Phase 1 Findings on Muskrat Falls Project Rate Mitigation

Newfoundland and Labrador Hydro Rate Mitigation Approaches:

Options for Cost Savings and Revenue Opportunities through Export Market Sales, Energy Efficiency, and In-Province Electrification After In-Service of the Muskrat Falls Project

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SUMMARY: PRELIMINARY FINDINGS

We summarize our preliminary findings from Phase 1 below. We emphasize that these are preliminary findings based upon information available and analysis conducted in a very short timeframe. Conclusions and recommendations on rate mitigation options should be based upon the Phase 2 results, after we have a chance to refine and improve our quantitative analysis. It will be especially important to investigate in more detail the export market opportunities and more granular temporal (i.e., hourly) impacts of different resource options.

In this report we analyze several resource and policy options to help offset the potential rate increases from the Muskrat Falls Project (MFP), based on the Reference Questions. We look at electrification and increased export sales to help increase utility sales and revenues. Increased sales will help the utilities spread the fixed MFP costs over more customers, and increased revenues will help bring in more funds to cover costs; both effects will help to lower costs for ratepayers. We also look at conservation and demand management (CDM) options to help increase opportunities for exporting power and reduce utility costs and reduce customer bills.

Load Forecasts

Total electricity sales (gigawatt hours or GWh) for the Island Interconnected System (IIS) have grown very little over the past few years, with annual sales increasing by less than 1%/year from 2014 through 2017. The monthly sales patterns are important for our analysis because they show a dramatic variation between peak and off-peak months. Winter peak sales in January are two and a half times greater than the off-peak sales in August.

IIS plus Labrador electricity sales are forecast to remain fairly flat in the future, with a modest decrease of 0.3% per year from 2018 through 2030.[1]

Future electricity sales and peak demand are likely to be affected by the retail price increases caused by MFP, as customers reduce consumption patterns in response to higher prices. Retail sales in 2030 could be as much as 4 to 11 percent lower than they would be without MFP, depending upon how much the project increases retail prices.

More rigorous investigations of elasticity effects are needed in Phase 2 in order to understand the fundamental drivers of load going forward and ensure appropriate analytical treatment of intermingled factors that affect ultimate load: economic demographics, price elasticity, CDM efforts, electrification trends and policies that may influence those trends, and rate design influences on consumption patterns.

[1] Excluding potential new load in Labrador.

Electrification

Electrification is likely to offer the single greatest opportunity to increase revenues to support electric sector revenue requirements associated with the MFP. Electrification will also help reduce oil consumption, reduce total energy costs, and reduce greenhouse gas emissions. Rate design and policy guidance will be critical to support electrification efforts, especially to avoid straining peak period requirements in extreme weather periods.

Our analysis suggests that under a high electrification scenario the amount of electric heating substituting for oil consumption in 2030 could be as much as 24 percent for the residential sector still depending on oil, and up to 60 percent for commercial sector heating that is dependent on oil. The transportation sector could see electric vehicle (EV) penetration up to 33 percent for light-duty vehicles and 60 percent for medium-duty vehicles. This high electrification scenario would increase electricity consumption in 2030 by as much as roughly 17% of total IIS and Labrador Interconnected System (LIS) energy (excluding self-generation provision) and could increase utility revenues by at least $100 million per year, relative to a baseline electrification scenario.

Conservation and Demand Management

CDM efforts are critically important as both an insurance policy for peak load reduction and as a source for winter energy savings that create more headroom for export sales. While recent savings trends from CDM are increasing, the utilities (Newfoundland Labrador Hydro (NLH) and Newfoundland Power (NP)) have historically implemented limited CDM programs, relative to other provinces and states, leaving opportunities for significantly increased cost-effective savings going forward. Further, air-source heat pump technologies offer a large opportunity to increase efficiency, reduce customer energy bills, and – for those residences with oil heat, as noted above - increase electricity sales.

Our mid-case results indicate that the utilities could save at least 500 GWh per year through CDM efforts, which represents a reduction in 2030 total energy consumption on the order of 5 percent. Our high case results indicate that utilities could save nearly 1,000 GWh per year through CDM. These results do not include the effect of heat pumps, which could reduce customer bills further (and increase sales for those residences switching from oil).

A shift in the avoided cost profile in Newfoundland and Labrador toward higher capacity costs and lower energy costs has implications for CDM program design, cost effectiveness testing, and more. This means that energy efficiency opportunities that primarily reduce peak demand will have much higher value than those that primarily reduce energy consumption only.

There are ways to manage peak impacts to proactively forestall any potential need for new supply-side capacity resources. CDM measures, including demand response technologies that have not been historically utilized in the Province, are a particularly critical and potentially cost-effective means to ensure sufficient resource adequacy. Even peak period energy consumption from electrification can be managed to minimize consumption during the subset of winter peak hours that represent critical resource availability/capability periods.

Export Market

There is a sizable potential for increasing export revenue from sales of surplus energy. This value can vary considerably, depending on the level of CDM, load response to price effects, and electrification. Figure 1 presents a summary of how the export energy sales volume might vary depending upon the scenarios we analyzed in this report.

Under base case assumptions the export sales volume is expected to be roughly 4,000 GWh. This could increase to as much as 4,500 GWh under the low-electrification, low energy efficiency scenario, or to roughly 4,800 GWh in the low-electrification, high energy efficiency scenario.

These export sales result in net export revenues of roughly $140 million by 2030 for the baseline case, rising to roughly $168 million by 2030 for the highest export volume scenario, incorporating high levels of energy efficiency and low levels of electrification. This is shown in Table 1 below.

Figure 1. Export energy annual sales volume

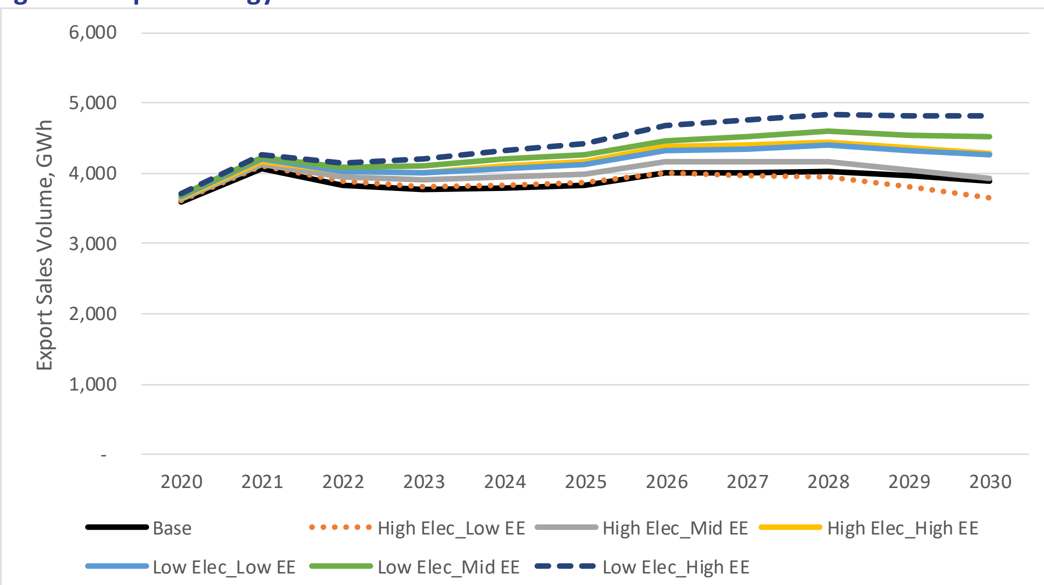

Table 1. Net Export Revenues by Scenario, $ '000 CAD

	2021	2025	2030
Base	92,464	90,968	141,694
High Elec_Low EE	93,016	91,360	134,764
High Elec_Mid EE	93,443	93,689	142,983
High Elec_High EE	94,182	97,014	153,216
Low Elec_Low EE	94,602	96,303	152,855
Low Elec_Mid EE	95,079	98,677	159,593
Low Elec_High EE	95,813	101,871	167,745

Source: Synapse. Note: net of estimated tariff, losses, and operational and administrative expenses to reach destination markets.

Capacity sales potential across the Maritime Link also exists, but we expect this to be a much smaller opportunity because aggressive, proactive peak load reduction (and/or containment of peak load growth that may arise if electrification is pursued as a policy) is required through various mechanisms to ensure sufficient Provincial resource adequacy.

Recommendations

Significantly offsetting the electricity rate increase from the MFP will clearly require pro-active policies on a variety of fronts. Synapse recommends several aggressive policy initiatives to promote electrification, cost-effective CDM initiatives, and increased export sales. We anticipate that Phase 2 work will allow exploration of rate design issues, including time-of-use rates, in support of further analysis of CDM and electrification initiatives.

Increased electrification avoids oil expenditures, contributes to reduced greenhouse gas emissions, and provides an incremental revenue stream to contribute to paying down MFP fixed costs. Aggressive CDM reduces ratepayer bills; ensures peak load reduction and reduced winter energy use to allow for increased export sales during higher-valued winter periods; provides headroom for increased electrification of oil end uses; and provides a crucial insurance policy and potentially cost-effective alternative forestalling or eliminating a possible need for future supply-side capacity resources to ensure resource-adequacy-based reliability.

Regarding electrification, we recommend consideration of time-of-use rates for all electric vehicle customers, and also for those switching from oil heating to electric heat pumps (or boilers, for institutional or commercial conversions); make-ready infrastructure to support electric vehicle charging stations; utility investment in fast-charging stations for low-income, commercial, and government customers; and recycling of revenues from federal and provincial greenhouse gas reduction programs, to the extent those will apply in Newfoundland and Labrador.

Regarding CDM initiatives, we recommend: decoupling; increased energy efficiency budgets; creation of an Energy Efficiency Stakeholder Advisory Group; avoided cost studies; aggressive demand response programs; and investigation of heat pump programs that will minimize combined heat pump and electric resistance heating consumption contribution during the highest winter peak periods, independent of whether the heat pumps represent electrification of oil end uses, or substitution for electric resistance heat provision.

1. Introduction and Background

Synapse Energy Economics, Inc. (Synapse) was engaged by the Newfoundland and Labrador Board of Commissioners of Public Utilities (Board) in late September 2018 to assist in the Board's review required for the Government of Newfoundland and Labrador's Reference Questions concerning Rate Mitigation Options and Impacts associated with the anticipated commencement of in-service operations for the Muskrat Falls Project (MFP) in 2020. Phase 1 of our scope of work includes initial review and reporting on MFP rate mitigation issues in 2018, which will allow the Board to report its interim findings to the Government in February 2019. Phase 2 efforts will include more rigorous analysis of technical issues, preparation of a final report, and expert witness support during formal hearing proceedings in late 2019.

The MFP consists primarily of the Muskrat Falls hydroelectric generation station, the Labrador Transmission Assets, the Labrador-Island Link (LIL), and ancillary components such as the high-voltage DC to AC (HVDC) converter stations on either end of the LIL. Upon completion, the MFP will allow Newfoundland Labrador Hydro (NLH or Hydro) to deliver energy across the LIL to the Island of Newfoundland, serving Newfoundland Power (NP) customers and its own rural and industrial customers with MFP energy. The MFP and LIL completion will enable retirement of and fuel savings from the Holyrood oil-fired generation station on the Avalon peninsula.

The Maritime Link (ML), placed into operational service in early 2018 and interconnecting Newfoundland Island with the North American electric grid for the first time, serves as a key transmission link that will allow surplus energy from the MFP to be sold into Canadian and U.S. electric markets. The ML HVDC converter terminals at Bottom Brook in Newfoundland and Woodbine in Nova Scotia are connected by the ML HVDC cable that crosses under the sea and electrically connects the NLH and Nova Scotia Power systems in Cape Breton and Southwestern Newfoundland.

The Government's Reference Questions seek to determine how—and to what extent—the Province can mitigate the forthcoming electric rate increases for electricity customers on the IIS that are required to pay for the MFP. Based on information provided by NLH, their projected base revenue requirements will increase from a total of roughly $592 million in 2019 to in excess of $1.1 billion in 2020, further increasing to roughly $1.3 billion per year by 2030. IIS customers (both NLH's and Newfoundland Power's customers) will see total payments rise from roughly $506 million in 2019 to more than a billion dollars per year in 2021, reaching $1.2 billion by 2030. Most of these revenue requirements represent fixed costs that must be repaid regardless of the level of in-Province consumption. The preface to the Reference Questions notes that, absent mitigation, rates to domestic customers could rise to 22.9 cents per kilowatt hour (kWh) by 2021.

As set out in the Reference Questions, a form of rate mitigation can arise from at least two paths of increased electricity sales to help pay down the fixed costs of the MFP: increased domestic load in the Province and/or increased export sales to customers outside of Newfoundland and Labrador.

Electrification of end-uses currently served by oil[2] allows for electricity rate mitigation while reducing expenditures on another fuel. Continuing use of conservation and demand management (CDM) practices, which we often refer to as energy efficiency improvements, can lead to reduced customer bills even with increasing rates—or at least limit bill increases that would otherwise occur.

CDM practices can free up energy and reduce losses, especially during peak periods,[3] to allow for greater export sales while contributing to peak load reduction. Even though the Province will have surplus energy to export once the MFP is online, there remains a potential concern of having sufficient resources to meet the most extreme winter peak loads seen in the Province.[4] Thus, CDM should continue to play an important role in ensuring electric reliability in the Province by reducing peak demand. Simultaneously, load-building through electrification—especially when focused on incentivizing electricity consumption mostly, if not wholly, during non-extreme winter peak periods—can assist in lowering average rates while saving consumer expenditures on oil.

The Reference Questions require the Board to review and report on the following:

1. Options to reduce the impact of MFP costs on electricity rates up to the year 2030, or such shorter period as the Board sees fit, including cost savings and revenue opportunities with respect to electricity, including generation, transmission, distribution, sales, and marketing assets and activities of Nalcor Energy and its Subsidiaries, including NLH, Labrador Island Link Holding Corporation, LIL General Partner Corporation, LIL Operating Corporation, Lower Churchill Management Corporation, Muskrat Falls Corporation, Labrador Transmission Corporation, Nalcor Energy Marketing Corporation, and the Gull Island Power Company (together the "Subsidiaries," and collectively with Nalcor Energy, "Nalcor");

2. The amount of energy and capacity from the MFP required to meet Island interconnected load and the remaining surplus energy and capacity available for other uses such as export and load growth; and

3. The potential electricity rate impacts of the options identified in Question 1, based on the most recent MFP cost estimates.

The Reference Question document also pointedly notes the importance of considering sources of Nalcor income that could help reduce rate increases, including export sales, and "whether it is more advantageous to Ratepayers to maximize domestic load or maximize exports." It further notes, explicitly, the potential for increased electrification of oil-fired end uses (oil-fired heating boilers, home

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[2] And potentially by other fuels, such as wood and propane. Our initial assessment focuses on displacement of oil with electricity consumption.

[3] As we note in this Preliminary Findings report, the term "peak periods" in general refers to those periods of the winter when Provincial load is highest, during the coldest days and during the early morning and early evening periods.

[4] See, for example, NLH's reference to potential "capacity shortfalls" on page 15 of the Executive Summary of its 2018 Reliability and Resource Adequacy Study, dated November 16, 2018 and filed with the Board.

heating equipment, and vehicles) and the ability for conservation that lowers peak demand to increase the availability of both capacity and energy for export.

Synapse provides these Preliminary Findings for the Board to answer the second Reference Question and a portion of the first Reference question. Synapse will address the third question during the second phase of our work in 2019. Synapse's charge with respect to the first question includes assessing the cost savings and revenue opportunities associated with electricity consumption and electricity sales. It is our understanding that another consultant, Liberty Consulting Group (Liberty), is examining other aspects of the first Reference Question, including the Nalcor/NLH organizational structure and operating improvements.

In this first phase of Synapse's work for the Board, we conduct an initial analysis of the following key elements to inform our preliminary findings:

- The forecast of load for the Province, including both the Island Interconnected System (IIS) and the Labrador Interconnected System (LIS); combined, these comprise the Newfoundland and Labrador Interconnected System (NLIS);
- The current, historical, and projected CDM program effects on load across all sectors (residential, commercial, industrial);
- The potential to electrify oil-fired end uses in the Province, with an initial focus on (a) large institutional-scale oil-fired boilers, (b) residential scale oil furnaces and boilers (replaced or supplemented with electric heat pumps), and (c) transportation options (e.g., electric vehicles); and
- The range of export energy (gigawatt hours or GWh) and capacity (megawatts or MW) that could be available post-Muskrat Falls (i.e., from 2020 onward) and post-Holyrood retirement for sale to external markets.

Consideration of rate design issues, particularly the potential benefit of time-of-use rate mechanisms, will be analyzed in Phase 2 of our work. The challenge of ensuring reliability by lowering peak load through CDM and related activities can at first be seen as at odds with mitigating rates by increasing domestic consumption. The critical distinction though, is the specific time periods required for saving energy and how they contrast with the best periods for consuming "surplus" energy. As reflected in a load duration curve, the need for the highest level of available generation resources occurs over relatively few hours of the year. In short, there is significant headroom for consuming surplus energy, or selling excess energy externally, without undermining the requirement to meet the Province's peak load during the coldest periods of the year as long as careful attention is paid to super peak load consumption and incentives to lower such peak demand. However: as we note in these findings, and as we expect to explore next year, an understanding of load duration curve fundamentals does not readily translate into an understanding of which planning or programmatic solutions may work best to achieve the aims of off-peak consumption and on-peak savings.

Our analytical approach and methodology are described in the next section. In each of the sections that follow, aligned with the four elements bullet-listed above, we describe what we did, identify the sources for the information used (we received most information from NLH and, in some cases, from Newfoundland Power), present our preliminary results, discuss our findings, and describe our recommendations for continuing analysis in 2019.

We have coordinated our efforts with Liberty. We have engaged in teleconference calls to ensure no or minimal overlap of effort expended to answer the Reference Questions. Generally, our focus is on core supply/demand issues in the Province and how they affect export volumes and net revenue from increasing domestic uses of electricity. Liberty's focus, as we understand it, is mostly removed from our technical assessment of load, export markets, CDM, and electrification and focuses on organization and operational issues affecting NLH and Nalcor.

2. ANALYTICAL APPROACH / METHODOLOGY

2.1. Overview

Phase 1 of Synapse's work encompasses an initial response to Reference Question 1 and 2.[5] During Phase 2 we will conduct a more extensive assessment of the key technical issues, supplementing our initial efforts, focusing mostly on the temporal dimensions of our analysis of export revenue opportunities, and the impacts of CDM and electrification. This will include examination of rate design considerations and how they can affect demand patterns on export opportunities. To some extent, it may include review of certain resource planning assumptions, and their impact on Reference Question concerns. At the conclusion of Phase 2 analysis we will provide detailed analysis on Reference Questions 1, 2, and 3.

Figure 2 illustrates our overall Phase 1 approach and methodology for analyzing potential rate mitigation opportunities associated with export market sales, cost savings from CDM, and domestic load increases through beneficial electrification (i.e., switching from oil to electricity). We reviewed publicly available documentation, examined information obtained from NLH and NP, developed initial spreadsheet analyses of core issues, visited with NLH and NP in St. John's to allow for in-person communications on key issue areas, and developed these preliminary findings. Each of the major steps are described in the following subsection.

Summary of Approach

Synapse began by reviewing the company's short and long-term load forecasts to assess the reasonableness of the assumptions and methodologies that the company used. We then developed an alternative load forecast based on our assessment of future consumption patterns. Simultaneously we evaluated CDM and electrification potential for the IIS and LIS. We identified key end uses that can be electrified and assessed the increase in electricity demand that would accompany a high and a low electrification scenario. We also reviewed existing CDM program performance and heat-pump installations and potential analysis for the Province and assessed the decrease in energy consumption and peak demand that we could see under a high, mid, and low CDM and heat pump adoption scenario.

We combined the updated load forecast with the electrification and CDM potential analysis to calculate IIS and LIS energy demand under each of the CDM and electrification scenarios. We then added system losses to complete an energy balance. Finally, we fed the alternative IIS and LIS load scenarios into an export market valuation model to calculate the change in energy available to export to external markets during each month. We calculated the potential revenue streams from export sales under each CDM and electrification scenario.

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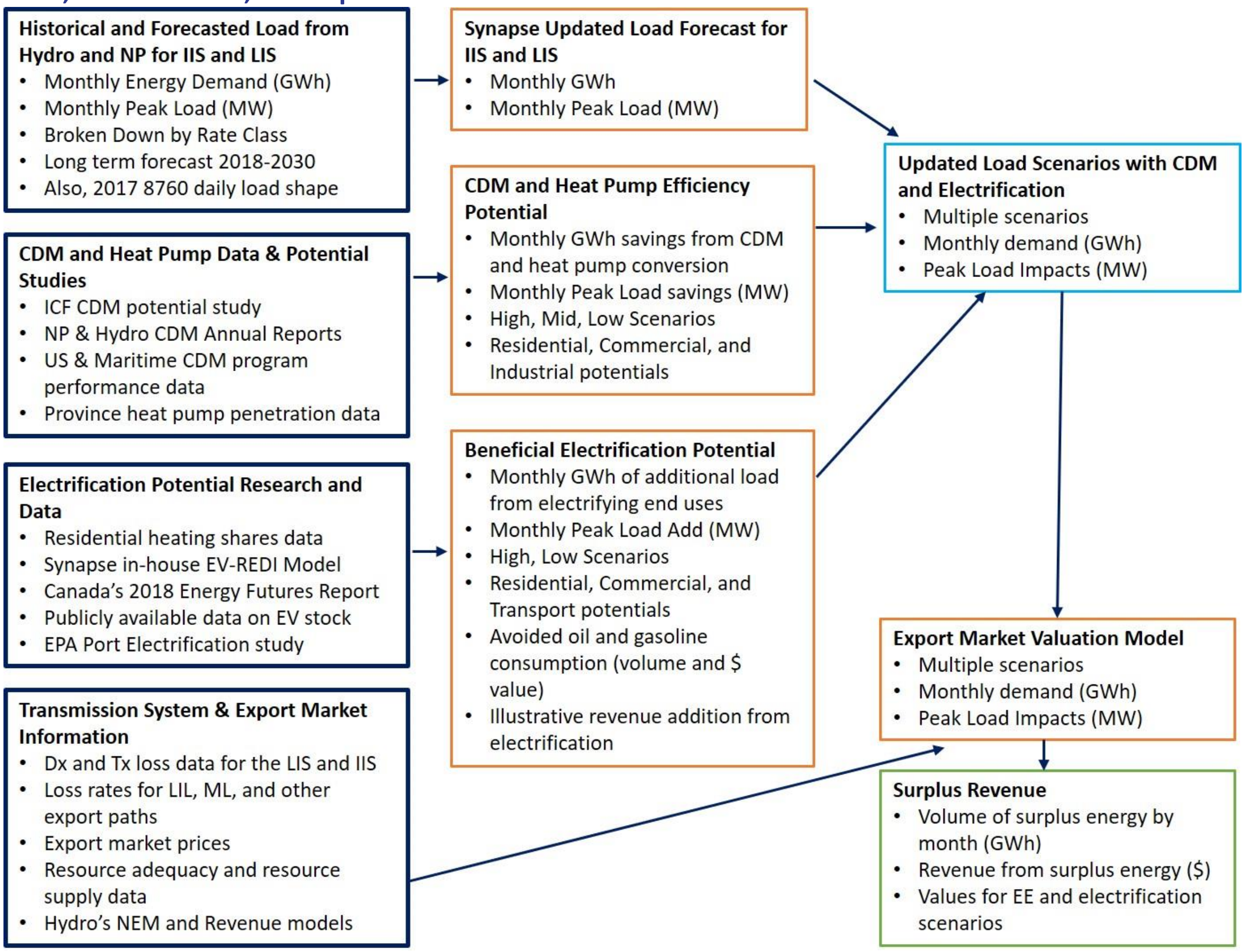
[5] Synapse and Liberty are addressing different aspects of Reference Question 1. Synapse is addressing Reference Question 2.

Figure 2. Synapse approach and methodology: cost savings and revenue opportunities associated with CDM, electrification, and export market sales



Interaction with Liberty

Although our charge was distinct from that of Liberty, we recognize there are still areas of overlap. We coordinated with Liberty, to ensure no or minimal overlap of responsibilities and shared interim findings to inform necessary components of analysis.

Data collection

Synapse obtained information from NLH and NP on the supply and demand side of the Newfoundland and Labrador electric power system. We engaged with NLH and NP using phone calls, virtual work sessions, and one set of in-person meetings with NLH and NP. Both NLH and NP were responsive and helpful in providing the information Synapse needed to perform Phase 1 analysis.

As noted above, Synapse also obtained information independently from government sources, industry documents, and other public sources of information. Synapse also had an initial teleconference call with the Department of Natural Resources to collect information on electrification efforts and potential in the region.

Synapse also brought to our work an existing familiarity with the overall electric power system in the Maritimes region, based on our work for each of the Provincial regulators (New Brunswick, Prince Edward Island, and Nova Scotia). Synapse's work in the Maritimes includes examination and analysis of various issues associated with resource planning, energy efficiency, and transmission.

2.2. Core Analysis

Stage 1: Assess load forecast; evaluate electrification and CDM potential

Load forecast

Synapse assessed NLH's existing load forecasts for the IIS and LIS and updated key assumptions to produce a new set of load forecasts. We began with historical and forecasted monthly load (GWh) and peak demand (MW) data for both the IIS and the LIS. Specifically, we used NP's short-term five-year forecast disaggregated by rate class for the company's Island customers and NLH's long-term ten-year forecasts for the IIS as a whole (including wholesale service to NP and industrial customers) and the LIS.

Synapse reviewed both the short- and long-term load forecasts and evaluated the reasonableness of the economic assumptions, inputs, methodology, and resulting trend patterns. We considered price elasticity effects, GDP assumptions, and broader demographic trends in assessing the current load forecasts. While we conducted an initial, time-limited review of regression results from NLH, we note that a more in-depth examination of regression parameters and methods is anticipated for Phase 2.

Both the short- and long-term Island forecasts display gradually declining energy demand through 2023, which we find to be reasonable. However, post 2023, NLH projects an upswing in economic activity for the IIS and an accompanying increase in load for NP, which Synapse believes may be overly optimistic. NLH's LIS forecast displays flat energy demand through 2030, which we believe is reasonable.

Based on these assessments, Synapse produced an alternative reference load forecast for the IIS, modestly different from NLH's, which applies the declining demand trend from NP's short-term forecast to NP load for the entire time period (through 2030). We retained NLHs forecast for the remainder of the IIS load. This alternative reference forecast matches NLH's through 2023 for the IIS after which it diverges and gradually declines. Synapse adopted NLH's forecast for the LIS for this Phase 1, but we note that we have not yet examined the effects on potential LIS load increases not present in NLH's September 2018 forecast.

Conservation and Demand Management

Synapse assessed energy savings and peak reductions potential from existing CDM programs as well as electric resistance heat to heat pump conversions to develop a set of low, mid, and high energy efficiency scenarios. For both the CDM and heat pump analysis, Synapse calculated savings as a percent of sales. Savings levels were bounded by limits on program ramping and annual achievable savings.

We started with NP's and NLH's annual CDM program reports and other publicly available data to establish a baseline of current CDM performance in the Province. We reviewed data on annual CDM program ramping rates and annual savings realized in New England and the Maritime Provinces, as well as the consulting firm ICF's CDM potential report for Newfoundland (2015). Synapse then developed a range of expected annual savings levels by sector and region and an annual average program ramping rate across sectors and regions. We applied these assumptions to our base sales forecast to calculate GWh of energy saved and MW of peak savings from CDM efforts. These savings levels were bounded by limits on program ramping and annual achievable savings. Peak savings from CDM efforts were estimated using the ICF potential studies and recent historical CDM program data.

For the heat-pump analysis, Synapse began with data from NP on customer heat pump installations and ICF's CDM potential study report. We updated ICF's assumptions and study results for some areas where we found that both the recent dramatic uptake of heat pumps in the Province and the expected increased retail electricity rates were not reflected in the ICF Study. We then calculated cumulative savings as a percent of sales in 2030 based on heat pump penetration rates and the energy consumption differential between electric resistance heating and heat pumps. We developed a linear annual savings rate to reach that level. MW peak savings potential were calculated using meteorological data and heat pump performance curves.

Synapse developed low, mid, and high scenarios for CDM and heat-pump adoption to show the range of achievable energy efficiency savings potential based on customer behavior and program roll-out. The output from each efficiency scenario is a final monthly GWh and peak load (MW) impact forecast for the residential, commercial, and industrial sectors that will be used to reduce the load in Synapse's scenarios that assess export market opportunities under different net load forecast scenarios.

Beneficial Electrification

Synapse assessed the electrification potential across key end-uses sectors on the island and in Labrador for low and high electrification scenarios. We started by reviewing fuel consumption patterns in the Province and identified residential heating, commercial heating, and transportation as the best electrification candidates.

Synapse reviewed current data on residential heating fuel shares provided by NLH, as well as oil consumption data and projection from Canada's 2018 Energy Futures report. We developed assumptions about annual oil to electric heat pump conversions and calculated annual GWH impacts as well as peak MW impacts from heating electrification based on building size and heat pump performance data. We also assumed that a large institution will install electric resistance boilers to offset a significant fraction of their oil consumption.

For the transportation sector, Synapse focused on electrification of light-duty and medium-duty vehicles, as well as shore-side power at ship-births at the port. We fed publicly available data on the current stock of electric vehicles in the Province into Synapse's in-house Electric Vehicle Regional Emission and Demand Impacts (EV-REDI) tool to predict electric vehicle adoption in the Province and the associated GWh and peak (MW) impact on electricity demand. We calculated port electrification potential based on current data on port traffic and cargo at St. John's Port and a current port electrification study from the U.S. Environmental Protection Agency.

For each end-use, Synapse developed a low and high electrification scenario to show the range of outcomes possible under different rate designs and policy environments. The output from the electrification analysis is a final monthly GWh and peak load (MW) impact forecast for each end use and electrification scenario that will be added to Synapse's updated load forecast scenarios. Synapse also calculated avoided spending on oil and gasoline for each beneficial electrification scenario.

Stage 2: Combine the alternative reference load forecast with the electrification and CDM potential results

Synapse combined the new reference load forecast with the two electrification and three CDM potential scenarios to develop a final set of nine load forecast scenarios (including the baseline scenarios for both energy efficiency and electrification) disaggregated by month and rate class. The final output from this intermediate step is a new set of monthly energy demand forecasts for the domestic, general service, and industrial customer classes in the LIS and IIS. For the purposes of export market evaluation of a pool of surplus energy, sectoral consumption proportions are not relevant, only the overall Provincial demand.

Stage 3: Determine surplus energy volumes and export market revenue potential

Energy and Capacity Sales – Export Market

Synapse calculated the monthly surplus energy available for export under each load scenario and the associated revenue that could be earned from selling the surplus energy into surrounding markets (Nova Scotia, New England, and New York via Quebec). Resource supply assumptions were the same across all scenarios (with Muskrat Falls coming online in 2020). Therefore, the volume of surplus energy available to sell was controlled only by the CDM and electrification assumptions in the net load scenarios that Synapse developed. Net export volumes were calculated based on total energy available to the Province, subtracting energy needed to meet domestic, commercial, and industrial loads (and associated transmission and distribution loses) on the LIS and IIS in each scenario.

Synapse reviewed information from NLH on resource supply availability, transmission capacity and constraints, export market prices, NS Block and Supplemental energy levels, future contract sale opportunities, and current load assumptions. While Nalcor provided several confidential, internal spreadsheet models that it uses to calculate net export market revenue and volumes, as well as revenue impacts on Nalcor/NLH, Synapse developed its own independent export market valuation model based on the information provided and our knowledge of the export markets, and used the company's models as a guide when reviewing our final results.

Synapse evaluated net energy available for export to each market during peak (non-holiday weekdays 7am – 11pm) and off-peak periods (weekends, holidays, 11pm-7am) each month of each year. Markets were ranked based on export volume and market prices to develop an order of market sales.

Transmission constraints and losses were incorporated to limit the volume of energy sent to each market based on the capacity of the path. Transmission constraints represented were (1) within the Province, (i.e., over the LIL between Labrador and the Newfoundland Island); and (2) outside the Province, through Quebec and over the Maritime link (to Nova Scotia, New Brunswick, and New England).

For each load scenario Synapse calculated monthly volumes of energy available for export and revenue associated with the export sales. The final output from this step was net annual revenue to NLH from export market sales. Synapse also calculated the change in revenue potential relative to the baseline CDM and electrification scenario for each scenario.

2.3. Limitations and Next Steps

Limitations

Our Phase 1 analysis was limited by both time constraints and numerous uncertainties applicable to technical parameters. Key uncertainties underlying relevant technical parameters include the following:

- **Range of price elasticity effects on the load forecast**. The percentage price increases contemplated fall outside the range of conventionally considered effects. The extent of those increases is uncertain as are the effects on customer loads. Econometric forecast models based on historical data with modest price changes are inadequate to capture the effects of such large price changes.
- **Potential for rate design to influence consumption patterns**. We have not investigated the direct potential of rate design—especially some form of time-of-use (TOU) rate—to influence both CDM behavior and electrification from oil uses or consumption patterns in general. Our electrification and CDM work will benefit from a more careful assessment of how varying marginal price signals (e.g., highest during winter extreme peaks, lowest during off-peak periods) will affect uptake in these areas. Our analysis may underestimate the potential for CDM and electrification to increase export market revenues during peak hours. It may overestimate it for off-peak hours.
- **The temporal granularity was limited to primarily monthly differentiation**. We did allocate export energy to on-peak and off-peak “buckets,” and we did make some assumptions regarding how CDM and electrification will affect peak and on-peak usage. However, a more refined and analytically rigorous approach, likely employing an hourly time-step in most or all analyses, will improve the accuracy of our estimations.
- **Resource adequacy, reliability, and energy available for export**. We have assumed existing resources, plus Muskrat Falls, less Holyrood Steam (2021). Any additions or retirements of other resources would affect overall energy or capacity available for potential export sale.
- Unknown or unclear **governmental policies** to influence electrification.
- Unknown impact of the **impending update to the CDM technical potential study**.

Next Steps – Phase 2 and Beyond

The next steps in assessing rate mitigation options include the following:

Rate Design

Synapse will evaluate the impact of alternative rate design mechanisms, most importantly some form of TOU pricing. TOU pricing comes in many flavors, and a systematic approach to considering and evaluating the ramifications of TOU pricing is required to increase the accuracy of assessing the effects of CDM and electrification on rate mitigation. Rate design, and TOU mechanisms in particular, can affect the level of capacity headroom on the system during peak periods and lower overall net system costs by allowing for greater export revenues. On systems that rely on fossil generation for energy, lower production costs are possible; this is less of a concern going forward for Newfoundland and Labrador, given the Province's increasing reliance on non-fossil electricity generation resources.

Further Analysis of Price Elasticity Effects on Load Forecast

When Muskrat Falls comes online in 2020, rates will increase and this in turn will impact sales. Synapse will further evaluate the elasticity impacts from increased rates on energy sales in the Province, in part through more careful assessment of the regression construct and parameters currently employed by NLH. Synapse will propose in early 2019 a more detailed and systematic approach to help inform Phase 2 work scope in this area. To some extent, bounding analysis—i.e., defining likely lower and upper bounds to load forecast outcomes—may be the best approach to shape possible mitigation paths under different outcomes of customer response to higher prices.

Production Cost Modeling

Synapse will use a more granular analytical tool—most likely the Plexos software for production cost analysis—to more rigorously track the ability of the energy supply sources in the Province to provide as much available energy during higher-priced hours relative to energy sold during lower-priced hours. This will allow us to better capture on-peak/off-peak granularity within any given month on the energy availability side and thus better estimate the timing effects associated with CDM and electrification profiles across the hours of any given day.

Resource Planning Issues Affecting Mitigation Approaches (+ Export Market Sales + Purchases)

In combination with use of a production cost model to better assess export sales volume potential, Synapse can consider how resource planning issues in general might influence available revenues from export sales. For example, if the Province plans for the contingency loss of the LIL during extreme winter periods by adding more resources, scenario analysis can assess how such resource changes could increase the level of export market guarantees NLH or Nalcor could make. Increasing export market guarantees would enable NLH and Nalcor to earn more revenues and reduce ratepayer impacts.

Policy Landscape: CDM, Electrification, Rate Design, Resource Planning, Export Market Sales and Purchases

Synapse can evaluate best practice policies associated with CDM, electrification, rate design, and resource planning issues. Time constraints during Phase 1 have limited our ability to systematically assess the overall use of industry best practices in a winter peaking region.

3. LOAD FORECAST

3.1. Overview

The electrical load in the Province consists of consumption within three systems: the IIS, the LIS, and isolated systems serving remote communities in both Labrador and Newfoundland. Synapse's scope of work in Phase 1 did not include the assessment of rate mitigation options for the isolated systems,[6] thus our study focuses only on the loads associated with IIS and LIS.[7]

NLH serves as a retail load provider to certain domestic and commercial customers on the IIS and in the LIS. NLH also serves as a wholesale provider to large industrial customers in both IIS and LIS and to NP. NLH is responsible for supplementing transmission system losses across the Province (excluding losses associated with NP's transmission assets, downstream of connection to points to NLH) and for providing the energy to offset Island Rural distribution system losses. As shown in Table 2, NP serves the majority of load (and customers) in the Province, providing service to domestic, commercial, and smaller industrial customers. An overview of each system is provided below:

- **Island Interconnected System**: This is the largest segment of load, representing about 73 percent of the total NLH energy requirement volume (including losses) and a greater fraction of total Provincial energy requirements (roughly 76 percent) when considering the level of self-supply by NP and Island industrial customers. It includes NP, Island industrial customers and Hydro-served rural interconnected customers. NLH sales to NP represent about 59 percent of its total provincial energy provision.

- **Labrador Interconnected System:** This includes service to Labrador West and East, including rural customers and a significant level of industrial load, all served primarily by generation assets at Churchill Falls. The LIS comprises about 26 percent of the total NLH energy provision.

[6] The isolated rural systems represent only 1 percent of the total provincial load and are not connected to the electric grid. Historically they have relied on expensive diesel generators, thus CDM and potentially renewable energy/battery systems may be especially cost effective there.

[7] It is our understanding that the Labrador Island Link, currently in testing and commissioning phases, is expected to be commercially operational in 2019.

- **Isolated Systems:** Rural loads served with local (mainly diesel) generation. In total, these systems makeup approximately 1 percent of the provincial load.

Table 2. 2018 Test Year consolidated loads (NLH, excluding self-supply)

Island Interconnected System			% of Total
Newfoundland Power		5,824.5	59%
Island Industrial Customers		726.0	7%
NLH Rural Interconnected		457.0	5%
Losses		215.0	2%
	Total	**7,222.5**	73%
Labrador Interconnected System			
NLH Rural Customers		688.6	7%
Industrial Customers		1,734.3	18%
CFB Goose Bay Secondary		0.0	0%
Losses		151.1	2%
	Total	**2,574.0**	26%
Isolated Systems			
L'Anse au Loop		26.8	0%
Labrador Isolated Systems		46.1	0%
Island Isolated Systems		7.5	0%
	Total	**80.5**	1%
Total Consolidated Load			
		9,877	100%

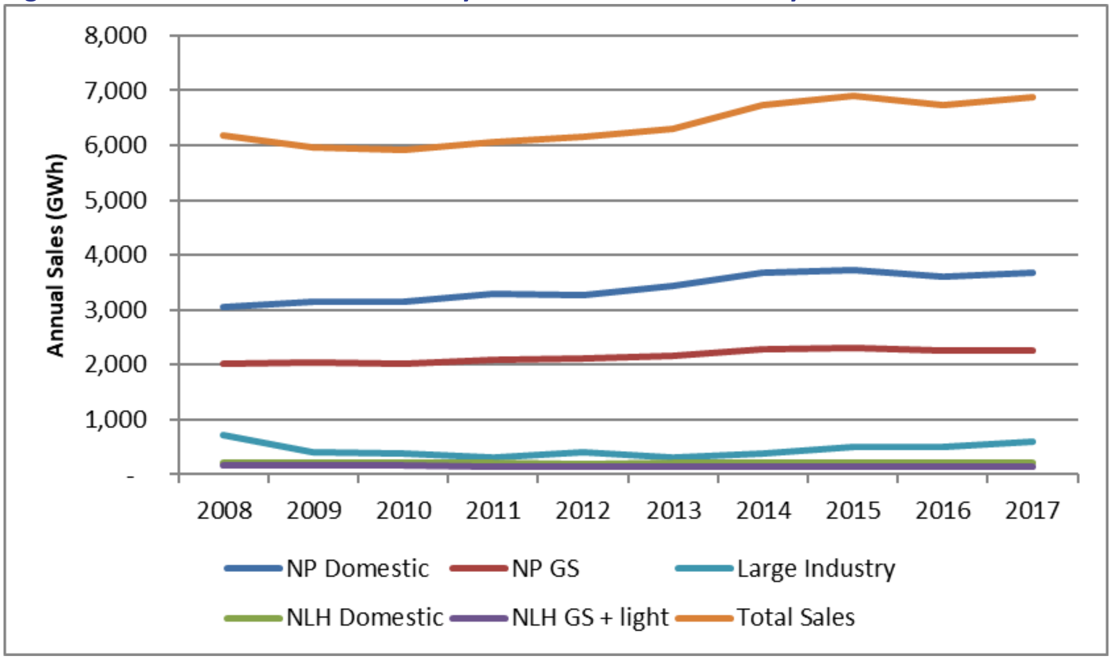
Source: NLH

3.2. Historical Load

As noted above, the Newfoundland and Labrador electrical load consists of many separate pieces. At the highest level the divisions are the (1) Island Interconnected, (2) Labrador Interconnected, and (3) Isolated systems. Each of those has further geographic subdivisions and different customer classes.

From 2008 to 2014, the IIS annual sales increased from 6,187 to 6,875 GWh, representing a net increase of 11 percent. Most of this increase was due to NP domestic sales, as shown in Figure 3 below. However, since 2014 consumption has leveled off. Large industry sales have varied from year to year and have increased since about 2014. The NLH domestic and general service sales are a small portion of the total and have declined by nearly 10 percent since 2008.

Figure 3. Historical NLH sales summary – Island Interconnected System



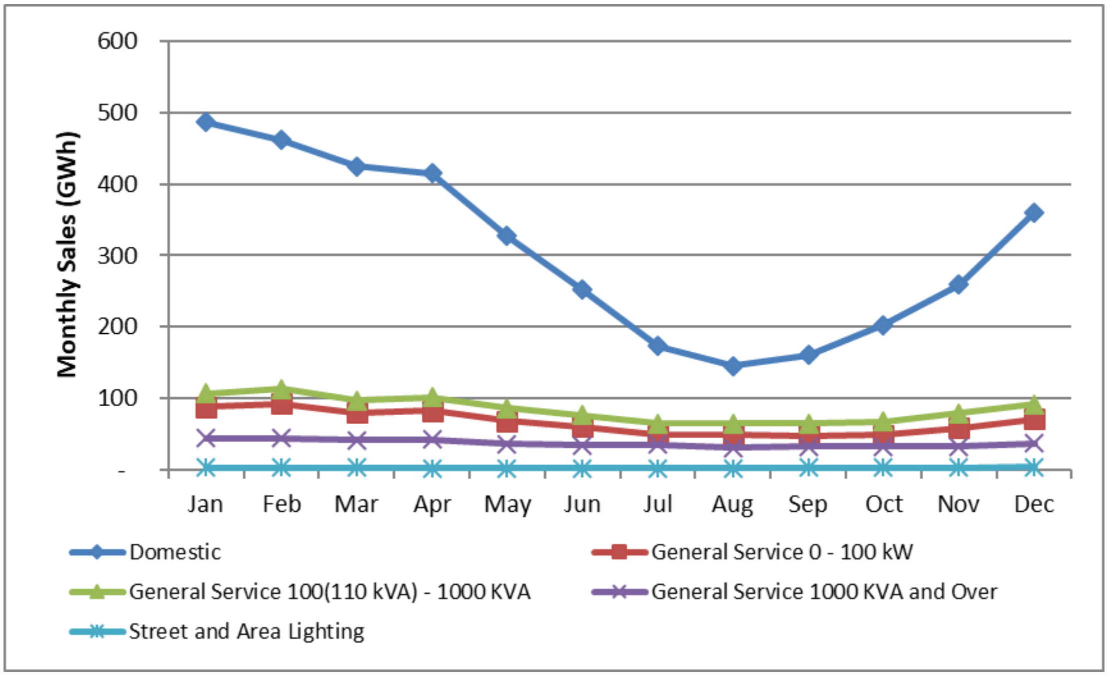
Source: NLH historical loads.

Note: Excludes self-generation from Newfoundland Power and industrial load.

Synapse also evaluated the monthly electricity sales patterns in the Province, using NP's sales by sector in 2017 as a proxy (Figure 4). The highest monthly sales in 2017 were in January (730 GWh) and the lowest in August (293 GWh), equating to a ratio of two and a half to one (2.5:1). The greatest variation is in the monthly domestic load, which varies by more than a factor of three throughout the year. That seasonal variation is due to the combined effects of heating and lighting loads. The general service load also varies but only by a factor of about one and a half.

The NLH industrial sales vary moderately (5-10 percent) from month to month but do not show any significant seasonal patterns.

Figure 4. NP 2017 monthly sales[8]



Source: NLH

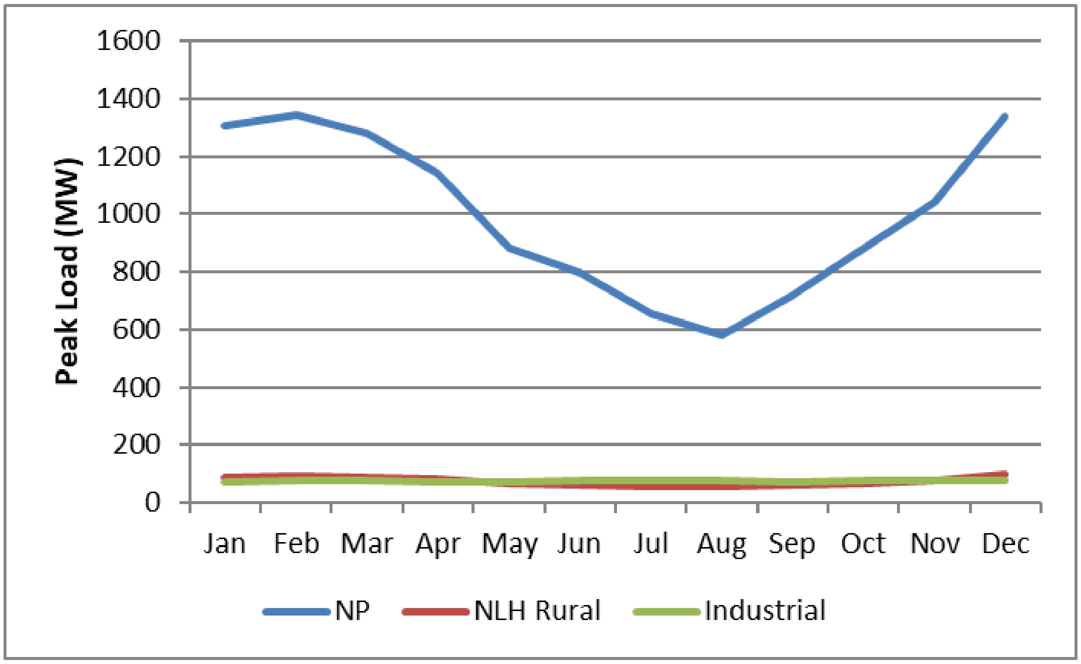
As shown in Figure 5, there is also a strong monthly pattern for peak loads in the Province. The monthly peak in 2016 varied from 1,500 MW in February and December to a low of 711 MW in August. Unsurprisingly, NP dominates the Island's peak load.

In 2018, LIS customers represented about 26 percent of the total Provincial load. Of that load, 20 percent is comprised of NLH Rural customers (domestic and general service). A few large industrial customers represent the remaining 80 percent. Figure 6 illustrates that industrial customer load began to dominate demand beginning in 2015.

The isolated rural systems represent only 1 percent of the total provincial load and are not connected to the electric grid. Historically, these isolated systems have relied on expensive diesel generators, thus conservation measures may be especially cost effective there.

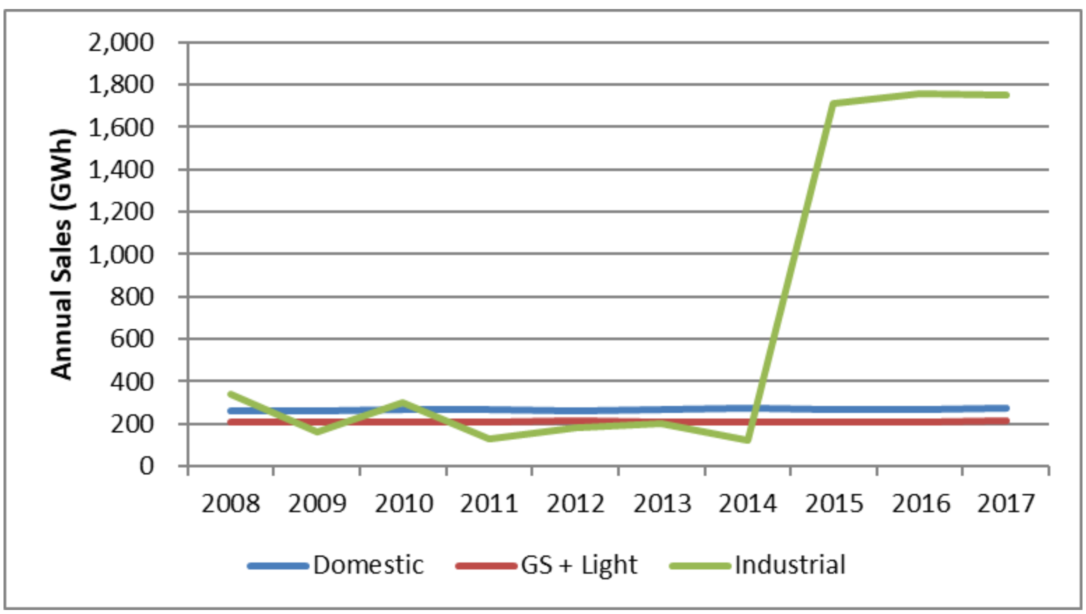
[8] Provided by NLH.

Figure 5. Monthly Peak Loads for Newfoundland Island - 2016[9]



Source: NLH

Figure 6. Labrador Interconnect Historical Sales[10]



Source: NLH

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[9] Provided by NLH.

[10] Provided by NLH.

3.3. Forecast Load

For Phase 1, Synapse relied primarily on the energy forecasts provided by NLH. However, we have attempted to break out peak loads by sector, which were not provided. We have also made an adjustment to the NP load post-2024 to replicate the trends in the NP five-year forecast, which is described in detail below.

Table 3: IIS base forecast

Energy Sales (GWh)	2018	2030	Change
NP Retail	5,915	5,711	-3.4%
NLH Retail	439	401	-8.8%
Industry	1481	1490	0.6%
Total	7,836	7,602	-3.0%
Peak Loads (MW)	**2018**	**2030**	**Change**
NP Retail	1360	1320	-3.0%
NLH Retail	102	94	-7.4%
Industry	187	182	-2.7%
Total	1,649	1,596	-3.2%

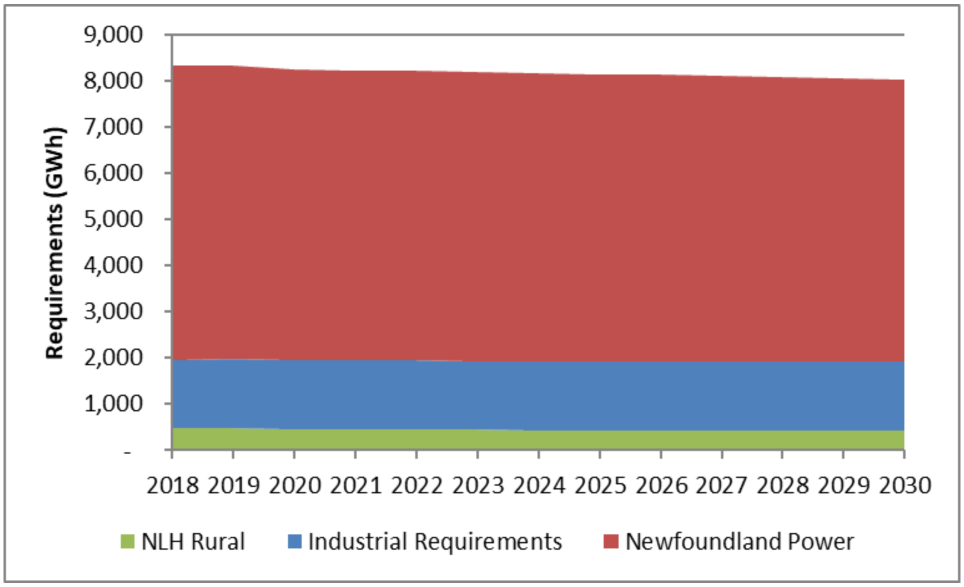
Source: Synapse, based on components provided by Hydro.

Figure 7 shows the total Newfoundland Island energy requirements for 2018 to 2030, including NP's own generation (~430 GWh per year) and industry self-generation (~870 GWh per year).[11] Thus, net energy sales by NLH are about 1,300 GWh below the total energy requirement on the island. Industrial requirements are flat, although there is a possibility of new industrial customers.[12] The NLH and NP loads decline slightly reflecting higher prices, stagnant economic conditions, and improved efficiency of end-use technology. The underlying forecast methodology is essentially econometrically and trend-based. Presently, there is insufficient information to identify more precisely the end-use components of the load or the effects of various drivers. However, an analysis of the monthly and hourly historical data indicates that much of the load and the peak, which occurs in the winter, is weather-dependent.

[11] Provided by NLH.

[12] We understand additional load in Labrador is potentially developing for 2019.

Figure 7. Island requirements forecast[13]



Source: NLH

Synapse made a modest reduction to NLH's forecast of NP's load after 2024. In NLH's reference forecast there was a slight decline from 2018 through 2024 averaging about -0.3 percent per year, and then a sharp upturn increasing at a rate of 0.7 percent per year thereafter. Although this was based on econometric forecast models, we think such an upturn is unlikely; therefore, the Synapse forecast continues the initial slightly declining trend throughout the forecast period. Some of the reasons for this adjustment are: (1) the recent historical trends for NP sales have been flat, (2) the most recent near-term forecast from NP predicts a sales decline of 0.24 percent per year,[14] (3) NP customers are already switching to heat pumps and other conservation measures in anticipation of price increases, (4) customer prices will continue to rise through 2030, and (5) the modest economic upturn used in the econometric model inputs is not sufficient to generate the forecasted sales increase.

Although the energy forecast declines at an annual rate of -0.4 percent over the forecast period, the peak load increases at an annual rate of 0.2 percent over the same period. This reflects an expected increase in the electric space heat fraction. Although the expansion of heat pump usage is expected to reduce energy demand, their effect on the peak is less certain.

The NLH forecast for Labrador projects relatively flat consumption through 2030, with a 0.4 percent increase in energy and a 0.6 percent decrease in the peak by 2030. However, the industrial load may change during that time frame. Some new industrial customers have been approved, and there are some potential new ones as well. For the Labrador System, the Wabush Mines are being reactivated

[13] Data behind this forecast was provided by NLH.

[14] "Newfoundland Power – 2019/2020 General Rate Application", Customer Energy and Demand Forecast, Appendix B, June 2018.

with loads of 55 MW and 430 GWh. Hydro advised that there are other new potential loads of 50 to 165 MW which would represent a significant increase for Labrador. For the Island System, there are potential new loads in the range from 10 to 32 MW. Typically, these industrial loads have high load factors but remain in operation during the winter peak periods.

Table 4: Labrador Base Forecast

Energy Sales (GWh)	2018	2030	Change
Retail	696	719	3.2%
Industry	1,753	1,741	-0.7%
Total	2,450	2,459	0.4%
Peak Loads (MW)	2018	2030	Change
Retail	154	153	-0.4%
Industry	252	250	-0.8%
Total	406	403	-0.6%

Source: Synapse, based on components provided by NLH.

Combined Load Forecast – IIS and Labrador

The tables on the following page show the combined forecast for the Province prior to adjustments for increased electrification and CDM.

Table 5: Synapse load forecast for Newfoundland Island and Labrador - GWh

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Newfoundland Island - Total Load + Losses	8,640	8,626	8,476	8,453	8,436	8,422	8,395	8,371	8,346	8,325	8,301	8,278	8,256
Labrador - Total Load + Losses	2,617	2,654	2,641	2,633	2,635	2,637	2,640	2,643	2,647	2,650	2,653	2,656	2,659
Isolated Systems	81	82	83	84	85	86	87	88	89	90	91	92	93
Total Load + Losses	11,338	11,361	11,200	11,169	11,155	11,144	11,121	11,102	11,081	11,064	11,044	11,026	11,007
Self-Supply – NP	435	430	437	433	437	437	437	437	437	437	437	437	437
Self-Supply – Industrial	869	873	879	880	879	879	879	879	880	880	880	880	880
Total Self Supply	1,304	1,303	1,316	1,312	1,316	1,316	1,316	1,316	1,317	1,317	1,317	1,317	1,317
Hydro Net Supply, Interconnected Systems	9,954	9,977	9,801	9,773	9,755	9,742	9,719	9,699	9,676	9,658	9,637	9,617	9,598

Table 6: Synapse peak load forecast for Newfoundland Island and Labrador (MW)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Newfoundland Island - Total Load + Losses	1681	1725	1705	1700	1702	1706	1706	1706	1706	1707	1707	1707	1707
Self Supply - Industrial	84	82	80	80	80	80	80	80	79	79	79	79	79
Self Supply at Peak - NP	70	70	70	70	70	70	70	70	70	70	70	70	70
Hydro Peak Load for Newfoundland Island	1527	1573	1555	1550	1552	1556	1556	1556	1557	1558	1558	1558	1558
Labrador - Total Load + Losses[1]	398	392	389	390	390	391	391	392	393	394	394	395	396

Price Impacts on Load – Elasticity Effects

Once Muskrat Falls begins operation, customer prices are expected to increase substantially to cover the costs of building that facility. The magnitude of those increases is uncertain, as are the effects on customer loads. Econometric forecast models based on historical data with modest price changes are inadequate in capturing the effects of such large price changes. The options available to domestic and general service customers are few, as only fuel oil and wood are available as alternatives. The province is not well located for solar energy, especially for the winter peak. Most likely responses are conservation approaches (turning down the thermostat), energy efficiency improvements (CDM measures such as insulation), and improved technology such as heat pumps. Some large industrial customers, which are price sensitive, are at risk of converting to self-supply or relocation.

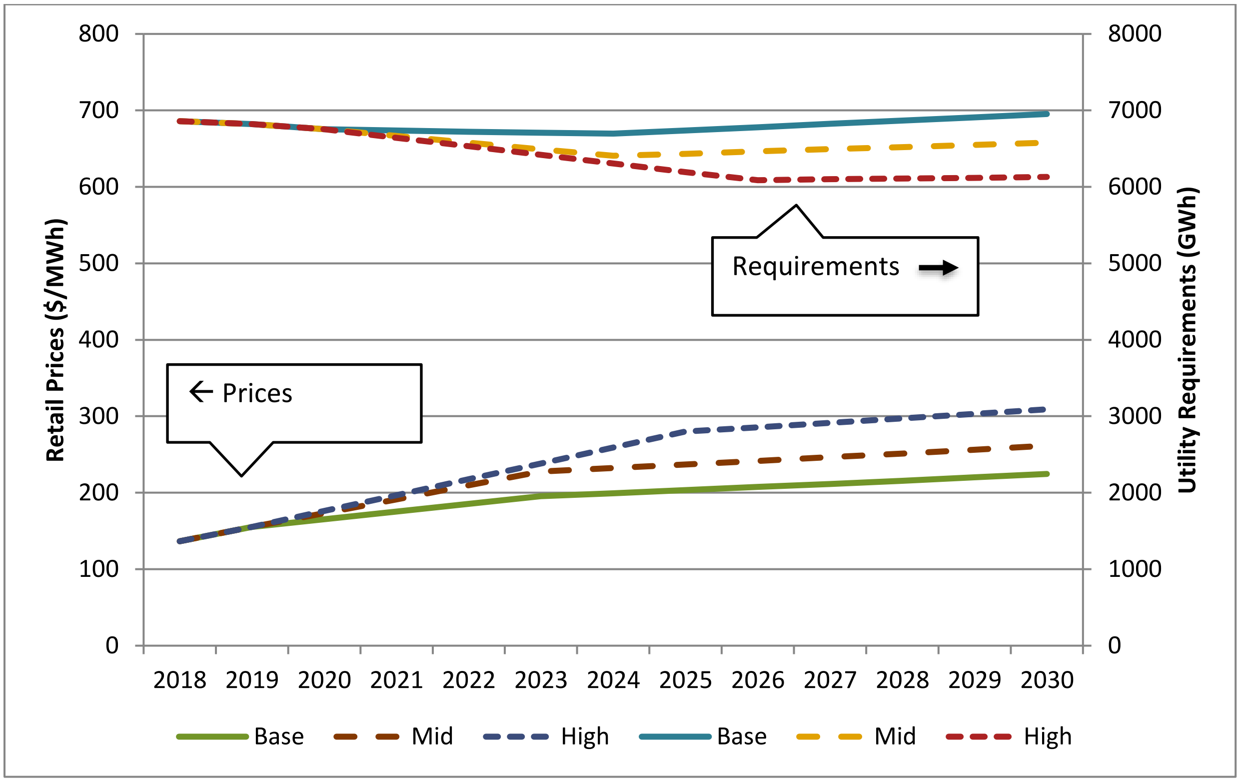
NLH has considered several future price and load scenarios. These represent the Utility (NP + NLH Rural) load and are illustrated in Table 7 and Figure 8.[15] For all cases, the starting price in 2018 is $137 per MWh. By 2030, the Base Case price is $225 per MWh and the High Case price is $309 per MWh, which is 38 percent above the Base Case. In the Base Case, the 2030 load is 1.4 percent greater than that of 2018. The load in the High Case is 12 percent below that of the Base Case. This implies a price elasticity of approximately -0.31. For example, a 2 percent increase in price will produce a -.62 percent change in load (calculated -0.31*2). This is consistent with the elasticity values given. We note, however, that those elasticity calculations are based on historical data and only modest changes in electricity prices. Large price increases may trigger more drastic responses and technology shifts. In such circumstances, an examination of end-uses and technology alternatives may be more informative.

Table 7: Island utility load forecast scenarios

	Retail Price ($/MWh)			Utility Requirement (GWh)		
Case	2018	2030	% Change	2018	2030	% Change
Base	137	225	64%	6,859	6,953	1.4%
Mid	137	262	91%	6,859	6,580	-4.1%
High	137	309	126%	6,859	6,130	-10.6%
High/Base		38%			-12%	

[15] Synapse, based on information from NLH.

Figure 8. NLH Island Utility Load Forecast Scenarios – Base, Mid and High Retail Prices



Source: NLH

4. ELECTRIFICATION

This analysis focused on electrifying the fuel consumption of three end-use sectors in Newfoundland and Labrador: residential heating, commercial heating, and transportation. We did not analyze industrial electrification due to a lack of data on which fuel-based industrial end uses can feasibly be electrified in the near-term. Phase 2 of our analysis can address this concern through additional research and information request processes and could result in an expansion of our overall estimation of increased electric consumption and decreased alternative fuel (i.e., oil) consumption.

For each of the three sectors, Synapse developed both a low and high electrification scenario to illustrate the potential range of future outcomes in Newfoundland and Labrador. The methodology for each sector, a summary of key assumptions, and appropriate next steps in this analysis are described in detail in the sections below.

4.1. Methodology

Residential Space Heating

The residential analysis evaluated the potential to electrify oil-heated homes by installing ductless mini-split air source heat pumps. Due to the prevalence of electric residential heating in Labrador (and its small number of homes overall), this analysis assumes that residential electrification to heat pumps will only take place on the Island. Currently the percentage of residences on the Island with oil heating systems is estimated at 15 percent.[16] The low scenario assumes that 0.4 percent of oil-heated homes convert to heat pumps per year, reaching 5 percent of homes by 2030; the high scenario assumes that 2 percent of oil-heated homes convert to heat pumps per year, reaching 24 percent by 2030.

Annual historical oil consumption data and projections are available for Newfoundland and Labrador's residential sector from Canada's Energy Future Report.[17] The projections were used to calculate the annual GWh impacts for both the low and high scenarios. The electricity outputs from heat pumps were estimated using the average annual coefficient of performance (COP) of cold-climate air source heat pumps (ccASHP) in Newfoundland and the average efficiency of the existing oil system. The average annual COP was estimated based on hourly weather data and a detailed COP performance curve for cold climate heat pumps. This is described in more detail in Section 4.2.

Peak impacts from residential heat pumps were estimated by estimating the peak energy use by a heat pump and calculating a "peak factor" (in MW peak load per GWh annual consumption) for ccASHPs

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[16] Synapse information from Hydro on Home Heating Fuel Shares.

[17] Canada's Energy Future 2018, "End-Use Demand: Reference Case", Region: Newfoundland and Labrador. Available at: https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

running in Newfoundland's climate. This peak factor was multiplied by the total annual energy consumption by residential heat pumps, yielding the total annual peak impact.

Commercial Space Heating

The commercial analysis evaluated the electrification potential of oil-heated small, large, and institutional (e.g., universities, K-12 schools, hospitals) commercial buildings in both the Island and Labrador Interconnected Systems. This analysis assumes that small and large commercial buildings will convert to heat pumps, whereas institutional buildings will convert their existing oil boilers to electric resistance boilers. The low scenario assumes that 0.4 percent of oil-heated commercial buildings convert to heat pumps each year, reaching 18 percent of those buildings by 2030; the high scenario assumes that 4 percent of oil-heated commercial buildings convert to heat pumps each year, reaching 60 percent by 2030.

The commercial sector analysis was conducted in a manner similar to the residential sector analysis. Annual historical oil consumption data and projections for Newfoundland and Labrador's commercial sector were first taken from Canada's Energy Future Report. The oil energy consumption per square foot was calculated using these data and assumptions about the percentage of oil-heated small, large, and institutional commercial buildings. Because fuel consumption data was not available by square foot for commercial buildings, this analysis assumes that small and large commercial buildings are approximately 30 percent oil-heated, while institutional commercial buildings are 100 percent oil-heated. These values can be refined upon the collection of additional data to inform these values.

The only exception to this methodology was for a large institutional facility in St. John's, which is considering adding two 10 MW electric resistance boilers to its central heating plant, replacing a portion of its oil consumption.[18] The low scenario assumes one electric boiler is added in 2020, replacing half of the institution's oil consumption. The high scenario assumes a second boiler is added in 2023, replacing an additional 25 percent of the institution's oil consumption. We assume that the institution will continue to use some oil during on-peak hours to avoid high electric demand charges. For this reason, we also make the critical assumption that the large institutional facility's boiler conversion does not impact winter peak.

For small and large commercial buildings, the calculated energy impacts were estimated using the average annual COP of ccASHPs in Newfoundland used for the residential analysis and the average efficiency of the existing oil system. For institutional buildings switching to electric resistance boilers, the energy impacts were only adjusted for the average efficiency of the existing oil system.

Peak impacts were calculated using the same approach described for the residential sector. "Peak factors" were calculated for both heat pumps and electric resistance boilers and then multiplied with the respective energy usage from heat pumps and electric boilers.

[18] Based on a preliminary conversation with Newfoundland and Labrador's Department of Natural Resources..

Transportation

The transportation analysis evaluated the electrification potential of existing light-duty vehicles, medium-duty vehicles, and ship berths for shore-side power. Heavy-duty vehicles were not analyzed because a commercially viable electrified technology is not expected to be available in the near-to-medium term.

Light-Duty Vehicles

For this analysis, light-duty vehicles include cars and light trucks.[19] The electrification potential of light-duty vehicles was calculated using Synapse's in-house tool EV-REDI.[20] This tool applies a technology adoption curve to historical electric vehicle adoption data, predicting electric vehicle adoption into the future. The tool can also fit the technology curve to a specific fleet target (e.g. 30 percent of stock is electric vehicles by 2030).

For both the low and high adoption scenarios, Synapse used Newfoundland's historical electric vehicle adoption data to develop the early portion of the technology curve.[21] For the high scenario, we assume that the remainder of the curve follows the projected trajectory electric vehicle adoption in Canada (as determined by the EV-REDI model), as a percentage of stock. The low scenario assumes the high scenario curve is delayed by five years. By 2030, 7 percent of light-duty vehicles are electrified in the low scenario and 34 percent are electrified in the high scenario.

The model calculates the GWh of wholesale electricity consumed by the electric vehicles and the gallons of avoided gasoline as a result of displaced gasoline vehicles. The results were adjusted slightly for vehicle performance variations due to temperature. To determine the impacts on IIS and LIS, the total province results were scaled based on the percentage of the population in each location.

Based on charging patterns from residential customers in locations with TOU electricity rates, approximately 5 percent of charging occurs on-peak.[22] This value was used to calculate the approximate impact of light-duty vehicle charging on critical winter peaking periods.

Medium-Duty Vehicles

The medium-duty vehicle electrification analysis included school buses, transit buses, intercity buses, and delivery trucks—those that are most likely to be electrified by 2030. These vehicle types are all

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[19] Light trucks include SUVs and pick-up trucks. All other passenger vehicles (e.g., sedans) are considered cars. The analysis assumes that cars and light trucks are electrified at the same rate and that the average vehicle lifetime is eleven years.

[20] The model assumes that half of electric vehicles sold in Newfoundland are battery electric vehicles (BEV) and the other half are plug-in hybrid electric vehicles (PHEV). Moreover, we assume that 66 percent of the kilometers traveled by PHEVs are powered by electricity.

[21] Newfoundland electric vehicle stock was estimated based on this article: https://www.cbc.ca/news/canada/newfoundland-labrador/looking-for-a-place-to-plug-in-1.4625565

[22] Data taken from Pacific Gas & Electric TOU electric rates.

assumed to be fueled by diesel. The low scenario assumes that 1 percent of medium-duty vehicles are electrified annually, while the high scenario assumes that 5 percent of medium-duty vehicles are electrified annually.

Annual historical energy consumption data and projections are available by mode of transport through Natural Resources Canada.[23] The relevant transport mode categories available in this dataset include medium-duty trucks (e.g. delivery trucks), school buses, urban transit buses, and intercity buses. The projected annual energy usage was converted from petajoules (PJ) to equivalent GWh using calculated or published efficiency improvement factors to account for the relative efficiency of conventional and electric vehicles.[24] Like the light-duty vehicle analysis, the final energy consumption results were adjusted slightly for vehicle performance variations due to temperature impacts. The impacts for the IIS and LIS were scaled by population.

For this analysis, Synapse assumes that electrified medium-duty vehicles will not contribute to the critical winter peaking periods, given that the charging of fleets can be incentivized to be off-peak.

Shore-Side Power

The overwhelming majority of ship traffic in Newfoundland and Labrador travels into and out of St. John's port.[25] Therefore, Synapse did not evaluate the electrification of ship berths at any other port in the province. St. John's port recently completed the expansion of its Pier 17, which hosts two ship berths with shore-side power capabilities.[26] As such, Synapse assumed that the electrification potential of the port will begin in January of 2019. Because St. John's port has not historically been equipped with side-shore power, Synapse used the Hueneme Port in California as a proxy given its similarity in cargo volume. Because all berths at Hueneme Port have side-shore power, the St. John's 2019 electricity consumption potential was scaled by the percentage of berths at St. John's that have side-shore power (two of thirty-six berths).

In the low electrification case, St. John's port assumes that its on-shore power consumption increases by 10 percent annually. In the high electrification case, power consumption increases by 30 percent annually and the port is 100 percent electrified by 2030.

[23] Data taken from Canada's National Energy Use Database for the transportation sector, available here: http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=tran&juris=nf&rn=7&page=0

[24] Given their similar driving patterns, school buses and transit buses were assumed to have an equivalent efficiency improvement factor. For the same reason, intercity buses and delivery trucks were assumed to have an equivalent efficiency improvement factor.

[25] Newfoundland port information and comparisons available at: https://www.searates.com/maritime/canada.html

[26] https://sjpa.com/projects/pier-17/

For this analysis, Synapse assumes that side-shore power at St. John's port will not contribute to the critical winter peaking periods, given that ships at berth can adjust when they are using power. This assumption can be refined as electricity consumption data becomes available for Pier 17.

Avoided Fuel Costs

Electrification avoids consumption of gasoline from light-duty vehicles, diesel from medium-duty vehicles, heavy fuel oil from ships at port in St. John's, and heating oil from the residential and commercial sectors. Fuel costs were taken from Canada's Energy Future 2018 Report, using the low prices for the low electrification scenario and the high prices for the high electrification scenario.[27]

4.2. Summary of Key Assumptions

This section summarizes the key assumptions impacting the electrification results. Table 8 outlines the percentage of oil-heated buildings that have the potential to be electrified to either ccASHPs or electric resistance boilers. The assumptions pertaining to the share of commercial buildings that are oil-heated were developed out of necessity given a lack of data, but ultimately have a large impact on the results. These assumptions can be adjusted upon collection of additional data.

Table 8. Shares of oil-heated buildings by sector

Building Type	% Oil-Heated	Source
Residential	15%	Discovery Response
Commercial, Small	30%	Assumption
Commercial, Large	30%	Assumption
Commercial, Institutional	100%	Assumption

Table 9 summarizes the performance assumptions of the technologies evaluated in the electrification analysis. The ccASHP COP is calculated based on a Cadmus report summarizing temperature-based performance of ccASHPs[28] and hourly weather data for St. John's in a typical weather year.[29] The three remaining parameters are assumed based on typical efficiencies for the technologies. For oil system efficiency, Synapse assumed that the average efficiency for existing oil systems will be slightly less than the Canadian performance standard for new oil boilers, which at this time of this report is 84 percent efficiency.[30]

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27 Canada's Energy Future 2018, "End-Use Prices," Region: Newfoundland and Labrador. Available at: https://apps.neb-one.gc.ca/ftrppndc/dflt.aspx?GoCTemplateCulture=en-CA

28 Cadmus. 2016. *Ductless Mini-Split Heat Pump Impact Evaluation*, December 30, 2016.

29 Canadian Weather Energy and Engineering Datasets (CWEEDS). Available at: http://climate.weather.gc.ca/prods_servs/engineering_e.html

30 Natural Resources Canada. https://www.nrcan.gc.ca/energy/regulations-codes-standards/products/6929

Table 9. Key technology performance assumptions

Electrification Parameter	Value	Source
ccASHP Average COP	2.86	Calculated
Annual COP Improvement Rate	2%	Assumption
Diesel Genset Efficiency (Ships)	50%	Assumption
Existing Oil System Efficiency	80%	Assumption

A summary of electrification growth rates by sector is provided in Table 10. The annual electrification rates were adapted from typical growth rates seen in regions in the United States that have shown either slow or fast adoption of electrification technologies. These rates are intended to represent a realistic lower and upper bound on the rate of electrification for each sector, though there is some uncertainty about how well the selected rates directly apply to Newfoundland and Labrador.

An annual electrification growth rate is not provided for light-duty vehicles due to the use of a non-linear technology growth curve in the EV-REDI model. Moreover, the electrification penetration in the commercial sector by 2030 does not scale with the annual growth rate largely due to the installation of one or two electric resistance boilers at a large institutional facility.

Table 10. Electrification growth rate assumptions by sector

Sector	Annual Electrification Rate		Electrification % by 2030	
	Low Scenario	High Scenario	Low Scenario	High Scenario
Residential	0.4%	2%	5%	24%
Commercial*	1%	4%	18%	60%
Light-Duty Vehicles**	-	-	7%	33%
Medium-Duty Vehicles	1%	5%	12%	60%
Shore-Side Power	15%	30%	25%	100%

*Commercial electrification by 2030 does not scale with the annual growth rate due to a large institutional facility.
**LDV electrification does not grow linearly, therefore an annual electrification rate is not provided.

4.3. Results

The results presented below are highly dependent upon the assumptions described in the previous section and the uncertainty associated with each of the assumptions. These results are the best approximation of the electrification impacts based on the information available to the analysis at the time of this report.

The electrification analysis results are presented firstly in the context of the low and high electrification scenarios. Within the scenario results, the distinct impacts to the IIS and LIS electric systems are outlined in detail.

Low Electrification

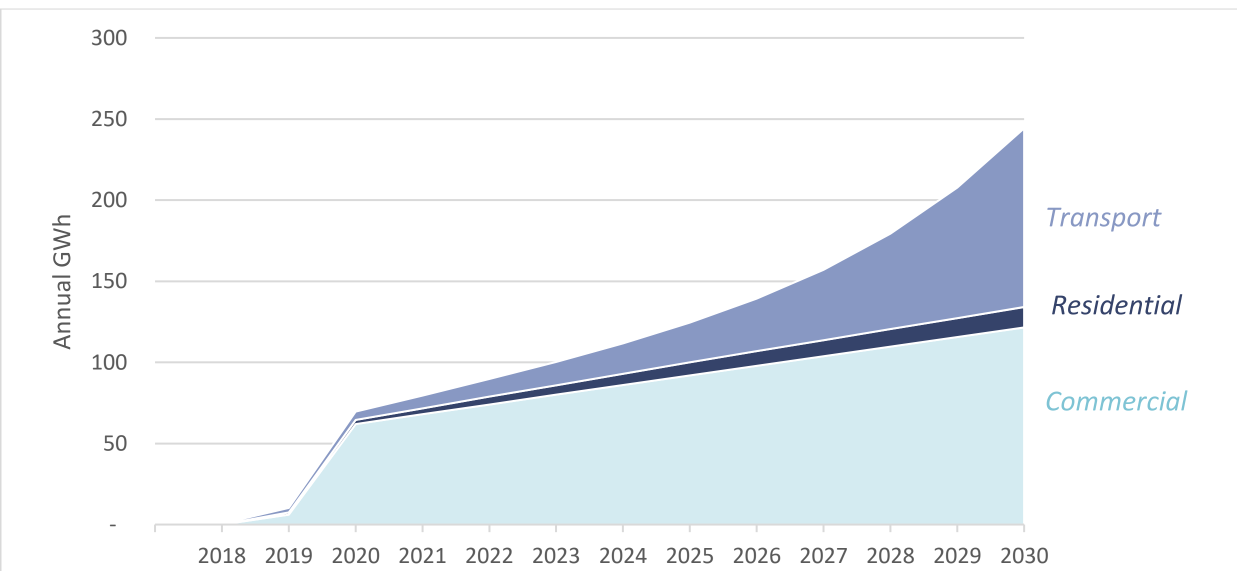
Under the low electrification scenario, energy and peak impacts in the province are expected to reach 245 GWh and 29 MW by 2030, respectively. The IIS will experience nearly 230 GWh of increased energy consumption and 25 MW of peak impacts due to electrification, representing 94 percent of energy impacts and 88 percent of the peak impacts in the province.

Figure 9 illustrates the relative contributions from each of the three end-use sectors on electrification by 2030. Commercial building electrification dominates the total energy impacts from the three sectors, contributing 121 GWh by 2030. Institutional buildings make up approximately 90 percent of the electrification potential in the commercial sector, due in part to the assumption that all institutional buildings are currently heated by oil (whereas we assume 30 percent of small and large commercial buildings are heated with oil) and the assumption that institutional buildings will convert to electric resistance boilers, which use three to four times more energy than ccASHPs. Commercial building electrification also dominates the peak load impacts, comprising 86 percent of the total peak impacts in 2030. The step-wise increase in energy impacts between 2019 and 2020 is a result of the addition of a 10 MW electric boiler at a large institutional facility in St. John's.

Transportation electrification contributes slightly less energy than the commercial sector, at 110 GWh by 2030. Light-duty vehicle electrification comprises 81 percent of the energy impacts at 89 GWh; medium-duty vehicles contribute 21 GWh and shore-side power contributes less than 1 GWh.

Residential heating electrification makes up the smallest portion of energy and peak impacts at 13 GWh and 5 MW in 2030, respectively.

Figure 9. Low electrification scenario results by end-use sector



Note: Graph reflects year-over-year electrification potential.

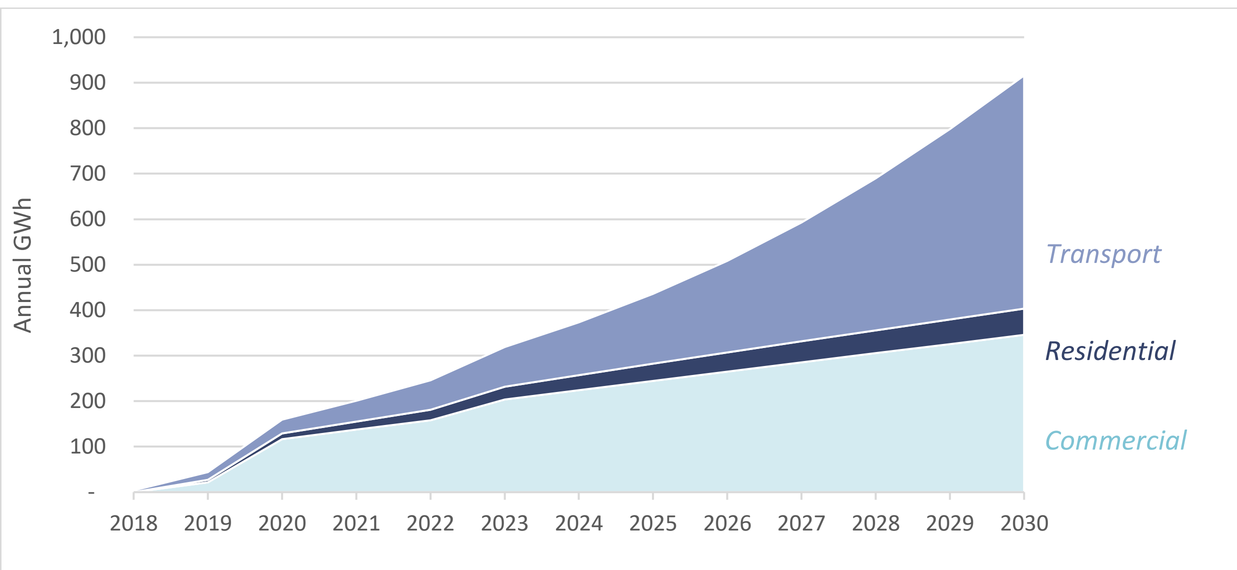
High Electrification

Under the high electrification scenario, energy and peak impacts in the province are expected to reach 916 GWh and 109 MW by 2030, respectively. The IIS will experience nearly 845 GWh of increased energy consumption and 95 MW of peak impacts due to electrification, representing 92 percent of energy impacts and 87 percent of the peak impacts in the province.

Figure 10 illustrates the relative contributions from each of the three end-use sectors on electrification by 2030. The primary difference between the high and low electrification scenarios is that transportation electrification dominates the energy impacts of the high scenario, contributing 512 GWh of energy impacts (56 percent). Light-duty vehicle electrification comprises 78 percent of the energy impacts at 400 GWh; medium-duty vehicles contribute 112 GWh and shore-side power contributes 2 GWh. Transportation only contributes 10 MW (9 percent) of peak impacts, while the commercial sector represents 38 percent of energy impacts and 78 percent of peak impacts. Like the low scenario, institutional buildings comprise a significant portion of both energy and peak impacts in the commercial sector. The step-wise increases in energy impacts between 2019 to 2020 and 2022 to 2023 are a result of the addition of two 10 MW electric boilers at a large institutional facility in St. John's.

Residential heating electrification makes up the smallest portion of energy and peak impacts at 58 GWh and 24 MW in 2030, respectively.

Figure 10. High electrification scenario results by end-use sector



Note: Graph reflects year-over-year electrification potential.

Avoided Fuel Costs

Avoided fuel costs from electrification in Newfoundland and Labrador are presented in Figure 11. Electrification avoids consumption of gasoline from light-duty vehicles, diesel from medium-duty vehicles, heavy fuel oil from ships at port in St. John's, and heating oil from the residential and commercial sectors. By 2030, the low scenario is expected to save a total of $48 million (2018 C$), while the high scenario is expected to save $300 million.

Figure 11. Avoided fuel costs as a result of low and high electrification scenarios

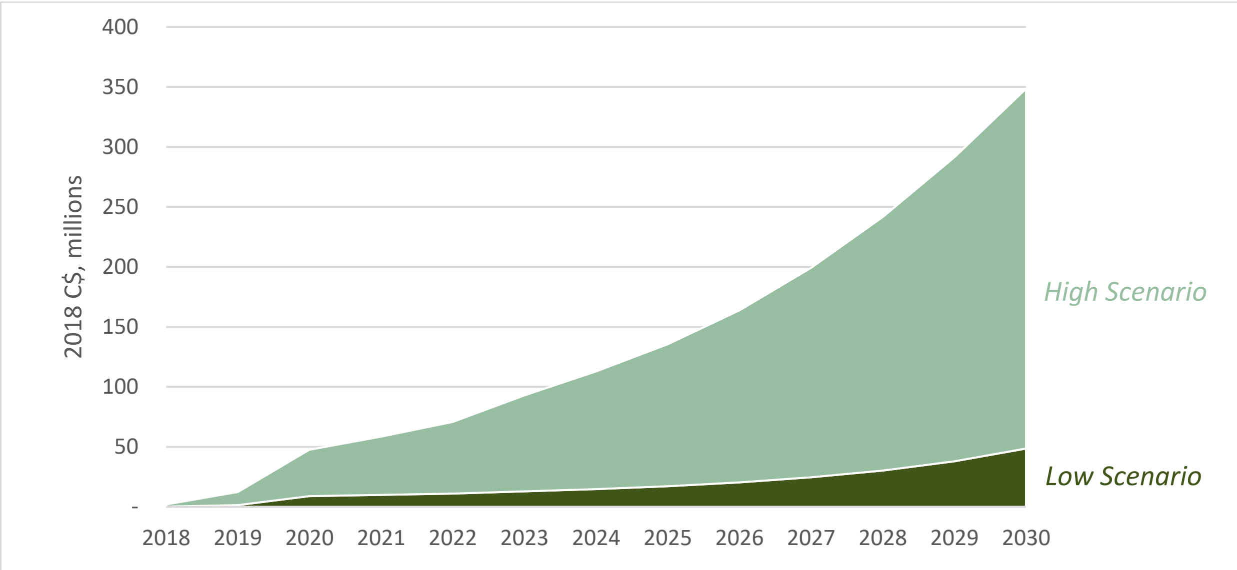


Illustration of Electrification Revenue Potential

Table 11 below illustrates the level of potential revenue resulting from electrification, based on the estimated "high electrification scenario" and an illustrative-only electricity rate that might apply to new consumption from electrification. We emphasize that this estimation—using an average 2018 rate of 10 cents per kWh, inflated by 2 percent per year out to 2030—is only intended to demonstrate an order of magnitude revenue return from increased end uses that currently rely on oil. Actual rate design, rate setting for "new" uses, and related policy constructs could lead to rates that are different from the level used for this estimation. New electric uses from existing oil-fired end uses (a) could be placed in the same rate class as currently used, with identical rates; (b) could be subject to new TOU rate structures; (c) could reflect a form of economic development rate that incentivizes new electricity use through lower rates that might sunset after a defined period of time; or (d) could reflect some other construct. This illustration is not intended to reflect such concerns. In addition to economic efficiency, equity issues across customers and customer sectors would, and should, be considered when thinking of rate structures applied to increase the level of electrification.

Table 11. Estimate of increased revenues from high electrification scenario

Year	2018	2019	2020	2025	2030
Increased Electricity Consumption (GWh)					
Commercial	0	21	117	245	346
Residential	0	6	12	38	58
Transportation	4	16	30	153	512
Nominal Rates ($/kWh)					
Inflation	0%	2%	4%	14%	26%
Commercial	0.10	0.10	0.10	0.11	0.13
Residential	0.10	0.10	0.10	0.11	0.13
Transport	0.10	0.10	0.10	0.11	0.13
Gross Incremental Revenue ($000, nominal)					
Commercial	$ -	$ 2,159	$12,128	$27,983	$43,525
Residential	$ -	$ 638	$ 1,269	$ 4,328	$ 7,255
Transport	$ 366	$ 1,673	$ 3,136	$17,509	$64,483
Total	$ 366	$ 4,470	$16,533	$49,819	$115,262

Source: Synapse, illustrative example.

Next Steps

There are several assumptions that could be refined with additional data, but the two primary areas for improvement are the industrial and commercial sectors. Notably, the industrial sector is ignored in this analysis due to a lack of data pertaining to the end-uses of industrial fuel consumption. According to the Energy Future 2018 Study, the industrial sector is expected to consume significant quantities of oil that could, if converted to electricity use, represent a potential of at least hundreds of GWh per year, depending on assumptions one makes concerning the applicability of end uses for electrification and the adoption curves of such uptake. Depending on how many oil-based industrial processes can be electrified in the near-term, this sector could increase Newfoundland's electrification potential significantly by 2030.

There is potential for further refinement in the commercial sector assumptions as well. As mentioned previously, the percentage of commercial buildings (or commercial square footage) heated with oil is unknown. These parameters have a strong influence on the electrification results; therefore, data to constrain these numbers would be extremely useful. Finally, a better understanding of commercial building heating systems (e.g., percentage of square footage with forced air, hot water, or steam heating) would provide a more accurate estimate of how many commercial buildings would convert to heat pumps or electric resistance boilers.

Lastly, Phase 2 efforts will consider the net cost impact associated with incremental infrastructure expenditures required for any given level of increased electrification. Some of those requirements would likely be made privately, and some would be utility-specific or provided as public sector investment.

5. CONSERVATION & DEMAND MANAGEMENT

This section addresses potential savings and costs of energy efficiency through utility programs offering some combination of financial incentives, technical assistance, education, and contractor training. In Section 5.1, we address all energy efficiency measures other than heat pumps. Heat pumps are addressed separately from other energy efficiency measures, because they have shown enormous growth in the Province recently and we expect this trend continues. Section 5.2 includes discussion of application of heat pumps in settings where electric resistance heating is the primary heat source. Section 4 addresses heat pump applications that involve fuel switching.

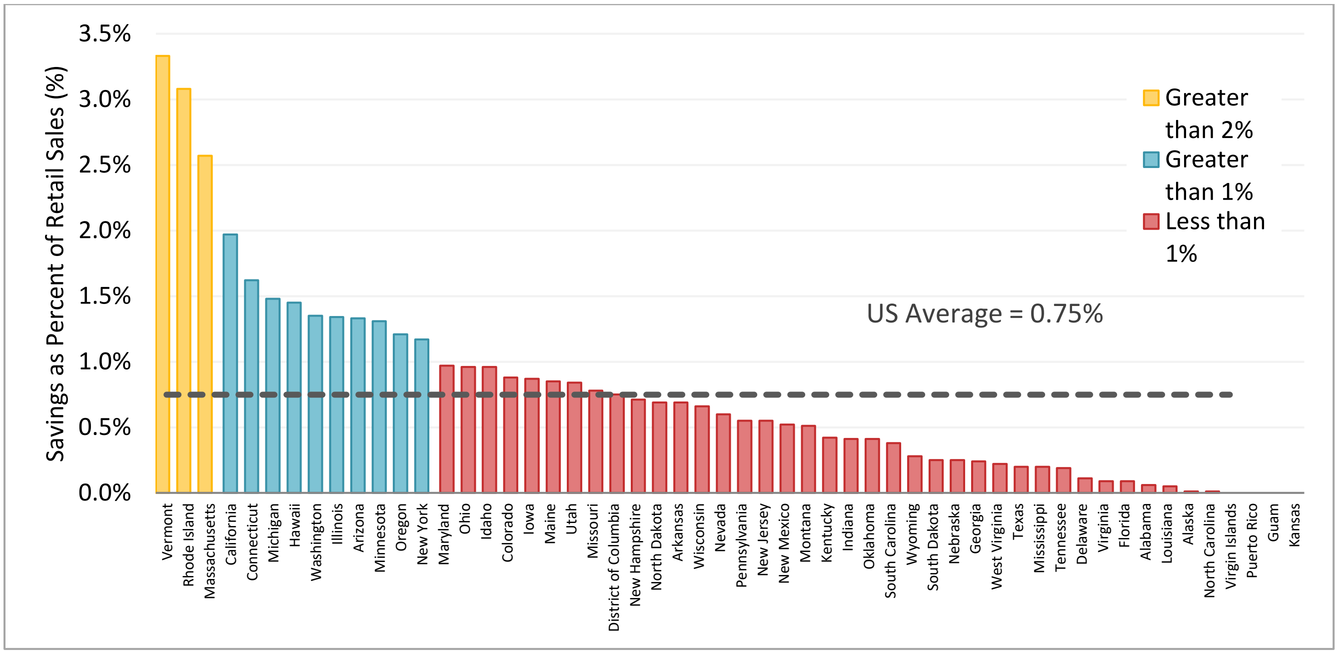
5.1. Energy Efficiency Excluding Heat Pumps

We developed three scenarios—low, mid, and high—for the roll out of programs implementing CDM measures other than heat pumps. We developed these CDM scenarios using two constraints: the rate at which program savings can be ramped up and the highest rate at which annual savings are sustained. Both are expressed as savings as a percent of sales.

Savings

The scenarios each assume annual savings (as a percent of sales) plateau at certain levels in Newfoundland and Labrador. We drew on the experience of other jurisdictions to inform these assumptions. Figure 12, below, shows savings as a percent of sales for U.S. states in 2017. On average, states attained incremental savings at 0.75 percent of sales in 2017.

Figure 12. Energy efficiency achievement of U.S. states in 2017

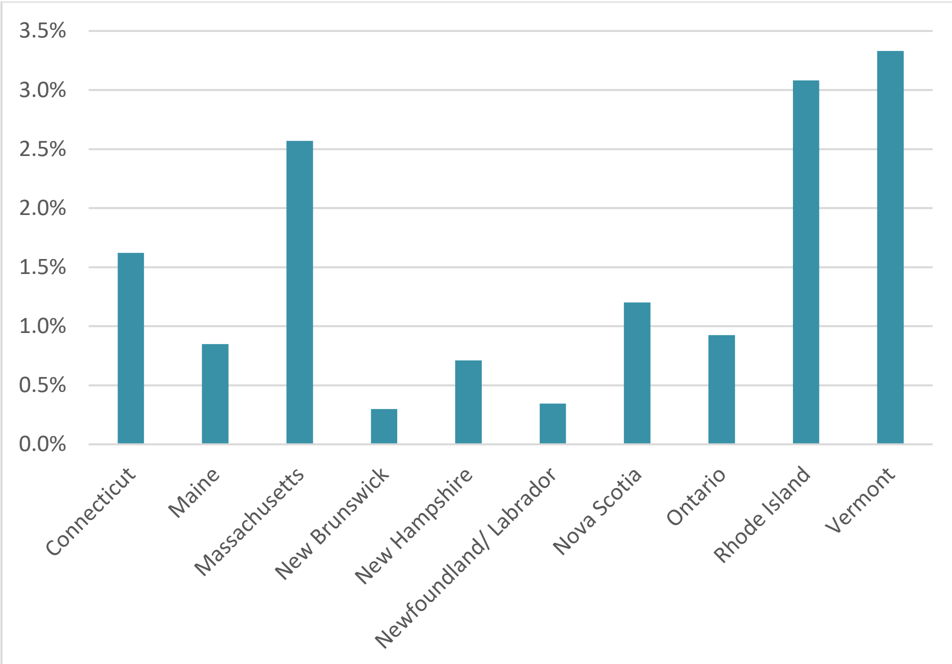


Source: ACEEE's the State Energy Efficiency Scorecard reports, http://aceee.org/state-policy/scorecard.

Figure 13 shows a sample of recent savings achievements in northeastern U.S. and Canadian jurisdictions. Achievements in 2017 by this sample of U.S. states ranged from a low savings of 0.7 percent of sales in New Hampshire to a high of 3.3 percent in Vermont. Programs with the highest savings levels—Massachusetts, Rhode Island, and Vermont—are mature programs; however, lighting measures account for a large portion of these states' recent savings achievements, which will likely decline in the coming years as federal efficiency standards reduce the amount of lighting savings that can be claimed by utility programs.

Recent savings achievements in the Canadian jurisdictions were somewhat lower, ranging from 0.3 percent in Newfoundland and New Brunswick to 1.2 percent in Nova Scotia. In 2016, Ontario's programs achieved 0.9 percent of sales. CDM programs in Ontario are offered in a challenging environment. Many local distribution companies serve electricity load so coordination can be difficult. While 2016/2017 savings in New Brunswick were only 0.3 percent of sales, New Brunswick Power is currently ramping up energy efficiency to attain higher savings levels in future years. Prince Edward Island, currently offering only educational programs and designing an efficiency portfolio, is not shown here.

Figure 13. Energy efficiency achievement of Northeast U.S. states and Canadian provinces in 2016 and 2017



Sources:

CT, MA, ME, NH, RI, VT: ACEEE's the State Energy Efficiency Scorecard reports

NB: New Brunswick Power responses to NBEUB IR-39, 49, and 51 in New Brunswick Matter No. 375

NL: NLH November. 5, 2018 CDM Overview presentation, NLH 2017 Conservation and Demand Management Report, NP 2017 Conservation and Demand Management Report, April 11, 2018, and NLH responses

NS: Efficiency Nova Scotia Evaluation of 2017 DSM Programs and Nova Scotia Power 2018 Load Forecast Report

ON: IESO 2016 Conservation Results Report and IESO Power Data Demand Overview

As discussed further in the next section, programs in the United States that are in the range of five to 10 years old have achieved incremental savings from 0.9 percent of sales to as high as 1.7 percent.

In Newfoundland and Labrador, we assume that savings from each scenario reach different levels for each sector and for each region, as described below.

Low CDM: For the residential and commercial sectors, the low case assumes that the historical 2017 CDM savings as a percent of sales is the highest amount that will be achieved. Savings for the industrial sector are assumed to top out at the 2011 to 2017 average savings as a percent of sales.[31] Savings levels were extrapolated between the island and Labrador based on historical CDM performance data for NP and NLH, adjusted to remove savings associated with NLH's isolated systems.

[31] In the province as elsewhere, industrial investments in energy efficiency have been intermittent and lumpy. Hence, we use the average value.

Mid CDM: The mid CDM scenario is assumed to reach as high as the mid-point between low and high scenario savings as a percent of sales.

High CDM: For the residential sector, the high scenario reaches savings levels that have been achieved in Nova Scotia for the residential sector.[32] For the commercial and industrial sectors, we draw on the 2015 ICF potential study findings for the highest level as a percent of sales achieved by the high scenario.

The highest levels of annual incremental savings as a percent of sales that are assumed for Newfoundland and Labrador are shown in Figure 14.

Figure 14. Assumed annual maximum savings levels by sector and region (% of sales)

	Residential	Commercial	Industrial
Low case			
Island Interconnected	0.6%	0.4%	0.3%
Labrador Interconnected	0.4%	0.2%	0.3%
Mid case			
Island Interconnected	0.9%	0.9%	0.7%
Labrador Interconnected	0.4%	0.8%	0.7%
High case			
Island Interconnected	1.2%	1.5%	1.2%
Labrador Interconnected	0.5%	1.5%	1.2%

Our assumptions for the highest annual savings levels to be reached in Newfoundland and Labrador are much lower than levels being achieved in several of the jurisdictions in the northeast United States, such as Vermont, Massachusetts, and Rhode Island. Our assumptions in Figure 14 take into account the anticipated decline in savings from lighting measures due to the phase in of federal lighting standards in the United States. Our mid case is roughly comparable to savings achievements in New Hampshire (0.7 percent), while the high case for the commercial sector approaches savings levels seen in Connecticut (1.6 percent).

Compared with Canadian jurisdictions, savings assumptions for the low case are roughly in line with what Newfoundland and Labrador and New Brunswick have achieved recently. The mid case

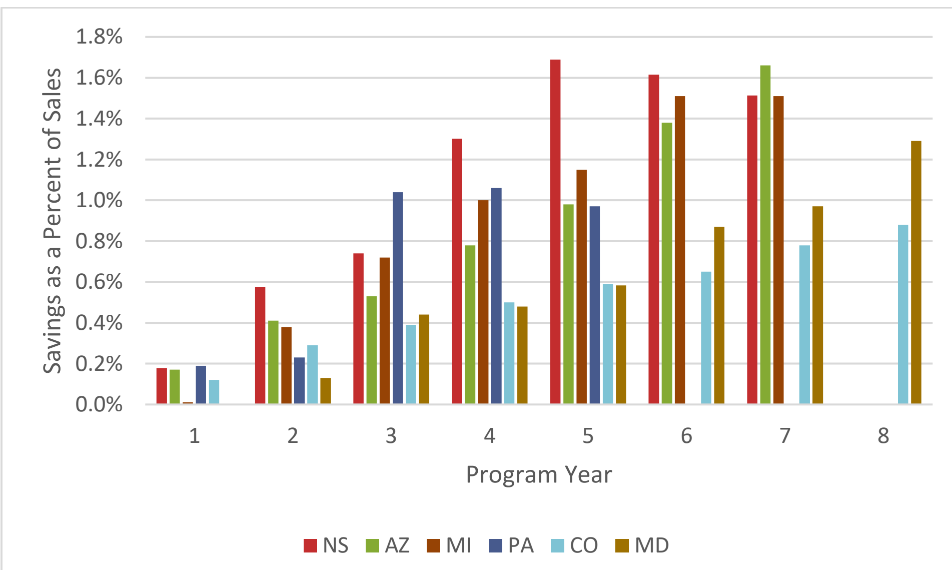
[32] In Nova Scotia, residential savings as a percent of sales in 2017 were 1.24 percent of sales for all programs and roughly 1.15 percent without the Green Heat program. The Green Heat program saw a dramatic increase in heat pump installations that year. In 2017, mini-split heat pumps constituted 87 percent of all Green Heat installations. Of the mini-split heat pump installations, electrically heated homes accounted for 81 percent. 19 percent were installed in previously non-electrically heated homes (Econoler 2018. *2017 DSM Evaluation Reports: Efficiency Nova Scotia*. p. 36).

assumptions are comparable to savings in Ontario, while the high case for most sectors is in line with savings achievements in Nova Scotia.

Our assumptions for savings achievements for the high case are based on ICF's Upper Achievable potential estimates for the commercial and industrial sectors, while our assumption for the residential sector is higher than ICF's high estimate. Based on our review of energy efficiency programs in other jurisdictions, we expect that the province can reach higher savings levels than what the ICF estimated for the residential sector. Therefore, we chose a higher assumption based on historical achievements. For the low case, we use lower assumptions for the industrial sector than ICF estimated for lower achievable potential for that sector, but higher assumptions for the residential sector to adjust for ICF's conservative participation assumptions.[33]

We assumed that CDM programs would be constrained in how fast their participation and savings levels could be ramped up. The assumed ramp rate for CDM programs reflects the experience of other jurisdictions that have programs that are new to moderately mature, in the range of five to 10 years old. We reviewed performance of several jurisdictions that have rapidly expanded their programs and increased annual energy savings in recent years.

Figure 15. Performance of a sample of jurisdictions with rapid growth programs



Source: ACEEE's the State Energy Efficiency Scorecard reports, http://aceee.org/state-policy/scorecard.

[33] ICF International reports: (1) *Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 Residential Sector Final Report*; (2) *Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 Commercial Sector Final Report*; (3) *Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 Industrial Sector Final Report*.

Figure 15 summarizes the increase in annual energy savings for programs in five U.S. states and one Canadian province, Nova Scotia. Over five to eight years, these programs quickly ramped up from essentially no annual incremental energy savings at the start to a range of 0.9 percent to 1.7 percent of sales at the end of the period. On average, the annual ramp-up in energy savings for these jurisdictions was roughly 0.2 percent of sales.[34]

Combining the ramp rate and savings cap, our scenarios assume that 2018 savings start at 2017 levels, then ramp up by 0.2 percent of sales each year until reaching the cap for the scenario.

Low CDM scenario:

Residential and commercial sectors on the Island have attained the highest levels for this scenario by 2018. Industrial savings start at the 2017 historical level (0 percent of sales) in 2018 and ramp up to 0.3 percent of sales in 2020.

Residential and commercial sectors in Labrador reach the highest assumed annual savings levels by 2018. Industrial incremental savings start at zero in 2018, based on savings attained in 2017, and ramp up to 0.3 percent of sales in 2020.

Mid CDM scenario:

Residential savings on the island top out in 2019, while commercial programs reach the maximum assumed level of 0.9 percent in 2021. Industrial savings start at the 2017 historical level (0 percent) in 2018 and ramp up to 0.7 percent of sales in 2022.

In Labrador, savings for the residential sector start at 0.4 percent in 2018 and remain at that level through the period of analysis, while the commercial programs start at 0.2 percent in 2018 and reach 0.8 percent in 2021, where they stay through 2030. Industrial incremental savings start at the zero in 2018 and ramp up to 0.7 percent of sales in 2022.

High CDM scenario:

On the Island, residential sector savings start at 0.4 percent in 2018 and reach the maximum assumed annual savings level for that sector, 1.2 percent of sales, in 2021. The savings for the commercial sector on the IIS start at current levels (0.4 percent) and reach their highest levels (1.5 percent of sales) in 2024. Industrial savings start in 2018 at the level achieved in 2017 (0 percent) and ramp up to annual incremental savings of 1.2 percent of sales in 2024.

In Labrador, residential sector savings start at 0.4 percent of sales in 2018, rise to 0.5 percent of sales in 2019, and remain at the 2019 level throughout the period. Commercial savings go from their current level of 0.2 percent in 2018 to 1.5 percent in 2025, where they remain for the duration of the period of analysis. Industrial savings start at zero in 2018, based on savings attainment in 2017. Industrial savings

[34] More mature programs in Rhode Island and Massachusetts have been able to ramp-up energy savings by about 0.4 percent of sales per year.

are assumed to reach their highest level (1.2 percent of sales) in 2024 and attain that level each year thereafter.

Monthly CDM savings are assumed to mirror historical monthly load profiles for each sector and region that we obtained from NP and NLH.

To estimate peak savings for each scenario, we calculated peak savings ratios in terms of kW per MWh based on the ICF potential study and historical peak savings. Given that the historical peak results are not on a coincident peak basis, we primarily rely on the peak savings factors based on the ICF potential study, slightly adjusted downward to account for historical results. These average peak savings ratios are applied to the energy savings for each scenario.

Cost of Saved Energy

We conducted a high-level analysis of cost of saved energy for this report to gain insight into the level of expected spending by scenario. We assume a first-year cost of saved energy of $0.27 per kWh for all sectors, based on historical Program Year 2017 costs of CDM incentives and program costs. This is consistent with the average first-year cost for industrial programs in the ICF potential study. This is somewhat higher than the average cost of conserved energy identified in the ICF potential study for the residential and commercial sectors. However, it is in line with the highest cost measure identified for the commercial sector and with the cost of conserved energy for the 90th percentile measure for the residential sector.

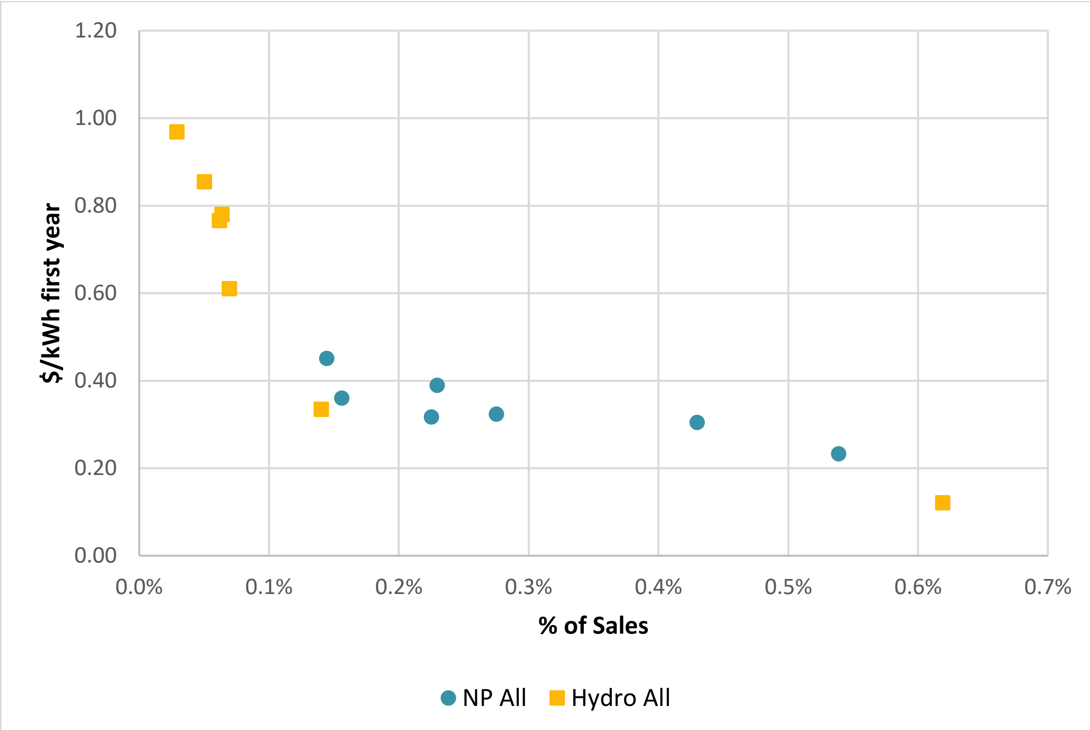
Historically, the cost of saved energy in the province has declined as energy savings have increased, as shown in Figure 16 below. This effect, which has been observed in many other jurisdictions, is likely due to improved economies of scale. Thus, it is possible that the cost of saved energy for the province may decline as the savings increase in the future. In this respect, our cost assumption is conservative.

As a comparison, Nova Scotia's portfolio first-year cost of saved energy was $0.23 per kWh in 2017, however Efficiency Nova Scotia is projecting an increase in the cost of saved energy. Efficiency Nova Scotia expects that the portfolio average cost per first-year kWh saved will be $0.25 per kWh in 2018 and will rise to $0.27 per first-year kWh in 2019.[35]

Amortized, this is equivalent to $0.05 per kwh at a 5 percent real discount rate, assuming a 7 percent weighted average cost of capital and a 2 percent general inflation rate. We use an amortization period of seven years consistent with standard cost recovery practice in the province.

[35] Efficiency Nova Scotia 2018, *ENS 2017 DSM Annual Progress Report*, p. 4; EfficiencyOne 2018, Response to Synapse IR-10 in M08604 (E-ENS-R-18), p. 8; and EfficiencyOne 2018, Evidence of EfficiencyOne as Holder of the Efficiency Nova Scotia Franchise in M08604 (E-ENS-R-18), p. 18.

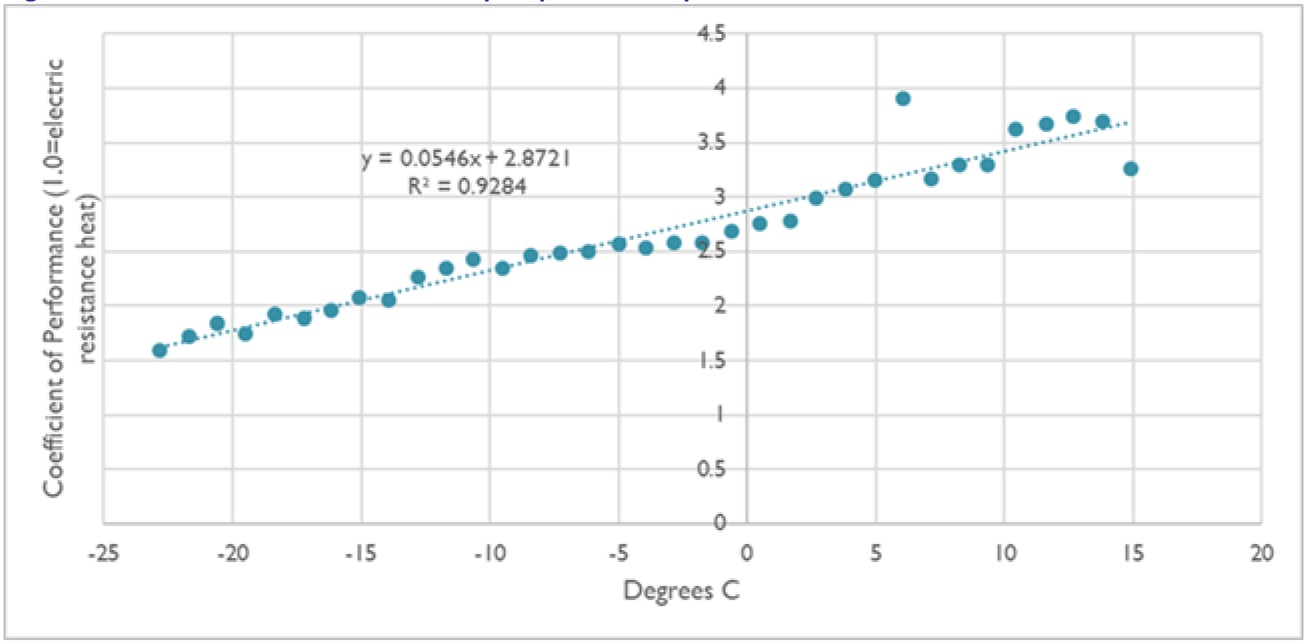
Figure 16. Cost of saved energy and savings as a percent of sales in Newfoundland and Labrador



5.2. Heat Pumps

Heat pumps are a more efficient method of producing heat from electricity than traditional electric resistance heaters. Figure 17 below illustrates the underlying technical reason this is so: heat pumps act as a reverse refrigerator, moving heat from colder areas (outside) to indoors and taking advantage of thermodynamic principles. The COP of a heat pump is a measure of how much heat it produces for interior conditioning relative to electric resistance heating. A COP of 1.0 is equivalent to producing heat at the same efficiency as electric resistance heaters. A COP of 2.0 illustrates that twice as much heat can be obtained for the same amount of electricity. The COP for heat pumps varies with the outdoor temperature—at warmer temperatures, more heat is available in the outside environment, and thus the COP is higher. Heat pumps designed to extract the maximum amount of heat from colder climates are known as cold climate heat pumps.

Figure 17. Illustrative cold climate heat pump COP - temperature curve



As with energy efficiency, we developed three scenarios—low, mid, and high—for adoption of heat pumps to replace or supplement electric resistance heating. These scenarios reflect our projections of total cumulative savings from heat pumps as a portion of sales in 2030 and a linear annual incremental savings rate to reach that level.

Savings

Synapse developed assumptions for total cumulative heat pump savings by sector and by region. In general, we find that ICF's estimates of achievable potential are too low, given the dramatic recent uptake of heat pumps on the Island.

High HP scenario

On the Island, we start with ICF's economic potential for heat pumps for the residential sector based on a $0.20 per kWh retail rate.[36] We assume that 80 percent of ICF's economic potential for that sector, less our estimate of current heat pump related savings not reflected in the ICF potential studies, is achievable. For the commercial sector, we calculate potential as 60 percent of ICF's estimate of commercial economic potential based on a $0.15 per kWh retail rate, minus our estimate of the heat pump-related savings that is not reflected in the ICF potential studies. The industrial potential draws directly from the ICF potential study's finding on achievable potential for heat pumps in HVAC and process heating end uses. The total high-scenario cumulative potential for heat pumps on the Island of

[36] We use $0.20 per kWh to reflect the expected electricity rate increase associated with the Muskrat Falls project, which was not factored into the ICF potential study.

Newfoundland for the residential, commercial, and industrial sectors is 5.3 percent, 4.9 percent, and 0 percent of the sector-specific base load forecasts, respectively.

In Labrador, we similarly draw on the ICF studies for all sectors. For the residential sector, we assume that 10 percent of ICF's reported economic potential for mini-split heat pumps can be installed by 2030.[37] This translates into 1.3 percent of the residential load. On the other hand, heat pump savings for the other sectors are based on the achievable potential estimates by the ICF potential studies. In Labrador, total assumed cumulative potential for heat pumps for the residential, commercial, and industrial sectors in the high scenario is 1.4 percent, 4.5 percent, and 0.1 percent, respectively.

Mid HP scenario

For both Newfoundland Island and Labrador, the mid HP scenario reflects the mid-point between low and high scenario HP savings potentials. On the Island, the mid-scenario assumptions for total 2030 heat pump potential are 3.4 percent, 3.6 percent, and 0 percent for the residential, commercial, and industrial sectors, respectively. In Labrador, total cumulative potential for heat pumps in the mid scenarios is assumed to be 0.8 percent for the residential sector, 3.1 percent for commercial, and 0 percent for the industrial sector.

Low HP scenario

On the Island, total 2030 cumulative potentials for the residential and commercial sectors are assumed to be half of the high case potential for those sectors, adjusted for Synapse's estimate of current heat pump related savings not reflected in the ICF potential studies. For industrial potential, we use the ICF potential study's finding on industrial lower achievable potential for heat pumps in HVAC and process heating end uses. The Island total assumed cumulative potential for heat pumps for the residential, commercial, and industrial sectors in the low scenario is 1.4 percent, 2.3 percent, and 0 percent, respectively.

For Labrador, we assume that 1 percent of residential economic potential for mini-split heat pumps can be installed by 2030. This translates into 0.1 percent of the total projected residential load that year. Savings for the other sectors are based on the lower achievable potential estimates by the ICF potential studies. Our assumptions for Labrador cumulative potential in 2030 are 0.1 percent, 1.6 percent, and 0 percent for the residential, commercial, and industrial sectors, respectively.

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[37] The ICF study estimated zero achievable potential savings for the residential sector in Labrador, likely based on its observation that the market for heat pumps in Labrador is unfavorable (ICF 2015, Appendix H, H-3). We find that this assumption is too conservative. We assume that a small percentage (10 percent) of the economic potential estimated in the ICF potential study is achievable.

Monthly savings from heat pumps reflect our estimates of monthly heat pump load profiles, which we developed using hourly weather and average COP data for cold climate heat pumps.[38],[39]

Our estimates of current heat pump energy savings are based on the current heat pump penetration rate for residential customers obtained from NP and our estimates of per unit heat pump energy savings relative to electric resistance heating. The customer data from NP shows that, as of partway through 2018, 13 percent of customers have installed heat pumps. Of these customers, 7 percent had heat pumps installed for the first time since 2016 (after the ICF potential study was conducted). We assumed that many customers use a heat pump as supplemental heating. To account for use of heat pumps as supplemental heating, we reduced our estimate of the full savings potential from heat pumps per household by 50 percent; this yielded an average heat pump savings per customer of approximately 6 MWh. The current penetration for the commercial sector in the Island Interconnected region is assumed to be just 5 percent of the current residential penetration rate.

To estimate peak savings for Newfoundland Island and Labrador combined, Synapse applied our analysis of hourly TMY-3 (Typical Meteorological Year, "3" indicating formatting of data elements) data for St. John's and Goose Bay, as well as heat pump performance curves. For Labrador, although our analysis estimated a 0.17 kW per MWh peak reduction factor, we assume zero reduction in peak load from heat pump uptake, to be conservative given the lower temperatures relative to the Island.

Cost of Saved Energy

Costs on the current heat pump loan program are not available and are not likely to reflect the cost of saved energy currently experienced by NP and NLH for technical assistance to contractors, education and outreach initiatives, and other support for the heat pump market. We assume no costs for these activities. We plan to further investigate these costs in the next phase of our work.

5.3. CDM Results

Figure 18 shows annual energy savings for the island under two scenarios, while Figure 19 shows annual energy savings for Labrador. Total potential savings in 2030 on the IIS show a more than two-fold difference between the low and high cases, ranging from 436 GWh to 1,111 GWh in 2030. On the LIS, total potential savings in 2030 also display a wide range, from 71 GWh in the low case to 224 in the high case.

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[38] We used St. John's weather station data for Newfoundland and the Goose Bay Airport station data for Labrador.

[39] Canadian Weather Energy and Engineering Datasets (CWEEDS). Available at: http://climate.weather.gc.ca/prods_servs/engineering_e.html

Figure 18. Island Interconnected annual energy savings (GWh) - Low Case (left) and High Case (right)

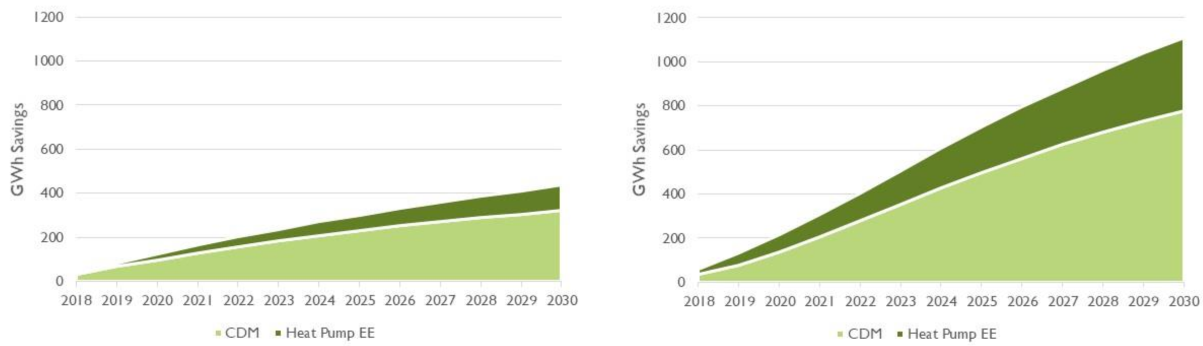


Figure 19. Labrador Interconnected annual energy savings (GWh) - Low Case (left) and High Case (right)

Savings associated with heat pumps comprise a significant share of savings in Newfoundland but a modest share of savings in Labrador. On the IIS, potential heat pump savings in 2030 range from 25 to 30 percent of total CDM savings, depending on the scenario (Figure 20). As shown in Figure 21, potential savings from heat pumps on Labrador account for 21 percent of total potential CDM savings in the low scenario but only 10 percent in the high scenario.

Figure 20. Island Interconnected - CDM annual energy savings summary by sector and scenario (GWh)

	CDM w/o HP		HP		Total CDM	
	Low	High	Low	High	Low	High
Residential	207	369	55	209	262	577
Commercial	80	280	60	125	140	405
Industrial	34	128	0	0	34	128
Total	321	777	115	334	436	1,111
% of Load	4%	10%	1%	4%	5%	14%

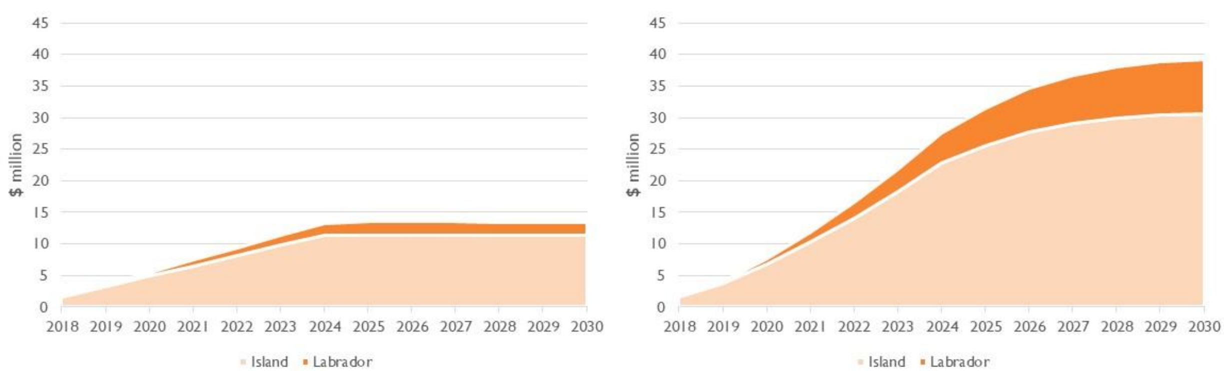
Figure 21. Labrador Interconnected - CDM annual energy savings summary by sector and scenario (GWh)

	CDM w/o HP		HP		Total CDM	
	Low	High	Low	High	Low	High
Residential	12	14	3	5	15	19
Commercial	5	38	11	17	16	55
Industrial	40	149	1	1	40	151
Total	57	202	15	23	71	224
% of Load	2%	8%	0%	1%	3%	9%

As shown in Figure 20, above, total CDM savings on the IIS are 14 percent of projected 2030 load for the high case, but only 5 percent of 2030 load in the low case. Figure 21 shows that total CDM savings on the LIS range from 3 percent in the low case to 9 percent in the high case.

The costs of the different cases vary roughly threefold between the low and high cases, as shown in Figure 22. In the low case, total CDM costs across both regions are projected to be $13 million in 2030, with CDM costs for the LIS accounting for a small fraction of that total ($2 million). In the high case, total costs for CDM programs are $31 million for the IIS and $9 million for LIS.

Figure 22. Projected annual program costs for CDM programs - Low Case (left) and High Case (right) ($ million)



5.4. Rate and Bill Impacts of Increased CDM

CDM offers customers the opportunity to reduce their overall energy consumption and bills, even faced with an increase in rates. CDM is unique among utility investments in that it empowers customers to manage their bills. Particularly in Newfoundland, opportunities to participate in CDM should be expanded so that the benefits of CDM are spread to the vast majority of customers over time.

As discussed elsewhere in this report, we anticipate a shift in the province's avoided cost profile toward lower energy costs and higher capacity costs tied to export energy. This shift in avoided costs has implications for the design, delivery, and cost effectiveness testing of CDM programs. Future CDM studies, including the potential study currently underway, should consider the benefits and costs of both conventional CDM and demand response resources that provide energy reductions on peak, given the new avoided cost profile.

Next Steps for Our CDM Potential Analysis

- **Impacts of increased electricity rates on the island on CDM programs**: For the current report, we investigated the impact of higher electricity rates on heat pump efficiency measure adoption on the island using ICF's residential and commercial potential studies. We plan to further refine this analysis, as well as estimate the impact of higher electric rates on other CDM measures, especially on the island.

- **Costs of saved energy**: Our preliminary analysis used the cost of saved energy from the 2017 CDM programs at the portfolio level. Also, we assumed no program costs for heat pump efficiency measures, reflecting the high levels of activity in the market for heat pumps in the recent months despite minimal program intervention. In the second phase, we plan to conduct more detailed analyses of costs of saved energy by sector and of the magnitude of economies of scale for expanded CDM programs. We will also investigate whether additional programmatic assistance (e.g., education, training, incentives, loans, etc.) is needed to support uptake of heat pump efficiency measures, and if so, the associated costs.

- **Heat pump efficiency potential methodology and assumptions**: We plan to refine our heat pump efficiency potential methodology in the second phase in the following areas:

    - In our preliminary analysis, we adjusted the results of the ICF potential studies for heat pump efficiency measures for different avoided costs. However, significant uncertainty about the adoption rates for heat pumps remains and is not fully reflected in the initial analysis. In the second phase, we plan to investigate detailed electricity end-use consumption data, avoided costs, and customer adoption rates. We will consider refining our methodology and assumptions.

    - In cases where we drew on ICF's economic potential estimates, our estimates of heat pump savings do not take into account potential interactive effects with other CDM measures. In the second phase, we plan to incorporate these effects into our heat pump efficiency potential estimates.

- **Peak reduction factors**: The preliminary analysis estimates peak reductions from CDM using portfolio-level peak reduction factors based on the ICF potential studies and recent historical CDM program data. Peak reduction potential differs by measure mix and sector. In the second phase, we plan to investigate this area further and break out peak reduction factors by sector and by region.

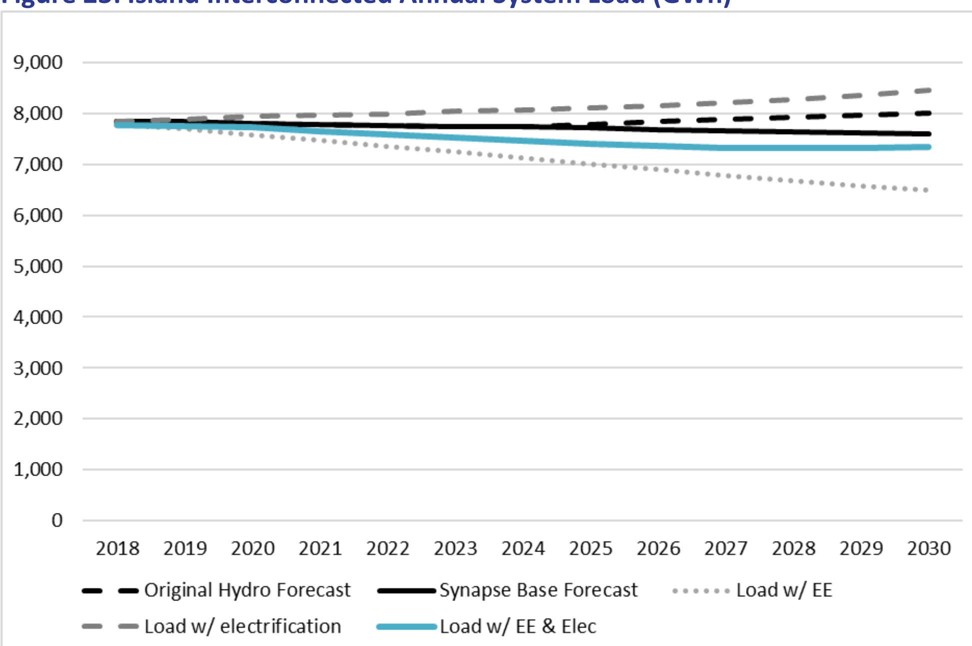
- **Embedded CDM impact in the base load forecast**: Some of the historical CDM impacts may be embedded in the base load forecast, since the NP and NLH's load forecast underlying our load forecast and analysis were developed using a regression of historical load data. While the long-term historical CDM impact is small when compared to what we expect in the future—particularly for the high case scenario--we will further investigate the extent to which CDM impacts are embedded in the base forecast. This includes impacts of heat pump conversions from electric resistance and oil heating.

6. Export Market Revenue Opportunities – Surplus Capacity and Energy

6.1. Approach

Our approach to determine Provincial net load[40] input assumptions for use in estimating export market revenue opportunities for surplus energy was described in detail in Section 2. Export volumes available for sale depend on the level of such net load. Figure 23 below demonstrates, for the IIS, the variation in eventual load depending on the level of CDM and electrification considered.

Figure 23: Island Interconnected Annual System Load (GWh)



Source: Synapse

In summary, the volume of energy exports available to sell after Muskrat Falls comes online in 2020 consists of the total available energy in the Province, less the total required energy necessary to meet

[40] Provincial net load in this instance is the sum total of requirements NLH must meet, after accounting for customer self-generation, losses, and the effects of changing levels of CDM and electrification, as modeled.

industrial, commercial, and residential loads[41] and makeup transmission and distribution losses within the Province. This high-level energy balance is affected by the level of loads and available energy that varies month-to-month, over the course of any given day, and across the years. It is also affected by the presence of transmission constraints: broadly speaking, within the Province, primarily between Labrador and the Island;[42] and outside of the Province, based on either the level of available transmission through Quebec, or the headroom[43] on the Maritime Link for flows south towards Nova Scotia and markets beyond (potentially New England or the other Maritime Provinces).

This analysis uses monthly energy flow balances to estimate net export energy volumes and the potential revenue available from those volumes, based on estimated market prices. The monthly volumes are split between on-peak and off-peak periods. Peak periods are non-holiday weekdays between 7AM and 11PM; off-peak periods are overnight and weekend hours. Actual peak loading periods in the Province occur in the winter, generally during well-defined morning and evening hours.

The ability to make energy available for export in the higher-priced hours—generally, peak hours—will depend in part on storage and inflow characteristics of hydroelectricity capability in Newfoundland and Labrador. It will also depend on the relative demand from customers during on-peak and off-peak hours. In Phase 2 of this analysis, we will use a more granular analytical tool—Plexos production cost analysis software, most likely—to more rigorously track the ability of the energy supply sources in the Province to provide as much available energy during higher-priced hours relative to energy sold during lower-priced hours. For this Phase 1 analysis, our approach is less granular in determining the volumes available for sale (we use monthly data) and more granular in allocating those volumes to different markets (we split between on-peak and off-peak hours). In Phase 2 we will be able to better capture on-peak/off-peak granularity within any given month on the energy availability side, and thus better estimate the timing effects associated with CDM and electrification profiles across the hours of any given day.

Synapse's spreadsheet model to determine export energy volumes and value those volumes at market prices accounted for the "best" first market into which to sell excess volumes. Subsequently, Synapse's model "sold" the next tranche of surplus energy into the next best market, while accounting for transmission constraints. Transmission constraints primarily affect how much export volume can be directed to any given market destination based on the paths out of the Province (i.e., via Quebec or Nova Scotia). But they can potentially also affect flows between the Island and Labrador. After first describing Newfoundland and Labrador's resources in the next subsection, we present the results of our

41 Net of the self-generation used to meet part of industrial and Newfoundland Power loads.

42 I.e., the Labrador Island Link. For this Phase 1, we have not addressed potential transmission constraints that could affect flows on the Island between supply sources and load or affect flows between generation sources and load in Labrador. We anticipate more rigorous analysis in 2019 that could refine export energy estimates to account for these variables.

43 In this instance, "headroom" refers to availability for flow after meeting the obligated NS block and NS supplemental energy requirements.

analysis of different scenarios of "net" loading in the Province. These cases reflect various scenarios in which consumption increases due to electrification and consumption decreases due to CDM.

6.2. Resource Availability

Table 12 below is a snapshot of the NLH/Nalcor resources available in the Province to meet net load and to export to external markets. The energy volumes and capacity capabilities were obtained from Hydro's Reliability and Resource Adequacy Study, dated November 16, 2018 and filed with the Board, and the monthly patterns assumed for export market assessment were based on supplemental information provided by NLH. The table includes Holyrood Steam capacity, summarizes resource availability with and without the units, and excludes energy available from Holyrood (steam) based on the assumption that it will retire during 2021.

Table 12. Resource summary, post-Muskrat Falls, post-Holyrood Steam retirement

Resource Name	Installed Capacity (MW)	Gross Continuous Capacity, MW	Annual Energy (normal), GWh
TwinCo	225	225	1,971
Recapture	300	300	2,416
Muskrat Falls Project	824	790	4,936
Happy Valley GT	25	25	-
Subtotal Labrador Interconnected System	1,374	1,340	9,323
Bay d'Espoir	613	613	2,653
Cat Arm	137	134	754
Hinds Lake	75	75	353
Granite Canal	40	40	245
Paradise River	8	8	35
Upper Salmon	84	84	556
Mini Hydro	4	4	4
Exploits - GF/BF	96	63	615
Exploits -Star Lake	18	18	142
St. Lawrence wind	27	12	105
Fermeuse wind	27	12	84
Rattle Brook	4	-	15
CBPP cogen.	15	8	67
New World Dairies	-	-	4
Holyrood Steam	490	490	-
Holyrood GT	124	124	9
Hardwoods GT	50	50	-
Stephenville GT	50	50	-

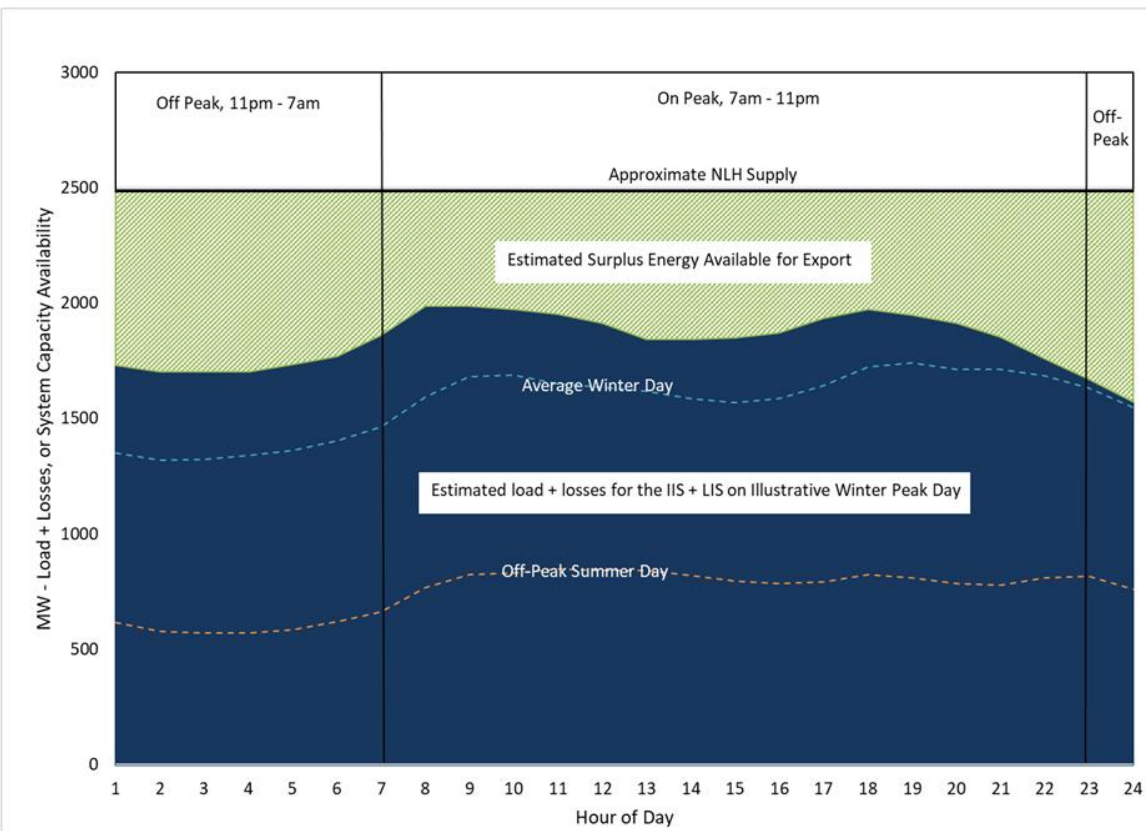
Diesels	27	23	1
Subtotal Island Interconnected System	1,888	1,808	5,641
Newfoundland + Labrador	3,262	3,148	14,964
Without Holyrood Steam	2,772	2,658	14,964
Excluding NS Block/Supp + Holyrood Steam	2,602	2,488	13,716

Source: Hydro, Reliability and Resource Adequacy Study.

Pattern of resource availability for energy export

Figure 24 below illustrates an energy and capacity balance for a relatively high-load peak day in winter, a more average winter day, and an off-peak summer day. The figure shows that even on a winter peak day, NLH still has a significant quantity of surplus energy available to export. The volume of surplus energy will shift up or down depending on the electrification and EE policies that are adopted in the Province.

Figure 24. Illustrative peak day profile - energy available for sale



Source: Synapse. Illustrative only; based on information from Hydro.

6.3. Export Market Valuation Results

Energy

The level of net export volumes available for sale are shown in Table 13.

Table 13. Total export sales volumes by scenario, GWh

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Base	4,058	3,832	3,775	3,793	3,838	4,004	4,012	4,038	3,963	3,898
High Elec_Low EE	4,102	3,890	3,815	3,829	3,863	4,006	3,978	3,952	3,802	3,646
High Elec_Mid EE	4,130	3,957	3,910	3,951	3,995	4,161	4,160	4,167	4,047	3,925
High Elec_High EE	4,172	4,027	4,014	4,105	4,174	4,377	4,409	4,447	4,363	4,276
Low Elec_Low EE	4,198	4,031	4,016	4,075	4,123	4,318	4,351	4,400	4,335	4,272
Low Elec_Mid EE	4,227	4,094	4,117	4,198	4,256	4,471	4,527	4,596	4,551	4,515
Low Elec_High EE	4,269	4,153	4,214	4,328	4,424	4,673	4,753	4,844	4,829	4,820

Source: Synapse export market evaluation workbook, based on NLH information on available energy and Synapse computation of net loads for listed scenarios. Note: Export volumes net of losses on paths to destination markets. Export volumes do not include obligations for the Nova Scotia Block and Supplemental Energy.

As seen in Figure 25, the range of export sales volumes varies across the scenarios, with the highest level of absolute volumes seen in the scenarios with greatest levels of improved energy efficiency in the Province ("High EE," or high CDM effects) in combination with the lowest levels of electrification; and conversely, the lowest level of export volumes is seen for circumstances where electrification is highest and CDM efforts are weakest.

Figure 26 below show the range of net export market sales income, based on the destination market, the market prices, exporting costs (e.g., including path-to-market tariff and losses charges, and administration costs) and the volumes sold during on-peak and off-periods.

Figure 25. Total export sales volume by scenario, by year, GWh

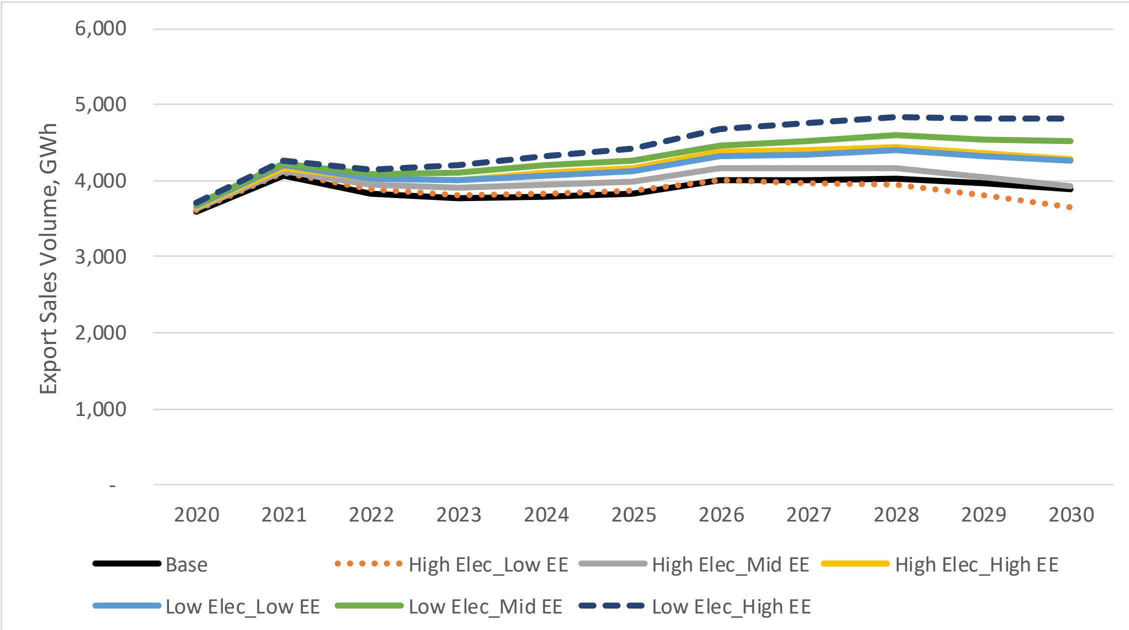
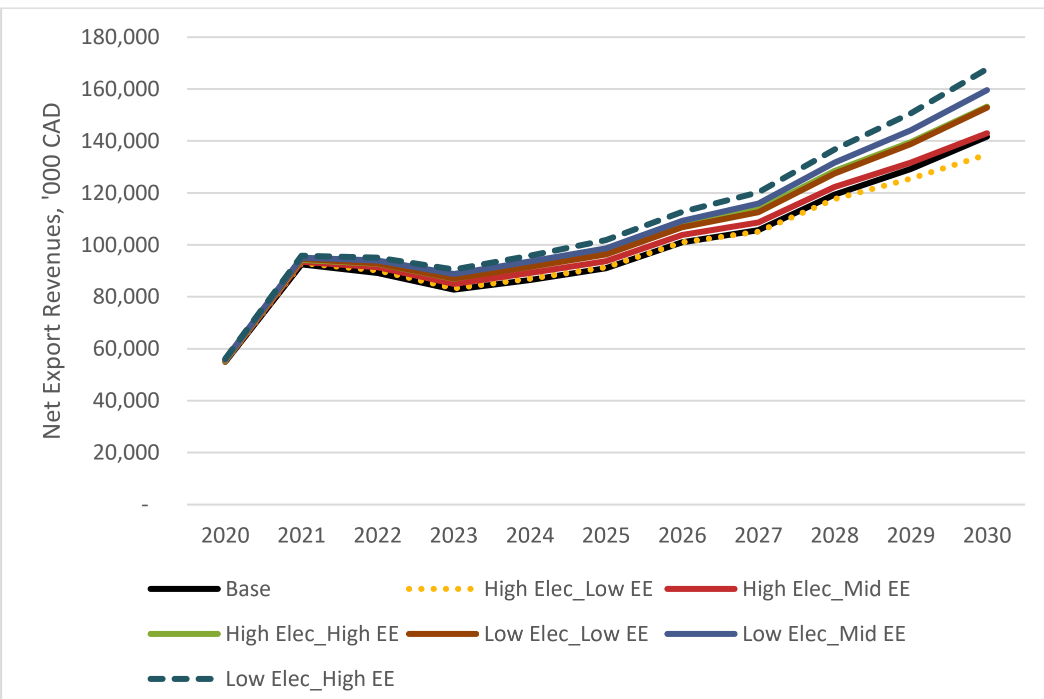


Figure 26. Total net export sales revenue by scenario, $000 (Canadian $)



Source, Figure 25 & 26: Synapse export market evaluation workbook, based on Hydro information on available energy and Synapse computation of net loads for listed scenarios. Note: Export volumes net of losses on paths to destination markets.

Capacity

Sale of surplus capacity to an external market would bring additional revenues beyond those expected from selling surplus energy volumes. Whether or not the Province has surplus capacity and can sustain surplus amounts over any given period of time depends on the projected headroom of capacity above planning reserve requirements, which represent overall capacity needed for operations during peak load periods.[44] This Phase 1 analysis is limited in its assessment of surplus capacity, but for the purposes of estimating potential sales revenue for surplus capacity, we do assume sufficient reserves in Newfoundland and Labrador to support an export sale.

The potential destination markets for surplus capacity consist of Quebec, New York, New England, and the Maritimes. However, various limitations exist for considering a capacity sale into the U.S. markets. During this Phase 1 analysis, Synapse has limited exploration of surplus capacity sales to solely a single destination, Nova Scotia, for the purpose of estimating potential revenue quantities. During Phase 2, we will expand our investigation to determine if it is reasonable to explicitly consider any of the other destination markets for capacity sales.

The Nova Scotia market is the only market currently contracted for an effective capacity sale—the NS Block, as part of the overall sale of energy to Emera to serve load in Nova Scotia. The Maritime Link can support a nominal flow of energy at its rated 500 MW, though the ability to sell a firmer product, guaranteed capacity, is limited to the transfer capability under a contingency event that results in the loss of one of the two bi-poles of the HVDC link.[45] Since the NS Block is an injection of roughly 170 MW in Newfoundland, up to roughly 80 additional MW could be injected for delivery over the Maritime Link, representing a sale of roughly 70 MW after accounting for losses.

The value of a sale of capacity to Nova Scotia would range from the buying parties' going-forward costs, to the new cost of a pure capacity resource, depending upon the selling and purchasing parties' perceptions of value. The value would also ultimately depend upon the terms and conditions of sale, which would reasonably contain specific information on circumstances in which power could be interrupted and potential contractually-based penalties that might be associated with such terms. We do not attempt to capture such value perceptions in this analysis, or in sum the respective parties "willingness to pay" (buyer) and "willingness to accept" (seller).

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[44] NLH recently filed a *Reliability and Resource Adequacy Study* that indicates a proposed overall Provincial reserve requirement of 13 percent and a reserve requirement for the Island of 14 percent, based on probabilistic studies using a loss of load expectation standard of 0.1, or 1 event every ten years. See Volume I, p. 42, Table 4: Planning Reserve Margin Results.

[45] It is our understanding, based on conversations with NLH, that capacity sales across the Maritime Link would likely be limited to roughly half of its transfer capacity, or 250 MW. For example, see page 32 of the Liberty Consulting Group's August 2016 report *Review of Newfoundland and Labrador Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls Final Report*, which states "Any power on the Maritime Link in excess of 250 MW is not Firm Power," whereas "firm power" is defined as secure power not interruptible. Report available at http://www.pub.nl.ca/applications/IslandInterconnectedSystem/phasetwo/files/reports/TheLibertyConsultingGroup-PhaseTwoReport-2016-08-19.pdf.

In Phase 2 we will do further detailed analysis on the amount and value of capacity sales in all potential markets.

7. Conclusions/Recommendations

The following summarizes our broad conclusions and recommendations stemming from our Phase 1 work:

1. Electrification of oil-fired end uses offers the greatest promise of increasing revenues to offset fixed MFP costs. Development of time-of-use rate policies associated with beneficial electrification is most likely to support economic and environmental synergies:

    - prevention of excessive peak-load increases;
    - incentivizing fuel switching;
    - saving oil and reducing greenhouse gas production;
    - supporting export sales during highest-priced peak periods; and
    - promoting CDM that is tailored to critical peak period load reductions.

    The Province can also simultaneously consider "economic development rates", or the like, to spur off-peak period electrification, while still addressing customer equity issues associated with pricing existing consumption and pricing potentially new electricity consumption end-uses. We further recommend prioritizing the electrification potential of larger commercial and institutional buildings, with maximum control over periods of consumption.

2. Export sales of surplus energy during higher-value periods can be increased through CDM programs that save winter energy. CDM programs that emphasize on-peak (evening, morning) savings can further help support increased export sales revenues during the highest-value hours. CDM programs that emphasize peak period savings will benefit from higher avoided capacity costs that now face the Province, once Holyrood is retired.

3. Continuing to support and increase CDM programs can help to ensure available capacity for resource adequacy. Regardless of CDM's impact on export sales, or even on consumer bills, CDM as a resource for longer-term planning purposes will be critical. Especially when expanded to include demand response resources not historically considered in Newfoundland and Labrador, CDM can buy considerable time before the Province may need to grapple with potential new supply-side resources so soon after the MFP commences service.

4. A Phase 2 analysis must support more careful examination of hourly patterns of resource availability, peak loading, and export opportunities. The temporal dimensions

considered – annual, monthly, daily, and hourly – will drive the level of accuracy to be expected from any form of resource analysis.

5. Conventional treatment of price elasticity in load forecasting may not work in Newfoundland and Labrador because the prospective price increases are so high. We recommend a careful scoping of the different methods that might be employed – such as end-use forecasting approaches rather than econometric approaches – when considering Phase 2 analyses.