183	$257,919	$1,154,185	$2,987,468	$503,669	$3,491,137	$4,645,322	$20,068,296	-$1,515	$0	$0	$20,066,782	$20,997,880	3.1%	$21,000,825	7.322
18	General Demand	102.9%	1,173,559	19.2%	2,558,628,146	25.3%	2,392,958,563	$71,355,408	$16,083,409	$974,269	$1,345,815	$646,031	$2,966,115	$19,549,587	$12,897,051	$32,446,638	$1,391,937	$668,171	$2,060,108	$9,465,006	$24,499,021	$3,816,332	$28,315,353	$37,780,359	$162,692,037	-$13,146	$0	$0	$162,678,891	$167,429,115	25.1%	$167,452,595	6.998
19	Large General	99.4%	157,778	2.6%	417,034,269	4.1%	392,840,580	$11,476,844	$2,784,436	$157,032	$219,356	$86,855	$463,243	$3,186,414	$1,733,934	$4,920,348	$226,874	$89,832	$316,705	$1,542,714	$3,993,129	$513,084	$4,506,212	$6,048,927	$26,010,503	-$2,100	$0	$0	$26,008,403	$25,839,348	3.9%	$25,842,972	6.578
20	Small Industrial	102.5%	121,227	2.0%	265,975,600	2.6%	250,444,410	$7,370,377	$1,703,765	$999,917	$139,901	$66,734	$306,552	$2,032,227	$1,332,245	$3,364,472	$144,695	$69,021	$213,716	$983,910	$2,546,733	$394,221	$2,940,954	$3,924,864	$16,883,746	-$1,378	$0	$0	$16,882,368	$17,297,674	2.6%	$17,300,100	6.908
21	Medium Industrial	98.5%	195,237	3.2%	504,530,272	5.0%	474,373,865	$13,846,245	$3,333,705	$189,038	$265,378	$107,476	$561,892	$3,854,940	$2,145,597	$6,000,537	$274,473	$111,159	$385,632	$1,866,384	$4,830,908	$634,898	$5,465,806	$7,332,190	$31,460,200	-$2,715	$0	$0	$31,457,485	$30,973,040	4.6%	$30,977,383	6.530
22	Large Industrial	97.4%	298,769	4.9%	903,650,383	8.9%	861,915,417	$24,775,745	$6,051,324	$337,750	$475,312	$164,469	$977,531	$6,904,478	$3,283,381	$10,187,859	$491,601	$170,106	$661,707	$3,342,829	$8,652,508	$971,576	$9,624,084	$12,966,913	$55,621,079	-$4,801	$0	$0	$55,616,278	$54,192,501	8.1%	$54,200,101	6.288
23	Municipal	97.7%	76,265	1.2%	131,438,507	1.3%	124,819,979	$3,747,132	$764,683	$51,086	$69,135	$41,983	$162,205	$1,004,276	$838,131	$1,842,407	$71,505	$43,422	$114,927	$486,224	$1,258,532	$248,009	$1,506,541	$1,992,765	$8,624,118	-$664	$0	$0	$8,623,454	$8,422,527	1.3%	$8,423,709	6.749
24	Unmetered	100.0%	46,885	0.8%	89,252,555	0.9%	81,034,159	$2,467,073	$585,305	$33,266	$46,946	$25,810	$106,022	$681,948	$515,255	$1,197,203	$48,555	$26,694	$75,249	$330,168	$854,599	$152,468	$1,007,066	$1,337,234	$5,768,085	-$471	$0	$0	$5,767,614	$5,767,614	0.9%	$5,768,423	7.119
25	Total	100.0%	6,107,565	100.0%	10,127,375,305	100.0%	9,358,535,650	$286,257,923	$60,705,811	$3,890,242	$5,326,906	$3,362,145	$12,579,293	$77,379,750	$67,120,250	$144,500,000	$5,509,464	$3,477,369	$8,986,833	$37,463,698	$96,970,238	$19,861,374	$116,831,612	$154,295,310	$667,325,170	-$50,903	$0	$0	$667,274,266	$667,180,702	100.0%	$667,274,266	7.130
26																				54.7%													
27	Puchased Power Allocation Factors.									30.9%	42.3%	26.7%	100.0%	53.6%	46.5%	100.0%	61.3%	38.7%	100.0%		83.0%	17.0%	100.0%										
29	Non-FAM Rate Classes																																
30–33	[redacted]																																
34	Total Below-the-line		213,853		1,172,736,092		1,147,422,644	$66,445,301	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$66,445,301	$0	$0		$66,445,301			$66,445,301	5.791
35–36	In Province Total		6,321,418		11,300,111,397		10,505,958,295	$352,703,224	$60,705,811	$3,890,242	$5,326,906	$3,362,145	$12,579,293	$77,379,750	$67,120,250	$144,500,000	$5,509,464	$3,477,369	$8,986,833	$37,463,698	$96,970,238	$19,861,374	$116,831,612	$154,295,310	$733,770,471	-$50,903	$0	$0	$733,719,567			$733,719,567	6.984
38	Exports	100.0%	-		1,903,449		1,903,449																										
39–40	Grand Total		6,321,418		11,302,014,846		10,507,861,744	$352,703,224	$60,705,811	$3,890,242	$5,326,906	$3,362,145	$12,579,293	$77,379,750	$67,120,250	$144,500,000	$5,509,464	$3,477,369	$8,986,833	$37,463,698	$96,970,238	$19,861,374	$116,831,612	$154,295,310	$733,770,471	-$50,903	$0	$0	$733,719,567			$733,719,567	6.983

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Monthly Fuel Cost Allocation

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
Purchased Power													
Imports	$2,105,620	$3,223,956	$2,472,789	$3,197,980	$6,270,292	$6,830,049	$7,558,073	$6,775,201	$8,010,532	$6,980,668	$4,753,711	$2,526,940	**$60,705,811**
Biomass													
IPP	$1,339,121	$1,078,283	$1,225,551	$1,128,166	$794,999	$780,097	$1,048,642	$1,061,121	$719,367	$928,203	$1,143,295	$1,332,448	**$12,579,293**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$1,339,121**	**$1,078,283**	**$1,225,551**	**$1,128,166**	**$794,999**	**$780,097**	**$1,048,642**	**$1,061,121**	**$719,367**	**$928,203**	**$1,143,295**	**$1,332,448**	**$12,579,293**
Maritime Link													
ML - NS Block (GWh)	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$144,500,000
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$12,041,667**	**$144,500,000**
Regular other than biomass and wind													
IPP	$72,291	$78,549	$100,341	$90,943	$97,398	$92,739	$96,583	$100,262	$89,902	$80,279	$68,486	$69,481	**$1,037,254**
Comfit	$643,715	$669,468	$671,519	$662,821	$629,230	$647,575	$696,258	$698,901	$641,229	$654,924	$670,078	$663,859	**$7,949,579**
Total	**$716,006**	**$748,017**	**$771,860**	**$753,764**	**$726,628**	**$740,315**	**$792,841**	**$799,163**	**$731,132**	**$735,203**	**$738,564**	**$733,340**	**$8,986,833**
Wind NRIS													
IPP	$4,663,984	$4,185,748	$4,947,660	$3,850,418	$3,390,270	$3,372,966	$2,512,723	$2,560,498	$3,013,718	$4,063,193	$4,455,600	$4,299,340	**$45,316,118**
Comfit	$7,101,477	$6,259,119	$7,648,995	$6,244,030	$5,896,763	$5,206,381	$4,430,822	$4,102,972	$5,021,029	$6,383,607	$6,588,549	$6,631,750	**$71,515,494**
Total	**$11,765,461**	**$10,444,868**	**$12,596,655**	**$10,094,447**	**$9,287,034**	**$8,579,347**	**$6,943,545**	**$6,663,470**	**$8,034,747**	**$10,446,800**	**$11,044,150**	**$10,931,089**	**$116,831,612**
Wind ERIS													
IPP	$3,729,058	$3,394,344	$3,717,190	$3,084,822	$3,021,160	$2,846,042	$2,119,706	$2,145,432	$2,578,093	$3,454,353	$3,622,638	$3,750,858	**$37,463,698**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$3,729,058**	**$3,394,344**	**$3,717,190**	**$3,084,822**	**$3,021,160**	**$2,846,042**	**$2,119,706**	**$2,145,432**	**$2,578,093**	**$3,454,353**	**$3,622,638**	**$3,750,858**	**$37,463,698**
Grand Total	**$19,655,266**	**$18,889,467**	**$20,784,045**	**$18,259,180**	**$20,100,113**	**$19,775,849**	**$18,462,808**	**$17,444,387**	**$20,073,870**	**$22,545,227**	**$21,302,358**	**$19,274,676**	**$236,567,247**
Plant Fuel Costs													
Plant Fuel Costs	$45,304,808	$43,464,236	$40,377,508	$32,504,254	$26,882,143	$16,173,214	$21,404,946	$25,385,078	$20,951,241	$20,893,219	$23,846,738	$35,515,838	**$352,703,224**
BTL Class Fuel-related costs													
[redacted]													
Total	$6,448,582	$8,233,006	$6,632,545	$5,538,327	$6,096,256	$3,763,726	$4,552,136	$4,713,841	$4,479,512	$5,507,904	$4,617,436	$5,862,029	**$66,445,301**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
ATL-related Fuel costs (net of BTL)	$38,856,225	$35,231,230	$33,744,963	$26,965,927	$20,785,887	$12,409,488	$16,852,810	$20,671,237	$16,471,729	$15,385,315	$19,229,302	$29,653,809	**$286,257,923**
Fuel costs before PP													
Domestic	$21,687,817	$19,445,463	$18,178,342	$13,646,635	$9,682,541	$5,141,291	$6,801,983	$8,475,354	$6,703,037	$6,700,150	$9,446,645	$16,475,540	$142,384,798
Small General	$1,215,857	$1,121,349	$1,037,856	$826,096	$665,441	$385,046	$542,452	$643,155	$498,353	$464,362	$564,185	$870,149	$8,834,303
General	$8,813,616	$8,104,418	$8,046,008	$6,531,964	$5,237,334	$3,488,134	$4,822,992	$5,787,662	$4,637,979	$4,189,596	$4,858,943	$6,836,761	$71,355,408
Large General	$1,269,282	$1,135,974	$1,148,614	$1,063,204	$910,402	$597,184	$912,093	$1,155,828	$869,068	$714,693	$730,983	$969,518	$11,476,844
Small Industrial	$882,482	$810,265	$764,893	$669,155	$596,916	$407,196	$544,472	$587,596	$491,471	$396,605	$509,693	$709,633	$7,370,377
Medium Industrial	$1,505,755	$1,431,606	$1,401,969	$1,278,833	$1,112,529	$779,462	$1,030,830	$1,197,927	$1,017,522	$893,518	$986,140	$1,210,153	$13,846,245
Large Industrial	$2,650,897	$2,414,435	$2,458,225	$2,364,232	$2,129,052	$1,332,573	$1,811,517	$2,357,363	$1,864,161	$1,689,945	$1,707,017	$1,996,326	$24,775,745
Municipal	$555,985	$503,667	$457,512	$341,964	$239,567	$145,751	$206,025	$249,021	$207,619	$200,287	$256,308	$383,426	$3,747,132
Unmetered	$274,536	$264,053	$251,545	$243,842	$212,105	$132,851	$180,445	$217,329	$182,517	$136,158	$169,387	$202,303	$2,467,073
Total	**$38,856,225**	**$35,231,230**	**$33,744,963**	**$26,965,927**	**$20,785,887**	**$12,409,488**	**$16,852,810**	**$20,671,237**	**$16,471,729**	**$15,385,315**	**$19,229,302**	**$29,653,809**	**$286,257,923**
Exports													
Domestic	$0	$0	$0	$2,879	$0	$1,191	$0	$0	$2,812	$1,365	$15,865	$0	$24,112
Small General	$0	$0	$0	$174	$0	$89	$0	$0	$209	$95	$948	$0	$1,515
General	$0	$0	$0	$1,378	$0	$808	$0	$0	$1,946	$854	$8,160	$0	$13,146
Large General	$0	$0	$0	$224	$0	$138	$0	$0	$365	$146	$1,228	$0	$2,100
Small Industrial	$0	$0	$0	$141	$0	$94	$0	$0	$206	$81	$856	$0	$1,378
Medium Industrial	$0	$0	$0	$270	$0	$181	$0	$0	$427	$182	$1,656	$0	$2,715
Large Industrial	$0	$0	$0	$499	$0	$309	$0	$0	$782	$344	$2,867	$0	$4,801
Municipal	$0	$0	$0	$72	$0	$34	$0	$0	$87	$41	$430	$0	$664
Unmetered	$0	$0	$0	$51	$0	$31	$0	$0	$77	$28	$284	$0	$471
Total	$0	$0	$0	$5,689	$0	$2,874	$0	$0	$6,910	$3,135	$32,295	$0	$50,903
Imports													
Domestic	$1,175,263	$1,779,425	$1,332,086	$1,618,400	$2,920,845	$2,829,711	$3,050,523	$2,777,881	$3,259,822	$3,040,011	$2,335,323	$1,403,958	$27,523,247
Small General	$65,887	$102,613	$76,053	$97,969	$200,738	$211,925	$243,277	$210,800	$242,359	$210,692	$139,473	$74,149	$1,875,936
General	$477,610	$741,623	$589,601	$774,648	$1,579,899	$1,919,832	$2,162,994	$1,896,963	$2,255,542	$1,900,915	$1,201,188	$582,592	$16,083,409
Large General	$68,782	$103,951	$84,169	$126,089	$274,633	$328,684	$409,052	$378,834	$422,645	$324,273	$180,708	$82,617	$2,784,436
Small Industrial	$47,822	$74,146	$56,050	$79,357	$180,066	$224,116	$244,183	$192,590	$239,012	$179,949	$126,002	$60,471	$1,703,765
Medium Industrial	$81,597	$131,004	$102,735	$151,661	$335,607	$429,008	$462,302	$392,632	$494,842	$405,409	$243,786	$103,123	$3,333,705
Large Industrial	$143,652	$220,941	$180,136	$280,382	$642,252	$733,434	$812,421	$772,649	$906,579	$766,767	$421,995	$170,116	$6,051,324
Municipal	$30,129	$46,090	$33,526	$40,555	$72,268	$80,220	$92,397	$81,619	$100,969	$90,875	$63,362	$32,673	$764,683
Unmetered	$14,877	$24,163	$18,433	$28,918	$63,984	$73,120	$80,925	$71,232	$88,762	$61,778	$41,874	$17,239	$585,305
Total	$2,105,620	$3,223,956	$2,472,789	$3,197,980	$6,270,292	$6,830,049	$7,558,073	$6,775,201	$8,010,532	$6,980,668	$4,753,711	$2,526,940	$60,705,811
Purchased Biomass Generation	11,822	8,522	9,643	8,314	1,800	1,820	7,482	7,566	4,397	7,626	9,120	11,901	90,011
Relative Share	13.1%	9.5%	10.7%	9.2%	2.0%	2.0%	8.3%	8.4%	4.9%	8.5%	10.1%	13.2%	100.0%
Bio-fuel Apportioned	$510,923	$368,305	$416,751	$359,340	$77,778	$78,657	$323,375	$327,010	$190,018	$329,601	$394,142	$514,341	$3,890,242
Domestic	$285,174	$203,282	$224,503	$181,851	$36,231	$32,588	$130,518	$134,076	$77,326	$143,538	$193,628	$285,766	$1,928,481
Small General	$15,987	$11,723	$12,818	$11,008	$2,490	$2,441	$10,409	$10,174	$5,749	$9,948	$11,564	$15,093	$119,403
General	$115,891	$84,723	$99,368	$87,043	$19,597	$22,110	$92,545	$91,558	$53,504	$89,754	$99,594	$118,583	$974,269
Large General	$16,690	$11,875	$14,185	$14,168	$3,407	$3,785	$17,501	$18,285	$10,026	$15,311	$14,983	$16,816	$157,032
Small Industrial	$11,604	$8,470	$9,446	$8,917	$2,234	$2,581	$10,447	$9,296	$5,670	$8,497	$10,447	$12,308	$99,917
Medium Industrial	$19,799	$14,966	$17,314	$17,041	$4,163	$4,941	$19,780	$18,951	$11,738	$19,142	$20,213	$20,990	$189,038
Large Industrial	$34,857	$25,240	$30,359	$31,505	$7,967	$8,447	$34,760	$37,292	$21,505	$36,204	$34,989	$34,626	$337,750
Municipal	$7,311	$5,265	$5,650	$4,557	$896	$924	$3,953	$3,939	$2,395	$4,291	$5,254	$6,650	$51,086
Unmetered	$3,610	$2,760	$3,107	$3,249	$794	$842	$3,462	$3,438	$2,106	$2,917	$3,472	$3,509	$33,266
Total	**$510,923**	**$368,305**	**$416,751**	**$359,340**	**$77,778**	**$78,657**	**$323,375**	**$327,010**	**$190,018**	**$329,601**	**$394,142**	**$514,341**	**$3,890,242**

Monthly Energy Allocators

Rate Class	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
kWh requirements													
ATL													
Domestic Total	611,973,982	548,527,677	550,647,518	429,190,749	344,377,072	279,543,184	291,090,618	299,953,217	276,491,822	319,398,874	418,832,945	574,832,755	4,944,860,413
Small General	34,308,347	31,631,581	31,438,119	25,980,959	23,667,623	20,935,801	23,214,220	22,762,057	20,556,425	22,136,345	25,014,114	30,359,570	312,005,160
General	248,697,392	228,613,621	243,724,887	205,432,227	186,275,245	189,657,468	206,399,779	204,832,477	191,310,785	199,719,758	215,429,430	238,535,077	2,558,628,146
Large General	35,815,841	32,044,154	34,793,137	33,438,088	32,380,095	32,470,190	39,033,005	40,906,171	35,847,957	34,069,723	32,409,360	33,826,549	417,034,269
Small Industrial	24,901,347	22,856,375	23,169,686	21,045,131	21,230,399	22,140,147	23,300,673	20,795,751	20,272,561	18,906,317	22,598,079	24,759,133	265,975,600
Medium Industrial	42,488,500	40,383,477	42,467,616	40,219,677	39,569,101	42,381,061	44,114,328	42,396,121	41,971,511	42,594,359	43,722,185	42,222,336	504,530,272
Large Industrial	74,801,444	68,107,642	74,463,077	74,355,810	75,723,598	72,454,900	77,523,818	83,429,988	76,894,297	80,560,372	75,683,485	69,651,951	903,650,383
Municipal	15,688,444	14,207,713	13,858,670	10,754,876	8,520,651	7,924,775	8,816,825	8,813,163	8,564,038	9,547,759	11,363,851	13,377,744	131,438,507
Unmetered	7,746,692	7,448,553	7,619,652	7,668,916	7,543,894	7,223,411	7,722,157	7,691,554	7,528,595	6,490,713	7,510,041	7,058,379	89,252,555
Total	1,096,421,989	993,820,792	1,022,182,361	848,086,431	739,287,679	674,730,937	721,215,421	731,580,498	679,437,992	733,424,220	852,563,491	1,034,623,494	10,127,375,305
Fuel Cost Allocators													
ATL													
Domestic	55.82%	55.19%	53.87%	50.61%	46.58%	41.43%	40.36%	41.00%	40.69%	43.55%	49.13%	55.56%	48.83%
Small General	3.13%	3.18%	3.08%	3.06%	3.20%	3.10%	3.22%	3.11%	3.03%	3.02%	2.93%	2.93%	3.08%
General	22.68%	23.00%	23.84%	24.22%	25.20%	28.11%	28.62%	28.00%	28.16%	27.23%	25.27%	23.06%	25.26%
Large General	3.27%	3.22%	3.40%	3.94%	4.38%	4.81%	5.41%	5.59%	5.28%	4.65%	3.80%	3.27%	4.12%
Small Industrial	2.27%	2.30%	2.27%	2.48%	2.87%	3.28%	3.23%	2.84%	2.98%	2.58%	2.65%	2.39%	2.63%
Medium Industrial	3.88%	4.06%	4.15%	4.74%	5.35%	6.28%	6.12%	5.80%	6.18%	5.81%	5.13%	4.08%	4.98%
Large Industrial	6.82%	6.85%	7.28%	8.77%	10.24%	10.74%	10.75%	11.40%	11.32%	10.98%	8.88%	6.73%	8.92%
Municipal	1.43%	1.43%	1.36%	1.27%	1.15%	1.17%	1.22%	1.20%	1.26%	1.30%	1.33%	1.29%	1.30%
Unmetered	0.71%	0.75%	0.75%	0.90%	1.02%	1.07%	1.07%	1.05%	1.11%	0.88%	0.88%	0.68%	0.88%
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%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Data Inputs

Category	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Annual
Plant Fuel Costs	$45,304,808	$43,464,236	$40,377,508	$32,504,254	$26,882,143	$16,173,214	$21,404,946	$25,385,078	$20,951,241	$20,893,219	$23,846,738	$35,515,838	$352,703,224
Maritime Link													
ML - NS Block	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$144,500,000
ML - Supp Block													
ML - Surplus													
Total	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$12,041,667	$144,500,000
Non-Wind Purchases													
Purchased Power Regular bfr Biomass	$72,291	$78,549	$100,341	$90,943	$97,398	$92,739	$96,583	$100,262	$89,902	$80,279	$68,486	$69,481	$1,037,254
Purchased Power - Biomass	$1,339,121	$1,078,283	$1,225,551	$1,128,166	$794,999	$780,097	$1,048,642	$1,061,121	$719,367	$928,203	$1,143,295	$1,332,448	$12,579,293
Non-Wind Purchases	$1,411,412	$1,156,832	$1,325,892	$1,219,109	$892,397	$872,836	$1,145,225	$1,161,383	$809,269	$1,008,482	$1,211,781	$1,401,929	$13,616,547
Wind Purchases													
Purchased Power Wind - NRIS	$4,663,984	$4,185,748	$4,947,660	$3,850,418	$3,390,270	$3,372,966	$2,512,723	$2,560,498	$3,013,718	$4,063,193	$4,455,600	$4,299,340	$45,316,118
Purchased Power Wind - ERIS	$3,729,058	$3,394,344	$3,717,190	$3,084,822	$3,021,160	$2,846,042	$2,119,706	$2,145,432	$2,578,093	$3,454,353	$3,622,638	$3,750,858	$37,463,698
Purchased Power Wind	$8,393,042	$7,580,092	$8,664,850	$6,935,240	$6,411,430	$6,219,008	$4,632,430	$4,705,930	$5,591,811	$7,517,547	$8,078,239	$8,050,198	$82,779,816
Comift													
Wind Generatiion (NRIS)	$7,101,477	$6,259,119	$7,648,995	$6,244,030	$5,896,763	$5,206,381	$4,430,822	$4,102,972	$5,021,029	$6,383,607	$6,588,549	$6,631,750	$71,515,494
Wind Generatiion (ERIS)													$0
Biomass Generation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Other	$643,715	$669,468	$671,519	$662,821	$629,230	$647,575	$696,258	$698,901	$641,229	$654,924	$670,078	$663,859	$7,949,579
Total Comfit	$7,745,192	$6,928,587	$8,320,514	$6,906,851	$6,525,994	$5,853,956	$5,127,081	$4,801,873	$5,662,259	$7,038,530	$7,258,628	$7,295,608	$79,465,073
Imports	$2,105,620	$3,223,956	$2,472,789	$3,197,980	$6,270,292	$6,830,049	$7,558,073	$6,775,201	$8,010,532	$6,980,668	$4,753,711	$2,526,940	$60,705,811
Export Revenues	$0	$0	$0	$5,689	$0	$2,874	$0	$0	$6,910	$3,135	$32,295	$0	$ 50,903.26
OM&G (Solid Fuel Handling) recovered in fuels													$0
Foreign Exchange (Fuel-related)													$0
Total FAM related costs	**$77,001,740**	**$74,395,370**	**$73,203,220**	**$62,805,100**	**$59,023,923**	**$47,990,731**	**$51,909,421**	**$54,871,132**	**$53,066,778**	**$55,480,113**	**$57,190,762**	**$66,832,180**	**$733,770,471**
Purchased Biomass Generation	11,822	8,522	9,643	8,314	1,800	1,820	7,482	7,566	4,397	7,626	9,120	11,901	90,011
BLT Fuel Costs	**Source-Revenue Forecast**												
[redacted]													
Total	**$6,448,582**	**$8,233,006**	**$6,632,545**	**$5,538,327**	**$6,096,256**	**$3,763,726**	**$4,552,136**	**$4,713,841**	**$4,479,512**	**$5,507,904**	**$4,617,436**	**$5,862,029**	**$66,445,301**
ERIS	**$4,663,984**	**$4,185,748**	**$4,947,660**	**$3,850,418**	**$3,390,270**	**$3,372,966**	**$2,512,723**	**$2,560,498**	**$3,013,718**	**$4,063,193**	**$4,455,600**	**$4,299,340**	**$45,316,118**	55%
NRIS	**$3,729,058**	**$3,394,344**	**$3,717,190**	**$3,084,822**	**$3,021,160**	**$2,846,042**	**$2,119,706**	**$2,145,432**	**$2,578,093**	**$3,454,353**	**$3,622,638**	**$3,750,858**	**$37,463,698**	45%
Total	**$8,393,042**	**$7,580,092**	**$8,664,850**	**$6,935,240**	**$6,411,430**	**$6,219,008**	**$4,632,430**	**$4,705,930**	**$5,591,811**	**$7,517,547**	**$8,078,239**	**$8,050,198**	**$82,779,816**	100.00%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Usage Data

kWh Requirements														
ATL Classes														
Domestic Total	611,973,982	548,527,677	550,647,518	429,190,749	344,377,072	279,543,184	291,090,618	299,953,217	276,491,822	319,398,874	418,832,945	574,832,755	4,944,860,413	4,995,329,980
Small General	34,308,347	31,631,581	31,438,119	25,980,959	23,667,623	20,935,801	23,214,220	22,762,057	20,556,425	22,136,345	25,014,114	30,359,570	312,005,160	283,848,228
General	248,697,392	228,613,621	243,724,887	205,432,227	186,275,245	189,657,468	206,399,779	204,832,477	191,310,785	199,719,758	215,429,430	238,535,077	2,558,628,146	2,553,756,467
Large General	35,815,841	32,044,154	34,793,137	33,438,088	32,380,095	32,470,190	39,033,005	40,906,171	35,847,957	34,069,723	32,409,360	33,826,549	417,034,269	434,465,234
Small Industrial	24,901,347	22,856,375	23,169,686	21,045,131	21,230,399	22,140,147	23,300,673	20,795,751	20,272,561	18,906,317	22,598,079	24,759,133	265,975,600	270,624,393
Medium Industrial	42,488,500	40,383,477	42,467,616	40,219,677	39,569,101	42,381,061	44,114,328	42,396,121	41,971,511	42,594,359	43,722,185	42,222,336	504,530,272	508,059,441
Large Industrial- FIRM	11,671,368	9,155,350	12,091,302	11,743,218	11,139,077	10,855,620	11,481,648	11,948,299	10,897,761	11,546,663	10,722,642	12,269,335	135,522,284	
Large Industrial- INT	63,130,077	58,952,292	62,371,774	62,612,592	64,584,521	61,599,280	66,042,170	71,481,689	65,996,536	69,013,709	64,960,842	57,382,616	768,128,099	
Large Industrial	74,801,444	68,107,642	74,463,077	74,355,810	75,723,598	72,454,900	77,523,818	83,429,988	76,894,297	80,560,372	75,683,485	69,651,951	903,650,383	828,615,963
Municipal	15,688,444	14,207,713	13,858,670	10,754,876	8,520,651	7,924,775	8,816,825	8,813,163	8,564,038	9,547,759	11,363,851	13,377,744	131,438,507	181,012,677
Unmetered	7,746,692	7,448,553	7,619,652	7,668,916	7,543,894	7,223,411	7,722,157	7,691,554	7,528,595	6,490,713	7,510,041	7,058,379	89,252,555	109,935,737
BTL														
[redacted]														
In-Province Total	**1,170,893,299**	**1,088,251,800**	**1,123,848,698**	**943,155,301**	**843,554,601**	**761,733,498**	**820,859,501**	**834,694,900**	**781,926,502**	**840,005,400**	**950,522,598**	**1,140,665,300**	**11,300,111,397**	**11,281,098,342**
kWh Sales														
ATL Classes														
Domestic Total	548,615,522	491,621,653	500,554,633	394,534,983	317,384,362	259,743,127	269,762,178	276,133,611	251,814,464	288,165,207	376,262,485	518,725,537	4,493,317,762	
Small General	31,256,478	28,794,813	28,872,635	23,993,146	21,936,453	19,592,784	21,574,407	20,973,298	18,772,597	20,302,499	22,749,620	28,012,187	286,830,917	
General	232,579,871	213,907,161	227,877,669	193,591,990	176,081,469	179,051,141	193,759,727	191,519,494	176,945,328	184,536,480	199,706,162	223,402,071	2,392,958,563	
Large General	33,579,021	30,164,851	32,799,925	31,642,544	30,881,363	31,042,014	36,752,959	38,487,427	33,527,993	31,733,507	30,222,644	32,006,332	392,840,580	
Small Industrial	23,507,319	21,505,388	21,806,992	19,888,004	20,165,792	21,057,124	22,130,779	19,596,825	18,886,077	17,544,034	21,014,016	23,342,060	250,444,410	
Medium Industrial	40,130,244	38,063,634	39,990,594	37,986,106	37,391,253	40,195,652	41,782,340	39,843,612	38,958,766	39,465,184	40,700,631	39,865,849	474,373,865	
Large Industrial- FIRM	11,080,908	8,678,720	11,486,204	11,171,750	10,597,624	10,383,880	10,896,631	11,290,725	10,129,744	10,710,186	10,001,131	11,613,385	128,040,889	
Large Industrial- INT	60,766,335	56,504,886	59,930,524	60,079,853	62,268,535	59,078,446	63,204,715	67,989,458	61,984,223	64,918,739	61,667,345	55,481,468	733,874,528	
Large Industrial	71,847,243	65,183,606	71,416,729	71,251,604	72,866,159	69,462,326	74,101,346	79,280,183	72,113,967	75,628,925	71,668,475	67,094,853	861,915,417	
Municipal	14,938,892	13,564,725	13,196,505	10,271,623	8,180,132	7,584,819	8,410,325	8,345,668	8,016,924	8,917,018	10,699,693	12,693,656	124,819,979	
Unmetered	7,016,814	6,758,670	6,975,016	7,045,026	6,890,697	6,570,987	6,993,330	6,965,682	6,771,769	5,874,924	6,758,975	6,412,269	81,034,159	
ATL Classes	**1,003,471,404**	**909,564,501**	**943,490,697**	**790,205,025**	**691,777,680**	**634,299,975**	**675,267,391**	**681,145,802**	**625,807,883**	**672,167,777**	**779,782,702**	**951,554,814**	**9,358,535,650**	
BTL Classes														
[redacted]														
Export kWh Sales	-	-	-	233,446	-	140,212	-	-	289,426	127,963	1,112,402	-	1,903,449	
Export kWh Losses	-	-	-	-	-	-	-	-	-	-	-	-	-	
Export kWh Req.	-	-	-	233,446	-	140,212	-	-	289,426	127,963	1,112,402	-	1,903,449	
In Province Losses	91,601,285	83,429,534	77,687,882	57,422,603	46,603,749	40,370,636	46,336,423	50,726,198	56,203,454	63,193,709	73,978,677	81,495,072	769,049,223	
NSR	**1,167,885,880**	**1,085,527,200**	**1,121,178,933**	**941,565,957**	**841,894,855**	**760,497,691**	**819,169,545**	**833,019,073**	**780,890,678**	**838,472,573**	**950,593,214**	**1,138,118,815**	**11,278,814,415**	

Winter kW Peaks	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**3CP**	**Annual Peak**
ATL Classes														
Domestic Total	1,313,879	1,226,394	1,082,899	894,756	626,684	615,961	435,416	587,779	571,320	722,233	971,857	1,342,687	3,882,961	1,313,879
Small General	66,507	46,735	49,320	29,205	40,372	34,219	52,628	41,292	31,305	29,104	41,197	41,641	154,883	66,507
General	436,463	383,923	370,794	317,063	335,712	322,265	447,680	394,999	329,712	323,980	393,414	353,173	1,173,559	436,463
Large General	58,141	52,225	53,052	48,182	52,131	48,532	72,026	69,328	62,327	46,310	52,414	47,412	157,778	58,141
Small Industrial	55,876	35,889	35,574	29,641	41,523	38,016	52,564	41,986	35,478	29,176	29,828	29,462	121,227	55,876
Medium Industrial	79,091	64,062	61,047	57,767	68,475	63,982	92,399	71,878	69,801	72,828	57,929	52,085	195,237	79,091
Large Industrial	105,146	92,617	108,650	114,357	99,569	111,029	119,882	120,458	119,898	108,598	106,789	101,006	298,769	105,146
Municipal	27,213	27,260	25,344	18,548	15,650	13,200	15,154	14,366	14,617	15,786	21,088	21,792	76,265	27,213
Unmetered	16,531	15,320	14,260	5,198	2,254	2,794	2,671	2,341	2,106	11,650	15,195	15,034	46,885	16,531
Total	**2,158,848**	**1,944,425**	**1,800,940**	**1,514,717**	**1,282,370**	**1,249,998**	**1,290,419**	**1,344,427**	**1,236,564**	**1,359,666**	**1,689,711**	**2,004,293**	**6,107,565**	**2,158,848**
BTL Classes													-	-
[redacted]														
Total	**74,877**	**65,758**	**134,985**	**136,982**	**132,261**	**135,926**	**147,462**	**139,360**	**136,309**	**137,388**	**137,348**	**73,218**	**213,853**	**74,877**
NSR Peak:	**2,233,725**	**2,010,183**	**1,935,926**	**1,651,698**	**1,414,631**	**1,385,924**	**1,437,882**	**1,483,787**	**1,372,873**	**1,497,054**	**1,827,058**	**2,077,510**	**6,321,418**	**2,233,725**

Biomass Calculations

($ in millions)	2020	
Capital	[redacted]	
Fuel		
Operating		
Total	38.6	100.0%

data came from CA IR-065P Confidential from the COSS Proceeding

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Annual Peak of ATL Classes	2,158,848
Annual Energy Requirement of ATL	10,127,375,305
System Coincident Load Factor	**53.5500%**

Rate Base		**Average**		**2013**		**2014**
Steam Plant	$	1,176,851	$	1,182,650	$	1,171,051
Steam Plant - CWIP	$	14,185	$	14,153	$	14,218
Steam Environmental & Fuel Conversion	$	179,463	$	183,964	$	174,961
Steam Enviromental & Fuel Conversion - CWIP	$	33	$	65	$	-
Hydro Plant	$	348,392	$	337,086	$	359,697
Hydro Plant - CWIP	$	18,245	$	16,478	$	20,011
Hydro Environmental & Fuel Conversion	$	4,824	$	4,888	$	4,759
Hydro Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
Wind Plant	$	12,902	$	12,703	$	13,100
Wind Plant - CWIP	$	17,697	$	3,598	$	31,795
Wind Plant - ERIS	$	90,465				
Wind Environmental & Fuel Conversion	$	80,018	$	174,537	$	166,428
Wind Enviromental & Fuel Conversion - CWIP	$	100	$	100	$	100
Gas Turbine Plant	$	5,939	$	5,586	$	6,291
Gas Turbine Plant - CWIP	$	574	$	574	$	574
Gas Environmental & Fuel Conversion	$	-	$	-	$	-
Gas Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
LM6000 Plant	$	57,894	$	58,968	$	56,819
LM6000 Plant - CWIP	$	13,523	$	5,323	$	21,723
LM6000 Environmental & Fuel Conversion	$	-	$	-	$	-
LM6000 Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
General Property Plant	$	216,887	$	222,532	$	211,241
General Property Plant - CWIP	$	17,386	$	17,270	$	17,501
Transmission Plant	$	449,439	$	440,217	$	458,661
Transmission Plant - CWIP	$	16,715	$	16,982	$	16,447
Transmission Environmental & Fuel Conversion	$	-	$	-	$	-
Transmisstion Enviromental & Fuel Conversion - CV	$	-	$	-	$	-
Distrbution Plant	$	676,641	$	662,471	$	707,406
Distribution Plant - CWIP	$	-	$	(8,339)	$	(8,260)
Distribution Environmental & Fuel Conversion	$	-	$	-	$	-
Distribution Enviromental & Fuel Conversion - CWIF	$	-	$	-	$	-
Dedicated Hydro Mersey Plant - Direct	$	-				
Dedicated LED- Direct	$	24,256	$	16,296	$	32,217

Generation Rate Base			**Initial Classification**			**Further Classification**			**Fully Classified**		
		Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$	1,370,532	$ 1,191,036	$ 179,496	$ -	$ (637,800)	$ 637,800	$ -	$ 553,236	$ 817,296	$ -
Hydro Plant	$	371,461	$ 366,637	$ 4,824	$ -	$ (196,334)	$ 196,334	$ -	$ 170,303	$ 201,158	$ -
Wind Plant	$	201,182	$ 201,182	$ -	$ -	$ (182,360)	$ 182,360	$ -	$ 18,822	$ 182,360	$ -
LM6000 Plant	$	71,417	$ 71,417	$ -	$ -	$ (38,244)	$ 38,244	$ -	$ 33,173	$ 38,244	$ -
Gas Turbine Plant - Other	$	6,513	$ 6,513	$ -	$ -	$ -	$ -	$ -	$ 6,513	$ -	$ -
Total Generation Plant	$	2,021,105	$ 1,836,785	$ 184,320	$ -	$ (1,054,738)	$ 1,054,738	$ -	$ 782,047	$ 1,239,058	$ -
General Property Plant	$	150,810.20	$ 137,057	$ 13,754	$ -	$ (78,702)	$ 78,702	$ -	$ 58,355	$ 92,456	$ -
Total Plant in Service	$	2,171,915	$ 1,973,842	$ 198,074	$ -	$ (1,133,440)	$ 1,133,440	$ -	$ 840,402	$ 1,331,513	$ -
									38.69%	**61.31%**	

BL

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

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

FOR THE YEAR ENDING DECEMBER 31, 2021

Line #	COLUMN	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q
6	FORMULA															
11		Cost Allocation Factors						Fuel-related Costs from COS								
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	KWh Energy	Relative Shares	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	98.9%	3,921,811	63.8%	4,921,124,861	48.6%	4,472,738,951	$109,295,654	$52,050,692	$1,804,731	$2,657,310	$2,220,797	$6,682,838	$42,591,072	$48,985,354	$91,576,426
17	Small General	104.6%	153,759	2.5%	312,932,013	3.1%	287,753,886	$6,728,283	$3,514,302	$112,348	$168,977	$87,069	$368,394	$2,708,346	$1,920,524	$4,628,870
18	General Demand	102.9%	1,151,739	18.7%	2,523,530,858	24.9%	2,360,702,401	$53,270,446	$29,323,895	$900,396	$1,362,657	$652,193	$2,915,246	$21,840,512	$14,385,782	$36,226,294
19	Large General	99.4%	157,622	2.6%	417,741,892	4.1%	393,602,945	$8,586,898	$5,098,292	$147,198	$225,572	$89,256	$462,026	$3,615,449	$1,968,772	$5,584,221
20	Small Industrial	102.5%	120,998	2.0%	266,052,489	2.6%	250,576,712	$5,556,979	$3,133,848	$93,788	$143,663	$68,517	$305,968	$2,302,616	$1,511,323	$3,813,939
21	Medium Industrial	98.5%	194,513	3.2%	502,833,364	5.0%	472,893,456	$10,350,136	$6,063,046	$176,346	$271,520	$110,146	$558,012	$4,351,894	$2,429,561	$6,781,455
22	Large Industrial	97.4%	320,457	5.2%	967,666,579	9.6%	923,344,819	$19,788,465	$11,781,779	$337,717	$522,521	$181,464	$1,041,703	$8,374,906	$4,002,660	$12,377,566
23	Municipal	97.7%	74,972	1.2%	129,114,632	1.3%	122,642,428	$2,827,146	$1,407,450	$47,103	$69,719	$42,454	$159,276	$1,117,454	$936,440	$2,053,894
24	Unmetered	100.0%	46,841	0.8%	89,231,008	0.9%	81,034,159	$1,839,882	$1,071,864	$31,193	$48,183	$26,524	$105,900	$772,271	$585,065	$1,357,336
25	Total	100.0%	6,142,710	100.0%	10,130,227,697	100.0%	9,365,289,756	$218,243,889	$113,445,168	$3,650,820	$5,470,122	$3,478,422	$12,599,364	$87,674,520	$76,725,480	$164,400,000
27	Puchased Power Allocation Factors.									29.0%	43.4%	27.6%	100.0%	53.3%	46.7%	100.0%
29	Non-FAM Rate Classes															
30–33	[redacted]															
34	Total Below-the-line		213,873		1,173,174,001		1,148,122,644	$65,654,536	$0	$0	$0	$0	$0	$0	$0	$0
36	In Province Total		6,356,583		11,303,401,698		10,513,412,401	$283,898,425	$113,445,168	$3,650,820	$5,470,122	$3,478,422	$12,599,364	$87,674,520	$76,725,480	$164,400,000
38	Exports	100.0%	-		2,426,048		2,426,048									
40	Grand Total		6,356,583		11,305,827,746		10,515,838,449	$283,898,425	$113,445,168	$3,650,820	$5,470,122	$3,478,422	$12,599,364	$87,674,520	$76,725,480	$164,400,000

Line #	COLUMN	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
6	FORMULA																	
11		Fuel-related Costs from COS													Fuel Costs used for FAM purposes			
12		Purchased Power other than Biomass and Wind			Purchased Power - Wind													
13					NRIS													
14	Rate Class	Fixed Energy-related	Fixed Demand-related	Total	ERIS	Energy-related	Demand-related	Total	Total	Total Fuel-related costs before Exports, OM&G and Foreign Exchange	Export Revenues	OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh
15	FAM Rate Classes (ATL)																	
16	Residential	$2,780,162	$2,323,468	$5,103,629	$18,199,346	$47,394,439	$12,757,914	$60,152,353	$78,351,699	$343,060,938	-$23,984	$0	$0	$343,036,955	$339,092,030	50.4%	$339,225,419	7.584
17	Small General	$176,789	$91,094	$267,883	$1,157,288	$3,013,790	$500,188	$3,513,978	$4,671,266	$20,178,999	-$1,791	$0	$0	$20,177,207	$21,113,430	3.1%	$21,121,735	7.340
18	General Demand	$1,425,654	$682,345	$2,107,999	$9,332,543	$24,303,657	$3,746,683	$28,050,339	$37,382,883	$161,226,763	-$16,231	$0	$0	$161,210,532	$165,917,880	24.7%	$165,983,147	7.031
19	Large General	$236,001	$93,383	$329,383	$1,544,897	$4,023,195	$512,754	$4,535,948	$6,080,845	$26,141,665	-$3,030	$0	$0	$26,138,636	$25,968,734	3.9%	$25,978,950	6.600
20	Small Industrial	$150,305	$71,685	$221,990	$983,918	$2,562,302	$393,614	$2,955,916	$3,939,834	$16,972,558	-$1,736	$0	$0	$16,970,822	$17,388,304	2.6%	$17,395,144	6.942
21	Medium Industrial	$284,073	$115,239	$399,312	$1,859,583	$4,842,695	$632,763	$5,475,458	$7,335,041	$31,487,001	-$3,585	$0	$0	$31,483,416	$30,998,572	4.6%	$31,010,766	6.558
22	Large Industrial	$546,678	$189,854	$736,531	$3,578,633	$9,319,417	$1,042,466	$10,361,883	$13,940,516	$59,666,559	-$7,005	$0	$0	$59,659,555	$58,132,270	8.6%	$58,155,138	6.298
23	Municipal	$72,943	$44,417	$117,360	$477,493	$1,243,479	$243,890	$1,487,369	$1,964,861	$8,529,987	-$726	$0	$0	$8,529,261	$8,330,529	1.2%	$8,333,806	6.795
24	Unmetered	$50,411	$27,751	$78,161	$329,995	$859,367	$152,376	$1,011,743	$1,341,738	$5,794,881	-$632	$0	$0	$5,794,249	$5,794,249	0.9%	$5,796,528	7.153
25	Total	$5,723,015	$3,639,234	$9,362,249	$37,463,695	$97,562,340	$19,982,648	$117,544,988	$155,008,683	$673,059,352	-$58,719	$0	$0	$673,000,633	$672,735,998	100.0%	$673,000,633	7.186
27	Puchased Power Allocation Factors.	61.1%	38.9%	100.0%	55.1%	83.0%	17.0%	100.0%										
29	Non-FAM Rate Classes																	
30–33	[redacted]																	
34	Total Below-the-line	$0	$0	$0	$0	$0	$0	$0	$0	$65,654,536	$0	$0		$65,654,536			$65,654,536	5.718
36	In Province Total	$5,723,015	$3,639,234	$9,362,249	$37,463,695	$97,562,340	$19,982,648	$117,544,988	$155,008,683	$738,713,888	-$58,719	$0	$0	$738,655,169			$738,655,169	7.026
38	Exports																	
40	Grand Total	$5,723,015	$3,639,234	$9,362,249	$37,463,695	$97,562,340	$19,982,648	$117,544,988	$155,008,683	$738,713,888	-$58,719	$0	$0	$738,655,169			$738,655,169	7.024

Monthly Fuel Cost Allocation

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Purchased Power													
Imports	$1,938,452	$6,332,397	$7,908,919	$12,074,693	$9,081,828	$10,789,813	$14,946,358	$12,563,125	$11,167,309	$10,895,143	$7,761,178	$7,985,953	**$113,445,168**
Biomass													
IPP	$1,357,604	$1,090,670	$1,240,632	$1,141,387	$803,525	$784,631	$1,057,125	$1,037,893	$749,536	$825,264	$1,158,434	$1,352,663	**$12,599,364**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$1,357,604**	**$1,090,670**	**$1,240,632**	**$1,141,387**	**$803,525**	**$784,631**	**$1,057,125**	**$1,037,893**	**$749,536**	**$825,264**	**$1,158,434**	**$1,352,663**	**$12,599,364**
Maritime Link													
ML - NS Block (GWh)	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$164,400,000
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$13,700,000**	**$164,400,000**
Regular other than biomass and wind													
IPP	$103,642	$114,217	$136,160	$122,607	$131,937	$127,040	$132,411	$136,393	$122,739	$108,742	$88,232	$88,550	**$1,412,670**
Comfit	$643,715	$669,468	$671,519	$662,821	$629,230	$647,575	$696,259	$698,901	$641,230	$654,924	$670,078	$663,859	**$7,949,579**
Total	**$747,356**	**$783,685**	**$807,679**	**$785,428**	**$761,168**	**$774,615**	**$828,670**	**$835,294**	**$763,969**	**$763,666**	**$758,310**	**$752,408**	**$9,362,249**
Wind NRIS													
IPP	$4,751,967	$4,266,026	$5,040,381	$3,923,829	$3,454,549	$3,428,812	$2,554,236	$2,600,935	$3,048,989	$4,107,766	$4,504,262	$4,347,737	**$46,029,489**
Comfit	$7,101,477	$6,259,120	$7,648,993	$6,244,030	$5,896,764	$5,206,379	$4,430,823	$4,102,972	$5,021,033	$6,383,609	$6,588,549	$6,631,749	**$71,515,499**
Total	**$11,853,444**	**$10,525,146**	**$12,689,374**	**$10,167,859**	**$9,351,313**	**$8,635,191**	**$6,985,059**	**$6,703,907**	**$8,070,022**	**$10,491,375**	**$11,092,812**	**$10,979,486**	**$117,544,988**
Wind ERIS													
IPP	$3,729,059	$3,394,344	$3,717,190	$3,084,824	$3,021,159	$2,846,040	$2,119,709	$2,145,435	$2,578,093	$3,454,350	$3,622,635	$3,750,857	**$37,463,695**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$3,729,059**	**$3,394,344**	**$3,717,190**	**$3,084,824**	**$3,021,159**	**$2,846,040**	**$2,119,709**	**$2,145,435**	**$2,578,093**	**$3,454,350**	**$3,622,635**	**$3,750,857**	**$37,463,695**
Grand Total	**$19,625,916**	**$22,126,242**	**$26,363,794**	**$27,254,191**	**$23,018,992**	**$23,830,291**	**$25,936,921**	**$23,285,655**	**$23,328,929**	**$26,429,797**	**$24,393,369**	**$24,821,367**	**$290,415,463**
Plant Fuel Costs													
Plant Fuel Costs	$39,776,745	$35,435,856	$32,646,271	$18,700,810	$16,334,266	$12,355,282	$16,091,384	$20,194,074	$16,425,366	$16,541,329	$24,712,809	$34,684,233	**$283,898,425**
BTL Class Fuel-related costs													
[redacted]													
Total	$4,968,811	$8,500,225	$7,369,012	$4,704,964	$4,689,064	$4,707,862	$5,513,498	$5,461,029	$4,717,900	$4,354,555	$5,093,971	$5,573,644	**$65,654,536**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
ATL-related Fuel costs (net of BTL)	$34,807,934	$26,935,631	$25,277,258	$13,995,846	$11,645,202	$7,647,420	$10,577,886	$14,733,045	$11,707,465	$12,186,774	$19,618,838	$29,110,589	**$218,243,889**
Fuel costs before PP													
Domestic	$19,384,269	$14,821,575	$13,568,883	$7,041,380	$5,379,962	$3,139,597	$4,238,110	$5,994,068	$4,722,972	$5,271,478	$9,599,002	$16,134,358	$109,295,654
Small General	$1,089,485	$857,277	$777,172	$429,588	$373,711	$238,312	$342,041	$460,946	$356,866	$369,860	$577,869	$855,156	$6,728,283
General	$7,786,930	$6,105,768	$5,936,296	$3,341,582	$2,891,852	$2,117,698	$2,986,788	$4,071,577	$3,254,123	$3,273,268	$4,888,254	$6,616,308	$53,270,446
Large General	$1,139,881	$870,470	$861,519	$552,500	$510,379	$368,138	$572,865	$824,202	$618,508	$566,938	$747,562	$953,937	$8,586,898
Small Industrial	$791,525	$619,401	$572,886	$347,124	$333,952	$250,510	$341,886	$419,144	$349,414	$314,120	$520,030	$696,988	$5,556,979
Medium Industrial	$1,345,789	$1,090,431	$1,046,256	$660,945	$620,132	$477,784	$644,952	$851,330	$720,695	$704,963	$1,002,473	$1,184,386	$10,350,136
Large Industrial	$2,534,135	$1,990,835	$1,989,412	$1,322,108	$1,285,000	$885,637	$1,210,941	$1,782,417	$1,410,269	$1,422,636	$1,854,105	$2,100,970	$19,788,465
Municipal	$489,780	$378,120	$336,524	$174,198	$131,616	$88,057	$127,051	$174,429	$144,940	$155,750	$256,810	$369,870	$2,827,146
Unmetered	$246,139	$201,753	$188,310	$126,420	$118,598	$81,688	$113,253	$154,933	$129,678	$107,762	$172,732	$198,616	$1,839,882
Total	**$34,807,934**	**$26,935,631**	**$25,277,258**	**$13,995,846**	**$11,645,202**	**$7,647,420**	**$10,577,886**	**$14,733,045**	**$11,707,465**	**$12,186,774**	**$19,618,838**	**$29,110,589**	**$218,243,889**
Exports													
Domestic	$0	$0	$0	$0	$0	$1,751	$0	$0	$19,111	$2,737	$248	$136	$23,984
Small General	$0	$0	$0	$0	$0	$133	$0	$0	$1,444	$192	$15	$7	$1,791
General	$0	$0	$0	$0	$0	$1,181	$0	$0	$13,168	$1,700	$126	$56	$16,231
Large General	$0	$0	$0	$0	$0	$205	$0	$0	$2,503	$294	$19	$8	$3,030
Small Industrial	$0	$0	$0	$0	$0	$140	$0	$0	$1,414	$163	$13	$6	$1,736
Medium Industrial	$0	$0	$0	$0	$0	$266	$0	$0	$2,916	$366	$26	$10	$3,585
Large Industrial	$0	$0	$0	$0	$0	$494	$0	$0	$5,707	$739	$48	$18	$7,005
Municipal	$0	$0	$0	$0	$0	$49	$0	$0	$586	$81	$7	$3	$726
Unmetered	$0	$0	$0	$0	$0	$46	$0	$0	$525	$56	$4	$2	$632
Total	$0	$0	$0	$0	$0	$4,266	$0	$0	$47,374	$6,328	$507	$246	$58,719
Imports													
Domestic	$1,079,509	$3,484,459	$4,245,523	$6,074,839	$4,195,710	$4,429,686	$5,988,371	$5,111,246	$4,505,064	$4,712,773	$3,797,348	$4,426,163	$52,050,692
Small General	$60,673	$201,540	$243,167	$370,620	$291,448	$336,236	$483,297	$393,057	$340,401	$330,660	$228,604	$234,596	$3,514,302
General	$433,654	$1,435,428	$1,857,388	$2,882,897	$2,255,289	$2,987,879	$4,220,277	$3,471,905	$3,103,985	$2,926,347	$1,933,785	$1,815,062	$29,323,895
Large General	$63,480	$204,642	$269,558	$476,661	$398,033	$519,409	$809,447	$702,811	$589,971	$506,850	$295,734	$261,695	$5,098,292
Small Industrial	$44,080	$145,617	$179,248	$299,476	$260,442	$353,446	$483,078	$357,412	$333,292	$280,827	$205,723	$191,206	$3,133,848
Medium Industrial	$74,947	$256,354	$327,360	$570,220	$483,627	$674,109	$911,305	$725,944	$687,444	$630,246	$396,577	$324,914	$6,063,046
Large Industrial	$141,126	$468,033	$622,461	$1,140,628	$1,002,143	$1,249,553	$1,711,037	$1,519,898	$1,345,202	$1,271,856	$733,481	$576,362	$11,781,779
Municipal	$27,276	$88,894	$105,294	$150,286	$102,645	$124,240	$179,521	$148,738	$138,253	$139,243	$101,594	$101,467	$1,407,450
Unmetered	$13,707	$47,431	$58,920	$109,067	$92,492	$115,255	$160,024	$132,114	$123,695	$96,340	$68,332	$54,487	$1,071,864
Total	$1,938,452	$6,332,397	$7,908,919	$12,074,693	$9,081,828	$10,789,813	$14,946,358	$12,563,125	$11,167,309	$10,895,143	$7,761,178	$7,985,953	$113,445,168
Purchased Biomass Generation	11,818	8,520	9,641	8,315	1,863	1,842	7,451	7,218	4,630	6,484	9,128	11,913	88,822
Relative Share	13.3%	9.6%	10.9%	9.4%	2.1%	2.1%	8.4%	8.1%	5.2%	7.3%	10.3%	13.4%	100.0%
Bio-fuel Apportioned	$485,754	$350,194	$396,275	$341,780	$76,558	$75,706	$306,261	$296,684	$190,287	$266,499	$375,165	$489,658	$3,650,820
Domestic	$270,513	$192,698	$212,721	$171,951	$35,369	$31,081	$122,706	$120,704	$76,765	$115,276	$183,559	$271,390	$1,804,731
Small General	$15,204	$11,146	$12,184	$10,491	$2,457	$2,359	$9,903	$9,282	$5,800	$8,088	$11,050	$14,384	$112,348
General	$108,669	$79,382	$93,064	$81,602	$19,012	$20,964	$86,476	$81,991	$52,891	$71,579	$93,477	$111,290	$900,396
Large General	$15,907	$11,317	$13,506	$13,492	$3,355	$3,644	$16,586	$16,597	$10,053	$12,398	$14,295	$16,046	$147,198
Small Industrial	$11,046	$8,053	$8,981	$8,477	$2,195	$2,480	$9,899	$8,440	$5,679	$6,869	$9,944	$11,724	$93,788
Medium Industrial	$18,781	$14,177	$16,402	$16,140	$4,077	$4,730	$18,673	$17,143	$11,714	$15,416	$19,170	$19,922	$176,346
Large Industrial	$35,365	$25,883	$31,188	$32,286	$8,448	$8,767	$35,060	$35,893	$22,922	$31,110	$35,455	$35,340	$337,717
Municipal	$6,835	$4,916	$5,276	$4,254	$865	$872	$3,679	$3,513	$2,356	$3,406	$4,911	$6,221	$47,103
Unmetered	$3,435	$2,623	$2,952	$3,087	$780	$809	$3,279	$3,120	$2,108	$2,357	$3,303	$3,341	$31,193
Total	**$485,754**	**$350,194**	**$396,275**	**$341,780**	**$76,558**	**$75,706**	**$306,261**	**$296,684**	**$190,287**	**$266,499**	**$375,165**	**$489,658**	**$3,650,820**

Monthly Energy Allocators

Rate Class	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
kWh requirements													
ATL													
Domestic Total	609,970,692	547,065,799	548,923,240	427,056,256	342,146,744	277,566,915	288,929,642	297,501,821	274,093,821	317,392,336	417,213,013	573,264,581	4,921,124,861
Small General	34,283,142	31,642,186	31,440,173	26,054,313	23,766,689	21,068,772	23,318,352	22,877,995	20,710,439	22,269,064	25,116,612	30,384,276	312,932,013
General	245,033,712	225,364,488	240,150,276	202,665,339	183,911,650	187,222,411	203,621,824	202,083,388	188,850,374	197,081,423	212,464,097	235,081,875	2,523,530,858
Large General	35,868,983	32,129,146	34,852,360	33,508,868	32,458,312	32,546,503	39,054,580	40,907,372	35,894,585	34,134,977	32,492,188	33,894,020	417,741,892
Small Industrial	24,907,170	22,862,161	23,175,852	21,052,905	21,238,190	22,147,158	23,307,789	20,803,267	20,277,931	18,912,938	22,602,688	24,764,440	266,052,489
Medium Industrial	42,348,359	40,247,930	42,325,829	40,085,999	39,438,218	42,240,130	43,969,073	42,253,790	41,824,968	42,445,353	43,571,692	42,082,023	502,833,364
Large Industrial	79,742,408	73,481,906	80,480,786	80,185,201	81,721,528	78,297,776	82,554,872	88,466,193	81,843,821	85,655,995	80,587,218	74,648,875	967,666,579
Municipal	15,412,048	13,956,450	13,613,950	10,565,019	8,370,344	7,784,949	8,661,604	8,657,371	8,411,481	9,377,637	11,162,064	13,141,713	129,114,632
Unmetered	7,745,334	7,446,738	7,618,003	7,667,296	7,542,398	7,221,951	7,720,903	7,689,741	7,525,775	6,488,253	7,507,661	7,056,957	89,231,008
Total	1,095,311,847	994,196,804	1,022,580,469	848,841,195	740,594,073	676,096,564	721,138,639	731,240,937	679,433,197	733,757,976	852,717,234	1,034,318,760	10,130,227,697
Fuel Cost Allocators													
ATL													
Domestic	55.69%	55.03%	53.68%	50.31%	46.20%	41.05%	40.07%	40.68%	40.34%	43.26%	48.93%	55.42%	48.58%
Small General	3.13%	3.18%	3.07%	3.07%	3.21%	3.12%	3.23%	3.13%	3.05%	3.03%	2.95%	2.94%	3.09%
General	22.37%	22.67%	23.48%	23.88%	24.83%	27.69%	28.24%	27.64%	27.80%	26.86%	24.92%	22.73%	24.91%
Large General	3.27%	3.23%	3.41%	3.95%	4.38%	4.81%	5.42%	5.59%	5.28%	4.65%	3.81%	3.28%	4.12%
Small Industrial	2.27%	2.30%	2.27%	2.48%	2.87%	3.28%	3.23%	2.84%	2.98%	2.58%	2.65%	2.39%	2.63%
Medium Industrial	3.87%	4.05%	4.14%	4.72%	5.33%	6.25%	6.10%	5.78%	6.16%	5.78%	5.11%	4.07%	4.96%
Large Industrial	7.28%	7.39%	7.87%	9.45%	11.03%	11.58%	11.45%	12.10%	12.05%	11.67%	9.45%	7.22%	9.55%
Municipal	1.41%	1.40%	1.33%	1.24%	1.13%	1.15%	1.20%	1.18%	1.24%	1.28%	1.31%	1.27%	1.27%
Unmetered	0.71%	0.75%	0.74%	0.90%	1.02%	1.07%	1.07%	1.05%	1.11%	0.88%	0.88%	0.68%	0.88%
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%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Data Inputs

Category	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Annual	
Plant Fuel Costs	$39,776,745	$35,435,856	$32,646,271	$18,700,810	$16,334,266	$12,355,282	$16,091,384	$20,194,074	$16,425,366	$16,541,329	$24,712,809	$34,684,233	$283,898,425	
Maritime Link														
ML - NS Block	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$164,400,000	
ML - Supp Block														
ML - Surplus														
Total	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$13,700,000	$164,400,000	
Non-Wind Purchases														
Purchased Power Regular bfr Biomass	$103,642	$114,217	$136,160	$122,607	$131,937	$127,040	$132,411	$136,393	$122,739	$108,742	$88,232	$88,550	$1,412,670	
Purchased Power - Biomass	$1,357,604	$1,090,670	$1,240,632	$1,141,387	$803,525	$784,631	$1,057,125	$1,037,893	$749,536	$825,264	$1,158,434	$1,352,663	$12,599,364	
Non-Wind Purchases	$1,461,246	$1,204,887	$1,376,792	$1,263,994	$935,462	$911,671	$1,189,536	$1,174,287	$872,275	$934,006	$1,246,666	$1,441,213	$14,012,034	
Wind Purchases														
Purchased Power Wind - NRIS	$4,751,967	$4,266,026	$5,040,381	$3,923,829	$3,454,549	$3,428,812	$2,554,236	$2,600,935	$3,048,989	$4,107,766	$4,504,262	$4,347,737	$46,029,489	55%
Purchased Power Wind - ERIS	$3,729,059	$3,394,344	$3,717,190	$3,084,824	$3,021,159	$2,846,040	$2,119,709	$2,145,435	$2,578,093	$3,454,350	$3,622,635	$3,750,857	$37,463,695	45%
Purchased Power Wind	$8,481,026	$7,660,370	$8,757,571	$7,008,653	$6,475,708	$6,274,852	$4,673,944	$4,746,370	$5,627,082	$7,562,116	$8,126,897	$8,098,595	$83,493,184	100%
Comift														
Wind Generatiion (NRIS)	$7,101,477	$6,259,120	$7,648,993	$6,244,030	$5,896,764	$5,206,379	$4,430,823	$4,102,972	$5,021,033	$6,383,609	$6,588,549	$6,631,749	$71,515,499	
Wind Generatiion (ERIS)													$0	
Biomass Generation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Other	$643,715	$669,468	$671,519	$662,821	$629,230	$647,575	$696,259	$698,901	$641,230	$654,924	$670,078	$663,859	$7,949,579	
Total Comfit	$7,745,192	$6,928,588	$8,320,512	$6,906,851	$6,525,994	$5,853,955	$5,127,082	$4,801,873	$5,662,263	$7,038,533	$7,258,628	$7,295,608	$79,465,078	
Imports	$1,938,452	$6,332,397	$7,908,919	$12,074,693	$9,081,828	$10,789,813	$14,946,358	$12,563,125	$11,167,309	$10,895,143	$7,761,178	$7,985,953	$113,445,168	
Export Revenues	$0	$0	$0	$0	$0	$4,266	$0	$0	$47,374	$6,328	$507	$246	$ 58,719.45	
OM&G (Solid Fuel Handling) recovered in fuels													$0	
Foreign Exchange (Fuel-related)													$0	
Total FAM related costs	**$73,102,661**	**$71,262,098**	**$72,710,065**	**$59,655,001**	**$53,053,258**	**$49,885,573**	**$55,728,305**	**$57,179,729**	**$53,454,295**	**$56,671,126**	**$62,806,178**	**$73,205,601**	**$738,713,888**	
Purchased Biomass Generation	11,818	8,520	9,641	8,315	1,863	1,842	7,451	7,218	4,630	6,484	9,128	11,913	88,822	
BLT Fuel Costs	**Source-Revenue Forecast**													
[redacted]														
Total	**$4,968,811**	**$8,500,225**	**$7,369,012**	**$4,704,964**	**$4,689,064**	**$4,707,862**	**$5,513,498**	**$5,461,029**	**$4,717,900**	**$4,354,555**	**$5,093,971**	**$5,573,644**	**$65,654,536**	
ERIS	**$4,751,967**	**$4,266,026**	**$5,040,381**	**$3,923,829**	**$3,454,549**	**$3,428,812**	**$2,554,236**	**$2,600,935**	**$3,048,989**	**$4,107,766**	**$4,504,262**	**$4,347,737**	**$46,029,489**	55%
NRIS	**$3,729,059**	**$3,394,344**	**$3,717,190**	**$3,084,824**	**$3,021,159**	**$2,846,040**	**$2,119,709**	**$2,145,435**	**$2,578,093**	**$3,454,350**	**$3,622,635**	**$3,750,857**	**$37,463,695**	45%
Total	**$8,481,026**	**$7,660,370**	**$8,757,571**	**$7,008,653**	**$6,475,708**	**$6,274,852**	**$4,673,944**	**$4,746,370**	**$5,627,082**	**$7,562,116**	**$8,126,897**	**$8,098,595**	**$83,493,184**	100.00%

Usage Data

kWh Requirements														
ATL Classes														
Domestic Total	609,970,692	547,065,799	548,923,240	427,056,256	342,146,744	277,566,915	288,929,642	297,501,821	274,093,821	317,392,336	417,213,013	573,264,581	4,921,124,861	4,995,329,980
Small General	34,283,142	31,642,186	31,440,173	26,054,313	23,766,689	21,068,772	23,318,352	22,877,995	20,710,439	22,269,064	25,116,612	30,384,276	312,932,013	283,848,228
General	245,033,712	225,364,488	240,150,276	202,665,339	183,911,650	187,222,411	203,621,824	202,083,388	188,850,374	197,081,423	212,464,097	235,081,875	2,523,530,858	2,553,756,467
Large General	35,868,983	32,129,146	34,852,360	33,508,868	32,458,312	32,546,503	39,054,580	40,907,372	35,894,585	34,134,977	32,492,188	33,894,020	417,741,892	434,465,234
Small Industrial	24,907,170	22,862,161	23,175,852	21,052,905	21,238,190	22,147,158	23,307,789	20,803,267	20,277,931	18,912,938	22,602,688	24,764,440	266,052,489	270,624,393
Medium Industrial	42,348,359	40,247,930	42,325,829	40,085,999	39,438,218	42,240,130	43,969,073	42,253,790	41,824,968	42,445,353	43,571,692	42,082,023	502,833,364	508,059,441
Large Industrial- FIRM	11,658,855	9,138,385	12,075,008	11,729,572	11,130,253	10,848,530	11,470,776	11,933,294	10,890,702	11,534,587	10,717,317	12,252,123	135,379,402	
Large Industrial- INT	68,083,553	64,343,521	68,405,778	68,455,628	70,591,275	67,449,245	71,084,096	76,532,899	70,953,120	74,121,408	69,869,900	62,396,752	832,287,177	
Large Industrial	79,742,408	73,481,906	80,480,786	80,185,201	81,721,528	78,297,776	82,554,872	88,466,193	81,843,821	85,655,995	80,587,218	74,648,875	967,666,579	828,615,963
Municipal	15,412,048	13,956,450	13,613,950	10,565,019	8,370,344	7,784,949	8,661,604	8,657,371	8,411,481	9,377,637	11,162,064	13,141,713	129,114,632	181,012,677
Unmetered	7,745,334	7,446,738	7,618,003	7,667,296	7,542,398	7,221,951	7,720,903	7,689,741	7,525,775	6,488,253	7,507,661	7,056,957	89,231,008	109,935,737
[redacted]														[redacted]
In-Province Total	**1,169,770,102**	**1,088,604,800**	**1,124,224,800**	**943,914,899**	**844,902,003**	**763,123,899**	**820,900,800**	**834,453,898**	**782,028,700**	**840,493,300**	**950,645,298**	**1,140,339,199**	**12,271,068,277**	**11,281,098,342**
kWh Sales														
ATL Classes														
Domestic Total	546,919,758	490,435,752	499,092,684	392,656,068	315,393,091	257,960,993	267,804,860	273,944,716	249,725,927	286,464,364	374,926,778	517,413,960	4,472,738,951	
Small General	31,238,992	28,811,488	28,880,773	24,065,970	22,032,641	19,721,211	21,674,703	21,085,095	18,920,334	20,431,967	22,850,081	28,040,633	287,753,886	
General	229,193,804	210,918,441	224,584,096	191,024,913	173,881,695	176,787,992	191,182,937	188,993,623	174,735,130	182,167,759	197,019,692	220,212,319	2,360,702,401	
Large General	33,634,741	30,252,231	32,862,869	31,716,221	30,962,098	31,121,260	36,779,245	38,497,630	33,584,186	31,806,341	30,309,488	32,076,635	393,602,945	
Small Industrial	23,516,939	21,516,075	21,817,518	19,899,553	20,177,193	21,068,050	22,141,133	19,608,529	18,898,159	17,556,831	21,024,965	23,351,768	250,576,712	
Medium Industrial	40,004,895	37,945,120	39,865,707	37,867,849	37,274,964	40,070,087	41,651,526	39,719,212	38,837,292	39,342,035	40,573,395	39,741,374	472,893,456	
Large Industrial- FIRM	11,070,968	8,664,750	11,473,209	11,161,126	10,591,328	10,379,196	10,888,081	11,279,204	10,126,977	10,703,042	9,999,333	11,599,431	127,936,644	
Large Industrial- INT	65,545,833	61,687,331	65,742,586	65,700,408	68,073,386	64,702,089	68,041,067	72,811,052	66,664,441	69,749,804	66,348,540	60,341,639	795,408,175	
Large Industrial	76,616,800	70,352,081	77,215,794	76,861,534	78,664,714	75,081,285	78,929,147	84,090,256	76,791,418	80,452,846	76,347,873	71,941,070	923,344,819	
Municipal	14,678,275	13,328,081	12,966,285	10,092,429	8,037,426	7,452,498	8,263,602	8,200,073	7,877,064	8,761,455	10,513,031	12,472,208	122,642,428	
Unmetered	7,016,814	6,758,670	6,975,016	7,045,026	6,890,697	6,570,987	6,993,330	6,965,682	6,771,769	5,874,924	6,758,975	6,412,269	81,034,159	
ATL Classes	**1,002,821,018**	**910,317,940**	**944,260,741**	**791,229,562**	**693,314,519**	**635,834,363**	**675,420,484**	**681,104,816**	**626,141,278**	**672,858,522**	**780,324,277**	**951,662,236**	**9,365,289,756**	
BTL Classes														
[redacted]														
Export kWh Sales	-	-	-	-	-	-	-	-	-	-	-	-	-	
Export kWh Losses	-	-	-	-	-	210,922	-	-	1,931,887	257,890	20,007	5,342	2,426,048	
Export kWh Req.	-	-	-	-	-	-	-	-	-	-	-	-	-	
In Province Losses	-	-	-	-	-	210,922	-	-	1,931,887	257,890	20,007	5,342	2,426,048	
NSR	**1,075,634,208**	**1,002,851,106**	**1,044,261,095**	**884,725,999**	**796,890,445**	**721,845,364**	**773,116,215**	**782,369,389**	**728,443,042**	**776,414,462**	**874,971,322**	**1,056,741,850**	**10,518,264,498**	

Winter kW Peaks	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**3CP**	**Annual Peak**
ATL Classes														
Domestic Total	1,325,593	1,243,008	1,093,992	897,688	627,164	613,963	435,048	585,811	567,762	721,078	977,262	1,353,210	3,921,811	1,325,593
Small General	66,193	46,454	48,924	28,832	40,390	34,225	52,918	41,407	31,342	28,982	40,987	41,111	153,759	66,193
General	428,390	378,027	363,478	311,365	331,301	317,665	442,914	390,501	325,628	319,050	386,856	345,322	1,151,739	428,390
Large General	58,099	52,208	53,015	48,205	52,287	48,635	72,240	69,474	62,544	46,378	52,474	47,315	157,622	58,099
Small Industrial	55,831	35,909	35,463	29,556	41,609	38,018	52,714	42,093	35,529	29,115	29,708	29,258	120,998	55,831
Medium Industrial	78,771	64,032	60,779	57,561	68,422	63,799	92,357	71,851	69,740	72,598	57,680	51,710	194,513	78,771
Large Industrial	112,160	99,914	117,742	123,656	107,627	120,234	127,904	127,918	127,956	115,649	113,864	108,382	320,457	112,160
Municipal	26,762	26,827	24,928	18,202	15,348	12,920	14,853	14,060	14,330	15,493	20,711	21,383	74,972	26,762
Unmetered	16,498	15,359	14,242	5,193	2,256	2,789	2,671	2,343	2,106	11,624	15,175	14,984	46,841	16,498
Total	**2,168,298**	**1,961,738**	**1,812,564**	**1,520,258**	**1,286,403**	**1,252,248**	**1,293,619**	**1,345,459**	**1,236,938**	**1,359,966**	**1,694,719**	**2,012,674**	**6,142,710**	**2,168,298**
BTL Classes													-	-
[redacted]														
Total	**74,859**	**65,799**	**135,061**	**137,027**	**132,348**	**135,814**	**147,366**	**139,295**	**136,258**	**137,289**	**137,401**	**73,214**	**213,873**	**74,859**
NSR Peak:	**2,243,157**	**2,027,537**	**1,947,624**	**1,657,285**	**1,418,751**	**1,388,062**	**1,440,985**	**1,484,754**	**1,373,196**	**1,497,255**	**1,832,120**	**2,085,888**	**6,356,583**	**2,243,157**

Biomass Calculations

($ in millions)	2021	
Capital	[redacted]	
Fuel		
Operating		
Total	36.9	100.0%

data came from CA IR-065P Confidential from the COSS Proceeding

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Annual Peak of ATL Classes	2,168,298
Annual Energy Requirement of ATL	10,130,227,697
System Coincident Load Factor	**53.3300%**

Rate Base		**Average**		**2013**		**2014**
Steam Plant	$	1,176,851	$	1,182,650	$	1,171,051
Steam Plant - CWIP	$	14,185	$	14,153	$	14,218
Steam Environmental & Fuel Conversion	$	179,463	$	183,964	$	174,961
Steam Enviromental & Fuel Conversion - CWIP	$	33	$	65	$	-
Hydro Plant	$	348,392	$	337,086	$	359,697
Hydro Plant - CWIP	$	18,245	$	16,478	$	20,011
Hydro Environmental & Fuel Conversion	$	4,824	$	4,888	$	4,759
Hydro Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
Wind Plant	$	12,902	$	12,703	$	13,100
Wind Plant - CWIP	$	17,697	$	3,598	$	31,795
Wind Plant - ERIS	$	90,465				
Wind Environmental & Fuel Conversion	$	80,018	$	174,537	$	166,428
Wind Enviromental & Fuel Conversion - CWIP	$	100	$	100	$	100
Gas Turbine Plant	$	5,939	$	5,586	$	6,291
Gas Turbine Plant - CWIP	$	574	$	574	$	574
Gas Environmental & Fuel Conversion	$	-	$	-	$	-
Gas Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
LM6000 Plant	$	57,894	$	58,968	$	56,819
LM6000 Plant - CWIP	$	13,523	$	5,323	$	21,723
LM6000 Environmental & Fuel Conversion	$	-	$	-	$	-
LM6000 Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
General Property Plant	$	216,887	$	222,532	$	211,241
General Property Plant - CWIP	$	17,386	$	17,270	$	17,501
Transmission Plant	$	449,439	$	440,217	$	458,661
Transmission Plant - CWIP	$	16,715	$	16,982	$	16,447
Transmission Environmental & Fuel Conversion	$	-	$	-	$	-
Transmisstion Enviromental & Fuel Conversion - CV	$	-	$	-	$	-
Distrbution Plant	$	676,641	$	662,471	$	707,406
Distribution Plant - CWIP	$	-	$	(8,339)	$	(8,260)
Distribution Environmental & Fuel Conversion	$	-	$	-	$	-
Distribution Enviromental & Fuel Conversion - CWIF	$	-	$	-	$	-
Dedicated Hydro Mersey Plant - Direct	$	-				
Dedicated LED- Direct	$	24,256	$	16,296	$	32,217

Generation Rate Base			**Initial Classification**			**Further Classification**			**Fully Classified**		
		Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$	1,370,532	$ 1,191,036	$ 179,496	$ -	$ (635,179)	$ 635,179	$ -	$ 555,857	$ 814,675	$ -
Hydro Plant	$	371,461	$ 366,637	$ 4,824	$ -	$ (195,528)	$ 195,528	$ -	$ 171,109	$ 200,352	$ -
Wind Plant	$	201,182	$ 201,182	$ -	$ -	$ (182,360)	$ 182,360	$ -	$ 18,822	$ 182,360	$ -
LM6000 Plant	$	71,417	$ 71,417	$ -	$ -	$ (38,087)	$ 38,087	$ -	$ 33,330	$ 38,087	$ -
Gas Turbine Plant - Other	$	6,513	$ 6,513	$ -	$ -	$ -	$ -	$ -	$ 6,513	$ -	$ -
Total Generation Plant	$	2,021,105	$ 1,836,785	$ 184,320	$ -	$ (1,051,154)	$ 1,051,154	$ -	$ 785,631	$ 1,235,474	$ -
General Property Plant	$	150,810.20	$ 137,057	$ 13,754	$ -	$ (78,435)	$ 78,435	$ -	$ 58,622	$ 92,188	$ -
Total Plant in Service	$	2,171,915	$ 1,973,842	$ 198,074	$ -	$ (1,129,588)	$ 1,129,588	$ -	$ 844,253	$ 1,327,662	$ -
									38.87%	**61.13%**	

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

FOR THE YEAR ENDING DECEMBER 31, 2022

Line #	COLUMN	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V	W	X	Y	Z	AA	AB	AC	AD	AE	AF	AG	AH
6	FORMULA																																
11		Cost Allocation Factors						Fuel-related Costs from COS																						Fuel Costs used for FAM purposes			
12			3 CP Demands		Energy Requirement					Purchased Power- Biomass				Maritime Link			Purchased Power other than Biomass and Wind			Purchased Power - Wind													
13														Basic and Supplemental Blocks							NRIS												
14	Rate Class	R/C Ratios	KW Demand	Relative Shares	KWh Energy	Relative Shares	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	Fixed Energy-related	Fixed Demand-related	Total	ERIS	Energy-related	Demand-related	Total	Total	Total Fuel-related costs before Exports, OM&G and Foreign Exchange	Export Revenues	OM&G costs recovered in fuels	Foreign Exchange	Total Fuel-related costs	Adjusted for R/C ratio and Unbalanced	Relative Share	Adjusted for R/C ratio and Balanced	cents per kWh
15	FAM Rate Classes (ATL)																																
16	Residential	98.9%	3,964,438	64.4%	4,929,733,629	48.8%	4,479,070,552	$112,738,147	$48,106,169	$1,700,428	$2,807,394	$2,377,818	$6,885,641	$41,927,266	$48,947,897	$90,875,163	$2,783,829	$2,357,858	$5,141,687	$18,278,032	$47,806,856	$12,932,170	$60,739,026	$79,017,058	$342,763,865	-$16,629	$0	$0	$342,747,235	$338,805,642	50.6%	$338,965,052	7.568
17	Small General	104.6%	151,851	2.5%	313,926,474	3.1%	288,574,314	$7,006,734	$3,251,571	$106,142	$178,775	$91,078	$375,995	$2,669,937	$1,874,862	$4,544,800	$177,275	$90,314	$267,588	$1,163,949	$3,044,351	$495,344	$3,539,695	$4,703,643	$20,150,332	-$1,188	$0	$0	$20,149,144	$21,084,064	3.1%	$21,093,984	7.310
18	General Demand	102.9%	1,127,284	18.3%	2,496,968,040	24.7%	2,335,055,289	$54,887,024	$26,852,306	$840,658	$1,421,978	$676,130	$2,938,767	$21,236,653	$13,918,290	$35,154,943	$1,410,042	$670,455	$2,080,497	$9,258,038	$24,214,734	$3,677,251	$27,891,985	$37,150,023	$159,063,560	-$10,419	$0	$0	$159,053,142	$163,697,493	24.4%	$163,774,514	7.014
19	Large General	99.4%	156,014	2.5%	414,899,805	4.1%	390,786,659	$8,942,658	$4,689,178	$138,184	$236,278	$93,575	$468,037	$3,528,713	$1,926,262	$5,454,975	$234,295	$92,790	$327,084	$1,538,329	$4,023,555	$508,924	$4,532,479	$6,070,808	$25,952,740	-$1,900	$0	$0	$25,950,840	$25,782,160	3.9%	$25,794,291	6.601
20	Small Industrial	102.5%	120,269	2.0%	266,522,878	2.6%	250,933,686	$5,827,305	$2,894,394	$88,518	$151,780	$72,136	$312,433	$2,266,771	$1,484,928	$3,751,698	$150,506	$71,530	$222,036	$988,190	$2,584,647	$392,322	$2,976,969	$3,965,159	$16,973,025	-$1,129	$0	$0	$16,971,896	$17,389,405	2.6%	$17,397,587	6.933
21	Medium Industrial	98.5%	192,160	3.1%	499,758,128	4.9%	469,836,538	$10,779,191	$5,576,383	$165,665	$284,603	$115,255	$565,523	$4,250,431	$2,372,545	$6,622,976	$282,214	$114,287	$396,502	$1,852,959	$4,846,482	$626,833	$5,473,315	$7,326,274	$31,266,849	-$2,270	$0	$0	$31,264,579	$30,783,104	4.6%	$30,797,588	6.555
22	Large Industrial	97.4%	319,878	5.2%	965,691,025	9.6%	921,131,524	$20,705,323	$10,903,294	$319,023	$549,944	$191,859	$1,060,825	$8,213,179	$3,949,453	$12,162,632	$545,327	$190,248	$735,576	$3,580,504	$9,364,938	$1,043,457	$10,408,395	$13,988,899	$59,556,549	-$4,417	$0	$0	$59,552,133	$58,027,598	8.7%	$58,054,901	6.303
23	Municipal	97.7%	74,057	1.2%	127,501,640	1.3%	121,070,504	$2,883,729	$1,282,046	$43,821	$72,610	$44,418	$160,849	$1,084,398	$914,357	$1,998,755	$72,000	$44,045	$116,046	$472,739	$1,236,467	$241,576	$1,478,043	$1,950,782	$8,392,206	-$482	$0	$0	$8,391,724	$8,196,197	1.2%	$8,200,053	6.773
24	Unmetered	100.0%	46,562	0.8%	89,262,085	0.9%	81,034,159	$1,930,378	$989,670	$29,430	$50,833	$27,927	$108,190	$759,172	$574,886	$1,334,058	$50,406	$27,693	$78,099	$330,958	$865,633	$151,886	$1,017,519	$1,348,477	$5,788,872	-$409	$0	$0	$5,788,464	$5,788,464	0.9%	$5,791,187	7.147
25	Total	100.0%	6,152,512	100.0%	10,104,263,706	100.0%	9,337,493,226	$225,700,489	$104,545,012	$3,431,868	$5,754,196	$3,690,196	$12,876,260	$85,936,520	$75,963,480	$161,900,000	$5,705,894	$3,659,220	$9,365,114	$37,463,699	$97,987,663	$20,069,762	$118,057,425	$155,521,124	$669,907,999	-$38,842	$0	$0	$669,869,157	$669,554,128	100.0%	$669,869,157	7.174
26																				55.4%													
27	Puchased Power Allocation Factors.									26.7%	44.7%	28.7%	100.0%	53.1%	46.9%	100.0%	60.9%	39.1%	100.0%		83.0%	17.0%	100.0%										
29	Non-FAM Rate Classes																																
30	[redacted]																																
34	Total Below-the-line		213,931		1,173,793,790		1,148,300,557	$62,235,468	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$62,235,468	$0	$0		$62,235,468			$62,235,468	5.420
36	In Province Total		6,366,444		11,278,057,497		10,485,793,783	$287,935,957	$104,545,012	$3,431,868	$5,754,196	$3,690,196	$12,876,260	$85,936,520	$75,963,480	$161,900,000	$5,705,894	$3,659,220	$9,365,114	$37,463,699	$97,987,663	$20,069,762	$118,057,425	$155,521,124	$732,143,467	-$38,842	$0	$0	$732,104,625			$732,104,625	6.982
38	Exports	100.0%			1,644,108		1,644,108																										
40	Grand Total		6,366,444		11,279,701,605		10,487,437,891	$287,935,957	$104,545,012	$3,431,868	$5,754,196	$3,690,196	$12,876,260	$85,936,520	$75,963,480	$161,900,000	$5,705,894	$3,659,220	$9,365,114	$37,463,699	$97,987,663	$20,069,762	$118,057,425	$155,521,124	$732,143,467	-$38,842	$0	$0	$732,104,625			$732,104,625	6.981

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Monthly Fuel Cost Allocation

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
Purchased Power													
Imports	$688,566	$2,987,440	$8,906,792	$10,821,637	$8,177,020	$9,184,127	$11,966,913	$12,925,009	$10,782,417	$10,970,985	$8,096,993	$9,037,111	**$104,545,012**
Biomass													
IPP	$1,377,563	$1,101,751	$1,256,118	$1,156,365	$799,433	$785,896	$1,041,394	$1,084,782	$763,247	$965,988	$1,173,024	$1,370,700	**$12,876,260**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$1,377,563**	**$1,101,751**	**$1,256,118**	**$1,156,365**	**$799,433**	**$785,896**	**$1,041,394**	**$1,084,782**	**$763,247**	**$965,988**	**$1,173,024**	**$1,370,700**	**$12,876,260**
Maritime Link													
ML - NS Block (GWh)	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$161,900,000
ML - Supp Block (GWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$13,491,667**	**$161,900,000**
Regular other than biomass and wind													
IPP	$103,848	$114,490	$136,333	$122,950	$132,231	$127,393	$132,518	$136,579	$123,205	$108,934	$88,182	$88,873	**$1,415,535**
Comfit	$643,715	$669,468	$671,519	$662,821	$629,230	$647,575	$696,259	$698,901	$641,230	$654,924	$670,078	$663,859	**$7,949,579**
Total	**$747,563**	**$783,958**	**$807,852**	**$785,771**	**$761,461**	**$774,968**	**$828,777**	**$835,480**	**$764,435**	**$763,858**	**$758,260**	**$752,731**	**$9,365,114**
Wind NRIS													
IPP	$4,804,799	$4,314,487	$5,096,055	$3,969,489	$3,492,685	$3,467,764	$2,578,526	$2,629,468	$3,084,566	$4,153,409	$4,553,719	$4,396,960	**$46,541,931**
Comfit	$7,101,478	$6,259,120	$7,648,993	$6,244,027	$5,896,765	$5,206,381	$4,430,824	$4,102,973	$5,021,031	$6,383,608	$6,588,549	$6,631,747	**$71,515,494**
Total	**$11,906,277**	**$10,573,607**	**$12,745,048**	**$10,213,517**	**$9,389,450**	**$8,674,146**	**$7,009,350**	**$6,732,441**	**$8,105,597**	**$10,537,017**	**$11,142,269**	**$11,028,707**	**$118,057,425**
Wind ERIS													
IPP	$3,729,059	$3,394,343	$3,717,190	$3,084,824	$3,021,159	$2,846,043	$2,119,709	$2,145,434	$2,578,093	$3,454,355	$3,622,636	$3,750,855	**$37,463,699**
Comfit	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	**$0**
Total	**$3,729,059**	**$3,394,343**	**$3,717,190**	**$3,084,824**	**$3,021,159**	**$2,846,043**	**$2,119,709**	**$2,145,434**	**$2,578,093**	**$3,454,355**	**$3,622,636**	**$3,750,855**	**$37,463,699**
Grand Total	**$18,449,029**	**$18,841,098**	**$27,433,000**	**$26,062,114**	**$22,148,524**	**$22,265,180**	**$22,966,143**	**$23,723,145**	**$22,993,788**	**$26,692,202**	**$24,793,183**	**$25,940,104**	**$282,307,510**
Plant Fuel Costs													
Plant Fuel Costs	$39,618,385	$35,832,399	$30,687,049	$19,543,034	$17,484,750	$14,870,714	$18,342,600	$19,727,267	$15,824,679	$16,684,743	$25,257,111	$34,063,228	**$287,935,957**
BTL Class Fuel-related costs													
[redacted]													
Total	$4,909,719	$6,793,195	$7,956,745	$4,993,436	$3,767,303	$4,191,152	$4,680,297	$3,950,652	$4,420,068	$4,872,751	$5,334,096	$6,366,055	**$62,235,468**

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
ATL-related Fuel costs (net of BTL)	$34,708,666	$29,039,205	$22,730,303	$14,549,599	$13,717,447	$10,679,562	$13,662,303	$15,776,614	$11,404,611	$11,811,992	$19,923,015	$27,697,172	**$225,700,489**
Fuel costs before PP													
Domestic	$19,419,689	$16,056,942	$12,261,886	$7,349,239	$6,358,231	$4,399,354	$5,493,173	$6,438,164	$4,612,755	$5,129,154	$9,794,336	$15,425,223	$112,738,147
Small General	$1,088,172	$926,203	$700,550	$449,036	$443,396	$335,995	$445,523	$498,172	$351,572	$361,767	$590,531	$815,817	$7,006,734
General	$7,687,876	$6,517,743	$5,286,308	$3,446,378	$3,384,089	$2,939,149	$3,833,542	$4,333,906	$3,152,549	$3,151,258	$4,921,891	$6,232,337	$54,887,024
Large General	$1,130,630	$933,265	$770,736	$571,895	$599,045	$512,532	$737,743	$880,087	$600,885	$547,571	$755,638	$902,631	$8,942,658
Small Industrial	$791,771	$669,665	$516,910	$362,419	$395,329	$351,734	$444,150	$451,629	$342,472	$306,093	$530,090	$665,043	$5,827,305
Medium Industrial	$1,335,833	$1,169,772	$936,643	$684,621	$728,351	$665,550	$831,272	$909,966	$700,702	$681,310	$1,013,776	$1,121,393	$10,779,191
Large Industrial	$2,525,721	$2,144,776	$1,788,240	$1,374,947	$1,515,238	$1,238,830	$1,567,243	$1,912,753	$1,376,765	$1,380,454	$1,882,869	$1,997,487	$20,705,323
Municipal	$483,060	$403,012	$299,348	$179,271	$153,581	$121,882	$162,723	$185,253	$140,014	$149,562	$258,059	$347,964	$2,883,729
Unmetered	$245,914	$217,827	$169,682	$131,791	$140,186	$114,535	$146,934	$166,684	$126,898	$104,823	$175,825	$189,279	$1,930,378
Total	**$34,708,666**	**$29,039,205**	**$22,730,303**	**$14,549,599**	**$13,717,447**	**$10,679,562**	**$13,662,303**	**$15,776,614**	**$11,404,611**	**$11,811,992**	**$19,923,015**	**$27,697,172**	**$225,700,489**
Exports													
Domestic	$0	$0	$0	$800	$0	$120	$0	$0	$11,634	$17	$3,673	$384	$16,629
Small General	$0	$0	$0	$49	$0	$9	$0	$0	$887	$1	$221	$20	$1,188
General	$0	$0	$0	$375	$0	$80	$0	$0	$7,951	$11	$1,846	$155	$10,419
Large General	$0	$0	$0	$62	$0	$14	$0	$0	$1,516	$2	$283	$22	$1,900
Small Industrial	$0	$0	$0	$39	$0	$10	$0	$0	$864	$1	$199	$17	$1,129
Medium Industrial	$0	$0	$0	$75	$0	$18	$0	$0	$1,767	$2	$380	$28	$2,270
Large Industrial	$0	$0	$0	$150	$0	$34	$0	$0	$3,472	$5	$706	$50	$4,417
Municipal	$0	$0	$0	$20	$0	$3	$0	$0	$353	$0	$97	$9	$482
Unmetered	$0	$0	$0	$14	$0	$3	$0	$0	$320	$0	$66	$5	$409
Total	$0	$0	$0	$1,584	$0	$292	$0	$0	$28,765	$39	$7,472	$690	$38,842
Imports													
Domestic	$385,257	$1,651,876	$4,804,778	$5,466,185	$3,790,165	$3,783,323	$4,811,511	$5,274,473	$4,361,099	$4,763,961	$3,980,556	$5,032,985	$48,106,169
Small General	$21,588	$95,284	$274,508	$333,982	$264,310	$288,946	$390,237	$408,128	$332,392	$336,010	$240,000	$266,187	$3,251,571
General	$152,516	$670,520	$2,071,422	$2,563,332	$2,017,268	$2,527,587	$3,357,828	$3,550,557	$2,980,557	$2,926,890	$2,000,325	$2,033,504	$26,852,306
Large General	$22,430	$96,011	$302,010	$425,362	$357,093	$440,764	$646,195	$721,012	$568,103	$508,584	$307,102	$294,513	$4,689,178
Small Industrial	$15,708	$68,893	$202,549	$269,559	$235,657	$302,481	$389,034	$369,998	$323,788	$284,299	$215,436	$216,992	$2,894,394
Medium Industrial	$26,501	$120,342	$367,020	$509,205	$434,173	$572,355	$728,118	$745,491	$662,474	$632,801	$412,013	$365,891	$5,576,383
Large Industrial	$50,106	$220,646	$700,716	$1,022,652	$903,239	$1,065,360	$1,372,760	$1,567,025	$1,301,653	$1,282,166	$765,225	$651,746	$10,903,294
Municipal	$9,583	$41,460	$117,298	$133,338	$91,550	$104,815	$142,531	$151,769	$132,376	$138,913	$104,879	$113,535	$1,282,046
Unmetered	$4,879	$22,409	$66,489	$98,023	$83,566	$98,497	$128,700	$136,556	$119,975	$97,360	$71,458	$61,758	$989,670
Total	$688,566	$2,987,440	$8,906,792	$10,821,637	$8,177,020	$9,184,127	$11,966,913	$12,925,009	$10,782,417	$10,970,985	$8,096,993	$9,037,111	$104,545,012
Purchased Biomass Generation	11,826	8,494	9,641	8,331	1,800	1,831	7,182	7,566	4,693	7,763	9,128	11,901	90,156
Relative Share	13.1%	9.4%	10.7%	9.2%	2.0%	2.0%	8.0%	8.4%	5.2%	8.6%	10.1%	13.2%	100.0%
Bio-fuel Apportioned	$450,173	$323,347	$367,000	$317,140	$68,504	$69,687	$273,396	$288,017	$178,628	$295,517	$347,449	$453,011	$3,431,868
Domestic	$251,874	$178,792	$197,978	$160,192	$31,753	$28,707	$109,924	$117,535	$72,249	$128,323	$170,809	$252,292	$1,700,428
Small General	$14,114	$10,313	$11,311	$9,788	$2,214	$2,192	$8,915	$9,095	$5,507	$9,051	$10,299	$13,343	$106,142
General	$99,712	$72,574	$85,352	$75,121	$16,900	$19,179	$76,713	$79,119	$49,378	$78,839	$85,836	$101,935	$840,658
Large General	$14,664	$10,392	$12,444	$12,466	$2,992	$3,344	$14,763	$16,067	$9,412	$13,699	$13,178	$14,763	$138,184
Small Industrial	$10,269	$7,457	$8,346	$7,900	$1,974	$2,295	$8,888	$8,245	$5,364	$7,658	$9,245	$10,877	$88,518
Medium Industrial	$17,326	$13,025	$15,123	$14,923	$3,637	$4,343	$16,635	$16,612	$10,975	$17,045	$17,680	$18,341	$165,665
Large Industrial	$32,759	$23,882	$28,873	$29,970	$7,567	$8,084	$31,362	$34,919	$21,564	$34,537	$32,836	$32,671	$319,023
Municipal	$6,265	$4,487	$4,833	$3,908	$767	$795	$3,256	$3,382	$2,193	$3,742	$4,500	$5,691	$43,821
Unmetered	$3,190	$2,425	$2,740	$2,873	$700	$747	$2,940	$3,043	$1,988	$2,623	$3,066	$3,096	$29,430
Total	**$450,173**	**$323,347**	**$367,000**	**$317,140**	**$68,504**	**$69,687**	**$273,396**	**$288,017**	**$178,628**	**$295,517**	**$347,449**	**$453,011**	**$3,431,868**

Monthly Energy Allocators

Rate Class	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total
kWh requirements													
ATL													
Domestic Total	611,801,306	549,022,557	550,635,222	427,686,070	342,190,890	277,488,733	288,762,842	297,168,447	273,729,676	317,643,408	418,363,635	575,240,843	4,929,733,629
Small General	34,281,951	31,668,952	31,459,080	26,131,474	23,862,935	21,192,841	23,420,049	22,994,290	20,862,968	22,403,889	25,224,434	30,423,611	313,926,474
General	242,200,181	222,856,141	237,388,228	200,560,578	182,126,812	185,386,491	201,520,056	200,041,506	187,078,279	195,154,247	210,237,832	232,417,690	2,496,968,040
Large General	35,619,567	31,910,400	34,610,869	33,281,225	32,239,749	32,327,916	38,781,366	40,622,457	35,657,643	33,910,526	32,276,983	33,661,103	414,899,805
Small Industrial	24,944,099	22,897,342	23,212,484	21,090,859	21,276,052	22,185,568	23,347,868	20,845,995	20,322,968	18,956,026	22,642,700	24,800,921	266,522,878
Medium Industrial	42,084,314	39,997,122	42,061,126	39,841,272	39,198,805	41,979,497	43,697,985	42,001,611	41,580,972	42,192,861	43,303,309	41,819,254	499,758,128
Large Industrial	79,570,749	73,334,658	80,303,143	80,014,492	81,547,963	78,139,071	82,386,185	88,287,593	81,699,852	85,490,112	80,426,482	74,490,726	965,691,025
Municipal	15,218,420	13,779,861	13,442,576	10,432,631	8,265,503	7,687,666	8,553,970	8,550,794	8,308,726	9,262,220	11,022,935	12,976,339	127,501,640
Unmetered	7,747,324	7,447,977	7,619,770	7,669,520	7,544,628	7,224,298	7,723,957	7,693,686	7,530,357	6,491,602	7,510,343	7,058,624	89,262,085
Total	1,093,467,911	992,915,010	1,020,732,496	846,708,120	738,253,336	673,612,080	718,194,278	728,206,379	676,771,440	731,504,892	851,008,652	1,032,889,112	10,104,263,706
Fuel Cost Allocators													
ATL													
Domestic	55.95%	55.29%	53.95%	50.51%	46.35%	41.19%	40.21%	40.81%	40.45%	43.42%	49.16%	55.69%	48.79%
Small General	3.14%	3.19%	3.08%	3.09%	3.23%	3.15%	3.26%	3.16%	3.08%	3.06%	2.96%	2.95%	3.11%
General	22.15%	22.44%	23.26%	23.69%	24.67%	27.52%	28.06%	27.47%	27.64%	26.68%	24.70%	22.50%	24.71%
Large General	3.26%	3.21%	3.39%	3.93%	4.37%	4.80%	5.40%	5.58%	5.27%	4.64%	3.79%	3.26%	4.11%
Small Industrial	2.28%	2.31%	2.27%	2.49%	2.88%	3.29%	3.25%	2.86%	3.00%	2.59%	2.66%	2.40%	2.64%
Medium Industrial	3.85%	4.03%	4.12%	4.71%	5.31%	6.23%	6.08%	5.77%	6.14%	5.77%	5.09%	4.05%	4.95%
Large Industrial	7.28%	7.39%	7.87%	9.45%	11.05%	11.60%	11.47%	12.12%	12.07%	11.69%	9.45%	7.21%	9.56%
Municipal	1.39%	1.39%	1.32%	1.23%	1.12%	1.14%	1.19%	1.17%	1.23%	1.27%	1.30%	1.26%	1.26%
Unmetered	0.71%	0.75%	0.75%	0.91%	1.02%	1.07%	1.08%	1.06%	1.11%	0.89%	0.88%	0.68%	0.88%
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%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Data Inputs

Category	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Total	
Plant Fuel Costs	$39,618,385	$35,832,399	$30,687,049	$19,543,034	$17,484,750	$14,870,714	$18,342,600	$19,727,267	$15,824,679	$16,684,743	$25,257,111	$34,063,228	$287,935,957	
Maritime Link														
ML - NS Block	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$161,900,000	
ML - Supp Block														
ML - Surplus														
Total	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$13,491,667	$161,900,000	
Non-Wind Purchases														
Purchased Power Regular bfr Biomass	$103,848	$114,490	$136,333	$122,950	$132,231	$127,393	$132,518	$136,579	$123,205	$108,934	$88,182	$88,873	$1,415,535	
Purchased Power - Biomass	$1,377,563	$1,101,751	$1,256,118	$1,156,365	$799,433	$785,896	$1,041,394	$1,084,782	$763,247	$965,988	$1,173,024	$1,370,700	$12,876,260	
Non-Wind Purchases	$1,481,411	$1,216,240	$1,392,451	$1,279,315	$931,664	$913,289	$1,173,912	$1,221,361	$886,451	$1,074,922	$1,261,206	$1,459,573	$14,291,795	
Wind Purchases														
Purchased Power Wind - NRIS	$4,804,799	$4,314,487	$5,096,055	$3,969,489	$3,492,685	$3,467,764	$2,578,526	$2,629,468	$3,084,566	$4,153,409	$4,553,719	$4,396,960	$46,541,931	55%
Purchased Power Wind - ERIS	$3,729,059	$3,394,343	$3,717,190	$3,084,824	$3,021,159	$2,846,043	$2,119,709	$2,145,434	$2,578,093	$3,454,355	$3,622,636	$3,750,855	$37,463,699	45%
Purchased Power Wind	$8,533,859	$7,708,830	$8,813,245	$7,054,313	$6,513,844	$6,313,807	$4,698,235	$4,774,902	$5,662,660	$7,607,764	$8,176,356	$8,147,815	$84,005,630	100%
Comift														
Wind Generatiion (NRIS)	$7,101,478	$6,259,120	$7,648,993	$6,244,027	$5,896,765	$5,206,381	$4,430,824	$4,102,973	$5,021,031	$6,383,608	$6,588,549	$6,631,747	$71,515,494	
Wind Generatiion (ERIS)													$0	
Biomass Generation	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Other	$643,715	$669,468	$671,519	$662,821	$629,230	$647,575	$696,259	$698,901	$641,230	$654,924	$670,078	$663,859	$7,949,579	
Total Comfit	$7,745,193	$6,928,588	$8,320,511	$6,906,848	$6,525,995	$5,853,957	$5,127,082	$4,801,874	$5,662,260	$7,038,532	$7,258,628	$7,295,605	$79,465,073	
Imports	$ 688,566	$ 2,987,440	$ 8,906,792	$ 10,821,637	$ 8,177,020	$ 9,184,127	$ 11,966,913	$ 12,925,009	$ 10,782,417	$ 10,970,985	$ 8,096,993	$ 9,037,111	$104,545,012	
Export Revenues	$0	$0	$0	$1,584	$0	$292	$0	$0	$28,765	$39	$7,472	$690	$ 38,841.7	
OM&G (Solid Fuel Handling) recovered in fuels														
Foreign Exchange (Fuel-related)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	
Total FAM related costs	**$71,559,080**	**$68,165,164**	**$71,611,715**	**$59,096,814**	**$53,124,940**	**$50,627,561**	**$54,800,410**	**$56,942,078**	**$52,310,134**	**$56,868,612**	**$63,541,960**	**$73,494,999**	**$732,143,467**	
Purchased Biomass Generation	11,826	8,494	9,641	8,331	1,800	1,831	7,182	7,566	4,693	7,763	9,128	11,901	90,156	
BLT Fuel Costs	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**	**Source-Revenue Forecast**		
[redacted]														
Total	**$4,909,719**	**$6,793,195**	**$7,956,745**	**$4,993,436**	**$3,767,303**	**$4,191,152**	**$4,680,297**	**$3,950,652**	**$4,420,068**	**$4,872,751**	**$5,334,096**	**$6,366,055**	**$62,235,468**	
ERIS	**$4,804,799**	**$4,314,487**	**$5,096,055**	**$3,969,489**	**$3,492,685**	**$3,467,764**	**$2,578,526**	**$2,629,468**	**$3,084,566**	**$4,153,409**	**$4,553,719**	**$4,396,960**	**$46,541,931**	55%
NRIS	**$3,729,059**	**$3,394,343**	**$3,717,190**	**$3,084,824**	**$3,021,159**	**$2,846,043**	**$2,119,709**	**$2,145,434**	**$2,578,093**	**$3,454,355**	**$3,622,636**	**$3,750,855**	**$37,463,699**	45%
Total	**$8,533,859**	**$7,708,830**	**$8,813,245**	**$7,054,313**	**$6,513,844**	**$6,313,807**	**$4,698,235**	**$4,774,902**	**$5,662,660**	**$7,607,764**	**$8,176,356**	**$8,147,815**	**$84,005,630**	100.00%

Usage Data

kWh Requirements														
ATL Classes														
Domestic Total	611,801,306	549,022,557	550,635,222	427,686,070	342,190,890	277,488,733	288,762,842	297,168,447	273,729,676	317,643,408	418,363,635	575,240,843	4,929,733,629	4,995,329,980
Small General	34,281,951	31,668,952	31,459,080	26,131,474	23,862,935	21,192,841	23,420,049	22,994,290	20,862,968	22,403,889	25,224,434	30,423,611	313,926,474	283,848,228
General	242,200,181	222,856,141	237,388,228	200,560,578	182,126,812	185,386,491	201,520,056	200,041,506	187,078,279	195,154,247	210,237,832	232,417,690	2,496,968,040	2,553,756,467
Large General	35,619,567	31,910,400	34,610,869	33,281,225	32,239,749	32,327,916	38,781,366	40,622,457	35,657,643	33,910,526	32,276,983	33,661,103	414,899,805	434,465,234
Small Industrial	24,944,099	22,897,342	23,212,484	21,090,859	21,276,052	22,185,568	23,347,868	20,845,995	20,322,968	18,956,026	22,642,700	24,800,921	266,522,878	270,624,393
Medium Industrial	42,084,314	39,997,122	42,061,126	39,841,272	39,198,805	41,979,497	43,697,985	42,001,611	41,580,972	42,192,861	43,303,309	41,819,254	499,758,128	508,059,441
Large Industrial- FIRM	11,647,514	9,144,226	12,060,365	11,717,969	11,122,946	10,843,148	11,462,387	11,923,388	10,890,161	11,528,784	10,715,008	12,236,530	135,292,427	
Large Industrial- INT	67,923,235	64,190,431	68,242,778	68,296,522	70,425,017	67,295,923	70,923,798	76,364,205	70,809,691	73,961,328	69,711,474	62,254,197	830,398,598	
Large Industrial	79,570,749	73,334,658	80,303,143	80,014,492	81,547,963	78,139,071	82,386,185	88,287,593	81,699,852	85,490,112	80,426,482	74,490,726	965,691,025	828,615,963
Municipal	15,218,420	13,779,861	13,442,576	10,432,631	8,265,503	7,687,666	8,553,970	8,550,794	8,308,726	9,262,220	11,022,935	12,976,339	127,501,640	181,012,677
Unmetered	7,747,324	7,447,977	7,619,770	7,669,520	7,544,628	7,224,298	7,723,957	7,693,686	7,530,357	6,491,602	7,510,343	7,058,624	89,262,085	109,935,737
BTL	[redacted]													
In-Province Total	**1,167,945,299**	**1,087,543,398**	**1,122,400,401**	**941,809,398**	**842,592,101**	**760,667,699**	**817,995,901**	**831,472,299**	**779,429,403**	**838,295,299**	**948,971,699**	**1,138,934,601**	**11,278,057,497**	**11,281,098,342**
kWh Sales														
ATL Classes														
Domestic Total	548,423,368	492,111,569	500,531,268	393,121,364	315,341,873	257,806,091	267,545,835	273,499,933	249,243,873	286,543,786	375,827,089	519,074,503	4,479,070,552	
Small General	31,229,881	28,831,062	28,891,440	24,130,244	22,115,327	19,830,899	21,760,623	21,181,408	19,048,082	20,545,066	22,939,978	28,070,302	288,574,314	
General	226,485,245	208,536,174	221,949,604	188,986,231	172,143,308	174,997,518	189,134,748	186,988,057	172,990,170	180,293,374	194,885,639	217,665,221	2,335,055,289	
Large General	33,392,280	30,041,264	32,627,595	31,491,624	30,744,522	30,902,202	36,507,508	38,209,893	33,342,197	31,580,904	30,097,988	31,848,682	390,786,659	
Small Industrial	23,545,756	21,545,598	21,846,935	19,929,647	20,207,190	21,097,732	22,170,436	19,638,726	18,928,608	17,587,753	21,054,662	23,380,643	250,933,686	
Medium Industrial	39,745,249	37,702,388	39,607,204	37,625,751	37,037,735	39,809,905	41,378,359	39,461,911	38,587,233	39,087,832	40,309,081	39,483,892	469,836,538	
Large Industrial- FIRM	11,057,358	8,668,846	11,456,639	11,146,852	10,581,247	10,370,676	10,875,816	11,264,061	10,120,313	10,692,139	9,993,608	11,581,932	127,809,487	
Large Industrial- INT	65,374,691	61,530,321	65,570,724	65,528,700	67,892,988	64,534,038	67,860,787	72,613,303	66,489,203	69,563,266	66,174,459	60,189,557	793,322,037	
Large Industrial	76,432,049	70,199,167	77,027,362	76,675,553	78,474,235	74,904,714	78,736,603	83,877,364	76,609,516	80,255,405	76,168,067	71,771,489	921,131,524	
Municipal	14,490,142	13,157,253	12,800,094	9,963,073	7,934,409	7,356,979	8,157,687	8,094,972	7,776,103	8,649,159	10,378,284	12,312,350	121,070,504	
Unmetered	7,016,814	6,758,670	6,975,016	7,045,026	6,890,697	6,570,987	6,993,330	6,965,682	6,771,769	5,874,924	6,758,975	6,412,269	81,034,159	
ATL Classes	**1,077,192,833**	**979,082,312**	**1,019,283,881**	**865,644,064**	**690,889,295**	**633,277,027**	**672,385,128**	**677,917,948**	**623,297,550**	**670,418,203**	**778,419,763**	**950,019,352**	**9,337,493,226**	
BTL Classes	[redacted]													
Export kWh Sales	-	-	-	64,171	-	16,096	-	-	1,243,558	1,682	303,045	15,557	1,644,108	
Export kWh Losses													-	
Export kWh Req.	-	-	-	64,171	-	16,096	-	-	1,243,558	1,682	303,045	15,557	1,644,108	
In Province Losses	91,363,155	83,205,992	77,479,314	57,274,295	46,481,379	40,263,638	46,219,235	50,610,726	56,082,989	63,055,013	73,797,617	81,292,078	767,125,433	
NSR	**1,241,369,178**	**1,154,999,382**	**1,196,763,549**	**1,016,543,138**	**840,946,601**	**759,162,013**	**816,300,094**	**829,793,246**	**780,305,645**	**836,516,741**	**947,430,501**	**1,136,411,474**	**11,256,207,432**	

Winter kW Peaks	**January**	**February**	**March**	**April**	**May**	**June**	**July**	**August**	**September**	**October**	**November**	**December**	**3CP**	**Annual Peak**
ATL Classes														
Domestic Total	1,341,091	1,257,319	1,107,471	903,010	629,835	614,184	436,576	585,931	566,258	722,305	984,781	1,366,028	3,964,438	1,341,091
Small General	65,668	45,780	48,328	28,339	40,248	34,089	53,026	41,353	31,242	28,739	40,581	40,402	151,851	65,668
General	420,179	370,058	355,778	305,370	326,674	312,892	438,130	385,742	321,290	313,914	379,754	337,048	1,127,284	420,179
Large General	57,546	51,681	52,503	47,792	51,960	48,295	71,895	69,108	62,230	46,029	52,027	46,786	156,014	57,546
Small Industrial	55,648	35,665	35,240	29,389	41,596	37,928	52,761	42,096	35,491	28,984	29,491	28,956	120,269	55,648
Medium Industrial	77,935	63,272	60,069	56,954	67,921	63,196	91,745	71,342	69,208	71,882	56,999	50,952	192,160	77,935
Large Industrial	111,920	99,766	117,614	123,597	107,605	120,118	127,777	127,791	127,884	115,517	113,756	108,192	319,878	111,920
Municipal	26,444	26,528	24,638	17,953	15,129	12,712	14,632	13,831	14,120	15,282	20,441	21,084	74,057	26,444
Unmetered	16,413	15,275	14,168	5,169	2,250	2,776	2,664	2,337	2,100	11,560	15,093	14,874	46,562	16,413
Total	**2,172,846**	**1,965,345**	**1,815,810**	**1,517,573**	**1,283,218**	**1,246,190**	**1,289,206**	**1,339,532**	**1,229,823**	**1,354,212**	**1,692,923**	**2,014,321**	**6,152,512**	**2,172,846**
BTL Classes	[redacted]												-	-
Total	**74,850**	**65,852**	**135,155**	**137,116**	**132,480**	**135,756**	**147,306**	**139,268**	**136,249**	**137,232**	**137,484**	**73,230**	**213,931**	**74,850**
NSR Peak:	**2,247,696**	**2,031,197**	**1,950,965**	**1,654,690**	**1,415,697**	**1,381,946**	**1,436,512**	**1,478,800**	**1,366,072**	**1,491,444**	**1,830,407**	**2,087,551**	**6,366,444**	**2,247,696**

Biomass Calculations

($ in millions)	2022	
Capital	[redacted]	
Fuel		
Operating		
Total	36.7	100.0%

data came from CA IR-065P Confidential from the COSS Proceeding

Annual Peak of ATL Classes	2,172,846
Annual Energy Requirement of ATL	10,104,263,706
System Coincident Load Factor	**53.0800%**

Rate Base		**Average**		**2013**		**2014**
Steam Plant	$	1,176,851	$	1,182,650	$	1,171,051
Steam Plant - CWIP	$	14,185	$	14,153	$	14,218
Steam Environmental & Fuel Conversion	$	179,463	$	183,964	$	174,961
Steam Enviromental & Fuel Conversion - CWIP	$	33	$	65	$	-
Hydro Plant	$	348,392	$	337,086	$	359,697
Hydro Plant - CWIP	$	18,245	$	16,478	$	20,011
Hydro Environmental & Fuel Conversion	$	4,824	$	4,888	$	4,759
Hydro Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
Wind Plant	$	12,902	$	12,703	$	13,100
Wind Plant - CWIP	$	17,697	$	3,598	$	31,795
Wind Plant - ERIS	$	90,465				
Wind Environmental & Fuel Conversion	$	80,018	$	174,537	$	166,428
Wind Enviromental & Fuel Conversion - CWIP	$	100	$	100	$	100
Gas Turbine Plant	$	5,939	$	5,586	$	6,291
Gas Turbine Plant - CWIP	$	574	$	574	$	574
Gas Environmental & Fuel Conversion	$	-	$	-	$	-
Gas Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
LM6000 Plant	$	57,894	$	58,968	$	56,819
LM6000 Plant - CWIP	$	13,523	$	5,323	$	21,723
LM6000 Environmental & Fuel Conversion	$	-	$	-	$	-
LM6000 Enviromental & Fuel Conversion - CWIP	$	-	$	-	$	-
General Property Plant	$	216,887	$	222,532	$	211,241
General Property Plant - CWIP	$	17,386	$	17,270	$	17,501
Transmission Plant	$	449,439	$	440,217	$	458,661
Transmission Plant - CWIP	$	16,715	$	16,982	$	16,447
Transmission Environmental & Fuel Conversion	$	-	$	-	$	-
Transmisstion Enviromental & Fuel Conversion - CV	$	-	$	-	$	-
Distrbution Plant	$	676,641	$	662,471	$	707,406
Distribution Plant - CWIP	$	-	$	(8,339)	$	(8,260)
Distribution Environmental & Fuel Conversion	$	-	$	-	$	-
Distribution Enviromental & Fuel Conversion - CWIF	$	-	$	-	$	-
Dedicated Hydro Mersey Plant - Direct	$	-				
Dedicated LED- Direct	$	24,256	$	16,296	$	32,217

Generation Rate Base			**Initial Classification**			**Further Classification**			**Fully Classified**		
		Total Company	Demand	Energy	Customer	Demand	Energy	Customer	Demand	Energy	Customer
Steam Plant	$	1,370,532	$ 1,191,036	$ 179,496	$ -	$ (632,202)	$ 632,202	$ -	$ 558,834	$ 811,698	$ -
Hydro Plant	$	371,461	$ 366,637	$ 4,824	$ -	$ (194,611)	$ 194,611	$ -	$ 172,026	$ 199,435	$ -
Wind Plant	$	201,182	$ 201,182	$ -	$ -	$ (182,360)	$ 182,360	$ -	$ 18,822	$ 182,360	$ -
LM6000 Plant	$	71,417	$ 71,417	$ -	$ -	$ (37,908)	$ 37,908	$ -	$ 33,509	$ 37,908	$ -
Gas Turbine Plant - Other	$	6,513	$ 6,513	$ -	$ -	$ -	$ -	$ -	$ 6,513	$ -	$ -
Total Generation Plant	$	2,021,105	$ 1,836,785	$ 184,320	$ -	$ (1,047,081)	$ 1,047,081	$ -	$ 789,704	$ 1,231,401	$ -
General Property Plant	$	150,810.20	$ 137,057	$ 13,754	$ -	$ (78,131)	$ 78,131	$ -	$ 58,926	$ 91,884	$ -
Total Plant in Service	$	2,171,915	$ 1,973,842	$ 198,074	$ -	$ (1,125,212)	$ 1,125,212	$ -	$ 848,630	$ 1,323,285	$ -
									39.07%	**60.93%**	

RATE SCHEDULES

RESIDENTIAL TARIFFS

Domestic Service Rate	units	2019 Rates	2020 Rates	Variance	% Variance
Customer Charge	$/mo	**10.830**	**10.830**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	6.321	8.170	1.849	29.3%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		15.603	17.452	1.849	11.9%
FAM AA	¢/kWh	0.000	0.372	0.372	0%
FAM BA	¢/kWh	0.000	-1.979	-1.979	0%
		0.000	-1.607	-1.607	0%
Domestic Service TOD Rate					
Customer Charge	$/mo	**18.820**	**18.820**	0.000	0.0%
December, January & Feb: energy charge					
Base cost of fuel	¢/kWh	6.321	8.170	1.849	29.3%
Non-fuel	¢/kWh	13.640	13.640	0.000	0.0%
		19.961	21.810	1.849	9.3%
FAM AA	¢/kWh	0.000	0.372	0.372	0%
FAM BA	¢/kWh	0.000	-1.979	-1.979	0%
		0.000	-1.607	-1.607	0%
Base cost of fuel	¢/kWh	6.321	8.170	1.849	29.3%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		15.603	17.452	1.849	11.9%
FAM AA	¢/kWh	0.000	0.372	0.372	0%
FAM BA	¢/kWh	0.000	-1.979	-1.979	0%
		0.000	-1.607	-1.607	0%
Base cost of fuel	¢/kWh	6.321	8.170	1.849	29.3%
Non-fuel	¢/kWh	2.355	2.355	0.000	0.0%
		8.676	10.525	1.849	21.3%
FAM AA	¢/kWh	0.000	0.372	0.372	0%
FAM BA	¢/kWh	0.000	-1.979	-1.979	0%
		0.000	-1.607	-1.607	0%
Other months: energy charge					
Base cost of fuel	¢/kWh	6.321	8.170	1.849	29.3%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		15.603	17.452	1.849	11.9%
FAM AA	¢/kWh	0.000	0.372	0.372	0%
FAM BA	¢/kWh	0.000	-1.979	-1.979	0%
		0.000	-1.607	-1.607	0%
Base cost of fuel	¢/kWh	6.321	8.170	1.849	29.3%
Non-fuel	¢/kWh	2.355	2.355	0.000	0.0%
		8.676	10.525	1.849	21.3%
FAM AA	¢/kWh	0.000	0.372	0.372	0%
FAM BA	¢/kWh	0.000	-1.979	-1.979	0%
		0.000	-1.607	-1.607	0%

COMMERCIAL TARIFFS					
Small General Rate	**units**	**2019 Rates**	**2020 Rates**	**Variance**	**% Variance**
Customer Charge	$/mo	**12.6500**	**12.650**	0.0000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	6.385	7.955	1.570	24.6%
Non-fuel	¢/kWh	9.900	9.900	0.000	0.0%
		16.285	17.855	1.570	9.6%
					0%
FAM AA	¢/kWh	0.000	0.282	0.282	0%
FAM BA	¢/kWh	0.000	-1.698	-1.698	0%
		0.000	-1.416	-1.416	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	6.385	7.955	1.570	24.6%
Non-fuel	¢/kWh	8.086	8.086	0.000	0.0%
		14.471	16.041	1.570	10.8%
FAM AA	¢/kWh	0.000	0.282	0.282	0%
FAM BA	¢/kWh	0.000	-1.698	-1.698	0%
		0.000	-1.416	-1.416	0%
General Rate					
Demand Charge	$/kW	**10.497**	**10.497**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	5.781	7.155	1.374	23.8%
Non-fuel	¢/kWh	6.231	6.231	0.000	0.0%
		12.012	13.386	1.374	11.4%
FAM AA	¢/kWh	0.000	0.691	0.691	0%
FAM BA	¢/kWh	0.000	-1.712	-1.712	0%
		0.000	-1.021	-1.021	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	5.781	7.155	1.374	23.8%
Non-fuel	¢/kWh	2.952	2.952	0.000	0.0%
		8.733	10.107	1.374	15.7%
FAM AA	¢/kWh	0.000	0.691	0.691	0%
FAM BA	¢/kWh	0.000	-1.712	-1.712	0%
		0.000	-1.021	-1.021	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Large General Rate					
Demand Charge (Ratcheted)	$/kVA	**13.345**	**13.345**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	6.273	6.547	0.274	4.4%
Non-fuel	¢/kWh	3.253	3.253	0.000	0.0%
		9.526	9.800	0.274	2.9%
FAM AA	¢/kWh	0.000	-0.121	-0.121	0%
FAM BA	¢/kWh	0.000	-0.042	-0.042	0%
		0.000	-0.163	-0.163	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%

INDUSTRIAL TARIFFS

Small Industrial Rate	units	2019 Rates	2020 Rates	Variance	% Variance
Demand Charge	$/kVA	**7.714**	**7.714**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	5.754	7.056	1.302	22.6%
Non-fuel	¢/kWh	5.175	5.175	0.000	0.0%
		10.929	12.231	1.302	11.9%
FAM AA	¢/kWh	0.000	0.645	0.645	0%
FAM BA	¢/kWh	0.000	-1.610	-1.610	0%
		0.000	-0.965	-0.965	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	5.754	7.056	1.302	22.6%
Non-fuel	¢/kWh	2.792	2.792	0.000	0.0%
		8.546	9.848	1.302	15.2%
FAM AA	¢/kWh	0.000	0.645	0.645	0%
FAM BA	¢/kWh	0.000	-1.610	-1.610	0%
		0.000	-0.965	-0.965	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Medium Industrial Rate					
Demand Charge	$/kVA	**12.501**	**12.501**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	5.501	6.171	0.670	12.2%
Non-fuel	¢/kWh	2.543	2.543	0.000	0.0%
		8.044	8.714	0.670	8.3%
FAM AA	¢/kWh	0.000	0.559	0.559	0%
FAM BA	¢/kWh	0.000	-0.822	-0.822	0%
		0.000	-0.263	-0.263	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Large Industrial Rate					
Demand Charge (Ratcheted)	$/kVA	**11.995**	**11.995**	0.000	0.0%
Firm					
Energy					
Base cost of fuel	¢/kWh	5.302	5.786	0.484	9.1%
Non-fuel	¢/kWh	3.023	3.023	0.000	0.0%
		8.325	8.809	0.484	5.8%
FAM AA	¢/kWh	0.000	0.515	0.515	0%
FAM BA	¢/kWh	0.000	-0.577	-0.577	0%
		0.000	-0.062	-0.062	0%
Interruptible					
Energy					
Base cost of fuel	¢/kWh	5.351	5.848	0.497	9.3%
Non-fuel	¢/kWh	2.625	2.625	0.000	0.0%
		7.976	8.473	0.497	6.2%
FAM AA	¢/kWh	0.000	0.515	0.515	0%
FAM BA	¢/kWh	0.000	-0.625	-0.625	0%
		0.000	-0.110	-0.110	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Interruptible Credit	$/kVA	**-3.430**	**-3.430**	0.000	0.0%

MUNICIPAL TARIFFS					
Municipal Rate	**units**	**2019 Rates**	**2020 Rates**	**Variance**	**% Variance**
Demand Charge (Ratcheted)	$/kVA	**12.445**	**12.445**	0.000	
Energy					
Base cost of fuel	¢/kWh	5.609	6.575	0.966	17.2%
Non-fuel	¢/kWh	2.871	2.871	0.000	0.0%
		8.480	9.446	0.966	11.4%
FAM AA	¢/kWh	0.000	0.596	0.596	0%
FAM BA	¢/kWh	0.000	-1.157	-1.157	0%
		0.000	-0.561	-0.561	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%

OTHER TARIFFS					
Outdoor Recreational Light Rate	**units**	**2019 Rates**	**2020 Rates**	**Variance**	**% Variance**
Energy					
Base cost of fuel	¢/kWh	5.638	7.420	1.782	31.6%
Non-fuel	¢/kWh	10.408	10.408	0.000	0.0%
		16.046	17.828	1.782	11.1%
FAM AA	¢/kWh	0.000	0.992	0.992	0%
FAM BA	¢/kWh	0.000	-2.365	-2.365	0%
		0.000	-1.373	-1.373	0%
Miscellaneous Small Loads Rate					
Demand Charge	$/kW	**11.777**	**11.777**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	5.638	7.420	1.782	31.6%
Non-fuel	¢/kWh	8.434	8.434	0.000	0.0%
		14.072	15.854	1.782	12.7%
FAM AA	¢/kWh	0.000	0.992	0.992	0%
FAM BA	¢/kWh	0.000	-2.365	-2.365	0%
		0.000	-1.373	-1.373	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	5.638	7.420	1.782	31.6%
Non-fuel	¢/kWh	3.908	3.908	0.000	0.0%
		9.546	11.328	1.782	18.7%
FAM AA	¢/kWh	0.000	0.992	0.992	0%
FAM BA	¢/kWh	0.000	-2.365	-2.365	0%
		0.000	-1.373	-1.373	0%

RATE SCHEDULES

RESIDENTIAL TARIFFS

Domestic Service Rate	units	2020 Rates	2021 Rates	Variance	% Variance
Customer Charge	$/mo	**10.830**	**10.830**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	8.170	6.810	-1.360	-16.6%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		17.452	16.092	-1.360	-7.8%
FAM AA	¢/kWh	0.372	0.000	-0.372	-100.0%
FAM BA	¢/kWh	-1.979	0.000	1.979	-100.0%
		-1.607	0.000	1.607	-100.0%
Domestic Service TOD Rate					
Customer Charge	$/mo	**18.820**	**18.820**	0.000	0.0%
December, January & Feb: energy charge					
Base cost of fuel	¢/kWh	8.170	6.810	-1.360	-16.6%
Non-fuel	¢/kWh	13.640	13.640	0.000	0.0%
		21.810	20.450	-1.360	-6.2%
FAM AA	¢/kWh	0.372	0.000	-0.372	-100.0%
FAM BA	¢/kWh	-1.979	0.000	1.979	-100.0%
		-1.607	0.000	1.607	-100.0%
Base cost of fuel	¢/kWh	8.170	6.810	-1.360	-16.6%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		17.452	16.092	-1.360	-7.8%
FAM AA	¢/kWh	0.372	0.000	-0.372	-100.0%
FAM BA	¢/kWh	-1.979	0.000	1.979	-100.0%
		-1.607	0.000	1.607	-100.0%
Base cost of fuel	¢/kWh	8.170	6.810	-1.360	-16.6%
Non-fuel	¢/kWh	2.355	2.355	0.000	0.0%
		10.525	9.165	-1.360	-12.9%
FAM AA	¢/kWh	0.372	0.000	-0.372	-100.0%
FAM BA	¢/kWh	-1.979	0.000	1.979	-100.0%
		-1.607	0.000	1.607	-100.0%
Other months: energy charge					
Base cost of fuel	¢/kWh	8.170	6.810	-1.360	-16.6%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		17.452	16.092	-1.360	-7.8%
FAM AA	¢/kWh	0.372	0.000	-0.372	-100.0%
FAM BA	¢/kWh	-1.979	0.000	1.979	-100.0%
		-1.607	0.000	1.607	-100.0%
Base cost of fuel	¢/kWh	8.170	6.810	-1.360	-16.6%
Non-fuel	¢/kWh	2.355	2.355	0.000	0.0%
		10.525	9.165	-1.360	-12.9%
FAM AA	¢/kWh	0.372	0.000	-0.372	-100.0%
FAM BA	¢/kWh	-1.979	0.000	1.979	-100.0%
		-1.607	0.000	1.607	-100.0%

COMMERCIAL TARIFFS					
Small General Rate	**units**	**2020 Rates**	**2021 Rates**	**Variance**	**% Variance**
Customer Charge	$/mo	**12.6500**	**12.6500**	0.0000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	7.955	6.695	-1.260	-15.8%
Non-fuel	¢/kWh	9.900	9.900	0.000	0.0%
		17.855	16.595	-1.260	-7.1%
					0%
FAM AA	¢/kWh	0.282	0.000	-0.282	-100.0%
FAM BA	¢/kWh	-1.698	0.000	1.698	-100.0%
		-1.416	0.000	1.416	-100.0%
Block 2 Energy					
Base cost of fuel	¢/kWh	7.955	6.695	-1.260	-15.8%
Non-fuel	¢/kWh	8.086	8.086	0.000	0.0%
		16.041	14.781	-1.260	-7.9%
FAM AA	¢/kWh	0.282	0.000	-0.282	-100.0%
FAM BA	¢/kWh	-1.698	0.000	1.698	-100.0%
		-1.416	0.000	1.416	-100.0%
General Rate					
Demand Charge	$/kW	**10.497**	**10.497**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	7.155	6.495	-0.660	-9.2%
Non-fuel	¢/kWh	6.231	6.231	0.000	0.0%
		13.386	12.726	-0.660	-4.9%
FAM AA	¢/kWh	0.691	0.000	-0.691	-100.0%
FAM BA	¢/kWh	-1.712	0.000	1.712	-100.0%
		-1.021	0.000	1.021	-100.0%
Block 2 Energy					
Base cost of fuel	¢/kWh	7.155	6.495	-0.660	-9.2%
Non-fuel	¢/kWh	2.952	2.952	0.000	0.0%
		10.107	9.447	-0.660	-6.5%
FAM AA	¢/kWh	0.691	0.000	-0.691	-100.0%
FAM BA	¢/kWh	-1.712	0.000	1.712	-100.0%
		-1.021	0.000	1.021	-100.0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Large General Rate					
Demand Charge (Ratcheted)	$/kVA	**13.345**	**13.345**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	6.547	6.497	-0.050	-0.8%
Non-fuel	¢/kWh	3.253	3.253	0.000	0.0%
		9.800	9.750	-0.050	-0.5%
FAM AA	¢/kWh	-0.121	0.000	0.121	-100.0%
FAM BA	¢/kWh	-0.042	0.000	0.042	-100.0%
		-0.163	0.000	0.163	-100.0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%

INDUSTRIAL TARIFFS

Small Industrial Rate	units	2020 Rates	2021 Rates	Variance	% Variance
Demand Charge	$/kVA	**7.714**	**7.714**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	7.056	6.438	-0.618	-8.8%
Non-fuel	¢/kWh	5.175	5.175	0.000	0.0%
		12.231	11.613	-0.618	-5.1%
FAM AA	¢/kWh	0.645	0.000	-0.645	-100.0%
FAM BA	¢/kWh	-1.610	0.000	1.610	-100.0%
		-0.965	0.000	0.965	-100.0%
Block 2 Energy					
Base cost of fuel	¢/kWh	7.056	6.438	-0.618	-8.8%
Non-fuel	¢/kWh	2.792	2.792	0.000	0.0%
		9.848	9.230	-0.618	-6.3%
FAM AA	¢/kWh	0.645	0.000	-0.645	-100.0%
FAM BA	¢/kWh	-1.610	0.000	1.610	-100.0%
		-0.965	0.000	0.965	-100.0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Medium Industrial Rate					
Demand Charge	$/kVA	**12.501**	**12.501**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	6.171	6.333	0.162	2.6%
Non-fuel	¢/kWh	2.543	2.543	0.000	0.0%
		8.714	8.876	0.162	1.9%
FAM AA	¢/kWh	0.559	0.000	-0.559	-100.0%
FAM BA	¢/kWh	-0.822	0.000	0.822	-100.0%
		-0.263	0.000	0.263	-100.0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Large Industrial Rate					
Demand Charge (Ratcheted)	$/kVA	**11.995**	**11.995**	0.000	0.0%
Firm					
Energy					
Base cost of fuel	¢/kWh	5.786	6.162	0.376	6.5%
Non-fuel	¢/kWh	3.023	3.023	0.000	0.0%
		8.809	9.185	0.376	4.3%
FAM AA	¢/kWh	0.515	0.000	-0.515	-100.0%
FAM BA	¢/kWh	-0.577	0.000	0.577	-100.0%
		-0.062	0.000	0.062	-100.0%
Interruptible					
Energy					
Base cost of fuel	¢/kWh	5.848	6.141	0.293	5.0%
Non-fuel	¢/kWh	2.625	2.625	0.000	0.0%
		8.473	8.766	0.293	3.5%
FAM AA	¢/kWh	0.515	0.000	-0.515	-100.0%
FAM BA	¢/kWh	-0.625	0.000	0.625	-100.0%
		-0.110	0.000	0.110	-100.0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Interruptible Credit	$/kVA	**-3.430**	**-3.430**	0.000	0.0%

MUNICIPAL TARIFFS					
Municipal Rate	**units**	**2020 Rates**	**2021 Rates**	**Variance**	**% Variance**
Demand Charge (Ratcheted)	$/kVA	**12.445**	**12.445**	0.000	
Energy					
Base cost of fuel	¢/kWh	6.575	6.434	-0.141	-2.1%
Non-fuel	¢/kWh	2.871	2.871	0.000	0.0%
		9.446	9.305	-0.141	-1.5%
FAM AA	¢/kWh	0.596	0.000	-0.596	-100.0%
FAM BA	¢/kWh	-1.157	0.000	1.157	-100.0%
		-0.561	0.000	0.561	-100.0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%

OTHER TARIFFS					
Outdoor Recreational Light Rate	**units**	**2020 Rates**	**2021 Rates**	**Variance**	**% Variance**
Energy					
Base cost of fuel	¢/kWh	7.420	6.463	-0.957	-12.9%
Non-fuel	¢/kWh	10.408	10.408	0.000	0.0%
		17.828	16.871	-0.957	-5.4%
FAM AA	¢/kWh	0.992	0.000	-0.992	-100.0%
FAM BA	¢/kWh	-2.365	0.000	2.365	-100.0%
		-1.373	0.000	1.373	-100.0%
Miscellaneous Small Loads Rate					
Demand Charge	$/kW	**11.777**	**11.777**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	7.420	6.463	-0.957	-12.9%
Non-fuel	¢/kWh	8.434	8.434	0.000	0.0%
		15.854	14.897	-0.957	-6.0%
FAM AA	¢/kWh	0.992	0.000	-0.992	-100.0%
FAM BA	¢/kWh	-2.365	0.000	2.365	-100.0%
		-1.373	0.000	1.373	-100.0%
Block 2 Energy					
Base cost of fuel	¢/kWh	7.420	6.463	-0.957	-12.9%
Non-fuel	¢/kWh	3.908	3.908	0.000	0.0%
		11.328	10.371	-0.957	-8.4%
FAM AA	¢/kWh	0.992	0.000	-0.992	-100.0%
FAM BA	¢/kWh	-2.365	0.000	2.365	-100.0%
		-1.373	0.000	1.373	-100.0%

RATE SCHEDULES

RESIDENTIAL TARIFFS

Domestic Service Rate	units	2021 Rates	2022 Rates	Variance	% Variance
Customer Charge	$/mo	**10.830**	**10.830**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	6.810	7.059	0.249	3.7%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		16.092	16.341	0.249	1.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Domestic Service TOD Rate					
Customer Charge	$/mo	**18.820**	**18.820**	0.000	0.0%
December, January & Feb: energy charge					
Base cost of fuel	¢/kWh	6.810	7.059	0.249	3.7%
Non-fuel	¢/kWh	13.640	13.640	0.000	0.0%
		20.450	20.699	0.249	1.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Base cost of fuel	¢/kWh	6.810	7.059	0.249	3.7%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		16.092	16.341	0.249	1.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Base cost of fuel	¢/kWh	6.810	7.059	0.249	3.7%
Non-fuel	¢/kWh	2.355	2.355	0.000	0.0%
		9.165	9.414	0.249	2.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Other months: energy charge					
Base cost of fuel	¢/kWh	6.810	7.059	0.249	3.7%
Non-fuel	¢/kWh	9.282	9.282	0.000	0.0%
		16.092	16.341	0.249	1.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Base cost of fuel	¢/kWh	6.810	7.059	0.249	3.7%
Non-fuel	¢/kWh	2.355	2.355	0.000	0.0%
		9.165	9.414	0.249	2.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%

COMMERCIAL TARIFFS					
Small General Rate	**units**	**2021 Rates**	**2022 Rates**	**Variance**	**% Variance**
Customer Charge	$/mo	**12.6500**	**12.6500**	0.0000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	6.695	6.852	0.157	2.3%
Non-fuel	¢/kWh	9.900	9.900	0.000	0.0%
		16.595	16.752	0.157	0.9%
					0%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	6.695	6.852	0.157	2.3%
Non-fuel	¢/kWh	8.086	8.086	0.000	0.0%
		14.781	14.938	0.157	1.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
General Rate					
Demand Charge	$/kW	**10.497**	**10.497**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	6.495	6.867	0.372	5.7%
Non-fuel	¢/kWh	6.231	6.231	0.000	0.0%
		12.726	13.098	0.372	2.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	6.495	6.867	0.372	5.7%
Non-fuel	¢/kWh	2.952	2.952	0.000	0.0%
		9.447	9.819	0.372	3.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Large General Rate					
Demand Charge (Ratcheted)	$/kVA	**13.345**	**13.345**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	6.497	6.611	0.114	1.8%
Non-fuel	¢/kWh	3.253	3.253	0.000	0.0%
		9.750	9.864	0.114	1.2%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%

INDUSTRIAL TARIFFS					
Small Industrial Rate	units	2021 Rates	2022 Rates	Variance	% Variance
Demand Charge	$/kVA	**7.714**	**7.714**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	6.438	6.794	0.356	5.5%
Non-fuel	¢/kWh	5.175	5.175	0.000	0.0%
		11.613	11.969	0.356	3.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	6.438	6.794	0.356	5.5%
Non-fuel	¢/kWh	2.792	2.792	0.000	0.0%
		9.230	9.586	0.356	3.9%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Medium Industrial Rate					
Demand Charge	$/kVA	**12.501**	**12.501**	0.000	0.0%
Energy					
Base cost of fuel	¢/kWh	6.333	6.774	0.441	7.0%
Non-fuel	¢/kWh	2.543	2.543	0.000	0.0%
		8.876	9.317	0.441	5.0%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Large Industrial Rate					
Demand Charge (Ratcheted)	$/kVA	**11.995**	**11.995**	0.000	0.0%
Firm					
Energy					
Base cost of fuel	¢/kWh	6.162	6.617	0.455	7.4%
Non-fuel	¢/kWh	3.023	3.023	0.000	0.0%
		9.185	9.640	0.455	5.0%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Interruptible					
Energy					
Base cost of fuel	¢/kWh	6.141	6.559	0.418	6.8%
Non-fuel	¢/kWh	2.625	2.625	0.000	0.0%
		8.766	9.184	0.418	4.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%
Interruptible Credit	$/kVA	**-3.430**	**-3.430**	0.000	0.0%

MUNICIPAL TARIFFS					
Municipal Rate	**units**	**2021 Rates**	**2022 Rates**	**Variance**	**% Variance**
Demand Charge (Ratcheted)	$/kVA	**12.445**	**12.445**	0.000	
Energy					
Base cost of fuel	¢/kWh	6.434	6.870	0.436	6.8%
Non-fuel	¢/kWh	2.871	2.871	0.000	0.0%
		9.305	9.741	0.436	4.7%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Transformer Ownership Credit	¢/kVA	**-32.000**	**-32.000**	0.000	0.0%

OTHER TARIFFS					
Outdoor Recreational Light Rate	**units**	**2021 Rates**	**2022 Rates**	**Variance**	**% Variance**
Energy					
Base cost of fuel	¢/kWh	6.463	6.885	0.422	6.5%
Non-fuel	¢/kWh	10.408	10.408	0.000	0.0%
		16.871	17.293	0.422	2.5%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Miscellaneous Small Loads Rate					
Demand Charge	$/kW	**11.777**	**11.777**	0.000	0.0%
Block 1 Energy					
Base cost of fuel	¢/kWh	6.463	6.885	0.422	6.5%
Non-fuel	¢/kWh	8.434	8.434	0.000	0.0%
		14.897	15.319	0.422	2.8%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%
Block 2 Energy					
Base cost of fuel	¢/kWh	6.463	6.885	0.422	6.5%
Non-fuel	¢/kWh	3.908	3.908	0.000	0.0%
		10.371	10.793	0.422	4.1%
FAM AA	¢/kWh	0.000	0.000	0.000	0%
FAM BA	¢/kWh	0.000	0.000	0.000	0%
		0.000	0.000	0.000	0%

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2020 Sales Priced at 2019 Rates	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	4,211.5	$0.15603	$657.1							4,211.5	$657.1				5.4	$ 10.83	$58.1	$715.2
ETS	21.0	$0.19961	$4.2	66.6	$0.15603	$10.4	194.2	$0.08676	$16.8	281.8	$31.4				0.2	$ 18.82	$2.9	$34.3
Total	**4,232.5**		**$661.3**	**66.6**		**$10.4**	**194.2**		**$16.8**	**4,493.3**	**$688.6**				**5.5**		**$61.0**	**$749.5**
Commercial Sector																		
Small General	49.2	$0.16285	$8.0	237.6	$0.14471	$34.4				286.8	$42.4				0.3	$ 12.65	$3.9	$46.312
General Demand	1,282.3	$0.12012	$154.0	1,110.6	$0.08733	$97.0				2,393.0	$251.0	6,466.9	$10.497	$67.9				$318.9
Large General																		
Without Trans. Own.	238.4	$0.09526	$22.7							238.4	$22.7	509.9	$13.345	$6.8				$29.5
With Trans. Own.	154.5	$0.09526	$14.7							154.5	$14.7	330.4	$13.025	$4.3				$19.0
Sub-total	392.8		$37.4							392.8	$37.4	840.3		$11.1				$48.5
Total	**1,724.4**		**$199.5**	**1,348.2**		**$131.4**				**3,072.6**	**$330.8**	**7,307.1**		**$79.0**	**0.3**		**$3.9**	**$413.7**
Industrial Sector																		
Small Industrial	164.7	$0.10929	$18.0	85.7	$0.08546	$7.3				250.4	$25.3	826.3	$7.714	$6.4				$31.7
Medium Industrial	474.4	$0.08044	$38.2							474.4	$38.2	861.1	$12.501	$10.8				$48.9
Large Industrial Firm																		
Without Trans. Own.	48.9	$0.08325	$4.1							48.9	$4.1	105.4	$11.995	$1.3				$5.3
With Trans. Own.	79.2	$0.08325	$6.6							79.2	$6.6	170.8	$11.675	$2.0				$8.6
Sub-total	128.0		$10.7							128.0	$10.7	276.1		$3.3				$13.9
Large Industrial Interr.																		
Without Trans. Own.	234.3	$0.07976	$18.7							234.3	$18.7	525.5	$8.565	$4.5				$23.2
With Trans. Own.	499.5	$0.07976	$39.8							499.5	$39.8	1,120.2	$8.245	$9.2				$49.1
Sub-total	733.9		$58.5							733.9	$58.5	1,645.7		$13.7				$72.3
Total Large Industrial	861.9		$69.2							861.9	$69.2	1,921.9		$17.0				$86.2
Total Industrial	**1,501.0**		**$125.4**	**85.7**		**$7.3**				**1,586.7**	**$132.7**	**3,609.3**		**$34.1**				**$166.8**
Other																		
Municipal																		
Without Trans. Own.	79.4	$0.08480	$6.7							79.4	$6.7	295.7	$12.445	$3.7				$10.4
With Trans. Own.	45.4	$0.08480	$3.9							45.4	$3.9	169.3	$12.125	$2.1				$5.9
Sub-total	124.8		$10.6							124.8	$10.6	465.0		$5.7				$16.3
Unmetered	81.0	$0.25149	$20.4							81.0	$20.4							$20.4
Total	**205.9**		**$31.0**							**205.9**	**$31.0**	**465.0**		**$5.7**				**$36.7**
Total FAM Classes	**7,663.8**		**$1,017.1**	**1,500.6**		**$149.1**	**194.2**		**$16.8**	**9,358.5**	**$1,183.1**	**11,381.4**		**$118.9**	**5.8**		**$64.9**	**$1,366.8**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2020 Sales Priced at 2020 Rates	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	4,211.5	$0.17452	$735.0							4,211.5	$735.0	-	$0.000	$0.0	5.4	$ 10.83	$58.1	$793.1
ETS	21.0	$0.21810	$4.6	66.6	$0.17452	$11.6	194.2	$0.10525	$20.4	281.8	$36.7	-	$0.000	$0.0	0.2	$ 18.82	$2.9	$39.5
Total	**4,232.5**		**$739.6**	**66.6**		**$11.6**	**194.2**		**$20.4**	**4,493.3**	**$771.6**	**-**		**$0.0**	**5.5**		**$61.0**	**$832.6**
Commercial Sector																		
Small General	49.2	$0.17855	$8.8	237.6	$0.16041	$38.1	-		$0.0	286.8	$46.9	-	$0.000	$0.0	0.3	$ 12.65	$3.9	$50.8
General Demand	1,282.3	$0.13386	$171.7	1,110.6	$0.10107	$112.3	-		$0.0	2,393.0	$283.9	6,466.9	$10.497	$67.9				$351.8
Large General																		
Without Trans. Own.	238.4	$0.09800	$23.4							238.4	$23.4	509.9	$13.345	$6.8				$30.2
With Trans. Own.	154.5	$0.09800	$15.1							154.5	$15.1	330.4	$13.025	$4.3				$19.4
Sub-total	392.8		$38.5							392.8	$38.5	840.3		$11.1				$49.6
Total	**1,724.4**		**$218.9**	**1,348.2**		**$150.4**				**3,072.6**	**$369.3**	**7,307.1**		**$79.0**	**0.3**		**$3.9**	**$452.2**
Industrial Sector																		
Small Industrial	164.7	$0.12231	$20.2	85.7	$0.09848	$8.4				250.4	$28.6	826.3	$7.714	$6.4				$35.0
Medium Industrial	474.4	$0.08714	$41.3							474.4	$41.3	861.1	$12.501	$10.8				$52.1
Large Industrial Firm																		
Without Trans. Own.	48.9	$0.08809	$4.3							48.9	$4.3	105.4	$11.995	$1.3				$5.6
With Trans. Own.	79.2	$0.08809	$7.0							79.2	$7.0	170.8	$11.675	$2.0				$9.0
Sub-total	128.0		$11.3							128.0	$11.3	276.1		$3.3				$14.5
Large Industrial Interr.																		
Without Trans. Own.	234.3	$0.08473	$19.9							234.3	$19.9	525.5	$8.565	$4.5				$24.4
With Trans. Own.	499.5	$0.08473	$42.3							499.5	$42.3	1,120.2	$8.245	$9.2				$51.6
Sub-total	733.9		$62.2							733.9	$62.2	1,645.7		$13.7				$75.9
Total Large Industrial	861.9		$73.5						$1.0	861.9	$73.5	1,921.9		$17.0				$90.5
Total Industrial	**1,501.0**		**$134.9**	**85.7**		**$8.4**				**1,586.7**	**$143.4**	**3,609.3**		**$34.1**	**0.0**		**$0.0**	**$177.5**
Other																		
Municipal																		
Without Trans. Own.	79.4	$0.09446	$7.5							79.4	$7.5	295.7	$12.445	$3.7				$11.2
With Trans. Own.	45.4	$0.09446	$4.3							45.4	$4.3	169.3	$12.125	$2.1				$6.3
Sub-total	124.8		$11.8							124.8	$11.8	465.0		$5.7				$17.5
Unmetered	81.0	$0.26931	$21.8							81.0	$21.8							$21.8
Total	**205.9**		**$33.6**							**205.9**	**$33.6**	**465.0**		**$5.7**				**$39.3**
Total FAM Classes	**7,663.8**		**$1,127.1**	**1,500.6**		**$170.4**	**194.2**		**$20.4**	**9,358.5**	**$1,317.9**	**11,381.4**		**$118.9**	**5.8**		**$64.9**	**$1,501.7**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Variance	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	-	$0.01849	$77.9	-	$0.00000	$0.0	-	$0.00000	$0.0	-	$77.9	-	$0.000	$0.0	-	$ -	$0.0	$77.9
ETS	-	$0.01849	$0.4	-	$0.01849	$1.2	-	$0.01849	$3.6	-	$5.2	-	$0.000	$0.0	-	$ -	$0.0	$5.2
Total	**-**		**$78.3**	**-**		**$1.2**	**-**		**$3.6**	**-**	**$83.1**	**-**		**$0.0**	**-**		**$0.0**	**$83.1**
Commercial Sector																		
Small General	-	$0.01570	$0.8	-	$0.01570	$3.7	-		$0.0	-	$4.5	-	$0.000	$0.0	-	$ -	$0.0	$4.5
General Demand	-	$0.01374	$17.6	-	$0.01374	$15.3	-		$0.0	-	$32.9	-	$0.000	$0.0				$32.9
Large General										-		-	$0.000	$0.0				
Without Trans. Own.	-	$0.00274	$0.7							-	$0.7	-	$0.000	$0.0				$0.7
With Trans. Own.	-	$0.00274	$0.4							-	$0.4	-	$0.000	$0.0				$0.4
Sub-total	-		$1.1							-	$1.1	-		$0.0				$1.1
Total	**-**		**$19.5**	**-**		**$19.0**				**-**	**$38.5**	**-**		**$0.0**	**-**		**$0.0**	**$38.5**
Industrial Sector																		
Small Industrial	-	$0.01302	$2.1	-	$0.01302	$1.1				-	$3.3	-	$0.000	$0.0				$3.3
Medium Industrial	-	$0.00670	$3.2							-	$3.2	-	$0.000	$0.0				$3.2
Large Industrial Firm																		
Without Trans. Own.	-	$0.00484	$0.2							-	$0.2	-	$0.000	$0.0				$0.2
With Trans. Own.	-	$0.00484	$0.4							-	$0.4	-	$0.000	$0.0				$0.4
Sub-total	-		$0.6							-	$0.6	-		$0.0				$0.6
Large Industrial Interr.																		
Without Trans. Own.	-	$0.00497	$1.2							-	$1.2	-	$0.000	$0.0				$1.2
With Trans. Own.	-	$0.00497	$2.5							-	$2.5	-	$0.000	$0.0				$2.5
Sub-total	-		$3.6							-	$3.6	-		$0.0				$3.6
Total Large Industrial	-		$4.3						$1.0	-	$4.3	-		$0.0				$4.3
Total Industrial	**-**		**$9.6**	**-**		**$1.1**				**-**	**$10.7**	**-**		**$0.0**	**0.0**		**$0.0**	**$10.7**
Other																		
Municipal																		
Without Trans. Own.	-	$0.00966	$0.8							-	$0.8	-	$0.000	$0.0				$0.8
With Trans. Own.	-	$0.00966	$0.4							-	$0.4	-	$0.000	$0.0				$0.4
Sub-total	-		$1.2							-	$1.2	-		$0.0				$1.2
Unmetered	-	$0.01782	$1.4							-	$1.4							$1.4
Total	**-**		**$2.6**							**-**	**$2.6**	**-**		**$0.0**			**$0.0**	**$2.6**
Total FAM Classes	**-**		**$110.0**	**-**		**$21.3**	**-**		**$3.6**	**-**	**$134.9**	**-**		**$0.0**	**-**		**$0.0**	**$134.9**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2021 Sales Priced at 2020 Rates	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	4,185.5	$0.17452	$730.5							4,185.5	$730.5				5.4	$ 10.83	$58.5	$788.9
ETS	21.4	$0.21810	$4.7	67.9	$0.17452	$11.9	197.9	$0.10525	$20.8	287.2	$37.4				0.2	$ 18.82	$2.9	$40.2
Total	**4,206.9**		**$735.1**	**67.9**		**$11.9**	**197.9**		**$20.8**	**4,472.7**	**$767.8**				**5.6**		**$61.4**	**$829.2**
Commercial Sector																		
Small General	49.4	$0.17855	$8.8	238.4	$0.16041	$38.2				287.8	$47.1				0.3	$ 12.65	$3.9	$51.0
General Demand	1,265.0	$0.13386	$169.3	1,095.7	$0.10107	$110.7				2,360.7	$280.1	6,379.7	$10.497	$67.0				$347.0
Large General																		
Without Trans. Own.	238.8	$0.09800	$23.4							238.8	$23.4	510.9	$13.345	$6.8				$30.2
With Trans. Own.	154.8	$0.09800	$15.2							154.8	$15.2	331.1	$13.025	$4.3				$19.5
Sub-total	393.6		$38.6							393.6	$38.6	841.9		$11.1				$49.7
Total	**1,708.0**		**$216.7**	**1,334.0**		**$149.0**				**3,042.1**	**$365.7**	**7,221.6**		**$78.1**	**0.3**		**$3.9**	**$447.7**
Industrial Sector																		
Small Industrial	164.8	$0.12231	$20.2	85.7	$0.09848	$8.4				250.6	$28.6	826.7	$7.714	$6.4				$35.0
Medium Industrial	472.9	$0.08714	$41.2							472.9	$41.2	858.4	$12.501	$10.7				$51.9
Large Industrial Firm																		
Without Trans. Own.	48.8	$0.08809	$4.3							48.8	$4.3	105.3	$11.995	$1.3				$5.6
With Trans. Own.	79.1	$0.08809	$7.0							79.1	$7.0	170.6	$11.675	$2.0				$9.0
Sub-total	127.9		$11.3							127.9	$11.3	275.9		$3.3				$14.5
Large Industrial Interr.																		
Without Trans. Own.	254.0	$0.08473	$21.5							254.0	$21.5	569.6	$8.565	$4.9				$26.4
With Trans. Own.	541.4	$0.08473	$45.9							541.4	$45.9	1,214.1	$8.245	$10.0				$55.9
Sub-total	795.4		$67.4							795.4	$67.4	1,783.7		$14.9				$82.3
Total Large Industrial	923.3		$78.7							923.3	$78.7	2,059.6		$18.1				$96.8
Total Industrial	**1,561.1**		**$140.0**	**85.7**		**$8.4**				**1,646.8**	**$148.5**	**3,744.8**		**$35.3**				**$183.7**
Other																		
Municipal																		
Without Trans. Own.	78.0	$0.09446	$7.4							78.0	$7.4	297.5	$12.445	$3.7				$11.1
With Trans. Own.	44.6	$0.09446	$4.2							44.6	$4.2	170.3	$12.125	$2.1				$6.3
Sub-total	122.6		$11.6							122.6	$11.6	467.8		$5.8				$17.4
Unmetered	81.0	$0.26931	$21.8							81.0	$21.8							$21.8
Total	**203.7**		**$33.4**							**203.7**	**$33.4**	**467.8**		**$5.8**				**$39.2**
Total FAM Classes	**7,679.7**		**$1,125.3**	**1,487.7**		**$169.3**	**197.9**		**$20.8**	**9,365.3**	**$1,315.4**	**11,434.2**		**$119.1**	**5.9**		**$65.3**	**$1,499.8**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

2021 Sales Priced at 2021 Rates	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	4,185.5	$0.16092	$673.5							4,185.5	$673.5	-	$0.000	$0.0	5.4	$ 10.83	$58.5	$732.0
ETS	21.4	$0.20450	$4.4	67.9	$0.16092	$10.9	197.9	$0.09165	$18.1	287.2	$33.4	-	$0.000	$0.0	0.2	$ 18.82	$2.9	$36.3
Total	**4,206.9**		**$677.9**	**67.9**		**$10.9**	**197.9**		**$18.1**	**4,472.7**	**$707.0**	**-**		**$0.0**	**5.6**		**$61.4**	**$768.3**
Commercial Sector																		
Small General	49.4	$0.16595	$8.2	238.4	$0.14781	$35.2	-		$0.0	287.8	$43.4	-	$0.000	$0.0	0.3	$ 12.65	$3.9	$47.4
General Demand	1,265.0	$0.12726	$161.0	1,095.7	$0.09447	$103.5	-		$0.0	2,360.7	$264.5	6,379.7	$10.497	$67.0				$331.5
Large General																		
Without Trans. Own.	238.8	$0.09750	$23.3							238.8	$23.3	510.9	$13.345	$6.8				$30.1
With Trans. Own.	154.8	$0.09750	$15.1							154.8	$15.1	331.1	$13.025	$4.3				$19.4
Sub-total	393.6		$38.4							393.6	$38.4	841.9		$11.1				$49.5
Total	**1,708.0**		**$207.6**	**1,334.0**		**$138.7**				**3,042.1**	**$346.3**	**7,221.6**		**$78.1**	**0.3**		**$3.9**	**$428.3**
Industrial Sector																		
Small Industrial	164.8	$0.11613	$19.1	85.7	$0.09230	$7.9				250.6	$27.1	826.7	$7.714	$6.4				$33.4
Medium Industrial	472.9	$0.08876	$42.0							472.9	$42.0	858.4	$12.501	$10.7				$52.7
Large Industrial Firm																		
Without Trans. Own.	48.8	$0.09185	$4.5							48.8	$4.5	105.3	$11.995	$1.3				$5.7
With Trans. Own.	79.1	$0.09185	$7.3							79.1	$7.3	170.6	$11.675	$2.0				$9.3
Sub-total	127.9		$11.8							127.9	$11.8	275.9		$3.3				$15.0
Large Industrial Interr.																		
Without Trans. Own.	254.0	$0.08766	$22.3							254.0	$22.3	569.6	$8.565	$4.9				$27.1
With Trans. Own.	541.4	$0.08766	$47.5							541.4	$47.5	1,214.1	$8.245	$10.0				$57.5
Sub-total	795.4		$69.7							795.4	$69.7	1,783.7		$14.9				$84.6
Total Large Industrial	923.3		$81.5						$1.0	923.3	$81.5	2,059.6		$18.1				$99.6
Total Industrial	**1,561.1**		**$142.6**	**85.7**		**$7.9**				**1,646.8**	**$150.5**	**3,744.8**		**$35.3**	**0.0**		**$0.0**	**$185.8**
Other																		
Municipal																		
Without Trans. Own.	78.0	$0.09305	$7.3							78.0	$7.3	297.5	$12.445	$3.7				$11.0
With Trans. Own.	44.6	$0.09305	$4.2							44.6	$4.2	170.3	$12.125	$2.1				$6.2
Sub-total	122.6		$11.4							122.6	$11.4	467.8		$5.8				$17.2
Unmetered	81.0	$0.25974	$21.0							81.0	$21.0							$21.0
Total	**203.7**		**$32.5**							**203.7**	**$32.5**	**467.8**		**$5.8**				**$38.2**
Total FAM Classes	**7,679.7**		**$1,060.5**	**1,487.7**		**$157.6**	**197.9**		**$18.1**	**9,365.3**	**$1,236.2**	**11,434.2**		**$119.1**	**5.9**		**$65.3**	**$1,420.7**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Variance	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	-	($0.01360)	($56.9)	-	$0.00000	$0.0	-	$0.00000	$0.0	-	($56.9)	-	$0.000	$0.0	-	$ -	$0.0	($56.9)
ETS	-	($0.01360)	($0.3)	-	($0.01360)	($0.9)	-	($0.01360)	($2.7)	-	($3.9)	-	$0.000	$0.0	-	$ -	$0.0	($3.9)
Total	**-**		**($57.2)**	**-**		**($0.9)**	**-**		**($2.7)**	**-**	**($60.8)**	**-**		**$0.0**	**-**		**$0.0**	**($60.8)**
Commercial Sector																		
Small General	-	($0.01260)	($0.6)	-	($0.01260)	($3.0)	-		$0.0	-	($3.6)	-	$0.000	$0.0	-	$ -	$0.0	($3.6)
General Demand	-	($0.00660)	($8.3)	-	($0.00660)	($7.2)	-		$0.0	-	($15.6)	-	$0.000	$0.0				($15.6)
Large General										-		-	$0.000	$0.0				
Without Trans. Own.	-	($0.00050)	($0.1)							-	($0.1)	-	$0.000	$0.0				($0.1)
With Trans. Own.	-	($0.00050)	($0.1)							-	($0.1)	-	$0.000	$0.0				($0.1)
Sub-total	-		($0.2)							-	($0.2)	-		$0.0				($0.2)
Total	**-**		**($9.2)**	**-**		**($10.2)**				**-**	**($19.4)**	**-**		**$0.0**	**-**		**$0.0**	**($19.4)**
Industrial Sector																		
Small Industrial	-	($0.00618)	($1.0)	-	($0.00618)	($0.5)				-	($1.5)	-	$0.000	$0.0				($1.5)
Medium Industrial	-	$0.00162	$0.8							-	$0.8	-	$0.000	$0.0				$0.8
Large Industrial Firm													$0.000	$0.0				
Without Trans. Own.	-	$0.00376	$0.2							-	$0.2	-	$0.000	$0.0				$0.2
With Trans. Own.	-	$0.00376	$0.3							-	$0.3	-	$0.000	$0.0				$0.3
Sub-total	-		$0.5							-	$0.5	-		$0.0				$0.5
Large Industrial Interr.																		
Without Trans. Own.	-	$0.00293	$0.7							-	$0.7	-	$0.000	$0.0				$0.7
With Trans. Own.	-	$0.00293	$1.6							-	$1.6	-	$0.000	$0.0				$1.6
Sub-total	-		$2.3							-	$2.3	-		$0.0				$2.3
Total Large Industrial	-		$2.8						$1.0	-	$2.8	-		$0.0				$2.8
Total Industrial	**-**		**$2.6**	**-**		**($0.5)**				**-**	**$2.0**	**-**		**$0.0**	**0.0**		**$0.0**	**$2.0**
Other																		
Municipal																		
Without Trans. Own.	-	($0.00141)	($0.1)							-	($0.1)	-	$0.000	$0.0				($0.1)
With Trans. Own.	-	($0.00141)	($0.1)							-	($0.1)	-	$0.000	$0.0				($0.1)
Sub-total	-		($0.2)							-	($0.2)	-		$0.0				($0.2)
Unmetered	-	($0.00957)	($0.8)							-	($0.8)							($0.8)
Total	**-**		**($0.9)**							**-**	**($0.9)**	**-**		**$0.0**			**$0.0**	**($0.9)**
Total FAM Classes	**-**		**($64.8)**	**-**		**($11.7)**	**-**		**($2.7)**	**-**	**($79.2)**	**-**		**$0.0**	**-**		**$0.0**	**($79.2)**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

2022 Sales Priced at 2021 Rates	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	4,186.4	$0.16092	$673.7							4,186.4	$673.7				5.4	$ 10.83	$58.8	$732.5
ETS	21.9	$0.20450	$4.5	69.2	$0.16092	$11.1	201.6	$0.09165	$18.5	292.7	$34.1				0.2	$ 18.82	$2.9	$37.0
Total	**4,208.2**		**$678.1**	**69.2**		**$11.1**	**201.6**		**$18.5**	**4,479.1**	**$707.8**				**5.6**		**$61.7**	**$769.5**
Commercial Sector																		
Small General	49.5	$0.16595	$8.2	239.0	$0.14781	$35.3				288.6	$43.6				0.3	$ 12.65	$4.0	$47.5
General Demand	1,251.3	$0.12726	$159.2	1,083.8	$0.09447	$102.4				2,335.1	$261.6	6,310.4	$10.497	$66.2				$327.9
Large General																		
Without Trans. Own.	237.1	$0.09750	$23.1							237.1	$23.1	507.2	$13.345	$6.8				$29.9
With Trans. Own.	153.7	$0.09750	$15.0							153.7	$15.0	328.7	$13.025	$4.3				$19.3
Sub-total	390.8		$38.1							390.8	$38.1	835.9		$11.0				$49.2
Total	**1,691.6**		**$205.6**	**1,322.8**		**$137.7**				**3,014.4**	**$343.3**	**7,146.3**		**$77.3**	**0.3**		**$4.0**	**$424.5**
Industrial Sector																		
Small Industrial	165.1	$0.11613	$19.2	85.9	$0.09230	$7.9				250.9	$27.1	827.9	$7.714	$6.4				$33.5
Medium Industrial	469.8	$0.08876	$41.7							469.8	$41.7	852.9	$12.501	$10.7				$52.4
Large Industrial Firm																		
Without Trans. Own.	48.8	$0.09185	$4.5							48.8	$4.5	105.2	$11.995	$1.3				$5.7
With Trans. Own.	79.0	$0.09185	$7.3							79.0	$7.3	170.5	$11.675	$2.0				$9.2
Sub-total	127.8		$11.7							127.8	$11.7	275.6		$3.3				$15.0
Large Industrial Interr.																		
Without Trans. Own.	253.3	$0.08766	$22.2							253.3	$22.2	568.1	$8.565	$4.9				$27.1
With Trans. Own.	540.0	$0.08766	$47.3							540.0	$47.3	1,211.0	$8.245	$10.0				$57.3
Sub-total	793.3		$69.5							793.3	$69.5	1,779.1		$14.9				$84.4
Total Large Industrial	921.1		$81.3							921.1	$81.3	2,054.7		$18.1				$99.4
Total Industrial	**1,556.0**		**$142.2**	**85.9**		**$7.9**				**1,641.9**	**$150.1**	**3,735.4**		**$35.1**				**$185.2**
Other																		
Municipal																		
Without Trans. Own.	77.0	$0.09305	$7.2							77.0	$7.2	299.3	$12.445	$3.7				$10.9
With Trans. Own.	44.1	$0.09305	$4.1							44.1	$4.1	171.3	$12.125	$2.1				$6.2
Sub-total	121.1		$11.3							121.1	$11.3	470.6		$5.8				$17.1
Unmetered	81.0	$0.25974	$21.0							81.0	$21.0							$21.0
Total	**202.1**		**$32.3**							**202.1**	**$32.3**	**470.6**		**$5.8**				**$38.1**
Total FAM Classes	**7,658.0**		**$1,058.2**	**1,477.9**		**$156.8**	**201.6**		**$18.5**	**9,337.5**	**$1,233.4**	**11,352.3**		**$118.2**	**5.9**		**$65.7**	**$1,417.4**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

2022 Sales Priced at 2022 Rates	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	4,186.4	$0.16341	$684.1							4,186.4	$684.1	-	$0.000	$0.0	5.4	$ 10.83	$58.8	$742.9
ETS	21.9	$0.20699	$4.5	69.2	$0.16341	$11.3	201.6	$0.09414	$19.0	292.7	$34.8	-	$0.000	$0.0	0.2	$ 18.82	$2.9	$37.7
Total	**4,208.2**		**$688.6**	**69.2**		**$11.3**	**201.6**		**$19.0**	**4,479.1**	**$718.9**	**-**		**$0.0**	**5.6**		**$61.7**	**$780.6**
Commercial Sector																		
Small General	49.5	$0.16752	$8.3	239.0	$0.14938	$35.7	-		$0.0	288.6	$44.0	-	$0.000	$0.0	0.3	$ 12.65	$4.0	$48.0
General Demand	1,251.3	$0.13098	$163.9	1,083.8	$0.09819	$106.4	-		$0.0	2,335.1	$270.3	6,310.4	$10.497	$66.2				$336.5
Large General																		
Without Trans. Own.	237.1	$0.09864	$23.4							237.1	$23.4	507.2	$13.345	$6.8				$30.2
With Trans. Own.	153.7	$0.09864	$15.2							153.7	$15.2	328.7	$13.025	$4.3				$19.4
Sub-total	390.8		$38.5							390.8	$38.5	835.9		$11.0				$49.6
Total	**1,691.6**		**$210.7**	**1,322.8**		**$142.1**				**3,014.4**	**$352.9**	**7,146.3**		**$77.3**	**0.3**		**$4.0**	**$434.1**
Industrial Sector																		
Small Industrial	165.1	$0.11969	$19.8	85.9	$0.09586	$8.2				250.9	$28.0	827.9	$7.714	$6.4				$34.4
Medium Industrial	469.8	$0.09317	$43.8							469.8	$43.8	852.9	$12.501	$10.7				$54.4
Large Industrial Firm																		
Without Trans. Own.	48.8	$0.09640	$4.7							48.8	$4.7	105.2	$11.995	$1.3				$6.0
With Trans. Own.	79.0	$0.09640	$7.6							79.0	$7.6	170.5	$11.675	$2.0				$9.6
Sub-total	127.8		$12.3							127.8	$12.3	275.6		$3.3				$15.6
Large Industrial Interr.																		
Without Trans. Own.	253.3	$0.09184	$23.3							253.3	$23.3	568.1	$8.565	$4.9				$28.1
With Trans. Own.	540.0	$0.09184	$49.6							540.0	$49.6	1,211.0	$8.245	$10.0				$59.6
Sub-total	793.3		$72.9							793.3	$72.9	1,779.1		$14.9				$87.7
Total Large Industrial	921.1		$85.2						$1.0	921.1	$85.2	2,054.7		$18.1				$103.3
Total Industrial	**1,556.0**		**$148.7**	**85.9**		**$8.2**				**1,641.9**	**$156.9**	**3,735.4**		**$35.1**	**0.0**		**$0.0**	**$192.1**
Other																		
Municipal																		
Without Trans. Own.	77.0	$0.09741	$7.5							77.0	$7.5	299.3	$12.445	$3.7				$11.2
With Trans. Own.	44.1	$0.09741	$4.3							44.1	$4.3	171.3	$12.125	$2.1				$6.4
Sub-total	121.1		$11.8							121.1	$11.8	470.6		$5.8				$17.6
Unmetered	81.0	$0.26397	$21.4							81.0	$21.4							$21.4
Total	**202.1**		**$33.2**							**202.1**	**$33.2**	**470.6**		**$5.8**				**$39.0**
Total FAM Classes	**7,658.0**		**$1,081.3**	**1,477.9**		**$161.7**	**201.6**		**$19.0**	**9,337.5**	**$1,261.9**	**11,352.3**		**$118.2**	**5.9**		**$65.7**	**$1,445.8**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

Variance	First KWh Block			Second KWh Block			Third KWh Block			Total Energy		Demand			Base Charge			
FAM Classes	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue (millions)	Energy in GWh	Per KWh Charge	Revenue	GWHS	Revenue (millions)	MWS or MVAS	Charge per KW or KVA	Revenue (millions)	Billmonths (millions)	Base Charge	Revenue (millions)	Revenue (millions)
Residential Sector																		
Non-ETS	-	$0.00249	$10.4	-	$0.00000	$0.0	-	$0.00000	$0.0	-	$10.4	-	$0.000	$0.0	-	$ -	$0.0	$10.4
ETS	-	$0.00249	$0.1	-	$0.00249	$0.2	-	$0.00249	$0.5	-	$0.7	-	$0.000	$0.0	-	$ -	$0.0	$0.7
Total	**-**		**$10.5**	**-**		**$0.2**	**-**		**$0.5**	**-**	**$11.2**	**-**		**$0.0**	**-**		**$0.0**	**$11.2**
Commercial Sector																		
Small General	-	$0.00157	$0.1	-	$0.00157	$0.4	-		$0.0	-	$0.5	-	$0.000	$0.0	-	$ -	$0.0	$0.5
General Demand	-	$0.00372	$4.7	-	$0.00372	$4.0	-		$0.0	-	$8.7	-	$0.000	$0.0				$8.7
Large General										-		-	$0.000	$0.0				
Without Trans. Own.	-	$0.00114	$0.3							-	$0.3	-	$0.000	$0.0				$0.3
With Trans. Own.	-	$0.00114	$0.2							-	$0.2	-	$0.000	$0.0				$0.2
Sub-total	-		$0.4							-	$0.4	-		$0.0				$0.4
Total	**-**		**$5.2**	**-**		**$4.4**				**-**	**$9.6**	**-**		**$0.0**	**-**		**$0.0**	**$9.6**
Industrial Sector																		
Small Industrial	-	$0.00356	$0.6	-	$0.00356	$0.3				-	$0.9	-	$0.000	$0.0				$0.9
Medium Industrial	-	$0.00441	$2.1							-	$2.1	-	$0.000	$0.0				$2.1
Large Industrial Firm													$0.000	$0.0				
Without Trans. Own.	-	$0.00455	$0.2							-	$0.2	-	$0.000	$0.0				$0.2
With Trans. Own.	-	$0.00455	$0.4							-	$0.4	-	$0.000	$0.0				$0.4
Sub-total	-		$0.6							-	$0.6	-		$0.0				$0.6
Large Industrial Interr.																		
Without Trans. Own.	-	$0.00418	$1.1							-	$1.1	-	$0.000	$0.0				$1.1
With Trans. Own.	-	$0.00418	$2.3							-	$2.3	-	$0.000	$0.0				$2.3
Sub-total	-		$3.3							-	$3.3	-		$0.0				$3.3
Total Large Industrial	-		$3.9						$1.0	-	$3.9	-		$0.0				$3.9
Total Industrial	**-**		**$6.6**	**-**		**$0.3**				**-**	**$6.9**	**-**		**$0.0**	**0.0**		**$0.0**	**$6.9**
Other																		
Municipal																		
Without Trans. Own.	-	$0.00436	$0.3							-	$0.3	-	$0.000	$0.0				$0.3
With Trans. Own.	-	$0.00436	$0.2							-	$0.2	-	$0.000	$0.0				$0.2
Sub-total	-		$0.5							-	$0.5	-		$0.0				$0.5
Unmetered	-	$0.00423	$0.3							-	$0.3							$0.3
Total	**-**		**$0.9**							**-**	**$0.9**	**-**		**$0.0**			**$0.0**	**$0.9**
Total FAM Classes	**-**		**$23.1**	**-**		**$4.9**	**-**		**$0.5**	**-**	**$28.5**	**-**		**$0.0**	**-**		**$0.0**	**$28.5**

Note: Any differences between simulated revevenues in this document and apportioned revenue responsibilities to rate classes in Revenue Analysis Appendix are due to rounding of rate components.

REDACTED (CONFIDENTIAL INFORMATION REMOVED)

	Energy Splits			Demand Splits		
	2020	2021	2022	2020	2021	2022
Domestic Non-TOD	0.999	0.999	0.999			
Domestic Non-TOD	93.7%	93.6%	93.5%			
Domestic Time-of-Day	6.3%	6.4%	6.5%			
	100.0%	100.0%	100.0%			
Domestic Time-of-Day	1.004	1.004	1.004			
Blcok 1	7.5%	7.5%	7.5%			
Blcok 2	23.6%	23.6%	23.6%			
Blcok 3	68.9%	68.9%	68.9%			
	100.0%	100.0%	100.0%			
Small General	0.9996	0.9996	0.9996			
Blcok 1	17.2%	17.2%	17.2%			
Blcok 2	82.8%	82.8%	82.8%			
	100.0%	100.0%	100.0%			
General Demand	0.9982	0.9982	0.9982			
Blcok 1	53.6%	53.6%	53.6%			
Blcok 2	46.4%	46.4%	46.4%			
	100.0%	100.0%	100.0%			
Small Industrial	0.9998	0.9998	0.9998			
Blcok 1	65.8%	65.8%	65.8%			
Blcok 2	34.2%	34.2%	34.2%			
	100.0%	100.0%	100.0%			
Large General						
Without Trans. Own.	60.7%	60.7%	60.7%	60.7%	60.7%	60.7%
With Trans. Own.	39.3%	39.3%	39.3%	39.3%	39.3%	39.3%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Medium Industrial	0.992	0.992	0.992			
Large Industrial Firm						
Without Trans. Own.	38.2%	38.2%	38.2%	38.2%	38.2%	38.2%
With Trans. Own.	61.8%	61.8%	61.8%	61.8%	61.8%	61.8%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Large Industrial Interruptible						
Without Trans. Own.	31.9%	31.9%	31.9%	31.9%	31.9%	31.9%
With Trans. Own.	68.1%	68.1%	68.1%	68.1%	68.1%	68.1%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Municipal						
Without Trans. Own.	63.6%	63.6%	63.6%	63.6%	63.6%	63.6%
With Trans. Own.	36.4%	36.4%	36.4%	36.4%	36.4%	36.4%
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

DOMESTIC SERVICE TARIFF **Page 1 of 2**
Rate Codes 02, 03, 04

CUSTOMER CHARGE

$10.83 per month.

ENERGY CHARGE

	Cents per Kilowatt hour
Effective January 1, 2020	17.452
Effective January 1, 2021	16.092
Effective January 1, 2022	16.341

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $10.83.

AVAILABILITY:

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the domestic tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial

tariff shall be applied.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service rate.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)

Rate Code 05, 06 **Page 1 of 2**

CUSTOMER CHARGE

$18.82 per month

ENERGY CHARGES

	December, January and February			
	7:00 am to 12:00 pm	**12:00 pm to 4:00 pm**	**4:00 pm to 11:00 pm**	**11:00 pm to 7:00 am**
Effective January 1, 2020	21.810	17.452	21.810	10.525
Effective January 1, 2021	20.450	16.092	20.450	9.165
Effective January 1, 2022	20.699	16.341	20.699	9.414

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for 11:00 pm to 7:00 am.

	March to November	
	7:00 am to 11:00 pm	**11:00 pm to 7:00 am**
Effective January 1, 2020	17.452	10.525
Effective January 1, 2021	16.092	9.165
Effective January 1, 2022	16.341	9.414

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for 11:00 pm to 7:00 am.

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $18.82.

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)

Rate Code 05, 06 **Page 2 of 2**

AVAILABILITY:

This tariff is only available to customers employing electric-based heating systems utilizing Electric Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls approved by the Company.

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the Domestic Service Time Of Day Tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

SMALL GENERAL TARIFF
Rate Code 10 **Page 1 of 1**

CUSTOMER CHARGE

$12.65 per month

ENERGY CHARGE

	Cents per kilowatt hour	
	For the first 200 kilowatt hours per month	**For all additional kilowatt hours**
Effective January 1, 2020	17.855	16.041
Effective January 1, 2021	16.595	14.781
Effective January 1, 2022	16.752	14.938

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric energy for use where the annual consumption is less than 32,000 kWh per year and for which no other rates are applicable, and is available to customers on the General tariff where the annual consumption is less than 45,000 kWh per year.

For customers that elect to take service under the Small General tariff, where the General tariff is otherwise applicable, the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

GENERAL TARIFF
Rate Code 11 **Page 1 of 2**

DEMAND CHARGE

$10.497 per month per kilowatt of maximum demand.

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

	Cents per kilowatt hour	
	For the first 200 kilowatt-hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	13.386	10.107
Effective January 1, 2021	12.726	9.447
Effective January 1, 2022	13.098	9.819

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh, or greater and for which no other rates are applicable.

For General tariff customers eligible for the Small General tariff the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

GENERAL TARIFF
Rate Code 11 **Page 2 of 2**

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

LARGE GENERAL TARIFF
(2,000 kVA or 1 800 kW, and Over)
Rate Code 12

DEMAND CHARGE

$13.345 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

	Cents per kilowatt hour
Effective January 1, 2020	9.800
Effective January 1, 2021	9.750
Effective January 1, 2022	9.864

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW, and over.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation.

Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustments to the metered kWh usage will be made under the following conditions:

LARGE GENERAL TARIFF
(2,000 kVA or 1 800 kW, and Over)
Rate Code 12

(a) If the substation high voltage side is 69 kV or higher, and metering is on the high voltage side, meter readings shall be reduced by 1.75%.

(b) If the substation high voltage side is lower than 69 kV, and metering is on the low voltage side, meter readings shall be increased by 1.75%.

(2) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a billing demand of 2,000 kVA or 1,800 kW.

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

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

DEMAND CHARGE

$7.714 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

	Cents per kilowatt hour	
	For the first 200 kilowatt hours per month per kilovolt ampere of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	12.231	9.848
Effective January 1, 2021	11.613	9.230
Effective January 1, 2022	11.969	9.586

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kVA or 225 kW.

SPECIAL CONDITIONS:

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

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

MEDIUM INDUSTRIAL TARIFF
(250 kVA or 225 kW – 1,999 kVA or 1,799 kW)
Rate Code 22

DEMAND CHARGE

$12.501 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

	Cents per kilowatt hour
Effective January 1, 2020	8.714
Effective January 1, 2021	8.876
Effective January 1, 2022	9.317

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any industrial customer having a regular billing demand of 250 kVA (225 kW) and over, and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) The Company may withdraw the availability of this tariff to any specific customer, if, in the opinion of the Company, the customer is not maintaining a billing demand of 250 kVA (225 kW).

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

DEMAND CHARGE

$11.995 per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer

ENERGY CHARGE

	Cents per kilowatt hour	
	Firm customers	**Interruptible customers**
Effective January 1, 2020	8.809	8.473
Effective January 1, 2021	9.185	8.766
Effective January 1, 2022	9.640	9.184

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the greater of $12.65 or the demand charge.

AVAILABILITY:

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

SPECIAL CONDITIONS:

(1) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

(2) Metering will normally be at the low voltage side of the transformer. Should the customer's

requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering.

(3) The Company will withdraw the availability of this tariff to any specific firm load only customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. Any customer whose total or partial load is billed under the interruptible rider to this tariff and whose total demand fell, on a consistent basis, below 2 000 kVA or 1,800 kW after subscription to the interruptible service will be exempted from the minimum load requirement of this tariff.

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

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

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

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

AVAILABILITY:

This rider will be applicable to an agreed upon, between the Company and the customer, interruptible billing demand at 90% Power Factor, under the following terms and conditions:

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

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

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

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

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

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

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

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

Where:

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

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

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

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

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

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

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

(4) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

DEMAND CHARGE

$12.445 per month per kilovolt ampere of the higher of:

(a) maximum actual demand of the current month or

(b) the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months but excluding the actual monthly peak demands recorded during the first two hours following restoration of any outage of at least one hour in duration. In this circumstance, the next highest monthly peak demand, registered outside of the restoration period, will be used. Customers will make reasonable efforts to manage post-restoration demand peaks.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

	Cents per kilowatt hour
Effective January 1, 2020	9.446
Effective January 1, 2021	9.305
Effective January 1, 2022	9.741

FUEL ADJUSTMENT MECHANISM (FAM)

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

AVAILABILITY:

This tariff is applicable to three phase electric power and energy, supplied at the low voltage side of the bulk power transformer, to municipal electric utilities. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformation losses. Also, meter readings shall be reduced when metering is at transmission voltage.

OUTDOOR RECREATIONAL LIGHTING TARIFF
Rate Code 41

ENERGY CHARGE

	Cents per kilowatt hour
Effective January 1, 2020	17.828
Effective January 1, 2021	16.871
Effective January 1, 2022	17.293

FUEL ADJUSTMENT MECHANISM (FAM)

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

AVAILABILITY

This rate is available to all outdoor recreational lighting for the period May through October only.

(A) STREET AND AREA LIGHTING

AVAILABILITY:

These rates shall be applicable to the supply, operation and maintenance, or where indicated, operation and maintenance only, of street and area lighting. Except where otherwise indicated, the rates apply to fixtures operating for approximately 4000 hours per year. Maintenance does not include globe washing, cleaning, repair, or replacement of parts or bulbs necessitated by vandalism. Such costs will be charged to the customer.

FUEL ADJUSTMENT MECHANISM (FAM)

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

RATES

(1) INCANDESCENT

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Month.**	**2020**	**2021**	**2022**	
001	300 and less	97	24.09	23.16	23.57	
002	Greater than 300	154	34.22	32.74	33.39	

b) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Month.**	**2020**	**2021**	**2022**	
003	300 and Less	97	17.05	16.12	16.53	

(2) **MERCURY VAPOUR**

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
100	100	43	15.93	15.52	15.70	
101	125	52	19.01	18.51	18.73	
102	175	69	20.24	19.58	19.87	
103	250	97	25.90	24.97	25.38	
104	400	154	35.99	34.51	35.16	
105	700	260	55.81	53.32	54.42	
106	1000	363	74.94	71.47	73.00	
107	250	212	44.06	42.04	42.93	Continuous Operation

b) Operating and Maintenance Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
201	125	52	16.00	15.50	15.72	
202	175	69	17.27	16.61	16.90	
203	250	97	22.21	21.28	21.69	
204	400	154	32.22	30.74	31.39	
205	700	260	50.86	48.37	49.47	
206	1000	363	68.96	65.49	67.02	

c) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
301	125	52	9.13	8.63	8.85	
302	175	69	12.11	11.45	11.74	
303	250	97	17.05	16.12	16.53	
304	400	154	27.06	25.58	26.23	
305	700	260	45.70	43.21	44.31	
306	1000	363	63.80	60.33	61.86	

(3) **FLUORESCENT**

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)			Other
				2020	2021	2022	
110	24	2	30	18.02	17.74	17.86	
111	48	2	85	27.94	27.13	27.49	
112	72	2	116	33.87	32.76	33.25	
113	72	4	222	53.61	51.49	52.42	
114	96	1	47	21.53	21.08	21.28	
115	72	1	60	23.44	22.86	23.12	
116	48	4	166	42.76	41.17	41.87	

b) Operating and Maintenance Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)			
				2020	2021	2022	
213	72	4	222	49.31	47.19	48.12	
214	96	1	47	18.56	18.11	18.31	
215	72	1	60	20.86	20.28	20.54	
216	48	4	166	39.51	37.92	38.62	
217	48	1	49	18.90	18.43	18.64	
218	48	2	85	25.25	24.44	24.80	

c) Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)			
				2020	2021	2022	
330	35	4	47	8.25	7.80	8.00	

(4) **FLUORESCENT CROSSWALK**

a) Continuous Burning - Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)			
				2020	2021	2022	
117	72	4	486	68.91	64.26	66.31	
118	24	2	66	9.35	8.72	9.00	
119	48	4	364	51.63	48.15	49.68	
120	96	2	254	36.03	33.60	34.67	
150	96	4	613	86.93	81.06	83.65	

b) Photocell Operation - Operating Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)			Other
				2020	2021	2022	
310	24	2	30	5.28	5.00	5.12	
311	48	4	166	29.20	27.61	28.31	
312	72	2	116	20.41	19.30	19.79	
313	72	4	222	39.00	36.88	37.81	
314	96	1	47	8.25	7.80	8.00	
315	72	1	60	10.55	9.97	10.23	
350	96	4	280	49.22	46.55	47.73	

(5) LOW PRESSURE SODIUM

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
130	135	60	31.81	31.23	31.49	
131	180	80	37.91	37.15	37.48	
132	90	45	29.16	28.73	28.92	

b) Operating and Maintenance Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
231	180	80	29.53	28.77	29.10	

c) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
331	180	80	14.06	13.30	13.63	

(6) **HIGH PRESSURE SODIUM**

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
121	250	100	25.95	24.99	25.41	
122	400	150	34.86	33.42	34.05	
123	70	32	13.79	13.49	13.62	
124	100	45	16.10	15.67	15.86	
125	150	65	19.80	19.18	19.46	
126	100	99	27.38	26.43	26.85	Continuous Operation

b) Operating and Maintenance Only

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
221	250	100	$22.74	$21.78	$22.20	
222	70	32	10.77	10.47	10.60	
223	100	45	13.06	12.63	12.82	
224	150	65	16.58	15.96	16.24	

c) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
321	250	100	17.58	16.62	17.04	
322	70	32	5.61	5.31	5.44	
323	100	45	7.90	7.47	7.66	
324	150	65	11.42	10.80	11.08	
326	400	150	26.37	24.93	25.56	
327	500	183	32.18	30.42	31.20	
328	1000	363	63.81	60.34	61.87	
329	1500	500	87.88	83.10	85.21	

(7) **METALLIC ADDITIVE**

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
140	400	150	38.43	36.99	37.62	
141	1000	360	81.22	77.77	79.29	
142	250	100	33.70	32.74	33.16	
143	150	67	27.89	27.25	27.53	
144	100	50	24.91	24.43	24.64	

b) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
341	1000	360	63.28	59.83	61.35	
342	400	150	26.37	24.93	25.56	
343	250	100	17.58	16.62	17.04	
344	175	75	13.18	12.46	12.78	
345	150	67	11.77	11.13	11.41	
346	100	50	8.79	8.31	8.52	

(8) **LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY**

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
530	4.6	2	0.35	0.33	0.34	Non-Continuous
531	7.5	5	0.71	0.66	0.68	Continuous

(9) **LIGHT EMITTING DIODE (LED) – Operating Only**

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
532	44	15	2.64	2.49	2.56	
533	66	22	3.87	3.66	3.75	
534	88	29	5.10	4.82	4.94	
535	92	31	5.45	5.15	5.28	
536	105	35	6.15	5.82	5.96	
537	170	57	10.02	9.47	9.71	
539	110	37	6.50	6.15	6.31	
540	65	22	3.87	3.66	3.75	
541	55	18	3.16	2.99	3.07	
542	83	28	4.92	4.65	4.77	
543	48	16	2.81	2.66	2.73	
544	72	24	4.22	3.99	4.09	

(10) **LIGHT EMITTING DIODE (LED) – Operating & Capital Only (full charge)**

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
615	44	15	9.82	9.67	9.74	
616	55	18	10.34	10.17	10.25	
623	28	9	8.76	8.68	8.71	
624	50	17	10.17	10.01	10.08	
625	72	24	11.40	11.17	11.27	
626	100	33	12.98	12.66	12.80	
627	200	67	18.96	18.32	18.60	

(11) **LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital (full charge)**

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
724	55	18	10.27	10.10	10.18	
740	190	63	24.54	23.94	24.21	
741	261	87	30.49	29.66	30.03	
742	124	41	17.82	17.42	17.60	
743	84	28	14.85	14.58	14.70	

(B) **MISCELLANEOUS LIGHTING**

DEMAND CHARGE

$11.777 per month per kilowatt of connected load.

ENERGY CHARGE

	Cents per kilowatt hour	
	For the first 200 kilowatt hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	15.854	11.328
Effective January 1, 2021	14.897	10.371
Effective January 1, 2022	15.319	10.793

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill for the electric power and energy portion of the Miscellaneous Lighting Rate shall be $17.51 per month if such unmetered service is billed separately from any metered account.

CAPITAL CHARGE: (if applicable)

Depreciation based on a 25 year life, and interest at the Company's long term rate shall be used to determine the monthly capital charge.

MAINTENANCE CHARGE: (if applicable)

Cost of normal fixture maintenance and bulb replacement on the basis of current cost levels shall be used to calculate the monthly maintenance charge.

This portion of the rate does not include any provision for globe washing or cleaning. Repair or replacement of parts or bulbs necessitated by vandalism will be charged to the customer.

AVAILABILITY:

This rate shall be applicable to the supply, operation and maintenance of lighting units not provided for under the Street and Area Lighting rate.

(C) **MISCELLANEOUS SMALL LOADS**

DEMAND CHARGE

$11.777 per month per kilowatt of connected load.

ENERGY CHARGE

	Cents per kilowatt hour	
	For the first 200 kilowatt hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	15.854	11.328
Effective January 1, 2021	14.897	10.371
Effective January 1, 2022	15.319	10.793

The flat rate calculation (using a 30 day month) will be based on the specific information of each service using the above rate. The charge will be expressed in cents per kWh per month and will be rounded to hundredths of a cent in its application.

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall be $17.51 per month if such unmetered service is billed separately from any metered account.

AVAILABILITY:

A flat rate shall be calculated for any service requiring the supply of power and energy only, with a predeterminable usage, and where metering is considered to be impractical, such as: Telephone Booths, Cable Vision Power Supplies, Traffic Control Lights, Police Telephones, Railway Signals, etc.

APPLICABILITY:

This schedule is a mandatory rider to all electric rate schedules, except the following tariffs: Generation Replacement and Load Following, Extra High Voltage Time-of-Use Real Time Pricing, High Voltage Time-of-Use Real Time Pricing, Distribution Voltage Time-of-Use Real Time Pricing. FAM adjustments will apply to the Standard Energy Charge of the Extra Large Industrial 2P-RTP tariff. FAM adjustments will apply to Additional Energy supplied under the Mersey System Agreement when Additional Energy is priced at a tariff to which FAM adjustments apply.

FUEL ADJUSTMENT:

The applicable charges for electric service to the Company's retail and municipal customers shall be increased or decreased to the nearest 0.001 cents per kWh to recover or credit the difference in actual fuel cost from the costs in base rates in accordance with the following rate class-specific formula:

Fuel Adjustment Rider = AA + BA

Where:

"AA" is a rate class-specific Actual Adjustment which is the difference between fuel-related costs recovered from a rate class through the application of the base rates during the previous calendar year and the actual Fuel Costs incurred and allocated to the rate class for the same time period. The actual fuel costs will include the same cost items as base fuel costs.

"BA" is a rate class-specific Balance Adjustment which accounts for any over- or under-collections which have occurred as a result of prior adjustments.

SPECIAL CONDITIONS:

(1) Base Cost of Fuel

The Base Cost of Fuel can be re-set in a General Rate Application or, absent a General Rate Application, every second year as part of the FAM adjustment process. Changes in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the then-current Board-approved Cost of Service Methodology.

(2) Incentive

For a total fuel cost variance of up to $50 million dollars (Actual Fuel Costs - [(Actual Sales) x (Base Fuel Cost $/Mwh)]), 90% of any savings or increase in cost will be credited or charged to customers. The portion of any variance that is in excess of $50 million dollars will be fully applied in the calculation of the "AA". Credits or charges will be applied to the energy component of rates on a cents per kWh basis.

(3) Load Migration to non-FAM classes

When a customer transitions its load, whether in whole or in part, from a FAM class to a non-FAM class, NS Power shall determine the outstanding fuel cost imbalance of the customer at the time of transition. This determined imbalance will be adjusted as necessary in future FAM proceedings concerned with apportionment of fuel costs incurred in the period in question. The adjustments will be subject to UARB approval. The outstanding imbalance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB.

The applicable charges by rate class are as follows.

	Effective January 1, 2020		
Rate Class	**Actual Adjustment (AA) in cents per kWh**	**Balance Adjustment (BA) in cents per kWh**	**FAM AA/BA Combined in cents per kWh**
Domestic Service	0.372	(1.979)	(1.607)
Domestic Service Time of Day	0.372	(1.979)	(1.607)
Small General	0.282	(1.698)	(1.416)
General	0.691	(1.712)	(1.021)
Large General	(0.121)	(0.042)	(0.163)
Small Industrial	0.645	(1.610)	(0.965)
Medium Industrial	0.559	(0.822)	(0.263)
Large Industrial Firm	0.515	(0.577)	(0.062)
Large Industrial Interruptible	0.515	(0.625)	(0.110)
Municipal	0.596	(1.157)	(0.561)
Unmetered	0.992	(2.365)	(1.373)

	Effective January 1, 2021		
Rate Class	**Actual Adjustment (AA) in cents per kWh**	**Balance Adjustment (BA) in cents per kWh**	**FAM AA/BA Combined in cents per kWh**
Domestic Service	0.000	0.000	0.000
Domestic Service Time of Day	0.000	0.000	0.000
Small General	0.000	0.000	0.000
General	0.000	0.000	0.000
Large General	0.000	0.000	0.000
Small Industrial	0.000	0.000	0.000
Medium Industrial	0.000	0.000	0.000
Large Industrial Firm	0.000	0.000	0.000
Large Industrial Interruptible	0.000	0.000	0.000
Municipal	0.000	0.000	0.000
Unmetered	0.000	0.000	0.000

	Effective January 1, 2022		
Rate Class	**Actual Adjustment (AA) in cents per kWh**	**Balance Adjustment (BA) in cents per kWh**	**FAM AA/BA Combined in cents per kWh**
Domestic Service	0.000	0.000	0.000
Domestic Service Time of Day	0.000	0.000	0.000
Small General	0.000	0.000	0.000
General	0.000	0.000	0.000
Large General	0.000	0.000	0.000
Small Industrial	0.000	0.000	0.000
Medium Industrial	0.000	0.000	0.000
Large Industrial Firm	0.000	0.000	0.000
Large Industrial Interruptible	0.000	0.000	0.000
Municipal	0.000	0.000	0.000
Unmetered	0.000	0.000	0.000

DOMESTIC SERVICE TARIFF **Page 1 of 2**
Rate Codes 02, 03, 04

CUSTOMER CHARGE

$10.83 per month.

ENERGY CHARGE
~~15.603 cents per kilowatt hour~~

-	**Cents per Kilowatt hour**
Effective January 1, 2020	17.452
Effective January 1, 2021	16.092
Effective January 1, 2022	16.341

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $10.83.

AVAILABILITY:

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the domestic tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the

building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

Optional Green Power Rider

Customers taking service under this rider may choose to support NSPI's Green Power program by purchasing "blocks" of Green Power. For every block purchased, NSPI will provide 125 kWh per month from green energy sources, thereby displacing energy from fossil fuels. Blocks may be purchased at a cost of $5 per month. This charge shall be over and above the customer's normal bill for service taken under the Domestic Service rate.

Special Terms and Provisions

1. Green Power, as defined for the purposes of this rider includes energy produced from renewable resources that have minimal impact on the environment, and could be independently certified by third party environmental organizations.

2. Service under this rider may be limited at the discretion of the Company, based on the expected level of green energy available.

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 05, 06 **Page 1 of 2**

CUSTOMER CHARGE

$18.82 per month

ENERGY CHARGES

~~December, January and February~~

~~07:00 am to 12:00 pm 19.961 cents per kilowatt hour~~
~~12:00 pm to 04:00 pm 15.603 cents per kilowatt hour~~
~~04:00 pm to 11:00 pm 19.961 cents per kilowatt hour~~
~~11:00 pm to 07:00 am 8.676 cents per kilowatt hour~~

	December, January and February			
	7:00 am to 12:00 pm	**12:00 pm to 4:00 pm**	**4:00 pm to 11:00 pm**	**11:00 pm to 7:00 am**
Effective January 1, 2020	21.810	17.452	21.810	10.525
Effective January 1, 2021	20.450	16.092	20.450	9.165
Effective January 1, 2022	20.699	16.341	20.699	9.414

The above rates apply weekdays (Monday ~~to~~ through Friday inclusive), excluding statutory holidays. For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for -11:00 pm to 7:00 am. ~~of 8.676 cents per kilowatt hour.~~

~~March to November~~

~~07:00 am to 11:00 pm 15.603 cents per kilowatt hour~~
~~11:00 pm to 07:00 am 8.676 cents per kilowatt hour~~

	March to November	
	7:00 am to 11:00 pm	**11:00 pm to 7:00 am**
Effective January 1, 2020	17.452	10.525
Effective January 1, 2021	16.092	9.165
Effective January 1, 2022	16.341	9.414

The above rates apply weekdays (Monday through Friday inclusive), excluding statutory holidays.

DOMESTIC SERVICE TIME-OF-DAY TARIFF (OPTIONAL)
Rate Code 05, 06 **Page 2 of 2**

For Saturdays, Sundays and statutory holidays, all consumption will be billed at the rate for 11:00 pm to 7:00 am ~~of 8.676 cents per kilowatt hour~~.

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $18.82.

AVAILABILITY:

This tariff is only available to customers employing electric-based heating systems utilizing Electric Thermal Storage (ETS) equipment, and electric in-floor radiant heating systems utilizing thermal storage and appropriate timing and controls approved by the Company.

This tariff is applicable to electric energy used by any customer in a private residence for the customer's own domestic or household use, including lighting, cooking, heating, or refrigeration purposes. Upon application to the Company the Domestic Service Time Of Day Tariff shall be available to any other customer within the provisions of Section 73 of the Public Utilities Act, R.S.N.S. 1989, c. 380, as amended.

Any outbuilding located on residential property adjacent to a domestic dwelling and supplied electrically through a separate meter shall have rates applied in accordance with actual use of the building.

If the building is used principally for the owner's personal pursuits and hobbies, the Domestic tariff shall be applied.

If the building is used principally for commercial purposes the appropriate General or Industrial tariff shall be applied.

SMALL GENERAL TARIFF
Rate Code 10 **Page 1 of 2**

CUSTOMER CHARGE

$12.65 per month

ENERGY CHARGE

~~16.285 cents per kilowatt hour for the first 200 kilowatt hours per month~~

~~14.471 cents per kilowatt hour for all additional kilowatt hour~~

-	**Cents per kilowatt hour**	
	For the first 200 kilowatt hours per month	**For all additional kilowatt hours**
Effective January 1, 2020	17.855	16.041
Effective January 1, 2021	16.595	14.781
Effective January 1, 2022	16.752	14.938

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric energy for use where the annual consumption is less than 32,000 kWh per year and for which no other rates are applicable, and is available to customers on the General tariff where the annual consumption is less than 45,000 kWh per year.

SMALL GENERAL TARIFF
Rate Code 10 **Page 2 of 2**

For customers that elect to take service under the Small General tariff, where the General tariff is otherwise applicable, the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

GENERAL TARIFF
Rate Code 11 **Page 1 of 2**

DEMAND CHARGE

$10.497 per month per kilowatt of maximum demand.

32 cents per kilowatt reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

~~12.012 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of maximum demand.~~

~~8.733 cents per kilowatt hour for all additional kilowatt hours.~~

	Cents per kilowatt hour	
	For the first 200 kilowatt-hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	13.386	10.107
Effective January 1, 2021	12.726	9.447
Effective January 1, 2022	13.098	9.819

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

GENERAL TARIFF
Rate Code 11 **Page 2 of 2**

AVAILABILITY:

This tariff is applicable to electric power and energy where the annual consumption is 32,000 kWh, or greater and for which no other rates are applicable.

For General tariff customers eligible for the Small General tariff the following conditions apply:

- Customers must make a written request to take service under the Small General tariff.
- Customers can switch rate classes twice in a 24-month period.
- After switching, customers shall take service under this tariff for a minimum of six months subject to meeting the load threshold criteria.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

LARGE GENERAL TARIFF
(2,000 kVA or 1 800 kW, and Over)
Rate Code 12

DEMAND CHARGE

$13.345 per month per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

~~9.526 cents per kilowatt hour.~~

	Cents per kilowatt hour
Effective January 1, 2020	9.800
Effective January 1, 2021	9.750
Effective January 1, 2022	9.864

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy for any use except industrial, where the regular billing demand is 2,000 kVA or 1,800 kW, and over.

SPECIAL CONDITIONS:

LARGE GENERAL TARIFF
(2,000 kVA or 1 800 kW, and Over)
Rate Code 12

(1) Metering will normally be at the low voltage side of the substation.

Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustments to the metered kWh usage will be made under the following conditions:

(a) If the substation high voltage side is 69 kV or higher, and metering is on the high voltage side, meter readings shall be reduced by 1.75%.

(b) If the substation high voltage side is lower than 69 kV, and metering is on the low voltage side, meter readings shall be increased by 1.75%.

(2) The Company will withdraw the availability of this tariff to any specific customer, if, on a consistent basis, the customer is not maintaining a billing demand of 2,000 kVA or 1,800 kW.

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

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

DEMAND CHARGE

$7.714 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer was owned by the customer prior to February 1, 1974, or under Special Condition (2) as set out below.

ENERGY CHARGE

~~10.929 cents per kilowatt hour for the first 200 kilowatt hours per month per kilovolt ampere of maximum demand.~~

~~8.546 cents per kilowatt hour for all additional kilowatt hours.~~

	Cents per kilowatt hour	
	For the first 200 kilowatt hours per month per kilovolt ampere of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	12.231	9.848
Effective January 1, 2021	11.613	9.230
Effective January 1, 2022	11.969	9.586

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall not be less than $12.65.

AVAILABILITY:

SMALL INDUSTRIAL TARIFF
(Up to 249 kVA. or 224 kW)
Rate Code 21

This tariff is applicable to electric power and energy supplied to any customer, for industrial use, including farming and processing, where the regular billing demand is less than 250 kVA or 225 kW.

SPECIAL CONDITIONS:

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

Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter readings shall then be reduced by 1.75%.

(2) When the customer requires non-standard service provisions, the Company may require the customer to own any transformer normally provided by the Company.

MEDIUM INDUSTRIAL TARIFF
(250 kVA or 225 kW – 1,999 kVA or 1,799 kW)
Rate Code 22

DEMAND CHARGE

$12.501 per month per kilovolt ampere of maximum demand.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

~~8.044 cents per kilowatt hour.~~

	Cents per kilowatt hour
Effective January 1, 2020	8.714
Effective January 1, 2021	8.876
Effective January 1, 2022	9.317

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be $12.65.

AVAILABILITY:

This tariff is applicable to electric power and energy supplied to any industrial customer having a regular billing demand of 250 kVA (225 kW) and over, and for which no other rates are applicable.

SPECIAL CONDITIONS:

(1) Metering will normally be at the low voltage side of the substation. Should the customer's requirements make it necessary for the Company to provide primary metering, then the customer will be required to make a capital contribution equal to the additional capital cost of primary metering as opposed to the cost of secondary metering. Adjustment to the metered kWh usage will be made when metering is on the high voltage side. Meter

MEDIUM INDUSTRIAL TARIFF

(250 kVA or 225 kW – 1,999 kVA or 1,799 kW)

Rate Code 22

readings shall then be reduced by 1.75%.

(2) The Company may withdraw the availability of this tariff to any specific customer, if, in the opinion of the Company, the customer is not maintaining a billing demand of 250 kVA (225 kW).

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

DEMAND CHARGE

$11.995 per kilovolt ampere of maximum demand of the current month or the maximum actual demand of the previous December, January or February occurring in the previous eleven (11) months.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer

ENERGY CHARGE

~~8.325 cents per kilowatt hour for firm customers~~

~~7.976 cents per kilowatt hour for interruptible customerss~~

	Cents per kilowatt hour	
	Firm customers	**Interruptible customers**
Effective January 1, 2020	8.809	8.473
Effective January 1, 2021	9.185	8.766
Effective January 1, 2022	9.640	9.184

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

MINIMUM MONTHLY CHARGE

The minimum monthly charge shall be the greater of $12.65 or the demand charge.

AVAILABILITY:

LARGE INDUSTRIAL TARIFF
(2 000 kVA or 1 800 kW, and Over)
Rate Code 23

This tariff is applicable to three phase electric power and energy supplied at the low voltage side of the bulk power transformer to any industrial customer having a regular billing demand of 2 000 kVA or 1 800 kW, and over.

SPECIAL CONDITIONS:

(1) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

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

(3) The Company will withdraw the availability of this tariff to any specific firm load only customer, if, on a consistent basis, the customer is not maintaining a regular demand of 2 000 kVA or 1,800 kW or, as a result of transferring to this tariff from the Medium Industrial category the customer would not see a reduction in his electric cost for the energy supplied. Any customer whose total or partial load is billed under the interruptible rider to this tariff and whose total demand fell, on a consistent basis, below 2 000 kVA or 1,800 kW after subscription to the interruptible service will be exempted from the minimum load requirement of this tariff.

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

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

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

INTERRUPTIBLE RIDER TO THE LARGE INDUSTRIAL TARIFF (Rate Code 25)

Customers who qualify for interruptible service will receive a $3.43 per month per kilovolt ampere reduction in demand charge for billed interruptible demand. The billed interruptible demand is defined as the difference between any contracted firm demand requirements and the total billing

demand. Where the billing demand is less than the contracted firm demand, no interruptible credit shall apply. The billed interruptible demand will be the maximum interruptible demand of the current month or the maximum actual interruptible demand of the previous December, January or February occurring in the previous eleven (11) months.

AVAILABILITY:

This rider will be applicable to an agreed upon, between the Company and the customer, interruptible billing demand at 90% Power Factor, under the following terms and conditions:

(1) The customer has provided written notice of his desire to take service under this option, identifying that portion of the load that is to be firm and that portion that is to be interruptible.

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

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

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

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

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

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

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

Where:

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

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

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

(5) Should any customer under this rider desire to be served under any appropriate firm service rate, a five (5) year advance written notice must be given to the Company so as to ensure adequate capacity availability. Requests for conversion to firm service will be treated in the same manner as all other requests for firm service received by the Company. The Company may, however, permit an earlier conversion. In the event that the Customer desires to return to interruptible service in the future, the Customer may convert to interruptible service following two (2) years of service under the firm rate schedule. The Company may permit an earlier conversion from firm to interruptible service.

(6) Interruption is limited to 16 hours per day and 5 days per week to a maximum of 30% of the hours per month and 15% of the hours in a year.

SPECIAL CONDITIONS:

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

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

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

(4) At the option of the Company, supply may be at distribution voltage. Meter readings shall be increased by 1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformer losses. Also, meter readings shall be reduced when metering is at transmission voltage.

DEMAND CHARGE

$12.445 per month per kilovolt ampere of the higher of:

(a) maximum actual demand of the current month or

(b) the maximum actual demand of the previous December, January, or February occurring in the previous eleven (11) months but excluding the actual monthly peak demands recorded during the first two hours following restoration of any outage of at least one hour in duration. In this circumstance, the next highest monthly peak demand, registered outside of the restoration period, will be used. Customers will make reasonable efforts to manage post-restoration demand peaks.

32 cents per kilovolt ampere reduction in demand charge where the transformer is owned by the customer.

ENERGY CHARGE

~~8.480 cents per kilowatt hour.~~

	Cents per kilowatt hour
Effective January 1, 2020	9.446
Effective January 1, 2021	9.305
Effective January 1, 2022	9.741

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge.~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

AVAILABILITY:

This tariff is applicable to three phase electric power and energy, supplied at the low voltage side of the bulk power transformer, to municipal electric utilities. Meter readings shall be increased by

1.75% for each transformation between the meter and the low voltage side of the bulk power supply transformer to adjust for transformation losses. Also, meter readings shall be reduced when metering is at transmission voltage.

OUTDOOR RECREATIONAL LIGHTING TARIFF
Rate Code 41

ENERGY CHARGE

~~16.046 cents per kilowatt hour for all metered kilowatt hours per mont~~

-	**Cents per kilowatt hour**
Effective January 1, 2020	17.828
Effective January 1, 2021	16.871
Effective January 1, 2022	17.293

~~**DSM COST RECOVERY RIDER**~~

~~The Demand Side Management Cost Recovery Charge (in cents per kilowatt-hour) applicable to the Tariff for the current rate year, shown in the Demand Side Management Cost Recovery Rider, shall apply, in addition to the energy charge~~

FUEL ADJUSTMENT MECHANISM (FAM)

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

AVAILABILITY

This rate is available to all outdoor recreational lighting for the period May through October only.

(A) STREET AND AREA LIGHTING

AVAILABILITY:

These rates shall be applicable to the supply, operation and maintenance, or where indicated, operation and maintenance only, of street and area lighting. Except where otherwise indicated, the rates apply to fixtures operating for approximately 4000 hours per year. Maintenance does not include globe washing, cleaning, repair, or replacement of parts or bulbs necessitated by vandalism. Such costs will be charged to the customer.

FUEL ADJUSTMENT MECHANISM (FAM)

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

RATES

(1) INCANDESCENT

~~Rate Code~~	~~Watts~~	~~kWh/Mo.~~	~~$/Mo.~~	~~Other~~
~~a) Operating, Maintenance and Capital (Full Charge)~~				
~~001~~	~~300 and less~~	~~97~~	~~22.36~~	
~~002~~	~~Greater than 300~~	~~154~~	~~31.47~~	
~~b) Operating Only~~				
~~003~~	~~300 and Less~~	~~97~~	~~15.32~~	

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Month.**	**2020**	**2021**	**2022**	
001	300 and less	97	24.09	23.16	23.57	
002	Greater than 300	154	34.22	32.74	33.39	

b) Operating Only

Per Month ($)	

UNMETERED SERVICE RATES

Rate Code	Watts	kWh/Month.	2020	2021	2022	
003	300 and Less	97	17.05	16.12	16.53	

(2) **MERCURY VAPOUR**

~~Rate Code~~	~~Watts~~	~~kWh/Mo.~~	~~$/Mo.~~	~~Other~~
~~a) Operating, Maintenance and Capital (Full Charge)~~				
~~100~~	~~100~~	~~43~~	~~$15.16~~	
~~101~~	~~125~~	~~52~~	~~18.08~~	
~~102~~	~~175~~	~~69~~	~~19.01~~	
~~103~~	~~250~~	~~97~~	~~24.17~~	
~~104~~	~~400~~	~~154~~	~~33.24~~	
~~105~~	~~700~~	~~260~~	~~51.18~~	
~~106~~	~~1000~~	~~363~~	~~68.47~~	
~~107~~	~~250~~	~~212~~	~~40.29~~	~~Continuous Operation~~
~~b) Operating and Maintenance Only~~				
~~201~~	~~125~~	~~52~~	~~$15.07~~	
~~202~~	~~175~~	~~69~~	~~16.04~~	
~~203~~	~~250~~	~~97~~	~~20.48~~	
~~204~~	~~400~~	~~154~~	~~29.47~~	
~~205~~	~~700~~	~~260~~	~~46.23~~	
~~206~~	~~1000~~	~~363~~	~~62.49~~	
~~c) Operating Only~~				
~~301~~	~~125~~	~~52~~	~~$8.20~~	
~~302~~	~~175~~	~~69~~	~~10.88~~	
~~303~~	~~250~~	~~97~~	~~15.32~~	
~~304~~	~~400~~	~~154~~	~~24.31~~	
~~305~~	~~700~~	~~260~~	~~41.07~~	
~~306~~	~~1000~~	~~363~~	~~57.33~~	

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
100	100	43	15.93	15.52	15.70	
101	125	52	19.01	18.51	18.73	
102	175	69	20.24	19.58	19.87	
103	250	97	25.90	24.97	25.38	
104	400	154	35.99	34.51	35.16	

105	700	260	55.81	53.32	54.42	
106	1000	363	74.94	71.47	73.00	
107	250	212	44.06	42.04	42.93	Continuous Operation

b) Operating and Maintenance Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
201	125	52	16.00	15.50	15.72	
202	175	69	17.27	16.61	16.90	
203	250	97	22.21	21.28	21.69	
204	400	154	32.22	30.74	31.39	
205	700	260	50.86	48.37	49.47	
206	1000	363	68.96	65.49	67.02	

c) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
301	125	52	9.13	8.63	8.85	
302	175	69	12.11	11.45	11.74	
303	250	97	17.05	16.12	16.53	
304	400	154	27.06	25.58	26.23	
305	700	260	45.70	43.21	44.31	
306	1000	363	63.80	60.33	61.86	

(3) **FLUORESCENT**

~~Rate Code~~	~~Bulb Length~~	~~Number of Bulbs/Unit~~	~~kWh/Mo.~~	~~$/Mo.~~	~~Other~~
~~a) Operating, Maintenance and Capital (Full Charge)~~					
~~110~~	~~24~~	~~2~~	~~30~~	~~$17.49~~	
~~111~~	~~48~~	~~2~~	~~85~~	~~26.43~~	
~~112~~	~~72~~	~~2~~	~~116~~	~~31.80~~	
~~113~~	~~72~~	~~4~~	~~222~~	~~49.65~~	
~~114~~	~~96~~	~~1~~	~~47~~	~~20.69~~	
~~115~~	~~72~~	~~1~~	~~60~~	~~22.37~~	
~~116~~	~~48~~	~~4~~	~~166~~	~~39.80~~	
~~b) Operating and Maintenance Only~~					
~~213~~	~~72~~	~~4~~	~~222~~	~~$45.35~~	
~~214~~	~~96~~	~~1~~	~~47~~	~~17.72~~	
~~215~~	~~72~~	~~1~~	~~60~~	~~19.79~~	
~~216~~	~~48~~	~~4~~	~~166~~	~~36.55~~	
~~217~~	~~48~~	~~1~~	~~49~~	~~18.03~~	
~~218~~	~~48~~	~~2~~	~~85~~	~~23.74~~	
~~c) Operating Only~~					
~~330~~	~~35~~	~~4~~	~~47~~	~~7.41~~	

a) Operating, Maintenance and Capital (Full Charge)

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)			Other
				2020	2021	2022	
110	24	2	30	18.02	17.74	17.86	
111	48	2	85	27.94	27.13	27.49	
112	72	2	116	33.87	32.76	33.25	
113	72	4	222	53.61	51.49	52.42	
114	96	1	47	21.53	21.08	21.28	
115	72	1	60	23.44	22.86	23.12	
116	48	4	166	42.76	41.17	41.87	

b) Operating and Maintenance Only

Rate Code	Bulb Length	Number of Bulbs/Unit	kWh/Mo.	Per Month ($)			
				2020	2021	2022	

213	72	4	222	49.31	47.19	48.12	
214	96	1	47	18.56	18.11	18.31	
215	72	1	60	20.86	20.28	20.54	
216	48	4	166	39.51	37.92	38.62	
217	48	1	49	18.90	18.43	18.64	
218	48	2	85	25.25	24.44	24.80	

c) Operating Only

Rate Code	**Bulb Length**	**Number of Bulbs/Unit**	**kWh/Mo.**	**Per Month ($)**			
				2020	**2021**	**2022**	
330	35	4	47	8.25	7.80	8.00	

(4) **FLUORESCENT CROSSWALK**

~~a) Continuous Burning - Operating Only~~

~~117~~	~~72~~	~~4~~	~~486~~	~~$60.25~~
~~118~~	~~24~~	~~2~~	~~66~~	~~8.17~~
~~119~~	~~48~~	~~4~~	~~364~~	~~45.14~~
~~120~~	~~96~~	~~2~~	~~254~~	~~31.50~~
~~150~~	~~96~~	~~4~~	~~613~~	~~76.01~~

a) Continuous Burning - Operating Only

Rate Code	**Bulb Length**	**Number of Bulbs/Unit**	**kWh/Mo.**	**Per Month ($)**			
				2020	**2021**	**2022**	
117	72	4	486	68.91	64.26	66.31	
118	24	2	66	9.35	8.72	9.00	
119	48	4	364	51.63	48.15	49.68	
120	96	2	254	36.03	33.60	34.67	
150	96	4	613	86.93	81.06	83.65	

~~(4) **FLUORESCENT CROSSWALK (cont.)**~~

~~b) Photocell Operation - Operating Only~~

~~310~~	~~24~~	~~2~~	~~30~~	~~$4.75~~
~~311~~	~~48~~	~~4~~	~~166~~	~~26.24~~
~~312~~	~~72~~	~~2~~	~~116~~	~~18.34~~
~~313~~	~~72~~	~~4~~	~~222~~	~~35.04~~
~~314~~	~~96~~	~~1~~	~~47~~	~~7.41~~
~~315~~	~~72~~	~~1~~	~~60~~	~~9.48~~
~~350~~	~~96~~	~~4~~	~~280~~	~~44.24~~

b) Photocell Operation - Operating Only

Rate Code	**Bulb Length**	**Number of Bulbs/Unit**	**kWh/Mo.**	**Per Month ($)**			**Other**
				2020	**2021**	**2022**	
310	24	2	30	5.28	5.00	5.12	
311	48	4	166	29.20	27.61	28.31	
312	72	2	116	20.41	19.30	19.79	
313	72	4	222	39.00	36.88	37.81	
314	96	1	47	8.25	7.80	8.00	
315	72	1	60	10.55	9.97	10.23	
350	96	4	280	49.22	46.55	47.73	

(5) **LOW PRESSURE SODIUM**

~~Rate Code~~	~~Watts~~	~~kWh/Mo.~~	~~$/Mo.~~	~~Other~~
~~a) Operating, Maintenance and Capital (Full Charge)~~				
~~130~~	~~135~~	~~60~~	~~$30.74~~	
~~131~~	~~180~~	~~80~~	~~36.49~~	
~~132~~	~~90~~	~~45~~	~~28.36~~	
~~b) Operating and Maintenance Only~~				
~~231~~	~~180~~	~~80~~	~~28.11~~	
~~c) Operating Only~~				
~~331~~	~~180~~	~~80~~	~~12.64~~	

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
130	135	60	31.81	31.23	31.49	
131	180	80	37.91	37.15	37.48	
132	90	45	29.16	28.73	28.92	

b) Operating and Maintenance Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
231	180	80	29.53	28.77	29.10	

c) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
331	180	80	14.06	13.30	13.63	

(6) **HIGH PRESSURE SODIUM**

~~a) Operating, Maintenance and Capital (Full Charge)~~

~~121~~	~~250~~	~~100~~	~~$24.16~~	
~~122~~	~~400~~	~~150~~	~~32.18~~	
~~123~~	~~70~~	~~32~~	~~13.22~~	
~~124~~	~~100~~	~~45~~	~~15.30~~	
~~125~~	~~150~~	~~65~~	~~18.65~~	
~~126~~	~~100~~	~~99~~	~~25.62~~	~~Continuous Operation~~

~~(6) **HIGH PRESSURE SODIUM (**cont'd)~~

~~**Rate Code**~~	~~**Watts**~~	~~**kWh/Mo.**~~	~~**$/Mo.**~~	~~**Other**~~
~~b) Operating and Maintenance Only~~				
~~221~~	~~250~~	~~100~~	~~$20.95~~	
~~222~~	~~70~~	~~32~~	~~10.20~~	
~~223~~	~~100~~	~~45~~	~~12.26~~	
~~224~~	~~150~~	~~65~~	~~15.43~~	
~~c) Operating Only~~				
~~321~~	~~250~~	~~100~~	~~$15.79~~	
~~322~~	~~70~~	~~32~~	~~5.04~~	
~~323~~	~~100~~	~~45~~	~~7.10~~	
~~324~~	~~150~~	~~65~~	~~10.27~~	
~~326~~	~~400~~	~~150~~	~~23.69~~	
~~327~~	~~500~~	~~183~~	~~28.91~~	
~~328~~	~~1000~~	~~363~~	~~57.34~~	
~~329~~	~~1500~~	~~500~~	~~78.97~~	

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
121	250	100	25.95	24.99	25.41	
122	400	150	34.86	33.42	34.05	
123	70	32	13.79	13.49	13.62	
124	100	45	16.10	15.67	15.86	
125	150	65	19.80	19.18	19.46	
126	100	99	27.38	26.43	26.85	Continuous Operation

b) Operating and Maintenance Only

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
221	250	100	$22.74	$21.78	$22.20	
222	70	32	10.77	10.47	10.60	
223	100	45	13.06	12.63	12.82	
224	150	65	16.58	15.96	16.24	

c) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
321	250	100	17.58	16.62	17.04	
322	70	32	5.61	5.31	5.44	
323	100	45	7.90	7.47	7.66	
324	150	65	11.42	10.80	11.08	
326	400	150	26.37	24.93	25.56	
327	500	183	32.18	30.42	31.20	
328	1000	363	63.81	60.34	61.87	
329	1500	500	87.88	83.10	85.21	

~~(6) HIGH PRESSURE SODIUM (cont'd)~~

(7) **METALLIC ADDITIVE**

~~a) Operating, Maintenance and Capital (Full Charge)~~

~~140~~	~~400~~	~~150~~	~~$35.75~~
~~141~~	~~1000~~	~~360~~	~~74.80~~
~~142~~	~~250~~	~~100~~	~~31.91~~
~~143~~	~~150~~	~~67~~	~~26.69~~
~~144~~	~~100~~	~~50~~	~~24.02~~

~~b) Operating Only~~

~~341~~	~~1000~~	~~360~~	~~$56.86~~
~~342~~	~~400~~	~~150~~	~~23.69~~
~~343~~	~~250~~	~~100~~	~~15.79~~
~~344~~	~~175~~	~~75~~	~~11.85~~
~~345~~	~~150~~	~~67~~	~~10.57~~
~~346~~	~~100~~	~~50~~	~~7.90~~

a) Operating, Maintenance and Capital (Full Charge)

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
140	400	150	38.43	36.99	37.62	
141	1000	360	81.22	77.77	79.29	
142	250	100	33.70	32.74	33.16	
143	150	67	27.89	27.25	27.53	
144	100	50	24.91	24.43	24.64	

b) Operating Only

			Per Month ($)			
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
341	1000	360	63.28	59.83	61.35	
342	400	150	26.37	24.93	25.56	
343	250	100	17.58	16.62	17.04	
344	175	75	13.18	12.46	12.78	
345	150	67	11.77	11.13	11.41	
346	100	50	8.79	8.31	8.52	

(8) **LIGHT EMITTING DIODE (LED) LESS THAN 30 WATTS FOR TRAFFIC CONTROL SIGNALS ONLY**

~~Rate Code~~	~~$/Mo.~~	~~Other~~
~~530~~	~~$0.39~~	~~Non – Continuous~~
~~531~~	~~$0.67~~	~~Continuous~~

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
530	4.6	2	0.35	0.33	0.34	Non-Continuous
531	7.5	5	0.71	0.66	0.68	Continuous

(9) **LIGHT EMITTING DIODE (LED) – Operating Only**

~~Rate Code~~	~~Watts~~	~~kWh/Mo.~~	~~$/Mo.~~	~~Other~~
~~532~~	~~44~~	~~15~~	~~$2.37~~	
~~533~~	~~66~~	~~22~~	~~3.47~~	
~~534~~	~~88~~	~~29~~	~~4.58~~	
~~535~~	~~92~~	~~31~~	~~4.90~~	
~~536~~	~~105~~	~~35~~	~~5.53~~	
~~537~~	~~170~~	~~57~~	~~9.00~~	
~~539~~	~~110~~	~~37~~	~~5.84~~	
~~540~~	~~65~~	~~22~~	~~3.47~~	
~~541~~	~~55~~	~~18~~	~~2.84~~	
~~542~~	~~83~~	~~28~~	~~4.42~~	
~~543~~	~~48~~	~~16~~	~~2.53~~	
~~544~~	~~72~~	~~24~~	~~3.79~~	

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
532	44	15	2.64	2.49	2.56	
533	66	22	3.87	3.66	3.75	
534	88	29	5.10	4.82	4.94	
535	92	31	5.45	5.15	5.28	
536	105	35	6.15	5.82	5.96	
537	170	57	10.02	9.47	9.71	

539	110	37	6.50	6.15	6.31	
540	65	22	3.87	3.66	3.75	
541	55	18	3.16	2.99	3.07	
542	83	28	4.92	4.65	4.77	
543	48	16	2.81	2.66	2.73	
544	72	24	4.22	3.99	4.09	

(10) **LIGHT EMITTING DIODE (LED) – Operating & Capital Only (full charge)**

~~Rate Code~~	~~Watts~~	~~kWh/Mo.~~	~~$/Mo.~~	~~Other~~
~~615~~	~~44~~	~~15~~	~~$9.55~~	
~~616~~	~~55~~	~~18~~	~~10.02~~	
~~623~~	~~28~~	~~9~~	~~8.60~~	
~~624~~	~~50~~	~~17~~	~~9.87~~	
~~625~~	~~72~~	~~24~~	~~10.97~~	
~~626~~	~~100~~	~~33~~	~~12.39~~	
~~627~~	~~200~~	~~67~~	~~17.7~~	

			Per Month ($)			Other
Rate Code	Watts	kWh/Mo.	2020	2021	2022	
615	44	15	9.82	9.67	9.74	
616	55	18	10.34	10.17	10.25	
623	28	9	8.76	8.68	8.71	
624	50	17	10.17	10.01	10.08	
625	72	24	11.40	11.17	11.27	
626	100	33	12.98	12.66	12.80	
627	200	67	18.96	18.32	18.60	

(11) **LIGHT EMITTING DIODE (LED) – Operating, Maintenance & Capital (full charge)**

~~Rate Code~~	~~Watts~~	~~kWh/Mo.~~	~~$/Mo.~~	~~Other~~
~~724~~	~~55~~	~~18~~	~~$9.95~~	
~~740~~	~~190~~	~~63~~	~~23.42~~	
~~741~~	~~261~~	~~87~~	~~28.94~~	
~~742~~	~~124~~	~~41~~	~~17.09~~	
~~743~~	~~84~~	~~28~~	~~14.35~~	

			Per Month ($)			Other
Rate Code	**Watts**	**kWh/Mo.**	**2020**	**2021**	**2022**	
724	55	18	10.27	10.10	10.18	
740	190	63	24.54	23.94	24.21	
741	261	87	30.49	29.66	30.03	
742	124	41	17.82	17.42	17.60	
743	84	28	14.85	14.58	14.70	

(B) **MISCELLANEOUS LIGHTING**

DEMAND CHARGE

$11.777 per month per kilowatt of connected load.

ENERGY CHARGE

~~14.072 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.~~

~~9.546 cents per kilowatt hour for all additional kilowatt hours.~~

	Cents per kilowatt hour	
	For the first 200 kilowatt hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	15.854	11.328
Effective January 1, 2021	14.897	10.371
Effective January 1, 2022	15.319	10.793

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill for the electric power and energy portion of the Miscellaneous Lighting Rate shall be $17.51 per month if such unmetered service is billed separately from any metered account.

CAPITAL CHARGE: (if applicable)

Depreciation based on a 25 year life, and interest at the Company's long term rate shall be used to determine the monthly capital charge.

MAINTENANCE CHARGE: (if applicable)

Cost of normal fixture maintenance and bulb replacement on the basis of current cost levels shall be used to calculate the monthly maintenance charge.

This portion of the rate does not include any provision for globe washing or cleaning. Repair or replacement of parts or bulbs necessitated by vandalism will be charged to the customer.

AVAILABILITY:

This rate shall be applicable to the supply, operation and maintenance of lighting units not provided for under the Street and Area Lighting rate.

(C) **MISCELLANEOUS SMALL LOADS**

DEMAND CHARGE

$11.777 per month per kilowatt of connected load.

ENERGY CHARGE

~~14.072 cents per kilowatt hour for the first 200 kilowatt hours per month per kilowatt of connected load.~~

~~9.546 cents per kilowatt hour for all additional kilowatt hours.~~

- -	**Cents per kilowatt hour**	
	For the first 200 kilowatt hours per month per kilowatt of maximum demand	**For all additional kilowatt hours**
Effective January 1, 2020	15.854	11.328
Effective January 1, 2021	14.897	10.371
Effective January 1, 2022	15.319	10.793

The flat rate calculation (using a 30 day month) will be based on the specific information of each service using the above rate. The charge will be expressed in cents per kWh per month and will be rounded to hundredths of a cent in its application.

FUEL ADJUSTMENT MECHANISM (FAM)

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

MAXIMUM PER KWH CHARGE/MINIMUM BILL

The maximum charge per kWh will be that for a billing load factor of 10% except that the minimum monthly bill shall be $17.51 per month if such unmetered service is billed separately from any metered account.

AVAILABILITY:

A flat rate shall be calculated for any service requiring the supply of power and energy only, with a predeterminable usage, and where metering is considered to be impractical, such as: Telephone Booths, Cable Vision Power Supplies, Traffic Control Lights, Police Telephones, Railway Signals, etc.

APPLICABILITY:

This schedule is a mandatory rider to all electric rate schedules, except the following tariffs: Generation Replacement and Load Following, Extra High Voltage Time-of-Use Real Time Pricing, High Voltage Time-of-Use Real Time Pricing, Distribution Voltage Time-of-Use Real Time Pricing. FAM adjustments will apply to the Standard Energy Charge of the Extra Large Industrial 2P-RTP tariff. FAM adjustments will apply to Additional Energy supplied under the Mersey System Agreement when Additional Energy is priced at a tariff to which FAM adjustments apply.

FUEL ADJUSTMENT:

The applicable charges for electric service to the Company's retail and municipal customers shall be increased or decreased to the nearest 0.001 cents per kWh to recover or credit the difference in actual fuel cost from the costs in base rates in accordance with the following rate class-specific formula:

Fuel Adjustment Rider = AA + BA

Where:

"AA" is a rate class-specific Actual Adjustment which is the difference between fuel-related costs recovered from a rate class through the application of the base rates during the previous calendar year and the actual Fuel Costs incurred and allocated to the rate class for the same time period. The actual fuel costs will include the same cost items as base fuel costs.

"BA" is a rate class-specific Balance Adjustment which accounts for any over- or under-collections which have occurred as a result of prior adjustments.

SPECIAL CONDITIONS:

(1) Base Cost of Fuel

The Base Cost of Fuel can be re-set in a General Rate Application or, absent a General Rate Application, every second year as part of the FAM adjustment process. Changes in the Base Cost of Fuel will be reflected in customers' rates going forward and will be applied to each customer class in a manner consistent with the then-current Board-approved Cost of Service Methodology.

(2) Incentive

For a total fuel cost variance of up to $50 million dollars (Actual Fuel Costs - [(Actual Sales) x (Base Fuel Cost $/Mwh)]), 90% of any savings or increase in cost will be credited or charged to customers. The portion of any variance that is in excess of $50 million dollars will be fully applied in the calculation of the "AA". Credits or charges will be applied to the energy component of rates on a cents per kWh basis.

(3) Load Migration to non-FAM classes

When a customer transitions its load, whether in whole or in part, from a FAM class to a non-FAM class, NS Power shall determine the outstanding fuel cost imbalance of the customer at the time of transition. This determined imbalance will be adjusted as necessary in future FAM proceedings concerned with apportionment of fuel costs incurred in the period in question. The adjustments will be subject to UARB approval. The outstanding imbalance and subsequent adjustments will be paid (or reimbursed) in full on reasonable terms acceptable to the customer and NS Power, or if the parties are unable to agree, as determined by the UARB.

The applicable charges by rate class ~~for the calendar year 2019 effective on and after January 1st,~~ are as follows.

~~Rate Class~~	~~Actual Adjustment (AA) in cents per kWh~~	~~Balance Adjustment (BA) in cents Per kWh~~	~~FAM AA/BA Combined in Cents per kWh~~
~~Domestic Service~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Domestic Service Time of Day~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Small General~~	~~0.000~~	~~0.000~~	~~0.000~~
~~General~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Large General~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Small Industrial~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Medium Industrial~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Large Industrial Firm~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Large Industrial Interruptible~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Municipal~~	~~0.000~~	~~0.000~~	~~0.000~~
~~Unmetered~~	~~0.000~~	~~0.000~~	~~0.000~~

	Effective January 1, 2020		
Rate Class			

	Actual Adjustment (AA) in cents per kWh	Balance Adjustment (BA) in cents per kWh	FAM AA/BA Combined in cents per kWh
Domestic Service	0.372	(1.979)	(1.607)
Domestic Service Time of Day	0.372	(1.979)	(1.607)
Small General	0.282	(1.698)	(1.416)
General	0.691	(1.712)	(1.021)
Large General	(0.121)	(0.042)	(0.163)
Small Industrial	0.645	(1.610)	(0.965)
Medium Industrial	0.559	(0.822)	(0.263)
Large Industrial Firm	0.515	(0.577)	(0.062)
Large Industrial Interruptible	0.515	(0.625)	(0.110)
Municipal	0.596	(1.157)	(0.561)
Unmetered	0.992	(2.365)	(1.373)

	Effective January 1, 2021		
Rate Class	Actual Adjustment (AA) in cents per kWh	Balance Adjustment (BA) in cents per kWh	FAM AA/BA Combined in cents per kWh
Domestic Service	0.000	0.000	0.000
Domestic Service Time of Day	0.000	0.000	0.000
Small General	0.000	0.000	0.000
General	0.000	0.000	0.000
Large General	0.000	0.000	0.000
Small Industrial	0.000	0.000	0.000
Medium Industrial	0.000	0.000	0.000
Large Industrial Firm	0.000	0.000	0.000
Large Industrial Interruptible	0.000	0.000	0.000
Municipal	0.000	0.000	0.000
Unmetered	0.000	0.000	0.000

	Effective January 1, 2022		
Rate Class			

	Actual Adjustment (AA) in cents per kWh	Balance Adjustment (BA) in cents per kWh	FAM AA/BA Combined in cents per kWh
Domestic Service	0.000	0.000	0.000
Domestic Service Time of Day	0.000	0.000	0.000
Small General	0.000	0.000	0.000
General	0.000	0.000	0.000
Large General	0.000	0.000	0.000
Small Industrial	0.000	0.000	0.000
Medium Industrial	0.000	0.000	0.000
Large Industrial Firm	0.000	0.000	0.000
Large Industrial Interruptible	0.000	0.000	0.000
Municipal	0.000	0.000	0.000
Unmetered	0.000	0.000	0.000