

Nova Scotia Utility and Review Board

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

2022 Load Forecast Report

April 29, 2022

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- 16 Appendix A: 2022 NS Power Forecast
- 17 Appendix B: Forecast Model Details
- 18 Appendix C: Forecast Comparison (Partially Confidential)
- 19 Appendix D: Forecast Sensitivity (Partially Confidential)
- 20 Appendix E: E3 2022 Stakeholder Engagement Presentation

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1.0 EXECUTIVE SUMMARY

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

The 2022 Load Forecast provides an outlook on the energy and peak demand requirements of in-province customers for the period 2022 to 2032. In addition, it describes the considerations, assumptions, and methodology used in the preparation of the forecast. The Load Forecast provides the basis for the planning and overall operating activities to serve customer load.

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

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

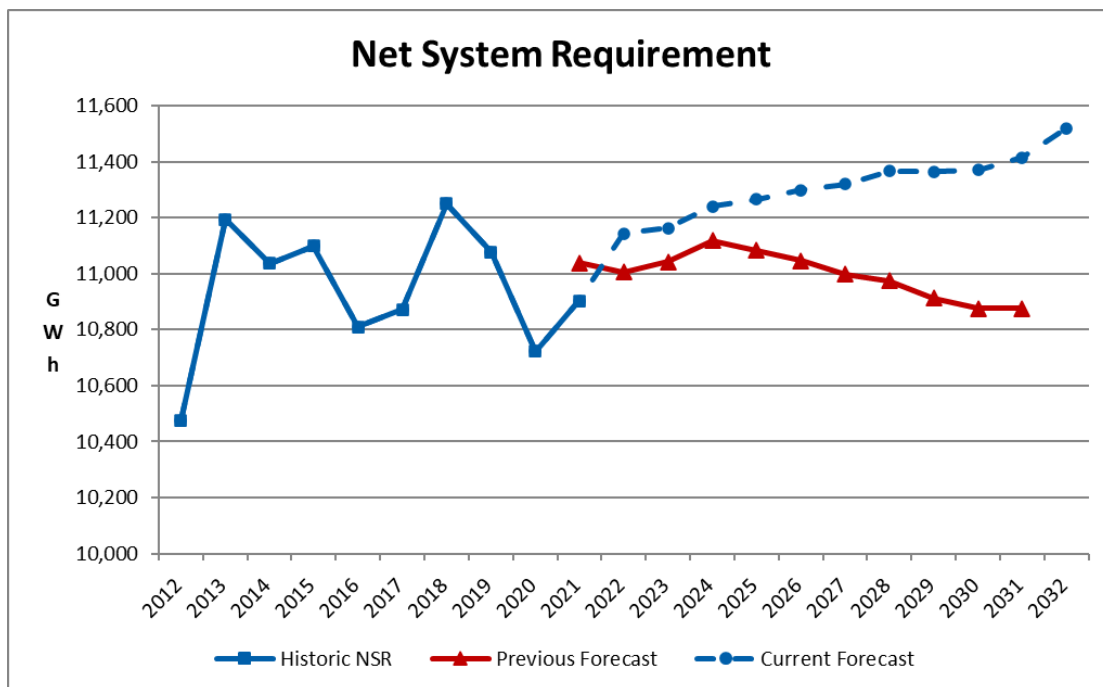
NS Power continues to use and refine Statistically Adjusted End-Use (SAE) models to forecast load for the residential and commercial rate classes. The SAE models explicitly incorporate end-use energy intensity projections into the Load Forecast. End-use energy forecasts derived from the residential and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

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

Compared to the 2021 Load Forecast, the 2022 Load Forecast shows higher growth in the near term due to greater customer growth and higher average use when adjusted for weather in 2021. Mid to long-term growth is driven by a combination of increased expectations for electric heating in both the residential and commercial classes, higher Electric Vehicle (EV) sales driven by the Province of Nova Scotia's goal of achieving 30 percent zero-emissions vehicle sales by 2030, as well as increased large customer sales driven by several large hospital expansions within the province. In the long term, energy sales will be reduced by Demand Side Management (DSM) initiatives and natural energy efficiency improvements outside structured DSM programs, as well as increased behind-the-meter small scale solar installations. The net result is a forecast annual increase of 0.3 percent. Annual historic and forecast NSR are shown below in **Figure 1**.

Figure 1: Historical and Predicted Annual Net System Requirement



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In addition to annual energy requirements, NS Power forecasts system peak demand. Customer growth and increased residential and commercial electric heating increase the peak, while DSM activities reduce the peak. As a result, the system peak demand is expected to increase at 1.6 percent annually over the forecast period, as shown in **Figure 2**. The 2021 forecast system peak is included for comparison.

Figure 2: Historical and Predicted Annual System Peak

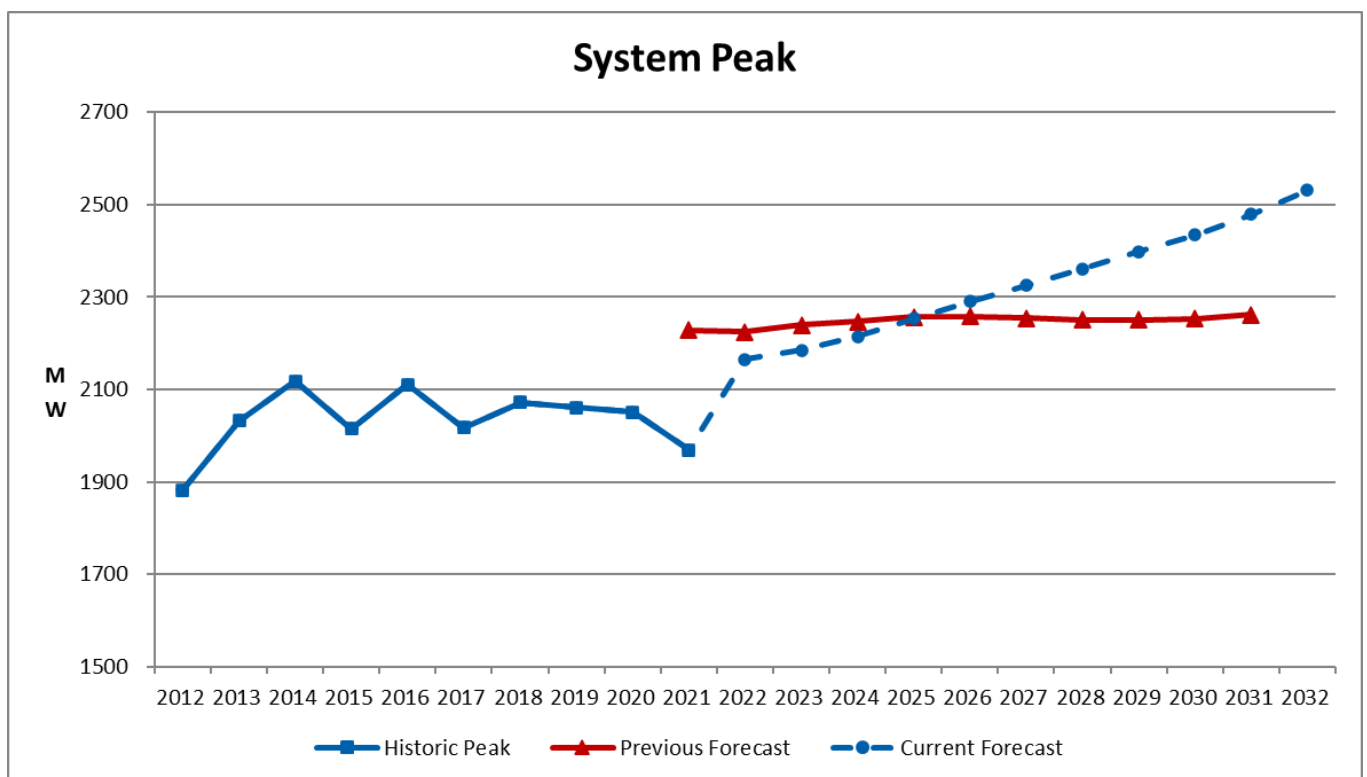


Figure 3 below shows the changes to system load and system peak over the historic and forecast periods.

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

Year	NSR (GWh)	Growth (%)	System Peak (MW)	Growth (%)
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	11,077	-1.5	2,060	-0.6
2020	10,723	-3.2	2,050	-0.5
2021	10,902	1.7	1,968	-4.0
2022	11,144	2.2	2,165	10.0
2023	11,163	0.2	2,185	0.9
2024	11,240	0.7	2,215	1.4
2025	11,265	0.2	2,253	1.7
2026	11,298	0.3	2,291	1.7
2027	11,319	0.2	2,326	1.5
2028	11,366	0.4	2,361	1.5
2029	11,363	0.0	2,398	1.6
2030	11,371	0.1	2,434	1.5
2031	11,414	0.4	2,479	1.9
2032	11,519	0.9	2,532	2.1

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2.0 INTRODUCTION

NS Power annually develops a forecast of energy sales and peak demand requirements to assess the effects of end-use and economic factors on the future power system load and load shape. The forecast is a foundational input to the overall planning, budgeting and operating activities of the Company. Produced in the winter of 2021-2022 and using information available at the time, this forecast covers the period of 2022-2032. Unless otherwise noted, reported average annual growth rates are for the 2022-2032 period.

In 2021, the NSUARB initiated a paper hearing process to review the 2021 Load Forecast Report.¹ The Consumer Advocate (CA), the Small Business Advocate (SBA), the Industrial Group (IG), EfficiencyOne (E1), and Heritage Gas Limited (Heritage) registered and took part as intervenors. In addition, Board Counsel engaged Synapse Energy Economics (Synapse) to review and provide a report on NS Power's 2021 Load Forecast.

Following NS Power's response to Information Requests (IRs), filing of evidence by intervenors and Board Counsel and Reply Evidence by NS Power, the Board issued its Decision respecting NS Power's 2021 Load Forecast. The Board recognized the progress and refinements that have been made in developing the Load Forecast and directed certain areas for continued improvement. The Board stated as follows:²

The Board notes that NS Power has agreed to many of the recommendations by intervenors. The Board accepts NS Power's commitment as a positive step toward continuous improvement related to the Load Forecast. While NS Power committed to incorporate numerous recommendations where appropriate, the Board directs NS Power to undertake the agreed upon recommendations.

The intervenors recommended that NS Power re-evaluate the use of a low design temperat[ur]e in future forecasts, to which NS Power agreed. The Board, therefore, directs NS Power to evaluate peak causing conditions and a peak forecast based on

¹ Nova Scotia Power Inc. 2021 Load Forecast Report P-194 (M10109).

² Nova Scotia Power Inc. 2021 Load Forecast Report, UARB Decision, October 27, 2021, pages 5-7 (M10109).

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1 historic peak temperatures (such as a 1-in-2) in its future load forecasts, as well as
2 add trends in peak weather in the 2022 Load Forecast Report.

3
4 NS Power agreed with the CA's recommendation on weather normalizing and
5 presenting a more accurate approach to estimating the impact of incremental cold
6 on loads. Therefore, the Board directs NS Power to evaluate improvements to the
7 weather normalization estimate and examine the impact of incremental cold on
8 loads in the temperate ranges where peak loads occur. These updates to the forecast
9 are to be provided in future load forecast reports, preferably in the 2022 Report, but
10 if not possible then in the 2023 Report.

11
12 The SBA suggested that NS Power include forecast accuracy for the system peak
13 in addition to the energy and firm peak presented in the Load Forecast Report. NS
14 Power is directed to incorporate this into future load forecast reports.

15
16 The CA stated that it is more common to use load-weighted averages of
17 temperatures from multiple weather stations in a load forecast, and cited NS
18 Power's planning reserve margin study that used weather station data from three
19 different areas of the province. NS Power agreed to add more weather station data
20 to future load forecasts, but stated that Halifax is the major load centre of the
21 province, followed by Sydney and the remainder of the load is dispersed throughout
22 the more rural areas of the province. NS Power suggested that increasing the data
23 may increase the complexity of the model without improving accuracy. However,
24 given the ranges in weather event occurrences throughout the province, the Board
25 directs NS Power to incorporate more weather station data into future load forecasts
26 using a load weighted approach.

27
28 NS Power's rebuttal was agreeable with many of the recommendations by
29 intervenors. However, in response to intervenors' request for more information on
30 the Smart Grid Nova Scotia and Water Heating Demand Response projects, NS
31 Power stated that the results are preliminary, although they also stated that the
32 results are incorporated into the load forecast when possible. The Company also
33 indicated that it provides semi-annual reporting to the Board and stakeholders on
34 the Smart Grid and the Demand Response projects, therefore, further reporting is
35 not necessary. However, the Board directs NS Power to report the results from the
36 Smart Grid and Water Heating Demand Response projects, as it relates to the
37 impacts that these pilot projects have on load, in the 2022 Load Forecast.

38
39 In addition to the above directives, the Board encourages NS Power to include
40 information on each of the following in future load forecasts:

- 41
42 - Provide a list of the literature that was used to inform the Load Forecast and
43 new sources that are being used for future Load Forecasts

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- 1 - Evaluate the input variables in the residential model and test over a period of
2 time if alternative inputs make the residential model more robust, considering
3 the following:
- 4 • Given the recent population growth and housing shortage in Nova Scotia,
5 re-evaluate the use of housing completions for the near-term;
 - 6 • Given the dependence of income on the retail sales variable, the retail sales
7 variable should be re-evaluated, particularly in the near-term given forecast
8 supply-chain issues;
 - 9 • Re-evaluate the use of the Total Provincial Disposable Income variable as
10 it may be biased by outliers;
 - 11 • Testing if Median Household Income provides a more accurate indicator
12 of the level of income in the province is encouraged; and
 - 13 • Consider incorporating household size and age of household residents to
14 determine if a better understanding of demand on the load by time of day
15 is achieved.

16
17 The Board acknowledges the intervenors participation in examining changes to the
18 Load Forecast and encourages NS Power to continue to actively engage with
19 intervenors as well as other stakeholders and their consultants well in advance of
20 filing its 2022 Load Forecast Report. As many of the recommendations made by
21 intervenors are important to discuss in the initial stakeholder meeting, it is prudent
22 to share how potential impacts were evaluated and what was incorporated into the
23 forecast early in the process.

24
25 In accordance with the Board's direction, NS Power revised and enhanced the 2022 Load
26 Forecast in the following manner:

- 27
- 28 • The peak design temperature was evaluated based on historic data to align with “1
29 in 2” peak causing weather. Please refer to Sections 4.2 and 10.
 - 30 • A warming trend in peak causing weather was evaluated and incorporated into the
31 forecast. Please refer to Section 4.2 and 10.
 - 32 • System peak accuracy is now included in Appendix C.
 - 33 • Population weighted (as a proxy for load weighted) weather from multiple stations
34 was evaluated for the residential model. Please refer to Section 4.2.
 - 35 • A summary of the Smart Grid and Demand Response projects is provided in
36 Sections 4.4 and 10.
 - 37 • Referenced information sources are footnoted throughout the document.
-

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- 1 • A discussion of the economic inputs to the residential model is provided in Section
2 4.3.

3
4 **Summary of Stakeholder Consultations**

5
6 On April 13, 2022 NS Power conducted a stakeholder session by videoconference with
7 representatives of NSUARB staff, Synapse, the Consumer Advocate (CA), the Small
8 Business Advocate (SBA), the Industrial Group (IG), EfficiencyOne (E1), Heritage Gas
9 and the Province of Nova Scotia. The agenda and presentation materials were provided to
10 the stakeholders in advance of the session, and are included in **Appendix E**. The NS Power
11 Load Forecast team discussed the following changes to the 2022 Load Forecast:

- 12
13 • COVID-19 impact on the forecast and related assumptions;
14 • Updated electric vehicle (EV) forecast;
15 • Updated forecast of space heating;
16 • Updated assumptions around peak savings related to time-varying pricing and
17 direct load control;
18 • Updated assumptions around peak temperatures;
19 • Class level trends;
20 • Variance of prior forecast to actuals;
21 • Discussion of ongoing forecasting work; and
22 • A presentation by Energy and Environmental Economics, Inc. (E3) explaining their
23 EV and space heating forecast methodology.

24
25 In addition to the foregoing, NS Power also responded to questions from stakeholders and
26 discussed topics such as the relationship of the Load Forecast to the Company's evergreen
27 IRP modeling update, the EV model assumptions, vehicle-to-grid technology, and
28 customer growth in the province.

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Work with E3

As part of the 2020 IRP Action Plan, NS Power has worked with third party consultant E3 to develop forecasts for space heating and EV uptake that will allow the province to meet stated emissions goals and EV sales targets over the next 20 years. This work uses stock rollover models to assess uptake required under scenarios that meet these goals, without assuming any specific changes to regulations or incentives, though both are possible in the timeframe of the current 10-year load forecast. The inputs are discussed in more detail in **Sections 4.4 and 10**. E3 discussed its analysis at the stakeholder session on April 13 and its presentation is included in Appendix E.

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3.0 FORECASTING APPROACH

NS Power continues to use a set of SAE models for the Residential³ and Commercial⁴ rate classes, an econometric model for the Small and Medium Industrial classes, and customer surveys and historical data for the Large Industrial⁵ customer classes.

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

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

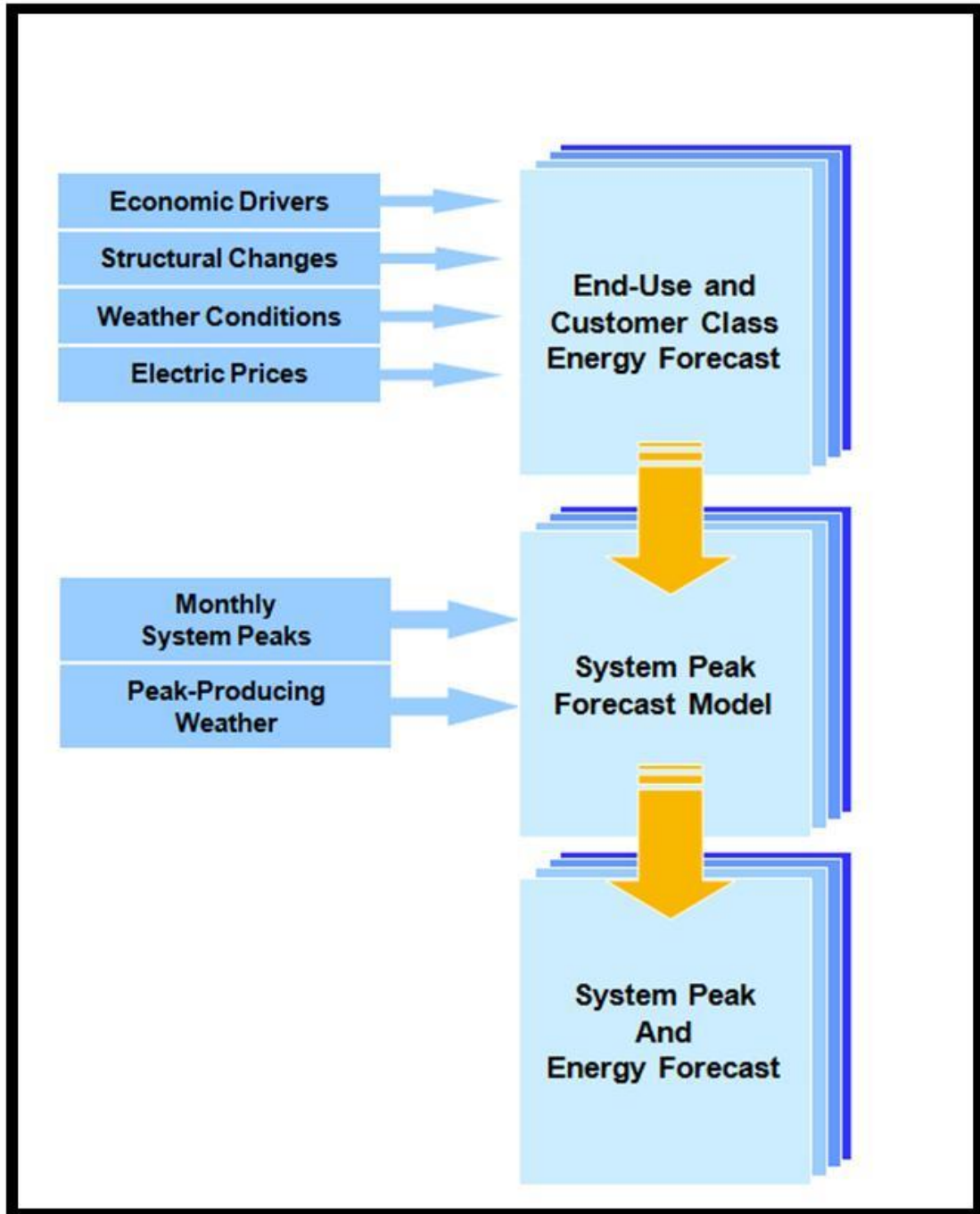
³ References to the Residential class include Domestic Service and Domestic Service Time-of-Day.

⁴ References to the Commercial class include Small General, General and Large General unless specified otherwise.

⁵ References to the Industrial class include the Small, Medium and Large Industrial classes unless specified otherwise.

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Figure 4: Forecast Approach



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4.0 DISCUSSION OF MAJOR INPUTS

4.1 Historical Class Sales and Energy Data

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

Historical monthly billed sales are the primary dependent variables in the linear regression models used in developing the forecast. For the 2022 Load Forecast, the residential and commercial energy forecasts are estimated using monthly billed sales data for the period January 2012 to December 2021. The industrial forecasts use the periods January 2010 to December 2021 (Small Industrial) and January 2006 to December 2021 (Medium Industrial) to improve the model fit.

For the peak demand forecast, historical system monthly energy and monthly demand data is derived from system hourly load data for the period January 2012 to December 2021. Large customer peak demand is forecast separately.

The Renewable to Retail (RtR) electricity market was established in Nova Scotia in 2016 to enable independent licensed retailers to sell renewable energy generated within the Province directly to NS Power’s retail customers. One application has been submitted by a third party to the NSUARB for approval as a Licensed Retail Supplier (LRS) to provide service under the RtR tariffs starting in 2023.⁶ The service is forecast to supply 29 GWh

⁶ The effective date for sales from a retail supplier to a retail customer to commence under s. 3C(1) of the Electricity Act has not been set. As such, the licence issued by the NSUARB included a condition that no sales can occur before the effective date prescribed by the Governor in Council. In addition, it is a condition of the license issued by the

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of energy sales through wind production, with 10 percent serving residential customers, 50 percent serving commercial customers, and 30 percent serving industrial customers. The corresponding energy amounts have been subtracted from the forecast. The peak forecast remains unchanged as NS Power is required to serve the full peak of these customers if needed.

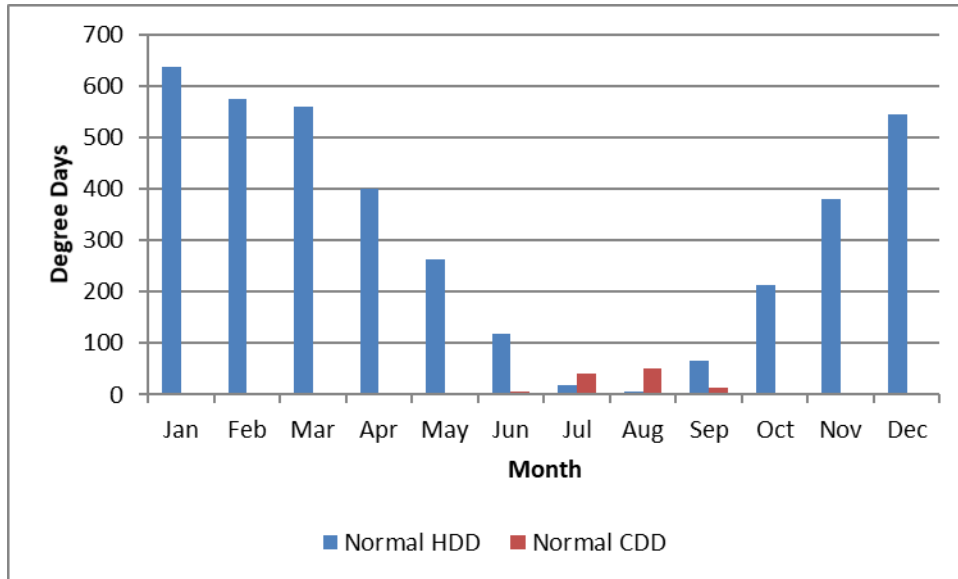
4.2 Weather Data

Weather conditions have the largest single impact on month-to-month variation in electric sales. The impacts of temperature are captured by monthly Heating Degree Day (HDD) and Cooling Degree Day (CDD) variables. HDD are a common measure of heating requirement based on the degree difference between the daily mean temperature and a given reference temperature. The reference temperature of 18 degrees Celsius (°C) is used for these calculations. 18°C is assumed to be a comfortable room temperature below which space heating is generally required and above which space cooling is also required. Monthly HDD and CDD are calculated from Environment Canada hourly temperature information for the Shearwater Airport. Normal monthly HDD and CDD, as shown in **Figure 5** below, are calculated using 10 years of actual weather data covering the period January 2012 to December 2021. The average temperature continues to show a warming trend: the 30-year average annual HDD is 3,924 while the 10-year average is 3,786.

NSUARB that if no electricity is sold to a customer under the authority of the license by December 31, 2024, the Licensed Retail Supplier must apply to the NSUARB to show cause why the licence should not be cancelled at that time (M10293).

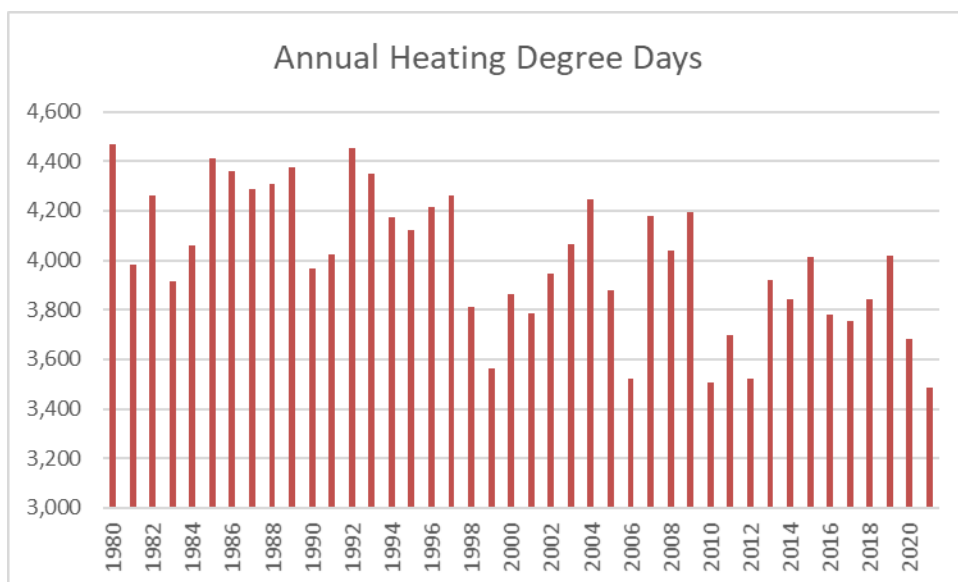
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Figure 5: Normal Monthly HDDs and CDDs



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

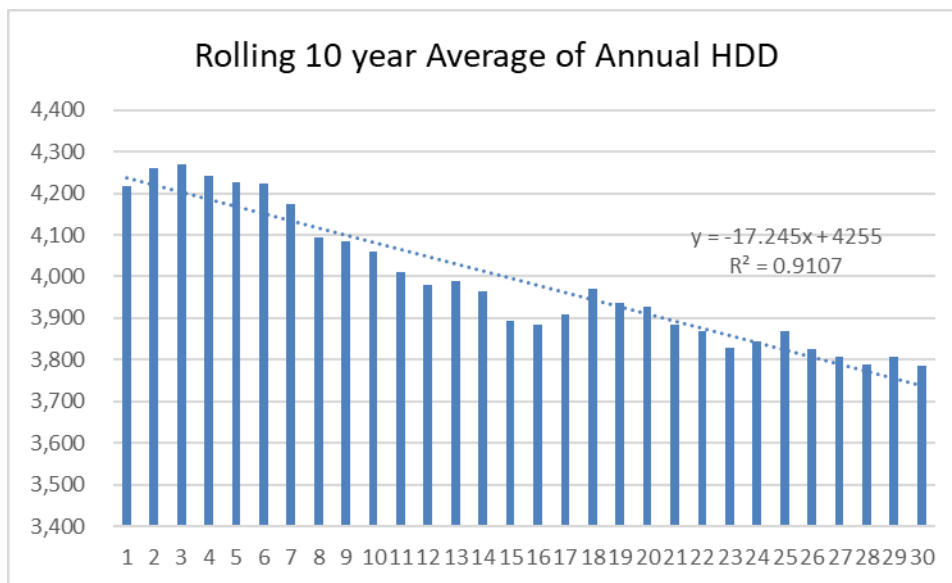
Figure 6: Historic Annual HDD



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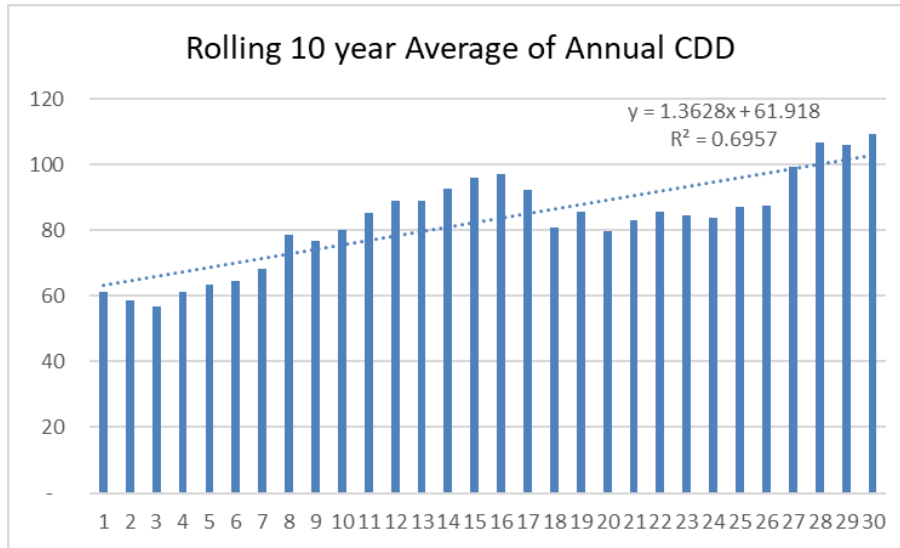
To reflect the general warming trend as seen in the 30-year vs 10-year averages, a declining trend is applied to the annual HDD and CDD variables. These trends are based on regression analysis of 30 years of historic data using a 10-year moving average (to smooth the series), with HDD decreasing by approximately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

Figure 7: HDD Trend



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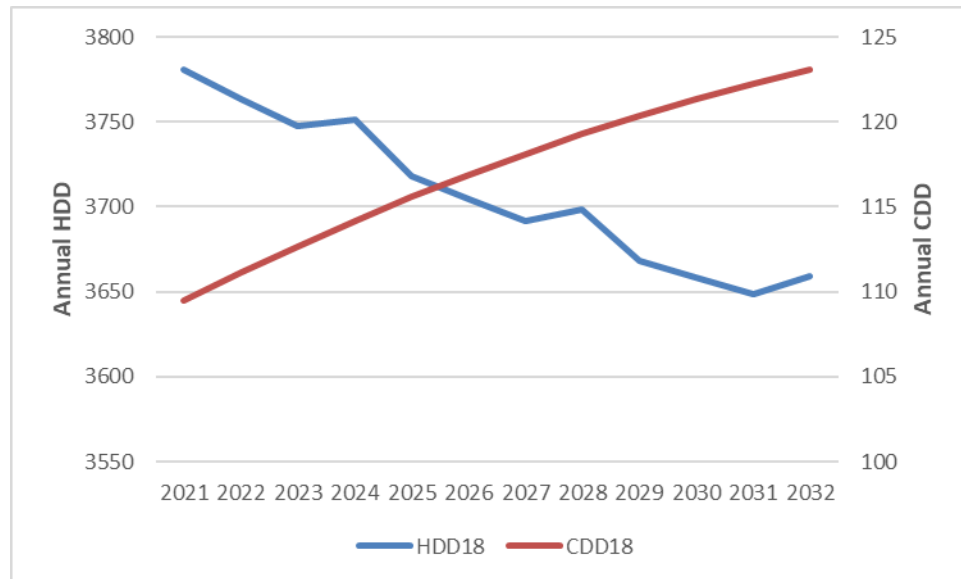
Figure 8: CDD Trend



These trends are reduced over time (approximately 40 years) such that the average annual HDD is not forced to 0 and the average annual CDD does not increase indefinitely. **Figure 9** shows how the HDD and CDD variables evolve over the 10-year forecast period. 2021 represents the 10-year average, and by 2032 the annual HDD value is reduced to 3,659 while the CDD value has increased to 123. The implication of this change is a reduced winter heating load and an increased summer cooling load in both the Residential and Commercial classes. The bumps in 2024, 2028 and 2032 are due to leap years which have an extra day in February.

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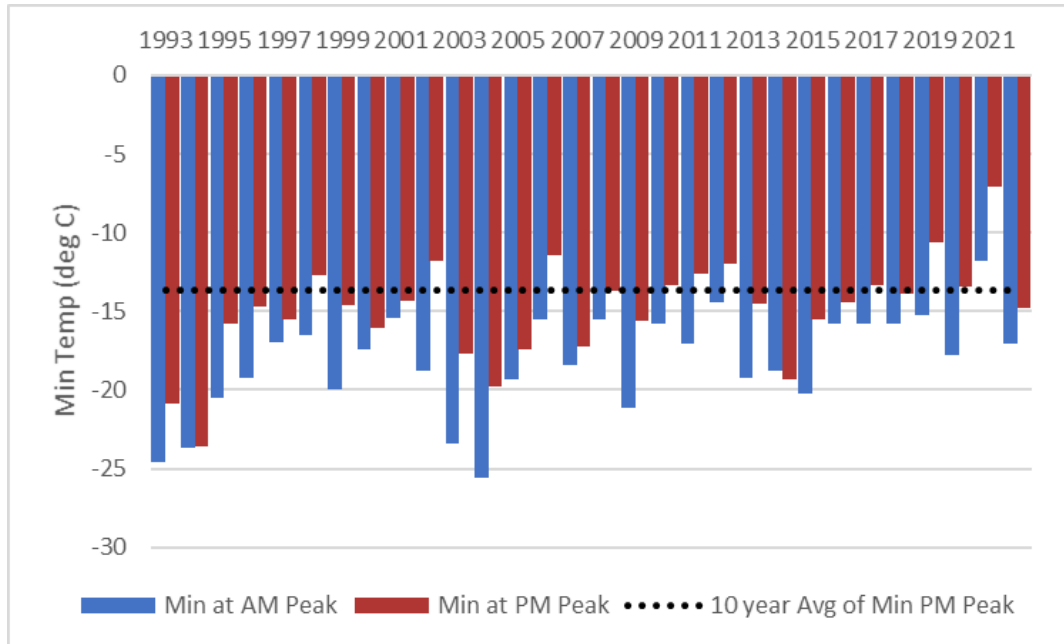
Figure 9: Annual HDD and CDD Over Time



With respect to peak temperatures, both the morning (7am – 10am) and evening peak period (5pm-8pm) annual minimum temperatures were evaluated to estimate the conditions for future peaks. These are not the coincident peak temperatures, but rather the annual minimums, as forecast peak temperatures are based on potential (or average) temperatures, which may or may not have been coincident with peaks in the past due to other factors that are independent of the weather such as the day of week. In the past 20 years only two annual peaks have occurred in the morning peak period despite colder temperatures at that time of day, so the average of the previous 10 year evening peak period minimum was therefore chosen as a good indicator of future peak conditions, representing a temperature of -13.7 degrees Celsius. **Figure 10** below shows the two peak period temperature series as well as the 10-year evening peak average.

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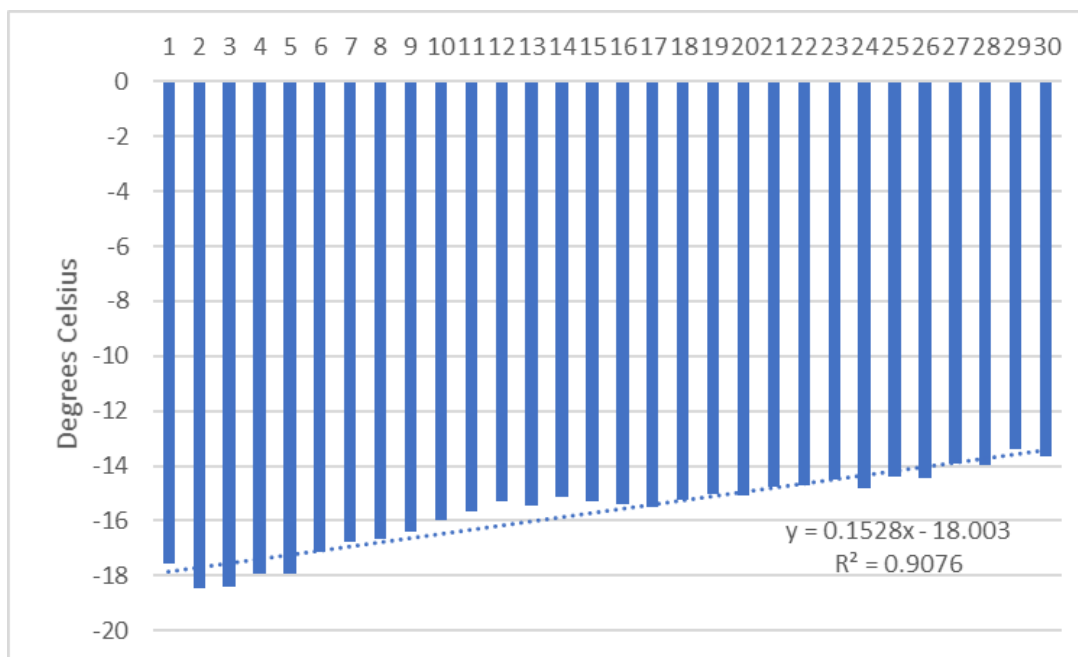
Figure 10: Peak Period Minimum Temperatures



The other factor included in the peak forecast temperature is a trend similar to the one included in the annual HDD calculations. Looking at a rolling 10-year average of annual minimum temperatures shows that the minimum is increasing at a rate of around 0.15 degrees per year, as shown in **Figure 11**. Like the trend in the HDD series, the peak trend also tapers off over a period of approximately 40 years.

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Figure 11: Rolling 10 Year Average of Annual Evening Min Trend



Several resources were consulted that support these assumptions. The Climate Atlas of Canada⁷ provides estimates for annual HDD as well as number of “Winter Days” that are -15° or colder under different climate change scenarios between now and 2050. Annual HDD is forecast to decline to 3597 by 2050 under the scenario where emissions continue at present rates, or to 3636 where emissions slow. The number of “Winter Days” are forecast to decrease from 13 to around 6 under both scenarios. Both trends are in line with the trends being applied to annual HDD and peak temperature increases in the forecast. Research on trends in New England⁸ points to general warming patterns both in terms of average temperatures as well as minimum and maximum temperatures.

⁷ <https://climateatlas.ca/map/canada>

⁸ [Overall Warming with Reduced Seasonality: Temperature Change in New England, USA, 1900-2020](#), Stephen S. Young and Joshua S. Young, 2001

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1 The weather in 2021 was noteworthy as it had the lowest number of HDD in over 40 years
2 (3484, or 8 percent less than the 10 year average), as well as the warmest minimum
3 temperature in over 40 years at -12.9°C, which occurred in the middle of the day in early
4 March (annual minimums usually occur overnight in January or February).

5
6 **Weather station impact on provincial sales forecast**

7
8 In its response to the 2021 Load Forecast, the Board directed NS Power to incorporate
9 more weather station data into future load forecasts using a load weighted approach.
10 Historically, Shearwater RCS station was used as the main weather station for Load
11 Forecast purposes, as the data series has very few gaps and contains many decades, and it
12 is also close to the load center of the province, Halifax Regional Municipality.

13
14 Rather than use load weighted data, a population weighted approach has been selected to
15 compare with the traditional forecast as geographic load data was not available. Weather
16 stations with high quality data sets were chosen as representative of counties or groups of
17 counties, where the ratio of county group population to the province population represent
18 the weighting. **Figure 12** shows the map of Nova Scotia with grouped counties.

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Figure 12: County Grouping

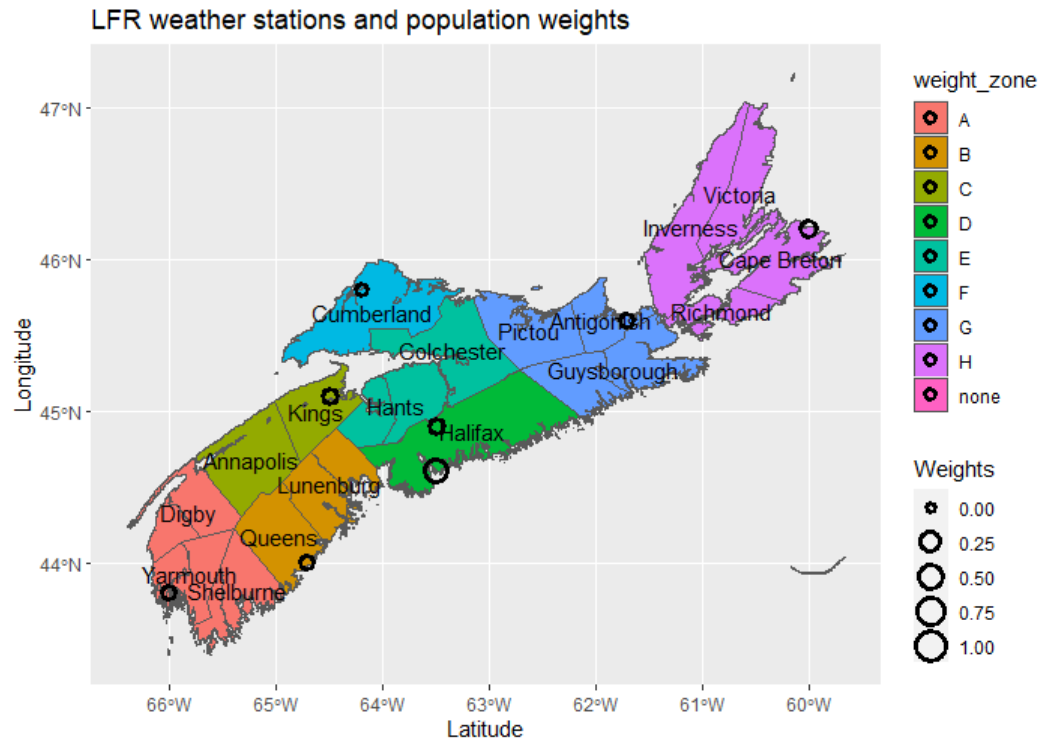


Figure 13 below shows the details of the weightings.

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Figure 13: Weather Station Weighting

Zone	Population	Weight	Counties included	Weather Station	latitude	longitude
A	56,047	0.05649586	Shelbourne, Yarmouth, Digby	Yarmouth A	43.8	-66
B	59,406	0.059881761	Queens, Lunenburg	Western Head	44	-64.7
C	85,266	0.085948864	Annapolis, Kings	Kentville CDS A	45.1	-64.5
D	460,232	0.463917827	Halifax	Shearwater RCS	44.6	-63.5
E	96,393	0.097164976	Hants, Colchester	Halifax Stanfield International Airport	44.9	-63.5
F	30,364	0.030607174	Cumberland	Nappan Auto	45.8	-64.2
G	72,112	0.072689518	Pictou, Guysborough, Antigonish	Tracadie	45.6	-61.7
H	132,235	0.133294021	Inverness, Richmond, Cape Breton, Victoria	Sydney A	46.2	-60

In order to compare the Load Forecast based on temperatures from one weather station (Shearwater RCS) versus temperatures from a weighted average from the weighted weather stations the metric used was the Mean Absolute Percentage Error (MAPE):

$$MAPE = \frac{100\%}{n} \sum_{t=1}^n \left| \frac{A_t - F_t}{A_t} \right|$$

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Where the 2021 monthly series ($n=12$) will be compared versus its respective forecast, A_t is the actual value, and F_t is the forecasted value. In both cases, forecast models have been informed by 10 years of actuals.

Figure 14 below show forecast MAPE comparisons between model weather dependent customer classes and accrued system peak.

Figure 14: Forecast Results

Class	MAPE (1 station)	MAPE (multiple stations)	Difference
Residential	2.58%	2.54%	0.04%
Small General	5.47%	5.43%	0.04%
General Demand	4.55%	4.58%	-0.03%

As the results above show, the differences are minimal with respect the energy forecast. As no significant impact was noted, this population-weighted approach was not incorporated into the final 2022 Load Forecast. NS Power will include a similar analysis for the peak forecast in the 2023 Load Forecast Report.

4.3 Economic Information

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

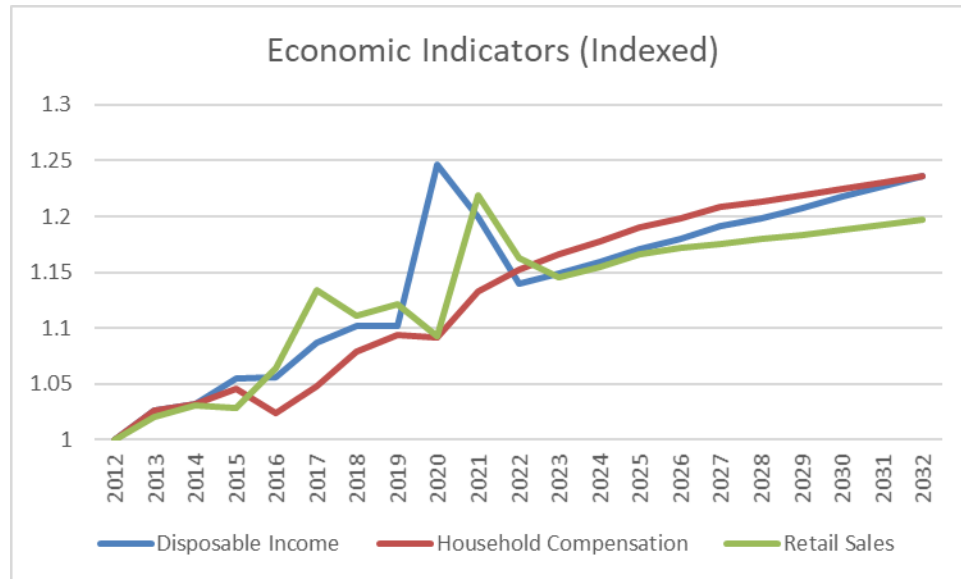
In the SAE framework, economic data drives the utilization of the end-use stock over the forecast period. For 2022, as noted in the NSUARB's Decision⁹, the residential model has been updated to use household compensation rather than retail sales and disposable income.

⁹ Nova Scotia Power Inc. 2021 Load Forecast Report, UARB Decision, October 27, 2021, pages 6 (M10109).

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Both retail sales and disposable income show distinct impacts from COVID, while household compensation shows only a small change, as shown in **Figure 15**.

Figure 15: Residential Economic Indicators

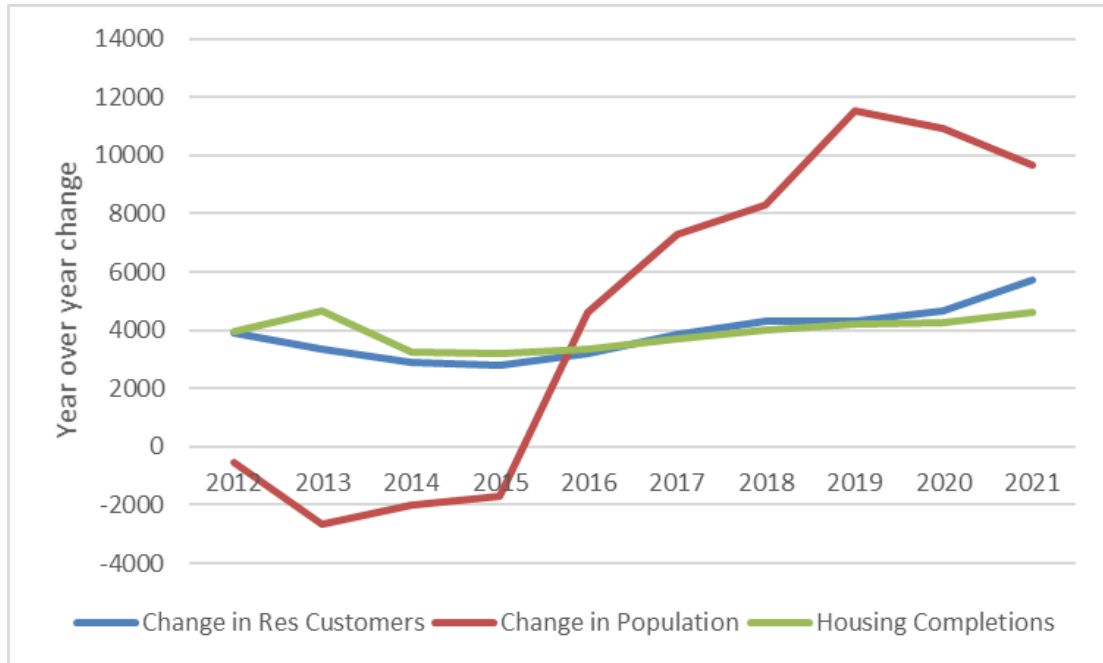


The impact of increased work-from-home activity on the residential class (increased sales) is handled by a distinct variable rather than relying on the economic variables. New housing completions for both single-family and multi-unit buildings are used in generating residential customer forecasts, with both declining over time due to projected declines in the population. One of the items in the NSUARB’s Decision was “Given the recent population growth and housing shortage in Nova Scotia, re-evaluate the use of housing completions for the near-term.”¹⁰ Housing completion numbers are highly correlated with residential customer count, as seen in **Figure 16**, and are the most appropriate indicator in the near term.

¹⁰ Nova Scotia Power Inc. 2021 Load Forecast Report, UARB Decision, October 27, 2021, pages 6 (M10109).

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Figure 16: Yearly Change in Customers, Population, and Housing Completions



In the commercial models, non-manufacturing gross domestic product (GDP) and non-manufacturing employment continue to be used. In the industrial sector, rate classes are forecast using an econometric framework, with manufacturing GDP and manufacturing employment used as the economic drivers. The regression timescale for the industrial models remains longer than the other class models (11 and 16 years versus 10 years for the residential model) to help improve the relevance of the economic variable in the small industrial model (the model produces a high P-value on the economic variable using a 10-year timeframe) and to help improve the fit in the medium industrial model (adjusted R squared of 0.509 for 10 years vs 0.757 for 16 years). **Figures 17, 18 and 19** summarize the economic drivers, on an annual basis, used in the 2022 Load Forecast. For financial measures, the variables have been adjusted to constant dollars, eliminating the inflation effects from the series.

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Figure 17: Residential Economic Drivers

Year	New Construction (number)	% Change	Household Compensation (mil \$02)	% Change
2012	3,955		16,717	
2013	4,660	17.8	17,150	0.4
2014	3,263	-30.0	17,254	2.6
2015	3,185	-2.4	17,488	0.6
2016	3,330	4.6	17,118	1.4
2017	3,699	11.1	17,517	-2.1
2018	4,029	8.9	18,036	2.3
2019	4,227	4.9	18,061	3.0
2020	4,269	1.0	18,052	0.1
2021	4,620	8.2	18,606	-0.1
2022	4,270	-7.6	18,637	3.1
2023	3,935	-7.9	18,747	0.2
2024	3,576	-9.1	18,941	0.6
2025	3,221	-9.9	19,184	1.0
2026	2,874	-10.8	19,346	1.3
2027	2,335	-18.7	19,507	0.8
2028	2,114	-9.5	19,588	0.8
2029	1,960	-7.3	19,678	0.4
2030	1,824	-7.0	19,775	0.5
2031	1,688	-7.5	19,865	0.5
2032	1,551	-8.1	19,964	0.5
12-21		1.7		1.2
22-32		-9.6		0.7

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Figure 18: Commercial Economic Drivers

Year	Non-Manufacturing GDP (mil \$12)	% Change	Non-Manufacturing Employment (000)	% Change
2012	31,890		421	
2013	31,880	0.0	418	-0.8
2014	32,350	1.5	412	-1.4
2015	32,571	0.7	411	-0.4
2016	33,027	1.4	410	-0.2
2017	33,723	2.1	412	0.6
2018	34,264	1.6	419	1.7
2019	35,170	2.6	429	2.4
2020	34,301	-2.5	408	-5.0
2021	36,074	5.2	431	5.6
2022	36,690	1.7	438	1.7
2023	37,438	2.0	441	0.7
2024	37,710	0.7	443	0.4
2025	38,047	0.9	445	0.4
2026	38,399	0.9	447	0.4
2027	38,820	1.1	449	0.3
2028	39,227	1.0	450	0.2
2029	39,640	1.1	450	0.1
2030	40,057	1.1	451	0.2
2031	40,463	1.0	452	0.2
2032	40,865	1.0	452	0.1
12-21		1.4		0.3
22-32		1.1		0.3

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Figure 19: Industrial Economic Drivers

Year	Manufacturing GDP (mil \$12)	% Change	Manufacturing Employment (000)	% Change
2012	2,588		33	
2013	2,504	-3.3	31	-5.2
2014	2,397	-4.3	30	-3.3
2015	2,443	1.9	29	-4.7
2016	2,462	0.8	29	2.9
2017	2,490	1.2	30	3.5
2018	2,577	3.5	32	4.0
2019	2,737	6.2	32	0.5
2020	2,650	-3.2	32	-0.1
2021	2,649	0.0	33	2.5
2022	2,748	3.7	33	-0.3
2023	2,879	4.8	32	-0.5
2024	2,949	2.4	33	0.6
2025	3,020	2.4	33	1.0
2026	3,093	2.4	33	0.9
2027	3,158	2.1	33	0.6
2028	3,206	1.5	34	0.5
2029	3,241	1.1	34	0.4
2030	3,274	1.0	34	0.5
2031	3,307	1.0	34	0.4
2032	3,343	1.1	34	0.4
12-21		0.3		-0.1
22-32		2.0		0.5

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4.4 End-Use Intensity Trends

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

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

In the case of end uses where there is little historical activity or where future behaviour is expected to vary significantly from the existing data set due to targeted programs, these are modeled outside the average use intensities. EVs and rooftop PV continue to be modeled outside the average use intensities as they have little historic data. This method also allows these items to be tracked more directly to help fine-tune future forecasts. The PV forecast has been updated based on actual installations in 2021. Key end uses are discussed individually below.

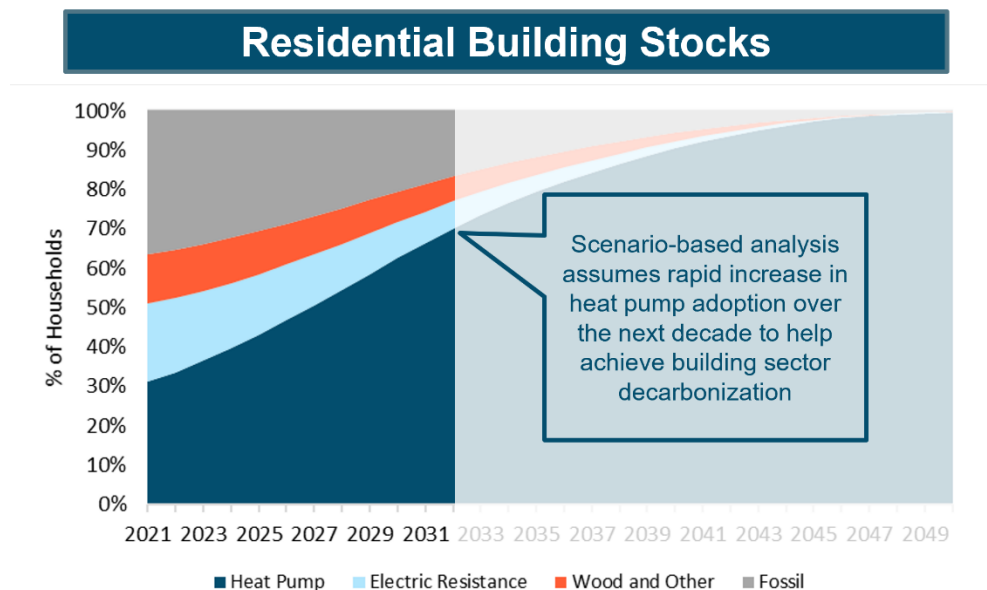
Heat Pumps

Heat pump usage continues to grow in the province as more customers find heat pumps an efficient way to heat and cool buildings as well as providing environmental and financial benefits. According to the 2019 end use survey, 33 percent of customers use heat pumps for some or all of their heating requirements, while 19 percent list heat pumps as their

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primary source of heat. End use survey responses indicated that 36 percent of households use heat pumps for cooling, so some customers have installed heat pumps exclusively for air conditioning purposes. The end-use model uses an estimated saturation of 35 percent of customers supplying their heat via heat pumps in 2022. E3 provided a forecast for heat pump adoption that would be required to achieve carbon reduction targets of net zero by 2050. The heat pump saturations were updated to reflect this forecast, with total saturation hitting 66 percent of homes by 2032, as shown in **Figure 20**.

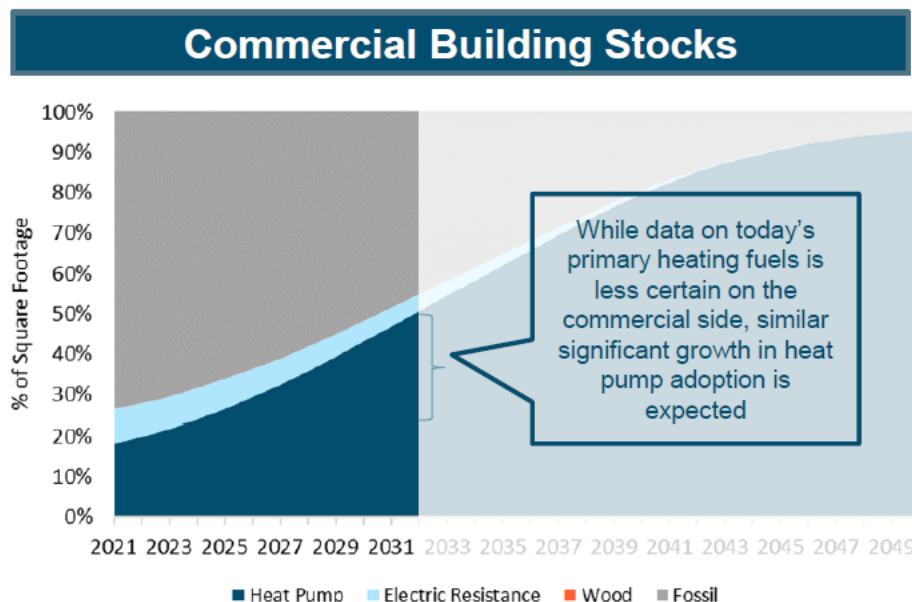
Figure 20: E3 Residential Space Heating Saturation



On the commercial side, the E3 electric heating stock model has a similar trajectory to that of the residential model (see **Figure 21**), but does not reach 100 percent by 2050 as there will be a portion of the buildings that may not be able to fully convert.

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Figure 21: E3 Commercial Space Heating Saturation

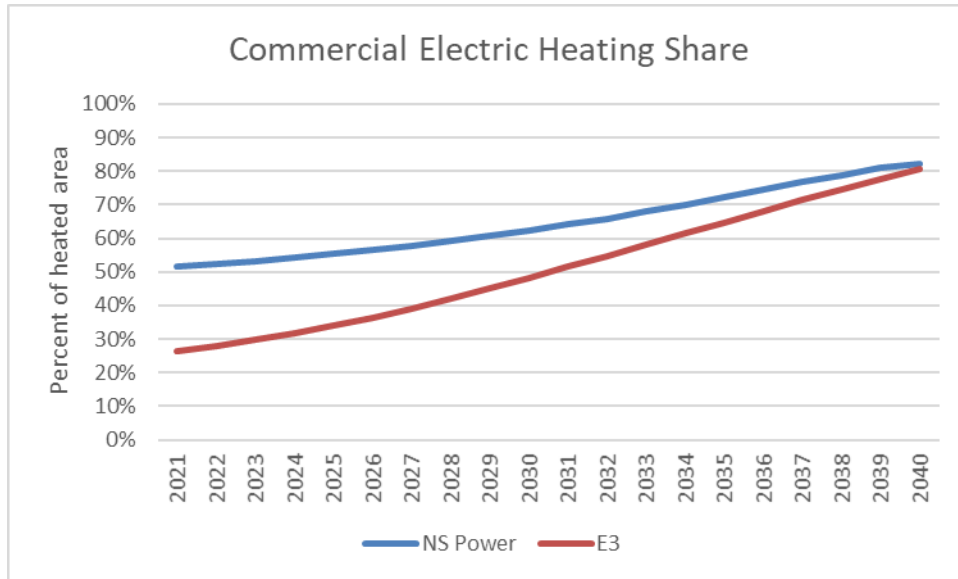


* Starting breakdown of heating fuel varies from NSP forecast given lack of data and reporting differences (e.g., primary heating source) – however, growth in HPs is aligned with NSP

E3 saturation estimates had a lower starting point than the NS Power models, so the NS Power series was adjusted to meet the E3 series by around 2040 as shown in **Figure 22**, resulting in a slightly lower trajectory.

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Figure 22: Commercial Space Heating Saturation Comparison



E3 also estimates peak impacts associated with increased electric space heating in both the residential and commercial sectors. Integrating the E3 share projections into the SAE model produces increased energy usage that is aligned with the E3 data, but the peak impact predicted by E3 using building stock modelling produces a higher peak impact than the existing SAE peak model. To account for this difference, an estimate of the peak impact over that predicted by the SAE model is added into the Load Forecast. In the case of the residential class approximately 25 percent is already captured, while in the commercial class approximately 20 percent is already captured. **Figure 23** shows the estimated energy and peak impact from the NS Power models compared to the E3 projections, as well as the amount added to the peak. The amount captured in the underlying forecast is an average that is applied across all years, but the amounts vary slightly from year to year so the 2030 values of the NS Power portion plus the additional portion are different than the E3 total value.

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Figure 23: Heat Pump Energy and Peak Comparison

Year	NS Power HP Energy (GWh)	E3 HP Energy (GWh)	NS Power HP Peak (MW)	E3 HP Peak (MW)	Additional Peak in Forecast (MW)
2025	60	34	26	95	69
2030	147	151	57	289	203

E3 used its in-house building electrification model, RESHAPE, to simulate diversified system-level heat pump and current resistance customer load shapes. RESHAPE considers several features of heat pump operations that could contribute to the higher peak load estimates than the existing SAE peak model. RESHAPE models the declining efficiency and capacity of heat pumps as outdoor air temperature decreases. On average, the coefficient of performance (COP) of heat pumps modeled in the RESHAPE scenario supporting the Load Forecast declines from 400 percent at 8°C to 233 percent at -15°C. Poorer performance at cold temperatures leads to significant peak impacts relative to the annual load impacts. The capacity of heat pumps in the model is also assumed to decline as a function of COP which causes greater reliance upon backup electric resistance heating with lower efficiency during coldest hours increasing peak impacts.

Figure 24 shows the forecast for residential installations and changes to saturation and intensity over the forecast period. Work is underway to collect more detailed data on the contribution of heat pumps to load and peak.¹¹

¹¹ NS Power Annual and Regulated Financial Statements – On-Bill Financing (P701) – Study Update, NS Power letter to UARB, January 31, 2022 (M09321).

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Figure 24: Heat Pump Forecast

Year	Total Cumulative New Installs	% Install Non-Elec. Heat	% Install Elec. Heat	Overall % Sat. for Heating	Overall Heating Intensity (kWh/house)	Overall % Sat. for Cooling	Overall Cooling Intensity (kWh/house)
2022	16,000	62	38	35	1,214	46	185
2023	32,174	63	37	38	1,310	49	198
2024	48,672	64	36	41	1,408	52	212
2025	65,334	65	35	44	1,506	56	226
2026	82,163	65	35	47	1,605	59	239
2027	99,161	65	35	50	1,705	63	253
2028	116,328	65	35	54	1,805	67	268
2029	133,581	65	35	57	1,905	70	282
2030	150,921	65	35	60	2,005	74	296
2031	168,347	65	35	63	2,104	77	310
2032	185,686	65	35	66	2,204	81	324

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Water Heaters

NS Power anticipates that some customers who convert their oil heating systems to heat pumps will also convert their hot water supply to electric hot water tanks because of the annual operating savings. The 2019 end use survey results had 63 percent of respondents citing electricity as the primary fuel for water heat, which is in line with past estimates of approximately 60 percent. Growth is expected to remain steady, with saturation increasing to 82 percent by 2032. As part of a joint working group, NS Power and E1 are continuing with a pilot using different vendors for controlling water heaters directly and looking at potential benefits to the system (see **Section 10**). **Figure 25** shows the expected changes in saturation and overall intensity over the forecast period.

Figure 25: Water Heater Forecast

Year	Overall % Saturation	Overall Intensity (kWh/household)
2022	68	1,537
2023	70	1,569
2024	72	1,601
2025	74	1,630
2026	75	1,655
2027	77	1,680
2028	78	1,707
2029	80	1,733
2030	80	1,747
2031	81	1,763
2032	82	1,779

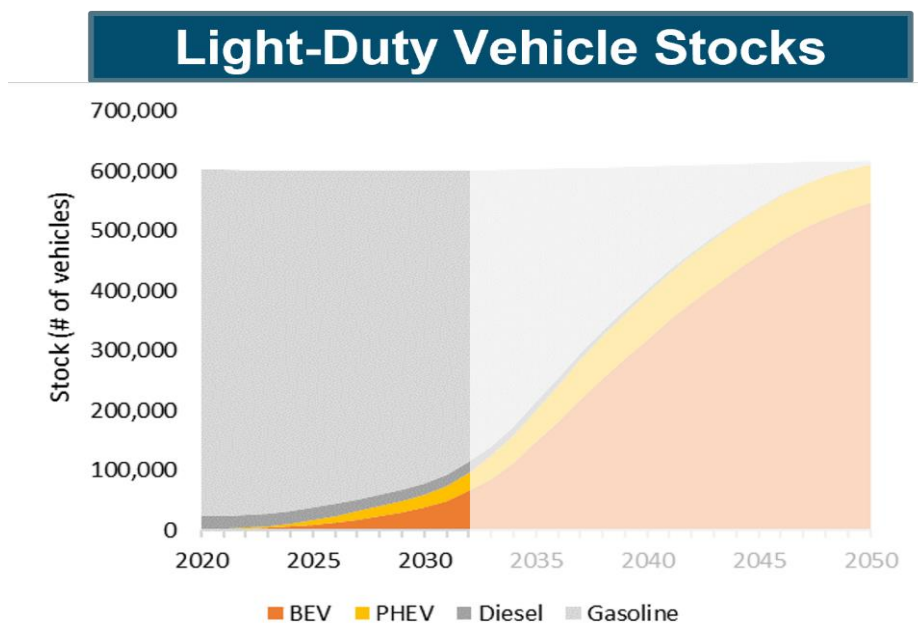
Electric Vehicles (EVs)

The existing federal incentives remain unchanged for 2022 at \$5000 for EVs and \$2500 for plug-in hybrid vehicles. The provincial government continues to provide incentives of \$3000 for new EVs, \$2000 for used EVs and new plug-in hybrid vehicles, and \$1000 for

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used plug-in hybrid vehicles. It is estimated that there were approximately 950 EVs in the province as of the end of 2021. The EV forecast has been updated for 2022 based on a stock rollover model prepared by E3 that estimates adoption to meet 2050 net-zero emissions goals combined with the provincial mandate of 30 percent of vehicles sales being EVs by 2030 and the federal target of 100 percent of vehicle sales being EVs by 2035. The 2022 Load Forecast for EVs includes both light duty vehicles (LDV) as well as medium duty vehicles (MDV) such as delivery trucks and other medium duty fleet vehicles, and heavy-duty vehicles (HDV) focusing on buses. The EV forecast estimates that Nova Scotia will have over 75,000 EVs on the road by 2031, mostly made up of LDVs (see **Figure 26**), compared to a forecast of 58,000 vehicles by 2031 in the 2021 Load Forecast, which had an estimate of 20 percent of vehicle sales by 2030.

Figure 26: LDV Stock Forecast



The impact of EVs on energy sales and peak demand depends on a number of factors including the types of vehicles adopted (plug-in hybrid vs. battery electric), charging capacity (anywhere from 3 kW to 20 kW depending on vehicle limits and home charger type, and higher for commercial DC Fast Chargers), driving patterns and access to

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charging. E3 provided estimates of total load and normalized per-vehicle electric vehicle load shapes over the course of the year based on E3's EV Load Shaping Tool. E3's tool simulates driving and charging electric vehicles in Nova Scotia, based on a bottom-up modelling approach that simulates driving and charging of thousands of EV drivers, and produces a load shape that captures the diversity of driving behavior, EV types, and charging access across the Nova Scotia driving population.. **Figure 27** shows the EV load and peak demand contribution estimated from the load shapes provided by E3:

Figure 27: E3 EV Mileage Assumptions and Load/Peak Modeling Results

Vehicle Type	Avg km/year ¹²	Avg kWh/year	Avg kW/vehicle on Peak
LDV	17,427	4,323	0.9
MDV	22,779	8,205	1.6
HDV	62,888	113,890	7.3

The peak impact assumes that 70 percent of charging is managed by NS Power (including smoothing through vehicle-grid integration) and 30 percent of charging is unmanaged. The load and peak demand contributions account for a mix of vehicle types and charging infrastructure based on the projected split of EV adoption by vehicle type and charger installation and utilization by EVs. The overall average peak contribution in E3's "blended" managed and unmanaged charging scenario is 0.9 kW/vehicle, which is higher than the 0.6 kW/vehicle in the 2021 Load Forecast. The 0.9 kW/vehicle peak for the blended managed and unmanaged scenario is still lower than the 1.3 kW/vehicle peak contribution assumed for entirely unmanaged charging. The management of charging in this scenario was based on minimizing the cost of electricity to charge with the electric rates referenced being the existing time of use tariffs that are currently in the pilot stage,

¹² Based on the *NRCAN 2009 Canadian Vehicle Survey Summary Report*,
<https://oee.nrcan.gc.ca/publications/statistics/cvs/2009/appendix-1.cfm?graph=11>

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1 coupled with vehicle-grid integration to smooth large spikes in charging that would occur
2 during switches from peak to off-peak periods.
3

4 Nova Scotia-specific information on the peak and energy impact of EVs is still being
5 collected through the Smart Grid Nova Scotia (SGNS) Project,¹³ where the impact of EV
6 charging on the grid is being investigated. Through the project 100 EV smart chargers
7 have been installed and testing is ongoing to demonstrate the impact of charging and the
8 benefit of utility-managed charging events. One vehicle-to-grid smart charger¹⁴ has been
9 installed with additional chargers expected to be installed in the first half of 2022. As the
10 project continues to progress, data collected will be used to inform forecast assumptions.
11 Some potential impacts are included in the scenarios provided in the “New Technologies”
12 subsection below (see **Figure 30**).
13

14 As shown in **Figure 28**, the estimated energy and peak impacts that correspond to the
15 number of EVs, along with potential peak impact without mitigation measures, which
16 assumes an average of 1.3 kW/vehicle, or around 20-30 percent charging on peak
17 depending on the mix of vehicle and charger types.
18

¹³ Smart Grid Nova Scotia Project, NS Power Application, December 5, 2019 (M09519).

¹⁴ Chargers that can use the EV’s battery to supply energy to the grid in response to inputs.

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Figure 28: EV Impact to Energy and Peak Forecasts (cumulative)

Year	EVs	Load (GWh)	Peak @ 0.9kW/vehicle (MW)	Peak @ 1.3kW/vehicle (MW)
2022	2,864	12	2	4
2023	5,978	26	5	8
2024	10,258	48	9	14
2025	15,680	76	14	21
2026	22,232	110	20	30
2027	29,908	153	27	40
2028	38,671	204	35	52
2029	48,465	259	45	66
2030	59,299	320	55	81
2031	75,192	403	69	102
2032	96,612	510	89	131

Solar Generation (PV)

Solar generation consists of two main types – distributed small-scale solar (mainly rooftop) that falls under NS Power’s net metering program and small to large-scale generation that is fed directly onto the grid via power purchase agreements or direct utility ownership. In the Load Forecast, only the former is considered, as it serves as a reduction in load mainly in the Residential class. The 2021 Load Forecast was for 1,193 new installations, while the actual number was 1,628, for a cumulative total of 4,022 (33 MW) by the end of the year¹⁵. As of 2021, the average installed capacity is approximately 8.3 kW for residential customers and 33 kW for non-residential, and total annual net metering solar generation is estimated at 36.5 GWh. The average capacity factor is estimated to be 12.6 percent.

¹⁵ NS Power, 2022 Net Metering Report, January 31, 2022.

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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 \$0.30/W of installed capacity¹⁶ and grants under the federal Greener Homes Program¹⁷. The forecast continues to be based on the 2019 study by Dunskey Energy Consulting for the Canadian Solar Industries Association.¹⁸ The uptake matches the “Maintain Current Market Activity” in the long term, with installed capacity of 170 MW in the residential sector by 2030, but the curve has been advanced based on the high number of installations in 2019 through 2021. This scenario assumes that rebates continue to be available in the coming years.

Commercial solar installations in 2021 included 651 kW installed across 20 sites, and the forecast assumes installations will continue at around the same level over the next five years. The overall impact from the commercial installations continues to be relatively small compared to residential installations; by 2032 they are forecast to represent 9.1 MW of installed capacity. The overall impact is shown in **Figure 29**. There is no forecast reduction in NS Power peak as solar generation occurs at times non-coincident with NS Power’s system peak (winter evenings).

¹⁶ <https://www.energycyns.ca/residential/services-rebates/solarhomes/> The rebate rate changed as of January 6 2022 to \$0.30/W up to 25 percent of eligible system costs (excluding HST) or \$3000, whichever is less.

¹⁷ <https://www.nrcan.gc.ca/energy-efficiency/homes/canada-greener-homes-grant/start-your-energy-efficient-retrofits/plan-document-and-complete-your-home-retrofits/eligible-grants-for-my-home-retrofit/23504>

¹⁸ Nova Scotia Residential Solar Market Outlook and Labour Force Study Final Report - April 2019 prepared by Dunskey 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

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Figure 29: PV Impact to Energy (cumulative)

Year	Total New Installs	Load (GWh)	Peak (MW)
2022	2,610	-24	0
2023	3,947	-36	0
2024	5,351	-49	0
2025	6,825	-63	0
2026	8,505	-78	0
2027	10,420	-95	0
2028	12,604	-115	0
2029	15,093	-138	0
2030	17,931	-164	0
2031	20,724	-185	0
2032	23,069	-205	0

New Technologies

The 2022 Load Forecast does not assume a significant amount of distributed solar/battery storage combinations. The cost of home batteries is still relatively expensive, in the range of \$15,000-\$20,000 for a single battery and installation (for 5-7 kW batteries). This is more expensive than the cost of a gas-powered generator, which varies from as little as \$1,000 for a moderately sized stand-alone generator to supply plug loads (also around 5-7 kW), up to \$10,000 or more for an installed whole-home generator. Currently the only major driver for residential batteries is for back-up power, so gas generators are a more cost-effective solution. The new critical peak pricing (CPP) and time-of-use (TOU) rates currently being piloted might start to encourage battery installation either alone or in conjunction with solar panels, but the initial costs associated with batteries are still high. As battery technology improves and costs come down over time this is likely to change, but research in these areas is ongoing and timelines for significant shifts in this technology are unknown.

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The impact of battery storage is being explored through the SGNS project, which will include data collection from both stand-alone battery backup and PV/battery combinations. EV smart charging and using EV batteries (vehicle-to-grid, or V2G technology) to power homes will also be investigated. Managed EV charging is incorporated into the EV load shapes provided by E3, and the forecast DR impacts could include impacts from smart charging or V2G. The technology required for V2G is still in development and is not widely available, but a few manufacturers have included the capability in existing vehicles (the Nissan Leaf is one example) or have announced that they will provide V2G capability in the near future (the Ford F150 Lightning will have an available option). For true V2G capabilities, which would not only allow a vehicle to power a home but also allow energy to be fed onto the grid, there is still development required on the technology as well as the codes and standards to allow that functionality.

Data on the impacts of new technologies on peak and energy demand continue to be collected and will be shared through project specific updates. However, some early information can be used to help provide context for some of these new technologies. **Figure 30** below shows a range of residential customer battery uptake scenarios as well as the peak impact mitigation potential based on early information from the SGNS project. These are illustrative estimates based on limited data sets and will be refined as the project continues.

Figure 30: Potential Peak Impacts from Batteries

Technology	Residential Share (%)			
	50%	25%	10%	5%
Battery Peak Impact - No Control (MW)	0	0	0	0
Battery Peak Impact - Optimal DR Control (MW)	(1,246)	(623)	(249)	(125)

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Battery peak estimates are based on the 5 kW batteries utilized in the SGNS project.

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

Intensities

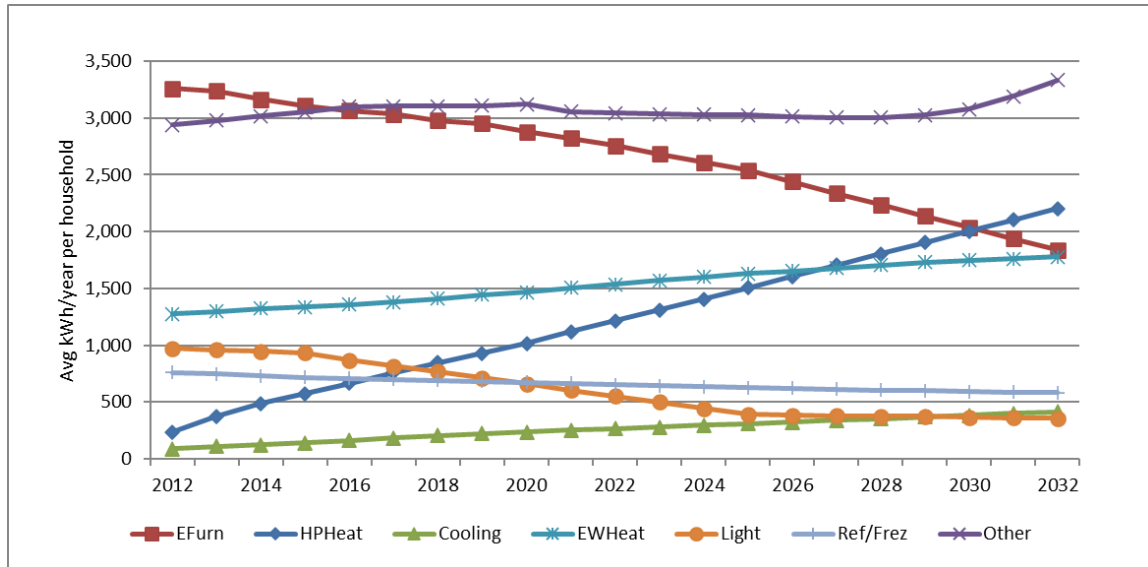
Figure 31 provides an estimate of the resulting residential end-use intensities. This figure represents the intensities that are inputs to the XHeat, XCool and XOther variables; they are not direct inputs to the forecast. The relative contribution of each will change based on the coefficient applied to the XHeat, XCool and XOther variables.

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

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

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Figure 31: Residential End-Use Intensities



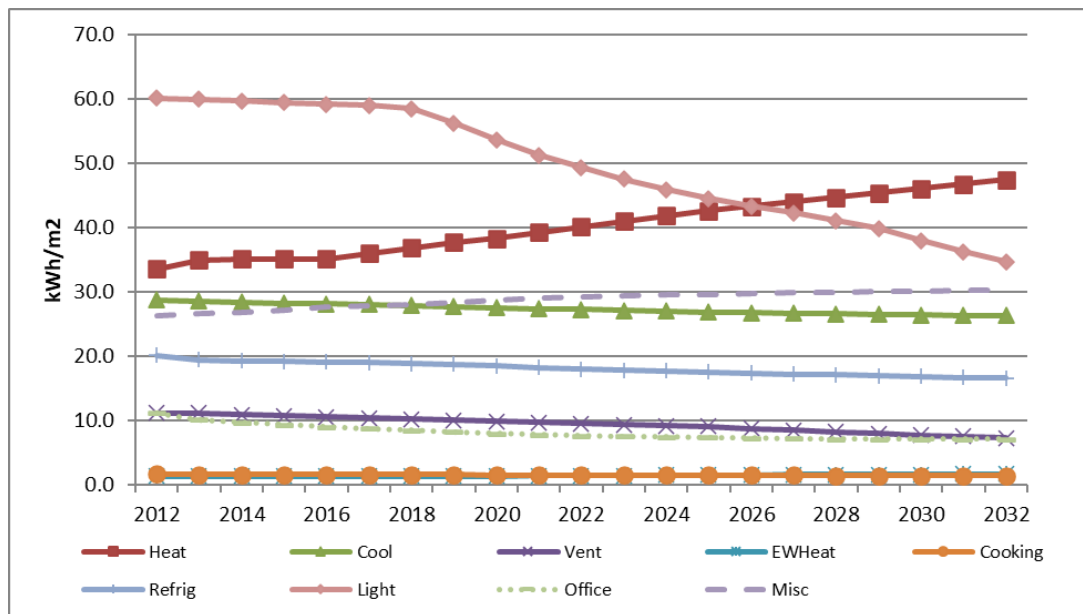
The intensity trends are similar to those in prior forecasts. The use of heat pumps for space heating is forecast to increase steadily throughout the forecast period including the conversion of both electric baseboard and non-electric homes. Offsetting this increase is a corresponding decrease in electric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

The end-use intensities for the commercial models are done on a per square metre basis, rather than per customer. The forecasts for the end-use intensities are set out in **Figures 32 and 33** below. The end uses listed include:

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

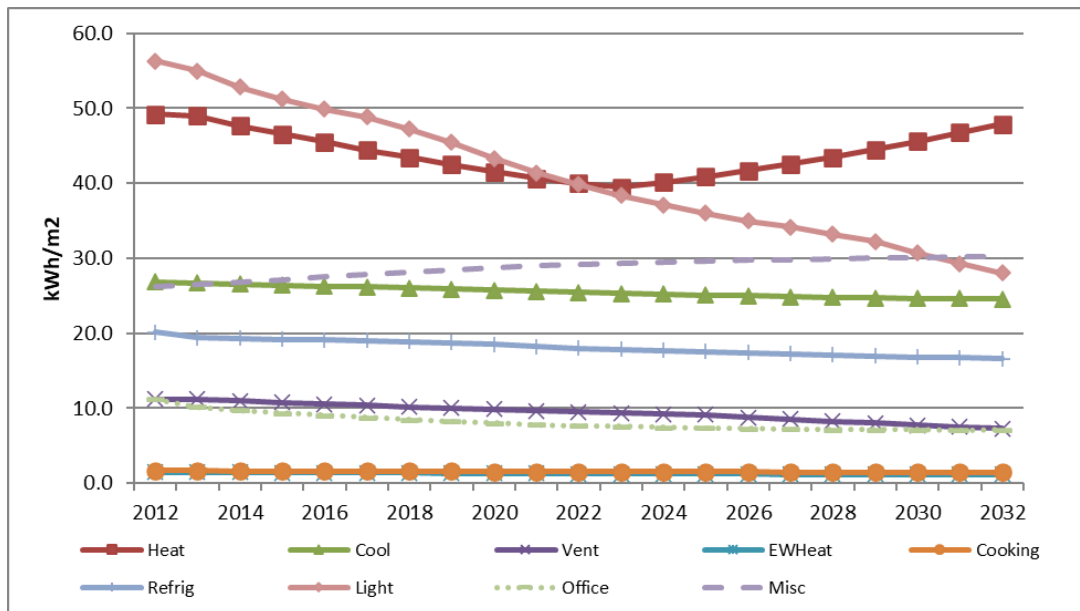
Figure 32: Historical and Projected Small General Commercial End-Use Intensity (kWh/m²)



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

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Figure 33: Historical and Projected General Commercial End-Use Intensity (kWh/m²)



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

For the 2022 Load Forecast, data from the EIA 2021 Annual Energy Outlook uses the same baseline data (2015 Residential Energy Consumption Survey and 2012 Commercial Building Energy Consumption Survey) as the 2021 Load Forecast. The heat pump intensity increases due to higher expected heat pump penetration based on E3's forecast.

Commercial and Industrial Growth

The commercial and industrial sectors are projected to see targeted growth as a result of the federal and provincial push to net-zero emissions and the resulting electrification programs designed to reduce customers' annual energy usage and lower their carbon emissions. These programs involve converting heating loads to electricity (mainly from oil), accelerating the uptake of electric cooling technologies, and examining opportunities to power industrial processes through electrification (as shown in **Figure 34**). Large

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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 34: Commercial and Industrial Electrification Forecasts (cumulative)

Year	SmGen (GWh)	GenDemand (GWh)	LrgGen (GWh)	SmInd (GWh)	MedInd (GWh)	LrgInd (GWh)	Coinc. Peak (MW)
2022	5	12	4	4	4	2	3
2023	10	28	7	8	8	2	7
2024	12	47	12	12	12	3	12
2025	14	52	15	14	14	6	15
2026	16	57	15	15	15	7	17
2027	17	59	15	16	16	8	18
2028	18	60	15	16	16	9	18
2029	18	60	15	16	16	9	18
2030	18	60	15	16	16	9	18
2031	18	60	15	16	16	9	18
2032	18	60	15	16	16	9	18

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4.5 Price Data

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

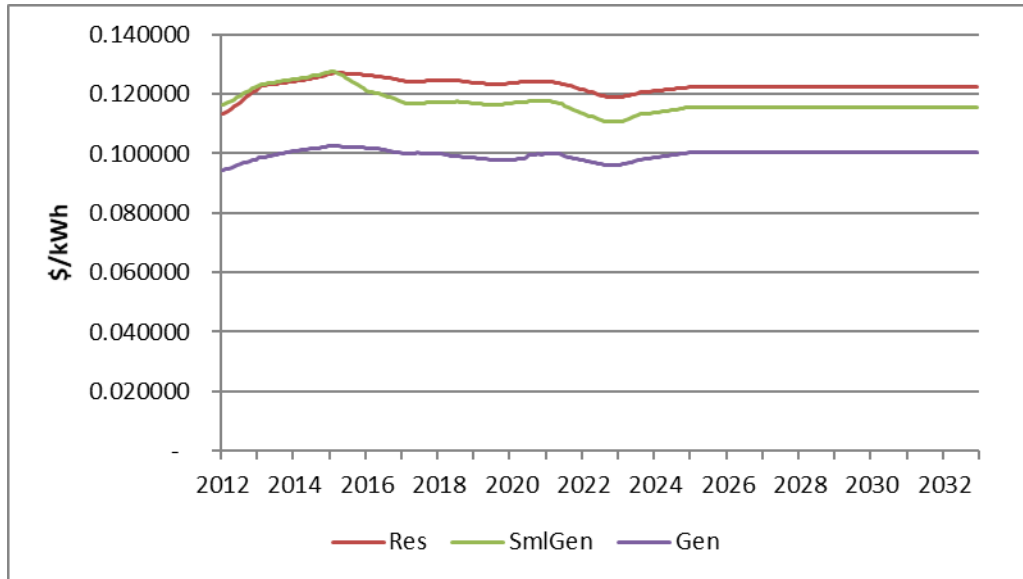
In the forecast period, the nominal price of electricity for 2022 is based on the rates included in the Company's 2020-2022 Fuel Stability Plan Compliance Filing filed on December 13, 2019¹⁹ and includes a nominal price increase of 1.5 percent. For the period 2022 to 2024, the nominal price of electricity changes at the rate proposed in the Company's recent General Rate Application (GRA), an average of 3.6 percent over 3 years²⁰. The remaining years are forecast to increase at an average of 2 percent per year, or around the rate of inflation, which results in a flat profile in real terms. **Figure 35** shows price forecasts by class.

¹⁹ M09288, NS Power 2020-2022 Fuel Stability Plan, NSUARB Decision, December 6, 2019.

²⁰ NS Power 2022-2024 General Rate Application, January 27, 2022, DE-03 – DE-04, Figure 12-5

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Figure 35: Historical and projected real electricity prices (real dollars per kWh)



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

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4.6 Demand Side Management

Demand Side Management (DSM) and conservation plans continue to play a role in the use of electricity in Nova Scotia, and the forecast takes the projected energy and demand savings into account. NS Power uses the DSM targets for 2022 as approved by the Board in matter M09096.²¹ Between 2022 and 2025, DSM amounts are based on E1's proposed supply agreement.²² Beyond 2025, DSM amounts are based on E1's 2019 Potential Study²³ base case scenario. These values are all in line with past assumptions about future DSM.

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

To address the issue of double counting, the approach used is the same as that used in prior forecasts: to introduce cumulative historical DSM savings as reported by E1 to the regression model as a load modifying variable, and allow the model to determine what level of DSM is already included in other variables. Assuming future DSM activities are similar to historic activities, the coefficient applied to historic DSM will also apply to the

²¹ M09096, Application for approval of a Supply Agreement for Electricity Efficiency and Conservation Activities between Efficiency One and Nova Scotia Power Inc., NSUARB Decision, September 16, 2019, 2019 NSUARB 105.

²² M10473, EfficiencyOne 2023-2025 DSM Resource Plan Filing, March 11, 2022.

²³ M08929, Exhibit N-1, EfficiencyOne, DSM Potential Study, August 14, 2019.

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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 0.989 vs 0.987 without the DSM variable, and a mean absolute percent error (MAPE) of 2.10 percent vs 2.31 percent). 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. 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 -0.512 (similar to prior values) meaning 48.8 percent of savings are already accounted for in the regression, and 51.2 percent are not captured by other variables, and need to be included in the forecast.

For the Commercial and Industrial classes, a combined model was created to identify the level of DSM already captured by other variables. DSM impacts are not provided for Commercial and Industrial customers by rate class or by month, so by creating a combined model for these classes, the level of uncertainty around allocating historical DSM savings across rate classes and months of the year is reduced. The DSM variable coefficient is lower than in 2021, but the statistics of the model are similar to 2021 (adjusted R squared of 0.842 vs 0.851) and continues to show a statistically significant DSM variable (p-value of 0.21 percent vs 0.49 percent). The coefficient is -0.38, meaning future years in the load forecast should be adjusted by 38 percent of the forecast DSM amounts. **Figure 36** shows the DSM levels (at the generator) incorporated into the forecast.

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Figure 36: Annual Forecast DSM Savings (incremental)

Year	Forecast Residential DSM savings (GWh)	Forecast Commercial and Industrial DSM savings (GWh)	DSM captured by Residential end use forecast (GWh)	DSM captured by Comm/Ind end use forecast (GWh)	DSM Adjustment for Residential with Coefficient (GWh)	DSM Adjustment for Comm/Ind with Coefficient (GWh)
2022	55.5	71.6	27.1	35.0	28.4	36.7
2023	69.3	51.4	33.8	25.1	35.5	26.3
2024	60.9	81.7	29.7	39.9	31.2	41.8
2025	65.6	83.9	32.0	40.9	33.6	42.9
2026	69.6	66.7	34.0	32.5	35.7	34.1
2027	71.6	65.5	34.9	32.0	36.6	33.5
2028	73.0	74.0	35.6	36.1	37.4	37.9
2029	73.7	61.4	35.9	30.0	37.7	31.4
2030	73.3	60.0	35.8	29.3	37.5	30.7
2031	74.1	56.5	36.2	27.6	37.9	28.9
2032	73.2	55.0	35.7	26.9	37.5	28.2

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

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

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5.0 RESIDENTIAL SECTOR

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

On a weather normalized basis, residential sales grew between 2019 and 2020 due primarily to an increased number of people working from home as a result of COVID-19. 2021 actuals were impacted by even warm weather, as well as a continued impact from COVID-19. **Figure 37** shows a breakdown of the different components for 2019, 2020 and 2021 actuals vs forecast and weather normalized totals, and the 2022 forecast.

Figure 37: Comparison of Forecast to Actuals

Year	2019	2020	2021	2022
Forecast Sales	4551	4540	4718	4715
Weather variance	+92	-91	-141	-
Non-weather variance	+45	+226	+42	-
Actual Sales	4688	4675	4619	-
Weather-adjusted sales	4596	4766	4760	4715

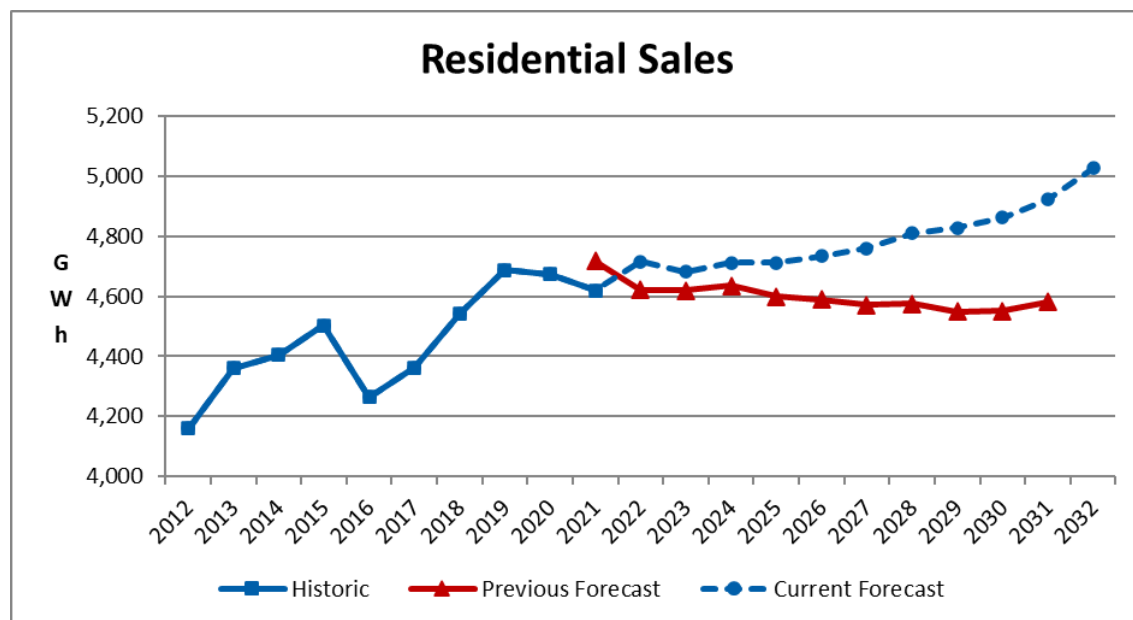
The non-weather variance in 2021 is mainly related to an increase in people working from home due to the COVID-19 pandemic and a higher number of new customers compared to forecast. The COVID-19 variable that was added in 2020 continues to be used, and is reduced in both March and October, 2022 as the work from home impact is expected to further decrease. The COVID-19 impact to the Residential forecast is approximately +100 GWh in 2022, and +54 GWh for 2023 and beyond. The long-term impact of the COVID-19 pandemic on working habits in Nova Scotia is still unknown, but the assumption in this

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forecast is that there will be a certain amount of continued work-from-home load, likely through hybrid work models.

Apart from the shift related to increased work from home, the long-term trend is higher than the previous forecast, with higher EV penetration rates and higher electric space heating uptake assumed in order to meet long-term environmental policy goals. These will impact the forecast mainly in the later years starting around 2025. As with the previous forecast, new customers will add to sales while DSM, naturally occurring efficiency improvements, and increased solar generation will all decrease sales. Over the 2022-2032 period, forecast sales in this class increase 0.6 percent annually. Historical and forecast annual residential sector loads are shown in **Figure 38**.

Figure 38: Historical and Forecast Annual Residential Sales



The forecast for new construction in 2021 was for 4,760 units, while actual customer growth was over 5,700. Nova Scotia's population also hit 1 million at the end of 2021, and the province has seen strong growth over the past five years (see **Figure 16**). The increase

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in remote work that resulted from COVID-19 restrictions contributed to further increases in population with people moving to Nova Scotia from other provinces. The Conference Board of Canada predicts continued strong population growth, slowly decreasing to around +1,500 per year by the end of the forecast period. Housing is expected to increase as well, with Halifax Regional Municipality recently announcing development plans to allow for over 22,000 new residential units to be constructed in the coming years to help address a housing shortage in the region. New customers in the Residential class are separated into single-family and multi-unit categories. Analysis of billing data showed that new single-family homes use approximately 16,000 kWh per year on average, while multi-unit homes use 4,860 kWh per year on average. In addition to using these averages, a structural index was applied that considers building shell efficiency (BSE from the EIA forecast) as well as projected changes in house size. Building efficiency is expected to improve, although based on calibration done in 2013, improvements are expected to be lower in Nova Scotia than in the EIA forecast for New England. While efficiency is expected to increase, house size is also expected to continue increasing, albeit at a slower rate than in previous years. These two factors combined lead to a slight expected decrease in average use per new residential customer. Building shell efficiency, floor area and the resulting structural index are in **Figure 39**. Details of both building efficiency and house size were included in the end use survey, and analysis is ongoing. Future surveys will help to identify trends in this area.

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Figure 39: Building Characteristics and Structural Index

Year	BSE Heat EIA (New England)	BSE Heat NS	Floor Area (m ²)	Structural Index
2022	0.948	0.982	150.5	1.000
2023	0.941	0.979	150.7	0.998
2024	0.933	0.976	150.9	0.997
2025	0.926	0.974	151.1	0.996
2026	0.919	0.971	151.3	0.994
2027	0.912	0.968	151.4	0.992
2028	0.905	0.966	151.5	0.990
2029	0.898	0.963	151.6	0.988
2030	0.891	0.961	151.7	0.986
2031	0.885	0.958	151.8	0.985
2032	0.878	0.956	151.9	0.983

Figure 40 provides a breakdown of the components of the Residential forecast at the system level. Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2022 to 2032.

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Figure 40: Residential Sales Components by Year

Year	Regression Model Output (GWh)	New Customers (GWh)	Solar Impact (GWh)	EV Impact (GWh)	RTR Sales (GWh)	DSM Adjustment (GWh)	Total Sales (GWh)		Total Res. DSM ²⁴ (GWh)	DSM captured by end uses ²⁵ (GWh)
2022	4,704	56	-31	12	0	-25	4,715		-50	-24
2023	4,664	92	-41	26	-2	-57	4,682		-112	-55
2024	4,678	126	-51	48	-3	-85	4,712		-167	-81
2025	4,664	155	-62	76	-3	-115	4,713		-225	-110
2026	4,671	179	-74	110	-3	-147	4,735		-288	-140
2027	4,680	200	-88	153	-3	-180	4,760		-352	-172
2028	4,710	219	-104	204	-3	-214	4,811		-417	-204
2029	4,706	237	-123	259	-3	-248	4,828		-483	-236
2030	4,717	253	-143	320	-3	-281	4,862		-549	-268
2031	4,730	268	-160	403	-3	-315	4,922		-616	-300
2032	4,764	282	-176	510	-3	-349	5,027		-681	-332

Figure 41 provides an approximation of the heat pump heating, heat pump cooling, electric baseboard, and water heater loads at the system level (these are included in the Regression Model Output column). This approximation uses the same methodology as outlined in the response to NSUARB IR-12 (e) from the 2020 Load Forecast, where the end-use intensity is multiplied by the number of existing customers, the appropriate X coefficient from the regression model, and either the HeatUse variable or the CoolUse variable (see **Appendix B** for details of these components). As this assumes that the X variables apply equally to all end uses, which may not be the case, the numbers are illustrative only. These numbers also do not include any DSM amounts that would impact the specific end use.

²⁴ Total DSM is the amount from Figure 20, adjusted for losses and with approximately 0.4 percent allocated to the Municipal class customers.

²⁵ These amounts are embedded in the Regression Model Output column through the end use efficiency estimates, i.e. the amount not captured by the DSM coefficient.

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Figure 41: Illustrative Contribution of Specific End Uses

Year	HP Heat (GWh)	HP Cool (GWh)	Baseboard Heat (GWh)	Water Heat (GWh)
2022	607	74	1096	710
2023	656	81	1059	725
2024	705	87	1018	740
2025	747	94	966	751
2026	794	101	907	763
2027	841	108	845	775
2028	892	115	788	789
2029	934	122	724	799
2030	980	130	663	806
2031	1,027	137	603	813
2032	1,078	144	547	823

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6.0 COMMERCIAL SECTOR

The Commercial SAE model creates a unique forecast for the Small General and General rate classes. Like the residential model, the commercial SAE models express monthly sales as a function of heating, cooling, and other loads. The Small General forecast is based on a monthly SAE average use model and a separate customer forecast. The General rate class model is estimated on a total monthly sales basis (class level sales vs customer level) where total monthly billed sales is a function of total monthly heating requirements, cooling requirements, and other use. The end-use variables are constructed by interacting annual end-use intensity projections that capture end-use intensity trends, with GDP and employment, real price, monthly HDD and CDD and a variable accounting for the number of days in each month. As discussed in the introduction, employment by sector has been added to the commercial intensity models to calibrate the underlying NRCan data for the Atlantic provinces to Nova Scotia specifically.

A detailed breakdown of the two commercial SAE models is provided in **Appendix B** and in **Attachments 6** and **7**. Although sales were negatively impacted by the COVID-19 pandemic in 2020 and 2021 they are expected to rebound through 2022 as the economy rebounds. The impact on the commercial sector in Nova Scotia was moderate, with fewer and shorter shutdowns than elsewhere in Canada. Temporary closures in the spring of 2020 were followed by opening restrictions (mandatory masks, reduced capacities, and increased distancing and cleaning requirements) on many commercial sectors including retail and restaurants. Schools have largely remained open since the fall of 2020, except for several universities that chose to deliver classes online for the 2020/2021 school year. Despite increased restrictions in late 2021/early 2022, businesses have largely been operating in some capacity and companies continue to return to office environments. Although 2021 was expected to show a rebound in sales, the impact of COVID-19 continued to be felt in the commercial sector. **Figure 42** shows the drop in 2020 and 2021 followed by an expected rebound in 2022. Results to date indicate that 2022 sales in the commercial class are more in line with 2019 values.

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Figure 42: Commercial Class Sales

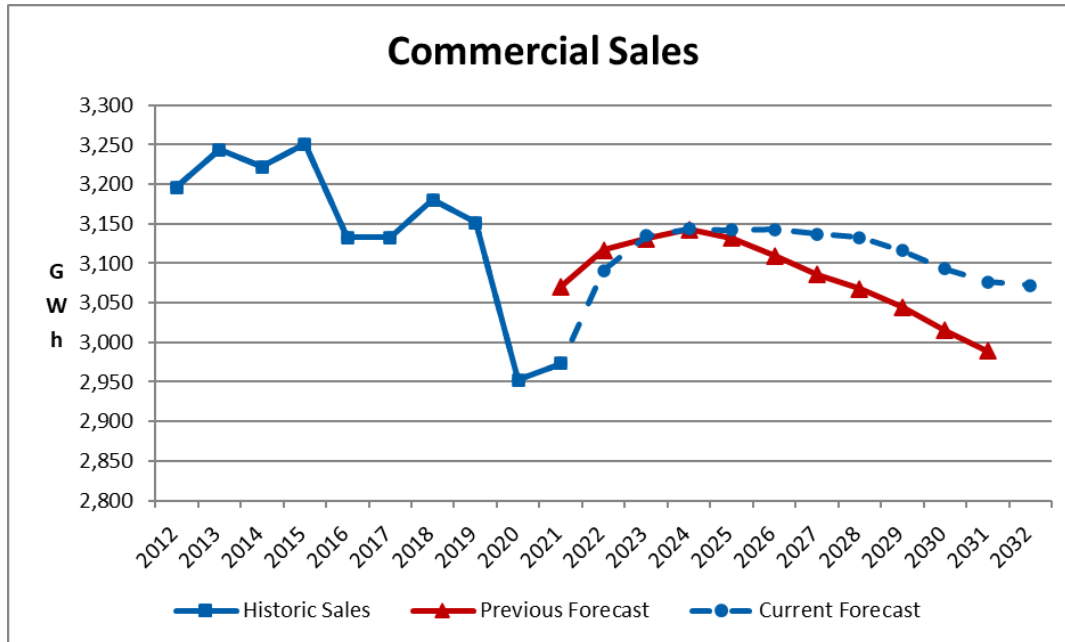
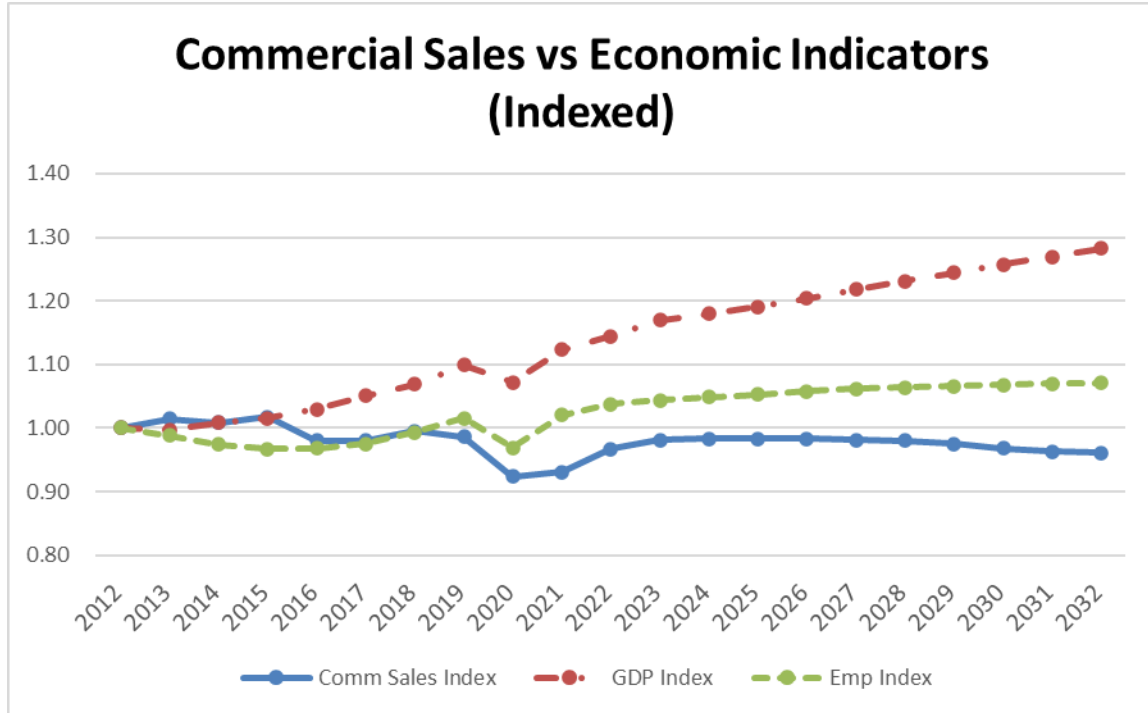


Figure 43 shows a comparison of commercial energy sales to both GDP and employment indicators for Nova Scotia. The sharp drop in 2020 is of a relatively similar magnitude in all three measures. Although sales lag the rebound in the economic variables, 2022 is expected to see a return to historic levels in this sector.

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Figure 43 Commercial Sales vs Economic Indicators

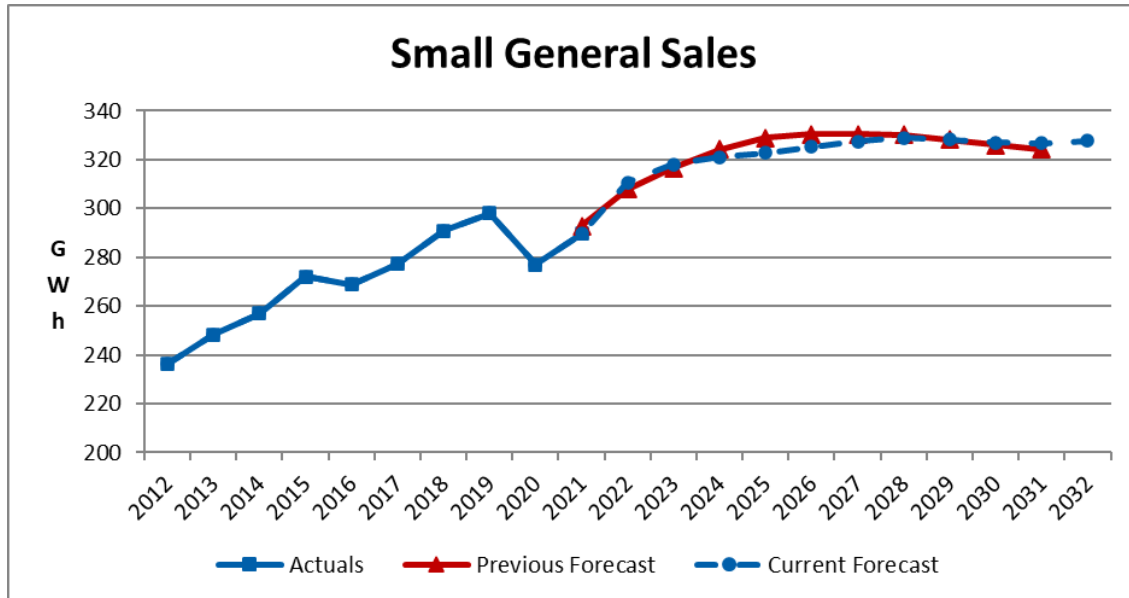


6.1 Small General Service

Historical and forecast Small General service loads are shown in **Figure 44**. Small General service load shows an average annual increase of 0.5 percent compared to an increase of 1.1 percent per year in the 2021 Load Forecast. Commercial electrification (see **Figure 34**) is expected to add 18 GWh by 2032, but this will be offset by a combination of DSM and decreased intensity forecasts for the ventilation, lighting and miscellaneous end uses. The EIA forecast assumes continued efficiency gains in lighting and ventilation equipment, which will be offset by an increase in heating intensity. As with the 2021 Load Forecast, the heating penetration from the residential class was used as the end-use intensities are similar.

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Figure 44: Historical and Forecast Annual Small General Sales



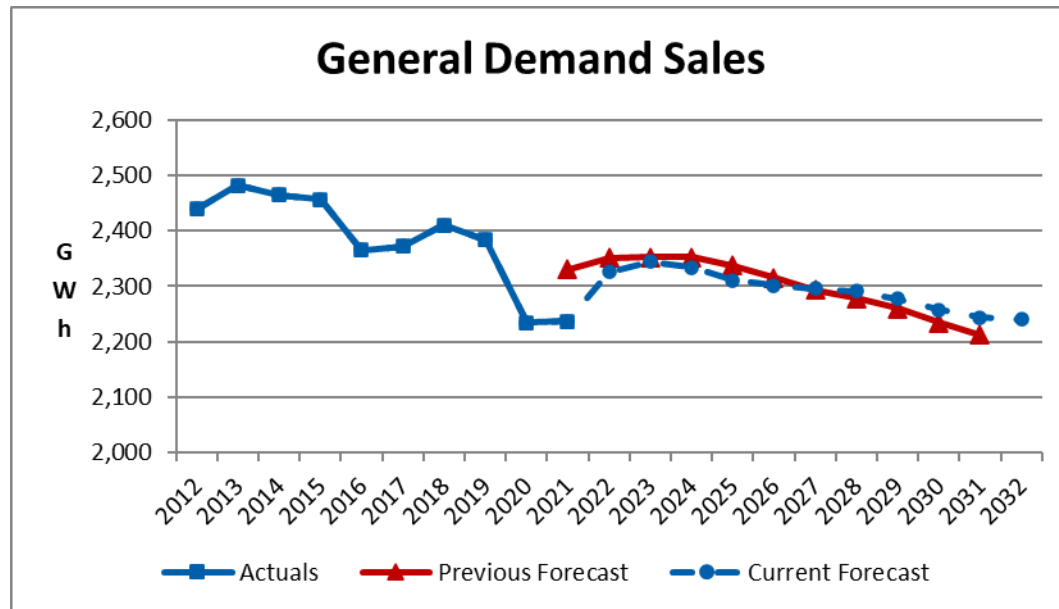
Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2022 to 2032. Total change between 2022 and 2032 is an increase of 5.5 percent.

6.2 General Service

Historical and forecast General class sales are shown in **Figure 45**. General class load is expected to decline by 0.4 percent per year during the 10-year forecast period, compared to a decline of 0.5 percent in the 2021 Load Forecast. Compared to the 2021 Load Forecast, increased space heating will contribute more to longer term growth but is offset by DSM programs as well as increased efficiency of the lighting and miscellaneous end uses.

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Figure 45: Historical and Forecast Annual General Demand Sales



Please refer to **Appendix B** for tables with a detailed breakdown of the changes from 2022 to 2032. Total change between 2022 and 2032 is a decrease of 3.7 percent.

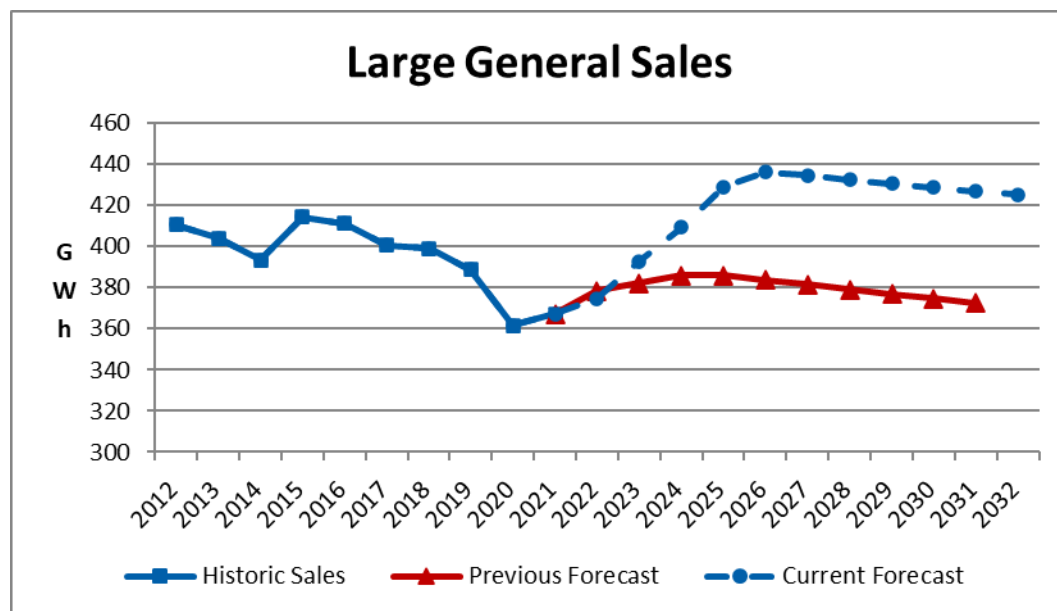
6.3 Large General Service

The Large General class remained unchanged from 2020 due to the impacts of the COVID-19 pandemic. The decreased sales continued in the large retail, office, university and transportation sectors, most of which are expected to return to pre-pandemic levels by the end of 2022. The class is forecast using a combination of customer survey and historical sales information. Customers are surveyed annually to determine their electricity requirements over the next three-year period. In addition, NS Power personnel are in regular contact with key customers within this class. Details on planned production levels or equipment changes help inform energy requirement expectations. In the absence of survey or publicly available information, load levels are forecast to be flat before the impact of any DSM activities. Thirteen (13) of the 19 Large General customers replied to the

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annual survey: two indicated no change, four indicated a decrease, seven indicated an increase. Growth in this class is expected to be driven by institutional facilities, in particular expansions at several hospital sites in the province. The recently released provincial capital budget included almost \$465 million for hospital redevelopment projects in Halifax and Sydney²⁶, which account for over half the increase in this class. The overall forecast has an increase of approximately 50 GWh by 2032 as shown in **Figure 46**.

Figure 46: Historical and Forecast Annual General Demand Sales



²⁶ <https://novascotia.ca/news/release/?id=20220323002>

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1 **7.0 INDUSTRIAL AND MUNICIPAL SECTORS**

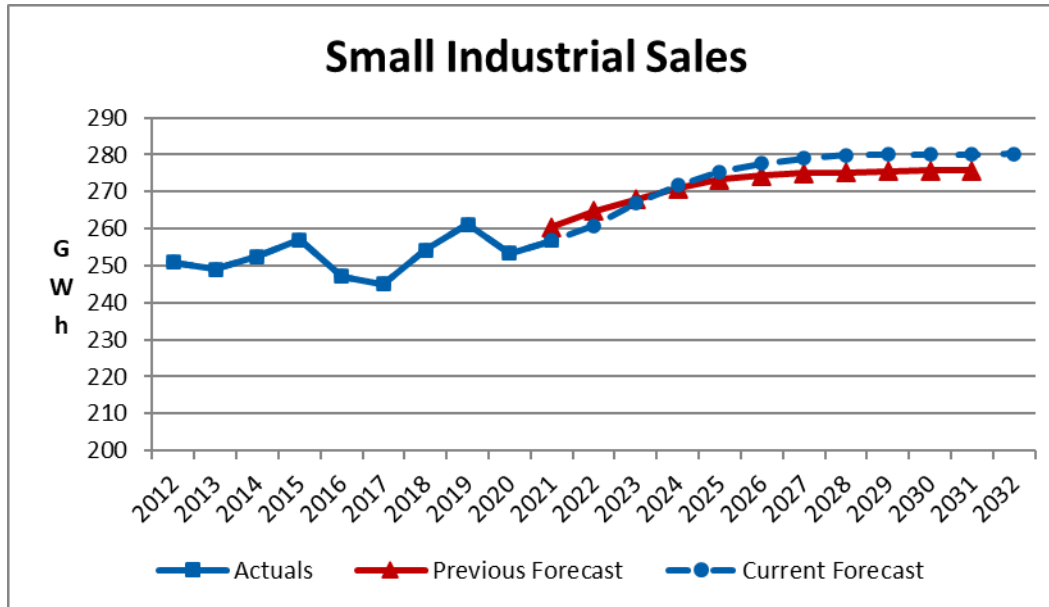
2
3 The forecast models for the Small Industrial and Medium Industrial classes are
4 econometric-based models (i.e. dependent on economic variables). Provincial
5 manufacturing GDP is used as the primary economic variable in the Small Industrial
6 forecast and manufacturing employment is used for the Medium Industrial class. The
7 Small and Medium Industrial class models are developed using monthly sales information,
8 as opposed to annual sales, in order to align the timeframes of industrial models with those
9 of the residential and commercial forecast models. This is required in order to implement
10 an end-use based peak forecast for the commercial and residential sectors. Supporting data
11 is included in **Attachments 8 and 9**.

12
13 **7.1 Small Industrial**

14
15 **Figure 47** depicts historical and projected sales for the Small Industrial class. Sales in this
16 class have been flat for the last 10 years and are expected to grow at 0.7 percent annually
17 over the forecast period due to underlying economic growth.
18

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Figure 47: Historical and Forecast Annual Small Industrial Sales

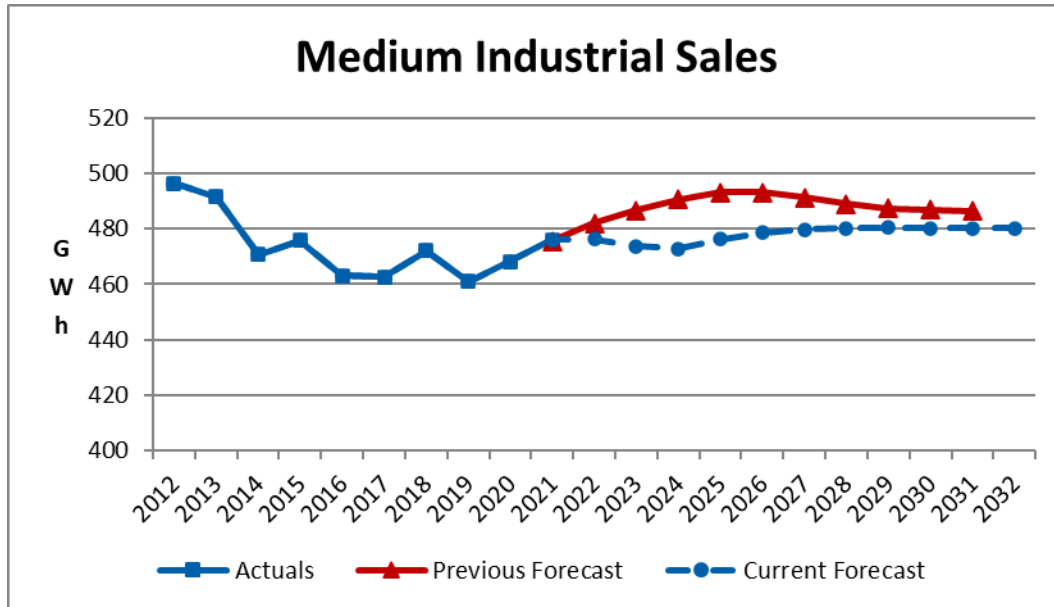


7.2 Medium Industrial

Figure 48 depicts historical and projected sales for the Medium Industrial class. Load in this class has been flat since 2014. There was an increase in sales in 2020 due to several new facilities ramping up production, and minimal impact from the COVID-19 pandemic restrictions. Sales are expected to grow slowly over the forecast period, with an average increase of 0.1 percent driven by economic activity.

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Figure 48: Historical and Forecast Annual Medium Industrial Sales



7.3 Other Industrial Rate Classes

Other Industrial rate classes include Large Industrial, Large Industrial Interruptible, Generation Replacement and Load Following, One-Part Real Time Pricing, Shore Power, and the Extra Large Industrial Active Demand Control tariff.

Like the Large General rate class, load for these rate classes is forecast using a combination of customer survey and historical sales information. Customers are surveyed regularly 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 expectations on energy sales. In the absence of any survey or general public information, load levels are forecast as being flat. 12 of the customers did not respond; of those that did respond, 9 said there would be no change, 10 said energy consumption would increase, and 4 said energy consumption would decrease. One customer makes up over [REDACTED] of sales within this class, and after a drop in sales in 2019 and 2020 operations started to return

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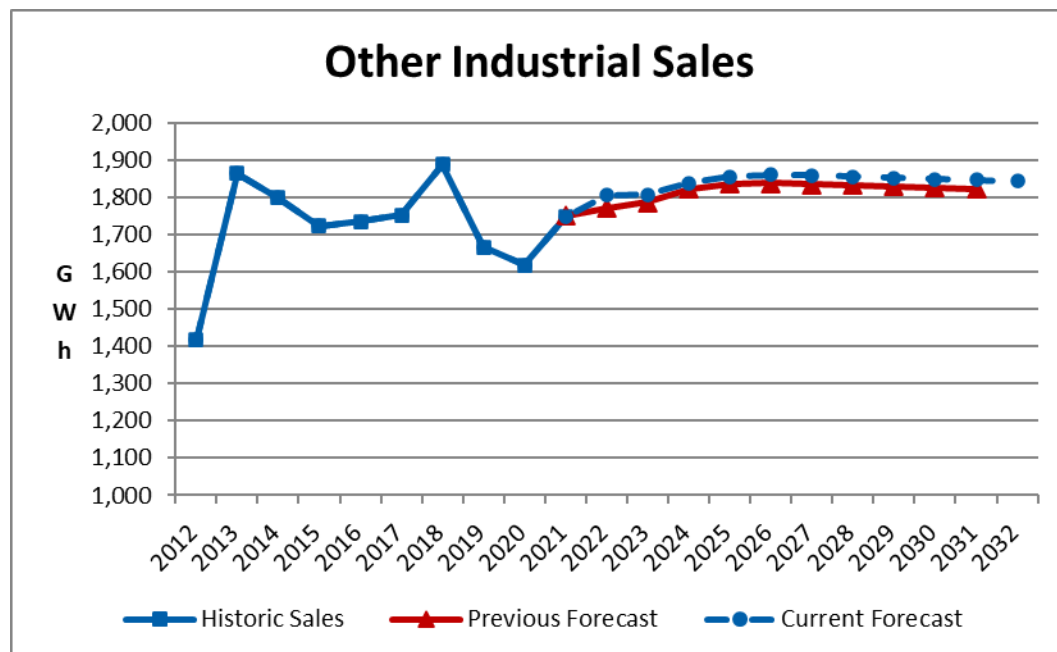
to historic levels in 2021 and are forecast to increase load by another [REDACTED] in 2022. Several new facilities or expansions are expected in the mining, manufacturing, and processing sectors in the coming years. Based on discussions with customers, these are expected to add the amounts shown in **Figure 49**.

Figure 49: New Large Industrial Projects

Year	New Large Industrial Projects (Cumulative GWh)
2022	9
2023	13
2024	49
2025	76

Figure 50 shows the historic and forecast sales for the Other Industrial sector.

Figure 50: Historical and Forecast Annual Other Industrial Sales



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7.4 Municipal

The Municipal class comprises municipal electric utilities that purchase wholesale electricity from NS Power and distribute it within their own service territories. Utility loads within these municipalities include customers in residential, commercial and industrial sectors. Energy in this class also includes the losses incurred by the municipal utilities in meeting their electricity requirements.

Since 2007, the municipal electric utilities have been able to source their electricity from providers other than NS Power through the Open Access Transmission Tariff (OATT). Four municipal electric utility customers were sourcing approximately half of their energy requirement from suppliers other than NS Power, and in 2020 increased their energy purchases to 100 percent from third parties, resulting in a reduction in municipal load of about 150 GWh from historic levels. These customers have their load served by a combination of in-province generation and imported third-party generation, as well as energy under the Wholesale Market Backup/Top-Up (BUTU) Tariff in cases where their third-party supply is unavailable or interrupted.

Because NS Power is required to provide back-up capacity, including reserve margin, to the municipal electric utilities taking third-party supply in the near term and must continue to plan for serving these customers in the long term, the full amount of the municipal electric utilities' peak demand is included in the Load Forecast. The group's forecast energy sales have been reduced to reflect only the reduced 2021 energy purchases from NS Power under the BUTU tariff.

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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.

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9.0 NET SYSTEM REQUIREMENT

The NSR is the energy required to supply the sum of residential, commercial, and industrial electricity sales, plus the associated system losses within the province of Nova Scotia. Loads served by industrial self-generation, exports, and transmission losses associated with energy exports are not included. **Figure 51** provides a breakdown of the significant variances between forecast and actuals for 2021.

Figure 51: 2021 Variance to Actual

	Res	Comm	Ind	Other	Losses	NSR
2021 Forecast	4,718	3,070	2,487	66	698	11,039
Est. Weather Impact	-141	-28		-3	-12	-184
Large Customer New Projects			-12			-12
Large Customer Actuals			-5			-5
Unexplained Variance	42	-69	10	9	71	63
2021 Actual	4,619	2,973	2,480	72	757	10,903

Note that the largest variances are due to weather and the unexplained variance in the residential and commercial classes, most of which can be attributed to continued COVID-19 impacts.

From 2022 to 2032, NSR is forecast to increase at an average of 0.3 percent per year, driven mainly by new customers, space heating and EV adoption in the residential class, as well as new projects in the large general and large industrial classes, with both solar and DSM offsetting sales. Annual NSR is shown below in **Figure 52**. Forecast NSR values and the contribution to NSR from the different sectors can be found in **Appendix A**.

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Figure 52: Historical and Forecast Annual NSR

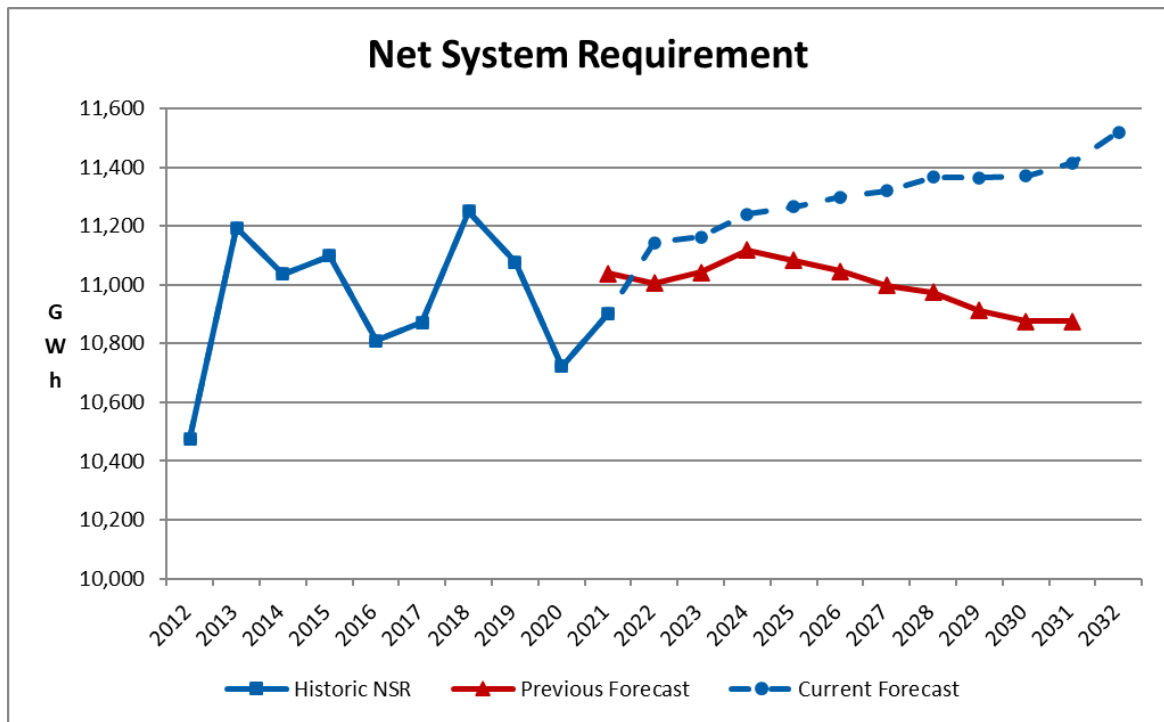


Figure 53 provides a breakdown of the various components of the change in the forecast from 2022 to 2032. Data for all classes is included in Attachment 4.

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Figure 53 Forecast Components

GWh	Res	Comm	Ind	Other	Losses	NSR
2022 Forecast	4,715	3,091	2,542	70	726	11,144
Model	60	63	26	3	75	226
New Customers	226	33				259
Solar	-145	-36				-181
EV	498					498
C&I Electrification		83	36			120
Large Customer Projects		52	65			117
RTR	-3	-16	-10			-29
DSM	-323	-197	-56	-3	-55	-635
2032 Forecast	5,027	3,073	2,604	70	746	11,519
Total DSM forecast	-681	-574	-102	-7	-124	-1,487
DSM captured in underlying models	-358	-377	-46	-4	-68	-853

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10.0 PEAK DEMAND

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

Since 2015 NS Power has employed an end-use approach to deriving the peak forecast. The breakdown of energy into heating, cooling, and other load components from the energy SAE forecasts was used as an input into the peak forecast. This allowed for the impact of changing heating and cooling requirements, which drive the peak in most months, to be reflected in the peak forecast (but does not provide details of the specific underlying end-uses). Details about the peak forecast model can be found in **Appendix B** and in **Attachment 10**.

For the 2022 Load Forecast, peak mitigation for EVs as well as a contribution from forecast demand response (DR) activities are included. The peak estimates for EVs are informed by E3's modeling as outlined in **Section 4.4**, with a combination of managed and unmanaged charging. DR savings amounts are based on the demand reduction amounts included in the 2020 Integrated Resource Plan (IRP), which evaluated an aggregation of DR programs. These programs were developed by E1 in its DSM Potential Study and were assessed as a Supply Side option in the IRP model. The individual programs within the 'Base' program are modeled and include Direct Load Control (DLC), Critical Peak Pricing (CPP) and BNI Curtailment. The achievable potential of these programs was used in the Load Forecast. NS Power's IRP action plan has targeted 75 MW of capacity for DR deployment by 2025. The estimates in the Load Forecast have been moved back by one year to align with the current program development for both DLC and CPP. DR forecasts continue to use an effective load carrying capacity (ELCC) of 48 percent to account for the fact that the full nameplate capacity will not be available at all times, and this value will be reassessed as more information is gathered through the implementation of DR programs.

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Annual DR totals by program are provided in **Figure 54**.

Figure 54: Demand Response

Year	Direct Load Control (MW)	Critical Peak Pricing (MW)	Business, Non-Profit & Industrial Curtailment (MW)	Total (MW)	Total with ELCC (MW)
2022	0	1	0	1	0
2023	4	4	1	9	4
2024	12	12	2	26	12
2025	24	22	4	50	24
2026	36	32	6	74	36
2027	39	36	7	82	39
2028	39	35	6	81	39
2029	39	35	6	80	39
2030	39	34	6	79	38
2031	39	34	6	79	38
2032	38	33	6	78	37

A pilot project is underway in conjunction with E1 to investigate water heater controls. Through the project 161 water heater controllers have been installed in residential customer homes, and testing is ongoing to demonstrate the benefit of utility-managed load shift events. Preliminary results from one group of pilot participants indicate that an average reduction of 0.5 kW of peak savings per unit is achievable.

NS Power is also working with E1 on a two-phased pilot project to investigate automatic and manual control of various loads for commercial and industrial customers. Three customers have been recruited for Phase 1, which involves the integration of customers' Building Management System with NS Power's Energy System Platform (ESP), as part of the SGNS Project. Phase 2 involves the procurement of a turnkey DR aggregator with the objective to provide 3 MW of available DR capacity before December 2022.

As the projects in conjunction with E1 continue to progress, data collected will be used to inform forecast assumptions. Learnings from these pilots will be incorporated in future

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Load Forecasts. The impact of these initiatives, at least within the 10-year timeframe of this forecast, is expected to fall within the sensitivity analysis provided in **Section 11**. Like the interruptible load, DR programs are a resource that can be called upon if required, but they will not inherently reduce demand. In recognition of this, peak reduction from DR is included in the firm peak but is excluded from the system peak.

For the 2022 Load Forecast, as discussed in **Section 4.2**, the assumed peak temperature was changed from -15 degrees Celsius to -13.7 degrees Celsius based on an analysis of peak time temperatures. The peak temperature was calculated as the 10 year average of the coldest evening (5-8pm) temperatures, as this is likely to reflect peak conditions. Other time periods were calculated as well as shown in **Figure 55**, but the 10 year period aligns with the annual HDD estimate and provides a better reflection of current weather trends.

Figure 55: Peak Temperatures

Time Period	Avg Evening Peak Min (°C)	Avg Morning Peak Min (°C)	Avg Annual Min, All Hours (°C)	Avg Daily Average Min (°C)
10 yr	-13.7	-16.8	-17.2	-13.5
20 yr	-14.4	-17.7	-18.0	-14.2
30 yr	-14.9	-18.2	-18.7	-14.7

Figure 55 also indicates that minimum temperatures have been increasing over the past 30 years. This trend (+0.15 degrees C per year) was also incorporated into the forecast, similar to the trend used in the annual HDD and CDD calculations.

The peak contribution from large customer classes continues to be calculated from historical coincident load factors for each of the rate classes and the large customer forecast is added to the accrued class forecast to obtain the total system peak. The forecast system peak for 2022 to 2032 is shown below in **Figure 56**, and is expected to increase by 1.6 percent annually.

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Figure 56: Historical and Forecast System Peak (no DR)

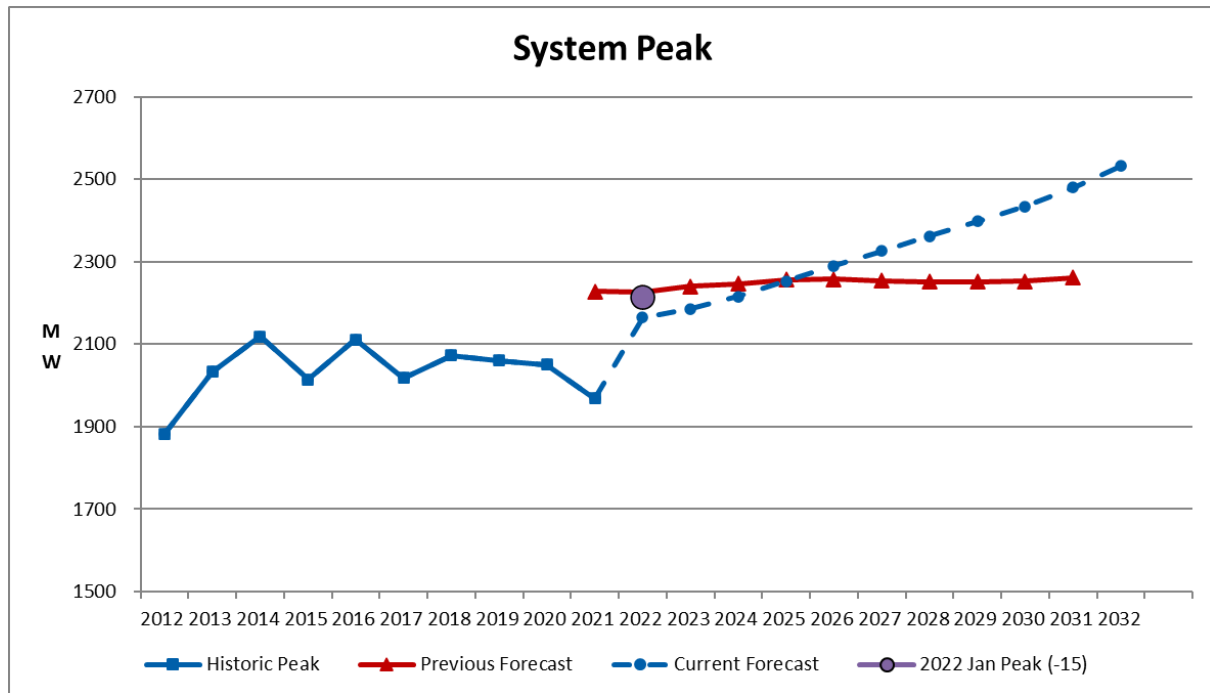
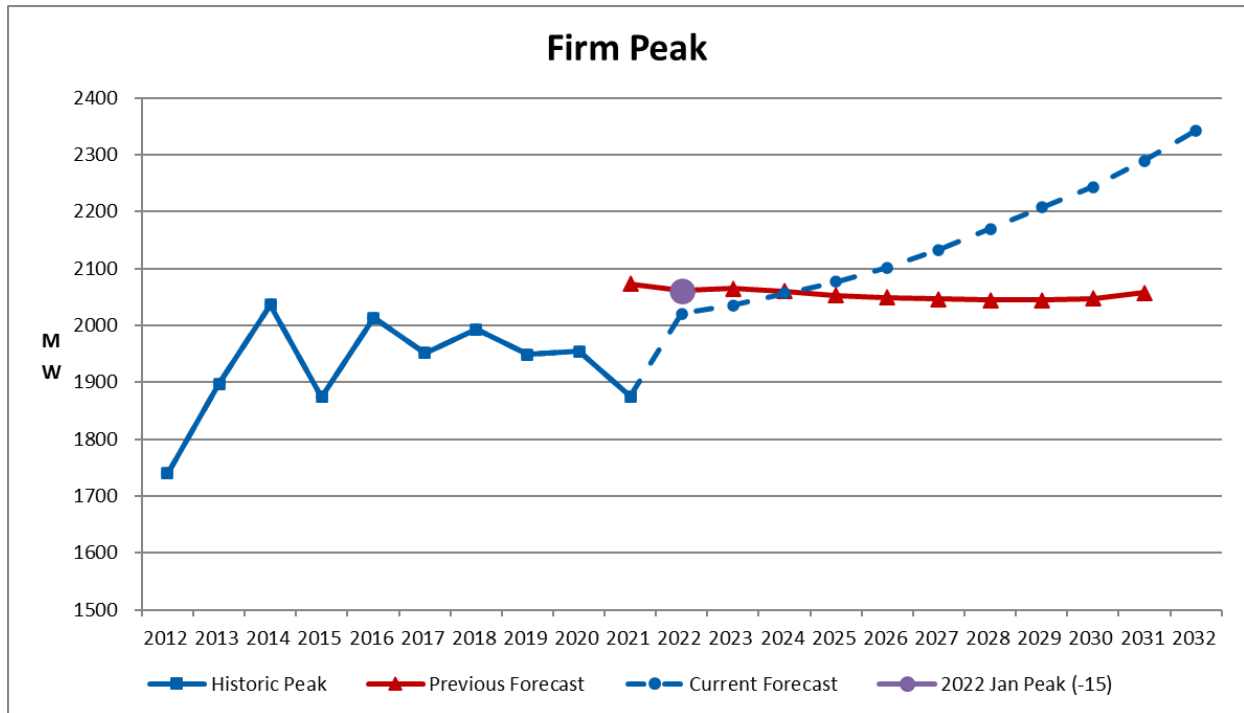


Figure 56 also shows the January 2022 peak, which occurred at a temperature of -14.6 degrees C, and was very close to the forecast peak which used -15 degrees C (2,216 MW actual vs 2,225 MW forecast).

As indicated in Figure 57, the firm peak (system peak less interruptible and DR) is expected to increase by 1.5 percent annually.

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Figure 57: Historical and Forecast Firm Peak (including DR)



Forecast peak values, firm peak and interruptible peak information can be found in **Appendix A**. As discussed in **Section 4.4**, the EV contribution to peak is expected to be mitigated via managed charging. The firm peak without EV peak mitigation (assuming 1.3 kW/ vehicle without mitigation) would grow at 2.6 percent per year, and the overall impact in 2032 would be to add approximately 49 MW to the peak compared to the base assumptions. The space heating contribution to peak based on E3’s modeling (as discussed in **Section 4.4**) are also included, with the heating component of the residential class estimated to add 120MW to peak by 2032 and the commercial class adding 170MW (included in the “C&I Elect” category).

Figure 58 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

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Intensity section are then added (including their associated losses), as well as large customer and interruptible customer contributions, and finally DSM.

Figure 58: Peak Contribution Components (MW)

	Modeled Peak (MW)	Res Heat Peak (MW)	EV (MW)	DR (MW)	C&I Elect. (MW)	Large Cust. (MW)	DSM (MW)	Firm Peak (MW)	Inter. Cust. (MW)	System Peak (MW)
2022	1,920	7	3	-0	10	99	-18	2021	144	2,165
2032	1,993	120	103	-37	193	112	-141	2342	152	2,532
2032 (no EV mitigation)	1,993	120	152	-37	193	112	-141	2392	152	2,581

The 2021 system peak occurred on Tuesday, March 2, 2021 in the evening at a temperature of -9.9°C and was 1,968 MW with a firm peak of 1,875 MW. The 2021 forecast system peak was 2,228 MW with a firm peak of 2,073 MW. The response of hourly demand to temperature (excluding large industrials, which are largely unaffected by temperature) shows that demand changes by 25 MW/°C in the winter months. Normalizing to the design temperature of -15°C would produce an adjusted firm peak of 2,002 MW. 2021 was a particularly warm winter, and the peak day of March 2 was not a particularly cold day. The temperature dropped over a period of around 12 hours from +5°C overnight to the daily minimum of -12.9°C at around 2pm. This was the coldest minimum temperature over the winter months (January – March, December), which made 2021 the highest winter minimum in over 40 years.

Peak producing conditions are a combination of day of week, time of day, temperature, and weather conditions at both an hourly and daily level; as a result, the peak compared to forecast will be more variable than energy (which considers longer time frames). **Figure 59** provides a breakdown of actual system peak compared to the forecast for 2021.

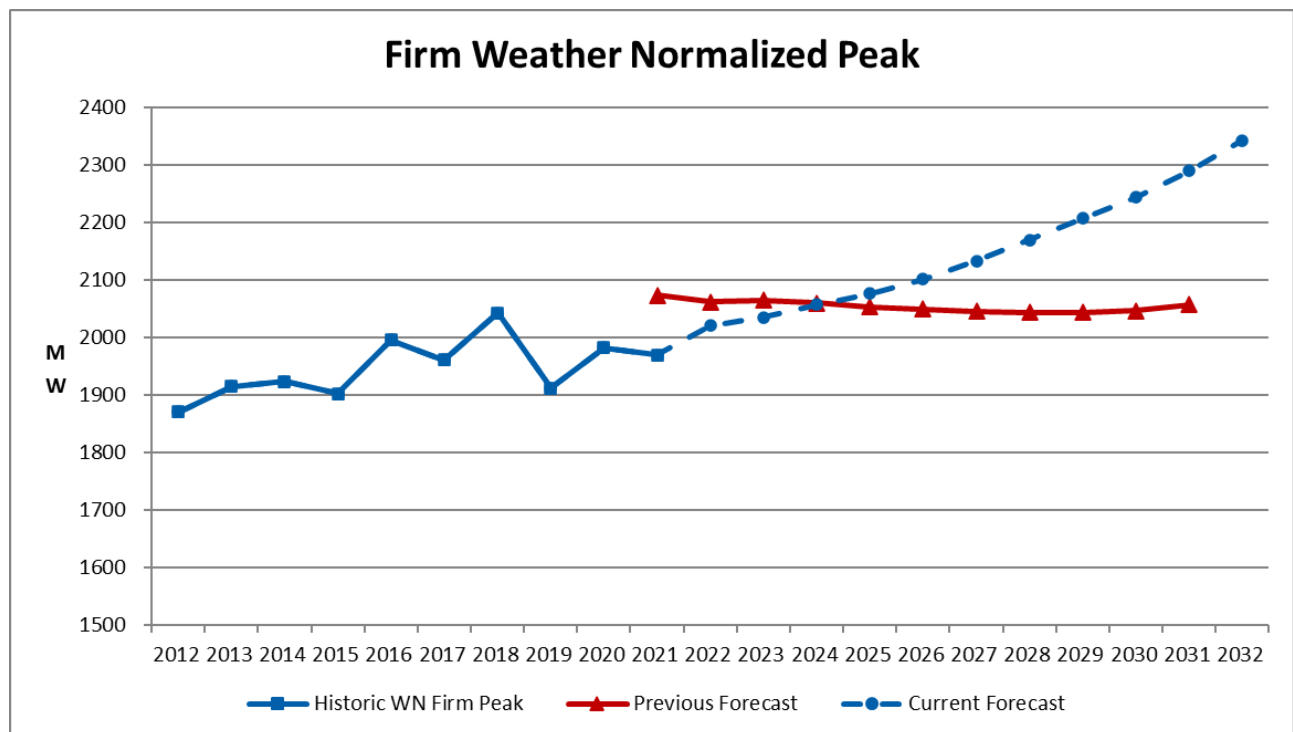
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Figure 59: Forecast Peak Variance vs Actuals

	MW
2021 Forecast Peak	2,228
Interruptible	-61
Weather	-128
Unexplained	-71
2021 Actual Peak	1,968

Normalizing the firm peak for weather compared to a peak temperature of -13.7°C (and for lighting load in 2019), the historic trend shows a better fit with the forecast peaks as shown in Figure 60.

Figure 60: Weather-Normalized Firm Peak (including DR)

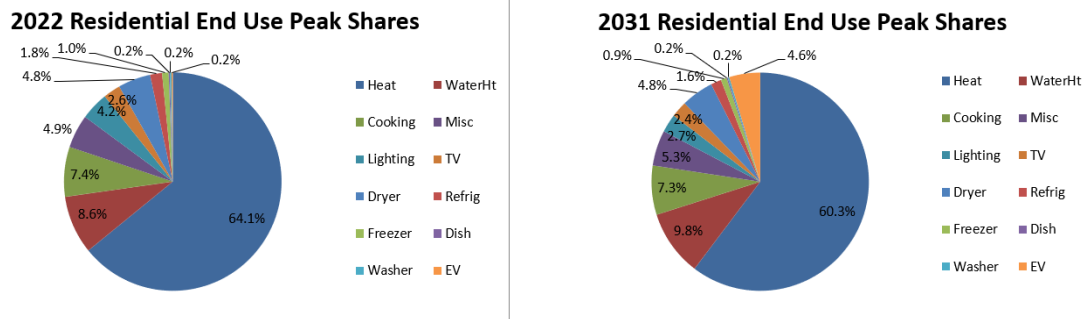


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While the Load Forecast is a good statistical fit for the historical data, it presents challenges when trying to assess the contribution of individual end uses to peak by class. The overall peak forecast looks at the heating, cooling and other variables across the Residential and Commercial classes. 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.

Figure 61 below shows illustrative breakdowns of contribution to peak by Residential end use.

Figure 61: Residential End-Use Peak Shares

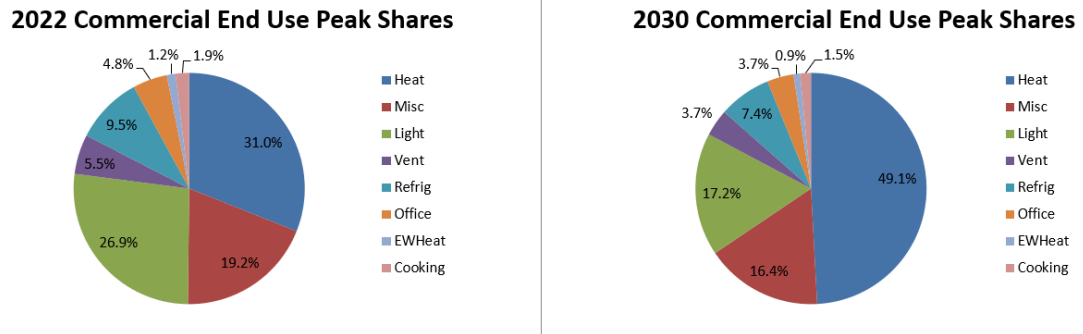


Over the forecast period the peak contribution of various end uses stays stable. However, this year the electrification estimates from E3 indicate an increase of the EV contribution to 4.6 percent of the total. The contribution of electric heating to peak will be investigated further through the ongoing heat pump monitoring project.

Figure 62 shows the breakdown in the contribution to peak by Commercial end use.

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Figure 62: Commercial End-Use Peak Shares



The trend in the Commercial classes shows that the heating component of the peak is expected to increase significantly over the forecast period, driven by the increased space heating electrification as estimated by E3. All other categories decrease through the forecast period.

Current Class Coincident Peak Demand Research

NS Power has been exploring ways of using interval data to understand peak at the class level from a bottom-up perspective, as discussed in prior Load Forecast reports. NS Power currently forecasts system peak at the aggregate level, as it is the most complete and granular information available (provided by the generation stations). Once peak information is obtained, the system peak is disaggregated into rate class contributions based on historic load factors, losses, and load research data. As more data from NS Power's Advanced Metering Infrastructure (AMI) system becomes available, further research on detailed bottom-up peak demand modeling at the class level will be possible.

Starting late in 2017, NS Power's load research sample was updated to represent class level loads. Data is collected remotely in 15-minute intervals, and, for the purpose of analysis of long-term trends, aggregated to the hour.

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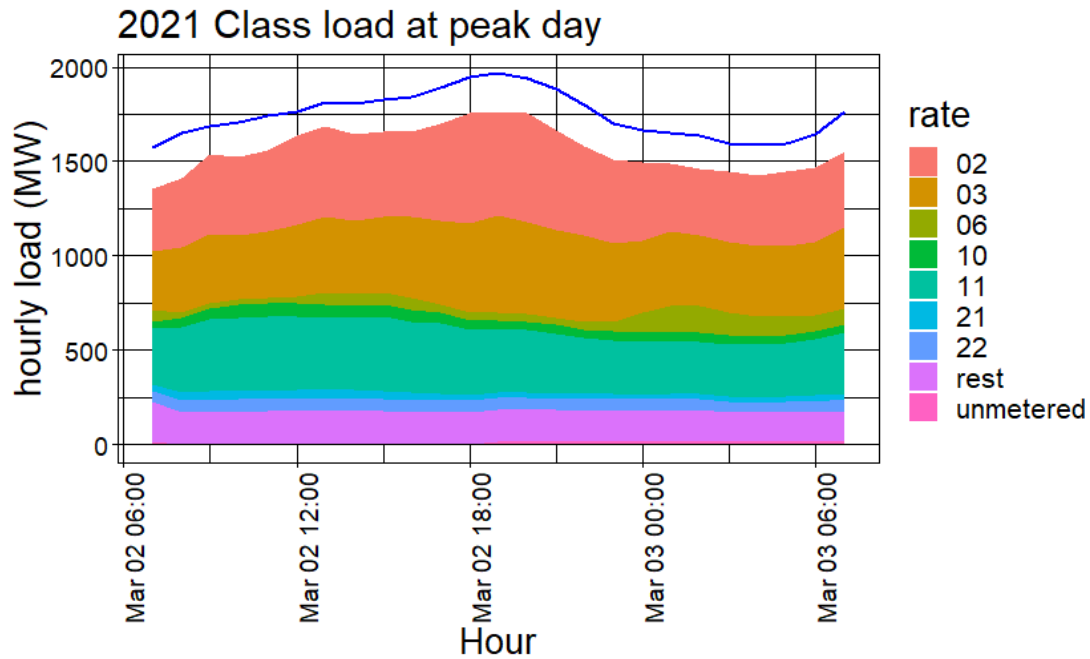
1 Due to the degradation of the sample prior to 2017, class peak trend analysis will require
2 several more years of data collection using the new sample. These additional years should
3 improve the reliability of the statistical analysis and conclusions. In the meantime, below
4 is an outline of findings to date.

5
6 For the current Load Forecast, an estimate of the “unmetered” class is also included, which
7 is mostly comprised of streetlights.

8
9 **Figures 63 and 64** show the 2021 combined load research for each of customer class. The
10 “rest” category is the sum of all the fully sampled (100 percent) classes, including Large
11 Industrial customers. Rates 2 and 3 are Residential (non-all-electric, and all-electric)
12 classes and Rate 11 is the General Demand class. To create these figures, a class level
13 weighted average was calculated (adjusted to monthly sales), and then multiplied by the
14 active number of customers in that month (extracted from NS Power’s billing system).
15 When aggregated, the load research data follows system generation (blue line) closely.
16

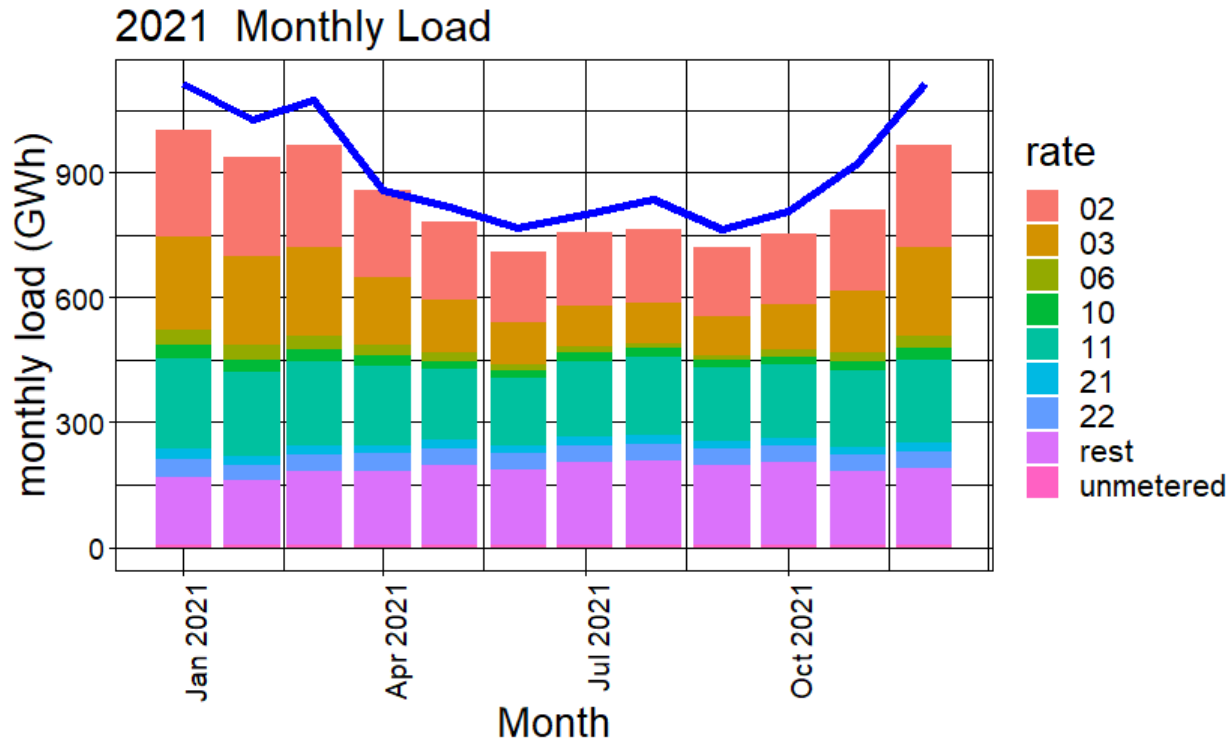
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Figure 63: 2021 Load Research Data vs System Generation, 2021 Annual Peak



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Figure 64: 2021 Monthly Load Research Data vs System Generation



Losses can be estimated by comparing the sum of load research sales to system generation and deriving hourly, monthly, and yearly system losses. This approach is being analyzed and compared to the current top-down approach. The load research approach will provide more information on the timing of sales and may improve accuracy when comparing sales to system generation on an hourly basis.

Class coincident peak demand forecast using LRS and the AMI future

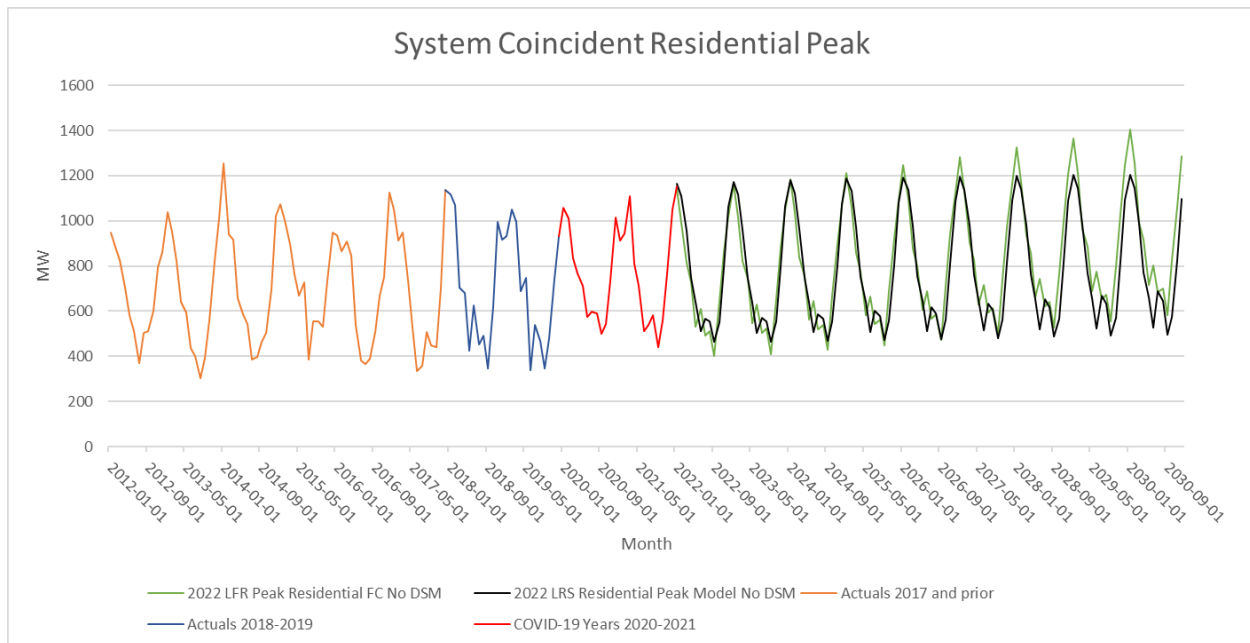
The 2021 class contribution to peak analysis focused on the residential class (2012-2017), including the updated load research sample (2018-2019), while avoiding the pandemic years. This year, load research data during the two years affected by the COVID-19 pandemic is included, which also coincided with 2021 been one of the warmest years on record. By including 2020 and 2021 this analysis aligns with the 10 years traditionally used in the Load Forecast process.

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1 The model does not need all 8760 hours available each year, only residential loads at the
2 hour of system peak of each month of the historical series. In addition, only peak weather,
3 relevant residential end-uses and economics are needed in the right-hand side of the SAE
4 Peak Demand equation (see **Appendix B**). **Figure 65** shows historical information, the
5 current residential system coincident demand forecast (top-down model), and the LRS-
6 driven forecast.
7

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Figure 65: Monthly historical Residential LRS load at peak and forecasts



Both the current residential peak demand forecast (green line) and the LRS peak experimental model (black line) are designed to produce a January peak forecast for a system design temperature of -13.7°C (the remaining months follow normal peak weather distributions) following the same conventions as the current system peak forecast. Noticeable is the improved resolution around the summer months, where cooling load (likely driven by the proliferation of heat pumps combined with people working from home) has become more evident in the last several years.

Differences between the forecast green (top-down) and black lines (bottom-up) highlight the different approaches and cover a range from near zero MW in the early years to 200 MW. Traditionally the top-down class peak estimates rely on load factors that at most can be updated once a year. There is no growth model for load factors and therefore residential trends are derived from system trends.

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1 The bottom-up approach, which relies on class-level load research, captures customer
2 behavior, at peak, more realistically. For instance, there is added resolution during the
3 summer months. However, the two years that include the COVID-19 pandemic may not be
4 representative of load shapes in the future.

5
6 The plan for the coming years is to use AMI smart meter data to test the accuracy of the
7 model and observe if the residential class has gone back to “normal” or if the COVID-19
8 consumption habits continue. Future load disaggregation and better end-use contribution
9 to peak may also help improve the class-level forecast.

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11.0 SENSITIVITY ANALYSIS

The sales and peak forecasts are fundamentally uncertain and depend on many variables, including economics, weather, adoption of distributed generation, electricity rates and DSM. Although each of these variables is forecast discretely, the uncertainty in these data sets will impact the load forecast to varying degrees. Load can also be affected by extraordinary events such as economic events, strikes, trade disputes, natural disasters, pandemics, and volatility in commodities.

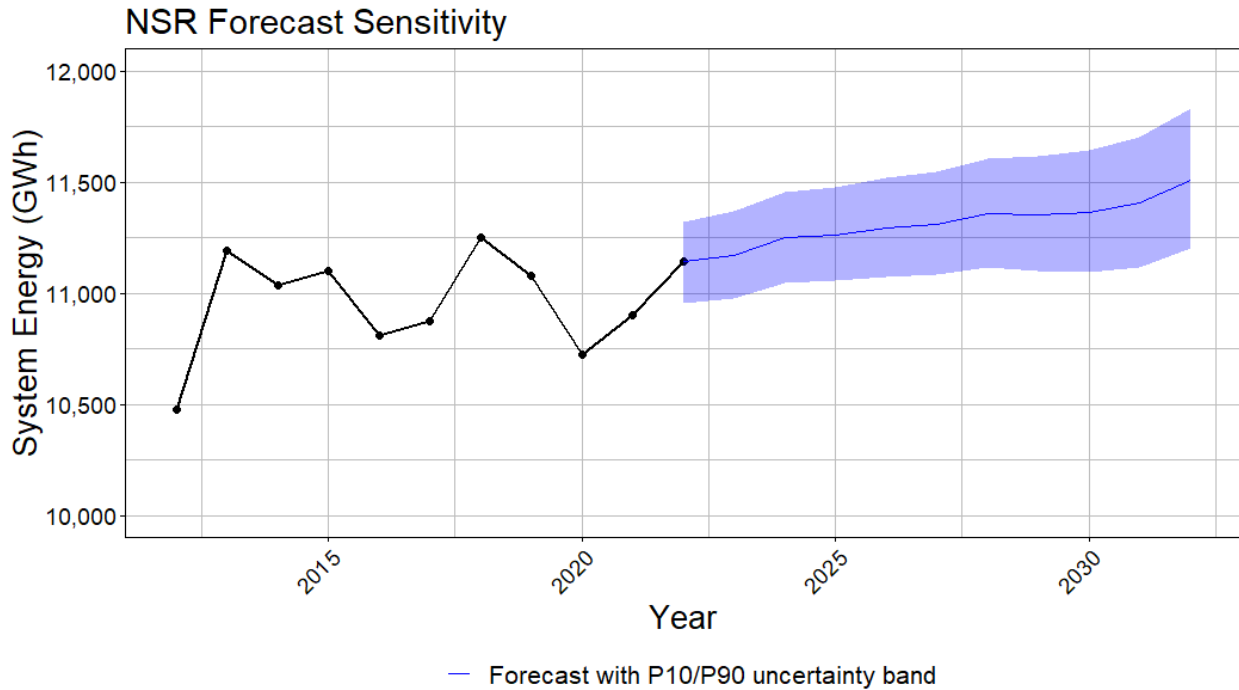
In 2017, based on recommendations from Synapse on the 2016 Load Forecast, NS Power developed a P10/P90 probability analysis using the Monte Carlo simulation approach. This was to create a high and low range for the forecast that encompasses possible (not extreme) scenarios. A full description of the sensitivity methodology is contained in Appendix D.

The probable distribution of future load is estimated by sampling 10,000 random trial values of the economics and weather each year using their respective historical distributions.

Figure 66 shows the sensitivity bands, which are represented by the shaded regions. These represent a range from the low 10th percentile to the high 90th percentiles (there is a 10/90 percent probability that the forecast will be below/above these shaded areas). These P10/P90 bands cover a range of approximately 360-630 GWh during the 10-year period, which is explained mainly by the impact of weather variation (HDD) and economic impact in the long term. The black line and points represent actual system totals.

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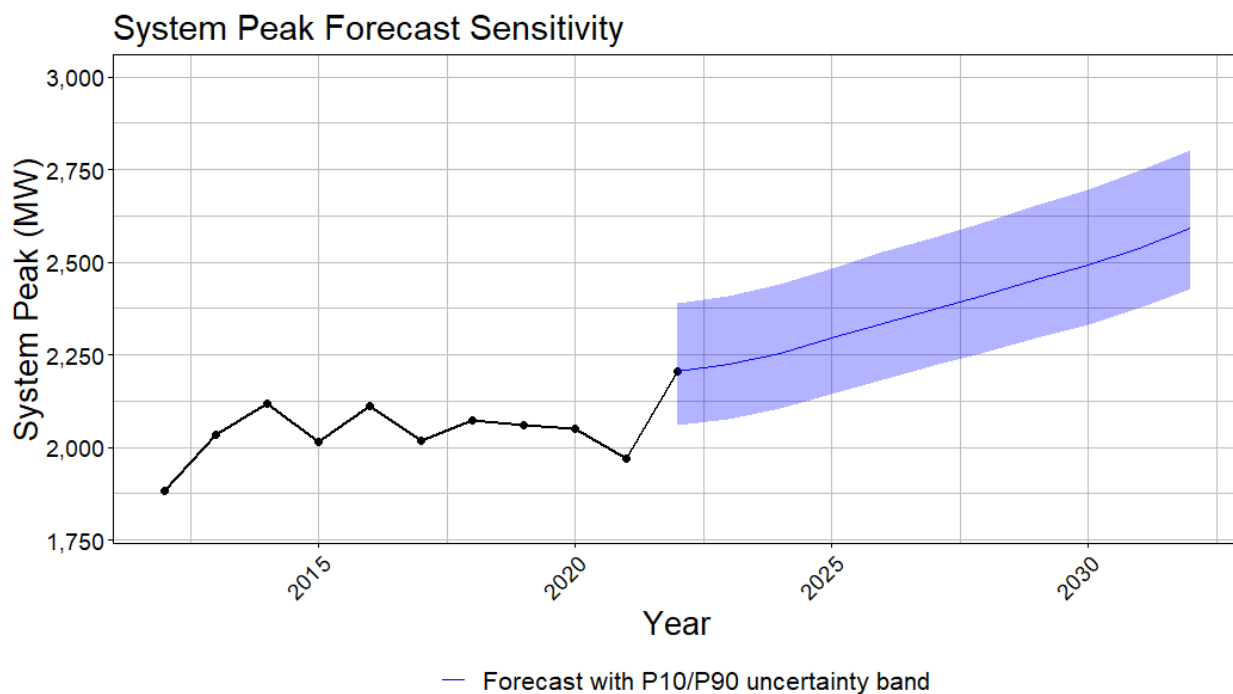
Figure 66: System Energy Sensitivity



Similarly, a P10/P90 scenario was created for peak demand using a random sampling of weather and economic drivers. The width of the P10/P90 envelope is approximately 330-380 MW, reflecting the greater overall variation in the peak. Unlike the energy forecast, where DSM dominates the variance, the peak variance is mainly driven by the variation of weather conditions (both in-month and peak day), resulting in enough variation that even the DSM scenarios fall mostly within the bands as seen in **Figure 68**.

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Figure 67: System Peak Sensitivity



This analysis provides a potential range of outcomes for the 2022 Load Forecast. Energy is most sensitive to Economics over the long term, while peak is most sensitive to temperature. In addition, peak is more variable overall. The impact of other inputs that cannot easily be represented by probabilistic analysis are provided in **Figure D8** in **Appendix D**.

2020 IRP Comparison

Figure 69 below compares the 2021 Load Forecast, the 2022 Load Forecast, and the Company's 2020 IRP cases with Base DSM. Although a new bottom-up analysis was performed by E3 on space heating and EV adoption to meet emissions targets, the end results are similar to the Mid Electrification forecast of the IRP by 2031. As discussed with stakeholders prior to the filing of the 2022 Load Forecast Report, although there are no specific assumptions around incentives that might impact EV and heat pump uptake,

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the values represent a slow ramp-up of uptake of these technologies that would allow interim sales targets as well as the target of net zero emissions by 2050 to be achieved. While the 2022 Load Forecast was being prepared, the federal government announced more aggressive targets for EV sales in Canada, with targets of 20 percent EV sales by 2026, 60 percent by 2030, and 100 percent by 2035. There will be more policy and regulation changes related to decarbonization targets in the course of the 10-year timeframe of this forecast, but the scenario developed represent the likely trajectories of these technologies.

Figure 68: IRP Scenarios Comparison

Item	2022 NSR Energy (GWh)	2022 Firm Peak (MW)	2031 NSR Energy (GWh)	2031 Firm Peak (MW)
2021 Load Forecast	11,005	2,062	10,875	2,057
2022 Load Forecast ²⁷	11,144	2,021	11,414	2,289
IRP High Electrification	11,392	2,115	11,590	2,718
IRP Mid Electrification	11,332	2,085	11,363	2,375
IRP Low Electrification	11,302	2,078	10,809	2,094

²⁷ Peak temperature of -13.7 compared to -15 for the other forecasts.

Appendix A – Forecast Values
2022 NS Power Load Forecast

1.1 Table A1: Energy Requirement – 2021 NS Power Forecast Energy Forecast

Year	Residential Sector	Growth	Commercial Sector	Growth	Industrial Sector	Growth	Municipal	Growth	Losses	Total Energy	Growth
	GWh	%	GWh	%	GWh	%	GWh	%	GWh	GWh	%
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	4,688	3.2	3,151	-0.9	2,388	-8.7	146	-4.7	704	11,077	-1.5
2020	4,675	-0.3	2,957	-6.2	2,343	-1.9	68	-53.6	688	10,731	-3.1
2021	4,619	-1.2%	2,973	0.7%	2,480	6.0%	72	5.6%	757	10,902	1.7%
2022	4,715	2.1%	3,091	4.0%	2,542	2.5%	70	-2.4%	726	11,144	2.2%
2023	4,682	-0.7%	3,135	1.4%	2,548	0.2%	70	0.0%	727	11,162	0.2%
2024	4,711	0.6%	3,143	0.3%	2,583	1.4%	70	0.1%	732	11,240	0.7%
2025	4,713	0.0%	3,142	0.0%	2,608	0.9%	70	-0.3%	732	11,265	0.2%
2026	4,735	0.5%	3,143	0.0%	2,617	0.4%	70	0.0%	734	11,298	0.3%
2027	4,760	0.5%	3,137	-0.2%	2,617	0.0%	70	-0.1%	735	11,319	0.2%
2028	4,811	1.1%	3,133	-0.1%	2,616	-0.1%	70	0.1%	737	11,366	0.4%
2029	4,829	0.4%	3,116	-0.5%	2,613	-0.1%	70	-0.2%	736	11,363	0.0%
2030	4,862	0.7%	3,093	-0.7%	2,610	-0.1%	70	-0.2%	736	11,371	0.1%
2031	4,922	1.2%	3,077	-0.5%	2,607	-0.1%	69	-0.1%	739	11,414	0.4%
2032	5,027	2.1%	3,073	-0.1%	2,604	-0.1%	70	0.1%	746	11,519	0.9%

Table A2: Coincident Peak Demand - 2021 NS Power Forecast Peak Forecast

Year	Interruptible Contribution to Peak (MW)	Demand Response (reduction in Firm Peak only, MW)	Firm Contribution to Peak (MW)	Net System Peak (MW)	Growth (%)	Temp at Peak (deg C)	Notes
2012	141	-	1,740	1,882	-13.2	-7	February 13 weekday evening
2013	136	-	1,897	2,033	8.0	-13	January 24 weekday evening
2014	83	-	2,036	2,118	4.2	-19	January 2 weekday evening
2015	141	-	1,874	2,015	-4.9	-12	January 6 weekday evening
2016	98	-	2,013	2,111	4.8	-14	December 16 weekday evening
2017	67	-	1,951	2,018	-4.4	-13	December 28 weekday evening (between holidays)
2018	80	-	1,993	2,073	2.7	-12	January 7 weekend evening
2019	111	-	1,949	2,060	-0.6	-15	February 27 weekday morning (min lighting load)
2020	96	-	1,954	2,050	-0.5	-13	January 17 weekday evening
2021	94	-	1,875	1,968	-4.0	-10	March 2 weekday evening
2022	144	-	2,021	2,165	10.0	-13.7	Forecast
2023	146	-4	2,035	2,185	0.9	-13.7	Forecast
2024	146	-12	2,057	2,215	1.4	-13.7	Forecast
2025	152	-24	2,076	2,253	1.7	-13.7	Forecast
2026	154	-36	2,101	2,291	1.7	-13.7	Forecast
2027	153	-39	2,133	2,326	1.5	-13.7	Forecast
2028	153	-39	2,170	2,361	1.5	-13.7	Forecast
2029	153	-39	2,207	2,398	1.6	-13.7	Forecast
2030	152	-38	2,243	2,434	1.5	-13.7	Forecast
2031	152	-38	2,289	2,479	1.9	-13.7	Forecast
2032	152	-37	2,342	2,532	2.1	-13.7	Forecast

Appendix B – Forecast Model Details
2022 NS Power Load Forecast

Residential Model Detail

The residential average use SAE model is defined as a function of the three primary end uses – cooling (X_{Cool}), heating (X_{Heat}) and other use (X_{Other}):

$$ResAvgUse_m = b_1 \times X_{Heat}_m + b_2 \times X_{Cool}_m + b_3 \times X_{Other}_m + b_4 \times AvgEESavings_m + b_5 \times CovidVariable_m + \sum Binaries + ARMA$$

The end-use variables incorporate both a variable that captures short-term utilization (Use) and a variable that captures changes in end-use efficiency and saturation trends (Index). The heating variable is calculated as:

$$X_{Heat} = HeatUse \times HeatIndex$$

Where

$$HeatUse = f(HDD, \text{Household Income, Household Size, and Price})$$

$$HeatIndex = g(\text{Heating Saturation, Efficiency, Shell Integrity, Square Footage})$$

The cooling variable is defined as:

$$X_{Cool} = CoolUse \times CoolIndex$$

Where

$$CoolUse = f(CDD, \text{Household Income, Household Size, and Price})$$

$$CoolIndex = g(\text{Cooling Saturation, Efficiency, Shell Integrity, Square Footage})$$

X_{Other} captures non-weather sensitive end uses:

$$X_{Other} = OtherUse \times OtherIndex$$

Where

$$OtherUse = f(\text{Seasonal Use Pattern, Household Income, Household Size, and Price})$$

$$OtherIndex = g(\text{Other Appliance Saturation and Efficiency Trends})$$

The $AvgEESavings$ term captures E1's DSM past reported savings for the residential class. The associated regression coefficient, b_4 , assesses the portion of embedded DSM activity that is already

included in the billed sales information. The negative sign of b_4 indicates that DSM activity reduces load.

The COVID variable is a binary that starts in July 2020 and attempts to mirror the impacts of COVID on load. It starts with a value of 1, is reduced to 0.5 in October 2020, reduced to 0.33 in March 2022, and finally reduced to 0.16 in September 2022. As discussed in **Section 5**, this variable was used to explain the increase in residential load from people working from home during the pandemic and stays in the forecast at a reduced level to recognize permanent changes related to working patterns.

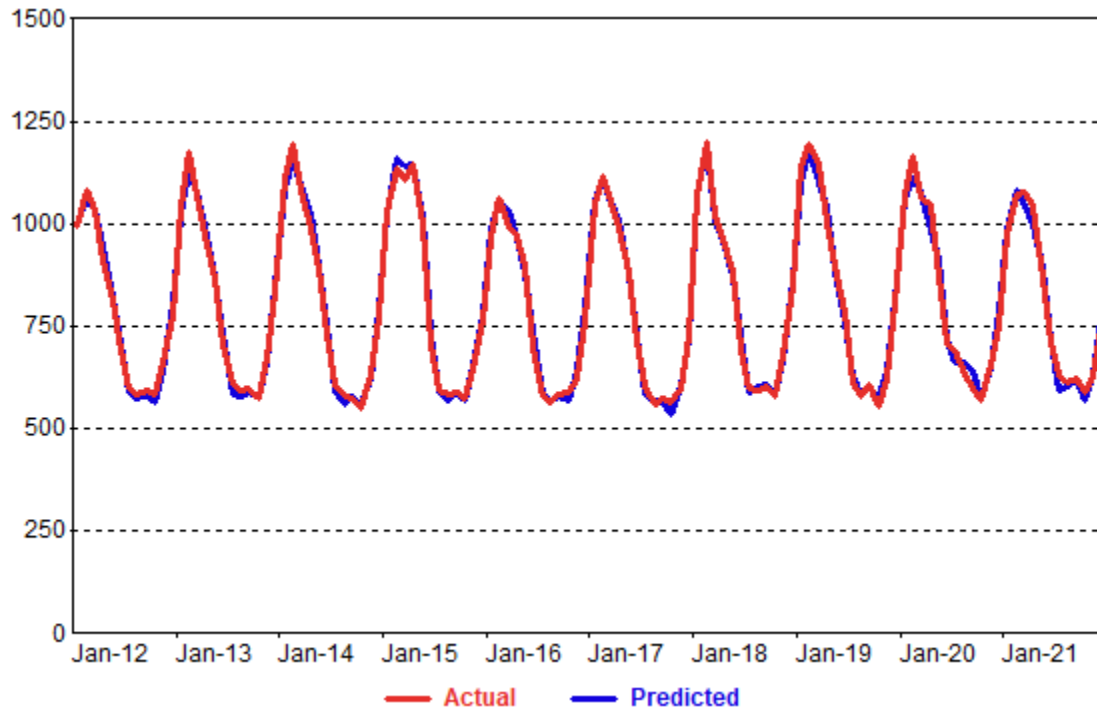
Binary shift variables are added to the model for the months of January, August, September, and October to improve model fit and particular monthly trends, while binaries for April and May of 2015 compensate for an anomaly in the billing data during this period related to delayed meter reads. Additional binaries were added for December 2017 and February 2018 to correct for high residual values in those months. After running the linear regression with the main variables, the residuals show a slight autocorrelation, which happens when a model does not take into account relatively small drivers that should explain the dependent variable (in this case, sales). To help eliminate this autocorrelation, a moving average, MA, of period 1, MA(1) was added, which estimates the autocorrelation with its the predecessor.

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructRes.WtXHeat	1.004	0.022	46.180	0.00%
MStructRes.WtXCool	0.601	0.171	3.522	0.06%
MStructRes.WtXOther	0.986	0.022	44.668	0.00%
MSales.AvgEESavingsProfiled	-0.512	0.116	-4.414	0.00%
MBin.Jan	73.225	7.022	10.428	0.00%
MBin.Aug	61.795	12.248	5.045	0.00%
MBin.Sep	88.709	15.212	5.832	0.00%
MBin.Oct	52.280	9.562	5.468	0.00%
MBin.May15	89.133	22.428	3.974	0.01%
MBin.Apr15	85.604	22.728	3.766	0.03%
MBin.Dec17	-61.852	20.651	-2.995	0.34%
MBin.Feb18	77.954	20.555	3.793	0.03%
MBin.Covid2020SteppedUpdate	57.696	14.613	3.948	0.01%
MA(1)	0.450	0.097	4.651	0.00%

Residential Model Statistics

Model Statistics	
Iterations	21
Adjusted Observations	120
Deg. of Freedom for Error	106
R-Squared	0.990
Adjusted R-Squared	0.989
AIC	6.308
BIC	6.633
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-534.77
Model Sum of Squares	5,131,567.67
Sum of Squared Errors	52,177.61
Mean Squared Error	492.24
Std. Error of Regression	22.19
Mean Abs. Dev. (MAD)	16.60
Mean Abs. % Err. (MAPE)	2.10%
Durbin-Watson Statistic	2.097
Durbin-H Statistic	#NA
Ljung-Box Statistic	28.30
Prob (Ljung-Box)	0.2475
Skewness	0.356
Kurtosis	3.133
Jarque-Bera	2.625
Prob (Jarque-Bera)	0.2692

Residential SAE Model Fit



Residential Model 2022-2032 Reconciliation

The following tables provide details reflecting the changes between 2022 and 2032 forecast years. Some of the numbers have small discrepancies compared to those used in the final annual figures as there is a conversion between monthly data at the model level to annual data at the system level.

Residential Load – Post Regression (GWh)

	Existing Customer Average Use from Regression Model (kWh/year)	New Cust. Load	EVs	Solar	RTR	Res DSM Adjust ment	Res Sales		Total Res DSM (at the meter)	DSM captured by end uses
2022	9,748	56	12	(31)	0	(26)	4,717		(50)	(24)
2032	9,872	287	510	(176)	(3)	(349)	5,029		(684)	(335)
Change to load	1.3%	4.9%	10.5%	-3.1%	-0.1%	-6.8%	6.6%			

Res Sales = Existing Customer Load + New Customer Load + EV Load + Solar Load + RTR + DSM

Existing customer load is calculated as Res Average Use (9,748 kWh/customer in 2022, 9,872 kWh/customer in 2032) x number of customers as of 2022 (482,771). The tables below show the appliance information incorporated in the end-use input tables.

Residential Average Use –Regression

	XHeat	XCool	XOther	AvgEE Savings	Binaries	ARMA	COVID Variable	Res Average Use
2022	4,135	222	5,626	(708)	276	(10)	208	9,748
2032	4,098	382	5,711	(708)	276	-	113	9,872
Change to load	-0.4%	1.6%	0.9%	0.0%	0.0%	0.1%	-1.0%	1.3%

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

Residential Input Variables – XHeat

	Intensities				Econ + Struct	Regression	
	Efurn	HP Heat	Secondary Heat	Furnace Fans	HeatUse Variable	Coeff	Total XHeat
2022	2,193	1,214	492	71	1.04	1.004	4,135
2032	1,118	2,204	660	63	1.01	1.004	4,098
Change to load	-26.0%	23.9%	4.1%	-0.2%	-2.7%	0.0%	-0.9%

$$XHeat = (Efurn + HP\ Heat + Secondary\ Heat + Furnace\ Fans) \times HeatUseVariable \times Coeff$$

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 $[(Efurn_{2031} - Efurn_{2021}) \times HeatUse \times Coeff] / WtXHeat_{2021}$

Residential Input Variables – XCool

	Intensities			Econ + Struct	Regression	
	Central AC	HP Cool	Room AC	CoolUse Variable	Coefficient	Total Xcool
2022	26	185	57	1.4	0.601	222
2032	31	324	60	1.5	0.601	382
Change to load	2.4%	62.8%	1.2%	10.7%	0.0%	71.8%

$$XCool = (Central\ AC + HP\ Cool + Room\ AC) \times CoolUseVariable \times Coeff$$

Residential Input Variables – XOther

	Intensities							Econ + Struct	Reg	
	Water Heat	Cook	Ref/Frz	Wash/ Dry	TV	Light	Misc	Other Use Var	Coeff	Total Xother
2022	1,537	529	654	805	438	552	1,365	0.97	0.986	5,626
2032	1,779	529	581	810	418	360	1,474	0.97	0.986	5,711
Change to load	4.3%	0.0%	-1.3%	0.1%	-0.3%	-3.4%	1.9%	0.3%	0.0%	1.5%

$X_{Other} = (Water\ Heat + Cook + Ref/Frz + Wash/Dry + TV + Light + Misc) \times OtherUseVariable \times Coeff$

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:

$$XHeat_m = EI_{heat} \times Price_m^{-1.5} \times SmlGenVar_m \times HDD_m$$

$$XCool_m = EI_{cool} \times Price_m^{-1.5} \times SmlGenVar_m \times CDD_m$$

$$XOther_m = EI_{other} \times Price_m^{-1.5} \times SmlGenVar_m \times Days_m$$

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.
- (3) Account for billing issues related to the pandemic in May and June 2020.

As in the residential model, analysis of the initial regression results indicated that the model would be improved by adding an ARMA process. A seasonal moving average of period 1, $SMA(1)$ was used.

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

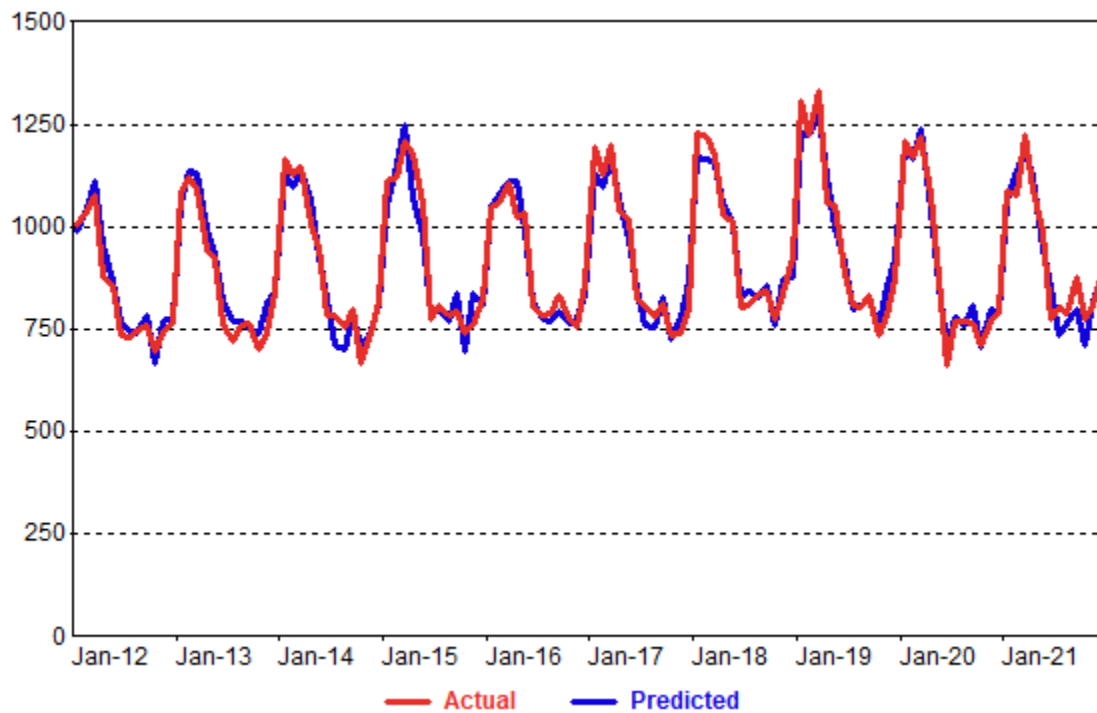
$$SmlGen_AvgUse_m = b_1 \times XHeat_m + b_2 \times XCool_m + b_3 \times XOther_m + MBin.Mar + MBin.Sep + MBin.Dec + MBin.Aft13 + MBin.May20 + MBin.Jun20 + SMA(1)$$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructSmlGen.WtXHeat	0.794	0.034	23.376	0.00%
MStructSmlGen.WtXCool	0.119	0.025	4.840	0.00%
MStructSmlGen.WtXOther	0.716	0.018	39.959	0.00%
MBin.Mar	95.882	21.984	4.361	0.00%
MBin.Sep	86.922	23.158	3.753	0.03%
MBin.Dec	-120.126	20.715	-5.799	0.00%
MBin.Aft13	45.325	10.234	4.429	0.00%
MBin.May20	-150.437	35.600	-4.226	0.01%
MBin.Jun20	-139.161	35.249	-3.948	0.01%
SMA(1)	0.592	0.089	6.684	0.00%

Small General Model Statistics

Model Statistics	
Iterations	13
Adjusted Observations	120
Deg. of Freedom for Error	110
R-Squared	0.947
Adjusted R-Squared	0.943
AIC	7.503
BIC	7.735
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-610.42
Model Sum of Squares	3,291,990.97
Sum of Squared Errors	184,117.63
Mean Squared Error	1,673.80
Std. Error of Regression	40.91
Mean Abs. Dev. (MAD)	31.99
Mean Abs. % Err. (MAPE)	3.56%
Durbin-Watson Statistic	2.040
Durbin-H Statistic	#NA
Ljung-Box Statistic	39.13
Prob (Ljung-Box)	0.0264
Skewness	0.113
Kurtosis	2.622
Jarque-Bera	0.971
Prob (Jarque-Bera)	0.6155

Small General Model Fit



Small General 2022-2032 Reconciliation

The Small General Demand customer forecast model is constructed like the residential model (including heat pump programs inside the SAE model). Adjustments done outside the regression include estimates for other commercial and industrial growth programs, PV 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	NS Power C&I Electrification	Solar	SG DSM adjustment	Small Gen Sales (with DSM)		Total SG DSM (at the meter)	DSM captured by end uses
2022	311	6	(4)	(2)	311		(6)	(4)
2032	353	22	(22)	(24)	328		(64)	(40)
Change	13.2%	5.0%	-5.8%	-7.0%	5.5%			

Small General Sales = Avg Use Existing x customer count forecast+ NS Power C&I Programs + Solar

Load + DSM

The load from the regression model is calculated as Small Gen Average Use (11,741 kWh/customer in 2022, 11,916 kWh/customer in 2032) x number of customers (26,526 in 2022, increasing to 29,621 in 2032).

Small General Average Use –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Avg Sales (kWh)
2022	3,594	249	7,180	607	104	11,734
2032	4,429	281	6,590	607	-	11,907
Change	7.1%	0.3%	-5.0%	0.0%	-0.9%	1.5%

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)
2022	53,566	1.21	0.794	0.070	3,594
2032	63,397	1.26	0.794	0.070	4,429
Change	19.1%	4.1%	0.0%	0.0%	23.3%

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 $[(\text{Heat}_{2032} - \text{Heat}_{2022}) \times \text{HeatUse} \times \text{Coeff} \times \text{Scaling}] / \text{WtXHeat}_{2022}$

Small General Input Variables – XCool

	Intensities	Econ + Struct	Regression		
	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total XCool (kWh)
2022	36,432	1.64	0.119	0.035	249
2032	35,120	1.92	0.119	0.035	281
Change	-4.2%	16.7%	0.0%	0.0%	12.5%

XCool = Cooling x CoolUseVariable x Coeff x Scaling Factor

Small General Input Variables – XOther

	Intensities							Econ + Struct	Reg		
	Vent	Water Heat	Cook	Refrig	Light	Office	Misc	OtherUse Var	Coeff	Scaling Factor	Total XOther (kWh)
2022	12,724	1,938	2,051	24,068	57,218	10,263	38,979	13.62	0.716	0.005	7,179
2032	9,769	2,255	1,934	22,183	40,242	9,495	40,432	14.57	0.716	0.005	6,588
Change	-2.1%	0.2%	-0.1%	-1.4%	-12.3%	-0.6%	1.1%	7.0%	0.0%	0.0%	-8.2%

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:

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

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

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

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

Binaries are added for COVID related billing issues in May and June 2020 as well as a high residual in February 2018, and an ARMA process for seasonal moving average (SMA(1)).

A monthly forecast sales model is then estimated as:

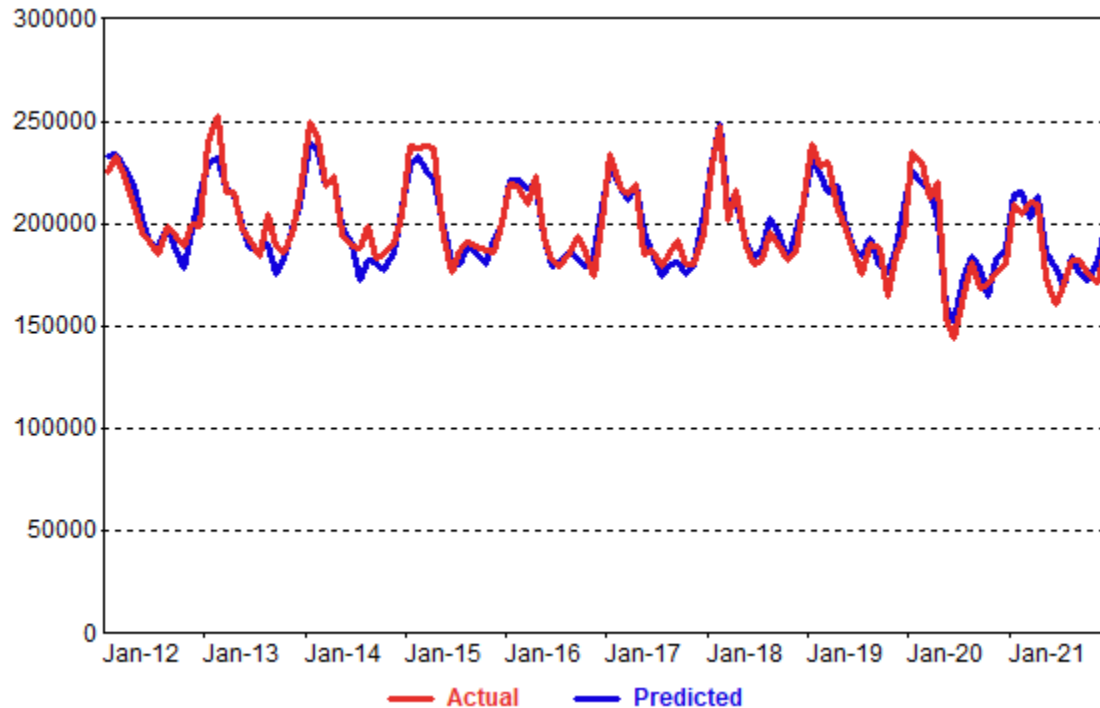
$$GenService_m = b1 \times XHeat_m + b2 \times XCool_m + b3 \times XOther_m + MBin.Feb18 + MBin.May20 + MBin.Jun20 + SMA(1)$$

Variable	Coefficient	StdErr	T-Stat	P-Value
MStructGen.WtXHeat	0.641	0.035	18.178	0.00%
MStructGen.WtXCool	0.325	0.048	6.807	0.00%
MStructGen.WtXOther	1.112	0.018	60.612	0.00%
MBin.Feb18	30290.281	7014.260	4.318	0.00%
MBin.May20	-31446.780	7153.494	-4.396	0.00%
MBin.Jun20	-27569.055	7155.916	-3.853	0.02%
SMA(1)	0.460	0.093	4.915	0.00%

General Service Model Statistics

Model Statistics	
Iterations	20
Adjusted Observations	120
Deg. of Freedom for Error	113
R-Squared	0.877
Adjusted R-Squared	0.871
AIC	17.997
BIC	18.159
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,243.08
Model Sum of Squares	49,916,393,908.65
Sum of Squared Errors	6,988,868,889.61
Mean Squared Error	61,848,397.25
Std. Error of Regression	7,864.38
Mean Abs. Dev. (MAD)	6,154.12
Mean Abs. % Err. (MAPE)	3.13%
Durbin-Watson Statistic	1.634
Durbin-H Statistic	#NA
Ljung-Box Statistic	43.60
Prob (Ljung-Box)	0.0085
Skewness	0.243
Kurtosis	2.665
Jarque-Bera	1.746
Prob (Jarque-Bera)	0.4178

General Service Model Fit



General Demand 2022-2032 Reconciliation

The general demand class, which makes up the largest portion of the commercial sector, is forecast as gross total sales rather than average use as is the case in the small general and residential classes.

Like the small general model, a flat scaling factor is used to adjust some of the end-use regression coefficients close to 1, making their interpretation a bit easier. Outside of the SAE regression model, adjustments include for NS Power commercial growth programs (mainly heat pumps), PV and DSM.

General Demand Load – Post Regression (GWh)

	Load Regression Model	NS Power C&I Electrification	Solar	GD DSM Adjustment	Gen Sales (with DSM)		Total GD DSM (at the meter)	DSM captured by end uses
2022	2,329	18	(4)	(17)	2,326		(44)	(27)
2032	2,375	73	(22)	(187)	2,240		(450)	(263)
Change	2.0%	2.4%	-0.8%	-7.3%	-3.7%			

Gen Sales = Sales + NS Power C&I Programs+ Solar Load + DSM

General Demand Sales –Regression

	XHeat	XCool	XOther	Binaries	ARMA	Sales (GWh)
2022	400,292	65,011	1,887,517	-	(24,109)	2,328,711
2032	514,189	75,451	1,785,800	-	-	2,375,439
Change	4.9%	0.4%	-4.4%	0.0%	1.0%	2.0%

Sales = XHeat + XCool + XOther + Binaries + ARMA

General Demand Input Variables – WtXHeat

	Intensities	Econ + Struct	Regression	
	Heating	HeatUse Variable	Coeff	Total XHeat
2022	493,867	1.26	0.641	400,292
2032	591,468	1.36	0.641	514,189
Change	21.2%	7.3%	0.0%	28.5%

XHeat = Heating x HeatUseVariable x Coeff

Note that because these factors are multiplicative, the growth rate for the intensities are multiplied by the coefficients to calculate the overall impact. For example, the contribution of Heating is calculated as $[(\text{Heat}_{2032} - \text{Heat}_{2022}) \times \text{HeatUse} \times \text{Coeff}] / \text{WtXHeat}_{2022}$

General Demand Input Variables – XCool

	Intensities	Econ + Struct	Regression		
	Cooling	CoolUse Variable	Coefficient	Scaling Factor	Total Xcool
2022	314,345	1.72	0.325	0.370	65,011
2032	303,026	2.07	0.325	0.370	75,451
Change	-4.3%	20.4%	0.0%	0.0%	16.1%

$\text{XCool} = \text{Cooling} \times \text{CoolUseVariable} \times \text{Coeff} \times \text{Scaling Factor}$

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
2022	117,578	15,697	18,950	222,404	491,890	94,840	360,196	14.27	1.112	0.090	1,887,517
2032	90,278	14,092	17,873	204,991	345,950	87,744	373,622	15.73	1.112	0.090	1,785,800
Change	-2.3%	-0.1%	-0.1%	-1.5%	-12.2%	-0.6%	1.1%	10.2%	0.0%	0.0%	-5.4%

$\text{XOther} = (\text{Ventilation} + \text{Water Heat} + \text{Cooking} + \text{Refrigeration} + \text{Lighting} + \text{Office} + \text{Miscellaneous}) \times \text{OtherUseVariable} \times \text{Coeff} \times \text{Scaling Factor}$

Industrial Econometric Model Details

Small Industrial model

$$SmlInd_Sales_m = MBin.Jan_m + MBin.Feb_m + MBin.Mar_m + MBin.Apr_m + MBin.May_m + MBin.Jun_m + MBin.Jul_m + MBin.Aug_m + MBin.Sep_m + MBin.Oct_m + MBin.Nov_m + MBin.Dec_m + b1 \times MEcon.ManGDP$$

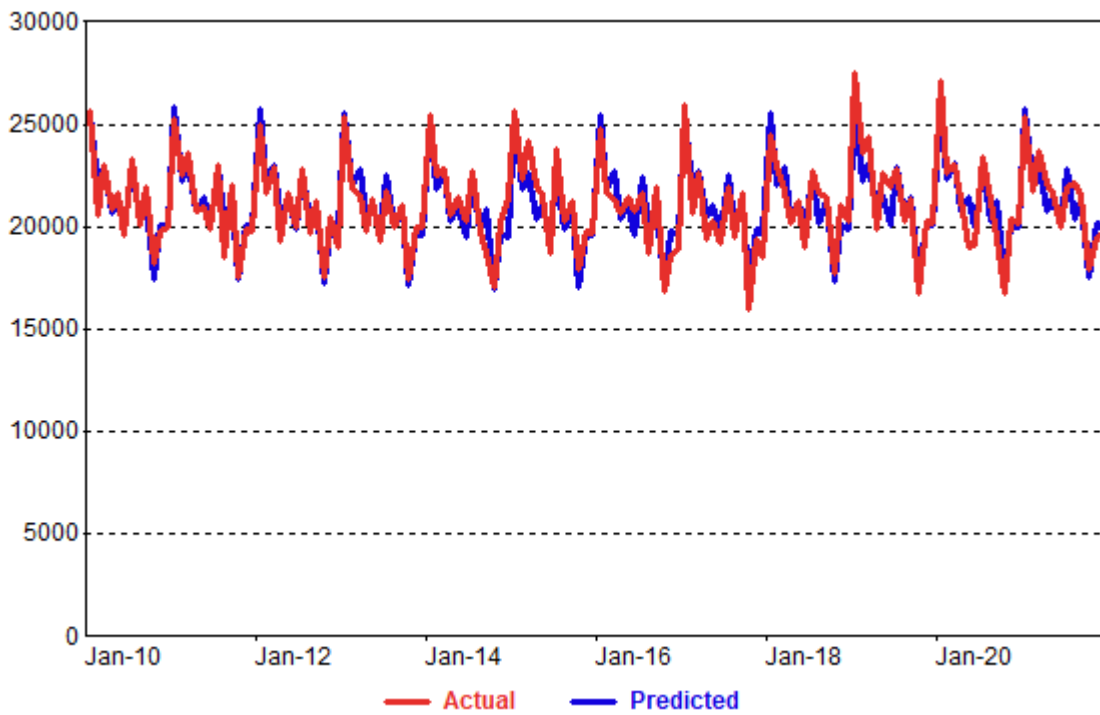
As discussed in Section 4.0, a historic period of 2010 – 2021 was used to improve model fit.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	20707.110	1851.738	11.183	0.00%
MBin.Feb	17148.856	1852.809	9.256	0.00%
MBin.Mar	17997.983	1853.879	9.708	0.00%
MBin.Apr	15663.855	1854.950	8.444	0.00%
MBin.May	16330.991	1856.020	8.799	0.00%
MBin.Jun	14875.442	1857.091	8.010	0.00%
MBin.Jul	17724.453	1858.161	9.539	0.00%
MBin.Aug	15226.949	1858.688	8.192	0.00%
MBin.Sep	16221.197	1859.215	8.725	0.00%
MBin.Oct	12356.584	1859.743	6.644	0.00%
MBin.Nov	15006.487	1860.270	8.067	0.00%
MBin.Dec	14862.949	1860.797	7.987	0.00%
MEcon.ManGDP	1.908	0.717	2.662	0.87%

Small Industrial Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	144
Deg. of Freedom for Error	131
R-Squared	0.858
Adjusted R-Squared	0.845
AIC	13.579
BIC	13.847
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,169.00
Model Sum of Squares	574,860,331.75
Sum of Squared Errors	94,871,248.78
Mean Squared Error	724,208.01
Std. Error of Regression	851.00
Mean Abs. Dev. (MAD)	626.87
Mean Abs. % Err. (MAPE)	3.00%
Durbin-Watson Statistic	1.746
Durbin-H Statistic	#NA
Ljung-Box Statistic	42.79
Prob (Ljung-Box)	0.0105
Skewness	-0.139
Kurtosis	3.231
Jarque-Bera	0.787
Prob (Jarque-Bera)	0.6747

Small Industrial Model Fit



Medium Industrial Model

$$MedInd_Sales_m = MBin.Jan_m + MBin.Feb_m + MBin.Mar_m + MBin.Apr_m + MBin.May_m + MBin.Jun_m + MBin.Jul_m + MBin.Aug_m + MBin.Sep_m + MBin.Oct_m + MBin.Nov_m + MBin.Dec_m + MBin.Aft18 + b1 \times MEcon.ManEmp$$

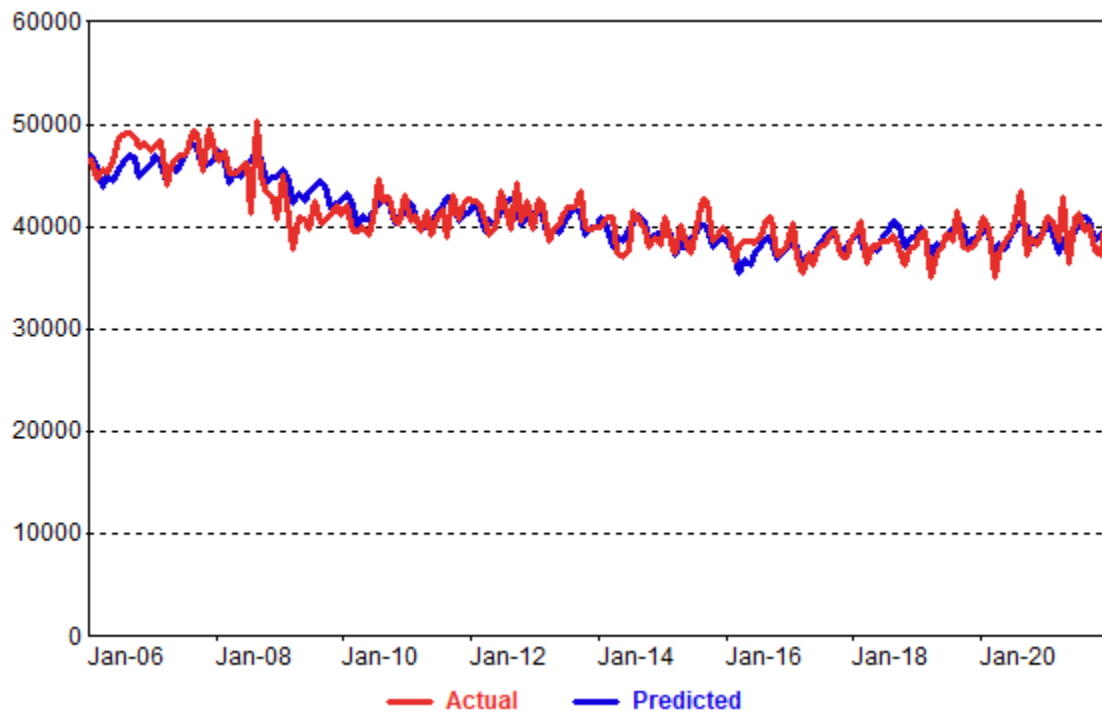
A binary variable for 2016 and subsequent years was added for improved model fit as the historic sales trend transitioned from declining to flat. As discussed in Section 4.0, a historic period of 2006–2021 was used to improve model fit.

Variable	Coefficient	StdErr	T-Stat	P-Value
MBin.Jan	21527.547	1321.699	16.288	0.00%
MBin.Feb	20617.228	1320.270	15.616	0.00%
MBin.Mar	18662.550	1318.842	14.151	0.00%
MBin.Apr	19908.327	1317.414	15.112	0.00%
MBin.May	19366.775	1315.986	14.717	0.00%
MBin.Jun	20588.604	1314.558	15.662	0.00%
MBin.Jul	21278.149	1313.130	16.204	0.00%
MBin.Aug	22001.016	1311.951	16.770	0.00%
MBin.Sep	21651.895	1310.771	16.518	0.00%
MBin.Oct	19640.876	1309.592	14.998	0.00%
MBin.Nov	20348.107	1308.413	15.552	0.00%
MBin.Dec	20544.320	1307.234	15.716	0.00%
MBin.Aft16	-1766.069	271.183	-6.512	0.00%
MEcon.ManEmp	635.788	36.151	17.587	0.00%

Medium Industrial Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	192
Deg. of Freedom for Error	178
R-Squared	0.774
Adjusted R-Squared	0.757
AIC	14.887
BIC	15.124
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,687.54
Model Sum of Squares	1,657,059,743.66
Sum of Squared Errors	484,276,687.81
Mean Squared Error	2,720,655.55
Std. Error of Regression	1,649.44
Mean Abs. Dev. (MAD)	1,220.65
Mean Abs. % Err. (MAPE)	2.97%
Durbin-Watson Statistic	1.461
Durbin-H Statistic	#NA
Ljung-Box Statistic	158.53
Prob (Ljung-Box)	0.0000
Skewness	-0.379
Kurtosis	3.652
Jarque-Bera	8.004
Prob (Jarque-Bera)	0.0183

Medium Industrial Model Fit



Combined Model for Commercial and Industrial DSM Coefficient

$$\begin{aligned} NonResSales_m = & b1 \times NonResEESavingsProfiled_m + b2 \times GenWtXHeat_m + b3 \times GenWtXCool_m + \\ & b3 \times GenWtXOther_m + b4 \times NonResCustomers_m + MBin.Feb18_m + MBin.May20_m + MBin.Jun20_m \\ & + MBin.Jan20_m \end{aligned}$$

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.EESavingsProfiled	-0.380	0.121	-3.153	0.21%
MStructGen.WtXCool	0.560	0.055	10.158	0.00%
MStructGen.WtXHeat	0.860	0.039	22.204	0.00%
MStructGen.WtXOther	0.683	0.316	2.160	3.29%
MSales.NonResCusts	4.639	1.272	3.648	0.04%
MBin.Feb18	36105.995	10970.429	3.291	0.13%
MBin.May20	-44754.225	10997.629	-4.069	0.01%
MBin.Jun20	-45856.474	11036.743	-4.155	0.01%
MBin.Jan20	30516.597	11191.467	2.727	0.74%

The coefficient on the EESavings variable represents the amount of DSM needed to explain historical sales trends beyond the changes in the underlying end-uses.

Combined Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	111
R-Squared	0.853
Adjusted R-Squared	0.842
AIC	18.649
BIC	18.858
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-1,280.22
Model Sum of Squares	75,024,721,087.52
Sum of Squared Errors	12,979,640,782.78
Mean Squared Error	116,933,700.75
Std. Error of Regression	10,813.59
Mean Abs. Dev. (MAD)	8,488.88
Mean Abs. % Err. (MAPE)	2.69%
Durbin-Watson Statistic	1.737
Durbin-H Statistic	#NA
Ljung-Box Statistic	46.04
Prob (Ljung-Box)	0.0044
Skewness	0.337
Kurtosis	2.701
Jarque-Bera	2.724
Prob (Jarque-Bera)	0.2561

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:

$$Peak_m = b1 \times HeatVar_m + b2 \times CoolVar_m + b3 \times BaseVar_m + b4 \times Binaries_m$$

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:

$$CoolLoad_m = B2 \times ResXCool_m + C2 \times SmlGSXCool_m + D2 \times GSCool_m$$

Where $B2$, $C2$, and $D2$ are the coefficients on $XCool$ in the residential, Small General Service, and General Service sales forecast models.

In constructing the monthly peak model variables, the heating and cooling load requirements are normalized for the number of days and hours in the month by expressing heating and cooling load requirements on an average MW load basis:

$$HeatAvgMW_m = HeatLoad_m / Days_m / 24$$

$$CoolAvgMW_m = CoolLoad_m / Days_m / 24$$

The impact of peak-day weather conditions are then captured by interacting peak-day HDD and CDD with average monthly heating and cooling load requirements. *HeatAvgMW* and *CoolAvgMW* are 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 *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:

$$OtherAvgMW_m = OtherLoad_m / Days_m / 24$$

Binary *mBin.Year20Plus* is used to account for the impact of COVID-19 starting in 2020.

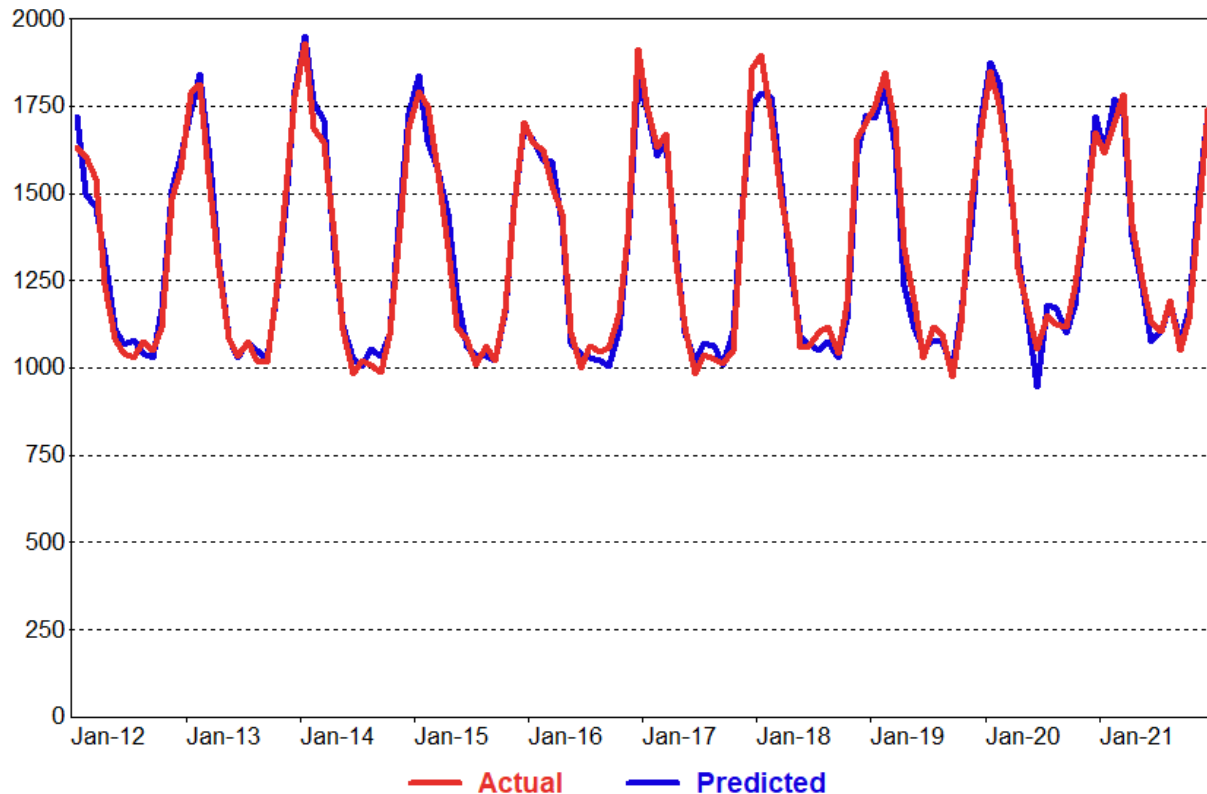
Variable	Coefficient	StdErr	T-Stat	P-Value
mVarsNew.Cool_Var	1.013	0.408	2.484	1.46%
mVarsNew.Heat_Var	1.444	0.104	13.867	0.00%
mVarsNew.Jan_Other	1.301	0.097	13.475	0.00%
mVarsNew.Feb_Other	1.243	0.104	11.943	0.00%
mVarsNew.Mar_Other	1.395	0.087	16.099	0.00%
mVarsNew.Apr_Other	1.605	0.047	33.956	0.00%
mVarsNew.May_Other	1.591	0.032	49.256	0.00%
mVarsNew.Jun_Other	1.671	0.027	62.285	0.00%
mVarsNew.Jul_Other	1.678	0.047	35.910	0.00%
mVarsNew.Aug_Other	1.545	0.053	28.901	0.00%
mVarsNew.Sep_Other	1.515	0.024	62.146	0.00%
mVarsNew.Oct_Other	1.584	0.029	54.141	0.00%
mVarsNew.Nov_Other	1.780	0.051	35.028	0.00%
mVarsNew.Dec_Other	1.674	0.086	19.471	0.00%
mBin.Year20Plus	45.747	11.561	3.957	0.01%

Peak Model Statistics

Model Statistics	
Iterations	1
Adjusted Observations	120
Deg. of Freedom for Error	105
R-Squared	0.974
Adjusted R-Squared	0.971
AIC	7.929673
BIC	8.278110
F-Statistic	#NA
Prob (F-Statistic)	#NA
Log-Likelihood	-631.05302
Model Sum of Squares	9,912,757.578
Sum of Squared Errors	259,669.507
Mean Squared Error	2,473.04292
Std. Error of Regression	49.72970
Mean Abs. Dev. (MAD)	38.00706
Mean Abs. % Err. (MAPE)	2.84%
Durbin-Watson Statistic	1.726
Durbin-H Statistic	#NA
Ljung-Box Statistic	28.18
Prob (Ljung-Box)	0.2526
Skewness	0.343
Kurtosis	2.721
Jarque-Bera	2.748
Prob (Jarque-Bera)	0.2531

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.



**Appendix C –
Forecast Comparison and Accuracy**

Figure C1: Total Nova Scotia Energy Requirement (NSR)

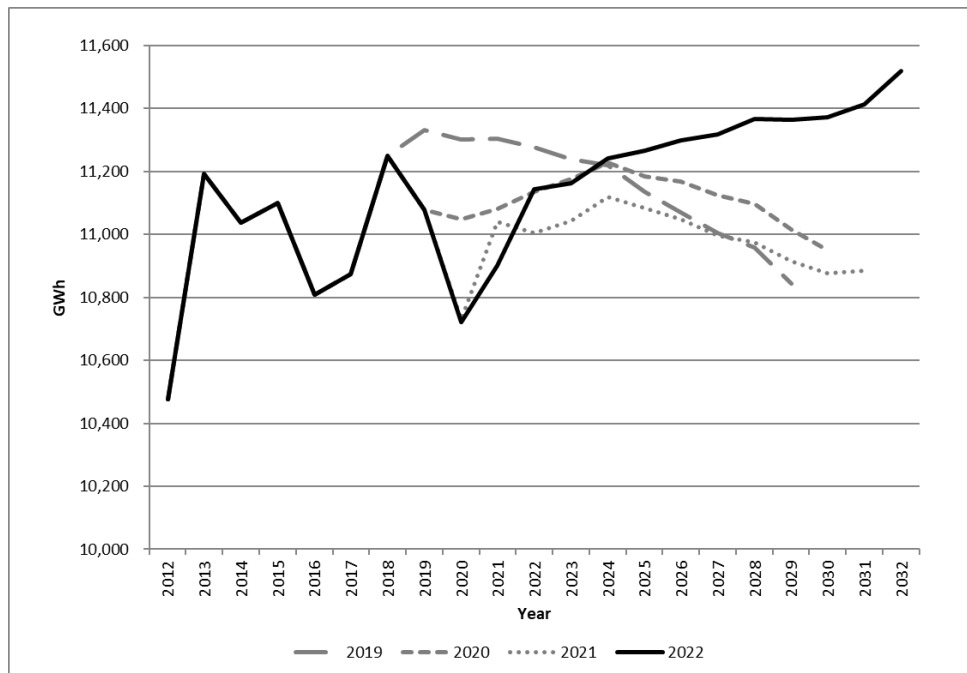


Figure C2: System Peak Demand

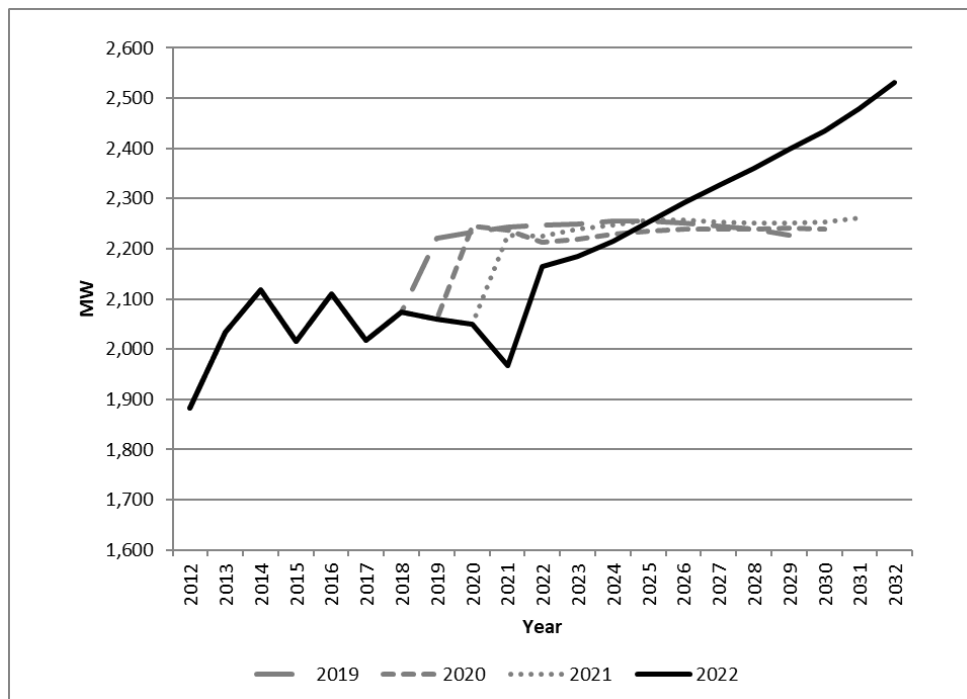


Figure C3: Firm Peak Demand

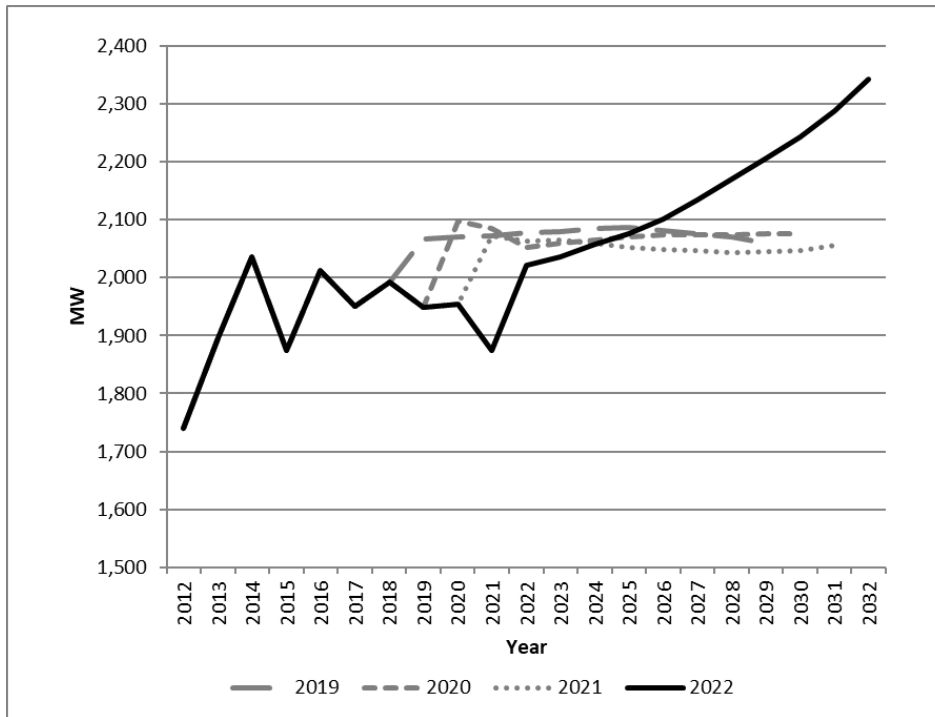


Figure C4 below provides an overview of the energy forecast accuracy. For these calculations, the load of the major pulp and paper mills is removed from the net system requirement as these contribute a significant amount of unforeseeable variance to the results. The rows show each years' 10-year forecast series with the forecast mill load removed. The row labeled "Actuals less mills" is the actual NSR with mill load removed. Each forecast year is compared to the corresponding actual value, and a 10-year average is calculated based on number of years out in the forecast series. So, a lead time of 1 would correspond to the average error of all the forecast first year estimates versus the corresponding actual value. The statistics show that on a 5-year basis the error (mean absolute percent error, or MAPE) averages less than 2 percent. Beyond 5 years the accuracy diminishes. **Figure C5** provides the same analysis for the firm peak load (the mills are not considered part of the firm load). As the peak is much more sensitive to weather, the error is larger, but averages under 4 percent in the first 7-year period, with accuracy diminishing in later years. **Figure C6** provides the system peak accuracy, with an average of just over 4 percent in the first 7-year period.

Figure C4: Energy Forecast Accuracy

NSR less mills										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>
2011	10329	10189	10021	9862	9690	9514	9333	9174	9015	8855
2012		10017	10006	9990	9964	9942	9913	9919	9920	9900
2013			9787	9790	9723	9647	9578	9603	9580	9533
2014				10101	10066	10063	10067	10076	10070	10071
2015					10013	10036	10020	9986	9918	9833
2016						10156	10180	10202	10233	10216
2017							9931	9896	9920	9891
2018								9944	9947	9860
2019									10168	10171
2020										10056
Actuals less mills:										
<u>Percent Error</u>										
2011	3.8%	0.6%	0.4%	-2.3%	-1.2%	-3.6%	-8.1%	-10.2%	-8.5%	-10.9%
2012		-1.1%	0.3%	-1.0%	1.6%	0.8%	-2.4%	-2.9%	0.7%	-0.4%
2013			-1.9%	-3.0%	-0.9%	-2.2%	-5.7%	-6.0%	-2.7%	-4.1%
2014				0.1%	2.6%	2.0%	-0.9%	-1.4%	2.3%	1.4%
2015					2.1%	1.7%	-1.4%	-2.2%	0.7%	-1.0%
2016						2.9%	0.2%	-0.1%	3.9%	2.8%
2017							-2.3%	-3.1%	0.7%	-0.5%
2018								-2.6%	1.0%	-0.8%
2019									3.3%	2.4%
2020										1.2%
<u>Statistics</u>										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10

NSR less mills										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	0.5%	0.3%	-0.1%	-0.4%	-0.7%	-2.2%	-3.1%	-4.5%	-4.4%	-10.9%
MAPE:	2.1%	1.7%	0.9%	1.9%	2.1%	3.1%	3.8%	5.0%	4.4%	10.9%

Figure C5: Firm Peak Forecast Accuracy

Firm Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>
2011	2,000	1,970	1,938	1,910	1,880	1,849	1,815	1,785	1,755	1,725
2012		1,958	1,953	1,945	1,935	1,933	1,928	1,930	1,930	1,928
2013			1,939	1,950	1,948	1,944	1,935	1,943	1,939	1,934
2014				1,940	1,932	1,916	1,911	1,907	1,910	1,899
2015					1,892	1,896	1,897	1,889	1,878	1,859
2016						1,987	2,009	2,023	2,033	2,041
2017							1,993	2,010	2,029	2,038
2018								2,001	2,015	2,016
2019									2,070	2,073
2020										2,085
Actual Firm Peak:	1,740	1,897	2,036	1861.3	2013.6	1,951	1,993	1,949	1954	1,875
<u>Percent Error</u>										
2011	14.9%	3.8%	-4.8%	2.6%	-6.6%	-5.2%	-8.9%	-8.4%	-10.2%	-8.0%
2012		3.2%	-4.0%	4.5%	-3.9%	-0.9%	-3.3%	-1.0%	-1.2%	2.8%
2013			-4.7%	4.8%	-3.3%	-0.4%	-2.9%	-0.3%	-0.8%	3.2%
2014				4.2%	-4.1%	-1.8%	-4.1%	-2.2%	-2.3%	1.3%
2015					-6.0%	-2.8%	-4.8%	-3.1%	-3.9%	-0.8%
2016						1.8%	0.8%	3.8%	4.0%	8.9%
2017							0.0%	3.1%	3.8%	8.7%
2018								2.7%	3.1%	7.5%
2019									5.9%	10.6%
2020										11.2%
<u>Statistics</u>										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10

Firm Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	3.3%	1.7%	0.6%	0.6%	-1.3%	-2.4%	-2.4%	-2.2%	-3.7%	-8.0%
MAPE:	5.5%	4.1%	4.3%	3.8%	4.2%	2.4%	3.0%	4.3%	6.5%	8.0%

Figure C6: System Peak Forecast Accuracy

System Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
Issued	<u>2012</u>	<u>2013</u>	<u>2014</u>	<u>2015</u>	<u>2016</u>	<u>2017</u>	<u>2018</u>	<u>2019</u>	<u>2020</u>	<u>2021</u>
2011	2,308	2,277	2,242	2,208	2,173	2,135	2,096	2,061	2,026	1,991
2012		2,098	2,093	2,084	2,073	2,070	2,064	2,065	2,064	2,060
2013			2,077	2,089	2,086	2,083	2,074	2,082	1,947	1,942
2014				2,078	2,062	2,057	2,053	2,051	2,045	2,042
2015					2,031	2,035	2,036	2,028	2,016	1,997
2016						2,130	2,156	2,170	2,180	2,188
2017							2,149	2,166	2,184	2,193
2018								2,157	2,172	2,174
2019									2,234	2,243
2020										2,237
Actual System Peak:	1,882	2,033	2,118	2015	2111	2,018	2,073	2,060	2050	1968
<u>Percent Error</u>										
2011	22.7%	12.0%	5.8%	9.6%	2.9%	5.8%	1.1%	0.0%	-1.2%	1.1%
2012		3.2%	-1.2%	3.4%	-1.8%	2.6%	-0.4%	0.2%	0.7%	4.7%
2013			-1.9%	3.7%	-1.2%	3.2%	0.1%	1.1%	-5.0%	-1.3%
2014				3.1%	-2.3%	2.0%	-0.9%	-0.5%	-0.3%	3.7%
2015					-3.8%	0.9%	-1.8%	-1.6%	-1.7%	1.5%
2016						5.6%	4.0%	5.3%	6.3%	11.2%
2017							3.7%	5.1%	6.5%	11.4%
2018								4.7%	5.9%	10.4%
2019									9.0%	14.0%
2020										13.6%
<u>Statistics</u>										
Lead Time (Years):	1	2	3	4	5	6	7	8	9	10

System Peak										
Forecast	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:	Forecast for:
No. Observations:	10	9	8	7	6	5	4	3	2	1
Average percent Error:	6.0%	4.7%	3.8%	3.7%	2.4%	1.5%	0.0%	-0.2%	1.7%	1.1%
MAPE:	7.1%	5.5%	4.6%	5.0%	3.1%	1.8%	2.5%	0.7%	2.9%	1.1%

Appendix D

Forecast Sensitivity Analysis

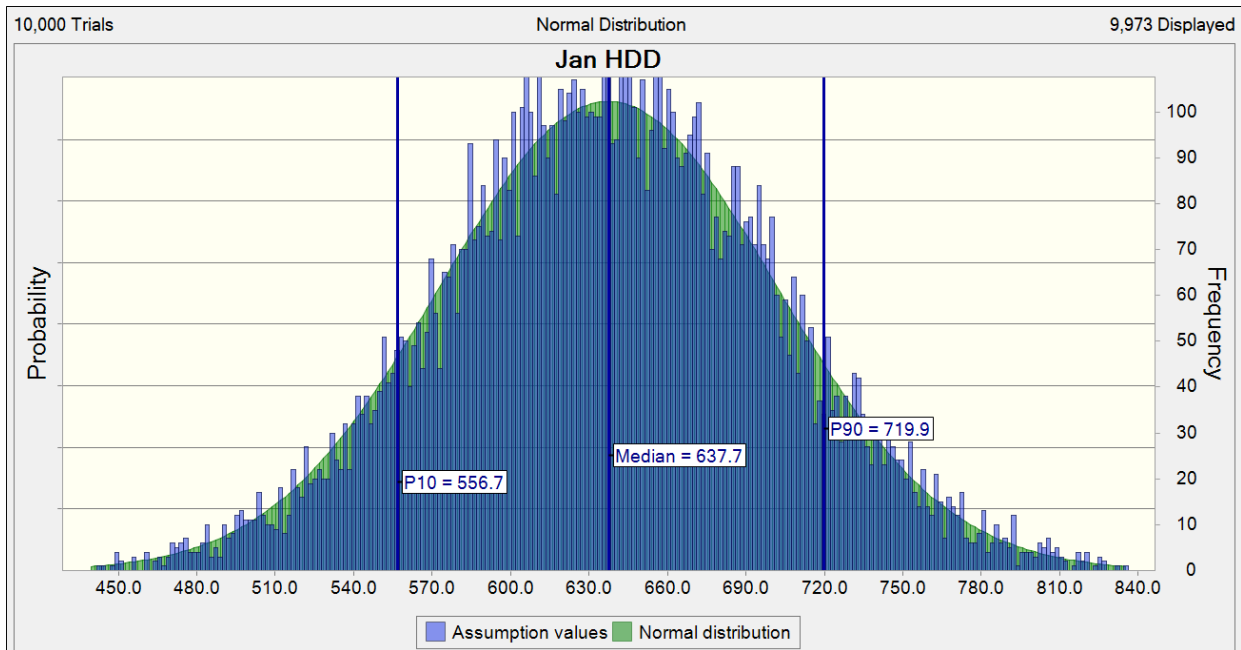
Sensitivity Analysis

The P10/P90 sensitivity analysis used Monte Carlo simulation for the economic and weather variables.

The algorithm uses the following sequence

1. Once the deterministic SAE class regression models are completed, the regression coefficients are exported into the Monte Carlo tool, called Oracle Crystal Ball (MS Excel add-on).
2. The Monte Carlo process assumes that the regression coefficients are held constant throughout the simulation, the historical variation of the inputs (predictors, independent variables) will affect the forecast prediction, in a probabilistic way. In other words, the simulations help to understand how the underlying SAE forecast responds to changes to the inputs based on historical variation.
3. For 2022 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 is treated as Normal distributions (see **Figure D1**).

Figure D1: Distribution of January HDD



5. Oracle's Crystal Ball runs about 10,000 trials, taking a random set of numbers from the relevant variables for each trial. For example, the random HDD variable for January (above), would have a Normal distributed weight, meaning that after 10,000 trials, a histogram of the variable will have an average and standard deviation that coincides with the distribution of the last 20 years.
6. Incorporating variability in the individual end uses is still in progress, as it is difficult to produce a distribution for historical end use data. EIA and NRCAN have revised their historical data sets in recent years, making historical variation studies challenging. However, as noted in previous sections, heat pumps are included in the input SAE models, and therefore their contributions to load will have an impact in the simulations as well.
7. At the end of the Monte Carlo run, 10,000 output forecast points are produced, each year represented by 10,000 possible outputs, with Normal distributed averages and standard deviations, which are the result of the different combination of the random variable trials.

These distributions are shown in **Figure D2** for energy and **Figure D3** for peak (both before the impact of DSM). 10th (10%) and 90th (90%) percentiles can easily be obtained from Normal distributions and so they are highlighted in D2.

Figure D2: Distribution of Energy (Before DSM)

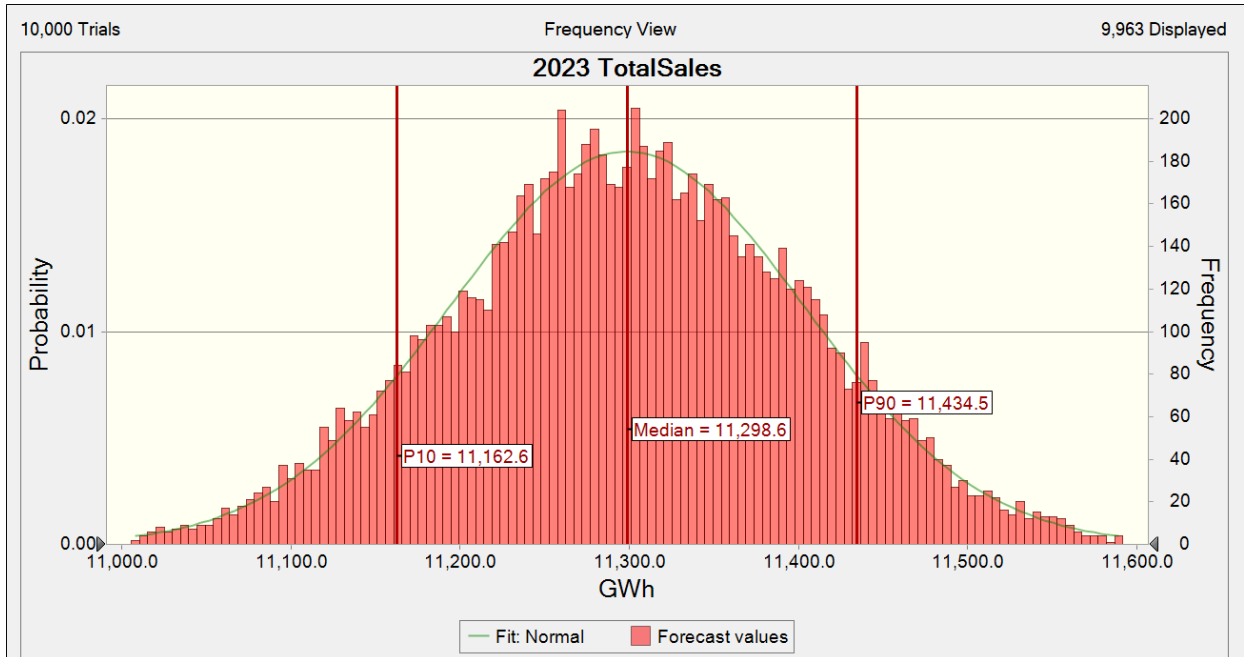
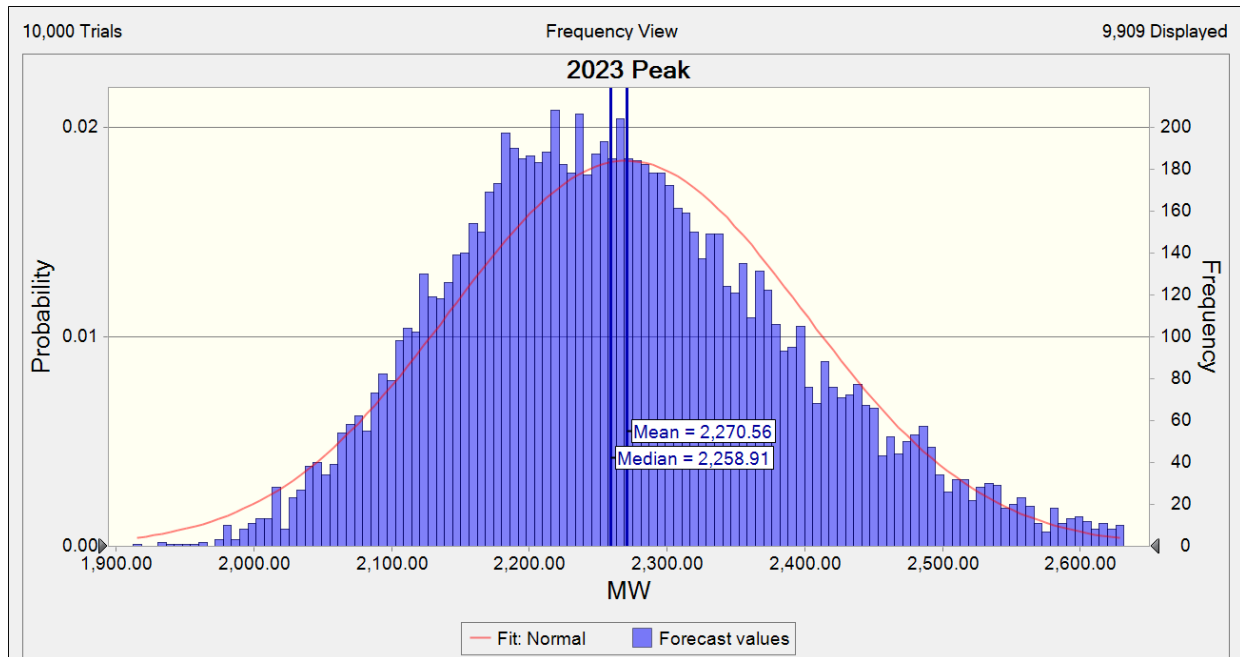
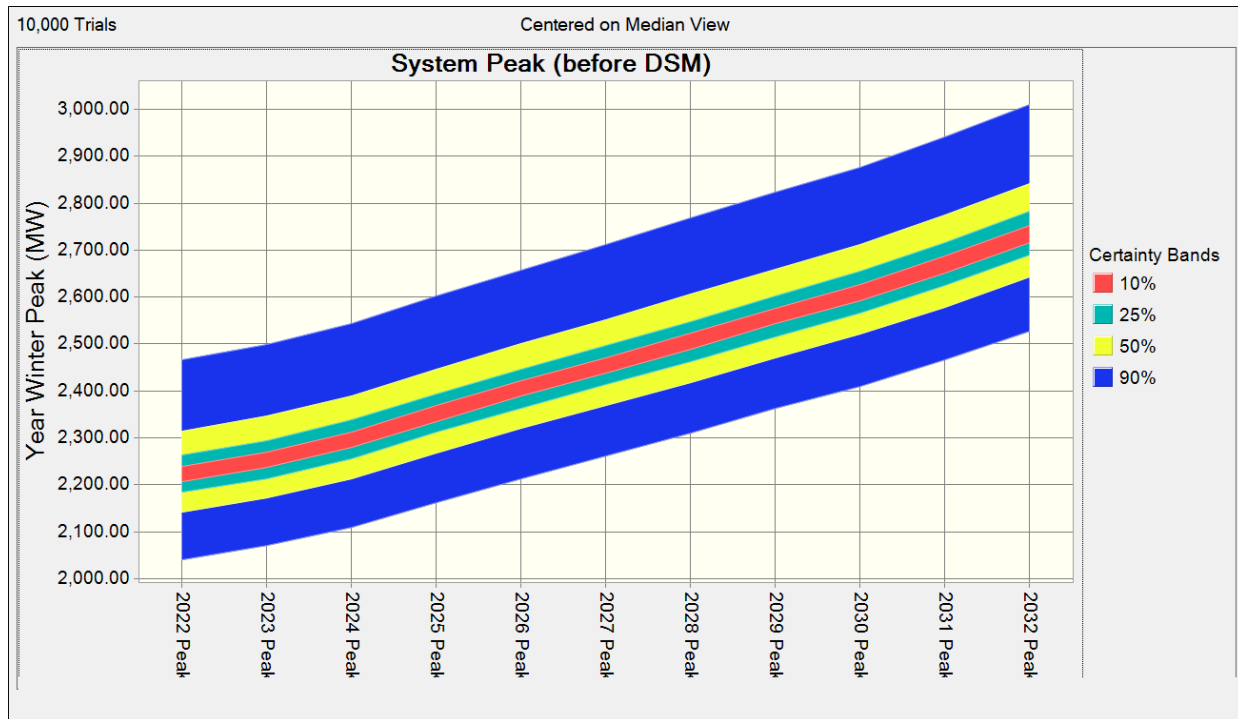


Figure D3: Distribution of Peak (Residential, Commercial and Small and Medium Industrial)



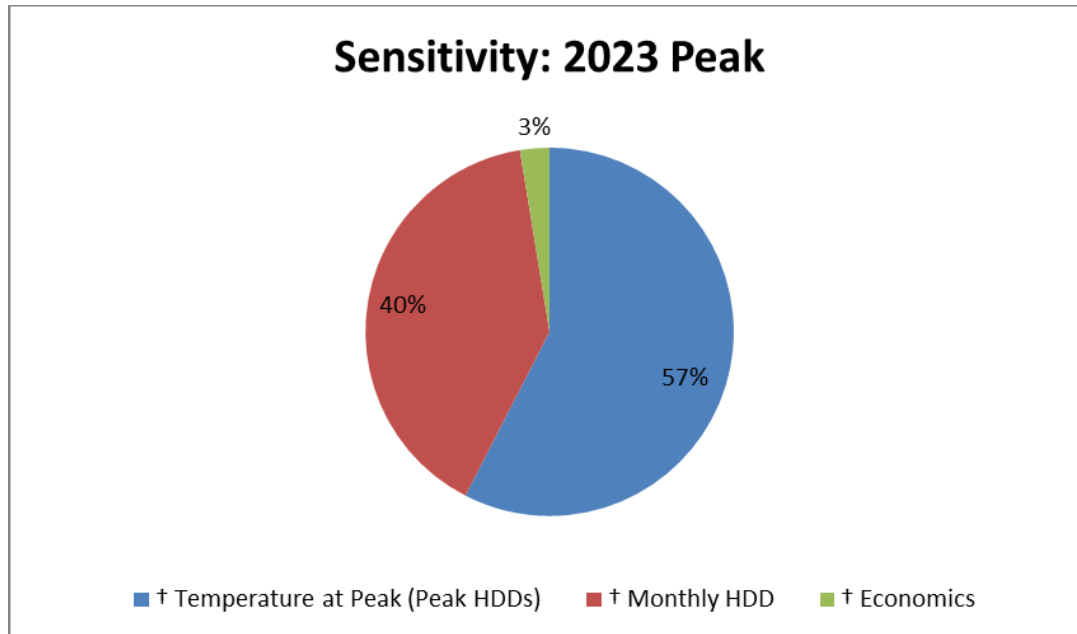
8. From these annual forecast distributions, the various probabilistic forecasts can be obtained as well as sensitivity diagrams that show the relative impact of the variables in each year. In **Figure D4** the probabilities of system peak forecasts (before DSM) around the median are shown. The area contained between blue borders represents a range of peaks that has a 90% chance of occurring; the yellow area highlights a 50% chance, and so on.

Figure D4: Peak Forecast (Residential, Commercial and Small and Medium Industrial)



The asymmetry in this figure, seen as the off-centre median, is explained by the bias introduced by plotting the maximum monthly Peak of a given year. Every month has a normal distributed daily Peak HDD, however by using the MAX function a skewed quasi-normal distribution is created when it selects the maximum Peak HDD from the 12 available months. Peak Demand and its associated SAE model are mostly sensitive to the Peak HDD temperature, however, as shown in **Figure D5**, the Monthly HDD has surpassed Peak HDD importance in 2022 as year-long residential heating had an impact on sales, and therefore, that impact (sensitive to monthly variations) was translated into Peak Demand. Compared to previous years, the Peak curve is steeper, due to the proposed E3 electrification scenarios highlighted in the main text.

Figure D5: Relative Sensitivity of Peak



In terms of the sensitivity of the energy sales forecast to the various input variables, **Figures D6 and D7** show that in the near term, weather represents the strongest sensitivity, while in the long term, economics becomes dominant. This is mainly due to the compounding effect of economics over time, as opposed to weather which will only impact a particular year. By 2032 the cumulative impact of the economic variables makes economics dominate the forecast sensitivity. The monthly (rather than cumulative) nature of HDD means it has much less relative impact in the long term.

Figure D6: Sensitivity of Energy Forecast (2023)

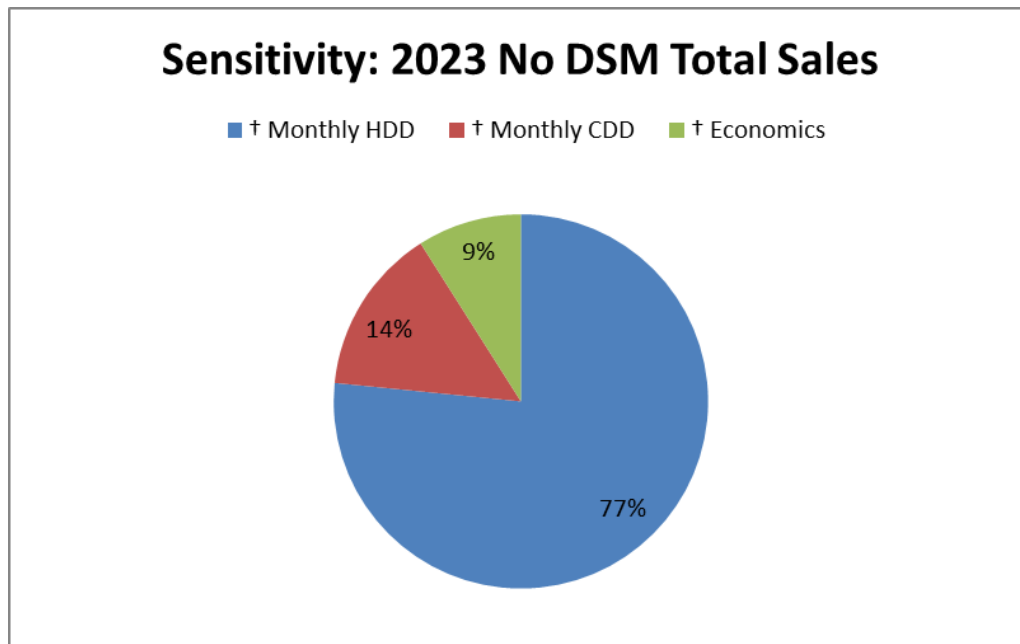
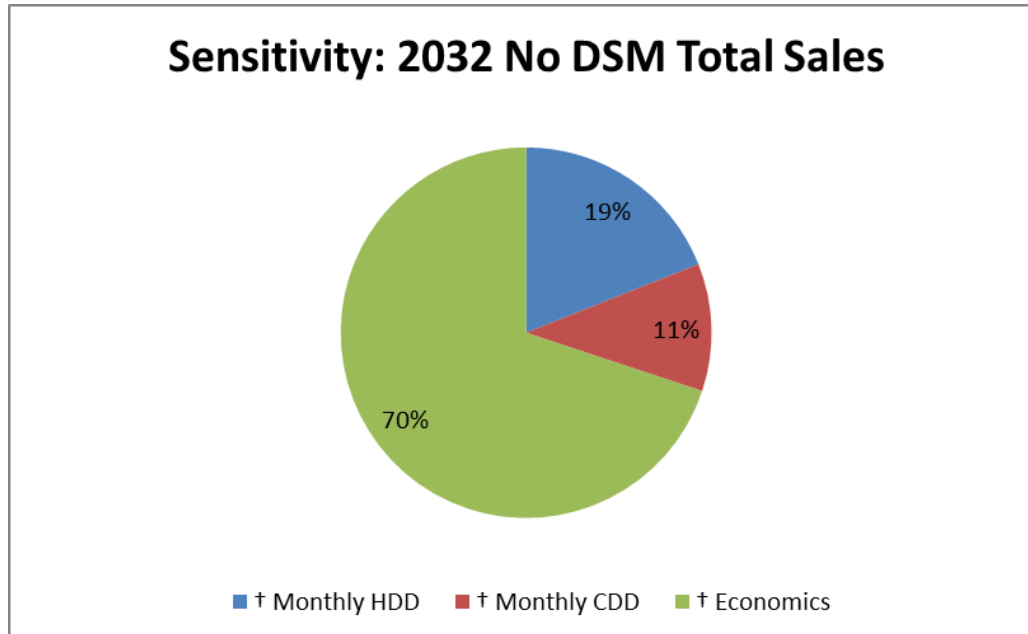


Figure D7: Sensitivity of Energy Forecast (2032)



In terms of relative magnitude of the sensitivities, except for the weather impact on peak, DSM and  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	2023 Energy (GWh)	2023 Peak (MW)	2032 Energy (GWh)	2032 Peak (MW)
Included in Forecast				
DSM (base case)	-248	-62	-1488	-285
Solar PV	-36	0	-205	0
EV (current forecast)	26	5	510	89/131 (no mitigation)
Other Possible Scenarios				
EV (high case)	3	1	534	108/228 (no mitigation)
EV (low case)	3	1	146	30/62 (no mitigation)
Battery (5% share by 2032)	0	0	0	-127
Weather/Economics P10/P90	+/-198	+/-164	+/-313	+/-188

Nova Scotia Power Electrification Support

Load Forecast Inputs – Overview

April 2022



Energy+Environmental Economics

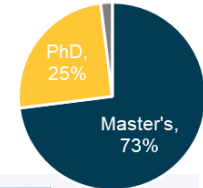
Liz Mettetal, PhD
Sierra Spencer
Michaela Levine
Arne Olson
Dan Aas





About E3

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300+ projects per year across our diverse client base



Recent Related Projects

- Nova Scotia Power Integrated Resource Planning Support & ongoing Electrification Strategy Report
- Transportation Electrification Plans/Roadmaps for Xcel Colorado (2020), Arizona (2021), and Hawaii (HECO)
- Building Electrification Studies for EWEB (Eugene, Oregon), California, Utah
- Net Zero New England: Electric Reliability under Deep Decarbonization

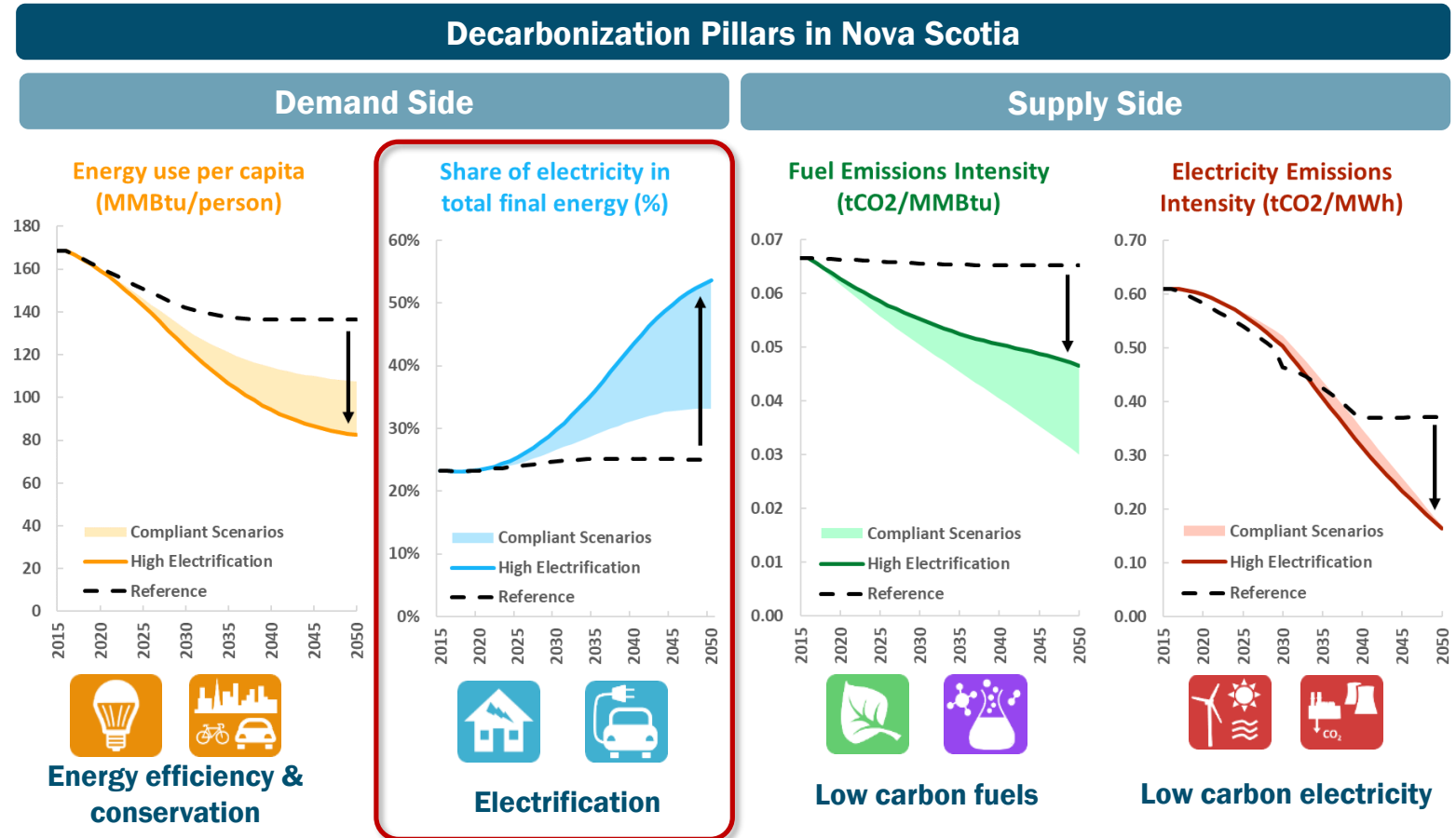


Electrification is key to achieving Net-Zero in Nova Scotia

+ In decarbonization modeling in Nova Scotia, consistent with the Canadian Net-Zero study, near-complete electrification of transportation and most buildings is a “safe bet”

- Measures are lower cost and commercially available to support economy-wide decarbonization

+ Electrification must be pursued in parallel to aggressive power sector GHG reductions, which remains a Net Zero lynchpin, with supporting energy efficiency and conservation



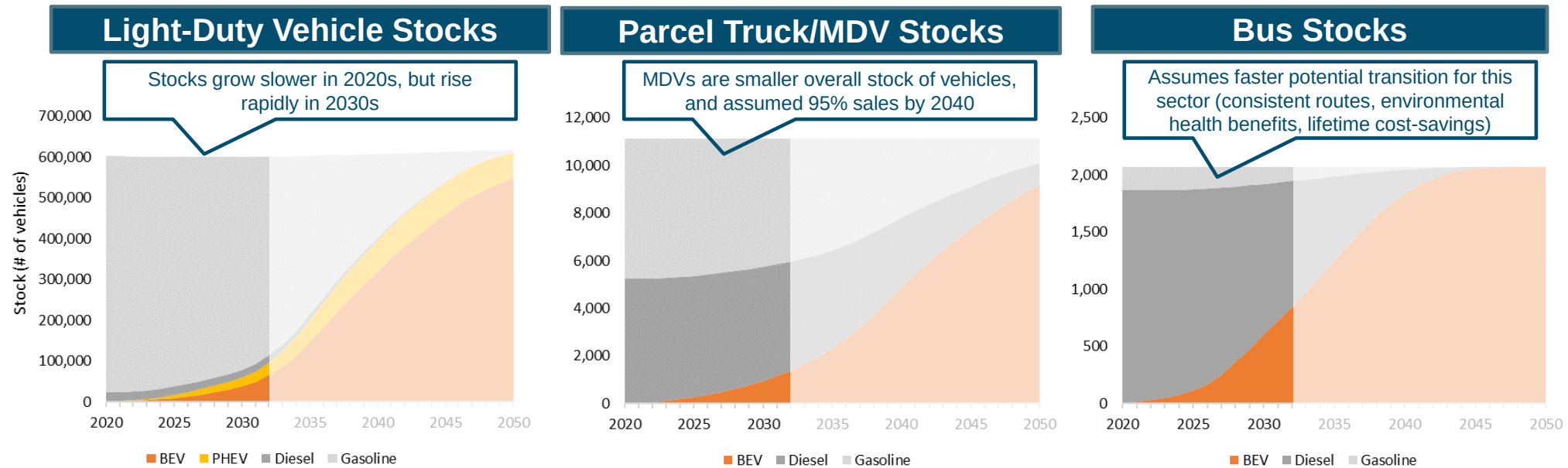
Source: E3 Nova Scotia Power PATHWAYS Phase 1 Report (Feb 2020)



Electric Vehicle Adoption Stock Rollover

+ EV adoption/stock estimate was developed in E3's PATHWAYS stock rollover model

- PATHWAYS is an infrastructure-based model reflecting vehicle lifetimes and relationship of sales to stocks
- Light-duty vehicle (LDV) forecast assumes 100% electric LDV sales by 2035, with the base forecasts relying on a “slow sales ramp” scenario that achieves 30% electric LDV sales by 2030



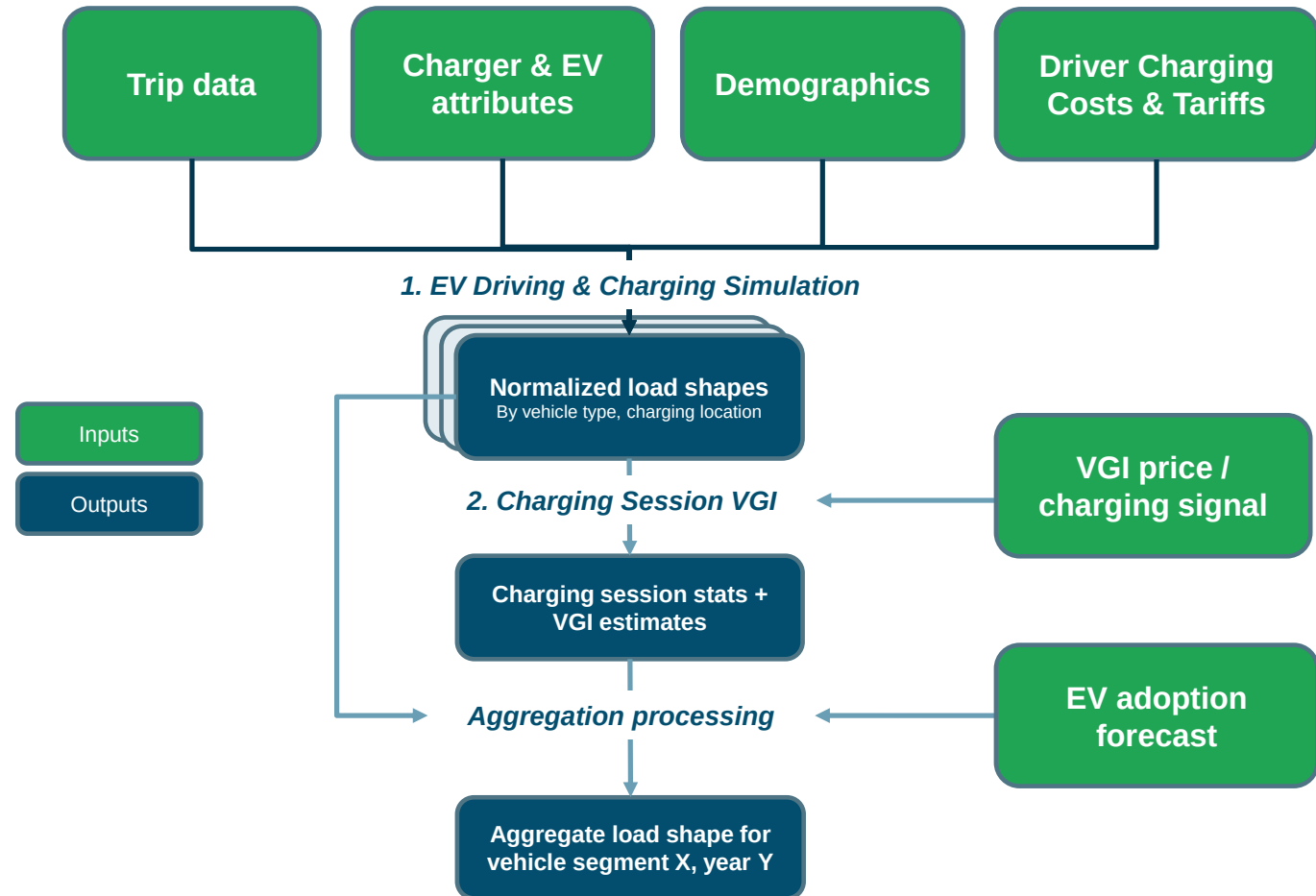


Transportation Load Shaping Process

+ E3 generates forecast of transportation load shape based on simulations of EV driving and charging behavior, using travel survey data

- Population characterized by vehicle type, charging access, cost of charging, etc.
- Drivers choose where and when to charge based on minimizing cost subject to constraints

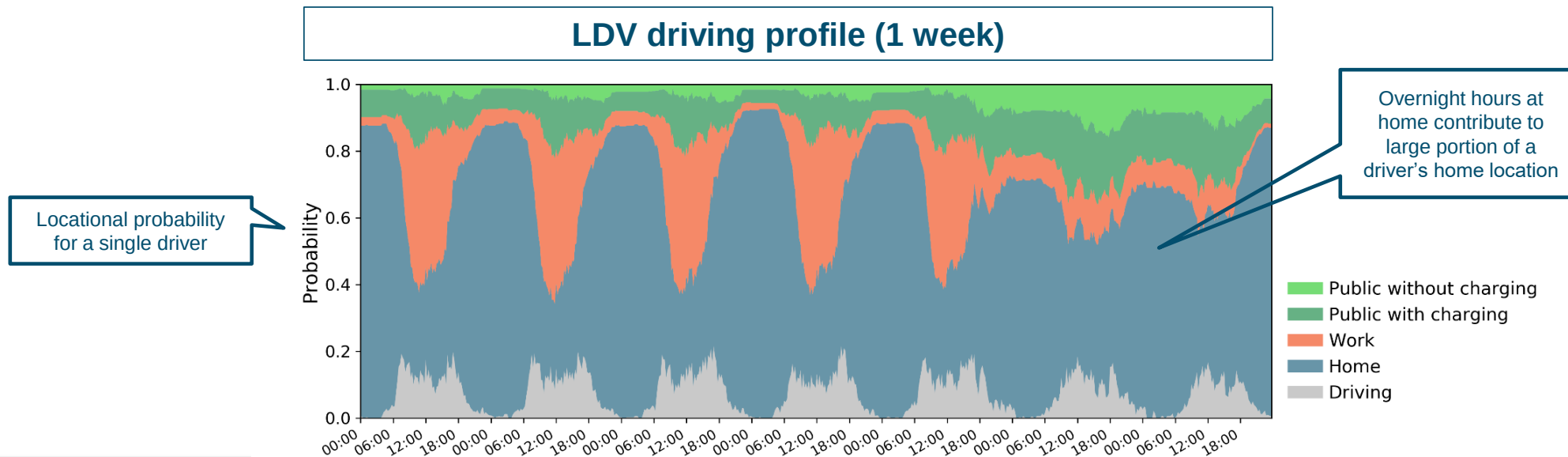
+ Modeling based on Nova Scotia population and driving statistics





Profiles for light-duty vehicle drivers were developed to inform future charging patterns

- + The driving profile shows the probability of a vehicle being at each location type, based on National Household Travel Survey data for New England (assumed to be representative of driving patterns in Nova Scotia)
- + Drivers are assumed to drive 10,830 miles/year (17,430 km/year) based on historical Nova Scotia VMT statistics
- + The simulated driving profiles are used as an input in the EV Load Shape Tool

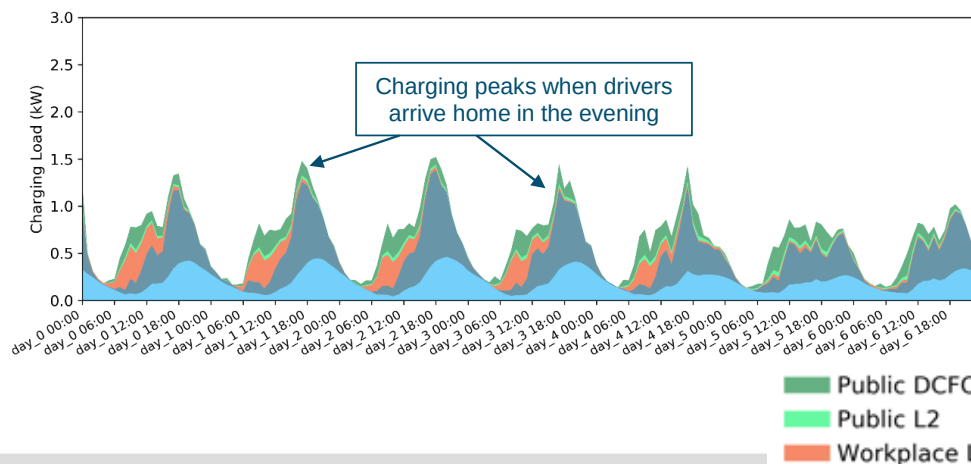




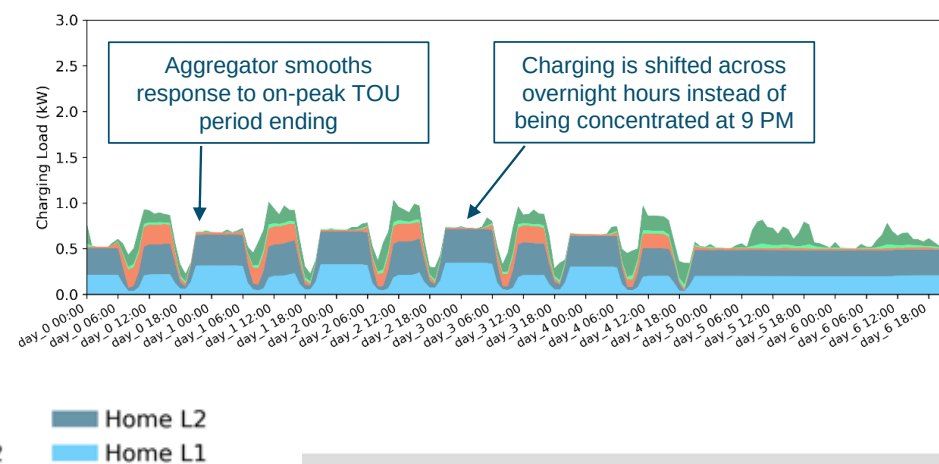
LDV Charging Profiles

- + Charging profiles represent population-level charging scaled down to one vehicle
- + In unmanaged charging, drivers begin charging immediately upon arrival at their charging location
- + Managed charging shifts timing of charging to reduce charging costs (based on time-varying rates)
 - Managed charging shown assumes NSP or a third-party aggregator performs additional coordinated charge management across EVs to flatten peak loads during off-peak periods.
 - This smooths the sharp increase in charging that occurs in the “Managed” case when the on-peak TOU period ends
 - E3’s input into the forecast assumes about 70% manage their charging with an aggregator

Unmanaged charging profile (winter, one week)



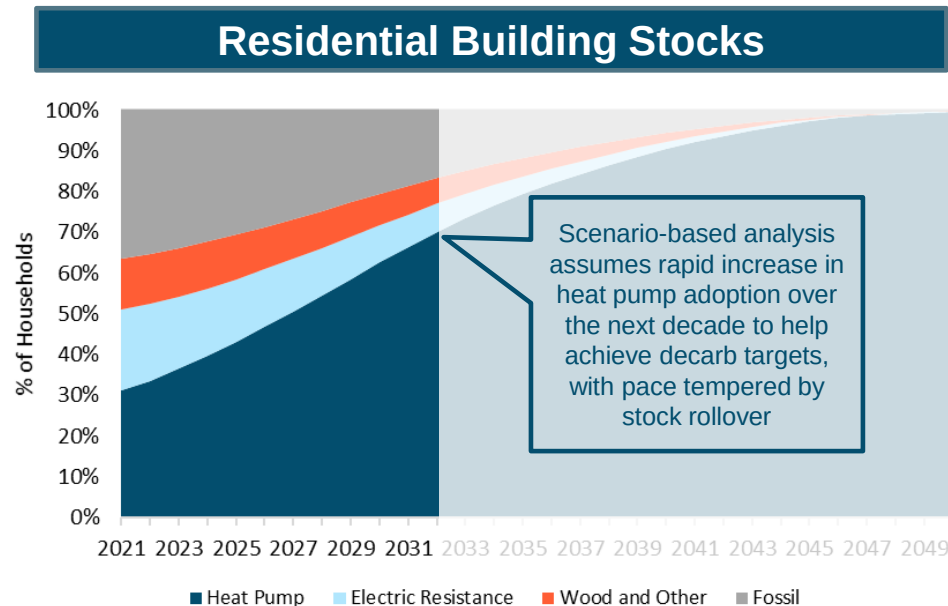
Managed charging profile w/ VGI Aggregator (winter, one week)



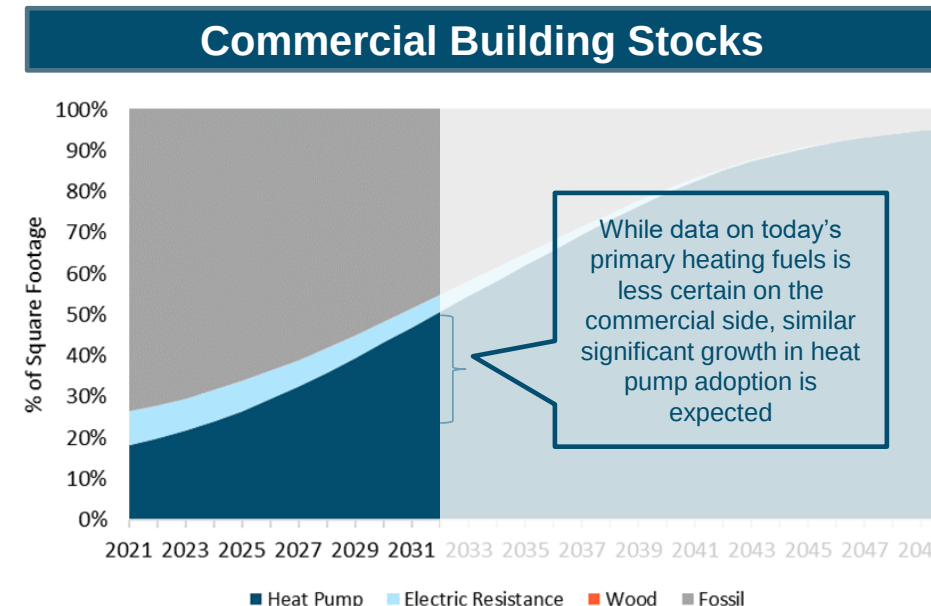


Heating Equipment Stock Rollover

- + E3's electrification study scenarios ultimately yield near-complete electrification of residential and commercial buildings by 2050; to achieve policy targets, E3 scenarios assume most sales are heat pumps sales by 2030s



* Both graphs reflect primary heating source



* Starting breakdown of heating fuel varies from NSP forecast given lack of data and reporting differences (e.g., primary heating source) – however, growth in HPs is aligned with NSP

2022 Load Forecast Report Attachments 1-3 have been filed electronically.

2022 Load Forecast Report Attachment 4 has been removed due to confidentiality.

2022 Load Forecast Report Attachments 5-10 have been filed electronically.