Phase 2 Report 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, In-Province Electrification and Rate Design Approaches After In-Service of the Muskrat Falls Project

Prepared for Board of Commissioners of Public Utilities, Province of Newfoundland and Labrador

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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. Our scope of work was to address certain factors underlying 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 was completed towards the end of 2018, and our findings were referenced in the Board's February 2019 Report.[1]

Phase 2 analytical efforts were completed this year, and our findings are reflected in this report. Phase 2 efforts have included more rigorous analysis of technical issues, participation in technical conferences in St. John's (late March, early June and early August), preparation of this final report, and planned expert witness support during formal hearing proceedings commencing in October 2019. Four primary refinements to our Phase 1 analyses are incorporated in our Phase 2 work and are reflected in this report:

1) use of an aggregate end-use electricity model to better categorize the potential for conservation and demand management (CDM) and to estimate demand response (DR) potential savings in the Province;

2) refinements to our electrification model to better capture hourly patterns of electrified load, overall potential estimates, and net costs to the Province for infrastructure;

3) the use of the PLEXOS[2] production cost model to estimate export sales volumes and revenues under different scenarios of net Provincial load; and

4) inclusion of rate design assessments to gauge mitigation effects and examine high-level time-of-use rate considerations.

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

[1] Newfoundland and Labrador Board of Commissioners of Public Utilities, Reference to the Board, Rate Mitigation Options and Impacts, Muskrat Falls Project. Interim Report, February 15, 2019.

[2] Licensed from Energy Exemplar.

with MFP energy. The MFP and LIL completion allows for retirement of and fuel savings from the Holyrood oil-fired generation station on the Avalon peninsula.[3]

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 on the Island of 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 Island Interconnected System (IIS) that are required to pay for the MFP. Based on information provided by the Liberty Consulting Group and NLH,[4] the projected base revenue requirements for IIS customers will increase from less than $0.6 billion in 2019 to more than $1.2 billion by 2030, absent mitigation of project-financing and related issues that are outside the scope of our analytical effort. 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 increased export sales to customers outside of Newfoundland and Labrador (Newfoundland). Electrification of end-uses currently served by oil[5] allows for electricity rate mitigation, while reducing customer expenditures on another fuel. Continuing use of 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,[6] to allow for greater export sales while contributing to peak load reduction. Even though the Province will have

[3] It is our understanding that reliability reviews continue to ascertain the expected availability of the LIL and whether or not back-up capacity support from the Holyrood station may be needed in the near and/or longer term. As we note in this report, peak demand savings opportunities are valued at an avoided cost of capacity on the assumption that irrespective of the current status of LIL reliability, a long-term marginal cost of capacity remains for the Island.

[4] PUB-Nalcor-049

[5] Those uses include primarily heating and transportation. The amount of wood or propane consumed for home and small commercial heating purposes is small relative to oil heat consumption in those sectors. In this report we base all electrification potential fuel savings and increased utility revenues on substitution away from oil heat.

[6] The term "peak periods" generally refers to winter periods when Provincial load is highest: during the coldest days and during the early morning and early evening periods. However, market sales of surplus energy exported from the Province also are considered as either "peak" or "off-peak" period sales, regardless of the seasonality of the sale. They are split between sales

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.[7] 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 as much as possible during non-extreme winter peak periods—can assist in lowering average rates (by spreading fixed costs across more sales) 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 Questions 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 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 Phase 2 Findings for the Board's consideration in responding to the Reference Questions.

Synapse's scope of work with respect to the first question includes assessing the cost savings and revenue opportunities associated with electricity consumption and electricity sales. This is the core focus of our analytical efforts, which consist of estimating different scenarios of total Provincial electricity consumption under different amounts of electrification and CDM; and then determining

occurring during a market-defined peak period (16 hours per day, weekdays) and the rest of the weekly hours, considered as off-peak. Market prices are defined for all days of the year according to this block categorization.

[7] 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, November 16, 2018.

export sales from surplus energy remaining after serving total Provincial Load. Liberty Consulting Group (Liberty), is examining other aspects of the first reference question, including the Nalcor/NLH organizational structure and operating improvements.

To address the second question, Synapse provides energy and capacity balances between the MFP and the IIS load in this report, including the amount of MFP available for export sales and electrification efforts. Notably, the energy and capacity balances change across our examination of scenarios that reflect different combinations of electrification and CDM implementation; export sales revenues vary across those scenarios also as they are a function of the surplus remaining from MFP (and Churchill Falls Recall or Recapture energy amounts) after netting out IIS and Labrador load.

We examine the rate impacts of CDM, demand response (DR) and electrification to inform the Board's consideration of the third reference question, and we also address related rate design issues at a high level. For each scenario, we develop total revenue effects (from internal load and from export sales revenues) as they differ from our reference case, and we account for any additional costs associated with CDM, DR, and electrification efforts. We measure total net changes in revenues (in dollars per year) for each scenario, and account for any incurred costs. Then we translate this effect to both an average rate effect (in cents per kWh) and an average electric and energy bill effects for customers. In our CDM scenarios, average consumption falls relative to our reference case, with significant implications for both revenues and customer bill impacts.

Consideration of rate design issues, particularly the potential benefit of time-of-use (TOU) rate mechanisms, was examined in this phase. Lowering peak load through CDM measures simultaneously reduces energy consumption, which at first seems in opposition to the need to increase domestic consumption to mitigate rates. 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; this is where rate design can be helpful.

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. Careful attention must be paid to peak period load consumption and incentives to lower such peak demand.

Critically, we also assume a need to reduce peak load during winter periods[8] and assign value to all efforts that lead to a reduction in peak load. Thus, peak load reduction associated with demand-side measures attracts a value equal to avoided capacity costs. Those demand-side measures include CDM, traditional DR, and potential use of rate designs reflecting Critical Peak Pricing (CPP) or using TOU rates

[8] See the Response and Attachment 1 to PUB-NALCOR-121. Attachment 1 is the "Marginal Cost Study Update – 2018" filed by Hydro to the Board on November 15, 2018.

that reduce peak (independent of whether those rates are supported through use of advanced metering infrastructure (AMI) or other mechanisms such as smart charging of electric vehicle load).

Our summary findings are presented in the next section. Chapter 3 describes our analytical approach and methodology to examine the above issues. Chapters 4 through 8 present our detailed analyses, Chapter 9 summarizes Policy Considerations, and Chapter 10 contains our major conclusions.

2. SUMMARY FINDINGS

Our summary findings are presented below.

We first report on the overall mitigating effect of different combinations of electrification, CDM, and rate design parameters, as reflected in the different scenarios we have modeled.[9] Comparing key metrics—i.e., rate impact, electric bill impact, mitigation cost, and energy expenditure impacts including oil savings—allows us to differentiate the effect for a given mitigating element or combination of elements. All scenario results are presented relative to our reference scenario. Synthesizing the results of our different modeling processes (CDM, electrification, export sales, rate design) was required to gauge the combined effect of these elements. A representative set of those scenarios is included in the summary tables on page 7 and 8; the full set of mitigation effects for all scenarios is presented in Chapter 8.

We then present summary results for our electrification analysis, which employed a spreadsheet model to estimate the utility effects (e.g., revenue increases) and certain customer economics for beneficial electrification technologies. We summarize our CDM and DR analyses, which utilized separate spreadsheet modeling to estimate costs and savings for those resources. We list the load requirements for the IIS under our Reference scenario. We proceed with our main findings on export sales and summarize our rate design efforts.

Overall Mitigation Impact

Our overall mitigation findings are illustrated by the summary Table 1 below and are relative to a Reference load scenario (Synapse LR, low rate, equal to Hydro domestic retail rate of 17.5 cents/kWh in 2021). The Reference scenario "low rate" assumes that average rates increase from 11.3 cents/kWh in

[9] This modeling approach was used to address all three Reference Questions. It addressed the first by examining cost savings and revenue opportunities associated with increasing export sales, increasing internal consumption (electrification), and saving energy (CDM). The PLEXOS modeling tool allowed us to develop a clear energy and capacity balance between the IIS and the MFP, which addressed the second question. The third question is directly addressed with our overall mitigation synthesis and through our use of rate design considerations, which can affect the patterns for all the mitigation elements.

2019 to 19.9 cents/kWh in 2023 (nominal), before flattening out after 2023.[10] The Reference load scenario reflects a "do nothing" approach for collecting the revenue requirements, and it contains no changes to load from either electrification, CDM, or rate design efforts. The table presents several illustrative scenarios:

- Scenario 6 "High CDM" represents a case with a high level of CDM, but no other mitigation efforts. This scenario reduces load in the province while simultaneously allowing for greater export sales. It also includes the cost of implementing CDM.
- Scenario 10 "High Elec" represents a case with high electrification in the Province—primarily in the form of conversion of oil heat to electric resistance heating (large institutional and commercial facilities) and heat pumps (residential and smaller commercial buildings) and adoption of electric vehicles. This scenario increases load in the Province while reducing exports. It also includes the cost of electrification programs.
- Scenario 12 "High Elec w/EV TOU" applies TOU rates to electric vehicle charging load, reducing peak demand from this newly electrified end use compared to the high electrification scenario absent EV TOU rates (Scenario 10). This scenario includes benefits from reduced capacity costs associated with lower peak demand (vs. Scenario 10). This case also includes costs associated with running an EV TOU program, such as incentives for smart EV chargers that transmit hourly charging data to the utility.
- Scenario 12a "High Elec w/EV TOU w/DR" adds additional demand response programs (primarily direct load control) to reduce the increase in peak load relative to Scenarios 12 or 10. This scenario also includes the cost of the DR programs.
- Scenario 20 "High Elec w/EV TOU, High CDM" combines the high electrification case with TOU for electric vehicles and assumes a high level of CDM. It shows a net reduction in capacity costs relative to the reference scenario, due to the CDM and the EV TOU effects.
- Scenario 20a "High Elec w/EV TOU, High CDM w/DR" simply adds demand response programs to the previous scenario, further enhancing relative capacity savings.
- Scenario 24 "High Elec w/EV TOU, High CDM w/TOU+CPP" is the same as Scenario 20a but employs TOU rates with Critical Peak Pricing to reduce peak demand rather than using traditional DR programs. The primary cost associated with this scenario is the advanced metering required to implement widespread time-varying rates for all customers. (We assume that the TOU+CPP rate is implemented through an opt-out enrollment mechanism.)

As noted, Table 1 first lists the overall mitigation effect associated with any given scenario, relative to the reference scenario. Mitigation manifests in changes to three quantities: electric utility revenues, electric rates, and total energy bills. Positive values for relative utility revenues generally correspond to

[10] Average rates reflect all customer classes, not just residential customers. The average residential rates will be comparable to the rates provided in PUB-Nalcor-074. That response is for domestic average rates inclusive of distribution costs.

reductions (negative values) for electric rates. Table 1 lists the relative electric utility revenues and average rate impact in 2025 and 2030 for each scenario. Table 1 also presents the aggregate total energy expenditures, including heating oil and transportation fuel savings from electrification, for the IIS in 2025 and 2030.

The right-hand side of Table 1 lists the average customer impacts of the Province-wide impacts. First it shows the average electric bill impact, in dollars per month, reflecting both the rate impacts and the effect of varying average consumption across the scenarios from energy efficiency and electrification (positive is bill increase, negative is lower bill). Finally, it provides a "net energy expenditure" metric that includes average fossil fuel savings per customer associated with each scenario. All of these scenarios have average energy bills lower relative to a reference case with no CDM, electrification, TOU, TOU+CPP, or DR. While we note that fossil fuel savings are not electricity bill savings, their positive effect on the average customer is highly relevant for overall policy considerations.

Table 1: IIS Net Mitigation Effects for CDM, DR and Electrification Relative to Baseline, for Select Scenarios, 2025 and 2030: $ Millions, $¢/kWh, $/mo. Bill Impact, and Avg. Fossil Fuel Savings Impact

Scenario	Delta Utility Revenues (Millions)		Avg Rate Mitigation (cents/kWh)		Delta Avg Electric Bill $/month		Delta Total Energy Expenditures (Millions)		Delta Avg Energy Expenditures $/month	
	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030
6. High CDM	($35)	($84)	0.549	1.431	($6)	($20)	($35)	($84)	($6)	($20)
10. High Elec	$33	$52	(0.490)	(0.799)	$9	$21	($80)	($191)	($22)	($46)
12. High Elec w/EV TOU	$34	$55	(0.505)	(0.847)	$9	$20	($79)	($188)	($22)	($47)
12a. High Elec w/EV TOU w/DR	$40	$70	(0.600)	(1.070)	$7	$16	($72)	($174)	($24)	($52)
20. High Elec w/EV TOU, High CDM	$2	($18)	(0.039)	0.310	$2	($1)	($110)	($262)	($29)	($69)
20a. High Elec w/EV TOU, High CDM w/DR	$9	($4)	(0.136)	0.069	$1	($6)	($103)	($248)	($31)	($73)
24. High Elec w/EV TOU, High CDM w/TOU+CPP	$7	$2	(0.108)	(0.038)	$1	($8)	($105)	($241)	($30)	($75)

Source: Synapse, synthesis of modeling results.
Note: Delta Average Energy Expenditures is average across all customers and does not reflect the average savings seen for a residential customer, as a large fraction of oil savings is for larger buildings. Positive "Delta Utility Revenues" indicate increased utility revenues relative to the Synapse LR Scenario. Negative "Average Rate Mitigation" values indicate a decrease in rates relative to the Synapse LR Scenario. Negative "Delta Total Energy Expenditures" indicate a decrease in total energy expenditures relative to the Synapse LR Scenario.

Table 2 below provides the components that comprise the overall utility revenue effect. These include the changes in internal revenues due to CDM, additional revenue from electrification and exports, CDM and electrification costs, and increased or reduced capacity costs associated with changes in peak demand.

Table 2. Components of Net Mitigation Effect, IIS

Scenario	Delta Internal Revenues		Delta Export Revenues (Millions)		CDM, Elec DR, TOU Costs (Millions)		Delta Capacity Costs (Millions)		Delta Utility Revenues (Millions)	
	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030
6. High CDM	($55)	($156)	$14	$45	$9	$23	($16)	($50)	($35)	($84)
10. High Elec	$65	$129	($13)	($29)	$3	$12	$17	$37	$33	$52
12. High Elec w/EV TOU	$65	$129	($12)	($29)	$5	$15	$15	$30	$34	$55
12a. High Elec w/EV TOU w/DR	$65	$128	($12)	($29)	$7	$23	$7	$6	$40	$70
20. High Elec w/EV TOU, High CDM	$11	($23)	$2	$19	$14	$38	($3)	($23)	$2	($18)
20a. High Elec w/EV TOU, High CDM w/DR	$11	($24)	$2	$19	$16	$46	($12)	($46)	$9	($4)
24. High Elec w/EV TOU, High CDM w/TOU+CPP	$11	($25)	$2	$19	$22	$42	($16)	($50)	$7	$2

Source: Synapse, synthesis of modeling results.
Note: Positive Delta Revenue values indicate increased utility revenue relative to the Synapse LR scenario. Positive Costs indicate increased utility spending relative to the Synapse LR Scenario.

Table 1 illustrates a range of mitigation effects, different for rates versus bills, across the years, associated with a representative selection of different scenarios we have examined in our attempt to distinguish important differences in analytical results that could or should influence policy considerations. The results in total illustrate the following:

1. **Electrification**. Electrification increases revenues for the utility and helps to pay for MFP fixed costs. As seen in all the scenarios with electrification, the magnitude of revenue increase is substantial, rising to (e.g.) $129 million per year by 2030 (Table 2, Scenario 10). The net increase in electric revenues in this scenario is $52 million by 2030, resulting in rate mitigation of 0.8 cents/kWh. The highest levels of rate mitigation occur in scenarios with high electrification, followed by low electrification. At the same time, electrification increases electric utility bills due to the increased use of electricity. For this reason, customer electric bills tend to increase under several of the electrification scenarios. However, customers who electrify also reduce their consumption of oil or other fuels. When these savings are accounted for, customers experience a significant reduction in their "net bills," as seen in the "Delta Avg. Energy Expenditures" column in Table 1.

2. **Export Revenues**. Export sales revenues are at their highest when CDM is high and no additional electrification is assumed (e.g., Table 2, Scenario 6, "Delta Export Revenues" indicates $45 million in increased export sales in 2030 relative to the reference scenario). Export revenues are at their lowest when no additional CDM beyond base levels are assumed and electrification is at its highest—essentially, more of the surplus energy production at MFP is consumed internally. While the export revenue level is an important indicator, it is not on its own the best metric to gauge successful mitigation efforts. It excludes the value associated with increased electrification accompanied by increased oil savings. Our results show that the High CDM, High electrification scenarios with TOU pricing for electric vehicle consumption lead to absolute export sales that approach $190 million per year by 2030 (Table 6, p.17), even with high levels of internal electrification. Export sales relative to the reference scenario are also higher, as seen for Scenarios 20, 20a, and 24 in Table 2, with "Delta Export Revenue" of $19 million in 2030. Maximum shifting of consumption into off-peak hours occurs, allowing capture of on-peak export prices for a greater share of exported energy.

3. **IIS CDM.** On their own, the CDM scenarios exhibit poor mitigation from a rates perspective, because of the loss of revenue from customers on the Island. The capacity avoidance value, along with the increased export revenue value, are not sufficient on their own to fully offset both the CDM cost (which is offset when considering only avoided capacity and energy value) and the revenue loss. From a customer economic perspective, however, the energy and electric bill impacts seen in Table 1 are most relevant; generally, both low and high CDM scenarios exhibit the best net benefits on the average electric bill.

4. **Rate Design Effects and Demand Response.** Rate design using TOU pricing for electric vehicle load or implementing TOU with critical peak pricing for all customers results in a reduction in peak load relative to the reference scenario. Table 1 shows the difference between these scenarios, and scenarios without such rate design effects. For example, Scenario 12 implements TOU for electric vehicles, while Scenario 10 does not. The use of TOU rates for electric vehicles reduces peak demand (relative to electrification scenarios with TOU), which results in a relative reduction in required generation capacity and associated reductions in revenue requirements, leading to lower bills and rates for customers than in Scenario 10. Demand response programs are assumed to have a similar peak reduction effect to the critical peak pricing component but have somewhat different costs. The scenarios that include DR or TOU+CPP generally result in the lowest rates and bills for customers, due to the value associated with reducing capacity requirements.

5. **Mitigation Potential.** Table 1 shows that rate mitigation by 2025 from electrification and CDM is limited to 0.6 cents/kWh or less, increasing to just over 1 cent/kWh in 2030, for high electrification scenarios, while other scenarios deliver even less rate mitigation. While Synapse recommends further analysis of enhanced electrification potential in the

Province, it is clear that implementation of such various initiatives will not, by themselves, reduce rates enough to offset the rate increase needed to cover Muskrat Falls costs. At the same time, the combination of electrification and increased CDM has the potential to reduce total Provincial energy costs by a greater amount than either electrification or CDM alone, while also delivering some rate mitigation.

The net mitigation results shown in Table 1 and Table 2 are, for each scenario, relative to a reference Scenario that reflects our Reference Load forecast. That forecast does not assume significant increases in electrification, and it assumes status quo CDM efforts. The reference case does assume some sensitivity to price increases and essentially projects a flat energy demand across the IIS through 2030. The net mitigation amounts shown for each scenario are derived from the following components (shown in Table 2):

- **Changes in Export Sales Net Revenues**. All scenarios use the PLEXOS production cost model to estimate the level of export sales available to the Province. All changes on the demand side (CDM load reductions and electrification energy additions) are reflected in the modeled scenarios. The total energy resource available (for Provincial sales and exports) is roughly the same across all scenarios and is generally reliant almost fully on non-fossil energy after Muskrat Falls commissioning (small increments of gas turbine consumption are seen in some years in higher load scenarios). Some economic purchases from off-Island are seen in most scenarios.

- **CDM, Electrification, Rate Design Costs**. Costs to obtain CDM, peak shaving time-varying rates or DR, and in support of electrification infrastructure (heat pump incentives and charger costs, for example) are included for all scenarios. CDM and advanced metering infrastructure costs are amortized; electrification costs are not amortized (except small portions reflecting likely distribution plant amortization). Utility-based costs are included to assess rate mitigation; customer costs are not included as a component of either electrification or CDM for rate mitigation analysis.

- **Revenue Changes from CDM Load Reduction and Electrification Load Increase**. A critical tension running through our analyses, from the perspective of the utility system, is the net effect of increasing revenues through electrification while losing revenues due to increased conservation and efficiency. We have applied a "low rate" trajectory for the supply component of costs in order to estimate the revenue losses in scenarios where CDM levels are higher than in our reference case. We apply different rate structures across the different scenarios to reflect the increases in revenues from electrified load.

- **Value of Avoided Capacity through Peak Reduction**. In all scenarios, we assign a value for avoiding capacity (or assign a cost for increasing capacity need) based on the scenario's peak load relative to the reference case. We use the current marginal cost of capacity ($284 per kW-year, $2019)[11] nominally inflated. We assume this need is always present on the Island, given reliability uncertainties.[12]

Electrification

On their own, electrification scenarios clearly show the most positive benefit to rate mitigation, as they directly increase load and allow for increased contribution to pay for MFP fixed costs. The underlying infrastructure costs for electrification consist of electric vehicle charging equipment and incentives for heat pumps on the utility system side. When assessing the utility system effects, we have not assumed any direct incentives for conversion of larger institutional heating from oil to electricity. Under our sensitivity analyses for rates, we allow for both lower rates for electric vehicle charging and DR payments for peak-shaving opportunities. The ability of large institutions to convert to electricity for most of their heating load, but retain oil capacity to use during a portion of winter peak periods suggests DR payments for these institutions may be appropriate, which are considered in the overall costs for those scenarios where we assume both electrification and DR.

Among the options explored in our analysis, increasing consumption through electrification of existing end uses offers the most promising way to mitigate rates on the Island. Figure 1 below shows the trajectory of energy increases possible through electrification of oil-based end uses. Heating end uses (mostly in the large institutional sector) dominate the increased energy use during the early years, but transportation electrification grows to become a significant share by 2030.

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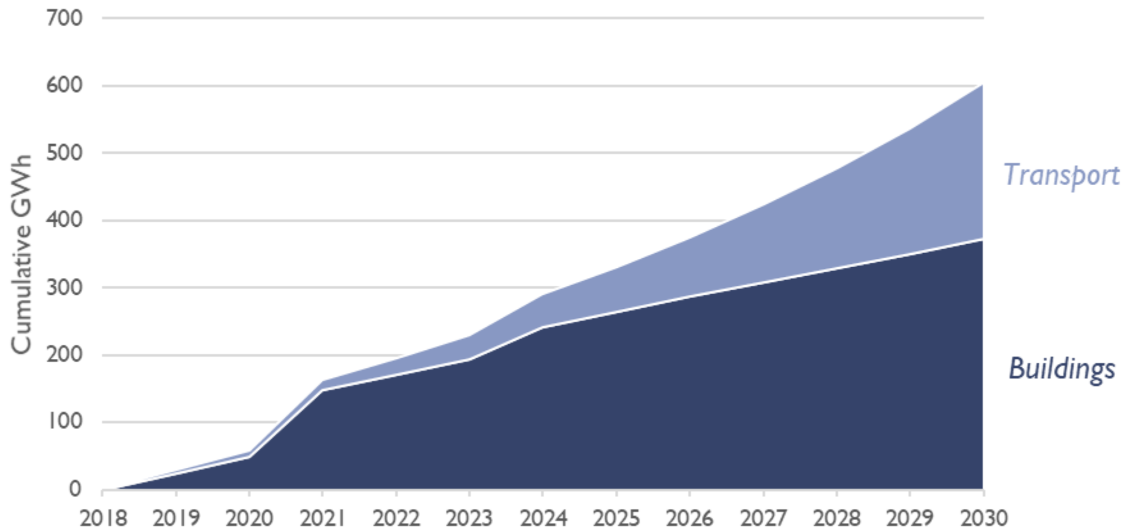
[11] Response to PUB-Nalcor-121, Appendix A of Attachment 1, at page 20.

[12] As noted in PUB-Nalcor-121, Appendix A of Attachment 1, at page 21.

Figure 1: High electrification scenario results by end-use sector



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

CDM and DR

Individually, CDM scenarios exhibit poor mitigation from an overall utility rates perspective, because of the loss of revenue and thus contribution to fixed costs. The capacity avoidance value associated with peak reductions from CDM efforts, along with the increased export revenue value, are not sufficient on their own to fully offset both the CDM cost (which is offset when considering only avoided capacity and energy value) and the revenue loss.

However, from a customer perspective, the bill impact is most relevant; generally, both low and high CDM scenarios exhibit the best net benefits from an average bill perspective because total average consumption for a typical NP domestic customer declines by roughly 12 percent (1,836 kW per year) between 2019 and 2030 in our high CDM scenario.[13] This is a critical observation: On its own, the rate mitigation indication might suggest little value in aggressively pursuing CDM, notwithstanding its contribution to avoiding new supply costs. This is because it results in significant loss of revenue for contribution to fixed costs. However, the average customer has lower bills, even if rates need to be higher to ensure sufficient revenue collection. Customers obtain their overall energy service through more efficient end uses—despite paying a higher average rate, they receive lower bills. And the Province sells additional surplus energy and avoids investment for new supply.

CDM and DR combined provide critical reductions to peak load during winter periods on the IIS. The peak reductions seen from these efforts will help offset consequential increases in peak demand from any new load, which would include electrification of existing end uses. While policies and rate design

[13] Synapse computation based on analysis of Newfoundland Power customer sales under high CDM scenario.

can be used to promote consumption during off-peak periods, we estimate some increase in peak period load from electrification. Thus, there could be a need to offset those peak period additions with CDM and DR to maintain resource adequacy headroom.

CDM also reduces overall energy consumption—significantly so in our high CDM case. Our overall mitigation summary incorporates the combined effects of export sales changes, electrification increases, CDM energy reduction, capacity avoidance savings, and CDM and DR costs. As seen in that summary, the high CDM case leads to lower total revenues relative to a reference case. In these scenarios, average rates would need to be higher (relative to a reference case rate) to ensure revenues are sufficient to meet overall requirements, though average bill savings (from significantly lower average consumption) offsets the increases from higher rates. The end result is a net benefit to customers who reduce their consumption, even as per-unit rates increase.

Table 3 below summarizes the peak load, and energy reduction amounts in our low and high CDM and demand response scenarios. Section 5 contains detailed results.

Table 3: IIS - CDM Net Annual Cumulative Energy Savings (GWh/year) and Winter Peak Savings (MW) in 2030, by Scenario

	CDM without Heat Pump		Heat Pump		DR		Total CDM	
	Low	High	Low	High	Low	High	Low	High
Total Energy Savings - GWh	123	299	0	533	NA	NA	123	832
Percent of Annual Energy	2%	4%	0%	7%	NA	NA	2%	11%
Total Peak Savings - MW	18	44	0	97	46	78	64	219
Percent of Load	1.1%	2.7%	0.0%	6.0%	2.8%	4.8%	3.9%	13.5%

The benefits of high levels of CDM on the IIS outweigh the costs. Table 4 shows the net energy and peak savings, net CDM costs, and the benefits ascribed to those savings from capacity avoidance and surplus energy sales. As seen, the overall Benefit/Cost (B/C) ratio approaches or is greater than three in all years.

Table 4. IIS – High Case Benefit Cost of CDM with Heat Pumps

Stream of Benefits, Real	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Energy Savings (GWh)	18	47	94	157	233	321	421	522	621	725	832
Net Peak Savings (MW)	3	8	17	27	40	55	72	89	105	123	141
Energy Benefits ($ million)	0.6	1.6	3.1	5.2	7.7	10.6	13.9	17.2	20.5	23.9	27.4
Capacity Benefits ($ million)	1.0	2.6	5.2	8.7	12.8	17.5	22.8	28.1	33.4	38.9	44.6
Total Benefits ($ million)	1.6	4.2	8.4	13.8	20.5	28.1	36.7	45.4	53.9	62.8	72.1
Net cumulative amortized costs ($ million)	1	1	3	5	7	10	13	16	18	20	22
BC Ratio	3.12	3.01	2.98	2.95	2.90	2.84	2.78	2.83	2.94	3.10	3.31

We note, as shown in the body of this report, that increases in CDM in Labrador are generally not cost effective, since there is no immediate need for new capacity and export sales opportunities do not fully cover CDM costs.

Our findings on CDM and DR for the IIS roughly align with the findings in the Conservation Potential Study by Dunsky Energy Consulting (Dunsky Report) that was filed in early August, 2019.[14] However, the scope, methodologies, and baselines used in our respective analyses make direct comparisons difficult without a more detailed examination of the report. We nonetheless note the following core findings associated with our initial high-level comparison:

- Overall levels of CDM and heat pump savings potential combined are of similar magnitude, though Synapse has a higher potential adoption rate for heat pump systems supplementing or replacing electric resistance heat. Thus, Synapse finds higher total savings in our high CDM case compared to Dunsky's Upper CDM (plus fuel-switching)[15] case. Our analysis and Dunsky's found more aggressive levels of CDM achievement than has been seen historically in the Province to be economically viable and achievable.
- The Dunsky Report emphasizes the importance of retaining and potentially increasing industrial curtailment capabilities as part of DR options. We agree. Our DR analysis, however, focused primarily on potential available from residential and commercial sectors. In these sectors, our findings were similar to Dunsky's findings on the overall potential available.
- Synapse and Dunksy present broadly similar findings on transportation electrification, recognizing that the benefits will be best obtained if careful attention is given to load management to minimize peak load additions from EV charging, for example. Dunksy's

[14] Response to PUB-NP-104, Attachment A.

[15] Dunsky separates the CDM estimates from "Fuel-Switching" savings that include the uptake of heat pump systems to displace electric resistance baseboard heating. We include CDM and heat pumps replacing electric heat as part of our overall analysis of energy efficiency improvements in Chapter 6.

findings on building heat electrification appear to initially diverge from Synapse's assessment, but as noted on closer review, Dunksy does support partial provision of heat with ductless mini-split heat pumps in oil-heated dwellings.

Load Requirements

Our load forecast chapter describes the methodologies used to determine our underlying reference load forecast. We mostly agree with the underlying forecast provided by Hydro as its "low rate" load forecast. We did adjust the 2024-2030 forecast values downward, to reflect our assessment (in line with NP's assessment) that price response effects would likely reduce those out year increases such that the net load forecast for the Island would be roughly flat. Table 5 shows our reference load forecast. We note, as seen in Chapter 4, that the net load forecast changes in each of our CDM and electrification scenarios.

Table 5. Island Load Requirements, Energy and Peak Demand, IIS, Reference Load Forecast

Energy Requirements (GWh)	2019	2020	2025	2030
Newfoundland Power	**6,350**	**6,291**	**6,220**	**6,104**
Deliveries from NLH	5,920	5,854	5,783	5,667
NP Own Generation	430	437	437	437
NLH Rural	**432**	**425**	**401**	**401**
Sales to Customers	432	425	401	401
Industrial	**1,520**	**1,493**	**1,493**	**1,490**
Deliveries from NLH	647	612	612	610
Industrial Self-Generation	873	881	881	880
NLH Total Island Sales	**6,999**	**6,892**	**6,796**	**6,678**
IIS Total Energy Requirement	**8,301**	**8,208**	**8,113**	**7,997**
Island Losses	295	362	426	417
LIL Losses	56	278	306	304
Total Energy Requirement	8,653	8,850	8,846	8,716
Peak Demand (MW)	**2019**	**2020**	**2025**	**2030**
Newfoundland Power Retail	1,402	1,397	1,398	1,399
NLH Rural Retail	105	105	105	105
Industrial Retail	185	182	182	182
Annual Retail Peak	1,692	1,684	1,684	1,685

Note: Synapse developed our reference forecast utilizing sales and bulk energy delivery input forecasts developed by NLH and NP at different times. For that reason, the components of load displayed here may not match exactly Totals, and the PLEXOS input loads differ slightly from total energy requirements displayed here.
Source: Synapse calculations, based on Response to Nalcor-PUB -112 and Nalcor-PUB-057.

Export Revenues

Energy export sales revenues vary depending on the level of internal provincial load (Island plus Labrador). As modeled, total energy production in the province after Muskrat Falls is online remains essentially the same across all scenarios and is sourced almost entirely from Labrador and Island hydroelectric assets. Fossil energy generation from peaking units is rarely required. Thus, export sales volumes are a direct function of the energy available after serving provincial load and meeting transmission and distribution loss requirements. Different scenarios of electrification levels and CDM effects directly influence the volume of export sales. Export sales revenues are a function of the timing of export volume availability, in either peak or off-peak periods as defined by the export market, and for any given month. Export market prices vary by month and by those peak and off-peak periods.

We present export market revenues net of transmission tariff and loss effects associated with delivering the energy to four destination markets: two through Quebec – New York, and New England via the Phase I/II transmission path; and two through Nova Scotia – New England via the Salisbury, New Brunswick path, and directly to Nova Scotia. The Nova Scotia market is priced based on New England market prices. An estimate of administrative costs is also used to net out the gross export revenues. All estimates for export market revenues take explicit account of the timing of energy exported; in particular, scenarios with TOU effects for energy consumption show relatively more energy exported during on-peak periods that those scenarios that do not reflect such TOU effects.

Table 6 below summarizes the volume of export sales and the net export revenues for 2021, 2025, and 2030 across a set of scenarios reflecting a range of export volumes. Other than the “Extreme Low Load” scenario, the high CDM (with TOU) scenario listed below reflects the highest level of export sales revenue. As seen, high electrification scenarios result in the lowest levels of export sales revenues. Critically, any consideration of the value of a particular scenario for mitigation purposes must consider not just the export sales effect, but also the increased revenues associated with internal electrification.

Table 6. Export Market Sales Volume and Revenue Summary, 2021, 2025, 2030, Select Scenarios

Scenario	2021	2025	2030
Volumes, GWh/year			
Synapse Low Rate Forecast	3,457	3,527	3,555
Synapse Low Rate, High CDM with TOU Scenario	3,498	3,853	4,413
Synapse Low Rate, High CDM with TOU, High Electrification with EV TOU	3,360	3,580	3,899
Synapse Low Rate, High Electrification Scenario	3,310	3,238	3,034
Net Revenues, $ millions/year			
Synapse Low Rate Forecast	120.2	125.0	169.8
Synapse Low Rate, High CDM with TOU Scenario	121.9	138.4	214.9
Synapse Low Rate, High CDM with TOU, High Electrification with EV TOU	116.4	127.3	188.9
Synapse Low Rate, High Electrification Scenario	114.0	113.2	141.1

Source: Synapse export market sales from PLEXOS production cost modeling. Notes: Export volume summary across all destination markets. Export volumes net of losses on paths to destination markets. Export volumes do not include obligations for the Nova Scotia Block and Supplemental Energy. Export revenues are net of tariff and losses incurred to reach destination markets. Revenues include administration costs associated with export sales marketing.

The availability of capacity export revenues will depend on the ability of peak reduction efforts to allow sufficient resource adequacy headroom to guarantee firm energy flows during winter peak periods. Under scenarios where such headroom exists, the price for capacity sales would need to be negotiated with counterparties. There is no liquid market for capacity sales that can be directly accessed by Hydro or Nalcor. Based on an estimate of avoided capacity costs in Nova Scotia, we have estimated the value of a capacity sale across the ML for the portion of the path that could support additional firm energy flows. We estimate the range of value for such a potential capacity sale to be $3.6 million to $7.1 million per year. However, any revenues received for such a capacity sale could directly lower the overall avoided capacity value we ascribe to peak reduction efforts as part of our net mitigation analysis. This range of capacity value for export sales should not be added directly to the net mitigation effect we compute—to do so could double count the value of the capacity.

Rate Design

Two primary rate designs were analyzed: (1) TOU rates with critical peak pricing for all customers implemented using advanced metering infrastructure and opt-out enrollment, and (2) TOU rates for electric vehicle customers only implemented using smart charging equipment instead of smart meters. These rate options tested both the benefits of various rate designs as well as the costs associated with their implementation. The scenarios with TOU+CPP rates can also be compared to the scenarios with demand response, as the TOU+CPP and DR scenarios result in similar peak reductions but have different implementation costs.

Our analysis indicates that by 2030, approximately 20 MW of peak reduction could be available from electric vehicles on TOU rates, while a full roll-out of TOU with CPP rates to all customers could result in approximately 77 MW of peak reduction. Although the results are similar, our analysis also indicates that a full roll-out of TOU+CPP rates to all customers (including TOU for EVs) results in slightly lower rates and bills for customers than with demand response.

In addition to an electric-vehicle TOU rate, we also analyzed an incentive rate for electric vehicle consumption based on a lower-priced flat rate. Special rates for electric vehicles may be beneficial for several reasons. First, time-varying rates help to reduce peak demand. Second, both TOU rates and discounted flat rates could be implemented to encourage greater adoption of electric vehicles.[16] However, since any incentive rate also reduces revenue requirements, the benefits of offering a discounted rate must be weighed against the reduced revenues from doing so. In these scenarios, we also tested how the rates for customers without electric vehicles would be affected. We found that the EV-TOU rate would result in customers without electric vehicles paying a rate $0.1 c/kWh higher than the average rate, while the discounted flat rate would result in customers without electric vehicles paying $0.1 to $0.4 c/kWh more than the average rate. In both cases, the electric vehicle customers are paying more than marginal cost, meaning that costs are not being *increased* for non-electric vehicle customers, but rather that the EV-specific rates are reducing some of the benefit from the additional electricity sales.

3. Analytical Approach / Methodology

3.1. Overview

Synapse began by reviewing Hydro’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, though we note that our underlying reference load forecast differs only slightly from Hydro’s “low rate” forecast.

Simultaneously, we evaluated CDM and electrification potential for the IIS and Labrador Interconnected System (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 and a low CDM

[16] Incentive rates can be most easily implemented for loads that can be separately measured, such as EVs. For this reason we chose to only apply incentive rates to EVs, rather than to all newly electrified load, which is more difficult to separate from overall household load.

and heat pump adoption scenario. We developed a DR forecast to apply when assessing peak demand reduction potential.

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 the PLEXOS production cost 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.

We developed rate impact assessments using a simplified revenue requirements spreadsheet model that accounted for the net loading in each scenario, the export sales, the patterns of hourly consumption, and the costs of CDM, DR, and electrification.

We ran scenarios on high and low export market pricing, extreme low load, and a high Labrador load case.

An overall synthesis of our export model findings and our CDM, electrification, and rate design models resulted in our summary of mitigation effects. Mitigation effects are presented in both rate and average bill effect in this report, since for scenarios with increases in CDM, the average annual consumption for a given consumer is lower relative to the consumption in the reference scenario, and rate-alone (i.e., c per kWh) mitigation effects do not fully convey the overall mitigation effect.

3.2. Comparison to Phase 1 Approach

Compared to our approach in Phase 1, our analysis in this Phase 2 employed the following refinements:

1. **IIS MFP Energy / Capacity Balance**. We explicitly represented energy and capacity balance between the IIS and the MFP in Labrador in Phase 2. Using the PLEXOS production cost model, we clearly differentiated between the two regions and represent the transmission transfer capacity between them.
2. **CDM Savings**. We developed an end-use model to estimate savings across aggregate end-use categories within sectors, and we developed an explicit DR savings estimate. Our assessment of CDM savings was based on a bottom-up approach, using savings potential for a set of aggregate end uses and a participation estimate (over the 2020-2030 period). We used a top-down method in Phase 1.
3. **CDM Costs and Benefits**. We estimated peak reduction benefits using the avoided costs of capacity on the Island. We estimated CDM costs in a more refined way, examining NL historical costs, along with costs for winter peaking system CDM programs that are more aggressive than NL's. We present a B/C ratio for the portfolio of programs on a region-specific and scenario-specific basis.
4. **Electrification**. We modeled the hourly profile of electric vehicle charging energy, based on assumed patterns under different rate designs. We modeled the hourly profile of building electrification energy using weather data to distribute such energy across

winter periods. For institutional facilities with non-weather dependent load, we modeled it evenly across remaining periods.

5. **Scenario development**. To properly assess changing patterns of export sales reflecting net loads with hourly perturbations due to CDM and electrification effects, we created a series of scenarios to model in PLEXOS.

6. **Export Sales Model**. We used the PLEXOS production cost model to estimate export market sales across roughly 24 different scenarios, reflecting combinations of changes to annual energy consumption, peak load, and periods of energy consumption (peak vs. off-peak).

7. **Net load inputs for scenarios**. We adjusted the Synapse reference load forecast based on the hourly pattern of the combination of CDM efforts and electrification efforts. CDM savings tied to heating load reductions were allocated across winter hours in proportion to weather data, and other CDM savings were allocated based on the underlying load shape on the Island. Electrification energy assignment for building energy conversions was also allocated based on weather data; an electric vehicle energy use was allocated based on either a “flat rate” or a TOU rate assumption to either peak or off-peak period hours.

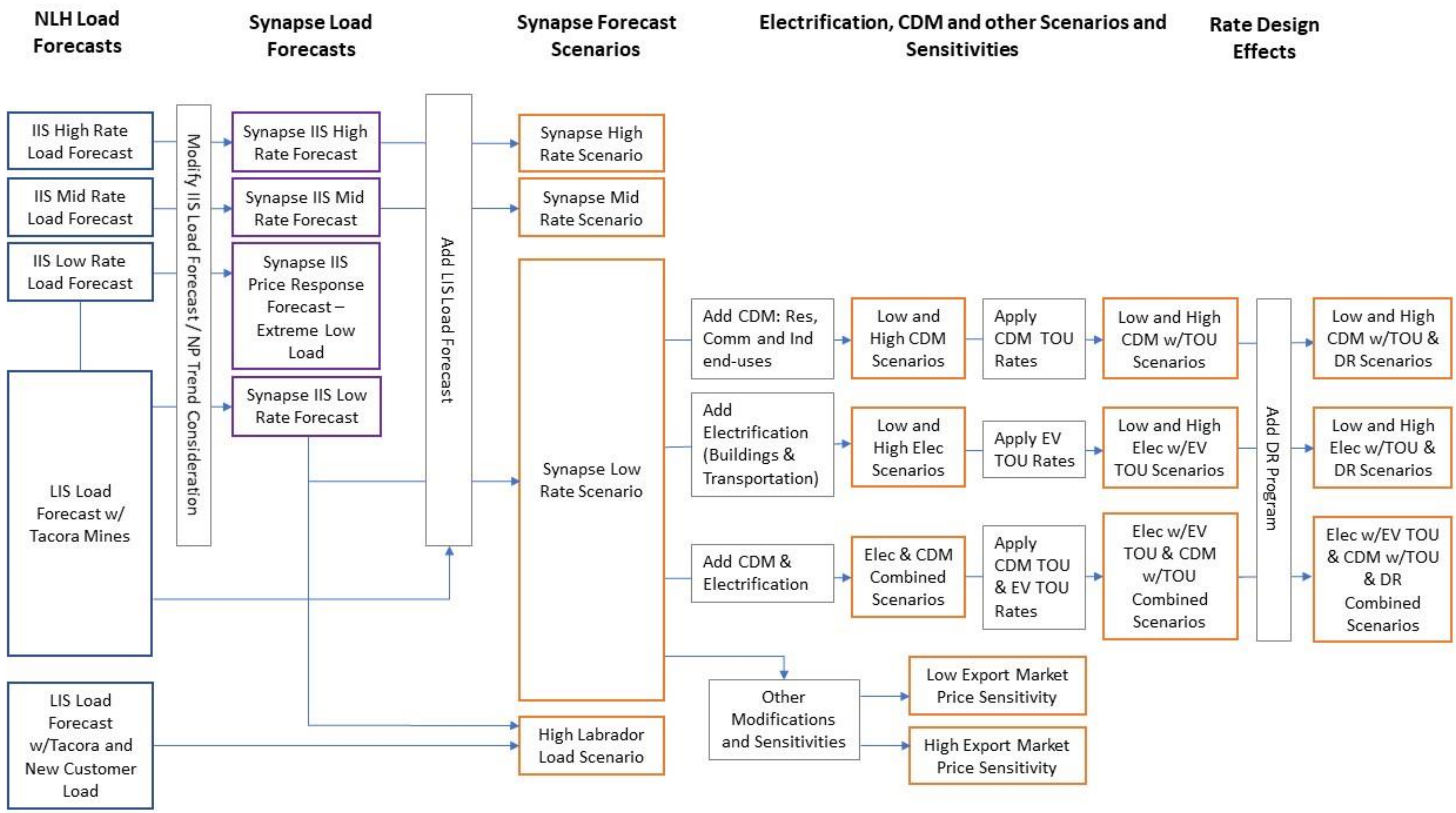
8. **Export Sales – Capacity**. We estimated the benefit for capacity sales by determining a reference value and allowable quantity for a possible capacity sale to Nova Scotia.

9. **Rate Design**. To further respond to Reference Question 3, and at the request of staff, we developed additional estimates of rate design effects on the overall mitigation. We examined average impacts under different levels of pricing for newly electrified end uses and explored effects of time-of-using methods that impact overall rates. Our focus was on development of rate effect relative to a reference load forecast.

Summary of Analytical Steps

The figure on the next page depicts our overall analytical steps used to determine net mitigation effects. The individual sections of this report describe the approaches in detail.

Figure 2: Analytical Synthesis



4. LOAD FORECAST

4.1. Overview

The load forecast was discussed previously in Section 3 of the Phase 1 report. Here we briefly review some of those key points and discuss additional aspects related to the Phase 2 modeling efforts, which include deriving scenario forecasts that account for CDM and electrification overlays to our reference forecast.

The electrical load in the Province that we are evaluating consists primarily of the IIS and LIS.[17] These systems are geographically separate, but soon to be fully connected by the LIL.[18]

The IIS is the larger of the two systems. Island load represents about 76 percent of the total NLH energy requirement volume (including losses) and roughly 78 percent of total Province load when accounting for self-supply by NP and Island industrial customers. Island load includes NP, Island industrial customers, and Hydro-served rural interconnected customers. The LIS is much smaller and includes service to Labrador West and East. Labrador's system includes rural customers and a significant level of industrial load, all served primarily by generation assets at Churchill Falls.

NLH serves as a retail load provider to domestic and commercial customers on Newfoundland Island (Island Rural) and in Labrador ("East" and "West"). NLH also serves as a wholesale provider to large industrial customers in both IIS and LIS and to NP. NLH is responsible for providing energy for 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 7, NP serves the majority of load (and customers) in the Province, providing service to domestic, commercial, and smaller industrial customers.

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[17] It is our understanding that the LIL, currently in testing and commissioning phases, is expected to be commercially operational in 2019 or 2020.

[18] NLH also serves isolated systems serving remote communities in both Labrador and the Island of Newfoundland. However, Synapse's scope of work does not include the assessment of rate mitigation options for the isolated systems, thus our study focuses only on the loads associated with IIS and LIS.

Table 7. Province Energy and Peak Load Requirements for 2018

	Load (GWh)	Peak (MW)
Island Interconnected System		
Newfoundland Power	5,839	1,280
Island Industrial Customers	623	95
NLH Rural Interconnected	479	92
Losses	241	122
Island Requirements	7,182	1,503
Labrador Interconnected System		
NLH Rural Interconnected	713	152
Industrial Customers	1,458	264
Losses	150	42
Labrador Requirements	2,321	420
Total System Requirements	**9,503**	**1,923**

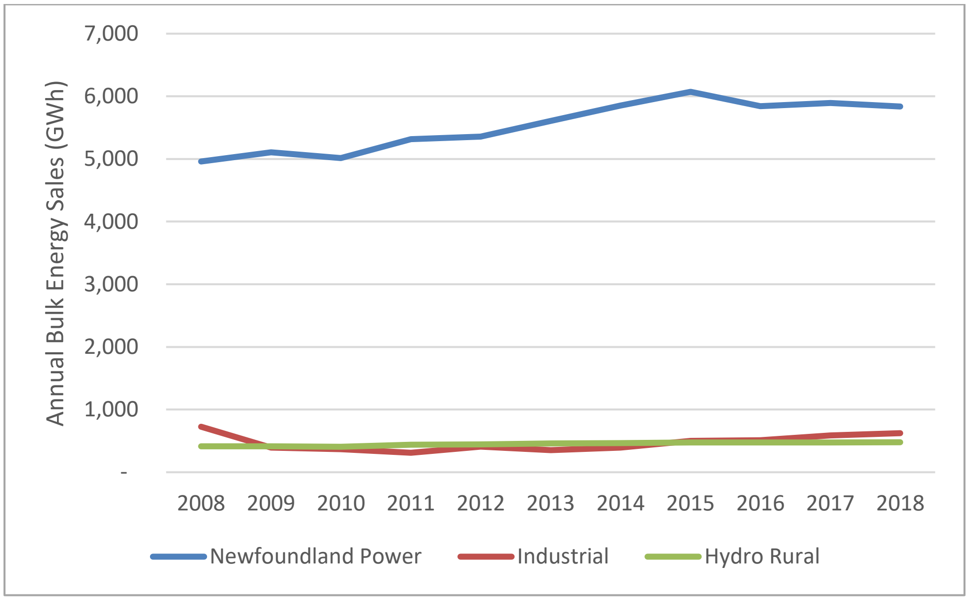
Source: PUB-Nalcor-57, Attachment 1. Tabulations by Synapse.

4.2. Historical Load

The IIS and the LIS each serve large geographic areas and several different customers classes. Annual load growth patterns and seasonal load shapes vary significantly across customer classes.

From 2008 to 2015, NLH Bulk Island sales increased approximately 15 percent. Most of this increase was due to NP domestic sales, as shown in Figure 3 below. Since 2015, however, consumption has leveled off. Large industry sales have varied from year to year but have increased steadily since 2013. The NLH Rural (predominately domestic and general service customers) represent a small portion of total NLH sales and have increased around 16 percent since 2008.

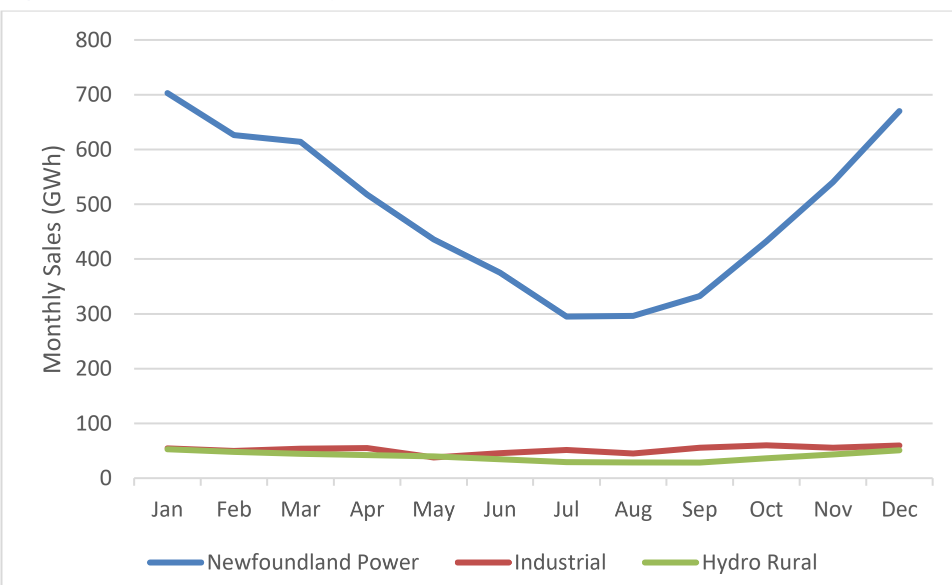
Figure 3: Historical NLH sales summary - Island Interconnected System



Source: Response to PUB-NALCOR-057. Graph and tabulations by Synapse.
Note: Excludes self-generation from Newfoundland Power and industrial load.

Synapse also evaluated the monthly electricity sales patterns in the Province (Figure 4). The highest monthly sales in 2018 were in January (828 GWh) and the lowest in July (384 GWh). 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.

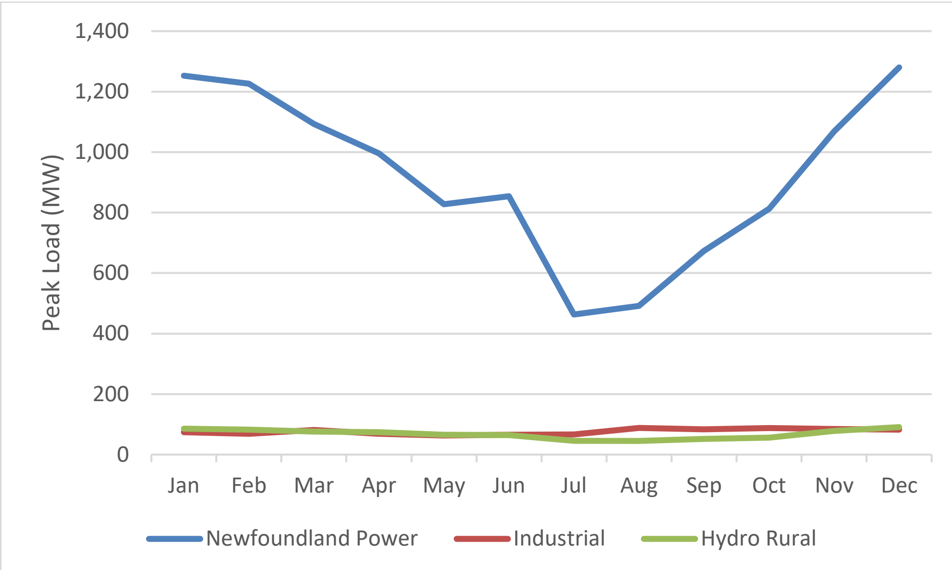
Figure 4: NLH 2018 Monthly Sales



Source: Response to PUB-Nalcor-057. Graph by Synapse.

As shown in Figure 5, there is also a strong monthly pattern for peak loads in the Province. The monthly peak in 2018 varied from 1,502 MW in January to a low of 679 MW in August. Unsurprisingly, NP dominates the Island's peak load.

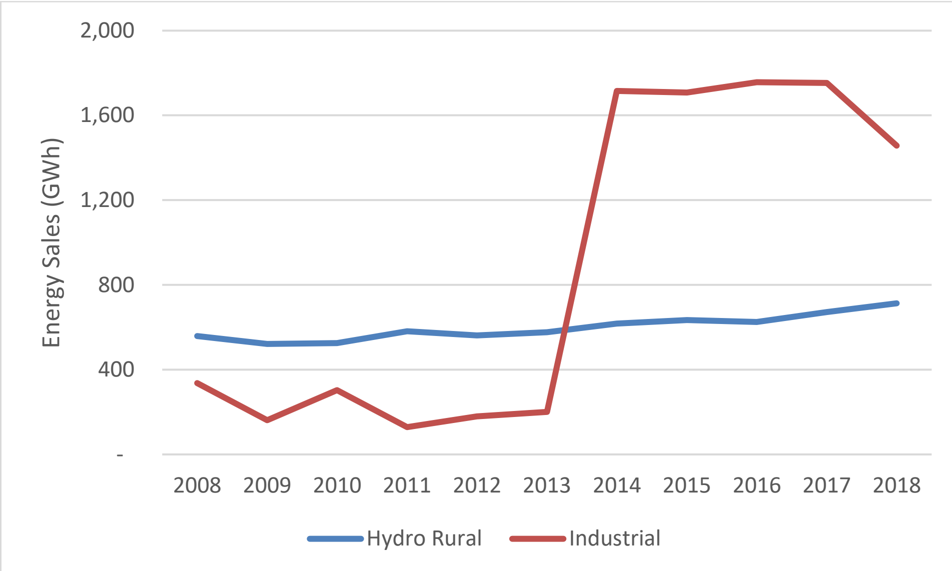
Figure 5: Island Monthly Peak Sales for 2018



Source: Response to PUB-Nalcor-057. Graph by Synapse.

In 2018, LIS customers represented about 24 percent of the total Provincial load. Of that load, 31 percent is comprised of NLH Rural customers (domestic and general service). A few large industrial customers represent the remaining 69 percent. Figure 6 illustrates that industrial customer load began to dominate demand beginning in 2014.

Figure 6: Labrador Historical Sales



Source: Response to PUB-Nalcor-057. Graph by Synapse.

4.3. Price Response

Load forecasts and electricity price trajectories for the IIS are highly uncertain at this point. Nalcor has created several price increase scenarios in an attempt to understand the potential load implications of future rate increase. Additionally, as part of this study, Liberty is developing revenue requirements, which provide the basis for future prices.

Changes in price will affect demand, but the nature and extent of that effect can vary widely depending on many factors. Energy use is largely determined by the existing infrastructure. Because electricity provides basic necessities and comforts such as light, heat, and cooking, the short-term options to significantly reduce usage are limited.

Domestic and commercial customers can immediately change some behaviors, such as turning off lights or turning down the temperature. Over the longer-term, customers can invest in more efficient buildings, appliances, and equipment. However, there is no viable option for extensive switching away from electricity in Newfoundland because oil and propane are, and likely will continue to be, more expensive than electricity—even if electricity reaches higher rates as projected. However, since a substantial fraction of electricity is used for electric resistance space heating, much of that could be replaced by heat pumps. This would reduce electricity consumption.

Industrial customers in energy intensive industries are subject to international markets and thus much more sensitive to energy prices. Most of the large industrial customers currently have relatively low rates. If prices were to increase significantly, or if international competitive conditions were to change, there could be a significant reduction in industrial load in the Province. This would be similar to what happened in Nova Scotia and Newfoundland[19]several years ago when a number of paper mills closed for economic reasons. But such an outcome is inherently difficult to predict.

Price elasticity is often used as a proxy for the price response of customer behavior to predict price and demand behavior. However, there is a great deal of inertia in customer electricity use because of the existing infrastructure. Over the longer-term, investments can be made in more efficient buildings, appliances, and equipment. Typically, this is represented as short- and long-term elasticities. Short-term being in the order of a few years, and long-term being in the order of equipment lifetimes. In 2014 the U.S. Energy Information Administration studied the price elasticities of energy use in buildings in the United States.[20] For residential electricity use, the one-year elasticity was -0.12, increasing to -0.24 in three years, and up to -0.40 in twenty-five years. The commercial short-term elasticities were similar, but the long-term value was twice as great at -0.82. One big caveat, though, is that the competitive energy source natural gas is widely available and relatively cheap in the United States, which is not the case in Newfoundland.

The electricity price elasticity as represented in the Nalcor forecasts is roughly -0.30, which is a little greater than the Energy Information Administration's three-year value of -0.24, but less than the twenty-five-year value of -0.40. The Consumer Advocate has suggested that the long-term price elasticity effect could be as great as -0.40 or -0.60.[21] Given the limited fuel substitution options available in Newfoundland we think that such large effects are unlikely, especially over the next ten years. However, we do explore an extreme low load case to understand the potential consequences.

The actual customer response to higher prices will depend on a number of factors, including: (1) how rapidly rates increase; (2) how high rates go; (3) what incentives are provided for increased electrification in buildings and transportation; (4) what incentives are provided for CDM measures and heat pump adoption in existing buildings; and (5) what utility and provincial programs are implemented. Ultimately, the province will have to closely monitor customer responses and implement programs that economically encourage the use of electricity.

4.4. Load Forecast Scenarios

Synapse began by developing three initial load forecasts based on Hydro's low rate, mid-rate, and high rate increase forecasts.[22] All three of Hydro's scenarios begin with a rate of 15.5 cents/kWh in 2019 ($2018), after which rates increased until 2023 (for low and mid) or 2025 (high), before flattening out.

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[19] Two large mills owned by Abitibi closed in Newfoundland in 2005 and 2009, resulting in a large drop in load.

[20] U.S. Energy Information Administration. 2014. "Price Elasticities for Energy Use in Buildings of the United States," October 2014. https://www.eia.gov/analysis/studies/buildings/energyuse/pdf/price_elasticities.pdf

[21] Feehan, J. P. 2018. "The Long-Run Price Elasticity of Demand for Electricity and the Feasibility of Raising Electricity Rates to Finance Muskrat Falls," July 31, 2018. Submitted in the 2017 General Rate Application process.

[22] Forecast data were provided in the responses to PUB-NACLOR-057, PUB-NALCOR-074, and PUB-NALCOR-112. All Hydro forecasts represented rate increases but varied as to degree and duration.

The low, mid and high rates flattened out at 18.2 cents/ kWh, 21.3 cents/kWh and 25.5 cents/kWh respectively.[23] We used NP's load forecast trends during the early part of the study period (2019-2023)[24] to develop load adjustments that sustained a flatter load-growth trend through the later years of the study period (2024 to 2030). Based on our understanding of the potential rate increases that may ultimately apply in the Province,[25] we assumed that Hydro's "low rate" forecast is most closely aligned with likely actual load trajectories. We use that low rate forecast, coupled with our 2024-2030 adjustments, to define our reference load forecast (Synapse LR) and to benchmark all our analyses of rate mitigation options.[26]

We also created two outlier load forecasts. The first represents a scenario where IIS load decreases significantly in the Province, below the level forecasted in Hydro's high rate forecast (which otherwise exhibits the largest declining load trajectory of Hydro's forecasts). The second represents an increase in Labrador load well beyond Hydro's current forecast (which already includes an increment of load due to the Tacora mine operation).[27]

In this section, we review the three rate forecasts that we developed based on Hydro's low, mid, and high rate forecasts, and we discuss how we developed the extreme load scenarios. Additionally, we review our methodology for developing our CDM and electrification-adjusted forecasts and present a sample of the load forecasts that bookend our Scenarios.

Synapse Low Rate (LR) - Reference Forecast Load

Synapse relied primarily on the energy forecasts provided by NLH and NP to develop the reference case forecast. We started with NLH's low rate forecast for the IIS, and then made an adjustment to the NP portion of the load post-2024 to replicate the trends seen in the NP five-year forecast, which is described in detail below.

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[23] Response to PUB-Nalcor-074.

[24] Response to PUB-NP-001.

[25] Announcements by the Provincial government in April 2019 indicated an intention to hold rates to levels lower than the 2021 unmitigated rate (22.9 c/kWh, domestic customer, per the Reference Questions). The "low rate" scenario forecast by Hydro exhibits the smallest increase in retail rates over time, and thus is the basis for our reference forecast.

[26] The reference case forecast is also used as an input to our CDM model.

[27] Response to PUB-Nalcor-103

Table 8: Synapse Island System Reference Forecast

Energy Requirements (GWh)	2019	2020	2025	2030
Newfoundland Power	**6,350**	**6,291**	**6,220**	**6,104**
Deliveries from NLH	5,920	5,854	5,783	5,667
NP Own Generation	430	437	437	437
NLH Rural	**432**	**425**	**401**	**401**
Sales to Customers	432	425	401	401
Industrial	**1,520**	**1,493**	**1,493**	**1,490**
Deliveries from NLH	647	612	612	610
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NLH Total Island Sales	**6,999**	**6,892**	**6,796**	**6,678**
IIS Total Energy Requirement	**8,301**	**8,208**	**8,113**	**7,997**
Island Losses	295	362	426	417
LIL Losses	56	278	306	304
Total Energy Requirement	8,653	8,850	8,846	8,716
Peak Demand (MW)	**2019**	**2020**	**2025**	**2030**
Newfoundland Power Retail	1,402	1,397	1,398	1,399
NLH Rural Retail	105	105	105	105
Industrial Retail	185	182	182	182
Annual Retail Peak	1,692	1,684	1,684	1,685

Note: Synapse developed our reference forecast utilizing sales and bulk energy delivery input forecasts developed by NLH and NP at different times. For that reason, the components of load displayed here may not match exactly Totals, and the PLEXOS input loads differ slightly from total energy requirements displayed here.
Source: Synapse calculations, based on Response to Nalcor-PUB -112,and Nalcor-PUB-057.

In NLH's reference forecast for the IIS, 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,[28] (2) the most recent near-term forecast from NP predicts a sales decline of 0.24 percent per year,[29] (3) NP customers are already switching to heat pumps and other conservation measures in anticipation of price increases,[30] (4) customer prices will continue to rise through 2030,[31] and (5) the modest economic upturn used in the econometric model inputs is not sufficient to generate the forecasted sales increase.

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[28] Response to PUB-NP-001.

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

[30] Response to PUB-NP-017.

[31] Based on expectations arising from the anticipated in-service of the MFP.

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, the effect on the peak is less certain.

The NLH forecast for Labrador projects relatively flat consumption through 2030, as shown in Table 9. 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 LIS, the Wabush Mines are being reactivated with loads of 55 MW (peak) and 430 GWh per year.[32] There are other new potential loads of 50 to 165 MW which would represent a significant increase for Labrador.[33] Typically, these industrial loads have high load factors and remain in operation during the winter peak periods. Some, however, participate in demand reduction programs.

Table 9: Labrador Base Forecast

Energy Sales (GWh)	2019	2020	2025	2030
Hydro Rural	753	742	795	736
Labrador Industrial	1,742	1,741	1,742	1,741
Reactivation Wasbush mines, Tacora	251	415	420	420
Total Sales	**2,745**	**2,897**	**2,956**	**2,897**
Transmission Losses	160	159	163	159
Total Energy Requirement	2,905	3,057	3,119	3,055
Peak Load (MW)	**2019**	**2020**	**2025**	**2030**
Hydro Rural	171	166	168	172
Labrador Industrial	251	250	250	250
Total	422	416	418	422

Source: Synapse calculations, based on Nalcor-PUB-057.

Synapse Mid and High Rate Load Forecast Scenarios

Hydro uses traditional econometric forecasting methodology which is reasonable given the relative historical stability of the loads and the key drivers. However, the anticipated large price increases are outside the historical range used to calibrate the models, and model predictions will be less reliable under such changed conditions. The price response effects could either be less or greater than those represented by the model elasticity coefficients (see Price Response section).

Hydro provided three alternative forecasts using different future rate increase assumptions.[34] The rate scenarios are: (1) Low rate increase (which we use as our reference case), (2) Mid-rate increase, and (3)

[32] Response to PUB-Nalcor-103.

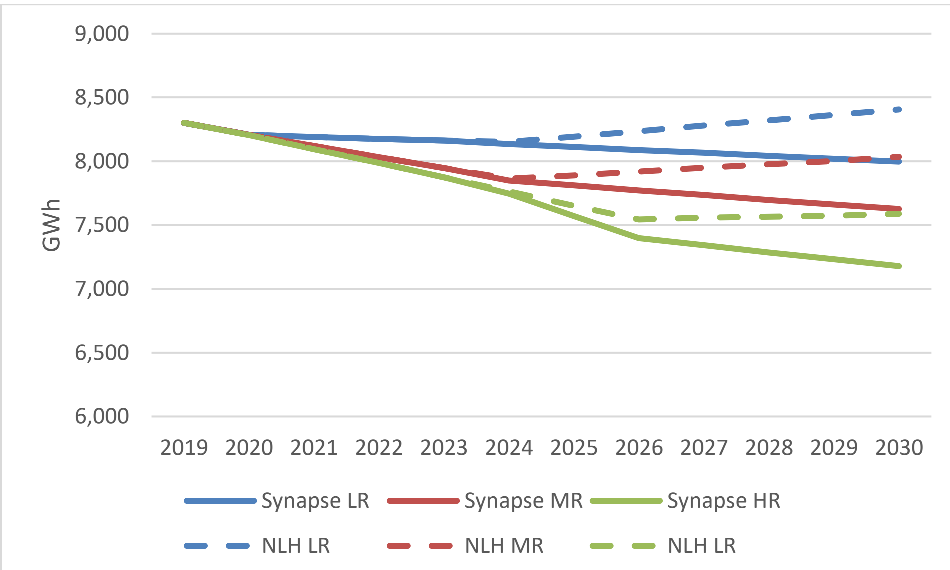
[33] Response to PUB-Nalcor-104.

[34] NLH also provided a High Growth scenario but without any price information.

High rate increase. Synapse modified the mid and high rate forecasts by applying NP's flatter forecast trend, as we did with the low rate scenario.

The Island requirements as forecasted by NLH, and then as adjusted by Synapse, are shown below in Figure 7. All NLH scenarios display an initial decline in requirements associated with price increases, but then recover mid-decade as prices stabilize. NLH's scenarios represent a negative price elasticity of about 0.30 as mentioned in the Phase 1 report. Analysis of the Hydro forecasts excluding price effects indicates that the overall annual growth rate is about 1 percent per year. That is, if the price were to stay constant in real terms, load would grow by 1 percent per year because of other factors (economic, demographic, etc.).

Figure 7. Synapse and NLH Island requirements forecast

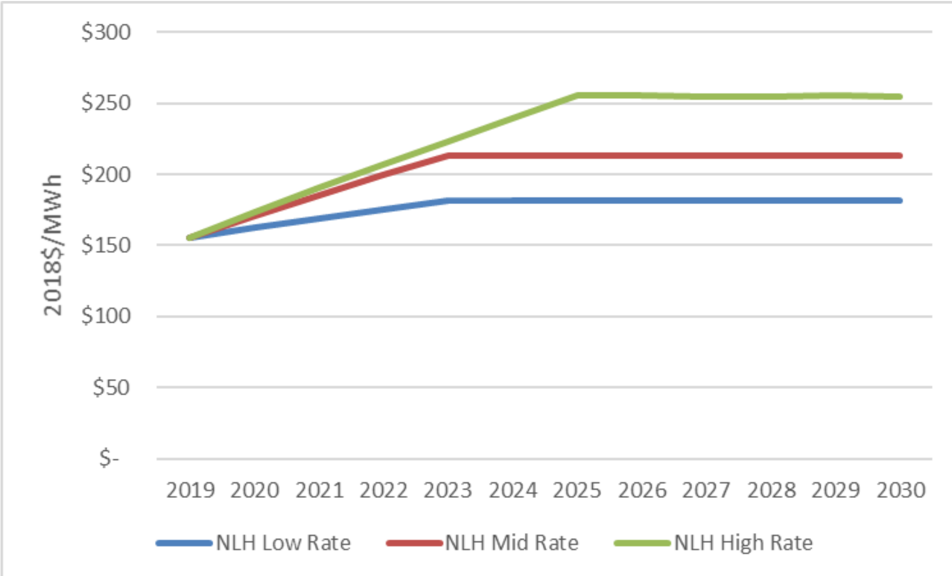


Note: Forecasts included NP self-generation, load served by industrial self-supply, as well as on-island losses.
Source: Synapse calculations based on PLEXOS model inputs provided by NLH and Nalcor-PUB-112.

The price response impacts for NLH's forecasts vary based on the magnitude of the rate impacts. The low rate (or Base Case) scenario flattens out fastest, and the high rate scenario takes the longest to stabilize. In total, the low rate scenario drops 149 GWh by 2023 (relative to the starting point in 2019), the mid-rate drops 437 GWh by 2024, and the high rate drops 757 GWh by 2026. The Synapse forecasts all assume a continued downward trend, with the low rate scenario dropping 3.7 percent by 2030 (relative to 2019), the mid-rate dropping 8.2 percent, and the high rate dropping 13.5 percent.

The scenario price trajectories (represented as residential rates) associated with NLH's three scenarios are shown in Figure 8 in real terms. The low case assumes a rate increase of 30 percent relative to 2019 rates by 2023, the mid-case an increase of 47 percent by 2023, and the high case an increase of 54 percent by 2023. Synapse's low-, mid-, and high-rate load forecasts are intended to reflect rate trajectories comparable to the NLH rate scenarios.

Figure 8: Rate Scenarios



Source: Synapse graph based on Nalcor-PUB-074. Rates are IIS average domestic retail rates.

The above forecasts are based on an average price elasticity of about -0.30. However, if there is a greater level of customer response to higher prices, loads may decrease more than represented in NLH's scenarios. Figure 9 shows what load could look like with a doubled level of price response. In the extreme case, such an assumption might lead to a 35 percent decrease in load for the highest price scenario.

Figure 9. Alternative Forecast with greater Elasticity (-0.6)

Source: Synapse calculations

IIS Extreme Low Load Scenario

Synapse developed an extreme low load scenario, displayed in Table 10, to stress test the system and evaluate the impact of an extreme loss of load. While such a scenario is unlikely, there are many varied and uncertain factors that could produce a substantial load reduction.

The customers most sensitive to prices are large industries. Currently large industries represent about 1,500 GWh of load (including self-gen) on the Island and 1,750 GWh in Labrador. If any of those customers were to leave or close, they would cause a significant reduction in the provincial load. This happened in Nova Scotia and Newfoundland several years ago when multiple large paper mills shuttered their doors.

Residential and commercial loads could also decline with the switch from electric resistance heating to heat pumps, or an out migration of population. That could reduce loads by ~1,500 GWh over several years. Such changes would be more gradual and could be compensated for with increased electrification programs.

To develop this scenario, we benchmarked using the load reduction levels in our High CDM scenarios. In the *Synapse Low Rate, High CDM with TOU rates scenario,* 2030 energy load and peak demand are 12 percent and 10 percent below 2030 levels in the reference *Synapse LR scenario.* We assumed that an extreme low load could lower energy and peak even further to 20 percent and 17 percent below the reference case energy load and peak demand in 2030. This scenario assumes a slightly lower load factor than seen in the reference case (based on the pattern of decreasing load factors as load decreased in the reference case). We also assumed that the load reduction relative to the baseline scenario was spread evenly over each year (this was a simplifying assumption).

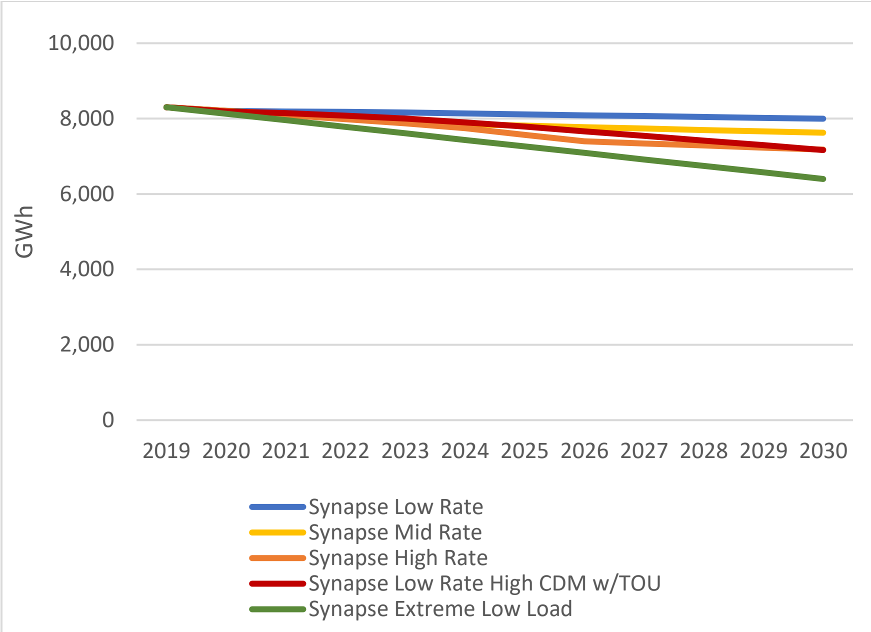
Table 10: Synapse Low Load Scenario

Year	Energy	Peak
2019	8,301	1,671
2020	8,128	1,644
2021	7,955	1,618
2022	7,782	1,591
2023	7,609	1,564
2024	7,436	1,538
2025	7,263	1,511
2026	7,090	1,485
2027	6,917	1,458
2028	6,744	1,431
2029	6,571	1,405
2030	6,398	1378
Delta from Synapse LR	-20%	-17%

Source: Synapse calculation

Figure 10 compares the Extreme Low case in comparison with other scenarios.

Figure 10: Island load in the extreme low load scenario compared to other scenarios



Source: Synapse calculations

Labrador High Load Scenario

Synapse used NLH's high new customer load forecast for Labrador to evaluate the impact of increased Labrador load on export market sales and revenue. NLH's high Labrador customer forecast assumes that Labrador's load increases considerably beyond its current forecasted load from (1) a Department of National Defense Central Heating Plant Fuel Conversion, (2) new data center load, and (3) an additional ore mine (beyond Tacora, which is already included in the base forecast).

We utilized the reference low rate forecast for the Island, combined with this new load forecast for Labrador to create the scenario. We ran PLEXOS to determine export market sales and revenue. We found that increased Labrador load utilizes more recall energy from Churchill Falls, as well as energy from Muskrat falls that is currently exported. Thus, depending on the contribution to overall revenue requirements associated with the increased Labrador load, the ultimate effect on IIS ratepayers could be to reduce the mitigation available from sales of recall energy not required to meet load.

CDM and Electrification Scenarios

Synapse created 24 different load shapes used in 27 different scenarios. The Synapse Low rate forecast was the starting point for 24 of the 27 scenarios we tested. As shown in Figure 2, each unique scenario adjusted the reference forecast by applying different levels of the following: (1) CDM measures that decrease existing load; (2) beneficial electrification of new buildings, heating loads, and transportation that adds new load; (3) TOU rates that partially shift some existing load from peak to off-peak hours; (4) electric vehicle TOU rates that aligns most new electric vehicle load with off-peak hours.

These loading scenarios serve as inputs to the PLEXOS production cost model, which we used to estimate the value of surplus energy sales to export markets. This exercise is primarily geared towards developing refinements to internal load consumption on an hourly basis, to allow a refined estimate of export sales of surplus energy. As is seen in our export market sales results, the different load forecasts give rise to different levels of export market sales; and the underlying load shapes of Provincial load—which are affected by the specific assumptions for electrification and CDM—lead to different sales levels in off-peak or on-peak market periods.[35] Table 11 below presents NLH's original forecast, the Synapse Reference forecast, and several "bookend" energy and peak load forecasts for the Province. The *Synapse Low Rate, High Electrification Scenario* has the highest island load forecast we model and bookends island load on the upper limit. The Extreme Low Load Scenario has the lowest load forecast we model and provides the lower bookend. Additionally, we show the *Synapse Low Rate, High CDM with TOU Scenario*, which utilizes the lowest load among our CDM and electrification scenarios. We provide all scenario forecasts in the Appendix.

[35] The underling export sales market is split between on-peak and off-peak periods, for any given day or month.

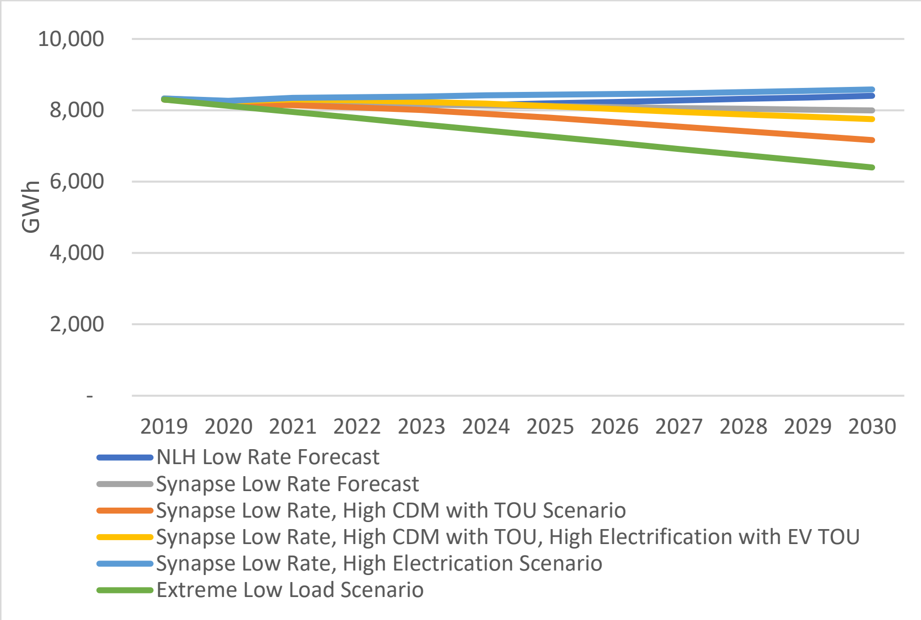
Table 11: Island Interconnected System Load Forecasts – Including Self-Generation and Losses

Load (GWh)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NLH Low Rate Forecast	8,301	8,208	8,191	8,176	8,162	8,152	8,192	8,235	8,281	8,321	8,362	8,406
Synapse Low Rate Forecast	8,301	8,208	8,191	8,176	8,162	8,136	8,113	8,087	8,065	8,041	8,019	7,997
Synapse Low Rate, High CDM w/TOU	8,301	8,190	8,144	8,081	8,005	7,902	7,792	7,666	7,544	7,417	7,295	7,165
Synapse Low Rate, High CDM w/TOU, High Electrification w/EV TOU	8,330	8,248	8,305	8,273	8,230	8,188	8,116	8,032	7,957	7,885	7,818	7,753
Synapse Low Rate, High Electrification	8,330	8,266	8,352	8,368	8,387	8,422	8,437	8,453	8,479	8,508	8,542	8,584
Extreme Low Load Scenario	8,301	8,128	7,955	7,782	7,609	7,436	7,263	7,090	6,917	6,744	6,571	6,398
Peak (MW)												
NLH Low Rate Forecast	1,671	1,662	1,657	1,659	1,663	1,666	1,672	1,677	1,686	1,696	1,706	1,716
Synapse Low Rate Forecast	1,671	1,662	1,657	1,659	1,663	1,662	1,663	1,662	1,664	1,664	1,664	1,664
Synapse Low Rate, High CDM with TOU	1,671	1,655	1,625	1,611	1,598	1,589	1,574	1,528	1,533	1,511	1,482	1,447
Synapse Low Rate, High CDM w/TOU, High Electrification w/EV TOU	1,675	1,665	1,647	1,646	1,638	1,622	1,606	1,590	1,574	1,552	1,532	1,513
Synapse Low Rate, High Electrification	1,675	1,671	1,679	1,694	1,704	1,704	1,714	1,733	1,735	1,751	1,749	1,767
Extreme Low Load Scenario	1,671	1,644	1,618	1,591	1,564	1,538	1,511	1,485	1,458	1,431	1,405	1,378

Excludes LIL losses. Includes NP and industrial self-generation. Source: Synapse calculations and underlying Responses to Nalcor-PUB-074, Nalcor-PUB -112 and Nalcor-PUB-057.

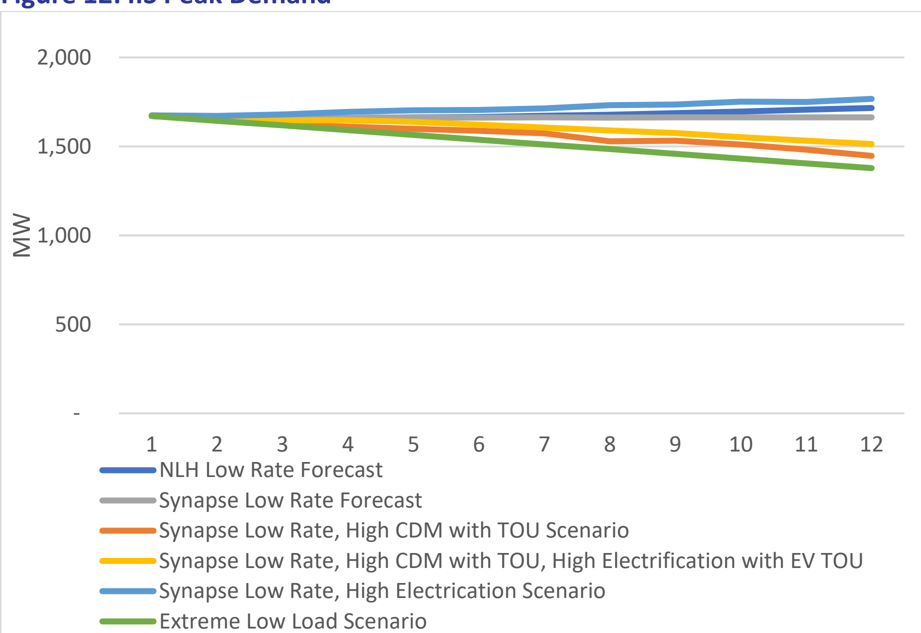
Figure 11 and Figure 12 present the forecasts in graphic form for total energy requirements and total Island peak load.

Figure 11: IIS Total Energy Requirement



Source: Synapse calculations

Figure 12: IIS Peak Demand



Source: Synapse calculations

5. ELECTRIFICATION

This analysis focused on electrifying the fuel consumption of three end-use sectors in Newfoundland: residential heating, commercial heating, and transportation. We did not analyze industrial electrification due to a lack of industrial end uses in Newfoundland that can be electrified.

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

5.1. Methodology

Building Electrification

The building electrification analysis focuses on the conversion of oil heating systems in the residential and commercial sectors to electrified heating systems (either heat pumps or electric resistance boilers). The low and high building electrification scenarios differ not only in their assumed annual rate of system conversion, but also in the following way:

- The **low scenario** assumes that all oil-heated buildings will maintain their oil systems as a back-up heating system and that the building will have integrated controls to allow use of the oil system below a certain temperature.[36] This “threshold” temperature is assumed to be -7°C (20°F). This assumption reduces temperature-dependent building load during peak days.
- The **high scenario** assumes that no oil-heated buildings will maintain their oil systems as a back-up heating system.

The construct described above provides a theoretical range of newly electrified load for Newfoundland’s future—a low growth scenario with peak reduction on the coldest days of the year, and a high growth scenario with no peak reduction. Therefore, the low and high scenarios define our assumed “lowest low” and “highest high” new load contributions from building electrification. The actual course pursued by the Province and its utilities will likely fall between these two cases and may have a different ratio of energy to peak additions, depending on the structure of the policies and programs implemented.

Residential Building Electrification

The residential analysis evaluated the potential to electrify oil-heated homes by installing ductless mini-split air source heat pumps in residences in both the IIS and LIS. Currently the percentage of residences

[36] We maintain that this assumption holds given a program that provides strong financial incentives to maintain a back-up non-electric heating system. Such financial incentives are reflected in the electrification chapter.

on the Island with oil heating systems is estimated at 23 percent.[37] In Labrador, that percentage is about 14 percent.[38] The low scenario assumes that 0.5 percent of oil-heated homes convert to heat pumps per year, reaching 6 percent of such 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's residential sector from the Canada's Energy Future Report.[39] These projections were used to calculate the annual GWh impacts for both the low and high scenarios in both the IIS and LIS. The electricity outputs from heat pumps were estimated using the average annual COP of cold climate air source heat pumps (ccASHP) in Newfoundland and the average efficiency of the existing oil system of 80 percent. 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 6.

Hourly load from residential heat pumps was calculated by multiplying each hour's "peak factor" (hourly heat pump load for a single residence divided by a single residence's total heat pump load) with the total annual load from heat pumps. This approach allocates the annual heat pump load across each hour of the year based on the temperature in each hour and the associated COP of the heat pump. For the low scenario, any hours at or below -7°C do not have any electric load, as we assume that the back-up oil system will be utilized below that temperature.

Commercial Building Electrification

The commercial building electrification analysis evaluated the electrification potential of oil-heated small, large, and institutional (e.g., universities, K-12 schools, hospitals) commercial buildings in both the IIS and LIS. 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 1 percent of oil-heated commercial buildings convert to electric heating systems each year; the high scenario assumes that 4 percent of oil-heated commercial buildings convert to electric heating systems each year.

The commercial sector analysis was conducted in a manner similar to the residential sector analysis. Annual historical oil consumption data and projections for Newfoundland's commercial sector were first taken from the Canada's Energy Future Report. The oil energy consumption per square foot was calculated using these data and information about the percentage of oil-heated small, large, and institutional commercial buildings. The oil heating shares for each type of commercial building in Newfoundland are presented in Table 12.

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[37] Response to PUB-NP-014

[38] Response to PUB-Nalcor-072

[39] 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

Table 12. Percentage of oil-heated commercial buildings in Newfoundland and Labrador.

Building Type	Newfoundland	Labrador
Small Commercial	18%	5%
Large Commercial	8%	5%
Institutional	46%	5%

Source: Responses to PUB-NP-014 and PUB-Nalcor-072. Note: Institutional buildings are defined as 1000+ kVA, small commercial buildings as 0-100 kVA, and large commercial buildings as 110-1000 kVA.

The only exception to this methodology was for Memorial University 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.[40] The low scenario assumes one electric boiler is added in 2021, replacing half of the university's oil consumption. The high scenario assumes a second boiler is added in 2024, replacing an additional 25 percent of the university's oil consumption. We assume that the university will continue to use some oil during on-peak hours to avoid high electric demand charges. We assume the electric boilers would be run continuously, with the oil units used to address increases in load during colder weather, which is why replacing only one boiler out of four with an electric boiler accounts for 50 percent of the heat consumption.

For small and large commercial buildings, the calculated energy impacts were estimated using the same 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.

Annual load estimates were translated into hourly loads using a similar approach described for the residential sector. However, because the electric load in commercial buildings is not entirely temperature-dependent (i.e., some of the load is baseload, or consistent throughout the year), the approach varies by type of commercial building:

- Small and large commercial buildings: We assume that all load in these buildings is temperature-dependent and will be served with heat pumps. Therefore, each hour's load was calculated in the same manner as the residential sector—by multiplying each hour's heat pump "peak factor" by the total annual load for small and large commercial buildings.

- Institutional buildings: We assume that 40 percent of institutional building load is baseload and 60 percent is temperature-dependent—both of which will be served by electric resistance boilers. Therefore, 40 percent of the institutional building load is distributed evenly across all hours of the year; the remaining load is distributed using each hour's "peak factor."

- Memorial University: We assume that 60 percent of Memorial University's load is baseload (serving classrooms, laboratories, and other year-round processes) and 40

[40] Based on a conversation with Newfoundland's Department of Natural Resources.

percent is temperature-dependent—both of which will be served by electric resistance boilers. Therefore, 60 percent of the institutional building load is distributed evenly across all hours of the year; the remaining load is distributed using each hour's "peak factor."

Transportation Electrification

The transportation analysis evaluated the electrification potential of 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.[41] The electrification potential of light-duty vehicles was calculated using Synapse's in-house tool EV-REDI. This tool applies a technology adoption curve to historical electric vehicle adoption data, predicting electric vehicle adoption into the future.[42] 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 (pre-2019) electric vehicle adoption data to develop the early portion of the technology curve.[43] For the high scenario, we assume that Newfoundland attains the all-Canada goal of reaching 30 percent electric vehicle sales by 2030.[44] The low scenario assumes the high scenario curve is delayed by five years and only attains 10 percent electric vehicle sales by 2030. By 2030, 1.5 percent of light-duty vehicle stock is electrified in the low scenario and 7.5 percent is 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-burning vehicles. To understand the impacts electric vehicle charging would have on the electric grid, the total annual electricity consumption was distributed over the year using data about how many miles are driven in each season and how much more energy electric vehicles consume in cold temperatures. These effects partially cancel out, as

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41 Light trucks include SUVs, pick-up trucks, and some crossovers and minivans. All other passenger vehicles (e.g., sedans) are considered cars. The analysis assumes that cars and light trucks are electrified at the same rate.

42 The model assumes that 57 percent of electric vehicles sold in Newfoundland in 2020 are battery electric vehicles (BEV) and 43 percent are plug-in hybrid electric vehicles (PHEV). By 2030, 83 percent of electric vehicles sold are BEVs. Moreover, we assume that 66 percent of the kilometers traveled by PHEVs are powered by electricity.

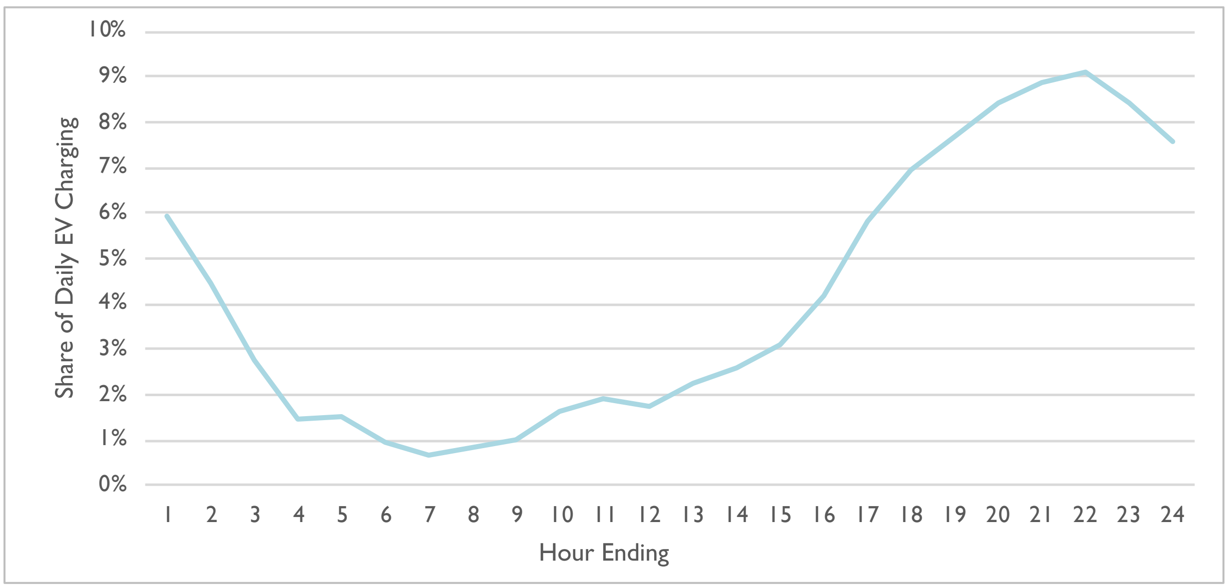
43 Newfoundland electric vehicle stock was estimated based on this article: https://www.cbc.ca/news/canada/newfoundland-labrador/looking-for-a-place-to-plug-in-1.4625565

44 Natural Resources Canada. 2019. "Zero-emission vehicle infrastructure program." Available at: https://www.nrcan.gc.ca/zero-emission-vehicle-infrastructure-program/21876?wbdisable=true

vehicles travel fewer kilometers during the winter on average but can become nearly 40 percent less efficient in cold temperatures due to the energy consumption required for heating.[45]

To determine the impacts on IIS and LIS, we scaled the total province results based on the percentage of the population in each location. Annual load from light-duty vehicles was converted to monthly load impacts using seasonal driving data for light-duty vehicles in Newfoundland.[46] On average, the fewest kilometers are driven between the months of January and March. Monthly load estimates were converted to hourly load using two steps: (1) First, evenly distributing electric vehicle load across all days in the month, then (2) distributing daily load to each hour of the day using a typical (flat rate) electric vehicle charging profile for a similar climate to Newfoundland (see Figure 13).[47]

Figure 13. Light-duty electric vehicle daily charging profile for flat rates



Source: DTE Electric Company, Direct Testimony of Camilo Serna, U-20162, July 6, 2018.

Medium-Duty Vehicles

The medium-duty vehicle electrification analysis included school buses, transit buses, and delivery trucks—those that are most likely to be electrified by 2030. These vehicles types are all assumed to be fueled by diesel today. The low and high scenarios both assume that medium-duty electric vehicles will follow the same stock percentage trajectory as light-duty vehicles. In other words, we assume that 1.5

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[45] https://www.aaa.com/AAA/common/AAR/files/AAA-Electric-Vehicle-Range-Testing-Report.pdf.

[46] Statistics Canada, "Archived - Canadian vehicle survey, vehicle-kilometres, by type of vehicle, province and territory, quarterly (x 1,000,000)", Table: 23-10-0097-01 (formerly CANSIM 405-0008). https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=2310009701

[47] We applied a daily charging profile for electric vehicles from DTE Electric Company (Michigan, USA), Direct Testimony of Camilo Serna, U-20162, July 6, 2018.

percent of the medium-duty vehicle stock will be electrified by 2030 in the low scenario; similarly, 7.5 percent of the medium-duty vehicle stock will be electrified by 2030 in the high scenario.

Annual historical energy consumption data and projections are available by mode of transport through Natural Resources Canada.[48] The relevant transport mode categories available in this dataset include medium-duty trucks (e.g., delivery trucks), school buses, and urban transit 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.[49] Like the light-duty vehicle analysis, we adjusted the final energy consumption results slightly for vehicle performance variations due to temperature impacts. The impacts on Newfoundland Island and Labrador were scaled by population.

Annual load from medium-duty vehicles was converted to monthly load impacts using seasonal driving data for buses (transit and school) in Newfoundland. For transit buses, the data indicate a greater number of kilometers traveled during the winter months than in the summer or shoulder months. For school buses, we re-distributed the monthly load percentages after removing any load associated with the summer months (June through August). For each class of medium-duty vehicle, monthly load estimates were converted to hourly load using two steps: (1) First, evenly distributing monthly electric vehicle load across all days in each month, then (2) distributing daily load to each hour of the day using assumed load profiles developed for each vehicle class (transit bus, school bus, delivery truck).[50]

St. John's Port

The overwhelming majority of ship traffic in Newfoundland and Labrador travels into and out of St. John's port.[51] 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.[52] 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

[48] 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

[49] Given their similar driving patterns, school buses and transit buses were assumed to have an equivalent efficiency improvement factor. Delivery trucks were assumed to have a slightly higher efficiency improvement factor than buses given their smaller load.

[50] We assume that school buses drive primarily in two-hour blocks in the morning and afternoon (6am and 2pm) and can charge evenly throughout the day and night in all non-driving hours. Transit buses are assumed to drive from about 5am to 9pm and will charge evenly throughout the evening hours. Delivery trucks are assumed to drive in two five-hour blocks starting at 6am and 1pm; therefore, they can charge evenly throughout all other hours of the day and night.

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

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

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, we assume that St. John's port increases its on-shore power consumption by 6 percent annually. In the high electrification case, power consumption increases by 12 percent annually.

To convert the annual load to hourly load, Synapse assumes that the load will be evenly distributed across all hours of the year, given that the port operates on a 24/7 basis year-round.

5.2. Summary of Key Assumptions

This section summarizes the key assumptions impacting the electrification results. Table 13 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[53] and hourly weather data for St. John's in a typical weather year.[54] 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.[55]

Table 13. Key technology performance assumptions

Electrification Parameter	Value	Source
ccASHP Average COP	2.75	Calculated
Annual COP Improvement Rate	2%	Assumption
Diesel Genset Efficiency (Ships)	50%	Assumption
Existing Oil System Efficiency	80%	Assumption

Source: Synapse calculations

A summary of electrification growth rates by sector is provided in Table 14. 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 electrified 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

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

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

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

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 Memorial University.

Table 14. Electrification growth rate assumptions by sector

Sector	Annual Electrification Rate	
	Low Scenario	High Scenario
Residential	0.5%	2%
Commercial	1%	4%
Light-Duty Vehicles*	1.5% stock by 2030	7.5% stock by 2030
Medium-Duty Vehicles*	1.5% stock by 2030	7.5% stock by 2030
St. John's Port	6%	12%

Note: Light-duty and medium-duty vehicle electrification grows exponentially throughout the study period; therefore, we present the percent of the vehicle stock electrified by 2030 instead of an annual electrification rate.

5.3. Scenario Results

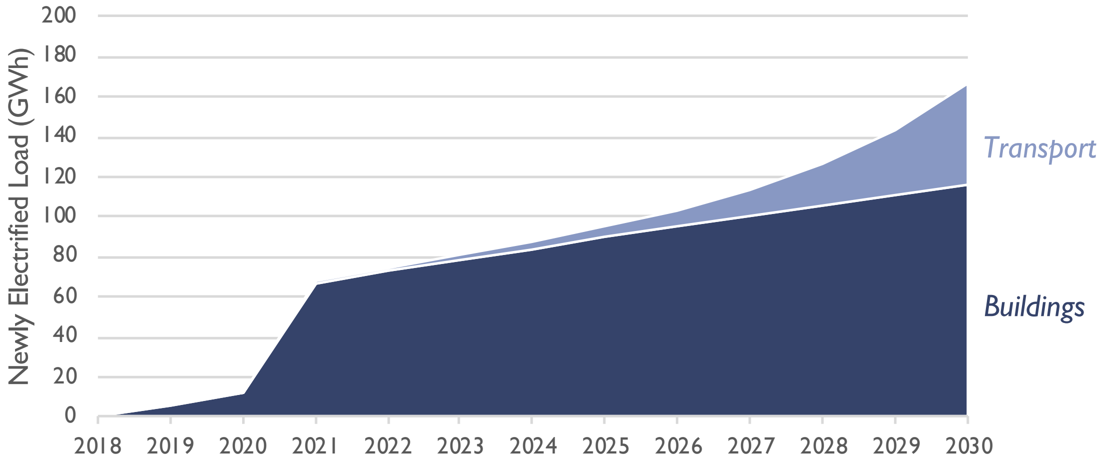
The results presented below are highly dependent upon the assumptions described in the previous section and the uncertainty associated with each of the assumptions. These results are the best approximation of the electrification impacts based on the information available to the analysis at the time of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

We present the electrification analysis results first in the context of the low and high electrification scenarios. Within the scenario results, we describe the distinct impacts to the IIS and LIS electric systems.

Low Electrification Scenario

Under the low electrification scenario, the load from newly electrified end uses is expected to reach 166 GWh by 2030 (Figure 14). The greatest hourly impact from the electrified load in this scenario is estimated to reach about 38 MW. The IIS will experience nearly 163 GWh of increased energy consumption and 37 MW of peak impacts due to electrification, representing 98 percent of energy impacts and 97 percent of the peak impacts in the province.

Figure 14. Low electrification scenario results by end-use sector



Source: Synapse calculations

Buildings

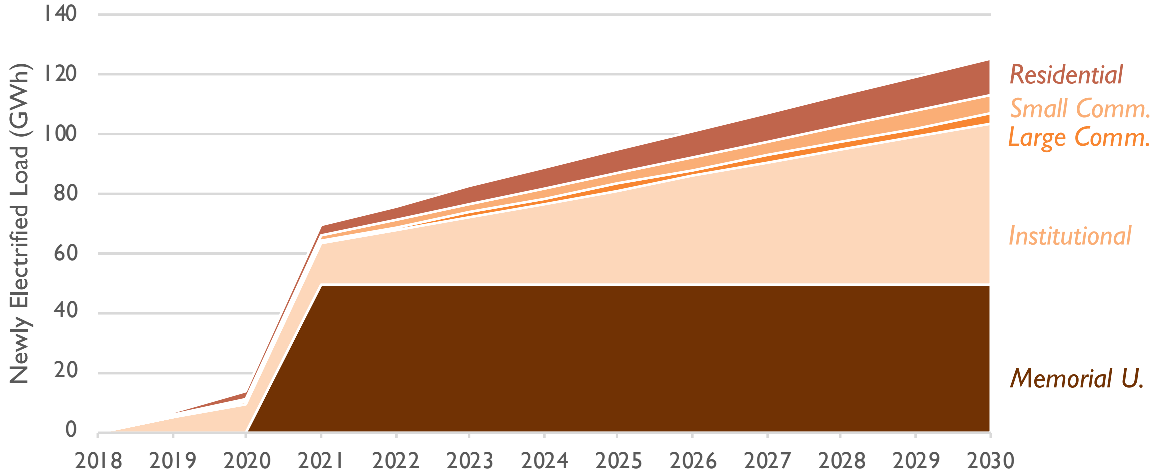
In the low scenario, 70 percent of newly electrified load in 2030 (117 GWh) is expected to be from building electrification. Within the building sector, we find that institutional buildings (including Memorial University) will have the highest load contribution of all newly electrified buildings in the low scenario—104 GWh in 2030. Figure 15 shows low electrification scenario results by building type. Institutional buildings make up approximately 83 percent of the electrification potential in the building sector for the following three reasons:

1. Institutional buildings make up a large portion of the building footprint, and therefore energy use, in the province;

2. Nearly half of institutional buildings on Newfoundland Island are currently heated by oil; and

3. We assume that institutional buildings will convert to electric resistance boilers, which use 2.8 times more energy than ccASHPs.

Figure 15. Low building electrification scenario results by building type

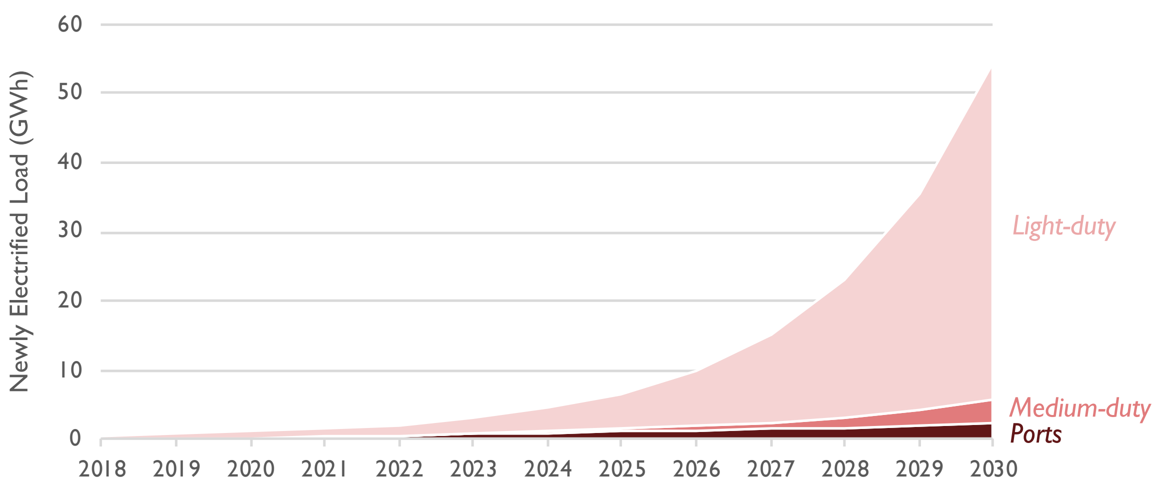


Source: Synapse calculations. Note: The step-wise increase in energy consumption between 2020 and 2021 is a result of the addition of an electric boiler at Memorial University.

Transportation

Transportation electrification (from light-duty vehicles, medium-duty vehicles, and St. John's port) makes up about 30 percent of the total electrification in the low scenario by 2030 (Figure 16). Light-duty vehicle electrification comprises 89 percent of the energy impacts at 48 GWh, medium-duty vehicles contribute 4 GWh, and St. John's port contributes 2 GWh.

Figure 16. Low transportation electrification results by transport type

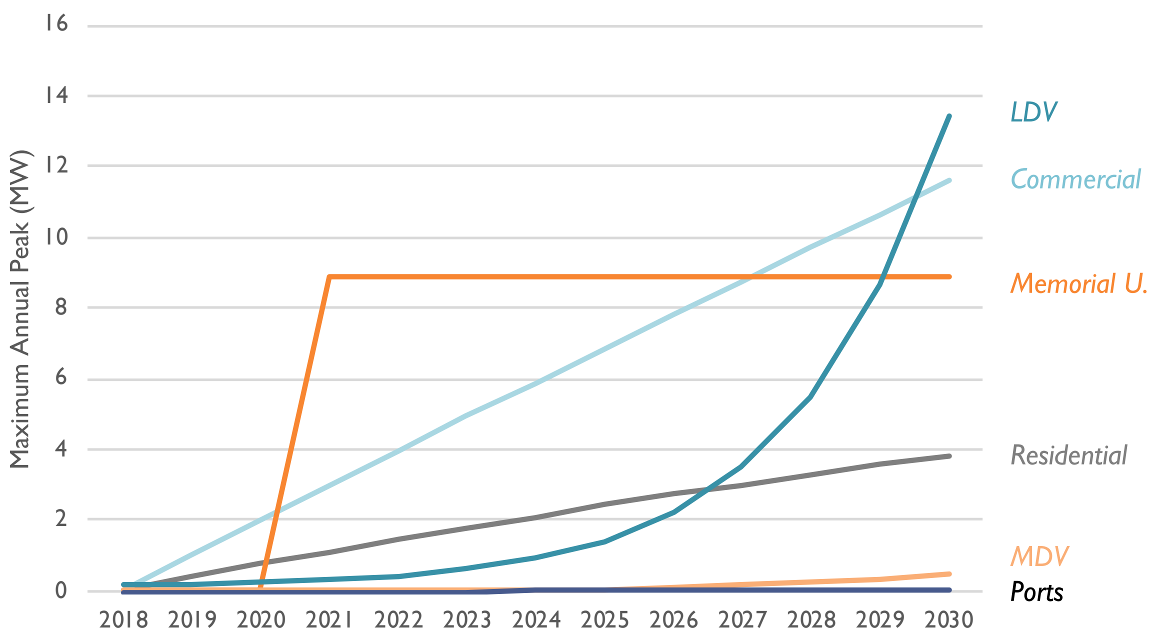


Source: Synapse calculations

Capacity

In the low scenario, the largest contributors to the IIS winter peak for the bulk of the study period are the commercial building sector and Memorial University (Figure 17). However, by 2029, light-duty vehicles surpass both commercial buildings and Memorial University in terms of peak capacity, reaching 13 MW in 2030. The sharp increase in peak load from Memorial University in 2021 is due to the addition of an electric boiler, which has a maximum annual peak load of nearly 9 MW. Residential buildings have a peak load of just under 4 MW by 2030. Medium-duty vehicles and St. John's Port have a very small contribution to the maximum peak (less than 1 MW each) for the entire study period.

Figure 17. Maximum annual peak associated with the low electrification scenario, by end use

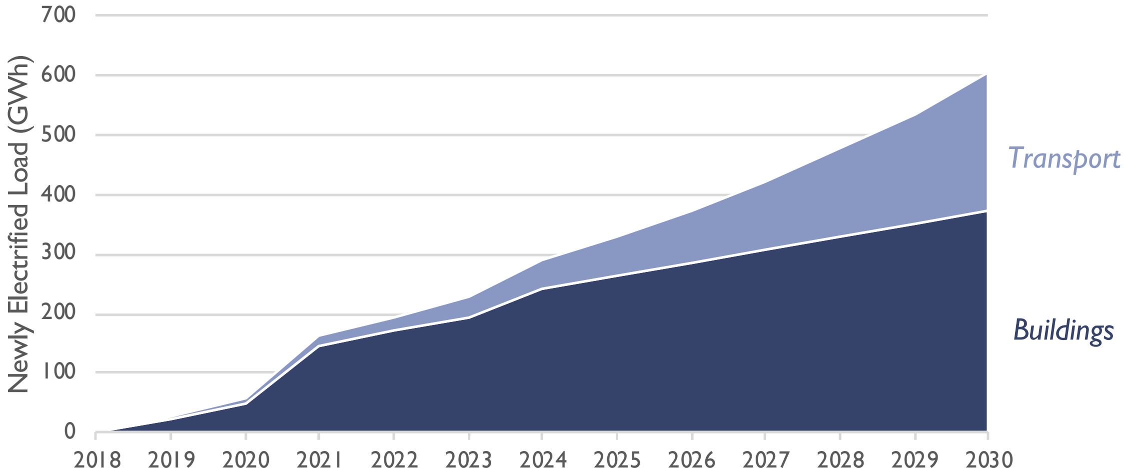


Source: Synapse calculations

High Electrification Scenario

Under the high electrification scenario, energy and peak impacts in the province are expected to reach 605 GWh per year and 151 MW by 2030, respectively (Figure 18). The IIS will experience nearly 587 GWh per year of increased energy consumption and 147 MW of peak impacts due to electrification, representing 97 percent of the energy and peak impacts in the province.

Figure 18. High electrification scenario results by end-use sector



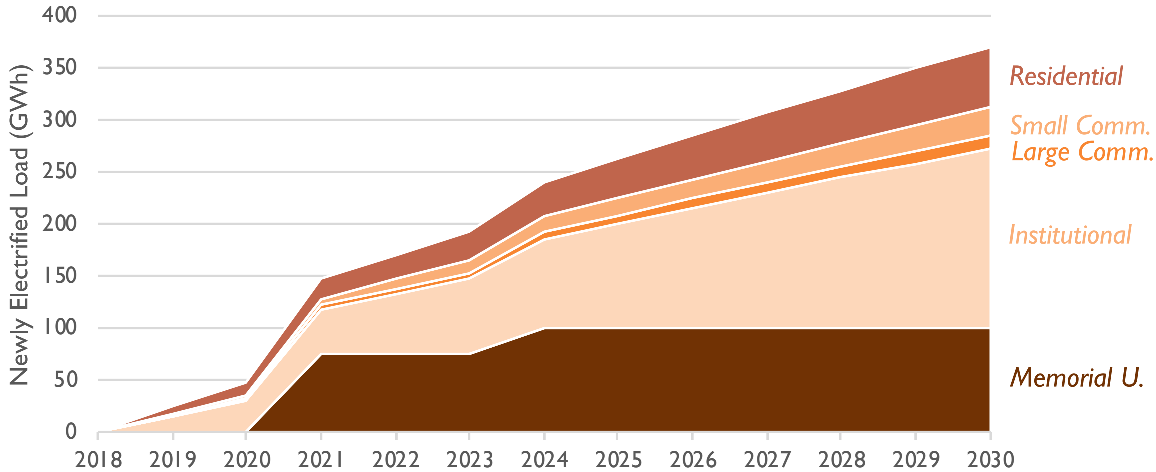
Source: Synapse calculations

Buildings

In the high scenario, 62 percent of newly electrified load in 2030 (372 GWh) is expected to be from building electrification. Similar to the low scenario, we find that institutional buildings (including Memorial University) will have the highest energy contribution of all newly electrified buildings in the low scenario—273 GWh in 2030 (Figure 19).

Residential buildings are expected to be the second-greatest contributor to building electrification, with a total annual consumption of 58 GWh by 2030 (16 percent of the expected building load). Small and large commercial buildings together represent 11 percent of the building electrification load in 2030, consuming about 39 GWh in that year.

Figure 19. High building electrification scenario results by building type

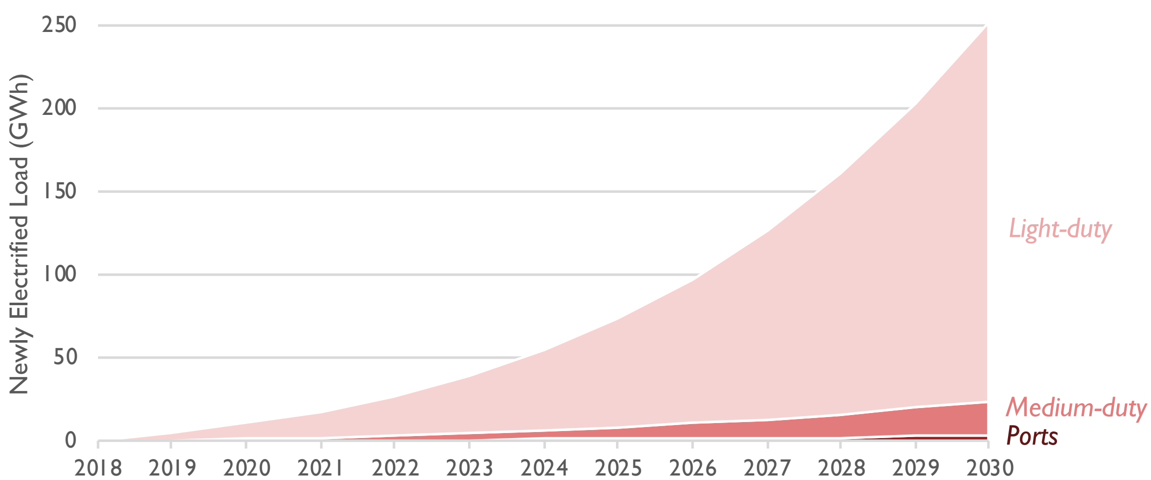


Source: Synapse calculations. Note: The step-wise increases in energy consumption in 2021 and 2024 are a result of the addition of two electric boilers at Memorial University.

Transportation

Transportation electrification (from light-duty vehicles, medium-duty vehicles, and St. John's port) makes up about 38 percent of the total electrification in the high scenario by 2030 (Figure 20). Light-duty vehicle electrification comprises 90 percent of the energy impacts at 230 GWh per year, medium-duty vehicles contribute 21 GWh per year, and St. John's port contributes 3 GWh per year.

Figure 20. High transportation electrification results by transport type

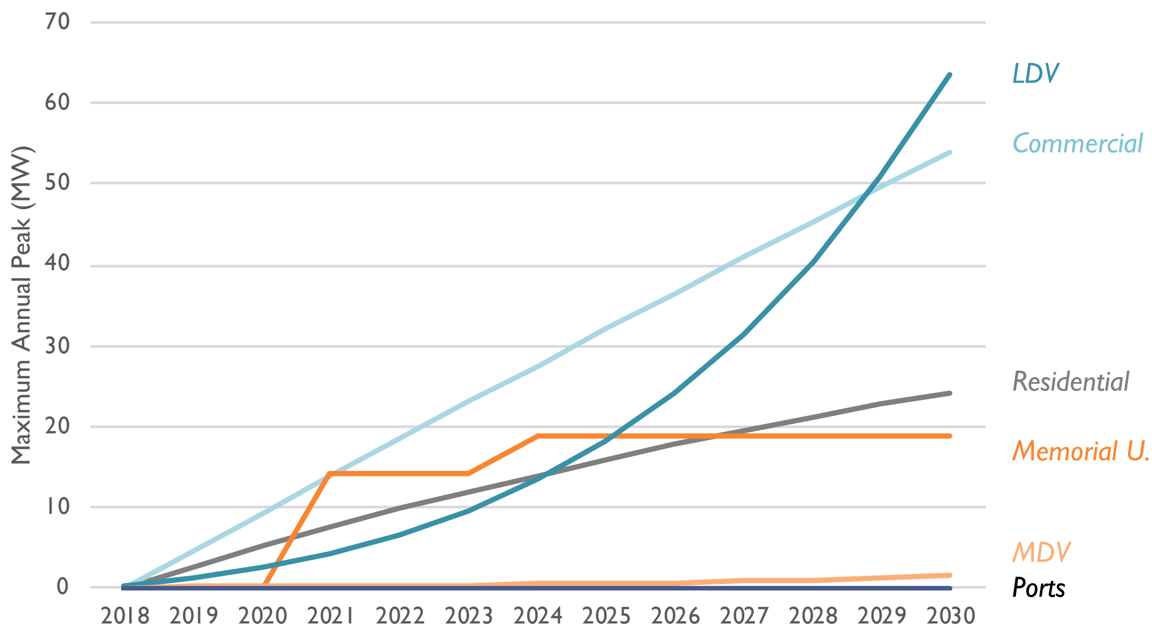


Source: Synapse calculations

Capacity

In the high scenario, the largest contributor to the IIS winter peak for the bulk of the study period is the commercial building sector (Figure 21). However, by 2029, light-duty vehicles surpass commercial buildings in terms of peak capacity, reaching nearly 64 MW in 2030. The increase in peak load from Memorial University is due to the addition of the two electric boilers in 2021 and 2024. By 2030, Memorial University requires nearly 20 MW of peak load. Residential buildings have a peak load of 24 MW by 2030. Medium-duty vehicles and St. John's Port have a very small contribution to the maximum peak (less than 2 MW each).

Figure 21. Maximum annual peak associated with the high electrification scenario, by end use



Source: Synapse calculations

5.4. Electrification Costs and Customer Economics

Electrification will have an impact on both utility and customer economics, given that revenue and cost streams are changing from fossil fuels to electricity. Furthermore, steady electrification (as illustrated in the low and high scenarios) is more likely to take place if financial incentive programs are available to customers. For these reasons, Synapse calculated the economic impact of electrification from the perspective of both the electric utility and residential customers (i.e., the purchasers of electric vehicles and heat pumps) for the IIS. For the electric utility, we present the total costs associated with electrification in this chapter. Electric utility revenues are presented separately in Chapter 8.

Additionally, we present the economics of electrification from the perspective of a "typical customer" – both for an electric vehicle customer and a residential heat pump customer.

Utility Perspective

From the perspective of the electric utility for the IIS, the costs associated with electrification are those pertaining to incentives for heat pumps and installation costs for electric vehicle charging stations. The federal incentive for electric vehicles was excluded from this analysis, as those costs are not borne by Newfoundland's electric utilities.

Incentives for heat pumps were calculated on a cost per ton basis. The incentive used for the low scenario is $1,000 per ton, while the incentive for the high scenario is $350 per ton (nominal CAD).[56] We applied a higher heat pump incentive to the low electrification scenario to reflect the added incentive required for customers to integrate their back-up oil heating system to provide heat for the coldest days of the year.

Installation costs for electric vehicle charging stations were calculated using several sources and assumptions:

- We derived the total number of charging stations required in each year of the analysis (2019-2030) from the U.S. National Renewable Energy Laboratory's EVI-Pro Lite Tool.[57] To operate this tool, the user inputs the location and number of light-duty electric vehicles as inputs, and the tool outputs the required number of charging stations (workplace level 2 chargers, public level 2 chargers, and fast chargers).[58]
- We derived the cost per charging station from Information Requests. Fast chargers are estimated as $150,000 per location and level 2 chargers are estimated as $16,013 per location.[59] About 42 percent of the cost of level 2 chargers is electrical (distribution) costs.
- We assumed that distribution system upgrades associated with the electric vehicle charging stations can be rate-based by the utility and, therefore, depreciated over the lifetime of the chargers (assumed to be 10 years). We assume that the remainder of the station costs (the chargers and site restoration costs) cannot be rate-based and depreciated and are therefore incurred in the year the station is installed.

Combining the heat pump and electric vehicle charging station costs, the low scenario is expected to cost the utility $2.4 million by 2030, while the high scenario is expected to cost $11.8 million by 2030 (Table 15). If the federal electric vehicle incentive were included as a cost in this assessment (or if the

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[56] Based on the incentive levels offered by utilities in the state of Massachusetts. See Electric Heating and Cooling Equipment. MassSave: https://www.masssave.com/en/saving/residential-rebates/electric-heating-and-cooling/

[57] EVI-Pro Lite. U.S. National Renewable Energy Laboratory. Available at: https://afdc.energy.gov/evi-pro-lite.

[58] The tool requires the user to select a U.S. state as the location for the electric vehicle chargers. As a proxy, Synapse selected three U.S. states similar in population and highway geography to Newfoundland (Maine, North Dakota, and Arkansas); the results for these locations were averaged to yield the likely number of chargers required in each year in Newfoundland.

[59] PUB-Nalcor-109 and PUB-NP-026.

Province were to offer its own similar electric vehicle incentive), the low scenario would cost an additional $10 million in 2030 and the high scenario would cost an additional $56 million in 2030.

Table 15. IIS electrification utility investment (millions CAD$) by scenario and year: 2020, 2025, 2030

Electrification Scenario	Investment	2020	2025	2030
Low	Heat Pump Installs	248	236	225
	Heat Pump Incentive Costs	$0.77	$0.81	$0.85
	L2 Charging Station Installs	2	7	81
	Fast Charger Installs	0	0	3
	EV Charging Station Costs	$0.02	$0.13	$1.52
	Total Costs	***$0.80***	***$0.94***	***$2.37***
High	Heat Pump Installs	981	889	810
	Heat Pump Incentive Costs	$1.07	$1.07	$1.07
	L2 Charging Station Installs	17	116	494
	Fast Charger Installs	1	4	18
	EV Charging Station Costs	$0.24	$2.39	$10.68
	Total Costs	***$1.31***	***$3.45***	***$11.76***

Source: Synapse calculations. Note: Values represent in-year investments (not cumulative).

Residential Customer Perspective

From the perspective of residential customers in Newfoundland, the costs associated with electrification are those pertaining to the purchase of an electric vehicle or heat pump (less any financial incentives) and the cost of electricity to power the electric vehicle and heat pump. Unlike the utility perspective calculation, the federal incentive for electric vehicles *was* included in this analysis. Though the federal incentive does not have a planned phase-out, we assume that once EV sales reach 3 percent, the incentive will step down to $4,000 per vehicle. Similarly, we assume once EV sales reach 4 percent, the incentive will step down to $3,000 per vehicle.

Given the high upfront cost of a new vehicle, we assume that electrification of private light-duty vehicles is likely to take place as customers replace their previously-owned gasoline vehicles. Therefore, in calculating electric vehicle costs, we only considered the premium of electric vehicles above the cost of a gasoline vehicle. Furthermore, we assume that vehicle owners will finance the purchase of the vehicle over five years at an interest rate of five percent. Electric vehicle premiums are made up of several components, including the car battery, in-home charger, and other items. All premiums excluding the car battery costs were taken from an Indiana University report; the car battery premiums were taken from a Bloomberg New Energy Finance report.[60,61]

Given that residential heating systems have a relatively long lifetime (20-30 years), we assume that residential heating electrification will not necessarily take place at the end-of-life of the existing oil boiler. Therefore, in calculating heat pump costs, we consider the full upfront cost of the system ($5,300 per ton and an average of 3 tons per household), less the financial incentive.[62] We assume that heat pump customers finance their system installation at the rate and terms currently offered by NP: five years at an interest rate of 7.95 percent.

To calculate the electricity costs to the customer, Synapse multiplied the electric load from heat pumps by the rates associated with the Synapse LR rate forecast (Table 16). For electric vehicle electricity costs, Synapse multiplied the electric load from electric vehicles with the three rates presented in Table 16: the Synapse LR rate, an electric vehicle incentive rate, and an average TOU rate that depends on the electrification scenario. The development of the inventive and TOU rates is discussed in Chapter 8.

Table 16. Rates ($/kWh) used in customer EV economic analysis.

Rate Type	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Synapse LR	0.1102	0.1235	0.1921	0.1900	0.1935	0.1974	0.2048	0.2074	0.2112	0.2163	0.2216	0.2250
Incentive	0.0800	0.0836	0.0874	0.0913	0.0954	0.0997	0.1042	0.1089	0.1138	0.1189	0.1242	0.1298
TOU – Low Scenario	0.0844	0.0945	0.1469	0.1452	0.1478	0.1509	0.1565	0.1585	0.1614	0.1653	0.1693	0.1720
TOU – High Scenario	0.0833	0.0940	0.1465	0.1450	0.1478	0.1509	0.1566	0.1586	0.1616	0.1655	0.1695	0.1722

Source: Synapse calculations

The benefits to the customer are avoided fuel costs (gasoline for light-duty vehicles and heating oil for residential oil furnaces). Projected fuel costs were taken from the Canada's Energy Future 2018 Report, using the low-price projection for the low electrification scenario and the high price projection for the high electrification scenario.[63]

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[60] Carley, S., D. Duncan, J. Graham, S. Siddiki, and N. Zigrogiannis. 2017. "A macroeconomic study of federal and state automotive regulations., pages 159-160. Available at: https://oneill.indiana.edu/doc/research/working-groups/auto-report-032017.pdf

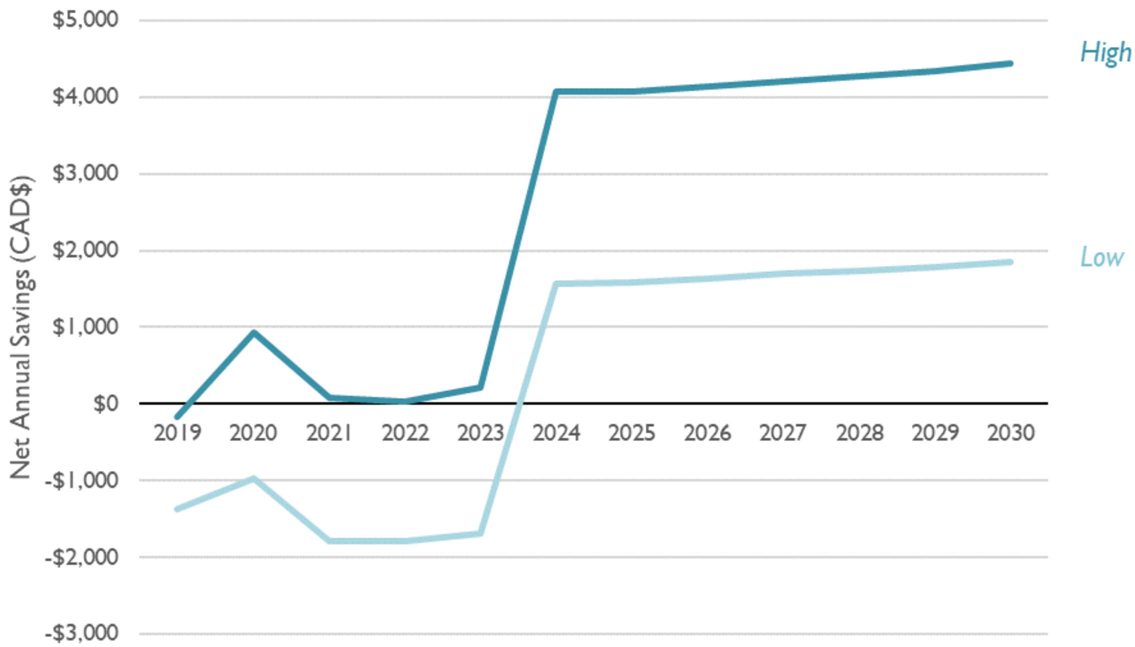
[61] Bloomberg New Energy Finance. April 2017. "When Will Electric Vehicles be Cheaper than Conventional Vehicles?," page 3. Available at: http://www.automotivebusiness.com.br/abinteligencia/pdf/EV-Price-Parity-Report.pdf

[62] Average heat pump costs were taken from the Massachusetts Clean Energy Center "Cost of Residential Air-Source Heat Pump" database. Ductless mini-split heat pumps are about $4,000 per ton. The database is available at: https://www.masscec.com/cost-residential-air-source-heat-pumps.

[63] 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

We examined the customer economics of heat pumps from the perspective of a customer installing a heat pump in 2019. Under the low scenario (i.e. low future oil prices), residential heat pump economics are favorable for such a customer from 2024 onward (Figure 22). The economics improve in 2024 due to the assumed length of the heat pump loan (5 years). Once the capital cost of the heat pump is paid off, a residential customer can expect to save $1,500-$1,800 per year compared to operating an oil furnace. The annual savings grow as the projected price of oil increases. Under the high scenario (i.e., high future oil prices), residential heat pump economics are favorable for the customer from 2020 onward. From 2020-2023 when the customer is paying off their heat pump loan, savings are moderate at $30-$900 per year. Beginning in 2024, a residential customer can expect to save $4,000-$4,400 per year compared to operating an oil furnace.

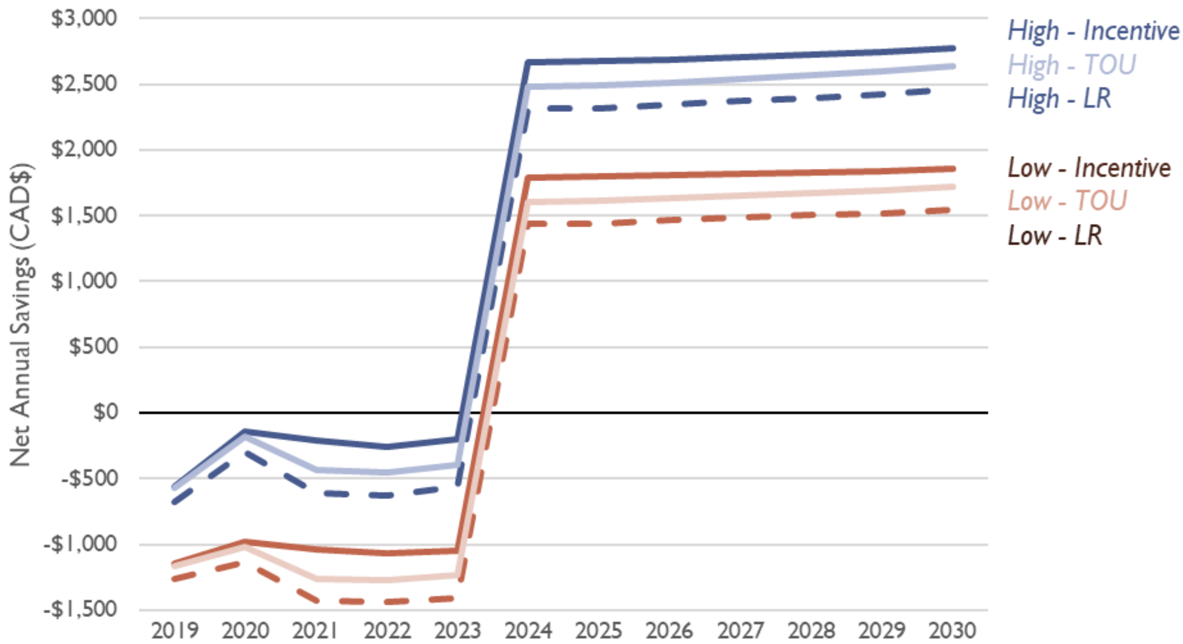
Figure 22. Typical heat pump customer savings by scenario, 2019-2030



Source: Synapse calculations

Under both the low and high scenarios, EV economics are favorable for a customer purchasing an EV in 2019 once the 5-year EV loan has been paid off (Figure 23). Beginning in 2024, an EV customer can expect to save $1,400-$1,900 per year compared to operating a gasoline vehicle, assuming low future gasoline prices (i.e., low scenario). If future gasoline prices are higher (i.e., high scenario), an EV customer can expect to save $2,300-$2,800 per year starting in 2024. For both scenarios, annual savings would be highest for customers on the EV incentive rate and lowest for customers on the LR rate.

Figure 23. Typical EV customer savings by scenario and rate type, 2019-2030



Source: Synapse calculations

6. Conservation & Demand Management and Demand Response

6.1. Overview

We forecasted a range of CDM and DR potential estimates for Newfoundland based on our end-use specific CDM and DR model. This section discusses details of the CDM and DR analysis methodology, key assumptions, and the results of our analysis.

6.2. Methodology

End-Use Model of Energy and Peak Savings

For this second phase, we developed a detailed integrated model that allows us to analyze CDM, heat pump adoption, and DR in one model by taking into account end-use specific adoption rates of certain key measures.

Our end-use CDM and DR model (CDM/DR model) estimates annual energy and winter peak demand savings and the associated program costs for CDM and DR measures by end-use and building types for the IIS and the LIS separately. For example, the model's residential sector analysis estimates savings for five end-use categories (i.e., space heating, water heating, lighting, refrigerator and freezer, and others) within five different building types (i.e., detached single family with electric heat, detached single family without electric heat, attached single family with electric heating, multifamily with electric heat, and others). Based on our literature review, we developed and incorporated assumptions for energy and peak savings, program participation rates and costs in the end-use model, and ensured that outputs from our model are reasonable against what has been achieved in other jurisdictions in North America.

The CDM/DR model consists of two main components for both CDM and DR: heat pumps and other measures. We analyze electric resistance to heat pump conversions separately from other generic CDM measures due to the scale of potential impacts and differences in recent market adoption.

The CDM/DR model analyzes costs and savings for three scenarios: the Base Case, the Low Case, and the High Case. The model estimates incremental impacts for the latter two cases relative to the Base Case. These cases mainly differ in their measure penetration rates. A high-level summary of these cases is provided below:

- **Base Case**: This case represents the level of energy and peak load reductions that we consider already embedded in the base load forecast in our analysis. We assume this load forecast includes a reasonable amount of conservation impacts due to expected electricity price increases in the near future. We assume this case and the load forecast include the current level of CDM activities and increasing amounts of heat pump conversions from electric resistance heaters but do not include any DR because there are currently no DR programs in the province.

- **Low Case**: This case assumes slightly increasing CDM activities over time relative to the recent CDM activities, the same level of heat pump conversions as in the Base Case, and gradually increasing levels of DR programs over time.

- **High Case**: This case assumes aggressively increasing levels of CDM and DR program activities and heat pump installations reflecting our sense of maximum achievable potential estimates over the next decade.

CDM Excluding Heat Pumps

The CDM module first estimates and projects energy savings over time from 2020 through 2030 based on two main factors: (a) end-use specific savings factors (in percentage of end-use specific annual consumption per participant) and (b) projected measure adoption rates (in percentage of end-use consumption in megawatt hours (MWh)). We developed and assumed fixed energy savings factors for all end-use CDM measures based on our review of potential studies.

CDM Savings Assumptions

The end-use savings factors used in our analysis are presented in Table 17. Our residential end-use assumptions are primarily based on a 2018 energy efficiency potential study by GDS for Vermont. For commercial measures, we developed savings assumptions based on end-use percentage savings data from our residential building assumptions for certain measures along with energy improvements in commercial buildings expected from the International Energy Conservation Code (IECC) over the past 10 years. We reviewed analyses of energy usage for 2006 IECC and 2015 IECC and found new buildings could save about 30 percent energy relative to a 10-year-old code, on average.[64] We expect that energy efficiency measures could provide more savings than the current codes, but we use this 30 percent savings as a reference point to bound all savings assumptions except lighting. For industry specific end-uses such as motors, compressors, and processes, we assumed 20 percent savings. While end-use percentage energy reductions are not readily available, we reviewed one energy efficiency potential study focusing on the mining industry prepared by the U.S. Department of Energy because mining is one of the largest industries in Newfoundland. Our review of this study revealed that the mining industry can reduce consumption by 20 to 55 percent with investments in state-of-art technology and further research.[65]

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[64] Based on two studies by the Pacific Northwest National Laboratory (PNNL), we found the 2015 IECC saves about 30 percent energy relative to the 2006 IECC. See PNNL (2014) *Energy and Energy Cost Savings Analysis of the 2015 IECC for Commercial Buildings* and PNNL (2013) *Energy and Energy Cost Savings Analysis of the IECC for Commercial Buildings*.

[65] U.S. Department of Energy. 2007. *Mining Industry Energy Bandwidth Study*.

Table 17. End-Use Energy Savings Factor by Sector

End-use	Savings (%)	Sources and notes
Residential End-Use		
Space heating	20%	Envelope measures. 30 to 40% max savings based on GDS 2018 VT potential study, p. 111
Domestic hot water	15%	Pipe and tank wrap, thermostatic valve, low flow water measures, train water heat recovery. The maximum savings could be close to 40% or 20% without drain heat recovery, based on GDS 2018 study
Refrigerator and freezer	15%	20% with Tier 3 refrigerator, based on GDS 2018 VT potential study, p. 101
Lighting	50%	Synapse assumption of LED savings taking into account potential impacts from expected Federal lighting standards. The current full savings from LED are around 70 to 80%.
Others	20%	Savings range from 10 to 50% for other measures based on GDS 2018 VT potential study
Commercial End-Use		
Space heating	20%	Extrapolated from the residential assumption backed by Synapse review of energy improvements in IECC commercial building codes in the past 10 years
Domestic hot water	15%	
HVAC fans & pumps	20%	Synapse assumption backed by Synapse review of energy improvements in IECC commercial building codes in the past 10 years
Lighting	50%	Extrapolated from the residential assumption
Others	10%	Synapse assumption
Industrial End-Use		
Motor, compressor, pump, fan	20%	U.S. DOE. 2007. Mining Industry Energy Bandwidth Study
Process	20%	
Comfort HVAC	20%	Based on the commercial assumption
Lighting	50%	Based on the commercial assumption
Other	10%	Synapse assumption

Source: GDS Associates. 2018 Energy Efficiency Potential in Vermont; U.S. DOE. 2007. Mining Industry Energy Bandwidth Study; PNNL 2014. Energy and Energy Cost Savings Analysis of the 2015 IECC for Commercial Buildings; PNNL 2013. Energy and Energy Cost Savings Analysis of the IECC for Commercial Buildings.

CDM Adoption Rates

We developed CDM participation or measure adoption rates by sector for the three different scenarios. Within each scenario, we assumed the same adoption rates by year across different end-uses within each sector. The initial adoption rates in 2020 and the cumulative adoption rates in 2030 are presented in Table 18 below. We increased annual incremental rates over time to reach the highest level in 2030, except in the High Case where we assumed the highest annual incremental adoptions occur in 2026 and then level out. An example of annual adoption rates is presented in Figure 24 for the residential measures in the IIS.

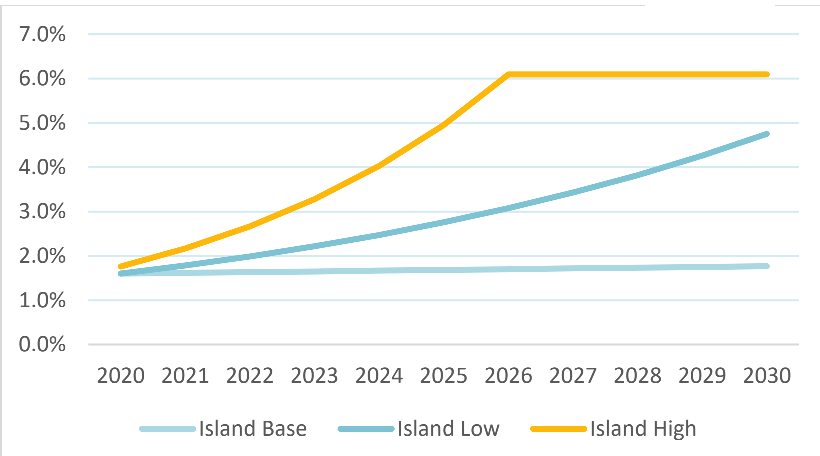
Correction to Figure 24 provided during testimony on October 7, 2019
Transcript reference: Page 4, Line 18 to Page 5, Line 25

Table 18. Measure Adoption Rates for CDM Programs (Initial in 2020 and Cumulative by 2030)

	Base		Low		High	
	2020	2030	2020	2030	2020	2030
Island						
RES	3.5%	39.5%	3.5%	44.0%	3.9%	52.6%
COM	1.6%	18.5%	1.6%	32.2%	1.8%	49.3%
IND	1.3%	14.5%	1.3%	25.8%	1.4%	40.1%
Labrador						
RES	2.0%	22.6%	2.0%	29.9%	2.0%	36.0%
COM	1.1%	12.7%	1.1%	22.1%	1.2%	33.9%
IND	1.3%	14.5%	1.3%	25.8%	1.4%	40.1%

Source: Synapse calculations

Figure 24. Annual CDM Measure Adoption Rates for Commercial CDM in IIS



Source: Synapse calculations

The main data sources for developing these rates are historical CDM performance in Newfoundland and a few other jurisdictions leading on demand-side management programs. We reviewed historical CDM program participation/adoption rates over the past several years achieved by NP and Hydro and determined the current participation rates.[66] We then estimated annual energy savings based on those participation rates and end-use savings factors and calibrated the adoption rates in 2020 so that the current annual savings become close to the current savings levels achieved by the two Newfoundland utilities.

For setting cumulative adoption rates for the High Case, we reviewed CDM participation rates by NP and program administrators in Vermont and Rhode Island—we concluded that aggressive programs could

[66] PUB-NP-010 - Attachment A; PUB-Nalcor-060, Attachment 1.

reasonably achieve 50 to 70 percent cumulative adoption.[67] In fact, the programs in Rhode Island, which are well known as some of the leading programs in North America, have achieved 70 to over 90 percent participation rates just over seven years from 2012 to 2018. To assess possible aggressive participation rates for Newfoundland, we also estimated what the possible cumulative participation rates would be if the current rates achieved by NP were to continue over a 10-year period, and then doubled that participation rate to set the upper limit for cumulative participation rates in the High case.[68] This analysis showed that indicative High-level cumulative rates could be about 50 percent for the residential sector and 40 percent for the commercial sector. Based on these reviews, we set residential cumulative adoption rates slightly higher than the commercial and industrial rates. We also set the total cumulative rates for Labrador lower relative to the Island to take into account expected additional barriers to residential CDM implementation in rural areas. For industrial measures, we assumed the same adoption rates between the two regions as we do not expect any distinct barriers between the two regions for large industrial customers.

CDM Peak Impacts

After estimating annual energy savings in the CDM module, we estimated winter peak load savings based on peak savings factors (in kW peak reduction over annual MWh savings) for all CDM measures. A summary table of peak savings factors is presented in Table 19 below. For all CDM measures except space heating measures (i.e., heat pump and envelope measures), we developed peak savings factors based on end-use specific energy and peak load data available in three separate ICF CDM potential studies published in 2015.[69] The CDM module then estimates monthly energy and peak load savings for these CDM measures, as our PLEXOS model requires changes in monthly energy and peak loads (or changes in hourly load). We estimated these monthly load changes by end-use based on load shape data we obtained from NREL's OpenEI for cold climate states.[70]

For space heating measures, we developed peak savings factors based on our analysis of space heating load outside of the CDM/DR model and estimated winter peak impacts in the CDM/DR model.[71] More

[67] The Narragansett Electric Company d/b/a National Grid. 2019. *2018 Energy Efficiency Year-End Report*, May 15, 2019. Attachment 4: Year-End Participation Memo; Synapse Energy Economics. 2014. Rate and Bill Impacts of Vermont Energy Efficiency Programs, Prepared for the Vermont Public Service Department.

[68] For residential measures, we used participation data for thermostats and insulation measures. We discounted the rates for thermostats by half because the expected savings from this measure is small in order to estimate approximate savings-adjusted participation rates.

[69] 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.

[70] NREL OpenEI's Commercial and Residential Hourly Load Profiles for all TMY3 Locations in the United States, available https://openei.org/doe-opendata/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-states

[71] Per Hydro's hourly load projections, the winter peak occurs around 8 am on January 16th.

specifically, Synapse developed a separate model ("Heating Hourly Model") to estimate hourly load impacts based on (a) 2015 historical hourly temperature data (as this was used by Hydro to estimate its own load forecasts) and (b) heat pump performance factors that take into account lower efficiency levels during cold weather. We then estimated kW/MWh peak reduction factors using Newfoundland's winter system peak hour data.[72] Lastly, we developed hourly savings shapes for both envelop measures and heat pumps in this model and generated hourly energy savings based on annual energy savings results from the CDM/DR model. We then incorporated these hourly savings impacts into the PLEXOS model for our alternative load analysis.

Table 19. Winter Peak Load Savings Factor by End-use (kW/MWh)

	kW/MWh factor	
End-use	**Island**	**Labrador**
Residential End-Use		
Space heating (HP)	0.18	0.21
Space heating (envelope)	0.19	0.22
Domestic hot water	0.29	0.28
Refrigerator and freezer	0.10	0.12
Lighting	0.17	0.20
Others	0.16	0.19
Commercial End-Use		
Space heating (HP)	0.18	0.21
Space heating (envelope)	0.19	0.22
Domestic hot water	0.37	0.37
HVAC fans & pumps	0.15	0.15
Lighting	0.16	0.16
Others	0.13	0.13
Industrial End-Use		
Motor, compressor, pump, fan	0.09	0.09
Process	0.08	0.08
Comfort HVAC	0.12	0.12
Lighting	0.09	0.09
Other	0.09	0.09

Source: Synapse calculations for space heating; ICF 2015 reports for the rest of the measures: (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.

Cost of Saved Energy for CDM

We developed the costs of saved energy for CDM measures based on Newfoundland's historical CDM program costs over the past several years, as well as forecasted data for 2019. We developed measure-

72 Per Hydro's hourly load projections, the winter peak occurs around 8 am on January 16th.

specific costs and program administration costs separately. We assumed the administration costs are equal to 10 percent of the total program cost for the Island and 16 percent for Labrador based on our review of NP's and Hydro's CDM programs.

Our CDM measure cost assumptions are presented in Table 20 along with amortized program costs. The costs for the Island are based on NP's program costs and the costs for Labrador are based on Hydro's program costs. Importantly, we take these CDM costs as a proxy for future CDM costs in constant dollars over the study period ($2019). This reflects many years of experience in historical CDM program costs in North America which have not changed substantially despite many years of CDM program implementation. Potential studies indicate CDM costs increase as the resources are depleted. However, in reality, technological improvements continue to occur across all end-use equipment.

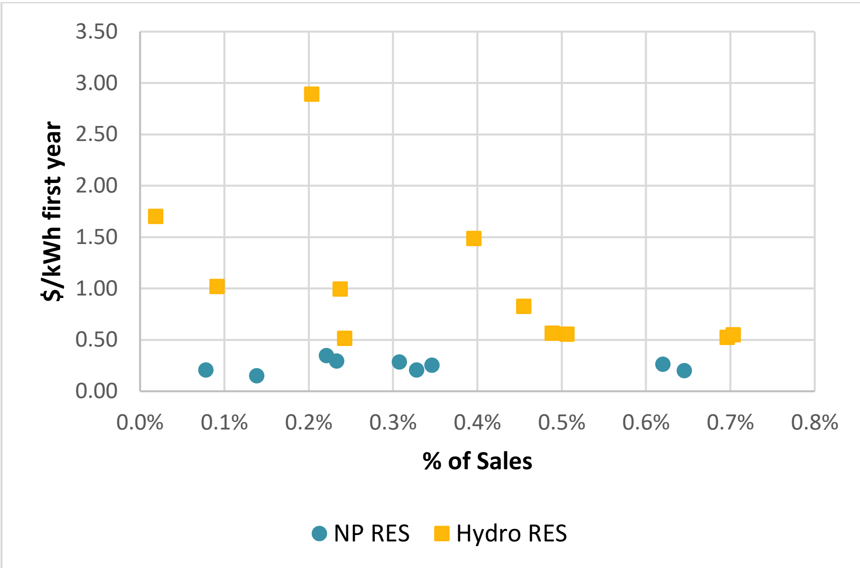
Table 20. CDM Program Cost Assumptions

Sector	$/kWh first year ($2019)	$/kWh Amortized	Source/notes
Island			
RES	0.25	0.04	Slightly increased costs relative to the average first year cost ($0.2/kWh) of 2015 to 2019 historical and projected programs to take into account potential cost increases due to federal lighting standards.
COM	0.29	0.05	NP's historical and projected CDM cost
IND	0.22	0.04	Hydro's industrial program data given NP does not provide information for industrial measures
Labrador			
RES	0.70	0.12	Hydro's historical CDM cost
COM	0.22	0.04	Hydro's historical and projected CDM cost
IND	0.22	0.04	Hydro's industrial program data

Note: average first year program costs are amortized over 7 years using a 7 percent weighted average cost of capital and a 2 percent inflation rate. Source: NL Hydro. 2018. 2017 Conservation and Demand Management Report. Table 1, 2 and 3; PUB-Nalcor-061, Attachment 1; PUB-NP-010 - Attachment A; NL Hydro. 2018. "CDM Overview," November 5, 2018, p. 8; NP 2013 CDM Report, Table 6.

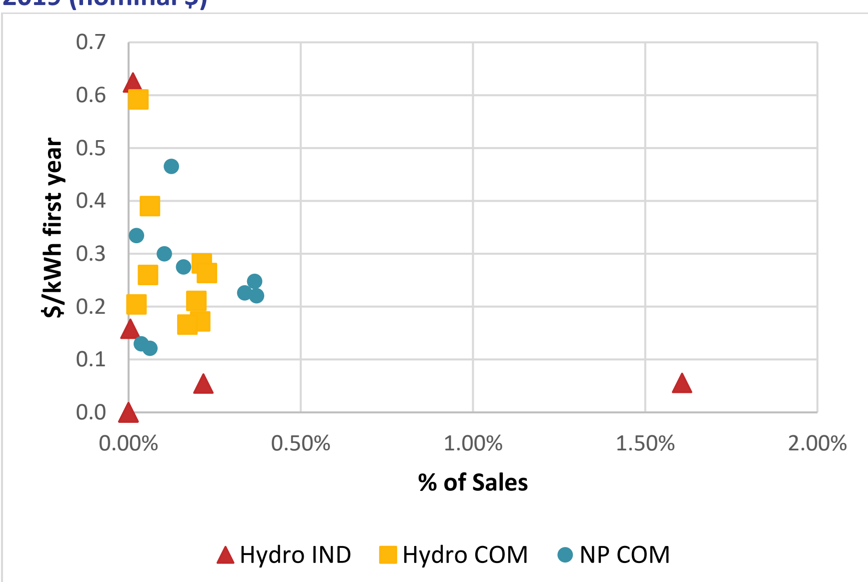
The historical CDM costs in Newfoundland are presented in Figure 25 and Figure 26 below along with savings achievements as a percentage of historical sales. While NP's residential program costs have been stable around $0.2 to 0.4 per kWh of first year savings, costs of saved energy are generally variable when the savings scale is small (in a percentage of sales) and become stable as the scale grows. Hydro's residential programs cost about $0.7 per kWh of first year savings in recent years. This is much higher than NP's residential programs and may reflect that it takes more time and costs to visit households on average in more rural areas. Commercial program costs are similar between NP and Hydro. Industrial program costs are very limited and only available from Hydro's programs. Since we do not expect any substantial difference between the two regions for the characteristics of industrial customers, we used the average costs of Hydro's industrial programs (over several years) for both Labrador and the Island.

Figure 25. Residential CDM Costs of Saved Energy (1st Yr.) by NP and Hydro: 2009 to 2019 (nominal $)



Sources: NL Hydro. 2018. 2017 Conservation and Demand Management Report. Tables 1, 2, and 3; PUB-Nalcor-061, Attachment 1; PUB-NP-010, Attachment A; NL Hydro. 2018. "CDM Overview," November 5, 2018, p. 8; NP 2013 CDM Report, Table 6.

Figure 26. Commercial and Industrial CDM Cost of Saved Energy (1st Yr.) by NP and Hydro: 2011 to 2019 (nominal $)



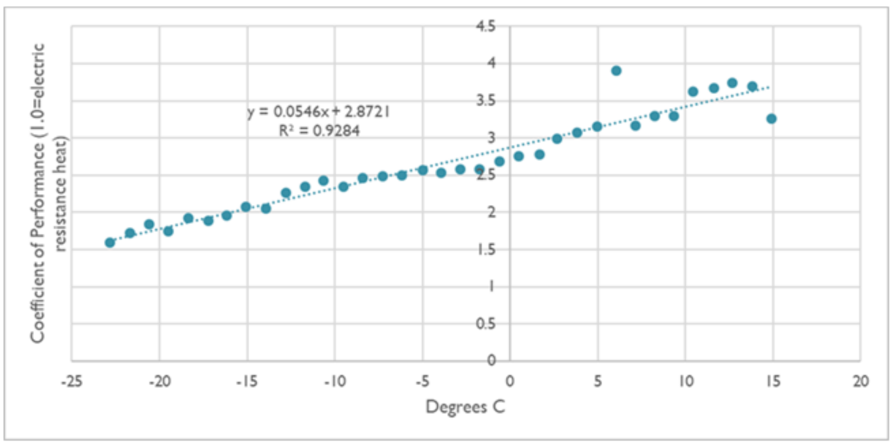
Sources: NL Hydro. 2018. 2017 Conservation and Demand Management Report. Tables 1, 2, and 3; PUB-Nalcor-061, Attachment 1; PUB-NP-010, Attachment A; NL Hydro. 2018. "CDM Overview," November 5, 2018, p. 8; NP 2013 CDM Report, Table 6.

Heat Pumps

Heat Pump Analysis

Heat pumps are a more efficient method of producing heat from electricity than traditional electric resistance heaters. Figure 27 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 coefficient of performance (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 the heat pump provides twice as much heat 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.

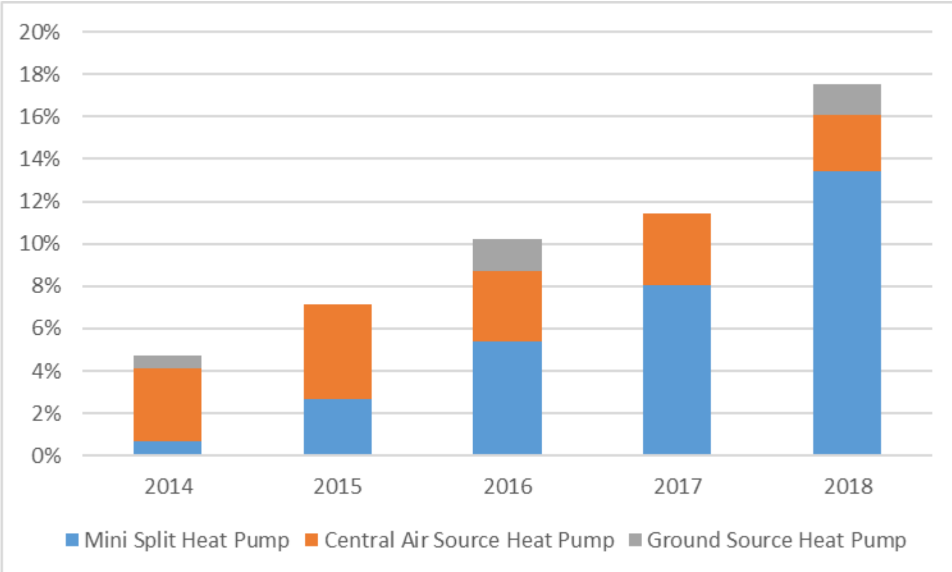
Figure 27. Cold climate heat pump COP - temperature curve



Source: Cadmus. 2016. Ductless Mini-Split Heat Pump Impact Evaluation, prepared for the Electric and Gas Program Administrators of Massachusetts and Rhode Island Part of the Residential Evaluation Program Area, available at http://ma-eeac.org/wordpress/wp-content/uploads/Ductless-Mini-Split-Heat-Pump-Impact-Evaluation.pdf

Over the past several years, heat pumps have been gaining in popularity in Newfoundland, particularly in NP's service territory. According to NP, the number of residential customers who installed heat pumps starts increasing dramatically in 2014, resulting in close to an 18 percent adoption rate among electric heated customers as shown in Figure 28. The vast majority of the newly installed heat pumps are ductless mini-split heat pumps. Mini-split heat pumps have been the most popular heat pump models in Asian countries for many years and were actively introduced in the North American market within the last decade, and Newfoundland customers started to install this type of heat pump soon thereafter. Mini-split models use small refrigerant pipes instead of ducts. They are easier to install than ducted models and, because they do not have losses in the ducts, they also perform more efficiently than ducted models. Manufacturers also introduced cold-climate mini-split heat pumps to the North American market in recent years, which spurred the market share of heat pumps in cold climate regions.

Figure 28. Cumulative Electric Heated Customers with Heat Pump Installations from 2014 to 2018



Notes: Developed based on PUB-NP-017 - Attachment A.XLSX. Customer breakdowns for 2014 were extrapolated based on the installation rates for 2015 through 2018.

Our CDM/DR model includes and forecasts energy and peak impacts from electric resistance heating conversion to heat pumps for residential and commercial buildings. This model captures the current heat pump adoption trend and a potentially more aggressive trend. While we are aware of large-scale heat pump technologies that could be adopted by industrial customers, we exclude the industrial sector from our heat pump analysis because the application of those technologies is currently limited and their potential is unknown.

Using the CDM/DR model, we estimated annual energy and peak savings from heat pumps based on annual savings factors and annual participation/installation rates for the three different scenarios. Annual savings factors of heat pumps incorporate various key assumptions, including region-specific hourly weather, weather sensitive heat pump performance, efficiency improvements in the future, and various saving discount factors that reduce the use of heat pumps discussed in the following section. As the next step, we estimated winter peak impacts using kW/MWh peak reduction factors. As explained above, these peak reduction factors were developed in our Heating Hourly Model using 2015 historical hourly temperature and heat pump performance factors.

Heat Pump Savings Assumptions

Annual energy and peak impacts from heat pumps do not only depend on how individual heat pump technologies perform relative to electric resistance heating at various temperature levels—they depend on how heat pumps are used in homes and businesses and whether building insulation has been added through CDM programs. Our analysis considered these factors : (a) historical hourly weather data, (b) temperature-specific heat pump performance, (c) performance improvement factors due to technological advancements, (d) performance discount factors associated with the use of electric resistance heating systems as backup or supplemental heating system, and (e) performance interaction factors associated with building envelope measures.

Table 21 below presents our heat pump energy estimates for full savings (per unit) and average savings (region-wide). The full savings reflect expected energy savings from fully operating a cold-climate heat pump without any back-up or supplemental heater. We developed this estimate using actual hourly weather data from 2015 (that were used by Nalcor for its load forecast)[73] and in-field performance data for 35 cold-climate heat pump units in Massachusetts and Rhode Island examined in a 2016 Cadmus study.[74,75] (A summary of the performance for these New England units is presented in Figure 28 above.) The average savings estimates in Table 21 reflect all the adjustment factors mentioned above except impacts related to building envelope. The table shows region-wide average savings for all systems installed by 2020 and 2030. In the CDM model, we applied these average savings factors to projected cumulative heat pump installations and reduced the base heating consumption level to incorporate an assumption of envelope upgrades accompanying half of heat pump installations each year.

Table 21. Heat Pump Savings Factors by Region

	Island			Labrador		
	Average COP	Full savings (per unit)	Average savings (region-wide)	Average COP	Full savings (per unit)	Average savings (region-wide)
2020	2.8	64%	32%	2.1	51%	26%
2030	3.3	77%	54%	2.5	61%	43%

Source: Synapse calculations

Heat Pump Adoption Rates

We developed heat pump adoption rates for the residential and commercial sectors for the three different scenarios based on our review of historical adoption rates in Newfoundland. The initial adoption rates in 2020 and the cumulative adoption rates in 2030 are presented in Table 22 below. In the CDM/DR model, these cumulative rates exclude historical installation rates and are applied to the electric loads of the remaining electric heating customers who have not installed heat pumps. Note that these rates are additional heat pumps beyond what has been installed to date in the province. The total cumulative participation rates including historical installations are approximately 32 percent for the Low

[73] Government of Canada Historical Weather Data for St. Johns, and Goose Bay, available at http://climate.weather.gc.ca/historical_data/search_historic_data_e.html.

[74] Cadmus. 2016. *Ductless Mini-Split Heat Pump Impact Evaluation*. Prepared for the Electric and Gas Program Administrators of Massachusetts and Rhode Island Part of the Residential Evaluation Program Area, available at http://ma-eeac.org/wordpress/wp-content/uploads/Ductless-Mini-Split-Heat-Pump-Impact-Evaluation.pdf

[75] This study evaluated the performance of about 150 of installed heat pumps in Massachusetts and Rhode Island in 2015 and 2016 and included 78 cold-climate heat pumps over the two-year period. We used the data for 2016 which includes 35 cold-climate units

Case and 80 percent for the High Case in Newfoundland. The cumulative rates for Labrador are close to the total rates including historical installations as we expect this area has a very small number of installations to date.

Table 22. Cumulative Heat Pump Adoption Rates (%)

	Base		Low		High	
	2020	2030	2020	2030	2020	2030
Island						
RES	2.7%	17.4%	2.7%	17.4%	5.0%	76.0%
COM	2.7%	17.4%	2.7%	17.4%	5.0%	76.0%
IND	n/a	n/a	n/a	n/a	n/a	n/a
Labrador						
RES	0.5%	15.0%	0.5%	15.0%	0.5%	39.5%
COM	0.5%	15.0%	0.5%	15.0%	0.5%	39.5%
IND	n/a	n/a	n/a	n/a	n/a	n/a

Source: Synapse assumption based on our review of market transformations that have occurred in other countries, available in Stats.ehpa.org

These cumulative rates are based on our assumptions for annual adoption rates. We present our annual adoption rates for the three cases for Island and Labrador separately in Figure 29 and Figure 30 below. A summary of each case is presented as follows:

- **Base Case**: For the Island, we assume the current trend of heat pump installations continues through 2021 for both the residential and commercial sectors and that the annual installation will start to decline over time. This results in the total cumulative installation of about 30 percent by 2030.[76] For Labrador, we assume penetration rates gradually increase in the early years to about 2.5 percent by 2024 following the historical trend in the Island and then decline to 1 percent per year. The total cumulative installation for Labrador reaches 15 percent by 2030. We assume all of the new heat pumps in the Base Case are already included and embedded in the base load forecast.

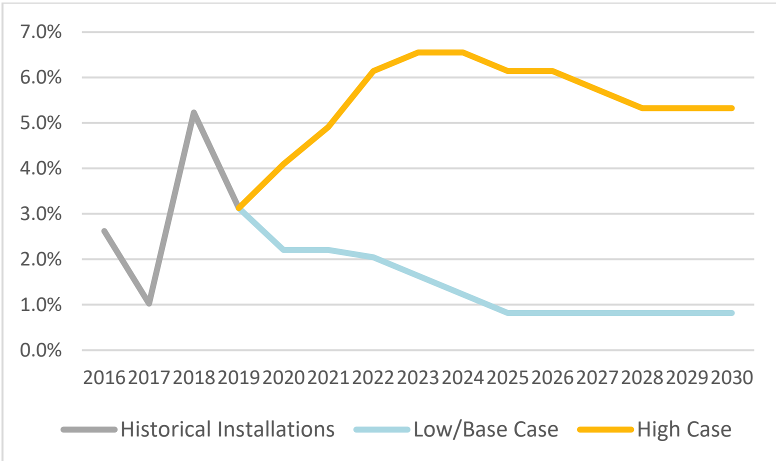
- **Low Case**: We assume the same heat pump penetration rates as assumed in the Base Case. Therefore, the Low Case has no incremental heat pump impacts from conversions from electric resistance heating.

- **High Case**: For the island, we assume that the annual installation rates gradually increase to 6.5 percent by 2023 and then decline slightly over time. In the development of this case, we looked at market transformations that have occurred in other countries such as Norway and Finland where heat pumps have become the default electric

[76] One of the local HVAC contractors we interviewed noted that they expect the total stock of heat pumps to reach 30 to 40 percent within 10 years and to eventually reach 50 percent.

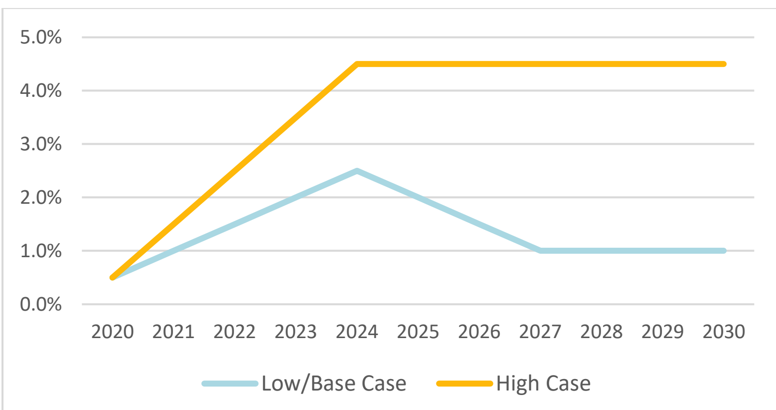
heating technology.[77] This results in the total cumulative installation of about 80 percent by 2030 in the IIS. For Labrador, we assume more increasing penetration rates in early years relative to the Base Case and stay at 4.5 percent per year from 2024 to 2030.

Figure 29. Heat Pump Annual Adoption Rates for Residential and Commercial Customers in the Island



Source: Synapse calculations

Figure 30. Heat Pump Annual Adoption Rates for Residential and Commercial Customers in Labrador



Source: Synapse calculations

[77] European Heat Pump Association. Stats.ehpa for heat pump sales overview, available at http://www.stats.ehpaorg/hp_sales/story_sales/

Cost of Saved Energy for Heat Pumps

We assumed no incentives or program costs for the Base Case and the Low Case as we assumed the impacts of heat pumps in these scenarios are already part of the load forecast. Thus, there are no program costs for heat pumps in these scenarios.

For the High Case, we assume Newfoundland utilities provide incentives and technical assistance to promote the installation of additional heat pumps beyond the level included in the current load forecast. We used a total of $1,500 incentive for an average size house ($500 per unit or per ton for a total of three units or three tons). We then estimated the costs of saved energy in cents per kWh using this incentive level and the expected annual savings levels (calculated in the Heating Hourly Model) separately for the Island and Labrador regions. The resulting incentive levels are 12 cents per kWh of annual savings for the Island and 11 cents per kWh for Labrador. We applied these incentives for both residential and commercial heat pump systems from 2020 through 2030.

Demand Response

The DR module estimates and projects winter peak load savings over time from 2020 through 2030 based on (a) end-use specific savings factors (in percentage of end-use specific peak load per participant) and (b) projected participation rates (in percentage of end-use load in MW). We developed these factors based on a few DR potential studies and DR pilot studies with a focus on winter peak savings measures.

Demand Response Savings Factor

We developed potential winter peak demand reductions by end-use based on a literature review of DR potential studies. For residential customers, we assumed direct load control programs for space and water heating end-uses. For commercial customers, we assumed demand curtailment program, interruptible tariffs, and lighting control technology. We used the commercial sector assumptions for most of the industrial DR end-uses because industry-specific data are limited. A summary of DR savings factors is presented in Table 23.

Table 23. Demand Response Savings Assumptions

End-use	% Savings	Sources and notes
Residential End-Use		
Space heating	20%	The impact ranges from 1 to 2.9 kW based on the following studies: Cadmus (2018) DR Potential in BPA; Navigant (2011) 2011 EM&V Report for PSE Residential Demand Response Pilot Program; Brattle (2016) PGE DR Market Research 2016-2035; and CEE (2019) MN EE Potential Study: 2020-2029. Appendix E.
Domestic hot water	100%	Assumes water heater is turned off during the DR event. Based on various studies including Cadmus (2018) DR Potential in BPA and CEE (2019) MN EE Potential Study: 2020-2029. Appendix E.
Commercial End-Use		
Space heating	25%	Ranges from 20 to 30% based on Cadmus (2018) DR Potential in BPA, Brattle (2016) PGE DR Market Research; Siemens (2017) C&I Technical Test Final Report
Domestic hot water	50%	Synapse assumption
HVAC fans & pumps	25%	Ranges from 20 to 30% based on Cadmus (2018) DR Potential in BPA, Brattle (2016) PGE DR Market Research; Siemens (2017) C&I Technical Test Final Report
Lighting	20%	BPA DR potential study
Industrial End-Use		
Motor, compressor, pump, fan	20%	based on the commercial DR assumptions
Process	20%	based on the commercial DR assumptions
Comfort HVAC	20%	based on the commercial DR assumptions
Lighting	20%	based on the commercial DR assumptions

DR Adoption Rates

We developed DR adoption rates by sector for the three different scenarios. The initial adoption rates in 2020 and the cumulative adoption rates in 2030 are presented in Table 24 below.

Table 24. Demand Response Adoption Rates

	Base		Low		High	
	2020	2030	2020	2030	2020	2030
Island						
RES	n/a	n/a	1.0%	12.8%	1.0%	27.2%
COM	n/a	n/a	1.0%	12.8%	1.0%	17.6%
IND	n/a	n/a	1.0%	12.8%	1.0%	17.6%
Labrador						
RES	n/a	n/a	0.5%	6.4%	0.5%	13.6%
COM	n/a	n/a	0.5%	6.4%	0.5%	8.8%
IND	n/a	n/a	0.5%	6.4%	0.5%	8.8%

Source: BPA 2018 DR potential Study. Note: We assumed half of the estimates developed by BPA 2018 DR potential study.

We reviewed a number of recent DR potential studies and chose to mainly rely on a 2018 DR potential by Cadmus for Bonneville Power Administration (BPA 2018 DR potential study) for developing our DR adoption rates.[78] We consider this study most useful and relevant to Newfoundland because it includes a benchmarking study on numerous DR programs in North America (including Quebec and Ontario) and developed DR potential estimates for its territory, which is a winter peaking area and mainly supplied by hydro power like Newfoundland. A high-level summary of each scenario is presented below.

- **Base Case**: We assumed no DR program participation in this case.
- **Low Case**: We assumed a gradually increasing level of program participation rates over time based on the low end of participation estimates for various DR end-uses and measures (e.g., space heating and water heating direct load control, smart thermostat, demand curtailment, commercial lighting control) used in Cadmus' study for BPA. We chose a conservative assumption for our Low Case scenario: half of the low end of participation rates from the 2018 BPA DR study.
- **High Case**: We assumed rapidly increasing levels of program participation based on the high end of participation estimates from the 2018 BPA DR potential study. However, we conservatively limited maximum participation to half of the high end of the maximum participation rates from this study for our High Case scenario because Newfoundland does not have much experience implementing DR programs. Further, the system's needs for winter peak load reductions may last longer than the 2 to 4 hours DR can typically provide.

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[78] Cadmus. 2018. Demand Response Potential in Bonneville Power Administration's Public Utility Service Area. Final Report. Available at https://www.bpa.gov/EE/Technology/demand-response/Documents/180319_BPA_DR_Potential_Assessment.pdf

Cost of Peak Reduction for DR

We developed DR program costs primarily based on the 2018 BPA DR potential study. We developed measure-specific costs and program administration costs separately. We assumed the administration costs are equal to 9 percent of the total program cost for both the Island and Labrador, in line with the 2018 BPA DR potential study. A summary of end-use specific costs is presented below along with annual amortized costs in Table 25.

Table 25. Demand Response Cost Assumptions

End-use	$/kW-year ($2019)	$/kW-year Amortized ($2019)
Residential End-Use		
Space heating	$65	$11.23
Domestic hot water	$159	$27.41
Commercial End-Use		
Space heating	$111	$19.10
Domestic hot water	$111	$19.10
HVAC fans & pumps	$111	$19.10
Lighting	$42	$7.19
Industrial End-Use		
Motor, compressor, pump, fan	$111	$19.10
Process	$111	$19.10
Comfort HVAC	$111	$19.10
Lighting	$42	$7.19

Note: The costs are based on Cadmus (2018) Demand Response Potential in BPA. The costs are adjusted for Canadian dollars. Amortized program costs assume a 7-year time frame with a 7 percent weighted average cost of capital and a 2 percent inflation rate.

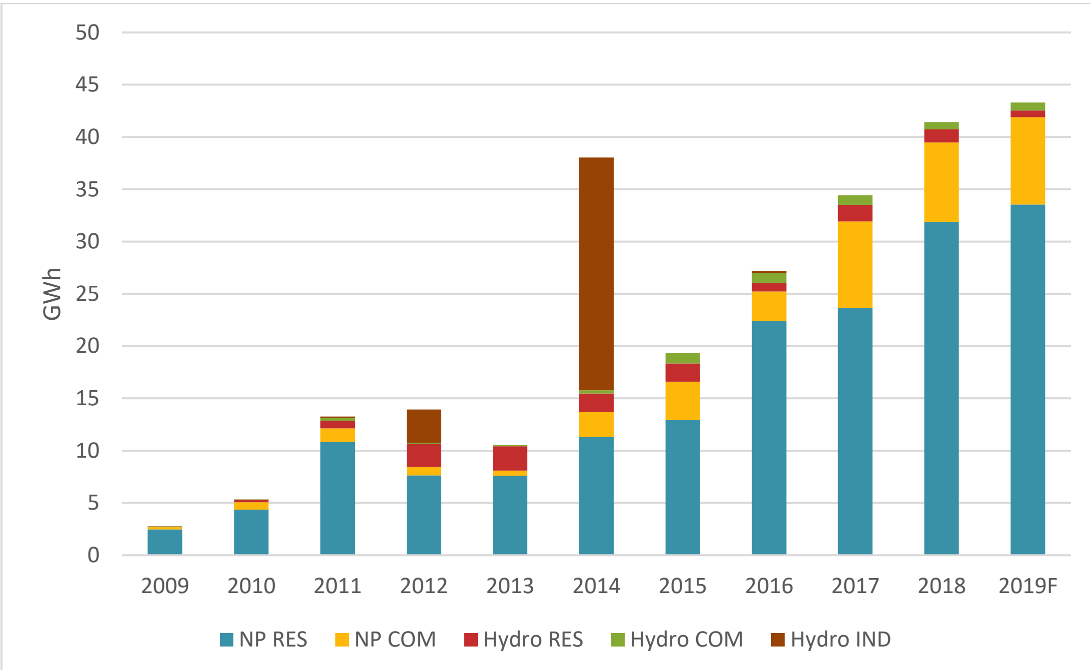
6.3. CDM and DR Analysis Results

Gross Savings

Our analysis sought to develop incremental savings beyond our Base Case (or what is already embedded in our base load forecast) and use it to adjust the base load forecast. We call these incremental savings "net" savings. Before presenting net savings results, this section will present our analysis on "gross" savings, which include all projected savings along with the Base Case savings in order to put Newfoundland's CDM program in perspective.

Newfoundland's CDM programs have increased energy savings since 2009, especially since 2013. The majority of the savings since 2014 have been from NP's CDM programs. Residential program savings accounted for nearly 80 percent of NP's savings, as shown in Figure 31 below. The total energy savings from NP's program are now slightly more than 40 GWh. The total energy savings from Hydro's CDM program have been from 1.5 to 2.5 GWh annually in recent years—only about 5 percent of NP's program savings. However, when large industrial customers participated in Hydro's CDM program, the program yielded substantial savings because Hydro has a large industrial base. For example, Hydro's CDM program produced about 22.5 GWh of savings just from its industrial program in 2014.

Figure 31. Historical and Forecasted Annual Incremental Savings by NP and Hydro (GWh)



Sources: NL Hydro. 2018. 2017 Conservation and Demand Management Report. Table 2; PUB-Nalcor-061, Attachment 1; PUB-NP-010 - Attachment A; NL Hydro. 2018. "CDM Overview", Nov. 5, 2018, p. 8.

Our analysis estimates and forecasts potential CDM-related energy and peak savings for the IIS and the LIS. While the majority of the load on the IIS comes from NP's customers, Hydro's large industrial customers are also part of the IIS. Thus, our CDM savings estimates are not directly comparable to the historical savings shown above but serve as a key reference point. It is also important to note that our estimates of industrial CDM programs are annual average values while historical industrial program savings have been very intermittent.

Figure 32 and Figure 33 present gross cumulative annual energy savings for conventional CDM (without heat pumps) and heat pumps separately by scenario. The total annual savings start around 38 to 42 GWh in the IIS and 3 to 7 GWh in the LIS in 2020. The total gross cumulative annual savings of CDM for the IIS in 2030 are about 710 GWh for the High Case, 535 GWh for the Low Case, and 410 GWh for the Base Case. This means that the net cumulative energy savings are about 300 GWh for the High Case and 120 GWh for the Low Case beyond the Base Case.

The total gross annual savings for heat pumps starts around 16 to 30 GWh in 2020 in the IIS and grows over time. The total gross cumulative annual savings for heat pumps are about 695 GWh in 2030 under the IIS for the High Case and 160 GWh for both the Base Case and the Low Case. The High Case gross cumulative savings for heat pumps are very close to the savings level projected for conventional CDM programs in 2030. The total net cumulative annual savings from heat pumps are about 530 GWh (695 GWh minus 160 GWh) for the High Case. The Low Case net savings are zero because it is defined to be equal to the Base Case.

Figure 32. Projection of Gross CDM Savings excluding Heat Pumps for IIS (Left) and LIS (Right)

Source: Synapse calculations

Figure 33. Projection of Gross Heat Pump Savings for IIS (Left) and LIS (Right)

Source: Synapse calculations

Table 26 below shows a detailed breakdown of gross cumulative energy savings in 2030 by sector and scenario for conventional CDM and heat pumps. Overall residential CDM and heat pumps are expected to have the largest savings impacts. The gross savings from CDM programs under the Low Case are three times larger than the savings from heat pumps in the IIS but are very close to the savings from heat pumps under the High Case. In the LIS (Table 27), the largest savings are expected to come from industrial CDM programs, accounting for over 70 percent of the gross savings in the Low Case and the High Case. Overall the CDM program savings in the LIS are 8 percent of the projected load for the High Case. This is comparable to the CDM savings in the IIS under the same scenario. However, heat pump savings in the LIS are only about 2 percent of the projected load under the High Case while heat pump savings in the IIS are about 9 percent of the load for the same scenario. This is largely because the LIS's largest customer base is the industrial sector which accounts for 70 percent of the regional consumption but our CDM analysis does not assume any heat pump installations for this sector.

Table 26. IIS - CDM Gross annual cumulative energy savings in 2030 by sector and scenario (GWh)

	CDM w/o HP			HP			Total CDM		
	Base	Low	High	Base	Low	High	Base	Low	High
Residential	295	329	394	118	118	508	413	447	902
Commercial	126	126	194	45	45	187	171	171	381
Industrial	45	80	125	0	0	0	45	80	125
Total	467	536	712	163	163	695	629	699	1,408
% of Load*	6%	7%	9%	2%	2%	9%	8%	9%	19%

Source: Synapse calculations

Note these are approximate estimates because our analysis assumes that the savings estimates for the Base Case are already embedded in our base load forecast.

Table 27. LIS - CDM Gross annual cumulative energy savings in 2030 by sector and scenario (GWh)

	CDM w/o HP			HP			Total CDM		
	Base	Low	High	Base	Low	High	Base	Low	High
Residential	15	21	25	14	14	37	30	35	62
Commercial	14	14	21	7	7	18	21	21	39
Industrial	8	94	146	0	0	0	8	94	146
Total	37	128	192	21	21	55	59	150	247
% of Load*	2%	5%	8%	1%	1%	2%	2%	6%	10%

Source: Synapse calculations

Note these are approximate estimates because our analysis assumes that the savings estimates for the Base Case are already embedded in our base load forecast

Table 28 and Table 29 present gross cumulative winter peak savings in 2030 from CDM and DR measures. Gross peak load savings from conventional CDM and heat pumps are similar to, but slightly lower than, the gross energy savings in percentage of the projected loads. For the Island, the total combined peak impacts from CDM and heat pumps are about 15 percent of the peak load, while the combined "energy" impacts are close to 19 percent for the same region. For the LIS, the gross combined peak impact from CDM and heat pumps is about 8 percent, while the combined energy impact is about 10 percent. However, DR provides additional peak savings beyond CDM and heat pumps. As a result, the total gross peak impact including DR is equal to or slightly greater than the total gross "energy" impact relative to load forecasts.

Between CDM and heat pumps, the relative peak impact of conventional CDM is also slightly lower than that of energy impacts when compared to the relative peak impact from heat pumps. This is mainly because conventional CDM measures include various measures that have lower peak coincident load profiles than heat pumps.

Table 28. IIS - CDM and DR Gross Annual Cumulative Winter Peak Savings in 2030 by Sector and Scenario

	CDM w/o HP		HP		DR		Total CDM	
	Low	High	Low	High	Low	High	Low	High
Residential	59	71	21	92	29	56	109	220
Commercial	23	35	8	34	13	16	43	85
Industrial	7	11	0	0	4	6	11	17
Total	89	116	29	127	46	78	164	321
% of Load*	5%	7%	2%	8%	3%	5%	10%	20%

Source: Synapse calculations

Note these are approximate estimates because our analysis assumes that the savings estimates for the Base Case are already embedded in our base load forecast

Between the LIS and the IIS, the LIS has much smaller relative gross peak impacts. This is because CDM penetration rates are markedly lower under the LIS, especially for heat pumps.

Table 29. LIS - CDM and DR Gross Annual Cumulative Winter Peak Savings in 2030 by Sector and Scenario

	CDM w/o HP		HP		DR		Total CDM	
	Low	High	Low	High	Low	High	Low	High
Residential	4	5	3	8	1	3	9	16
Commercial	3	4	1	4	1	1	5	9
Industrial	8	13	0	0	3	4	11	17
Total	15	22	4	12	5	8	25	42
% of Load	4%	5%	1%	3%	1%	2%	6%	10%

Source: Synapse calculations

Note these are approximate estimates because our analysis assumes that the savings estimates for the Base Case are already embedded in our base load forecast

Net Savings

Table 30 and Table 31 present detailed breakdowns of net annual cumulative energy savings projected for 2030 from conventional CDM and heat pumps for the IIS and the LIS. Under the Low Case, heat pumps do not yield any net savings because we assume the same level of heat pump installations between the Base Case and the Low Case. Savings impacts from CDM are about 2 percent of the projected base load under the Low Case for both the IIS and the LIS and about 4 to 5 percent under the High Case. In contrast, savings impacts from heat pumps are substantially higher at about 7 percent in the IIS under the High Case while the heat pump impact in the LIS is only about 1 percent. This low heat pump savings reflects mainly the low participation rates expected under the LIS, as well as lower heat pump performance due to colder winter temperatures in Labrador. The total CDM impacts including heat pumps are about 11 percent of the projected base load under the IIS and 6 percent under the LIS.

Table 30. IIS - CDM Net annual cumulative energy savings in 2030 by sector and scenario (GWh)

	CDM w/o HP		HP		Total CDM	
	Low	High	Low	High	Low	High
Residential	34	98	0	390	34	488
Commercial	54	121	0	143	54	264
Industrial	35	80	0	0	35	80
Total	123	299	0	533	123	832
% of Load	2%	4%	0%	7%	2%	11%

Source: Synapse calculations

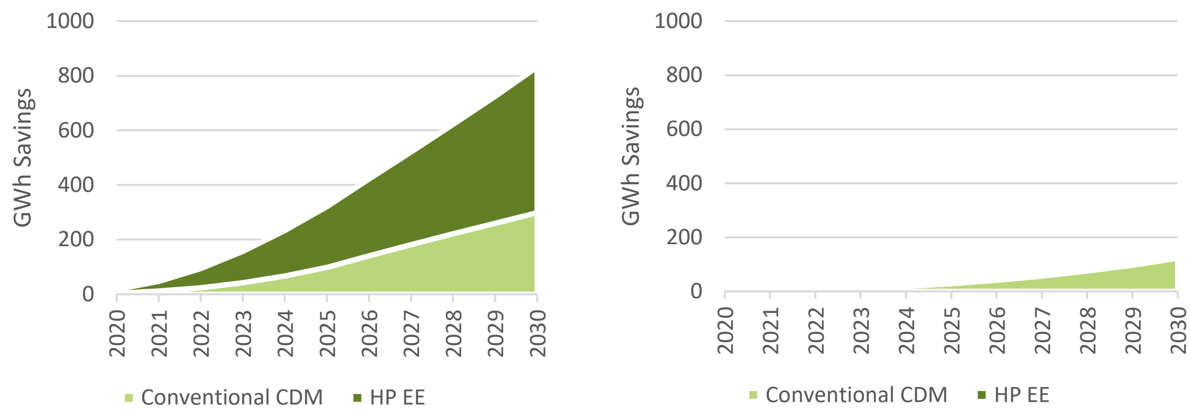
Table 31. LIS - CDM Net annual cumulative energy savings in 2030 by sector and scenario (GWh)

	CDM w/o HP		HP		Total CDM	
	Low	High	Low	High	Low	High
Residential	5	9	0	23	5	32
Commercial	6	13	0	11	6	13
Industrial	41	93	0	0	41	93
Total	52	116	0	23	52	139
% of Load	2%	5%	0%	1%	2%	6%

Source: Synapse calculations

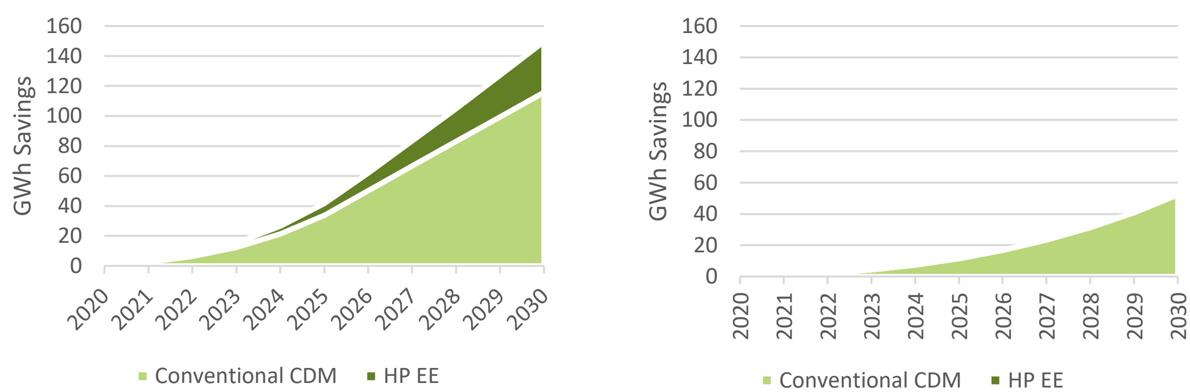
Figure 34 and Figure 35 present net cumulative energy savings for conventional CDM and heat pumps under the IIS and the LIS by scenario from 2020 through 2030.

Figure 34. IIS CDM and HP Net Annual Energy Savings – High Case (Left) and Low Case (Right) (GWh)



Source: Synapse calculations

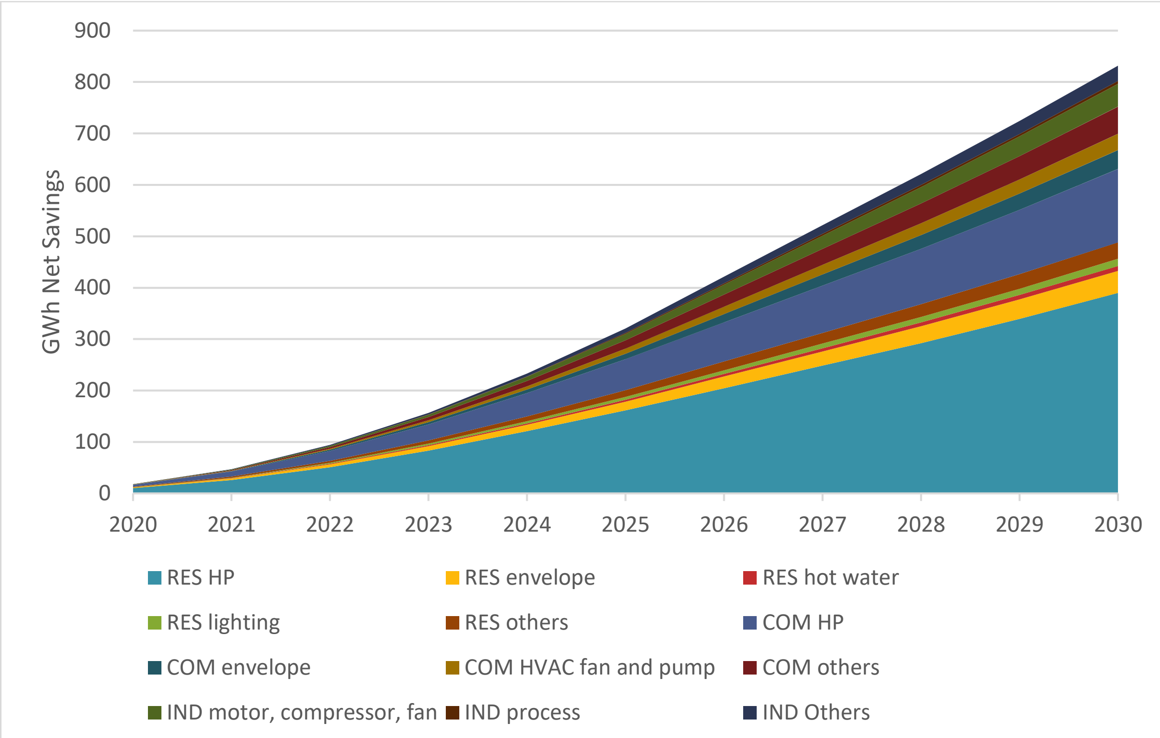
Figure 35. LIS CDM and HP Net Annual Energy Savings – High Case (Left) and Low Case (Right) (GWh)



Source: Synapse calculations

Figure 36 shows net annual energy savings by aggregated end-use categories for the High Case under the IIS. The largest net savings are expected to come from residential heat pumps accounting for about 47 percent of the total savings, followed by commercial heat pumps (17 percent), commercial others (6.3 percent), industrial motors, compressors, and fans (5.3 percent), residential envelop (5.1 percent), and commercial envelope (4.4 percent).

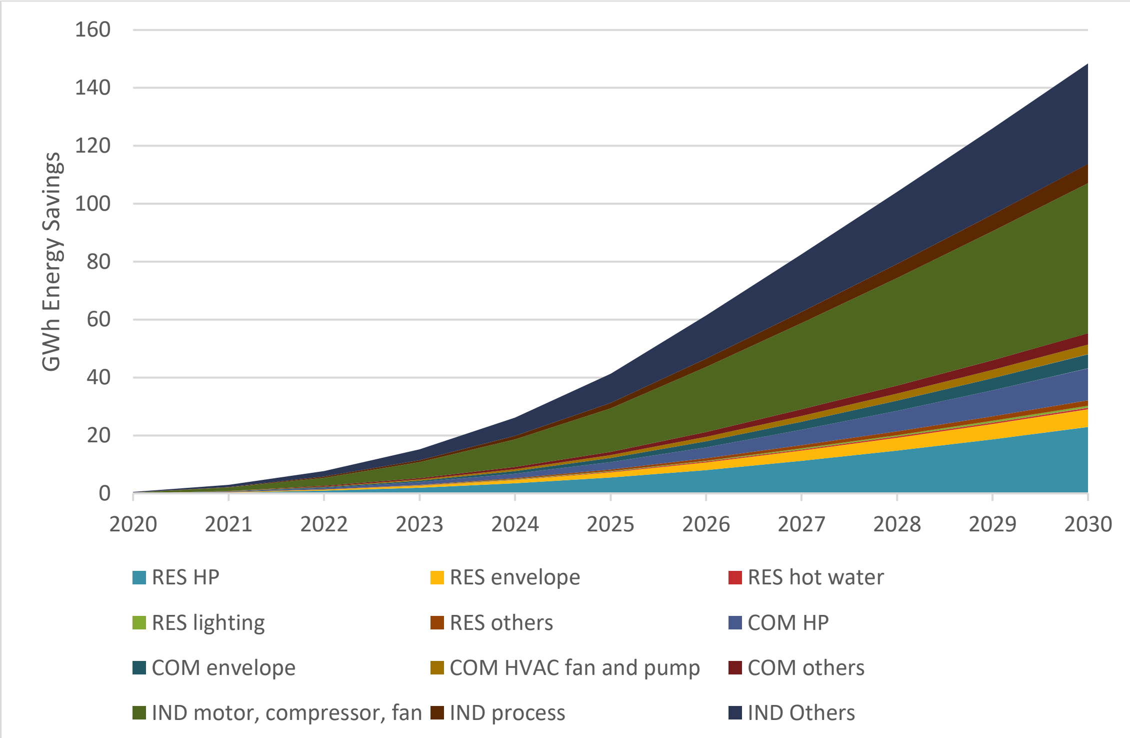
Figure 36. High Case – IIS Net Annual Energy Savings by Aggregated End-Use Categories (GWh)



Source: Synapse calculations

Figure 37 shows net annual energy savings by aggregated end-use categories for the High Case under the LIS. The largest net savings are industrial motors, compressors and fans, accounting for about 35 percent of the total savings, followed by industrial others (23 percent), residential heat pumps (15.4 percent), commercial heat pumps (7 percent), industrial others (5 percent), and residential envelope (4 percent).

Figure 37. High Case – LIS Net Annual Energy Savings for CDM and HP by Aggregated End-Use Categories (GWh)



Source: Synapse calculations

Table 32 and Table 33 present net cumulative winter peak impacts in 2030 by sector and scenario. As shown in these tables, net peak impacts on the LIS are low, ranging from 0.3 to 0.6 percent with the combined total ranging from 0.6 percent to 1.6 percent. In contrast, the combined total impacts on the IIS range from 3.9 percent to 13.5 percent.

Table 32. IIS - CDM Net Annual Cumulative Winter Peak Savings in 2030 by Sector and Scenario (MW)

	CDM w/o HP		HP		DR		Total CDM	
	Low	High	Low	High	Low	High	Low	High
Residential	6	18	0	71	29	56	35	145
Commercial	10	22	0	26	13	16	22	64
Industrial	2	4	0	0	4	6	6	10
Total	18	44	0	97	46	78	64	219
% of Load	1.1%	2.7%	0.0%	6.0%	2.8%	4.8%	3.9%	13.5%

Source: Synapse calculations

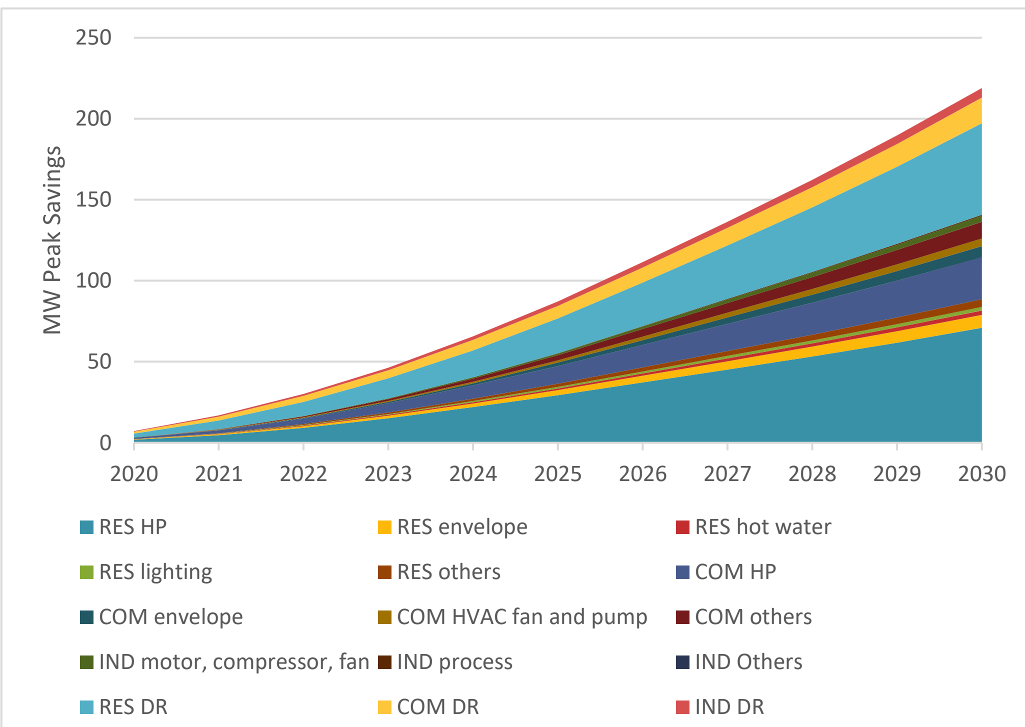
Table 33. LIS - CDM Net Annual Cumulative Winter Peak Savings in 2030 by Sector and Scenario (MW)

	CDM w/o HP		HP		DR		Total CDM	
	Low	High	Low	High	Low	High	Low	High
Residential	1.1	2.0	0.0	4.9	1.4	2.7	2.4	9.5
Commercial	1.2	2.6	0.0	2.3	0.9	1.1	2.1	6.1
Industrial	2.3	5.3	0.0	0.0	3.1	4.2	5.4	9.5
Total	4.6	9.9	0.0	7.2	5.3	8.0	9.9	25.1
% of Load	0.3%	0.6%	0.0%	0.4%	0.3%	0.5%	0.6%	1.6%

Source: Synapse calculations

Figure 38 shows net annual cumulative winter peak load savings by aggregated end-use and measure categories for the High Case under the IIS. The peak load impacts are dominated by residential heat pumps (32 percent) and residential DR measures (26 percent), followed by commercial heat pumps (12 percent) and commercial demand response (7 percent).

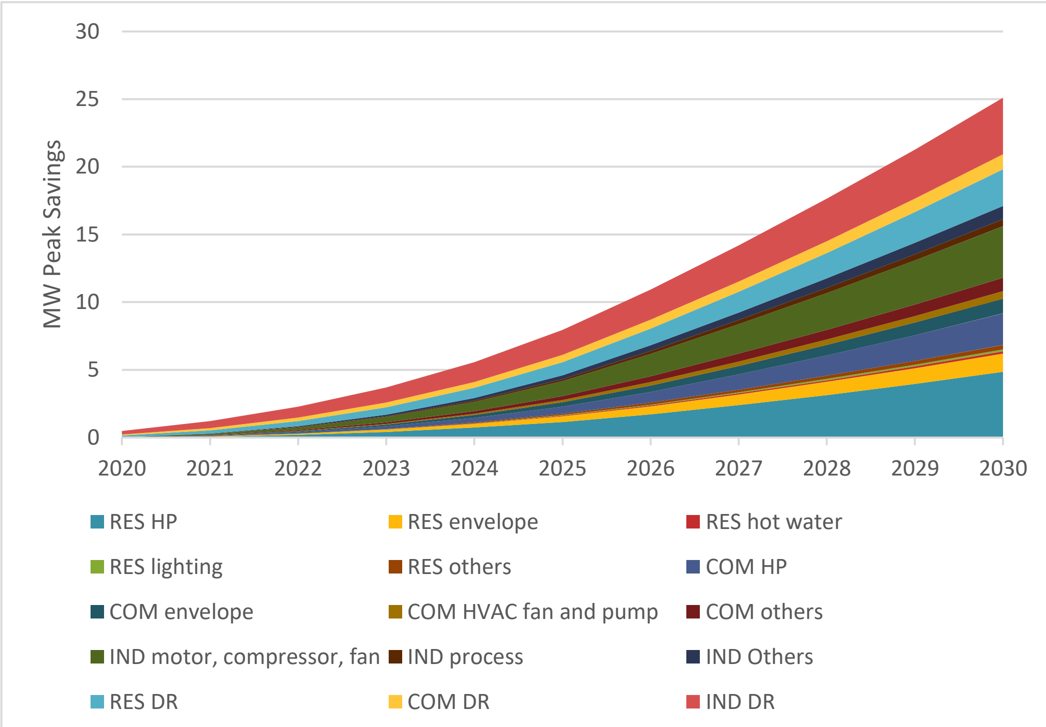
Figure 38. High Case - IIS CDM Net Annual Cumulative Peak Load Savings by Aggregated Category (MW)



Source: Synapse calculations

Figure 39 shows projected peak load impacts by aggregated end-use and measure categories for the High Case under the LIS. The largest savings are expected to come from residential heat pumps, accounting for about 19 percent of the total reduction, followed by industrial DR measures (17 percent); industrial motors, compressors, and fans (15 percent); residential DR measures (11 percent); and commercial heat pumps (9 percent).

Figure 39. High Case - LIS CDM Net Annual Cumulative Peak Load Savings by Aggregated Category (MW)

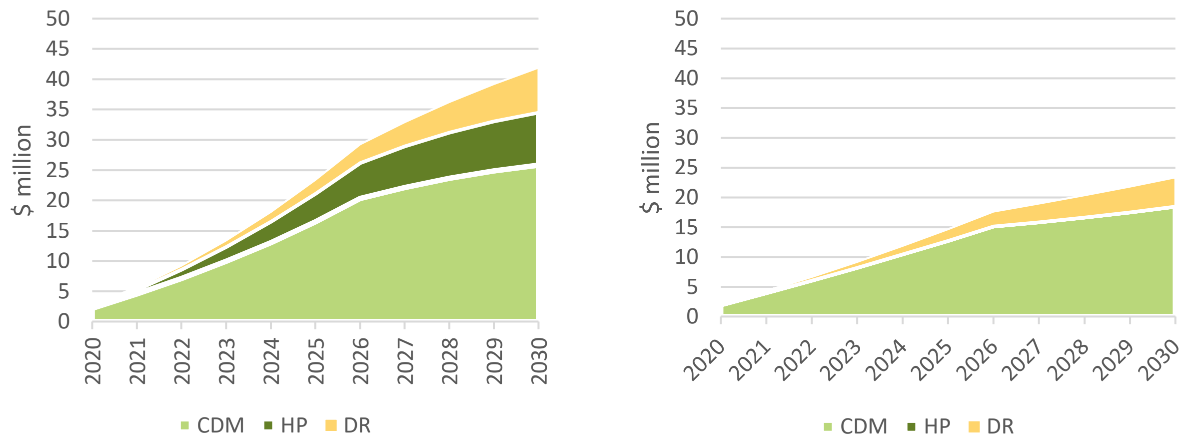


Source: Synapse calculations Projected Program Costs

We calculated the full program costs for each case based on the gross savings impact estimates.

Figure 40 below shows annual amortized program costs for CDM (including heat pumps) and DR measures for the IIS. First-year program costs for each program are amortized over seven years in this figure to be consistent with the current program cost recovery practice in the province. In the Low Case, the total amortized annual costs are expected to increase to about $23 million by 2030. About 80 percent of this total cost is for CDM programs and the rest is for DR programs. There is no heat pump cost for this scenario because we assume that all of the heat pumps installed under the Low Case (as well as the Base Case) will be installed by consumers without any CDM program incentives. In the High Case, the total annual costs are projected to increase to about $42 million by 2030. While we project heat pumps and conventional CDM measures will have equal amount of gross energy savings, the total cost of heat pumps in this scenario is small relative to the cost of CDM measures because the assumed program costs are small per unit of saved energy, reflecting the favorable customer economics for heat pump adoption. (This is consistent with achieving the baseline amount of heat pump installations without any utility program.) In both scenarios, the slope of program costs increases starts to decline in 2026 because amortized program costs in earlier years will be fully paid starting in this year.

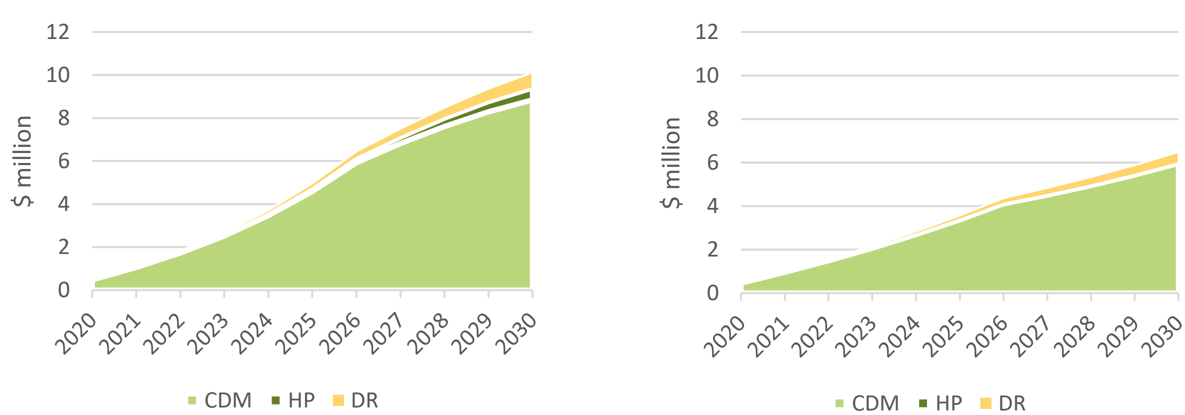
Figure 40. IIS - Annual Amortized Program Costs for CDM and DR for the High Case (left) and the Low Case (right) (2019$)



Source: Synapse calculations

Figure 41 below presents annual amortized program costs for CDM (including heat pumps) and DR measures for the LIS. The total annual amortized program costs are expected to increase to about $6 million by 2030 in the Low Case and $10 million in the High Case. Most of the costs in both scenarios come from conventional CDM measures. These costs represent about 24 to 28 percent of the total program costs in the High Case scenario.

Figure 41. LIS - Annual Amortized Program Costs for CDM, Heat Pump, and DR for the High Case (left) and the Low Case (right) (2019$)



Source: Synapse calculations

Table 34 and Table 35 provide detailed program costs for CDM (including heat pumps) and DR measures for the Base Case, Low Case, and High Case scenarios. For our benefit cost analysis of CDM and DR, we estimated net program costs by subtracting the costs for the Base Case from the Low Case and High Case scenarios.

Table 34. IIS – Annual Amortized Program Costs for CDM (including heat pumps) and DR for the Base, Low and High Cases (2019$)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CDM Costs											
Base CDM	2.00	3.95	5.86	7.74	9.57	11.35	13.08	13.03	12.97	12.92	12.85
Low CDM	2.00	4.05	6.14	8.31	10.55	12.85	15.23	15.96	16.76	17.63	18.58
High CDM	2.51	5.35	8.67	12.44	16.64	21.23	26.29	29.03	31.34	33.20	34.62
DR Costs											
Base DR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Low DR	0.09	0.26	0.52	0.86	1.29	1.80	2.39	2.98	3.58	4.18	4.78
High DR	0.09	0.27	0.56	0.96	1.49	2.15	2.97	3.88	4.89	6.03	7.29

Source: Synapse calculations

Table 35. LIS – Annual Amortized Program Costs for CDM (including heat pumps) and DR for the Base, Low and High Cases (2019$)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CDM Costs											
Base CDM	0.47	0.92	1.38	1.83	2.27	2.71	3.15	3.18	3.21	3.23	3.26
Low CDM	0.47	0.96	1.50	2.08	2.70	3.38	4.12	4.51	4.95	5.43	5.97
High CDM	0.49	1.07	1.76	2.58	3.56	4.74	6.15	7.12	8.00	8.76	9.40
DR Costs											
Base DR	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Low DR	0.01	0.03	0.05	0.09	0.14	0.19	0.25	0.32	0.39	0.45	0.52
High DR	0.01	0.03	0.06	0.10	0.15	0.22	0.30	0.39	0.49	0.60	0.72

Source: Synapse calculations

Benefit Cost Ratio of CDM and DR

We estimated benefit costs of our projections of CDM and DR programs separately. As mentioned in the previous section, we developed net savings and net program costs relative to those of the Base Case scenario. For estimating the value of avoided energy and capacity, we used a separate set of marginal energy and capacity costs for the IIS and the LIS using Nalcor's latest marginal cost study. For the IIS, we used $33 per MWh ($2019) for the avoided energy costs and $317 per kW-year ($2019) for the avoided generation and transmission capacity. For the LIS, we used $33 per MWh ($2019) for the avoided energy cost and $30 per kW-year as a proxy avoided transmission cost.[79]

With these assumptions, our analysis concluded that CDM programs with heat pumps in the IIS are very cost-effective. These programs are expected to have benefit cost ratios from 2.8 to 3.3 under the High Case between 2020 and 2030 and from 1.5 to 1.7 under the Low Case during the same time frame, as shown in Table 36 and Table 37 below. The substantially higher benefit cost ratios under the High Case are largely from the significant contributions of heat pumps that provide more energy savings than conventional CDM but cost significantly less.

Table 36. IIS - High Case Benefit Cost of CDM with Heat Pumps

Stream of Benefits, Real	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Energy Savings (GWh)	18	47	94	157	233	321	421	522	621	725	832
Net Peak Savings (MW)	3	8	17	27	40	55	72	89	105	123	141
Energy Benefits ($ million)	0.6	1.6	3.1	5.2	7.7	10.6	13.9	17.2	20.5	23.9	27.4
Capacity Benefits ($ million)	1.0	2.6	5.2	8.7	12.8	17.5	22.8	28.1	33.4	38.9	44.6
Total Benefits ($ million)	1.6	4.2	8.4	13.8	20.5	28.1	36.7	45.4	53.9	62.8	72.1
Net cumulative amortized costs ($ million)	1	1	3	5	7	10	13	16	18	20	22
B/C Ratio	3.12	3.01	2.98	2.95	2.90	2.84	2.78	2.83	2.94	3.10	3.31

Source: Synapse calculations

Table 37. IIS - Low Case Benefit Cost of CDM with Heat Pumps

Stream of Benefits, Real	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Energy Savings (GWh)	0	2	5	11	19	29	42	57	76	98	123
Net Peak Savings (MW)	0	0	1	2	3	4	6	8	11	14	18
Energy Benefits ($ million)	0.0	0.1	0.2	0.4	0.6	1.0	1.4	1.9	2.5	3.2	4.1
Capacity Benefits ($ million)	0.0	0.1	0.2	0.5	0.9	1.3	1.9	2.6	3.5	4.5	5.6
Total Benefits ($ million)	0.0	0.1	0.4	0.9	1.5	2.3	3.3	4.5	6.0	7.7	9.7
Net cumulative amortized costs ($ million)	0.0	0.1	0.3	0.6	1.0	1.5	2.2	2.9	3.8	4.7	5.7
B/C Ratio	n/a	1.50	1.51	1.51	1.52	1.53	1.53	1.54	1.58	1.63	1.69

Source: Synapse calculations

[79] PUB-Nalcor-121, Attachment 1. Nalcor. 2018. Marginal Cost Study Update – 2018.

In contrast, CDM programs are not cost-effective in the LIS in either of the scenarios. The benefit cost ratios range from 0.7 to 0.8 under the High Case and from 0.6 to 0.7 under the Low Case. The main reasons for these low benefit cost ratios are significantly lower avoided capacity costs and lower heat pump adoptions relative to the values used or projected for the IIS. Table 38 below shows the values for the High CDM case.

Table 38. LIS – High Case Benefit Cost of CDM with Heat Pumps

Stream of Benefits, Real	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Energy Savings (GWh)	1	3	7	14	25	39	58	78	98	118	139
Net Peak Savings (MW)	0	0	1	2	3	5	7	9	12	14	17
Energy Benefits ($ million)	0.02	0.09	0.24	0.48	0.82	1.29	1.92	2.57	3.23	3.90	4.58
Capacity Benefits ($ million)	0.00	0.01	0.03	0.05	0.09	0.14	0.20	0.28	0.35	0.43	0.51
Total Benefits ($ million)	0.02	0.10	0.27	0.53	0.91	1.43	2.13	2.85	3.59	4.33	5.09
Net cumulative amortized costs ($ million)	0	0	0	1	1	2	3	4	5	6	6
BC Ratio	0.73	0.70	0.70	0.70	0.70	0.71	0.71	0.72	0.75	0.78	0.83

Source: Synapse calculations

Lastly, we also analyzed benefit cost ratios of the DR programs under the High Case scenario. As shown in Table 39 our analysis found relatively high benefit cost ratios for the DR programs, more so than the CDM programs under the High Case especially in earlier years. The major factor for the high benefit cost ratio is the low cost of DR measures ranging from $50 to $160 per kW-year, which is much lower than the cost of capacity.

Table 39. High Case Benefit Cost of DR

Stream of Benefits, Real	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Net Energy Savings (GWh)											
Net Peak Savings (MW)	4	9	14	19	25	32	39	48	57	67	78
Energy Benefits ($ million)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Capacity Benefits ($ million)	1.28	2.71	4.29	6.05	7.99	10.13	12.49	15.11	18.01	21.23	24.80
Total Benefits ($ million)	1.28	2.71	4.29	6.05	7.99	10.13	12.49	15.11	18.01	21.23	24.80
Net cumulative amortized costs ($ million)	0.1	0.3	0.6	1.0	1.5	2.2	3.0	3.9	4.9	6.0	7.3
BC Ratio	14.76	10.06	7.72	6.32	5.38	4.71	4.21	3.89	3.68	3.52	3.40

Source: Synapse calculations

7. EXPORT MARKET REVENUE OPPORTUNITIES – SURPLUS CAPACITY AND ENERGY

7.1. Approach

Our approach to determine energy export market revenue opportunities used the PLEXOS production cost modeling tool to compute energy revenues under different scenarios of net load in the Province. The use of multiple scenarios allowed estimates of differential revenues between our reference scenario and any other scenario with modified load estimates. PLEXOS represents the different export market revenue opportunities – through Quebec to New York and New England markets, and to or through Nova Scotia to reach Maritime or New England markets – through use of market pricing at monthly and on-peak and off-peak periods,[80] for each of four total destination markets. While the PLEXOS tool is capable of supporting resource planning analytics, we used the tool only to estimate export market revenues.

All scenarios except our two export market price sensitivity runs (for high export prices, and for low export prices) used the same market price estimates based on confidential information from Nalcor, which we found to be reasonable.[81] We developed sensitivity case market price estimates using factors derived from the US EIA AEO forward natural gas price projections under high and low sensitivities for delivery to the New England market.[82]

[80] The bilateral non-firm energy markets are defined by these temporal attributes.

[81] Confidential Response to PUB-Nalcor-062.

[82] New England market prices are directly tied to natural gas prices, since natural gas-fired resources remain the core driver of spot energy prices in that region.

We estimated capacity market revenues based on the firm energy transfer headroom remaining on the Maritime Link (after accounting for firm obligations to deliver energy for the Nova Scotia Block), and an estimate for the avoided costs of capacity in Nova Scotia.

Our approach to determine Provincial net load[83] input assumptions for use in estimating export market revenue opportunities for surplus energy was described in Chapter 3. Export volumes available for sale depend on the level of such net load.

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 industrial, commercial, and residential loads[84] 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;[85] and outside of the Province, based on either the level of available transmission through Quebec, or the headroom[86] on the Maritime Link for flows south towards Nova Scotia and markets beyond (potentially New England or the other Maritime Provinces).

Our analysis uses PLEXOS hourly dispatch energy flow balances to estimate net export energy volumes and the potential revenue available from those volumes, based on estimated market prices. The volumes are split between, and priced by, 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 this Phase 2 we have used a more granular analytical tool—PLEXOS production cost analysis software—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. In Phase 1, our approach was less granular when we determined the volumes available for sale in each of the on-peak and off-periods as defined by the energy markets. We have better captured the pattern of energy

[83] 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.

[84] Net of the self-generation used to meet part of industrial and NP loads.

[85] I.e., the Labrador Island Link. The Plexos production cost model explicitly accounts for the transfer capability across the LIL when conducting dispatch, and thus our export volumes reflect that constraint. We do not conduct any sensitivities that assumes the LIL is out of service. If the LIL were to be out of service, the overall energy balances would be affected for those hours, including the level of export sales.

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

available for export during on-peak/off-peak hours within any given month, because we have modified the overall energy demand from within the Province to reflect specific hourly patterns of demand reduction arising from CDM, and demand increases from newly electrified load, respecting patterns of consumption that reflect, for example, primarily off-peak period charging of electric vehicles.

Ponding

PLEXOS directly considers purchase opportunities available from the Nova Scotia energy market, and our results include purchases when economic through that path, based on the market prices. Import opportunities come with both a market cost of purchase, and a tariff charge from the importing region. This is the way in which "ponding" opportunities are represented in PLEXOS. Notably, Hydro indicates that it currently does not forecast ponding opportunities to address reservoir storage management.[87] It also indicated (in the same discovery response) a 2018 analysis demonstrated an "immaterial impact" on reservoir levels. Synapse has not attempted to further examine opportunities going forward beyond the opportunistic energy purchases from external markets. A more careful examination of reservoir storage and hydrological conditions would be required.

Table 40 below shows the annual levels of purchases seen in our modeling, all of which are sourced from the Nova Scotia path. We note that the first two years of purchases reflect economic opportunities to avoid use of oil at Holyrood. Once the MFP is online, purchases drop off significantly. Generally, those purchases occur only in the winter months.

Table 40. Energy Purchases from External Sources – Synapse LR Scenario – 2019 -2030

Year	Purchase Quantity (GWh)
2019	54.7
2020	49.9
2021	4.7
2022	21.1
2023	21.6
2024	2.2
2025	20.1
2026	14.4
2027	14.0
2028	0.0
2029	9.7
2030	16.4

Source: Synapse PLEXOS modeling, Synapse LR Scenario.

[87] Response to PUB-Nalcor-97.

7.2. Resource Availability

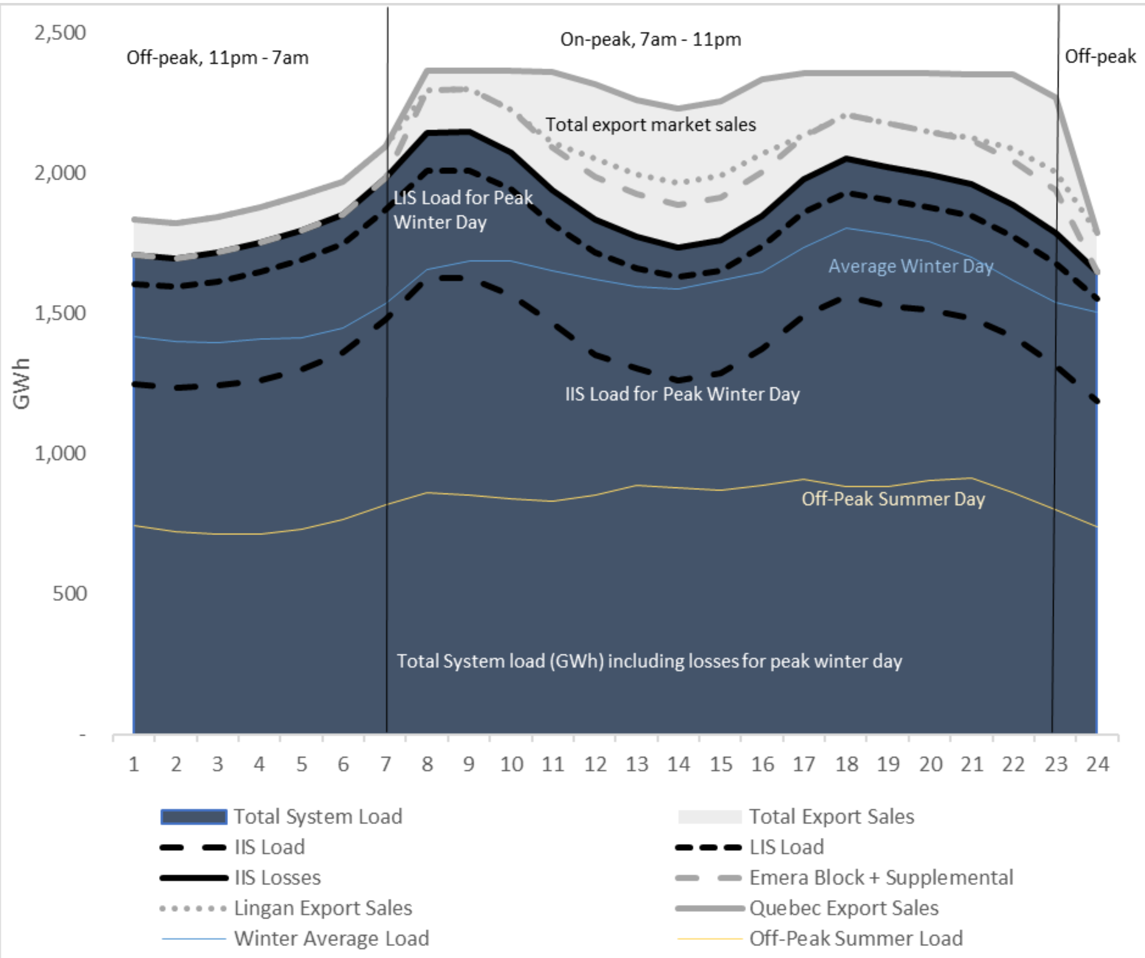
To develop export sales revenue estimates, we utilize the PLEXOS model, which is setup with NLH's representation of all capacity and energy resources on the IIS (both Hydro-owned or operated, purchased energy and capacity, industrial self-generation, and NP generation resources). The model also explicitly represents Labrador resources. The Labrador resources include the TwinCo Block, Recall or Recapture Energy, and small gas turbine resources, along with the Muskrat Falls units. Capacity and energy capability are represented for all resources, and the model is a production cost model run at an hourly scale. It represents the four destination export markets (Nova Scotia, New England via Salisbury, New England via Phase I/II through Quebec, and New York via Quebec).

Pattern of resource availability for energy export

Figure 42 below illustrates an energy and capacity balance for a high-load peak day in winter, a more average winter day, and an off-peak summer day in 2030. 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. outside the province. Representative winter average and summer off-peak loads are overlaid on top of the winter peak day profile.

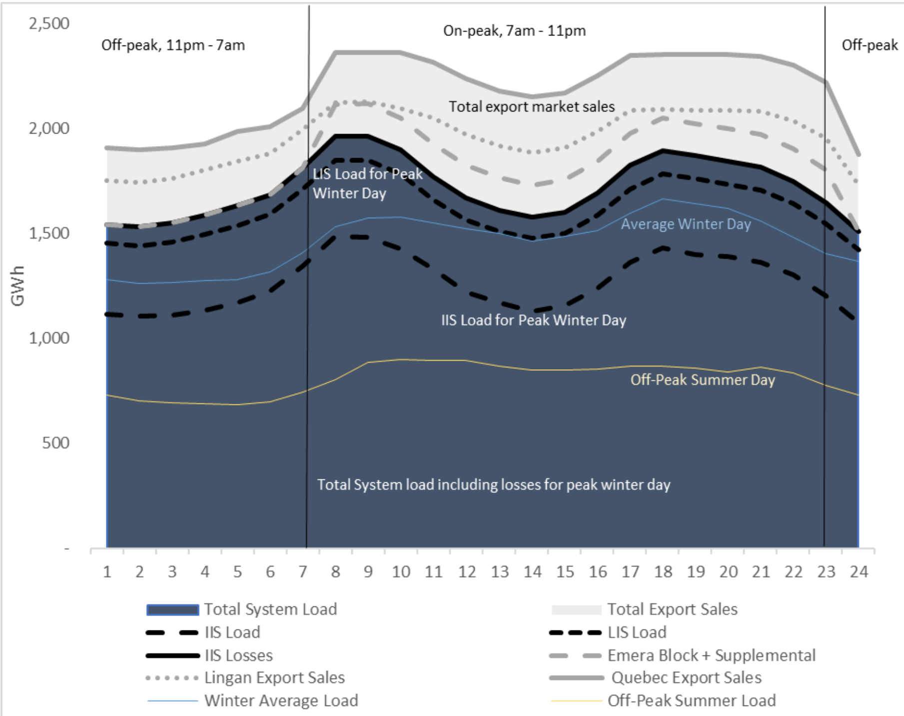
Figure 43 shows the capacity and energy balance for the High CDM scenario. Here, CDM investment on the Island has decreased internal load, therefore the energy available to export has increased. Figure 44 shows the High Electrification scenario. Here, on-island consumption has increased, leaving less energy available to export.

Figure 42: Winter peak day profile – Synapse LR Scenario



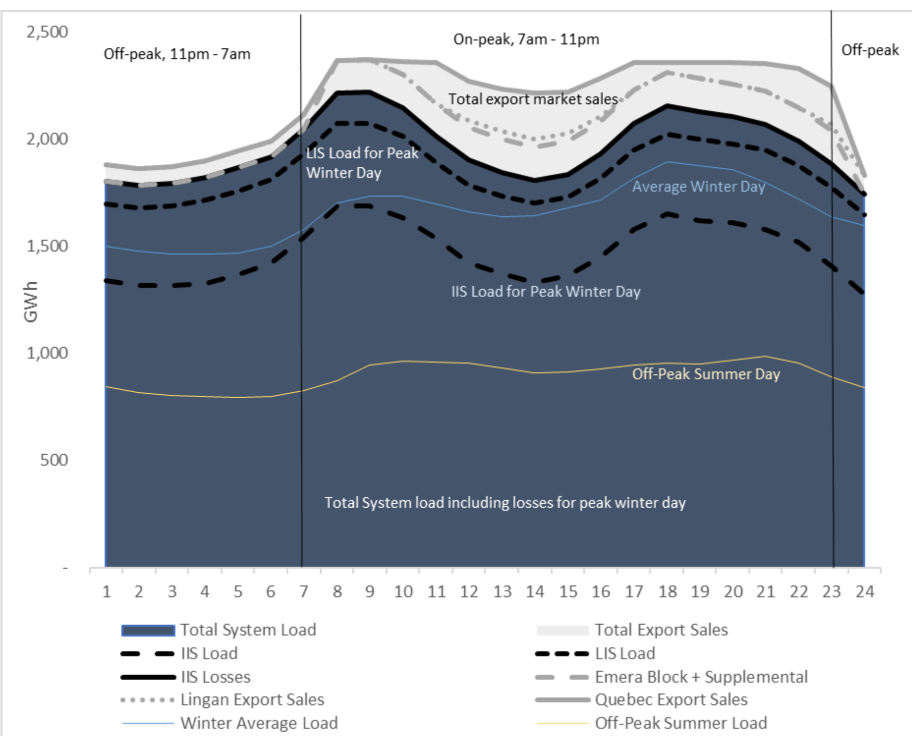
Source: Synapse PLEXOS modeling, Synapse LR Scenario.
Note: IIS Load, LIS Load and IIS Losses stack together to represent total Newfoundland Load. Emera Block + Supplemental, Lingan Export Sales, and Quebec Export Sales stack on top of load to represent total energy exported outside the province. Representative winter average and summer off-peak loads are overlaid on top of the winter peak day profile.

Figure 43: Winter Peak Day Profile – High CDM Scenario



Source: Synapse PLEXOS modeling, Synapse LR, High CDM Scenario.

Figure 44: Winter Peak Day Profile – High Electrification Scenario



Source: Synapse PLEXOS modeling, Synapse LR, High Electrification Scenario.

7.3. Energy and Capacity Balance – Island Interconnected System

Energy

Table 41 and Table 42 below show the energy balances between the IIS and the Muskrat Falls Project. Two tables are presented to illustrate that once the two regional systems are connected, the flows over the LIL could be considered as originating in the broader Labrador system, sourced from the pool of Labrador resources including the MFP, but also including the Churchill Falls resources.

Depending on how the energy is treated contractually, the flows over the LIL can be considered as coming from a combination of Labrador resources. Table 41 shows a balance wherein Labrador Load is met with TwinCo Block energy and Recall energy, and all remaining Recall energy is exported. Under this energy balance construction, the energy available at Muskrat Falls after meeting the needs of the IIS is seen to range from roughly 1.8 to 2.1 TWh (i.e., thousands of GWh) per year, shown in the last line of the table.

Table 41: MFP Energy Available for Load Growth / Export Sales, Selected Years (2020-2025, 2030), Synapse LR Reference, Excluding Recall Energy Availability

	2020	2021	2022	2023	2024	2025	2030
Island Load, Losses, and Generation							
Island Load (including self-supply)	8,078	8,039	7,981	7,967	7,942	7,919	7,806
Labrador Island Link Losses	305	324	317	318	317	319	321
Island Transmission Losses	418	432	452	447	447	450	441
Total Energy Requirement	8,801	8,795	8,750	8,732	8,706	8,688	8,568
Island Generation (all owners)	7,285	7,014	6,974	6,909	6,909	6,899	6,702
Net Requirement from Off-Island	1,516	1,781	1,776	1,823	1,796	1,789	1,866
Energy Balance - MFP Serving Balance of Needs Excluding Use of Recall Energy							
Net Requirement from Off-Island	1,516	1,781	1,776	1,823	1,796	1,789	1,866
Muskrat Falls Generation	4,068	5,043	5,035	5,043	5,057	5,041	5,042
Muskrat Fall Generation Available after Island Needs	2,552	3,262	3,259	3,220	3,261	3,252	3,175
Nova Scotia Block and Supplemental Obligation	682	1,132	1,148	1,149	1,133	1,043	916
Maritime Line Losses	100	155	141	138	138	140	136
Nova Scotia Obligation Energy Total	781	1,287	1,289	1,287	1,271	1,183	1,052
Muskrat Falls Generation Available after Island and Nova Scotia Obligations	**1,771**	**1,975**	**1,970**	**1,933**	**1,989**	**2,069**	**2,123**

Source: Synapse, PLEXOS modeling of Synapse LR Scenario, and Response to PUB-Nalcor-112.

Alternatively, Table 42 below shows the energy balance assuming that Recall energy available after meeting Labrador needs is used "first" on the IIS. The remaining MFP energy available would then be greater than seen in Table 41 above, ranging from 2.9 to 3.5 TWh per year.

Table 42: MFP Energy Available for Load Growth / Export Sales, Selected Years (2020-2025, 2030), Synapse LR Reference, Including Recall Energy Availability

	2020	2021	2022	2023	2024	2025	2030
Labrador Load, Losses and Generation							
Labrador Load	2,725	2,809	2,831	2,833	2,836	2,839	2,854
Labrador Losses	102	108	106	106	106	106	107
Total Energy Requirement	2,827	2,917	2,937	2,939	2,942	2,946	2,961
TwinCo Block Energy Available	1,952	1,971	1,971	1,971	1,976	1,971	1,971
Labrador Total Energy Requirement After TwinCo	874	946	966	968	965	975	990
Recall Energy Availability	2,092	2,418	2,383	2,409	2,426	2,392	2,389
Labrador Total Energy Requirement After TwinCo	874	946	966	968	965	975	990
Recall Energy Available for Island After Labrador Load Requirement	1,218	1,472	1,417	1,441	1,461	1,418	1,399
Net Requirement from Off-Island	1,516	1,781	1,776	1,823	1,796	1,789	1,866
Recall Energy Available for Island After Labrador Load Requirement	1,218	1,472	1,417	1,441	1,461	1,418	1,399
Island Net Requirement from Muskrat Falls after Recall	298	309	360	382	335	371	468
Muskrat Falls Energy	4,068	5,043	5,035	5,043	5,057	5,041	5,042
Island Net Requirements from Muskrat Falls after Recall	298	309	360	382	335	371	468
Nova Scotia Obligations	781	1,287	1,289	1,287	1,271	1,183	1,052
Muskrat Falls Energy Available after Island/Nova Scotia Needs	**2,989**	**3,447**	**3,386**	**3,374**	**3,450**	**3,487**	**3,522**

Source: Synapse, PLEXOS modeling of Synapse LR Scenario, and Response to PUB-Nalcor-112.

These balances are associated with the Synapse reference load forecast. For scenarios that include electrification or CDM, or both, the energy balances would change in direct alignment with the increases or decreases in export sales volumes seen relative to the Synapse reference scenario.

Capacity

Table 43 and Table 44 below show the capacity balances between the IIS and the Muskrat Falls Project. As with the energy balances shown above, two tables are presented to illustrate that once the two regional systems are connected, the capacity available for transfer over the LIL could be considered as originating in the Labrador system, sourced from the pool of Labrador capacity resources including the MFP, and the Churchill Falls resources.

Depending on how the capacity is treated contractually, the capacity transfer over the LIL can be considered as coming from a combination of Labrador resources. Table 43 shows a balance wherein Labrador capacity requirements are met with TwinCo Block and Recall capacity, and all remaining Recall capacity is available to support increased local (Labrador) load growth or exports. Under this capacity balance construction, the capacity available at Muskrat Falls after meeting the needs of the IIS is seen to range from roughly 196 to 201 MW, as shown in the last line of the table.

Table 43. MFP/IIS Capacity Balance, Selected Years (2020-2025, 2030), Synapse LR Reference, Excluding Recall Capacity Availability to Serve IIS Peak Demand

Island Load, Losses, Generation, and Labrador Island Link at Peak	Beginning of Year						
	2020	2021	2022	2023	2024	2025	2030
Island Load (including self-supplied load)	1,662	1,657	1,659	1,663	1,662	1,663	1,664
Island Transmission Losses	141	141	141	141	141	141	141
Total Capacity Requirement	1,804	1,798	1,800	1,805	1,803	1,804	1,805
Island Generation (all owners) Peak Capacity	1,935	1,935	1,345	1,345	1,345	1,345	1,345
Interruptible Capability	119	119	119	119	119	119	119
Capacity Available for Island Before Muskrat Falls/Labrador Island Link	2,054	2,054	1,464	1,464	1,464	1,464	1,464
Island Peak Load Total Requirements (Load + Losses)	1,804	1,798	1,800	1,805	1,803	1,804	1,805
Proposed Threshold Island Reserve Margin	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
Minimum Requirements at Above Reserve Margin	2,056	2,049	2,052	2,057	2,056	2,057	2,058
Capacity Required Across Labrador Island Link to Meet Reserve Margin	NA	NA	589	594	592	593	594
Muskrat Falls Firm Capacity			790	790	790	790	790
Excess Capacity at Muskrat Falls Available for Load Growth or Export (No use of Recall Capacity)			201	196	198	197	196

Source: Synapse, PLEXOS modeling of Synapse LR Scenario, and Response to PUB-Nalcor-112.

Alternatively, Table 44 below shows the capacity balance assuming that Recall capacity available after meeting Labrador needs is used “first” on the IIS. The remaining MFP capacity available for load growth or export sale would then be greater than seen in Table 43 above, and would range from 295 to 307 MW, as seen in the last line of the table.

Table 44. MFP/IIS Capacity Balance, Selected Years (2020-2025, 2030), Synapse LR Reference, Including Recall Capacity Availability to Serve IIS Peak Demand

Labrador Capacity Balance to Determine Recall Availability	Beginning of Year						
	2020	2021	2022	2023	2024	2025	2030
Labrador Peak Load	389	390	390	391	391	392	396
Labrador Losses	29	29	29	29	29	29	30
Labrador Total Capacity Requirement	418	419	419	420	421	421	425
TwinCo and Recall Capacity	525	525	525	525	525	525	525
Remaining Capacity After Labrador Requirements	107	106	106	105	104	104	100
Original Excess Capacity at Muskrat Falls before Remaining Recall Capacity			201	196	198	197	196
Excess Capacity at Muskrat Falls Available for Load Growth or Export (Use of Recall to meet partial needs)			307	301	302	300	295

Source: Synapse, PLEXOS modeling of Synapse LR Scenario, and Response to PUB-Nalcor-112.

7.4. Scenario Matrix

The PLEXOS model was used primarily for one purpose: to better estimate the export sales volumes and revenues, compared to the use of a simpler revenue model in Phase 1. In determining how many scenarios to run, and what the scenarios should involve, we discussed the different parameters that would affect overall export sales and mitigation results. Table 45. below shows a snapshot of the scenarios we modeled and the parameters addressed in each scenario.

Table 45. Scenario matrix for PLEXOS modeling

Key Input Parameters and Specifications								
	Scenario #	Scenario Name	Base IIS Load from NLH	Electrification of New Load	Rate for New EV Load	Rate for Existing Load	CDM - EE	Export Market Prices
Options			Low Rate, Mid Rate, High Rate	Baseline, Low, High	Flat, TOU	Flat, TOU and CPP	Baseline, Low, High	Baseline, Low, High
Hydro Reference	0	NLH Ref	Low Rate	Baseline		Flat	Baseline	Baseline
Synapse Reference	1	Syn Low Rate	Low Rate	Baseline		Flat	Baseline	Baseline
Base Load Modification	2	Syn Mid Rate	Mid Rate	Baseline		Flat	Baseline	Baseline
	3	Syn High Rate	High Rate	Baseline		Flat	Baseline	Baseline
CDM	5	Low CDM	Low Rate	Baseline		Flat	Low	Baseline
	5a	Low CDM w/DR	Low Rate	Baseline		Flat	Low	Baseline
	6	High CDM	Low Rate	Baseline		Flat	High	Baseline
	6a	High CDM w/DR	Low Rate	Baseline		Flat	High	Baseline
CDM w/TOU	7	Low CDM w/TOU	Low Rate	Baseline		TOU with CPP	Low	Baseline
	8	High CDM w/TOU	Low Rate	Baseline		TOU with CPP	High	Baseline
Electrification	9	Low Elec	Low Rate	Low	Flat	Flat	Baseline	Baseline
	9a	Low Elec, w/Low DR	Low Rate	Low	Flat	Flat	Baseline	Baseline
	9b	Low Elec, w/High DR	Low Rate	Low	Flat	Flat	Baseline	Baseline
	10	High Elec	Low Rate	High	Flat	Flat	Baseline	Baseline
	10a	High Elec, w/Low DR	Low Rate	High	Flat	Flat	Baseline	Baseline
	10b	High Elec, w/High DR	Low Rate	High	Flat	Flat	Baseline	Baseline
Electrification w/EV TOU	11	Low Elec w/EV TOU	Low Rate	Low	TOU	Flat	Baseline	Baseline
	12	High Elec w/EV TOU	Low Rate	High	TOU	Flat	Baseline	Baseline
Electrification & CDM	13	Low Elec, Low CDM	Low Rate	Low	Flat	Flat	Low	Baseline
	13a	Low Elec, Low CDM w/Low DR	Low Rate	Low	Flat	Flat	Low	Baseline
	14	Low Elec, High CDM	Low Rate	Low	Flat	Flat	High	Baseline
	14a	Low Elec, High CDM w/Low DR	Low Rate	Low	Flat	Flat	High	Baseline
	15	High Elec, Low CDM	Low Rate	High	Flat	Flat	Low	Baseline
	15a	High Elec, Low CDM w/High DR	Low Rate	High	Flat	Flat	Low	Baseline
	16	High Elec, High CDM	Low Rate	High	Flat	Flat	High	Baseline
	16a	High Elec, High CDM w/High DR	Low Rate	High	Flat	Flat	High	Baseline
Electrification & CDM w/EV TOU	17	Low Elec w/EV TOU, Low CDM	Low Rate	Low	TOU	Flat	Low	Baseline
	17a	Low Elec w/EV TOU, Low CDM w/Low DR	Low Rate	Low	TOU	Flat	Low	Baseline
	18	High Elec w/EV TOU, Low CDM	Low Rate	Low	TOU	Flat	High	Baseline
	18a	High Elec w/EV TOU, Low CDM w/High DR	Low Rate	High	TOU	Flat	Low	Baseline
	19	Low Elec w/EV TOU, High CDM	Low Rate	High	TOU	Flat	Low	Baseline
	19a	Low Elec w/EV TOU, High CDM w/Low DR	Low Rate	Low	TOU	Flat	High	Baseline
	20	High Elec w/EV TOU, High CDM	Low Rate	High	TOU	Flat	High	Baseline
	20a	High Elec w/EV TOU, High CDM w/High DR	Low Rate	High	TOU	Flat	High	Baseline
Electrification w/EV TOU , CDM w/TOU	21	Low Elec w/EV TOU, Low CDM w/TOU	Low Rate	Low	TOU	TOU with CPP	Low	Baseline
	22	Low Elec w/EV TOU, High CDM w/TOU	Low Rate	Low	TOU	TOU with CPP	High	Baseline
	23	High Elec w/EV TOU, Low CDM w/TOU	Low Rate	High	TOU	TOU with CPP	Low	Baseline
	24	High Elec w/EV TOU, High CDM w/TOU	Low Rate	High	TOU	TOU with CPP	High	Baseline
Export Market Price Sensitivity	25	Ref, Low Export Price	Low Rate	Baseline		Flat	Baseline	Low
	26	Ref, High Export Price	Low Rate	Baseline		Flat	Baseline	High
	29	Higher Price Response	Low Rate	Baseline		Flat	Baseline	Baseline

Source: Synapse.

7.5. Export Market Valuation Results

The energy available for Export market sales vary across scenarios based on the level of CDM investments and new electrification assumptions. The level of net export volumes available for sale are shown in Table 46. The net export sales revenues are shown in Table 47.

Table 46. Total export sales volumes by scenario, GWh, Bookend Scenarios

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NLH Low Rate Forecast	3,457	3,429	3,417	3,441	3,486	3,535	3,485	3,512	3,316	3,204
Synapse Low Rate Forecast	3,457	3,429	3,417	3,455	3,527	3,664	3,671	3,756	3,631	3,555
Synapse Low Rate, High CDM w/TOU	3,498	3,517	3,574	3,684	3,853	4,109	4,206	4,400	4,364	4,413
Synapse Low Rate, High CDM with TOU, High Electrification w/EV TOU	3,360	3,350	3,362	3,431	3,580	3,767	3,836	3,988	3,927	3,899
Synapse Low Rate, High Electrification Scenario	3,310	3,259	3,210	3,200	3,238	3,336	3,299	3,334	3,141	3,034
Extreme Low Load Scenario	3,661	3,763	3,898	4,046	4,265	4,499	4,638	4,846	4,824	4,883

Source: Synapse export market sales from PLEXOS production cost modeling. 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.

Table 47. Total net export sales revenues by scenario, $ millions, Bookend Scenarios

Scenario	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NLH Low Rate Forecast	120.2	115.2	114.0	118.8	123.1	131.6	133.9	148.0	147.2	150.5
Synapse Low Rate Forecast	120.2	115.2	114.0	119.4	125.0	137.0	141.8	159.3	162.5	169.8
Synapse Low Rate, High CDM with TOU	121.9	119.0	120.5	128.7	138.4	155.9	164.4	188.7	198.4	214.9
Synapse Low Rate, High CDM w/TOU, High Electrification w/EV TOU	116.4	112.1	112.0	118.6	127.3	141.6	149.2	170.4	177.4	188.9
Synapse Low Rate, High Electrification Scenario	114.0	108.2	105.7	109.2	113.2	123.2	125.9	139.8	138.8	141.1
Extreme Low Load Scenario	129.5	130.2	134.2	142.9	155.1	171.9	182.0	207.7	219.6	237.8

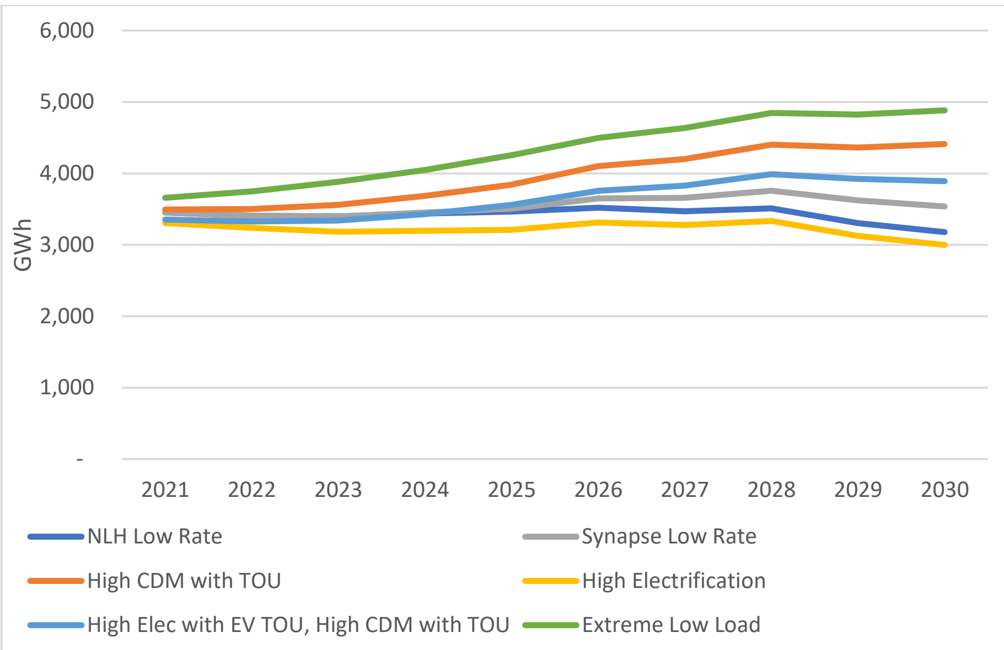
Source: Synapse export market sales from PLEXOS production cost modeling. Note: Export revenues are net of tariff and losses incurred to reach destination markets. Revenues are net of administration costs associated with export sales marketing.

Table 46 and Table 47 are presented visually in Figure 45 and Figure 46 below.

As seen in Figure 45, 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.

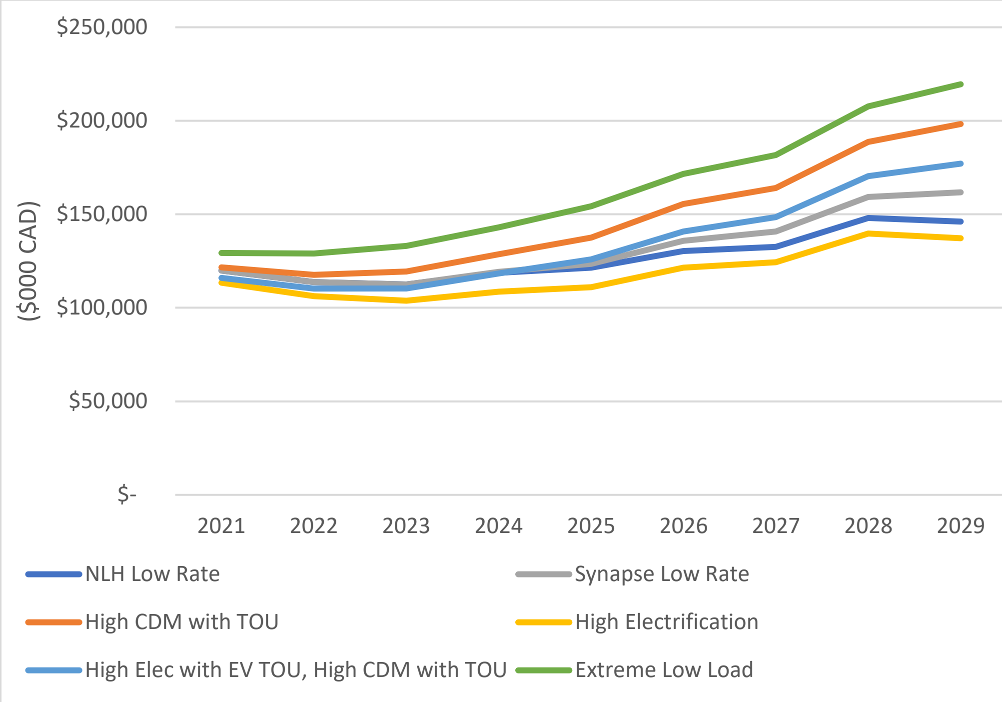
Figure 46 below show the range of net export market sales income, based on the destination market, the market prices, exporting costs (e.g., including path-to-market tariff and losses charges, and administration costs) and the volumes sold during on-peak and off-periods.

Figure 45: Total export sales volume by scenario, by year, GWh



Source: 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.

Figure 46: Total net export sales revenue by scenario, $000 (Canadian $)



Source: 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 Export Sale Potential

As we noted in our Phase 1 report, the 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 capacity sales – and potentially associated energy - over any given period of time depends on the projected headroom of capacity above planning reserve requirements, which represent overall capacity need for operations during peak load periods.[88] Table 43 and Table 44 illustrate that under the Synapse Reference load scenario, there is sufficient headroom available to support an export capacity sale, though notably before any considerations of LIL reliability and the impact this could have on capacity headroom; and before any considerations about further buffer requirements above a minimum reserve margin that the Province may wish to adhere to.

For the purposes of estimating revenues that could be available from a capacity sale, we assume that such headroom is available, as indicated in our Reference load forecast. While the headroom noted in

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[88] E.g., the Reliability and Resource Adequacy Study 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. Volume I, page 42, Table 4: Planning Reserve Margin Results. We make no determination regarding the appropriateness of this value, but as seen in our Table 43 and Table 44, we use the 14 percent value when estimating surplus capacity availability from the MFP for the purposes of estimating a potential capacity export sale revenue stream.

Table 43 above potentially indicates sales on the order of more than 200 MW, we limit consideration to additional headroom that is available across the Maritime Link, assuming a total firm transfer capability equivalent to half its 500 MW thermal transfer capability, or roughly 250 MW.[89] Since the Emera Block of firm energy requires use of the Link to serve the load obligations (injecting 170 MW at Bottom Brook),[90] we estimate that roughly 70 MW could be available for a capacity sale, after accounting for losses across the Maritime Link.

The potential destination markets for surplus capacity consist of Quebec, New York, New England, and the Maritimes. However, as we noted in the Phase 1 report, we will limit the capacity export opportunity to the Nova Scotia market for the purpose of demonstrating the rough value of an export sale.

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).

We base our range of estimated value for an incremental capacity sale on: 1) the annualized cost of new entry (CONE), or effectively the cost of a new combustion turbine in Nova Scotia;[91] and 2) a somewhat arbitrary lower bound assuming that the market value of an older-vintage coal plant in Nova Scotia (which retires) could be on the order of 50% of the cost of new entry, respecting both sustaining and fixed O&M costs.[92] On this admittedly broad basis, the value for selling an incremental 70 MW of

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[89] It is our understanding, based upon conversations with Hydro, that capacity sales across the Maritime Link would likely be limited to roughly half of its transfer capacity, or 250 MW. See also, for example, page 32 of the Liberty Consulting Group Report "Review of Newfoundland and Labrador Hydro Power Supply Adequacy and Reliability Prior to and Post Muskrat Falls Final Report", August 2016, 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.

[90] PLEXOS model inputs.

[91] We use $1,265 per kW ($2018) to reflect an estimate of the cost of new entry for a CT in Nova Scotia, based on NS Power's indications to Synapse (in November 2017) for use in analysis that resulted in the publicly posted report, "Nova Scotia Power Inc. Thermal Generation Utilization and Optimization," May 1, 2018, page 18 (corrected for 2018 year $). Available at: https://uarb.novascotia.ca/fmi/webd/UARB15, under Matter M08059. We estimate an annualized CONE value of $102 per kW-year based on economic life (30 years) and weighted average cost of capital (WACC – 7 percent nominal).

[92] For example, publicly available information on sustaining capital costs for older coal-fired plants in Nova Scotia can be estimated using information from Nova Scotia Power's current 10-Year System Outlook, available at http://oasis.nspower.ca/site/media/oasis/20180712%20NSPI%20to%20UARB%2010%20Year%20System%20Outlook%20REVISED.pdf. See page 23.

capacity would range from a low end of roughly $3.6 million per year, to a full CONE-based value of $7.1 million per year.

As we note earlier in this report, for all peak load reduction actions available in our scenarios, we assign a capacity avoidance value to the MWs of peak load reduction, based on Hydro's current longer-term marginal cost of capacity. Selling capacity would reduce the value we assign to such reductions, for the purposes of rate mitigation, thus we do not include the export sale value directly in our net mitigation computations.

8. Rate Impacts and Rate Design

The mitigation options described previously were implemented together with various rate designs. At their core, electricity rates are set to recover revenue requirements, but the specific design of those rates can also be used to encourage customers to consume less or more electricity, particularly during certain hours. In this way, rate design can be used as a tool to:

- Increase the adoption of beneficial electrification technologies such as electric vehicles;
- Reduce peak demand, thereby avoiding the need to build new capacity resources; and
- Shift local consumption to hours when export market prices are relatively low, allowing Newfoundland to increase exports during high priced hours.

Our analysis considered several different rate options, as well as the costs and benefits of each. These rate options consisted of:

1) TOU rates with CPP for all customers;
2) TOU rates for electric vehicle customers only; and
3) Lower-priced flat rates for charging electric vehicles to encourage transportation electrification.

In addition, we discuss other rate options, such as incentive rates for new load, load retention rates for existing load, and the potential to smooth rate increases.

The specific rate designs implemented will impact customers' hourly electricity consumption patterns, the costs incurred by Hydro and NP, the revenues collected from customers, the export revenues received, and the willingness of customers to electrify new loads. To the extent possible, we captured these impacts in our modeling, as described in greater detail below.

8.1. TOU Rates with Critical Peak Pricing for All Customers

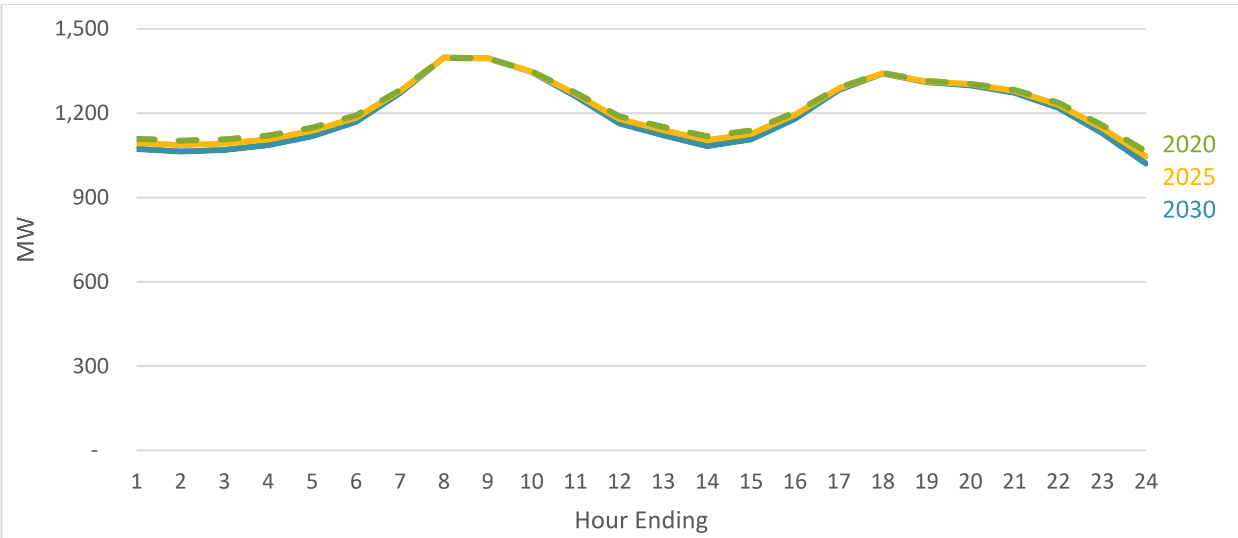
Design of TOU Rates

TOU rates apply different prices to consumption according to a set schedule, which is designed to roughly represent the costs of providing electricity during different hours of the day. A simple TOU rate may only have two different prices: one for on-peak periods and another for off-peak periods. This rate design approach can provide customers with a more accurate price signal, which encourages customers to shift their usage from on-peak periods to off-peak periods, to the extent feasible, thereby reducing system costs.

CPP assesses an extremely high price during only a small number of event hours per year. Customers are typically notified the day before an event. For example, a utility may call five CPP events during the year, each of which lasts for between two and four hours. During the events, electricity might be priced at $1.50 per kWh. CPP can be easily layered on top of a standard TOU rate.

In Newfoundland, costs are primarily driven by winter peak demand, as the system has limited ability to serve additional peak load.[93] During cold winter periods, demand on the IIS is highest during the morning and evening hours, as shown for the reference case in Figure 47 below. This load profile continues for the reference case with minimal change through the duration of our study period.

Figure 47: Synapse LR (Reference) Case, IIS Peak Winter Day 2020, 2025, 2030



Source: Synapse PLEXOS modeling, Synapse LR Scenario.

Hydro's 2018 marginal cost update study shows that the marginal costs associated with serving the winter morning and evening hours are nearly four times higher than serving load during the middle of the night. Further, the winter peak hours are nearly 11 times more costly to serve than non-winter hours.[94] We used the marginal costs provided by Hydro to design TOU and CPP rates for the island. We opted for a simple two-period TOU structure, as shown in the figure below. The on-peak hours were set to be 6:00 am – 10:59 am and 4:00 pm – 8:59 pm (i.e., hours ending 7 - 11 and 17 – 21).

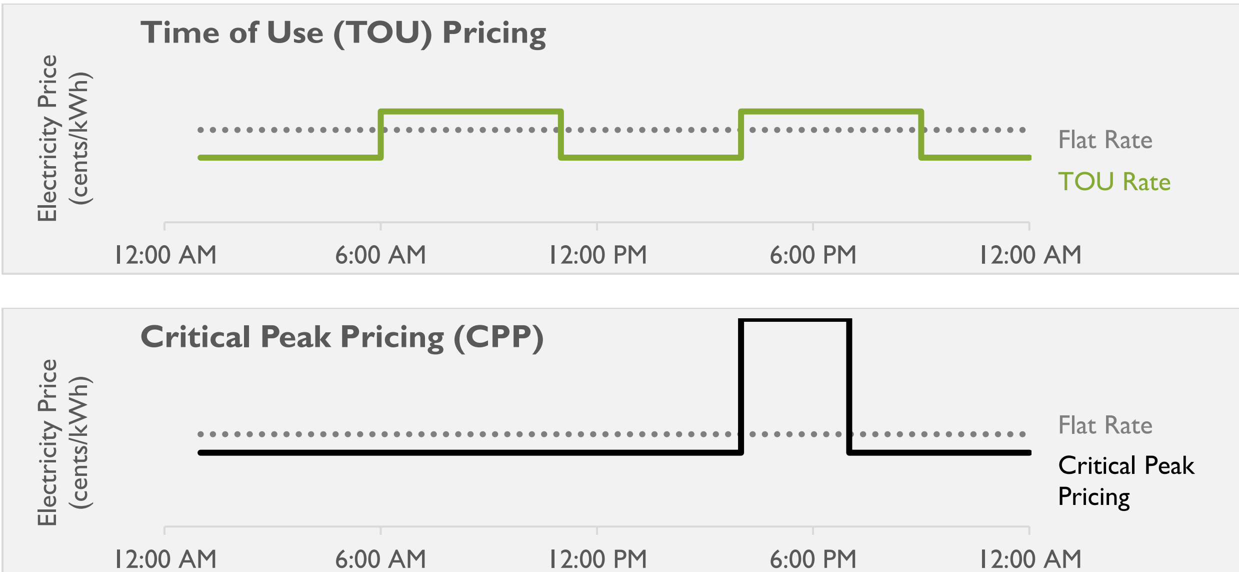
A CPP was then layered on top of the TOU rate to reduce peak demand. We assumed that critical peak events would be called when needed and apply to approximately 50 hours per year. Stylized examples

[93] Response to PUB-Nalcor-121, Attachment 1, Newfoundland Labrador Hydro, "Marginal Cost Study Update – 2018, A Report to the Board of Commissioners of Public Utilities," November 15, 2018, p. 11.

[94] Response to PUB-Nalcor-121, Attachment 1, Newfoundland Labrador Hydro, "Marginal Cost Study Update – 2018, A Report to the Board of Commissioners of Public Utilities," November 15, 2018, Figure 2, p. ES-3.

of TOU and CPP rates are shown in the figures below. The specific prices vary by scenario, but all were designed to be at or above marginal cost.

Figure 48. Stylized TOU and CPP Pricing



Source: Synapse calculations

Costs of Implementing TOU + CPP Rates

In order to implement advanced rate designs, interval metering is required. Advanced metering infrastructure (AMI) has been adopted by numerous utilities in order to reduce costs associated with manual meter reading as well as to implement time-varying rates. However, the majority of customers in Newfoundland are currently served by automated meter reading (AMR) technology, which allows meters to be read using a radio signal but is not capable of hourly metering for the purpose of implementing time-varying rates. For this reason, we assumed that widespread implementation of time-varying rates would require adoption of AMI.

In 2017, Nova Scotia Power, Inc. investigated AMI procurement costs for Nova Scotia and assembled cost benchmarks for other Canadian AMI installations and one utility in the United States with a comparable geography and customer volume.[95] The all-in costs by utility are presented in Table 48. These cost benchmarks were then used to estimate the cost of a full AMI rollout in Newfoundland.

[95] NS Power's Application, In the Matter of an Application by NS Power to Implement an Advanced Meter Infrastructure /CI47124 (NSUARB M08349), October 19, 2017, p. 54.

Table 48. AMI benchmark costs

Year deployment completed	2010	2012	2016	2017	2020
All-in cost per Meter (CDN $)	$409	$406 (after federal subsidies)	$404	$266	$269 (group bulk purchase price)
Utility	Ontario (including Hydro One)	Central Maine Power (CMP)	BC Hydro	Hydro Quebec	NS Power
Smart meters installed (millions)	4.8	0.6	1.8	3.8	0.5

Source: Adapted from NSPI AMI Application (NSUARB M08349), October 2017

Based on these data, we assumed that 290,000 smart meters would be installed at an all-in cost per meter of approximately $300, resulting in a total cost of $87 million.[96] We further assumed that the meters would be installed over a three-year period, with costs in the later years escalated for inflation. These costs were then amortized over a 20-year period.

Because NP recently installed AMR, few operational savings are likely to result from the installation of AMI in the near-term. Thus, it would only be cost-effective to install AMI if doing so allows the Province to materially reduce peak demand and avoid additional generation capacity costs.

Impacts of TOU + CPP Rates

Benchmarking Rate Impacts

Time-varying rates have been widely implemented on an opt-in basis, and, to a lesser extent, on a default (opt-out) basis. However, the majority of jurisdictions that have implemented time-varying rates are summer peaking and generally have high air-conditioning loads during peak hours. In contrast, relatively few analyses of time-varying rates have been performed in winter-peaking areas, such as Newfoundland.

To determine the likely impact of implementing TOU and CPP rates, we reviewed studies from jurisdictions determined to be broadly similar to Newfoundland. Specifically, we analyzed winter peak reductions under various time-varying rate structures tested by Hydro Quebec, Ontario electric utilities, and Portland General Electric in Oregon.

[96] The Dunsky Report (see Response to PUB-NP-104) indicates AMI installation costs ranging from $85 to $105 million. Appendix E, page 99.

Hydro Quebec is most similar to Newfoundland in that it is winter peaking, has a large proportion of electric heat,[97] and has a similar climate in its large population centers. Hydro Quebec implemented a TOU + CPP pilot from 2008-2010 on an opt-in basis. This pilot found winter peak reductions of approximately 3 percent during on-peak periods and 6 percent during critical events.[98] However, this peak reduction percentage rate would be expected to be much lower under an opt-out (default) enrollment process (although the total megawatt reduction would likely be higher due to a greater number of participants under a default enrollment mechanism).

Ontario differs from Newfoundland in that it is generally summer-peaking, with peaks driven by air conditioning use,[99] and has relatively little electric heat.[100] However, Ontario has implemented default TOU rates and reported winter peak reductions. According to analysis by the Brattle Group, winter peak demand reductions initially were approximately 2 percent prior to 2012 but have faded out over time with no statistically significant winter peak reductions reported in 2014.[101] This is shown in the graph below.

[97] Statistics Canada, Table 2, Type of main heating fuel used, by province, 2011. Available at https://www150.statcan.gc.ca/n1/pub/11-526-s/2013002/t002-eng.htm

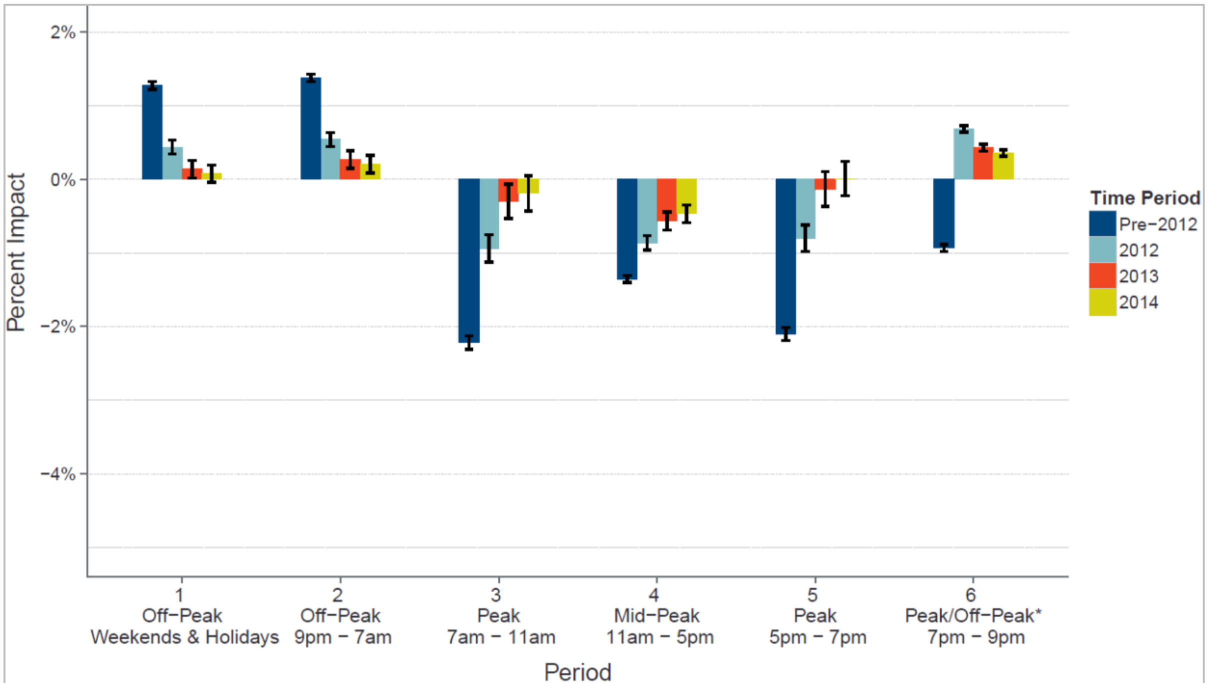
[98] Note that the critical event peak reductions were statistically significant at the 90 percent level, but the on-peak reductions were not. Hydro Quebec, Rapport final du projet tarifaire "Heure Juste", Demande R-3740–2010, p. 29. Available at http://www.regie-energie.qc.ca/audiences/3740-10/Demande3740-10/B-1_HQD-12Doc6_3740_02aout10.pdf

[99] Ontario Independent Electricity System Operator, Ontario Demand Forecast, December 17, 2018. Available at http://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/2018Q4OntarioDemandForecast.pdf

[100] Statistics Canada, Table 2, Type of main heating fuel used, by province, 2011. Available at https://www150.statcan.gc.ca/n1/pub/11-526-s/2013002/t002-eng.htm

[101] Faruqui, A. and S. Sergici. "Dynamic Pricing & Demand Response." Presentation to IPU's Annual Regulatory Studies Program: The Fundamentals Course. Lansing, Michigan. August 11, 2016, slide 50. Available at https://brattlefiles.blob.core.windows.net/files/5760_dynamic_pricing_and_demand_response.pdf

Figure 49. Ontario winter peak demand reductions



Provincial Winter Load Shifting for Residential

* Period 6 was peak before May 2011

Note: Black bars indicate 95% confidence intervals for the impact

Source: Faruqui & Sergici, 2016.

Portland General Electric (PGE) in Oregon has a warmer climate than Newfoundland, but is winter peaking and has a large share of customers with electric heating.[102] In 2017-2018, PGE tested a variety of rate designs and reported peak reductions for both summer and winter. Of particular interest are the peak reductions under a Peak Time Rebate (PTR) rate design, which is essentially the reverse of CPP. Instead of paying a higher price for consumption during the peak period, PTR offers a rebate to customers who reduce their consumption.[103] With a rebate of $1.55 USD per kWh, PGE obtained 6 percent peak load reductions from customers under opt-out enrollment. Similar reductions may be expected under a CPP rate. Under PGE's opt-out TOU rate, winter peak reductions were much lower, estimated to be in the range of 2-3 percent. However, these results were not statistically significant.[104]

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[102] Portland General Electric, Draft Integrated Resource Plan, May 2019, p. 26. Available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2019-irp.pdf.

[103] Although PTR has many attractive elements, it also introduces complexity due to the need to determine an individual customer baseline in order to measure load reductions. PTR also generally results in lower peak reductions relative to CPP. For these reasons we did not analyze PTR options for Newfoundland.

[104] Cadmus. Flex Pricing and Behavioral Demand Response Pilot Program Evaluation Report, Prepared for Portland General Electric, June 25, 2018, p. 5. Available at https://edocs.puc.state.or.us/efdocs/HAH/um1708hah16432.pdf.

Estimated Newfoundland TOU + CPP Peak Load Reductions

Based on the programs described above, we estimated that TOU rates alone would produce peak load reductions of approximately 1 percent in Newfoundland. Peak reductions under TOU rates were assumed to be energy neutral, with the load being shifted to the two hours immediately before and after the on-peak periods.

For CPP, we assumed that peak reductions would be similar to reductions achieved through direct load control demand response programs. This produces minor load reductions in the early years of the study period but increases to 3 percent and 7 percent by 2030, depending on the scenario.

8.2. TOU Rates for EV Customers

Although the implementation of whole-house TOU rates would require AMI, electric vehicles can utilize submetering technologies to avoid the need to replace the electric meter. Submetering is similar to having an additional meter, except that the submeter is located between the primary meter and the electric vehicle. This allows the electric vehicle load to be billed on a time-varying rate, while the rest of the household usage is billed on a standard rate. California has conducted extensive testing on the technology and several utilities are piloting submetering for electric vehicle tariffs.[105] The current technology options and costs associated with submeters include:

1) Stand-alone submeters like the WattBox™ from eMotorWerks, with a cost of approximately $330.[106]
2) Submeters integrated with the electric vehicle supply equipment ("EVSE," colloquially "charging station"). At-home EVSE are generally Level 2 charging stations such as the JuiceBox™ from eMotorWerks with a cost of approximately $835,[107] or the ChargePoint Home from ChargePoint with a cost of approximately $900.[108]
3) Mobile (in-car) submeters such as the FleetCarma C2 device.

Installation of both stand-alone and EVSE-integrated submeters typically requires an electrician and will incur an additional cost. In contrast, FleetCarma's C2 device is "plug-and-play," allowing the electric vehicle owner to simply plug it into the on-board diagnostics port found under the dash of the vehicle.

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105 California is in Phase II of its submetering pilot, while Xcel Minnesota recently obtained approval to proceed with its submetering pilot. Submetering has also been tested by some municipal utilities, such as Belmont Light in Massachusetts.

106 Cook, J. et al. 2016. *California Statewide PEV Submetering Pilot – Phase 1 Report*. Nexant. Prepared for the California Public Utilities Commission. Page 31. Converted from USD to CAD.

107 Pricing as of August 2019 on eMotorWerks website store: https://www.autochargers.ca/products/juicebox-chargers/juiceboxpro40charger.html

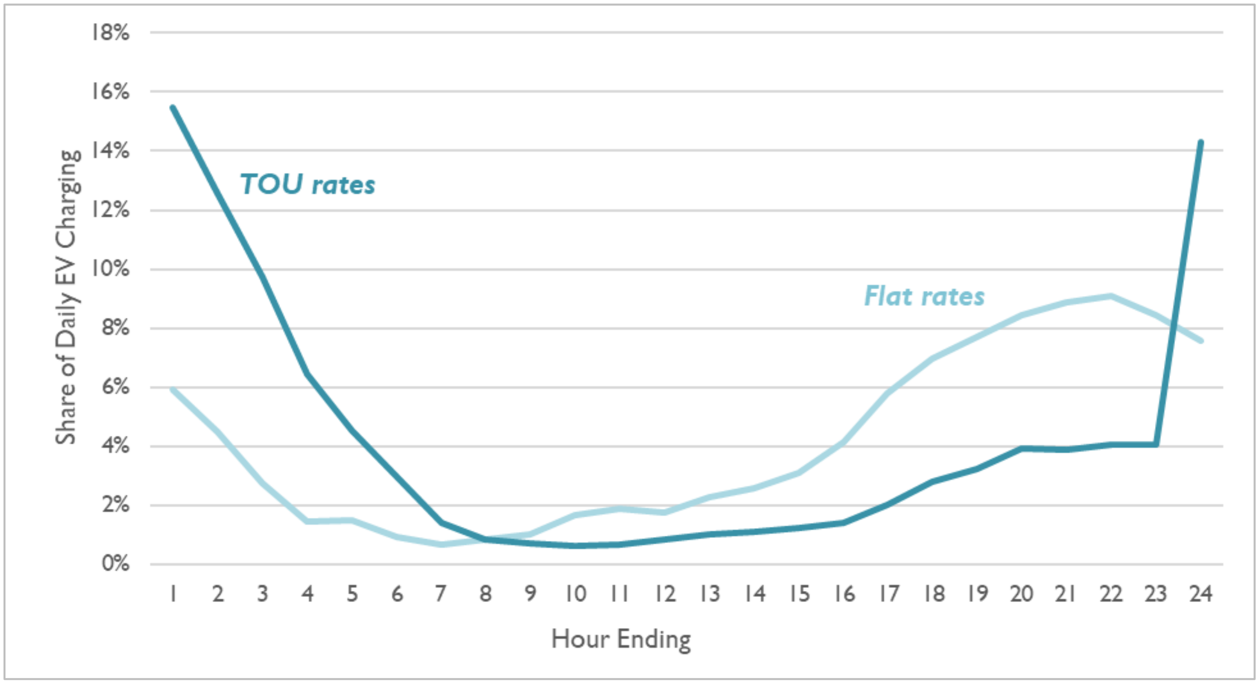
108 Pricing as of August 2019 on Amazon.ca: https://www.amazon.ca/dp/B071YDJ1F6/ref=cm_sw_em_r_mt_dp_U_xr.xDbFVQJNK5

All three submeter types collect electric vehicle charging data and use Wi-Fi or a cellular network to record and transmit usage data to third-party vendors or directly to the utility.

Using these technologies, we modeled the implementation of a TOU rate for electric vehicles only. The cost of this option was assumed to be $400 per electric vehicle to cover the program costs including a rebate to encourage customers to purchase a Wi-Fi-enabled submeter.[109]

As with TOU rates for all customers, the electric vehicle TOU rates were designed to reflect marginal costs. In addition, the electric vehicle TOU rates were designed to be revenue neutral to the flat rates, using the electric vehicle load profile under flat rates from a jurisdiction similar to Newfoundland.[110] However, we then assumed that electric vehicle load would largely shift to off-peak hours, as has occurred in other jurisdictions. The assumed electric vehicle load profiles under flat rates and TOU rates are shown in the Figure 50.

Figure 50. Light-duty electric vehicle daily charging profile for flat and TOU rates



Source: DTE Electric Company, Direct Testimony of Camilo Serna, U-20162, July 6, 2018.

Due to the reduction in charging during on-peak hours under TOU rates, costs to the utility system decline due to reduced peak demand. However, the actual revenues received by the utility from electric

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[109] Costs were escalated annually for inflation.

[110] We applied a daily charging profile for electric vehicles from DTE Electric Company, Direct Testimony of Camilo Serna, U-20162, July 6, 2018.

vehicle customers on TOU rates are also projected to decline relative to flat rates. These revenues must then be collected from the remaining customers through standard rates.

The electric vehicle TOU rate modeled begins at $0.07 per kWh for off-peak charging[111] and $0.20 per kWh for on-peak charging. These rates then increase at the same pace as rates under the reference case, reaching $0.14 per kWh for off-peak and $0.40 per kWh for on-peak by 2030.

8.3. Incentive Rates for Transportation Electrification

Transportation electrification can help to mitigate rates in the province by absorbing excess energy while reducing customers' expenditures on gasoline. However, electric vehicles are a relatively new technology that currently command a substantial price premium, despite having lower operating costs. It is possible that electric vehicle adoption as modeled in the High Electrification scenario will not occur without further incentives, such as reduced electricity prices for electric vehicle charging. To test the impact of implementing an electric vehicle incentive rate, we modeled a price set at marginal cost in 2019 that then increases at an annual rate of 4.5 percent, reaching $0.13 per kWh in 2030.

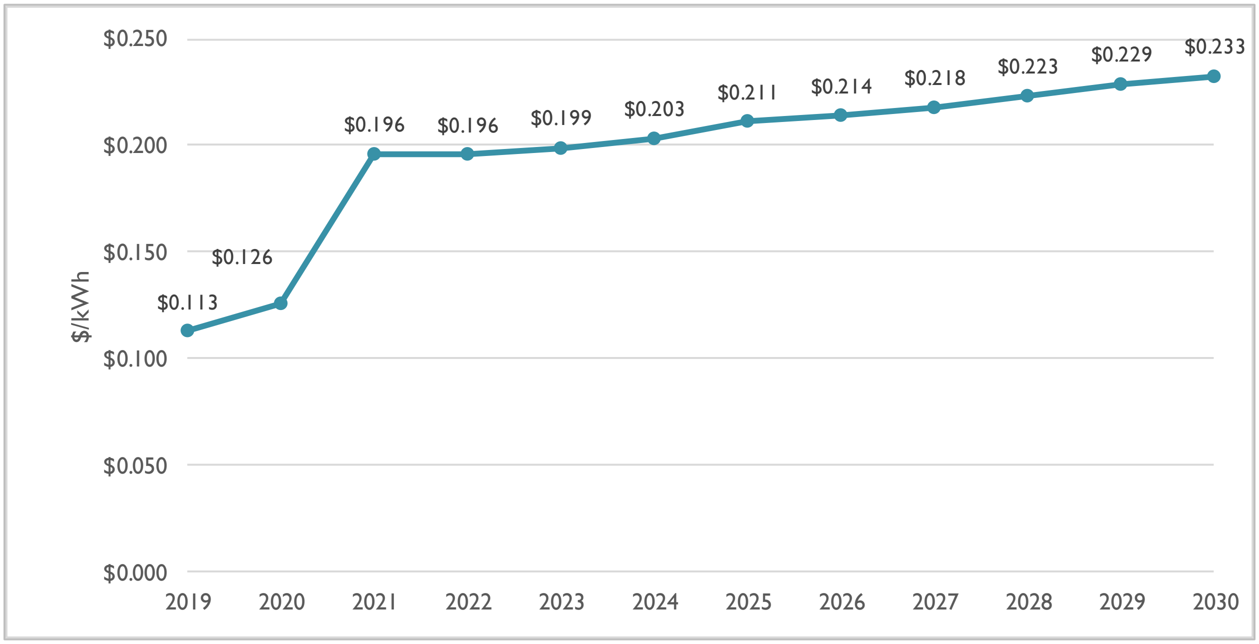
8.4. Rate Impacts by Scenario

Synapse Low Rate Reference Case

Under our reference case, we expect that rates will increase substantially as the costs of Muskrat Falls are introduced into the revenue requirements. Figure 51 below depicts a rapid increase in rates in 2021 followed by a more gradual increase in the following years. We note that our core rate analyses focus on the difference in rates under different designs; we understand that the absolute rate levels will be driven in significant part by overall mitigation approaches outlined in the work undertaken by Liberty, and ultimately by Provincial and Federal policies.

[111] The off-peak rate is set approximately 9 percent above the marginal cost for all off-peak hours.

Figure 51: Average Total Rate – Synapse LR Scenario

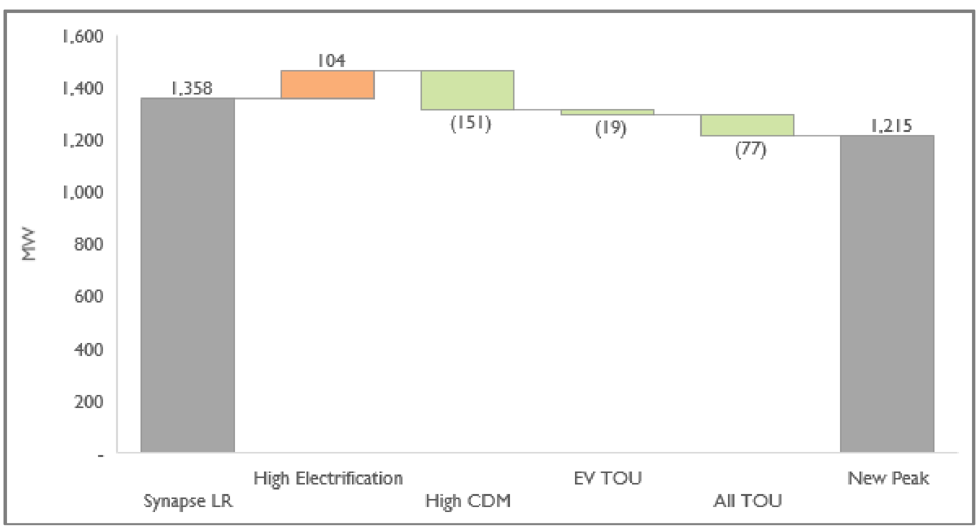


Source: Synapse, based on revenue requirements approximated for IIS under LR scenario, and excluding effect of export sales on average rate.

Rate Impacts for All Scenarios

The chart below illustrates the incremental impact of electrification, CDM, EV TOU rates, and TOU with CPP for all customers on peak demand in 2030, under the high electrification scenario. These changes in peak demand are a key component influencing the overall mitigation effect. In addition, changes in internal sales, export revenues, and CDM, DR, TOU rate, and electrification program costs influence the overall level of mitigation.

Figure 52. Incremental Impacts on Peak Demand, High Electrification Scenario, 2030



Note: Peak demand excludes NP and industrial self-supplied demand, and losses. Source: Synapse analysis.

Table 49 below shows the rate impacts for each of the scenarios in the year 2030, as compared to the reference scenario. Negative numbers indicate rate reductions relative to the reference case. The greatest rate reductions result from the sensitivity with higher export prices, while the greatest rate increase results from the sensitivity with extremely low load. It is important to note that each of these rate impacts is relative to the average rate of approximately $0.23 per kWh in 2030 under the reference scenario, which is a substantial increase relative to current rates.

In addition to showing the average rate impact for each scenario, the two right columns of Table 49 show rate impacts for non-EV customers after an incentive rate (i.e., a discount) or after an EV TOU rate is applied to EV customers. As can be seen, the flat rate incentive results in non-EV customers experiencing less benefit than they would if all customers paid the average rate. The impacts of the EV TOU rate also reduce the benefits experienced by non-EV customers, but only slightly. These impacts should be weighed against the need for incentive rate structures to attract new load.

Table 49. Summary of 2030 Rate Impacts Relative to Reference Case

Rank	Scenario	Avg Rate for All Customers	Average Rate for Non-EV Customers	
			EV Flat Rate Incentive	EV TOU
1	Synapse LR, High Export Price	-5.0%	N/A	N/A
2	High Elec w/EV TOU w/DR	-4.6%	-3.3%	-4.0%
3	High Elec w/DR	-4.4%	-3.1%	N/A
4	High Elec w/EV TOU, Low CDM w/DR	-3.8%	-2.5%	-3.2%
5	High Elec w/EV TOU, Low CDM w/TOU+CPP	-3.7%	-2.4%	-3.7%
6	High Elec, Low CDM w/DR	-3.7%	-2.3%	N/A
7	High Elec w/EV TOU	-3.6%	-2.3%	-3.0%
8	High Elec	-3.4%	-2.1%	N/A
9	High Elec w/EV TOU, Low CDM	-2.8%	-1.5%	-2.2%
10	High Elec, Low CDM	-2.7%	-1.3%	N/A
11	Low Elec w/DR	-1.8%	-1.5%	N/A
12	Low Elec w/EV TOU w/DR	-1.7%	-1.4%	-1.5%
13	Low Elec	-1.3%	-1.0%	N/A
14	Low Elec w/EV TOU	-1.1%	-0.8%	-1.0%
15	Low Elec w/EV TOU, Low CDM w/TOU+CPP	-1.0%	-0.7%	-1.0%
16	Low Elec, Low CDM w/DR	-0.9%	-0.6%	N/A
17	Low Elec w/EV TOU, Low CDM w/DR	-0.8%	-0.5%	-0.7%
18	Low Elec, Low CDM	-0.4%	0.0%	N/A
19	Low Elec w/EV TOU, Low CDM	-0.3%	0.0%	-0.1%
20	High Elec w/EV TOU, High CDM w/TOU+CPP	-0.2%	1.4%	-0.2%
21	Synapse Low Rate	0.0%	N/A	N/A
22	Low CDM w/TOU+CPP	0.3%	N/A	N/A
23	High Elec w/EV TOU, High CDM w/DR	0.3%	1.9%	1.2%
24	Low CDM w/DR	0.4%	N/A	N/A
25	High Elec, High CDM w/DR	0.5%	2.1%	N/A
26	Low CDM	0.9%	N/A	N/A
27	High Elec w/EV TOU, High CDM	1.3%	3.0%	2.2%
28	High Elec, High CDM	1.6%	3.2%	N/A
29	Synapse LR, Low Export Price	2.0%	N/A	N/A
30	Synapse LR, New Lab Cust Load	2.6%	N/A	N/A
31	Low Elec w/EV TOU, High CDM w/TOU+CPP	3.2%	3.6%	3.2%
32	Low Elec, High CDM w/DR	4.1%	4.5%	N/A
33	Low Elec w/EV TOU, High CDM w/DR	4.1%	4.5%	4.4%
34	Low Elec, High CDM	4.7%	5.1%	N/A
35	Low Elec w/EV TOU, High CDM	4.7%	5.1%	5.0%
36	High CDM w/TOU+CPP	4.8%	N/A	N/A
37	High CDM w/DR	5.0%	N/A	N/A
38	High CDM	6.2%	N/A	N/A
39	Extreme Low Load	15.8%	N/A	N/A

As noted previously, rate impacts are not the only consideration. Customers in Newfoundland pay electricity bills, not rates, and thus the bill impacts are highly relevant when making policy decisions regarding MFP mitigation. Table 50 below shows the impacts on monthly electricity bills in 2030, as well as the "net bill" impact, which includes reduced costs for oil to heat homes or drive vehicles.

Table 50. Bill Impacts and "Net Bill" Impacts in 2030, Relative to Reference Case ($/month)

Rank	Scenario	Bill Impact	"Net Bill" Impact (with Oil Savings)
1	Extreme Low Load	($50.52)	($50.52)
2	High CDM w/TOU+CPP	($25.31)	($25.31)
3	High CDM w/DR	($24.23)	($24.23)
4	Synapse LR, High Export Price	($20.97)	($20.97)
5	Low Elec w/EV TOU, High CDM w/TOU+CPP	($20.68)	($31.40)
6	High CDM	($20.05)	($20.05)
7	Low Elec, High CDM w/DR	($17.34)	($28.06)
8	Low Elec w/EV TOU, High CDM w/DR	($17.19)	($27.92)
9	Low Elec, High CDM	($15.01)	($25.73)
10	Low Elec w/EV TOU, High CDM	($14.86)	($25.59)
11	High Elec w/EV TOU, High CDM w/TOU+CPP	($7.52)	($75.16)
12	High Elec w/EV TOU, High CDM w/DR	($5.60)	($73.25)
13	Low CDM w/TOU+CPP	($5.41)	($5.41)
14	Low CDM w/DR	($5.03)	($5.03)
15	High Elec, High CDM w/DR	($4.68)	($72.33)
16	Low CDM	($2.65)	($2.65)
17	High Elec w/EV TOU, High CDM	($1.32)	($68.96)
18	Low Elec w/EV TOU, Low CDM w/TOU+CPP	($0.41)	($11.13)
19	High Elec, High CDM	($0.40)	($68.05)
20	Low Elec, Low CDM w/DR	($0.20)	($10.93)
21	Synapse Low Rate	$0.00	$0.00
22	Low Elec w/EV TOU, Low CDM w/DR	$0.12	($10.60)
23	Low Elec, Low CDM	$2.20	($8.52)
24	Low Elec w/DR	$2.42	($8.31)
25	Low Elec w/EV TOU, Low CDM	$2.52	($8.20)
26	Low Elec w/EV TOU w/DR	$2.98	($7.74)
27	Low Elec	$4.83	($5.90)
28	Low Elec w/EV TOU	$5.39	($5.33)
29	Synapse LR, Low Export Price	$8.49	$8.49
30	Synapse LR, New Lab Cust Load	$10.81	$10.81
31	High Elec w/EV TOU, Low CDM w/DR	$13.32	($54.33)
32	High Elec w/EV TOU, Low CDM w/TOU+CPP	$13.63	($54.01)
33	High Elec, Low CDM w/DR	$13.99	($53.66)
34	High Elec w/EV TOU w/DR	$16.07	($51.57)
35	High Elec w/DR	$17.02	($50.63)
36	High Elec w/EV TOU, Low CDM	$17.71	($49.94)
37	High Elec, Low CDM	$18.38	($49.26)
38	High Elec w/EV TOU	$20.48	($47.17)
39	High Elec	$21.42	($46.22)

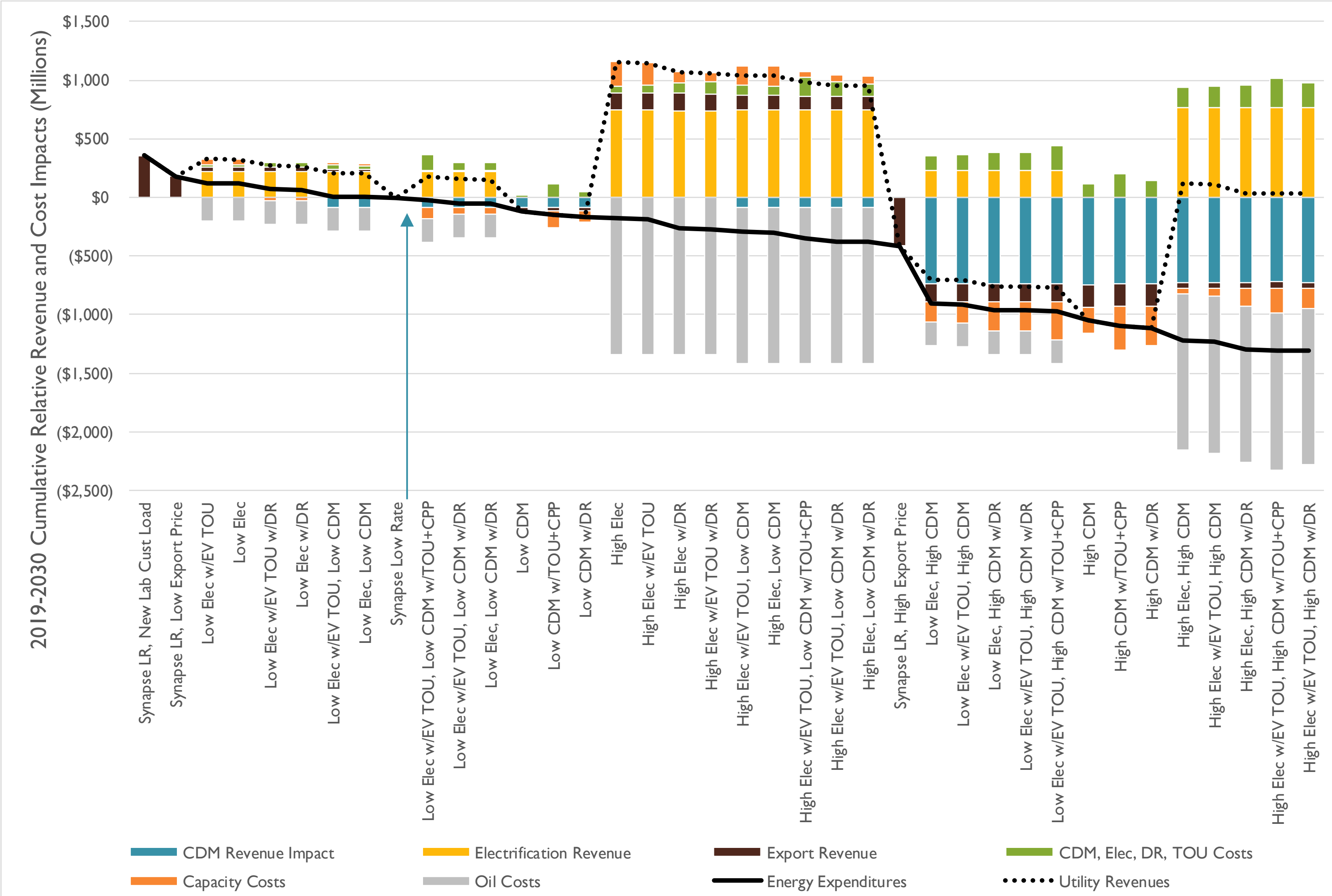
Components of Rate Impacts

These rate impacts are the product of several different components, which are shown in Table 51 below for each scenario, as compared to the reference case for both 2025 and 2030. The first component represents the revenue impacts from a reduction in internal sales due to the effects of CDM (or, in the Extreme Low Load scenario, the effect of much greater price elasticity of demand), combined with the increased revenue due to electrification. The second column shows the change in export sales revenues. The next two columns show changes in costs due to various electrification, CDM, and time-varying rate programs as well as changes in costs associated with increases or decreases in capacity requirements. (For these two columns, the positive numbers represent increased costs, while negative numbers represent cost reductions.) Finally, the right column shows the net mitigation effect in terms of utility revenues.

These impacts are also summarized in Figure 53 below as cumulative values for 2019-2030. However, in the graph the solid line shows the net mitigation effect including oil savings, while the dotted line shows only the mitigation impact on utility revenues.

Specifically, Figure 53 shows the cumulative impact of each scenario to Newfoundland energy consumers, relative to the Synapse Low Rate case, that results from changes to both costs and electric revenues. For example, in the “High CDM” case, consumers face costs for administering CDM programs, while their costs are reduced by reductions in electric use, by greater revenues for export sales, and by reduced need for capacity. In total, utility revenues fall relative to the Synapse LR case, and energy expenditure impacts are the same as utility revenue impacts. In contrast, in the “High Elec” case consumers face costs for electrification programs, increased electric consumption costs, increased need for capacity, and reduced export revenues. The net utility revenues in this case are high. However, oil savings more than compensate for increased electric costs, and customers’ overall energy expenditures fall. Other cases combine CDM and electrification in different ways and amounts, with and without DR and TOU rates, and show great variability in the resulting combinations of utility revenue and energy expenditures.

Figure 53. Cumulative Cost and Revenue Impacts, Customer Perspective



Revision 1 Note: Scenarios have been sorted in order of least-to-greatest customer benefit for energy expenditure metric.
Source: Synapse calculations

Table 51. Summary of Rate Mitigation Components for 2025 and 2030

		Delta Internal Sales (Millions)		Delta Export Revenue (Millions)		CDM, Elec DR, TOU Costs (Millions)		Delta Capacity Costs (Millions)		Delta Utility Revenues (Millions)	
#	Scenario	2025	2030	2025	2030	2025	2030	2025	2030	2025	2030
5	Low CDM	(5)	(24)	$1	$9	$1	$6	($2)	($7)	($3)	($14)
5a	Low CDM w/DR	(5)	(24)	$1	$9	$3	$11	($8)	($20)	$1	($5)
6	High CDM	(55)	(156)	$14	$45	$9	$23	($16)	($50)	($35)	($84)
6a	High CDM w/DR	(55)	(156)	$14	$45	$11	$30	($24)	($72)	($29)	($69)
7	Low CDM w/TOU+CPP	(5)	(24)	$1	$8	$11	$14	($13)	($25)	($2)	($4)
8	High CDM w/TOU+CPP	(55)	(156)	$14	$45	$19	$31	($28)	($77)	($32)	($65)
9	Low Elec	19	37	($3)	($6)	$1	$2	$5	$9	$9	$19
9a	Low Elec w/DR	19	36	($3)	($6)	$3	$7	($1)	($5)	$14	$28
10	High Elec	65	129	($13)	($29)	$3	$12	$17	$37	$33	$52
10a	High Elec w/DR	65	128	($13)	($29)	$5	$19	$8	$13	$39	$67
11	Low Elec w/EV TOU	19	37	($3)	($8)	$1	$4	$5	$8	$9	$17
11a	Low Elec w/EV TOU w/DR	19	36	($3)	($8)	$3	$9	($1)	($5)	$14	$26
12	High Elec w/EV TOU	65	129	($12)	($29)	$5	$15	$15	$30	$34	$55
12a	High Elec w/EV TOU w/DR	65	128	($12)	($29)	$7	$23	$7	$6	$40	$70
13	Low Elec, Low CDM	14	13	($2)	$1	$2	$8	$4	$0	$6	$5
13a	Low Elec, Low CDM w/DR	14	13	($2)	$1	$4	$13	($3)	($13)	$11	$14
14	Low Elec, High CDM	(36)	(118)	$11	$39	$10	$25	($12)	($40)	($24)	($64)
14a	Low Elec, High CDM w/DR	(36)	(118)	$11	$39	$12	$30	($18)	($53)	($19)	($56)
15	High Elec, Low CDM	61	106	($10)	($20)	$5	$18	$15	$28	$30	$40
15a	High Elec, Low CDM w/DR	60	105	($10)	($20)	$7	$25	$6	$5	$36	$55
16	High Elec, High CDM	11	(23)	$2	$19	$13	$34	($2)	($16)	$2	($21)
16a	High Elec, High CDM w/DR	11	(24)	$2	$19	$15	$42	($11)	($40)	$8	($7)
17	Low Elec w/EV TOU, Low CDM	14	13	($1)	$1	$2	$10	$4	$0	$7	$4
17a	Low Elec w/EV TOU, Low CDM w/DR	14	13	($1)	$1	$4	$15	($3)	($13)	$12	$13
18	High Elec w/EV TOU, Low CDM	61	106	($11)	($20)	$6	$21	$15	$22	$29	$42
18a	High Elec w/EV TOU, Low CDM w/DR	60	105	($11)	($20)	$8	$29	$6	($1)	$35	$57
19	Low Elec w/EV TOU, High CDM	(36)	(118)	$11	$38	$10	$26	($12)	($41)	($24)	($64)
19a	Low Elec w/EV TOU, High CDM w/DR	(36)	(118)	$11	$38	$12	$31	($18)	($55)	($19)	($56)
20	High Elec w/EV TOU, High CDM	11	(23)	$2	$19	$14	$38	($3)	($23)	$2	($18)
20a	High Elec w/EV TOU, High CDM w/DR	11	(24)	$2	$19	$16	$46	($12)	($46)	$9	($4)
21	Low Elec w/EV TOU, Low CDM w/TOU+CPP	14	13	($2)	$1	$12	$16	($7)	($17)	$7	$15
22	Low Elec w/EV TOU, High CDM w/TOU+CPP	(36)	(118)	$11	$39	$20	$33	($24)	($69)	($21)	($44)
23	High Elec w/EV TOU, Low CDM w/TOU+CPP	60	105	($11)	($19)	$15	$26	$3	$4	$32	$56
24	High Elec w/EV TOU, High CDM w/TOU+CPP	11	(25)	$2	$19	$22	$42	($16)	($50)	$7	$2
25	Synapse LR, Low Export Price	-	-	($20)	($31)	$0	$0	$0	$0	($20)	($31)
26	Synapse LR, High Export Price	-	-	$37	$75	$0	$0	$0	$0	$37	$75
29	Extreme Low Load	(176)	(364)	$39	$80	$0	$0	($49)	($102)	($88)	($182)
30	Synapse LR, New Lab Cust Load	0	(0)	($30)	($39)	$0	$0	$0	($0)	($30)	($39)

8.5. Rate Smoothing and Load Retention Rates

Rate Smoothing

As shown in Figure 51, the introduction of MFP costs into revenue requirements causes a sharp increase in rates. In our reference case, rates are projected to increase by 56 percent from 2020 to 2021. In his seminal work, *Principles of Public Utility Rates*, Professor James Bonbright discusses eight key principles for a sound rate design. One of these is the principle of gradualism, or, as Professor Bonbright describes it, "Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers."[112]

The rate increase that Newfoundland is facing is considerable and far in excess of that which utility customers are accustomed to, and it will be very difficult for customers to adjust to, particularly those on fixed incomes. In order to minimize rate shock, all options should be explored to reduce the overall revenue requirement and increase rates as gradually as possible. We refer to this as "rate smoothing." It is our understanding that several options are currently being explored to smooth the rate increase, including changes to the financing structure (i.e., sinking fund payments, interest payments, and the debt structure), and utilizing the dividends to mitigate rates. These options should continue to be explored in order to provide customers with time to adjust to the rate increase (by, for example, altering their consumption habits and investing in more efficient appliances) and reduce the near-term impact on rates.

Load Retention Rates

Our analysis considered incentive rates to attract new load, specifically for electric vehicles. However, it may also be necessary to consider load retention rates. Load retention rates are similar to economic development rates in that they provide a discount relative to the standard rate. The purpose of load retention rates is to prevent the loss of substantial load, which would result in increases in rates for remaining customers. Load retention rates should only be used where necessary to secure load, with care to avoid free-ridership. Load retention rates should always be set above marginal cost, or they provide no benefit to other customers. We did not conduct a detailed analysis of load retention rates for this study, as the particular rates should be developed on a case-by-case basis depending on the specific situation of the customer. Further, load retention rates should only be implemented where there is a demonstrated and verified risk that the load would depart the system without the rate discount.

[112] James Bonbright, *Principles of Public Utility Rates*, Columbia University Press, 1961, page 291.

9. POLICY CONSIDERATIONS

9.1. Existing / New Government Policies Affecting Rate Mitigation

Rate mitigation through changes in customer energy end use, such as through energy efficiency and electrification of both vehicles and buildings, will be shaped by programs and policies implemented by the provincial and federal governments, in addition to utility programs. This section summarizes governmental actions and programs that relate to the energy efficiency and electrification scenarios considered in this report.

Federal

The 2019 Canadian federal budget[113] includes several programs and funding sources that are relevant to the actions that Newfoundland , and its municipalities and residents, may take as part of the rate mitigation framework analyzed in this report. The most direct support takes the form of a $5,000 per vehicle incentive for the purchase of electric vehicles (or $2,500 for plug-in hybrid electric vehicles with batteries smaller than 15 kWh or an electric range of approximately 50-75 km).[114] The budget also supports business investment in electric vehicles (including medium- and heavy-duty electric vehicles) by allowing immediate expensing of electric vehicles. For medium- and heavy-duty electric vehicles, there is no cap to the per-vehicle value of this write-off. These actions would support both the light-duty electrification and the adoption of electric vehicle options for delivery trucks and buses presented in this report (where the buses are owned by for-profit entities that value the tax incentive).

The federal budget also includes $950 million to support efficiency and emissions reduction in public and community buildings, home retrofits, and affordable housing, through the Green Municipal Fund and the Federation of Canadian Municipalities.[115] These funds can be used for efficiency and renewable energy. The Community EcoEfficiency Acceleration program explicitly includes support for “replacing furnaces,” so if participating municipalities in Newfoundland accessed these funds they could support heat pumps as both an efficiency and fuel-switching measure.

Provincial

The Newfoundland Government has established an $89.4 million provincial Low Carbon Economy Leadership Fund (LCELF), funded half with provincial funds and half with federal funds.[116] These funds are intended to result in “material GHG reductions that are incremental to existing actions.” Five

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[113] Available at https://www.budget.gc.ca/2019/docs/plan/chap-02-en.html

[114] Program details at https://www.tc.gc.ca/en/services/road/innovative-technologies/zero-emission-vehicles.html

[115] More details available at https://fcm.ca/en/news-media/announcement/fcmp/new-investments-through-fcm-will-deliver-results-canadians

[116] Fund details available at https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_fund.html

programs have been launched under the LCELF, three of which support or are directly related to the efficiency and/or electrification scenarios developed in this report:[117]

1) **Climate Change Challenge Fund** ($20.26 million)[118]

   The Climate Change Challenge Fund is a competitive grant program for businesses and public sector entities to reduce greenhouse gas (GHG) emissions, with a minimum project size of $100,000. This program includes support for fuel-switching to electricity and could therefore support commercial and institutional building electrification.

2) **Expansion of the Home Energy Savings Program** ($8.57 million)[119]

   The Home Energy Savings Program provides grants to income-eligible homeowners for efficiency upgrades to their homes. This includes measures such as insulation and air sealing that are included in the CDM analysis presented in this report, although we have not separated this provincial funding from the ratepayer-funded programs described here. The program rules are flexible enough to potentially also support the addition of heat pumps to either electrically- or oil-heated homes. The LCELF support for the Home Energy Savings Program is in addition to other appropriations (such as $5 million in the 2017 provincial budget).

3) **Energy Efficiency and Fuel-Switching in Public Buildings** ($25.96 million)[120]

   This program supports fuel-switching to electricity for space heating in public buildings such as post-secondary institutions and medical clinics. The program description states that "[p]rojects involving fuel-switching to electricity will also assist in rate mitigation efforts." This fuel-switching and efficiency could directly correspond to institutional electrification.

The other two programs in the LCELF are the Freight Transportation Fuel Efficiency Program and Energy Efficiency in Oil Heated Homes Program. If the eligibility requirements for these programs were changed to allow funding to be used for electrification, these programs could also be used as part of a policy response for rate mitigation through electrification.

Provincial Rate Design Policies

Provincial rate design policies should be guided in part by the analysis explained in the previous section. There are mechanisms available to promote electrification while minimizing its impact on peak load

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117 The Freight Transportation Fuel Efficiency Program only supports retrofit of existing fossil fuel vehicles, not the purchase of electric medium- or heavy-duty vehicles. The Energy Efficiency in Oil Heated Homes Program supports insulation and advanced thermostats in oil-heated homes, but not fuel-switching or supplementing oil heat with heat pumps.

118 Program details at https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_programs/climatechangechallenge.html

119 Program details at https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_programs/homeenergysavings.html and https://www.nlhc.nl.ca/housing-programs/home-energy-savings-program-hesp/

120 Program details at https://www.exec.gov.nl.ca/exec/occ/low_carbon_economy_programs/publicbuildingsfuelswitching.html

levels. Foremost among those policies are use of TOU structures for newly electrified load. As noted in the previous chapter, the use of AMI as the primary vehicle to introduce TOU rates is one of the least cost-efficient ways to mitigate rates. However, the use of TOU for electric vehicle charging demonstrates better overall rate mitigation.

Our analyses were not intended to assess specific options while accounting for differences across the sectors and across rate classes. Additional analysis would be required to best apply the lessons to be gleaned from our high-level examination, to actual rate structures in the Province.

9.2. Dunsky Report Summary Comparison

The Dunsky Report was released in August 2019 and is provided as part of the record of this proceeding as the response to PUB-NP-104. Synapse listened to a preliminary briefing from Dunsky on the study prior to its release, and has conducted an initial, preliminary review of the now-available report. The analysis and results in our CDM and electrification models do not specifically utilize any of the information available from the Dunsky report, given the timing of its release; however, we do note some consistencies, and some differences, in our results based on an initial comparison. We note that we have not had sufficient time to develop a careful point-by-point comparison, or to assess how our recommended Provincial next steps should be modified given outcomes from Dunsky's detailed study.

The following are high-level indications from a comparison between the Dunsky Report results, and our study:

- Overall our CDM savings results for the High Case are comparable to Dunsky's Upper Case results. Our total CDM estimates are about 10 percent of our base load sales forecast. Dunsky's estimates are about 8 percent of their sales forecast. Our base load forecast differs from Dunsky's in that we include all Island load to develop CDM estimates, including load served by industrial and NP self-generation.

- Our estimates for savings for the IIS are slightly higher than Dunsky's (11 percent of sales vs. 8 percent of sales) as shown in the table below. The main difference between the two studies appear to be technology adoption rates and savings for heat pumps used to displace a portion of electric resistance baseboard heating. For example, the Dunsky study assumes the total additional adoption rate of 16 percent for heat pumps by 2034 for residential customers.[121] In contrast, in our high CDM scenario, we assume about 62 percent of additional heat pump adoption rates by 2030 (on top of the existing 18 percent adoption rate).

[121] Dunsky Report, Table F-19.

Table 52. CDM Potential Comparison: Synapse High Case vs. Dunsky Upper Case

	Synapse: High Case		Dunsky: Upper Case	
	2030 (GWh)	2030 (%)	2034 (GWh)	2034 (%)
IIS	832	10.9%	552	8.2%
LIS	150	6.1%	207	7.2%
Total	981	9.8%	759	7.9%

Source: Dunsky. 2019. Figure 2-1 and Synapse analysis

- Dunksy's results indicate both an economic and an achievable level of potential savings. Achievable savings are provided for Lower, Mid, and Upper scenarios; and "economic" potential is significantly greater than Dunsky's most aggressive achievable level, "Upper".[122] Thus, while Upper falls below Synapse's high CDM scenario savings, the overall economic potential seen by Dunsky is higher than our estimates. While end dates are different for the potential estimate (Dunsky – 2034, Synapse – 2030), the overall savings potential results are not inconsistent.

- Dunsky presents results in their fuel switching section indicating that it is not economic for oil-heated homes to fully convert to electric heating using heat pumps but does indicate supplementary use of ductless mini-split heat pump (DMSHP) systems to complement, but not replace, oil heated systems is economic.[123] We find that depending on oil price assumptions, and overall policy effects on costs to add DMSHPs, it can be cost effective to either replace or at least supplement oil heat with heat pump sources.

- Our DR results for the High case are slightly less than half of the DR potential estimates by Dunsky study as shown in the table below. However, this is largely due to the fact that that our DR analysis is exclusive of existing interruptible capacity of roughly 100 MW.[124] In addition, our assumption of 20 percent load savings from industrial end-uses may be overly conservative. In contrast, as shown in the second table below our estimates for residential and commercial customers are comparable to the estimates by Dunsky study.

[122] Dunsky Report, Executive Summary, Figure 0-2, "Cumulative Electric Potential Savings from Efficiency Under Mid-Rates (2034)," page v.

[123] Dunsky Report, Executive Summary, page xvi.

[124] Reliability and Resource Adequacy Study, Volume III, page 22.

Table 53. DR Potential Comparison: Synapse High Case vs. Dunsky Upper Case

	Synapse: High Case		Dunsky: Upper Case	
	2030 (MW)	2030 (%)	2034 (MW)	2034 (%)*
IIS	78	4.8%	183	11.7%
LIS	8	2.8%	19	5.1%
Total	86	4.2%	202	10.4%

*Source: Synapse analysis and Dunsky. 2019. Figure 2-9; Table 4-7: Note: * We assumes 1660 MW peak for the IIS and 375 MW for the LIS for Dunsky's study based on Figure 4-3 and 4-4 from the study.*

Table 54. DR Potential Comparison by Sector: Synapse High Case vs. Dunsky Achievable Potential

	IIS		LIS	
	Synapse: High Case	Dunsky: Achievable Potential	Synapse: High Case	Dunsky: Achievable Potential
Residential	56	34 - 60	10	6 - 12
Commercial	16		6	
Industrial	6	98 - 141	9	3 - 10
CVR	0	8	0	0
Total	78	154 - 183	25	19

Note: CVR stands for conservation voltage reduction. Source: Synapse analysis and Dunsky. 2019. Figure 4-8

Impacts on Policy Considerations – CDM and Electrification in the Synapse and Dunsky Analyses

Below is a summary of our initial thoughts on how the Dunsky Report, and our mitigation analyses, can be considered together to guide Provincial policy direction:

- CDM and DR: The Dunsky Report presents a much more in-depth analysis of local conditions and should be used for detailed input into 2020-2025 CDM program design, as was its intention. Our analysis supports generally high levels of CDM and DR on the IIS, as Dunsky also finds, but Dunsky does not address potential rate and revenue impacts, nor does it contain bill savings estimates. Combined, the findings support Provincial policy that aggressively pursues CDM and incremental DR, including retaining and maximizing existing curtailment options at industrial facilities – at least on the IIS – based on the underlying customer cost economies of energy efficiency improvement and peak savings from DR.

- Electrification: Synapse and Dunsky present broadly similar findings on transportation electrification, recognizing that the benefits will be best obtained if careful attention is given to load management to minimize peak load additions from EV charging, for example.[125] Dunsky's findings on building heat electrification appear to initially diverge from Synapse's assessment, but as noted on closer review Dunsky does support partial provision of heat with ductless mini-split heat pumps in oil-heated dwellings.

- Rate Design: Dunsky is more tentative on peak reduction potential through TOU, CPP, but allows for possible changes to conditions that may make these avenues more effective in the future.

[125] Dunsky Report, Executive Summary, page xx. In particular, Dunsky notes the following: "EV load management will be critical to enable the Utilities to handle the system impacts of EVs and benefit financially from EV adoption under baseline scenario as well as any investment scenario. As shown in **Table 0-3**, the modeled $20M investment can bring $170M in additional value to the Utilities by 2034 from the increased revenue in the presence of load management versus a loss of $113M under an unmanaged charging scenario. The Utilities should thus prioritize initiatives that can reduce peak impacts of EV loads to unlock any revenue opportunities from EVs, which could contribute to utility efforts to mitigate projected electricity rate increases stemming from the Muskrat Falls generation facility."

10. MAJOR CONCLUSIONS

The following summarizes our broad conclusions stemming from our Phase 2 work:

1. High levels of policy-supported electrification combined with enhanced CDM and use of possibly multiple forms of rate design (e.g., EV TOU and CPP to incentivize off-peak consumption while dis-incenting on-peak consumption) offers the best overall rate and bill mitigation effect. Scenarios that implement these pathways show reductions in the total energy bills paid by consumers in the Province by tens of millions of dollars per year by 2030. This result stems from scenarios that demonstrate some combination of either maximum rate mitigation, or maximum bill impact reduction for the average IIS customer. Maximum rate mitigation comes from electrification alone but remains limited on the scale of the overall MFP rate effect, with rate benefits growing slowly toward approximately 1 cent per kWh by 2030. Of note, revenue loss concern associated with higher levels of CDM can be reasonably addressed through relatively higher rates, while ensuring relatively lower average bills due to reduced average consumption.

2. Electrification has the highest value mitigation opportunity because of two underlying factors: avoided oil fuel expenditures (new savings) and the effect of technological improvements (mainly cars, batteries, and heat pumps). Also, coupled with the electrification efforts that best mitigate rates are technologies that support cost-effective CPP/DR and thus allow any unintended electrification 'leakage' into peak periods to be mitigated with corollary decreases in peak load. The opportunity for rate mitigation in this regard is, at a fundamental level, the economically inefficient use of oil expenditures for transportation and heating relative to electricity use for these services.

3. CDM on the IIS complements and supports the electrification elements not only because it allows increases in export sales, but because it mitigates the peak-load-increasing effect of electrification consumption that spills into peak periods. On its own, it frees up energy for sale to export markets while simultaneously reducing future capacity expenditure needs (avoided capacity costs are significant, so any scenario with an absence of CDM-enabled peak savings must reflect future capacity cost increase on top of MFP requirements).

4. Rate design at the sectoral level, guided by the high-level analyses we have presented here, can help to provide the price signals required to optimize load in the Province for rate mitigation. Rate design can play an especially important role in supporting widespread electrification while minimizing increases in peak demand. Specifically, TOU and CPP rates can encourage customers to reduce demand when capacity is constrained, while increasing consumption when the costs on the system are low, thereby reducing costs on the system and maximizing high-priced exports. Further, incentive rates can be provided to encourage customers to adopt beneficial electrification technologies, such as electric vehicles.

Advanced rate design for the transportation sector can be operationalized through either the use of smart charging equipment or via comprehensive AMI installation. Smart charging equipment represents a relatively low-cost modular solution for implementing electric vehicle rates in the near-term, while in the medium- to long-term, full roll-out of AMI may provide the most benefits. These issues can be explored further through more extensive information gathering, requests for information, and pilot programs.

Large building electrification can be achieved without full rollout of AMI across the Province, but demand response programs may be important for mitigating peaks. Residential and small commercial heating electrification with heat pumps may present the greatest rate design challenges. At a minimum demand response programs or special dual-fuel rates can be considered for customers who choose to retain oil as backup heat, since such choices avoid increasing peak load during extreme winter periods (essentially capturing the reliability of back-up oil for extreme peak periods).[126]

5. The use of existing industrial curtailment, and the potential use of increased levels of demand response (including DR allowed through the use of critical peak pricing tariff overlays, and/or direct load control mechanisms) is crucially important as a complement to all mitigation policies because it protects against a need for new capacity supply to meet peak load and reserve margin targets. In the absence of a full-blown AMI mechanism, it complements any TOU effect through, e.g., electric vehicle smart charging equipment, and critically provides necessary insurance against peak load increases.

6. Maximizing export energy sales would not best mitigate rate or bill concerns. Maximizing internal beneficial electrification first allows customers to capture oil savings, while providing revenues to help pay MFP fixed costs. However, ongoing CDM, especially on the Island, that allows for increased export sales is a valuable and cost-effective means to help reduce customer bills.

7. Broad use of AMI, to more fully implement marginal-cost-based pricing across all customers does not appear as economically attractive as we initially thought, because (1) other means to reduce peak load or prevent increases in peak load on extreme winter days are less expensive, and (2) some of the gains utilized in other jurisdictions to help pay for new metering have already been captured with NP's AMR infrastructure.

8. Federal government and Provincial policies have a material effect of reducing cost (and jumpstarting trends) to help incentivize actions that promote sustained electrification and CDM that supports ongoing trends to capture fuel savings in heating and transportation sectors.

[126] See, for example, Hydro Quebec's Rate DT http://www.hydroquebec.com/residential/customer-space/rates/rate-dt.html

TECHNICAL APPENDIX

Export Market Volumes by Scenario

Export Market Revenues by Scenario

MFP and IIS Capacity and Energy Balance Tables, Select Scenarios

CDM Model Tables by CDM Scenario

Electrification Model Tables by Electrification Scenario

Export Market Volumes by Scenario

Figure 54: Export Market Volumes by Scenario (GWh)

Export Market Volumes by Scenario (GWh)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1. Synapse LR	1,153	3,089	3,457	3,429	3,417	3,455	3,527	3,664	3,671	3,756	3,631	3,555
2. Synapse MR	1,153	3,090	3,512	3,551	3,593	3,701	3,787	3,937	3,951	4,055	3,929	3,873
3. Synapse HR	1,153	3,091	3,537	3,594	3,653	3,788	4,007	4,251	4,289	4,407	4,292	4,261
5. Low CDM	1,153	3,089	3,459	3,461	3,422	3,478	3,562	3,716	3,740	3,853	3,742	3,720
6. High CDM	1,153	3,100	3,497	3,518	3,559	3,684	3,863	4,088	4,203	4,400	4,366	4,413
7. Low CDM w/TOU	1,153	3,089	3,458	3,435	3,419	3,478	3,562	3,723	3,744	3,854	3,752	3,713
8. High CDM w/TOU	1,153	3,100	3,498	3,517	3,574	3,684	3,853	4,109	4,206	4,400	4,364	4,413
9. Low Elec	1,152	3,083	3,393	3,365	3,338	3,380	3,445	3,605	3,595	3,646	3,508	3,439
10. High Elec	1,152	3,057	3,310	3,259	3,210	3,200	3,238	3,336	3,299	3,334	3,141	3,034
11. Low Elec w/EV TOU	1,151	3,082	3,399	3,366	3,339	3,380	3,444	3,574	3,570	3,646	3,491	3,416
12. High Elec w/EV TOU	1,152	3,056	3,315	3,273	3,225	3,200	3,261	3,335	3,304	3,333	3,166	3,033
13. Low Elec, Low CDM	1,152	3,083	3,397	3,377	3,356	3,402	3,483	3,650	3,642	3,744	3,618	3,571
14. Low Elec, High CDM	1,152	3,093	3,442	3,454	3,488	3,609	3,776	4,001	4,106	4,292	4,247	4,290
15. High Elec, Low CDM	1,152	3,057	3,315	3,280	3,222	3,224	3,292	3,389	3,375	3,432	3,269	3,193
16. High Elec, High CDM	1,152	3,067	3,356	3,366	3,358	3,431	3,559	3,780	3,838	3,987	3,908	3,907
17. Low Elec w/EV TOU, Low CDM	1,151	3,082	3,401	3,382	3,347	3,403	3,500	3,627	3,643	3,744	3,618	3,571
18. High Elec w/EV TOU, Low CDM	1,152	3,056	3,318	3,265	3,219	3,224	3,275	3,415	3,374	3,432	3,281	3,195
19. Low Elec w/EV TOU, High CDM	1,151	3,092	3,442	3,479	3,501	3,609	3,783	4,001	4,106	4,292	4,256	4,274
20. High Elec w/EV TOU, High CDM	1,152	3,067	3,360	3,350	3,372	3,431	3,569	3,785	3,839	3,988	3,929	3,907
21. Low Elec w/EV TOU, Low CDM w/TOU	1,151	3,082	3,399	3,371	3,369	3,403	3,482	3,627	3,643	3,744	3,638	3,572
22. Low Elec w/EV TOU, High CDM w/TOU	1,151	3,092	3,441	3,454	3,510	3,609	3,777	4,018	4,106	4,293	4,270	4,289
23. High Elec w/EV TOU, Low CDM w/TOU	1,152	3,056	3,319	3,265	3,233	3,224	3,276	3,390	3,373	3,432	3,269	3,206
24. High Elec w/EV TOU, High CDM w/TOU	1,152	3,067	3,360	3,350	3,362	3,431	3,580	3,767	3,836	3,988	3,927	3,899
25. Synapse LR, Low Export Price	1,153	3,089	3,457	3,428	3,417	3,459	3,534	3,661	3,681	3,762	3,637	3,558
26. Synapse LR, High Export Price	1,153	3,089	3,457	3,428	3,412	3,452	3,525	3,658	3,668	3,747	3,608	3,563
29. Extreme Low Load	1,152	3,133	3,661	3,763	3,898	4,046	4,265	4,499	4,638	4,846	4,824	4,883
30. Synapse LR, Lab New Cust Load	357	1,621	1,626	1,720	1,716	1,757	1,748	1,784	1,758	1,866	1,777	1,709

Source: Synapse calculations

Export Market Revenues by Scenario

Figure 55: Export Market Revenue Net of Admin Costs by Scenario ($ millions)

Export Market Revenues by Scenario ($ millions)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
1. Synapse LR	28.1	99.7	120.2	115.2	114.0	119.4	125.0	137.0	141.8	159.3	162.5	169.8
2. Synapse MR	28.1	99.7	122.0	120.3	121.2	129.2	135.5	148.5	153.8	173.0	177.1	186.8
3. Synapse HR	28.1	99.7	123.4	122.0	123.6	132.7	144.3	161.6	167.7	188.8	194.6	206.9
5. Low CDM	28.1	99.7	120.4	116.5	114.3	120.3	126.4	139.2	144.7	163.7	167.8	178.4
6. High CDM	28.1	100.0	121.8	119.0	119.9	128.7	138.7	155.1	164.3	188.7	198.4	214.9
7. Low CDM w/TOU	28.1	99.7	120.2	115.5	114.1	120.3	126.4	139.4	144.9	163.7	168.3	178.1
8. High CDM w/TOU	28.1	100.0	121.9	119.0	120.5	128.7	138.4	155.9	164.4	188.7	198.4	214.9
9. Low Elec	28.1	99.4	117.3	112.7	111.0	116.4	121.7	134.5	138.6	154.4	156.6	163.3
10. High Elec	28.1	98.6	114.0	108.2	105.7	109.2	113.2	123.2	125.9	139.8	138.8	141.1
11. Low Elec w/EV TOU	28.1	99.5	118.1	112.7	111.0	116.5	121.7	133.3	137.7	154.4	155.9	162.2
12. High Elec w/EV TOU	28.1	98.7	114.6	108.7	106.3	109.1	114.0	123.2	126.1	139.8	140.0	141.2
13. Low Elec, Low CDM	28.1	99.4	117.7	113.2	111.7	117.3	123.2	136.4	140.7	158.8	161.9	170.7
14. Low Elec, High CDM	28.1	99.8	119.8	116.5	117.2	125.8	135.3	151.5	160.5	184.1	192.9	208.8
15. High Elec, Low CDM	28.1	98.6	114.2	109.0	106.2	110.1	115.3	125.4	129.1	144.3	144.9	149.8
16. High Elec, High CDM	28.1	98.9	115.8	112.6	111.8	118.6	126.5	142.1	149.3	170.3	176.5	189.2
17. Low Elec w/EV TOU, Low CDM	28.1	99.5	118.2	113.4	111.3	117.4	123.8	135.5	140.7	158.8	161.9	170.7
18. High Elec w/EV TOU, Low CDM	28.0	98.7	114.7	108.4	106.1	110.1	114.7	126.4	129.1	144.4	145.5	149.9
19. Low Elec w/EV TOU, High CDM	28.1	99.8	119.8	117.4	117.7	125.8	135.6	151.6	160.5	184.1	193.3	208.1
20. High Elec w/EV TOU, High CDM	28.0	99.0	116.5	112.0	112.3	118.6	126.8	142.3	149.4	170.4	177.5	189.3
21. Low Elec w/EV TOU, Low CDM w/TOU	28.1	99.5	118.0	113.0	112.2	117.3	123.2	135.5	140.7	158.8	162.9	170.7
22. Low Elec w/EV TOU, High CDM w/TOU	28.1	99.8	119.7	116.5	118.0	125.8	135.4	152.2	160.5	184.1	193.9	208.8
23. High Elec w/EV TOU, Low CDM w/TOU	28.0	98.7	114.7	108.4	106.7	110.1	114.7	125.5	129.1	144.3	145.0	150.4
24. High Elec w/EV TOU, High CDM w/TOU	28.0	99.0	116.4	112.1	112.0	118.6	127.3	141.6	149.2	170.4	177.4	188.9
25. Synapse LR, Low Export Price	28.1	99.7	120.2	108.7	102.6	103.4	104.5	115.7	120.4	133.1	135.1	139.3
26. Synapse LR, High Export Price	28.1	99.7	120.2	127.1	134.9	148.6	162.4	185.8	196.8	225.8	233.3	245.3
29. Extreme Low Load	28.1	101.3	129.5	130.2	134.2	142.9	155.1	171.9	182.0	207.7	219.6	237.8
30. Synapse LR, Lab New Cust Load	8.7	78.0	94.5	89.2	88.2	93.1	98.7	109.6	113.6	128.1	128.7	130.9

Source: Synapse Calculations.

MFP and IIS Capacity and Energy Balance Tables, Select Scenarios

Table 55: Synapse LR - MFP and IIS Energy Balance

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Load, Losses, and Generation											
Island Load (including self-supply)	8,078	8,039	7,981	7,967	7,942	7,919	7,894	7,873	7,849	7,828	7,806
Labrador Island Link Losses	305	324	317	318	317	319	316	319	316	318	321
Island Transmission Losses	418	432	452	447	447	450	448	456	450	440	441
Total Energy Requirement	8,801	8,795	8,750	8,732	8,706	8,688	8,658	8,648	8,615	8,586	8,568
Island Generation (all owners)	7,285	7,014	6,974	6,909	6,909	6,899	6,899	6,898	6,910	6,786	6,702
Net Requirement from Off-Island	1,516	1,781	1,776	1,823	1,796	1,789	1,760	1,751	1,705	1,800	1,866
Energy Balance - MFP Serving Balance of Needs Excluding Use of Recall Energy											
Net Requirement from Off-Island	1,516	1,781	1,776	1,823	1,796	1,789	1,760	1,751	1,705	1,800	1,866
Muskrat Falls Generation	4,068	5,043	5,035	5,043	5,057	5,041	5,039	5,044	5,054	5,037	5,042
Muskrat Fall Generation Available after Island Needs	2,552	3,262	3,259	3,220	3,261	3,252	3,279	3,293	3,349	3,237	3,175
Nova Scotia Block and Supplemental Obligation	681.6	1131.8	1148.1	1148.7	1133.5	1042.9	913.8	913.4	901.8	909.1	915.7
Maritime Line Losses	100	155	141	138	138	140	138	145	140	135	136
Nova Scotia Obligation Energy Total	781	1,287	1,289	1,287	1,271	1,183	1,052	1,058	1,042	1,044	1,052
Muskrat Falls Generation Available after Island and Nova Scotia Obligations	1,771	1,975	1,970	1,933	1,989	2,069	2,228	2,234	2,307	2,194	2,123

Source: Synapse Calculations

Table 56: High CDM Scenario - MFP and IIS Energy Balance

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Load, Losses, and Generation											
Island Load (including self-supply)	8,060	7,993	7,889	7,813	7,712	7,605	7,481	7,362	7,238	7,118	6,991
Labrador Island Link Losses	305	323	315	313	311	309	303	302	298	296	296
Island Transmission Losses	418	435	458	458	465	473	481	497	504	501	512
Total Energy Requirement	8,783	8,751	8,662	8,585	8,488	8,387	8,265	8,162	8,040	7,915	7,799
Island Generation (all owners)	7,278	7,009	6,974	6,909	6,910	6,899	6,899	6,897	6,911	6,786	6,702
Net Requirement from Off-Island	1,505	1,742	1,688	1,676	1,578	1,488	1,367	1,265	1,129	1,129	1,097
Energy Balance - MFP Serving Balance of Needs Excluding Use of Recall Energy											
Net Requirement from Off-Island	1,505	1,742	1,688	1,676	1,578	1,488	1,367	1,265	1,129	1,129	1,097
Muskrat Falls Generation	4,069	5,043	5,035	5,043	5,057	5,041	5,039	5,044	5,054	5,037	5,042
Muskrat Fall Generation Available after Island Needs	2,563	3,301	3,347	3,367	3,478	3,553	3,673	3,779	3,925	3,908	3,945
Nova Scotia Block and Supplemental Obligation	681.6	1131.7	1145.1	1142.7	1131.6	1035.8	904.5	905.2	901.8	900.5	901.4
Maritime Line Losses	100	157	146	146	152	159	163	177	182	181	190
Nova Scotia Obligation Energy Total	782	1,289	1,291	1,289	1,284	1,194	1,068	1,082	1,084	1,082	1,091
Muskrat Falls Generation Available after Island and Nova Scotia Obligations	1,782	2,012	2,056	2,077	2,195	2,359	2,605	2,697	2,841	2,827	2,853

Source: Synapse Calculations

Table 57: High Electrification Scenario - MFP and IIS Energy Balance

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Load, Losses, and Generation											
Island Load (including self-supply)	8,134	8,197	8,169	8,188	8,223	8,237	8,253	8,278	8,307	8,340	8,381
Labrador Island Link Losses	306	327	321	321	321	325	323	326	323	328	331
Island Transmission Losses	414	423	440	433	428	430	426	430	419	409	405
Total Energy Requirement	8,855	8,947	8,930	8,942	8,972	8,991	9,002	9,034	9,049	9,077	9,118
Island Generation (all owners)	7,303	7,013	6,974	6,909	6,910	6,899	6,899	6,898	6,911	6,786	6,703
Net Requirement from Off-Island	1,551	1,935	1,956	2,033	2,062	2,092	2,103	2,136	2,138	2,291	2,415
Energy Balance - MFP Serving Balance of Needs Excluding Use of Recall Energy											
Net Requirement from Off-Island	1,551	1,935	1,956	2,033	2,062	2,092	2,103	2,136	2,138	2,291	2,415
Muskrat Falls Generation	4,069	5,043	5,035	5,043	5,057	5,041	5,039	5,044	5,054	5,037	5,042
Muskrat Fall Generation Available after Island Needs	2,518	3,108	3,079	3,010	2,995	2,949	2,936	2,908	2,916	2,746	2,627
Nova Scotia Block and Supplemental Obligation	683.3	1133.4	1152.8	1153.9	1137.2	1053.9	922.0	920.6	902.7	918.6	935.4
Maritime Line Losses	97	146	131	127	123	125	121	124	115	110	107
Nova Scotia Obligation Energy Total	780	1,279	1,284	1,281	1,260	1,179	1,043	1,044	1,017	1,028	1,042
Muskrat Falls Generation Available after Island and Nova Scotia Obligations	1,737	1,829	1,796	1,729	1,735	1,770	1,893	1,863	1,898	1,718	1,585

Source: Synapse Calculations

Table 58: High Electrification w/EV TOU, High CDM w/TOU Scenario - MFP and IIS Energy Balance

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Load, Losses, and Generation											
Island Load (including self-supply)	8,117	8,151	8,077	8,034	7,993	7,923	7,841	7,767	7,696	7,630	7,567
Labrador Island Link Losses	306	326	318	317	315	313	308	308	303	301	303
Island Transmission Losses	415	426	446	443	444	451	455	468	467	460	466
Total Energy Requirement	8,838	8,902	8,840	8,794	8,752	8,687	8,603	8,543	8,466	8,391	8,335
Island Generation (all owners)	7,297	7,018	6,974	6,909	6,910	6,899	6,899	6,898	6,911	6,786	6,702
Net Requirement from Off-Island	1,540	1,884	1,867	1,885	1,843	1,788	1,705	1,645	1,556	1,606	1,633
Energy Balance - MFP Serving Balance of Needs Excluding Use of Recall Energy											
Net Requirement from Off-Island	1,540	1,884	1,867	1,885	1,843	1,788	1,705	1,645	1,556	1,606	1,633
Muskrat Falls Generation	4,069	5,043	5,035	5,043	5,057	5,041	5,039	5,044	5,054	5,037	5,042
Muskrat Fall Generation Available after Island Needs	2,528	3,159	3,168	3,158	3,214	3,253	3,335	3,398	3,498	3,432	3,409
Nova Scotia Block and Supplemental Obligation	682.6	1132.5	1151.0	1148.7	1133.3	1042.9	910.7	909.3	902.0	903.9	906.8
Maritime Line Losses	98	149	136	135	136	142	143	154	154	150	155
Nova Scotia Obligation Energy Total	780	1,281	1,287	1,284	1,269	1,185	1,054	1,064	1,056	1,054	1,062
Muskrat Falls Generation Available after Island and Nova Scotia Obligations	1,748	1,877	1,882	1,874	1,945	2,069	2,282	2,334	2,442	2,378	2,347

Source: Synapse Calculations

Table 59: Synapse LR – Capacity Balance - MFP Serving Balance of Needs Excluding Use of Excess Capacity Associated with Recall Energy

Island Load, Losses, Generation, and Labrador Island Link at Peak	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Peak (including self-supplied load)	1,662	1,657	1,659	1,663	1,662	1,663	1,662	1,664	1,664	1,664	1,664
Island Transmission Losses	141	141	141	141	141	141	141	141	141	141	141
Total Capacity Requirement	1,804	1,798	1,800	1,805	1,803	1,804	1,804	1,805	1,805	1,805	1,805
Island Generation (all owners) Peak Capacity	1,935	1,935	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345
Interruptible Capability	119	119	119	119	119	119	119	119	119	119	119
Capacity Available for Island Before Muskrat Falls/Labrador Island Link	2,054	2,054	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Island Peak Load Total Requirements (Load + Losses)	1,804	1,798	1,800	1,805	1,803	1,804	1,804	1,805	1,805	1,805	1,805
Proposed Threshold Island Reserve Margin	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
Minimum Requirements at Above Reserve Margin	2,056	2,049	2,052	2,057	2,056	2,057	2,056	2,058	2,058	2,058	2,058
Capacity Required Across Labrador Island Link to Meet Reserve Margin	NA	NA	589	594	592	593	593	594	594	594	594
Muskrat Falls Firm Capacity			790	790	790	790	790	790	790	790	790
Excess Capacity at Muskrat Falls Available for Load Growth or Export (No use of Recall Capacity)			201	196	198	197	197	196	196	196	196

Source: Synapse Calculations

Table 60: High CDM Scenario – Capacity Balance - MFP Serving Balance of Needs Excluding Use of Excess Capacity Associated with Recall Energy

Island Load, Losses, Generation, and Labrador Island Link at Peak	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Peak (including self-supplied load)	1,659	1,648	1,639	1,631	1,626	1,616	1,577	1,588	1,562	1,553	1,526
Island Transmission Losses	141	140	139	139	138	137	134	135	133	132	130
Total Capacity Requirement	1,800	1,789	1,778	1,769	1,764	1,754	1,711	1,723	1,695	1,685	1,656
Island Generation (all owners) Peak Capacity	1,935	1,935	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345
Interruptible Capability	119	119	119	119	119	119	119	119	119	119	119
Capacity Available for Island Before Muskrat Falls/Labrador Island Link	2,054	2,054	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Island Peak Load Total Requirements (Load + Losses)	1,800	1,789	1,778	1,769	1,764	1,754	1,711	1,723	1,695	1,685	1,656
Proposed Threshold Island Reserve Margin	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
Minimum Requirements at Above Reserve Margin	2,052	2,039	2,027	2,017	2,011	1,999	1,950	1,965	1,932	1,921	1,888
Capacity Required Across Labrador Island Link to Meet Reserve Margin	NA	NA	564	553	548	536	486	501	468	457	424
Muskrat Falls Firm Capacity			790	790	790	790	790	790	790	790	790
Excess Capacity at Muskrat Falls Available for Load Growth or Export (No use of Recall Capacity)			226	237	242	254	304	289	322	333	366

Source: Synapse Calculations

Table 61: High Electrification Scenario – Capacity Balance - MFP Serving Balance of Needs Excluding Use of Excess Capacity Associated with Recall Energy

Island Load, Losses, Generation, and Labrador Island Link at Peak	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Peak (including self-supplied load)	1,671	1,679	1,694	1,704	1,704	1,714	1,733	1,735	1,751	1,749	1,767
Island Transmission Losses	142	143	144	145	145	146	147	148	149	149	150
Total Capacity Requirement	1,814	1,822	1,838	1,848	1,849	1,860	1,880	1,883	1,900	1,898	1,917
Island Generation (all owners) Peak Capacity	1,935	1,935	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345
Interruptible Capability	119	119	119	119	119	119	119	119	119	119	119
Capacity Available for Island Before Muskrat Falls/Labrador Island Link	2,054	2,054	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Island Peak Load Total Requirements (Load + Losses)	1,814	1,822	1,838	1,848	1,849	1,860	1,880	1,883	1,900	1,898	1,917
Proposed Threshold Island Reserve Margin	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
Minimum Requirements at Above Reserve Margin	2,067	2,077	2,096	2,107	2,108	2,121	2,143	2,147	2,166	2,164	2,186
Capacity Required Across Labrador Island Link to Meet Reserve Margin	NA	NA	632	644	644	657	679	683	702	700	722
Muskrat Falls Firm Capacity			790	790	790	790	790	790	790	790	790
Excess Capacity at Muskrat Falls Available for Load Growth or Export (No use of Recall Capacity)			158	146	146	133	111	107	88	90	68

Source: Synapse Calculations

Table 62: High Electrification w/EV TOU, High CDM w/TOU Scenario – Capacity Balance - MFP Serving Balance of Needs Excluding Use of Excess Capacity Associated with Recall Energy

Island Load, Losses, Generation, and Labrador Island Link at Peak	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Island Peak (including self-supplied load)	1,665	1,647	1,646	1,638	1,622	1,606	1,590	1,574	1,552	1,532	1,513
Island Transmission Losses	141	140	140	139	138	137	135	134	132	130	129
Total Capacity Requirement	1,806	1,787	1,786	1,777	1,760	1,743	1,726	1,708	1,684	1,663	1,642
Island Generation (all owners) Peak Capacity	1,935	1,935	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345	1,345
Interruptible Capability	119	119	119	119	119	119	119	119	119	119	119
Capacity Available for Island Before Muskrat Falls/Labrador Island Link	2,054	2,054	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464	1,464
Island Peak Load Total Requirements (Load + Losses)	1,806	1,787	1,786	1,777	1,760	1,743	1,726	1,708	1,684	1,663	1,642
Proposed Threshold Island Reserve Margin	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%	14.0%
Minimum Requirements at Above Reserve Margin	2,059	2,037	2,036	2,025	2,006	1,987	1,967	1,947	1,919	1,895	1,872
Capacity Required Across Labrador Island Link to Meet Reserve Margin	NA	NA	573	562	543	523	504	484	456	432	408
Muskrat Falls Firm Capacity			790	790	790	790	790	790	790	790	790
Excess Capacity at Muskrat Falls Available for Load Growth or Export (No use of Recall Capacity)			217	228	247	267	286	306	334	358	382

Source: Synapse Calculations

CDM Model Tables by CDM Scenario

Table 63: CDM and HP Net Annual Energy Savings (GWh)

IIS High Case - CDM and HP Net Annual Energy Savings (GWh)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	4	12	24	42	67	99	141	181	221	260	299
HP EE	14	36	70	114	166	221	281	340	400	464	533
Total	18	47	94	157	233	321	421	522	621	725	832
IIS Low Case - CDM and HP Net Annual Energy Savings (GWh)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	0	2	5	11	19	29	42	57	76	98	123
HP EE	0	0	0	0	0	0	0	0	0	0	0
Total	0	2	5	11	19	29	42	57	76	98	123
LIS High Case - CDM and HP Net Annual Energy Savings (GWh)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	1	3	6	12	21	34	50	67	83	99	116
HP EE	0	0	1	3	5	8	12	17	22	28	34
Total	1	3	8	15	26	42	62	83	105	127	150
LIS Low Case - CDM and HP Net Annual Energy Savings (GWh)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	0	1	2	4	7	11	17	23	31	41	52
HP EE	0	0	0	0	0	0	0	0	0	0	0
Total	0	1	2	4	7	11	17	23	31	41	52

Source: Synapse Calculations

Table 64: CDM and DR Net Annual Cumulative Winter Peak Savings (MW)

IIS High Case - CDM and DR Net Annual Cumulative Winter Peak Savings (MW)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	1	2	4	7	10	15	21	27	33	38	44
HP EE	3	6	13	21	30	40	51	62	73	84	97
DR	4	9	14	19	25	32	39	48	57	67	78
Total	7	17	30	46	66	87	111	136	162	190	219
IIS Low Case - CDM and DR Net Annual Cumulative Winter Peak Savings (MW)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	0	0	1	2	3	4	6	8	11	14	18
HP EE	0	0	0	0	0	0	0	0	0	0	0
DR	4	8	12	16	21	25	29	33	38	42	46
Total	4	8	13	18	23	29	35	42	48	56	64
LIS High Case - CDM and DR Net Annual Cumulative Winter Peak Savings (MW)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	0	0	1	1	2	3	4	6	7	9	10
HP EE	0	0	0	1	1	2	2	4	5	6	7
DR	0	1	1	2	3	3	4	5	6	7	8
Total	0	1	2	4	6	8	11	14	18	21	25
LIS Low Case - CDM and DR Net Annual Cumulative Winter Peak Savings (MW)											
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Conventional CDM	0	0	0	0	1	1	1	2	3	4	5
HP EE	0	0	0	0	0	0	0	0	0	0	0
DR	0	1	1	2	2	3	3	4	4	5	5
Total	0	1	2	2	3	4	5	6	7	8	10

Source: Synapse Calculations

Table 65: Residential Sector Annual Consumption and Peak Load Share by End-Use

End-Use Type	Annual Consumption					Peak Load				
	SF-D, elec	SF-D, Non-elec	SF-A, elec	MF Elec	Others	SF-D, elec	SF-D, Non-elec	SF-A, elec	MF Elec	Others
Newfoundland Interconnected										
All end-use	60%	18%	11%	6%	5%	63%	14%	11%	7%	4%
Space heating	56%	13%	48%	45%	27%	70%	22%	63%	60%	42%
Domestic hot water	11%	17%	15%	18%	15%	12%	23%	17%	20%	21%
Refrigerator and freezer	6%	13%	7%	5%	9%	2.2%	6.2%	3%	2%	4%
Lighting	5%	10%	6%	5%	7%	3%	8%	4%	3%	7%
Others	22%	48%	25%	27%	42%	13%	41%	14%	15%	26%
Labrador Interconnected										
All end-use	61%	2%	31%	3%	3%	60%	3%	31%	4%	3%
Space heating	70%	38%	69%	55%	29%	78%	47%	76%	66%	44%
Domestic hot water	7%	11%	8%	15%	20%	8%	13%	9%	18%	30%
Refrigerator and freezer	4%	8%	4%	5%	12%	2.3%	5.2%	2.4%	2.9%	9.0%
Lighting	3%	7%	3%	4%	2%	3%	6%	2%	4%	2%
Others	16%	36%	16%	21%	37%	10%	29%	10%	10%	15%

Source: ICF. 2015. Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 Residential Sector Final Report

Table 66: Commercial Sector Annual Consumption and Peak Load Share by End-Use

End-Use Type	Annual Consumption					Peak Load				
	Office and retail	Hotels	Healthcare	Education	Others	Office and retail	Hotels	Healthcare	Education	Others
Newfoundland Interconnected										
All end-use	42%	4%	7%	14%	33%	46%	5%	8%	15%	27%
Space heating	29%	30%	38%	31%	17%	46%	36%	50%	48%	35%
Domestic hot water	15%	8%	19%	15%	7%	10%	5%	13%	10%	7%
HVAC fans & pumps	25%	22%	18%	34%	15%	19.2%	13.6%	13%	27%	16%
Lighting	2%	24%	6%	2%	5%	4%	41%	9%	3%	13%
Others	28%	16%	20%	17%	56%	21%	5%	16%	11%	29%
Labrador Interconnected										
All end-use	15%	3%	7%	6%	70%	16%	3%	6%	6%	69%
Space heating	43%	41%	19%	53%	31%	61%	42%	24%	67%	39%
Domestic hot water	8%	6%	22%	9%	11%	5%	5%	15%	6%	8%
HVAC fans & pumps	24%	31%	16%	23%	23%	17.6%	10.5%	15.2%	21.2%	18.4%
Lighting	2%	4%	7%	1%	6%	4%	37%	21%	3%	13%
Others	24%	18%	36%	13%	28%	13%	5%	24%	3%	23%

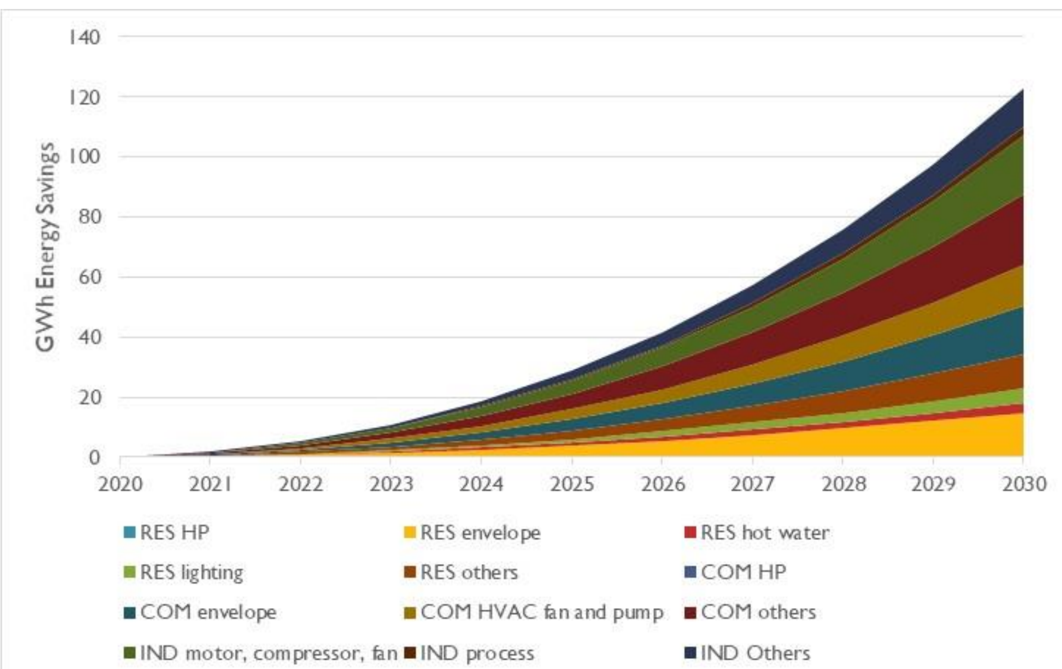
Source: ICF. 2015. Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 Commercial Sector Final Report

Table 67: Industrial Sector Annual Consumption and Peak Load Share by End-Use

End-Use Type	Annual Consumption All Facility Type	Peak Load All Facility Type
Newfoundland Interconnected		
All end-use	100%	100%
Motor, compressor, pump, fan	58%	57%
Process	36%	35%
Comfort HVAC	3%	4.6%
Lighting	3%	3%
Other	0%	0%
Labrador Interconnected		
All end-use	100%	100%
Motor, compressor, pump, fan	58%	57%
Process	36%	35%
Comfort HVAC	3%	5%
Lighting	3%	3%
Other	0%	0%

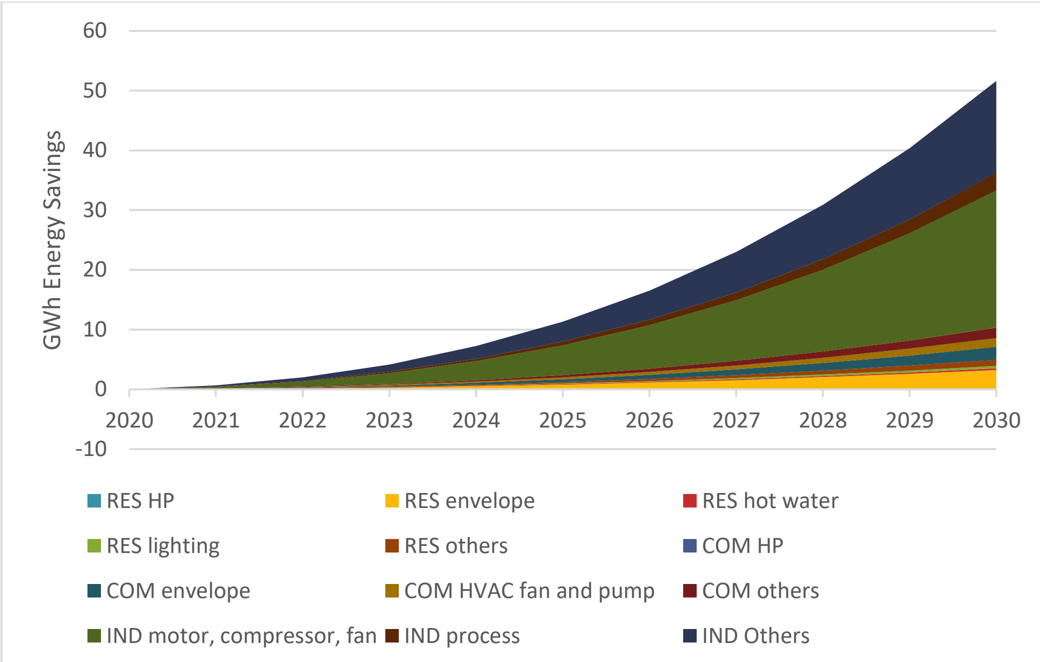
Source: ICF. 2015. Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015 Industrial Sector Final Report

Table 68: IIS Low Case - Net Annual Energy Savings by Aggregated End-Use Categories (GWh)



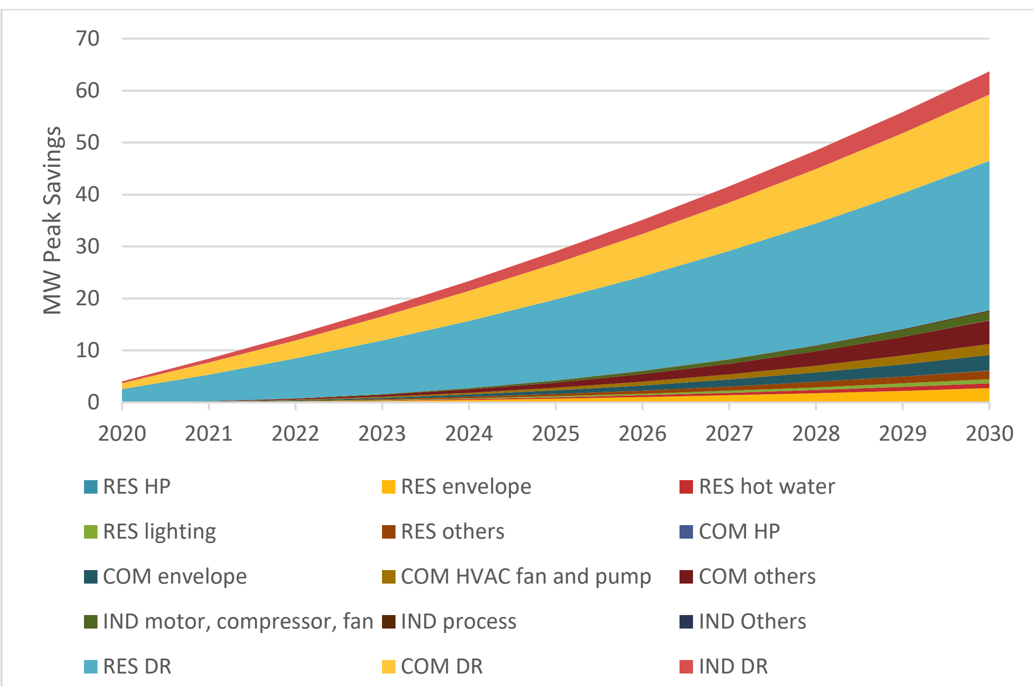
Source: Synapse calculations

Figure 56: LIS Low Case - Net Annual Energy Savings for CDM and HP by Aggregated End-Use Categories (GWh)



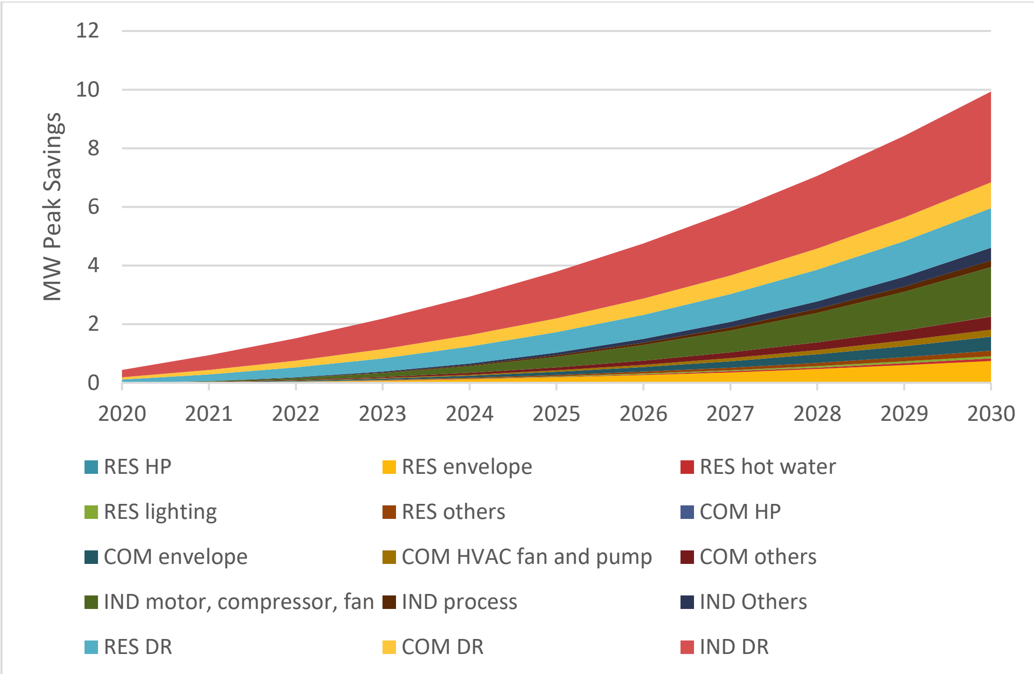
Source: Synapse calculations

Figure 57: IIS Low Case - CDM Net Annual Cumulative Peak Load Savings by Aggregated Category (MW)



Source: Synapse calculations

Figure 58: LIS Low Case - CDM Net Annual Cumulative Peak Load Savings by Aggregated Category (MW)



Source: Synapse calculations

Electrification Model Tables by Electrification Scenario

Table 69. Total electrification potential by scenario and sector (GWh), 2018-2030.

Scenario/ Sector	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Low Total	1	7	13	68	74	81	87	95	103	114	126	143	166
Buildings	0	6	12	67	73	79	84	90	95	101	106	111	117
Transport	1	1	1	1	2	2	3	5	8	13	20	32	50
High Total	1	29	59	164	196	230	291	332	375	424	478	538	605
Buildings	0	25	49	148	171	194	242	264	286	308	329	351	372
Transport	1	5	10	16	25	36	50	67	89	116	148	187	233

Table 70. Low scenario fuel price projections, 2020-2030 (2018 CAD$ per GJ)

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gasoline	$44.86	$43.04	$41.70	$41.52	$40.85	$40.39	$39.98	$39.59	$39.22	$38.86	$38.51
Diesel	$38.31	$36.65	$35.47	$35.46	$34.91	$34.54	$34.22	$33.93	$33.64	$33.37	$33.10
Heavy Fuel Oil	$22.87	$21.72	$20.98	$21.26	$20.96	$20.79	$20.66	$20.54	$20.43	$20.33	$20.21
Residential Heating Oil	$25.84	$24.42	$23.48	$23.71	$23.38	$23.20	$23.07	$22.95	$22.84	$22.73	$22.61

Source: Canada's Energy Future 2018 (Low Case)

Table 71. High scenario fuel price projections, 2020-2030 (2018 CAD$ per GJ)

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Gasoline	$62.10	$59.68	$57.77	$57.88	$57.63	$56.78	$56.09	$55.47	$54.92	$54.40	$53.99
Diesel	$55.54	$53.29	$51.54	$51.82	$51.69	$50.93	$50.33	$49.80	$49.34	$48.91	$48.57
Heavy Fuel Oil	$37.99	$36.32	$35.08	$35.61	$35.68	$35.17	$34.79	$34.47	$34.20	$33.96	$33.79
Residential Heating Oil	$43.08	$41.06	$39.55	$40.07	$40.16	$39.60	$39.18	$38.83	$38.53	$38.28	$38.08

Source: Canada's Energy Future 2018 (High Case)

Table 72. Fuel projections by building sector, 2020-2030 (PJ)

Fuel Type	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential Refined Petroleum Products	3.9	3.79	3.68	3.57	3.47	3.35	3.24	3.13	3.03	2.94	2.86
Commercial Refined Petroleum Products	2.94	2.93	2.93	2.92	2.91	2.93	2.92	2.9	2.9	2.92	2.94

Source: Canada's Energy Future 2018 (Reference Case)

Correction to Table 76 provided during testimony on October 7, 2019
Transcript reference: Page 4, Line 18 to Page 5, Line 25

Table 73. Historical fuel use by medium-duty vehicles (PJ)

Vehicle Type	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
Delivery Trucks	2.5	2.7	3.1	3.4	3.1	3.3	3.8	3.1	3.0	3.5	3.9
School Buses	0.4	0.4	0.4	0.5	0.4	0.4	0.5	0.3	0.2	0.3	0.3
Transit Buses	0.9	0.9	1.0	1.1	0.8	0.9	1.0	0.6	0.7	0.8	0.7

Source: Natural Resources Canada Comprehensive Energy Use Database, Transportation Sector (Table 7)

Table 74. EV customer economics assumptions

Parameter	Value	Source
Annual EV efficiency improvement	1.6%	EV-REDI
Annual EV electricity use (kWh)	3897	EV-REDI
Annual gasoline use (gallons)	397	EV-REDI
EV Loan Term (years)	5	Assumed
EV loan rate	5%	Assumed
EV incentive per vehicle	$5,000	Canadian Government

Table 75. Vehicle cost assumptions

Vehicle Type	2020	2025	2030	Source
Gasoline	$29,737	$34,649	$38,783	Annual Energy Outlook, 2019
EV pre-incentive	$38,193	$40,866	$44,065	Annual Energy Outlook, 2019 (base cost); Indiana University, 2017 (non-battery premiums); Bloomberg Energy New Finance, 2017 (battery premiums)
EV post-incentive (low scenario)	$33,193	$35,866	$41,065	Calculated
EV post-incentive (high scenario)	$34,193	$37,866	$41,065	Calculated

Table 76. Heat pump customer economics assumptions

Parameter	Value	Source
Annual heat pump efficiency improvement	2%	Assumed
Annual heat pump electricity use (kWh)	**10768**	Calculated
Annual furnace oil use (GJ)	133	Calculated
Heat pump loan term (years)	5	Newfoundland Power Financing Plans
Heat pump loan rate	8%	Newfoundland Power Financing Plans
Average residential heat pump system size (tons)	3	Assumed

Table 77. EV charging station depreciation parameters

Parameter	Value	Source
Asset life (years)	10	Assumed
Depreciation rate	10%	Assumed
WACC	7.04%	PUB-NP-075