Muskrat Falls Project - Rate Mitigation Phase 2 Report

September 30, 2019

Introduction

Introduction

- Phase 2 Scope of Analysis – to assist Board in answering Reference Questions
  - 1st Question – "Options to reduce the impact of Muskrat Falls Project (MFP) costs on electricity rates… including cost savings and revenue opportunities with respect to electricity", and "whether it is more advantageous to Ratepayers to maximize domestic load or maximize exports"
    - Our "electrification" scenarios examine the effect of increasing domestic load
    - Our conservation demand management (CDM) cases examine the effect of increasing exports (through lower in-Province load)
    - To determine what is more advantageous, the timing of consumption changes matters a lot – peak or off-peak period load changes? All of our analyses reflect this.
  - 2nd Question – "The amount of energy and capacity from the MFP required to meet Island Interconnected Load (IIS) and the remaining surplus energy and capacity available for other uses such as export and load growth"
    - We directly compute what remains for export from the MFP after accounting for IIS and Labrador load requirements, and overall resource capabilities.
    - We directly account for the transfers between Labrador and the IIS over the LIL, the existence of Recall energy and on-island resources, and load levels when determining the MFP surplus.
  - 3rd Question – "The potential electricity rate impacts of the options identified in Question 1"
    - The options from Question 1 include various combinations of electrification and CDM, inclusive of demand response effects.
    - We compute electricity rate impacts (c/kWh) from all scenarios.
- Because of the material effect on Ratepayers of reduced or increased electric consumption, and the corollary effect of reduced oil and gasoline use in electrification cases, we also compute bill impacts ($/month) that include both kWh consumption change and oil/gasoline savings effects.

Summary Findings

Summary Findings – Revenue Opportunities

Reference Question 1 – Revenue Opportunities, Load Growth/Export Sales

- No magic bullets for mitigation (i.e., increased net revenues) – customer actions occur slowly over time but have significant effects in long term.
- Electrification mitigates rate increases (greater sales base to cover fixed costs).
  - Oil/gasoline savings is the "new money" allowing cost-effective fuel switching and resulting mitigation of both average rates and average bills.
    - Distribution of these benefits across sectors and rate classes may not be even but policies can influence effects; and programmatic efforts can aim to increase participation.
  - Increased internal load brings greater revenues than increased export sales, per unit. Electrification scenarios lead to reduced export sales.
- CDM, and Demand Response (DR) in multiple forms:
  - Reduces peak kWh consumption, and reduces peak MW,
  - Thus crucially avoids capacity expansion costs, and
  - Also increases export sales.
- CDM exacerbates rate increases but results in lower average bills due to above effects.
  - Higher rates, but lower bills, not an uncommon tension. Policies and programs to promote wide participation over time can mitigate against the risk of non-participant inequities.

Summary Findings - Rate Design, Existing Policies, MFP Surplus

Reference Question 1 - continued

- Rate Design a potentially powerful tool to shape consumption patterns and improve mitigation outcomes.
  - Smart electric vehicle (EV) chargers in lieu (initially) of AMI (advanced metering infrastructure) investment is "least regrets" to increase load in mostly off-peak periods;
    - But broader application of time-of-use (TOU) rates w/ critical peak pricing (CPP) possibly economic.
  - Additional sectoral and rate-class level analysis needed to narrow best rate design choices.
- Existence of Federal and Provincial policies have material impact on revenue opportunities:
  - Energy efficiency and fuel switching funds, and EV rebates all available to lower net costs. Analysis includes these effects in different ways (EV rebates directly; fuel switching and efficiency funds indirectly).

Reference Question 2 – MFP Quantity to Meet IIS Load, and Surplus Availability

- MFP Surplus is of sufficient quantity to fully support electrification efforts, and still export a surplus; CDM efforts increase the surplus.

Reference Question 3 – Rate impacts from Question 1 Options

- Rate and bill impacts are shown for all our modeled scenarios.

Summary Findings - Export Sales

- Pricing for export sales based on confidential Nalcor estimates of Nova Scotia, New England, New York market destinations for energy. It reflects a reasonable representation of energy market prices.
- Sensitivity to those prices based on Synapse estimates using US EIA low and high scenarios for gas prices in New England (NE), and confidential “basis” data. Electric market prices in NE are based on gas prices.
- Export sales
  - Maximized with high levels of CDM, rising to $215 million/year by 2030 ($138 million/year by 2025)
  - Minimized with high levels of electrification, $141 million/year by 2030 ($111 million/year by 2025).
  - Sales revenue lower than what is available with internal load increases (i.e., electrification earns more revenue)
- Export sales volumes and revenues vary by scenario, for different reasons
  - CDM and electrification combinations will affect volumes available for sale
  - CDM will affect hourly patterns, allowing for shifts in both on-peak and off-peak period volume sales
  - Use of TOU rates will allow some energy to be made available in on-peak periods for sales during these generally higher-priced hours
- Sensitivity on market prices: increase in export sales revenues of $75 million/yr. by 2030 (high prices), reduction in revenues of $31 million/yr. (low prices)

Summary Findings – Rates and Bills

- Rate mitigation ramps in slowly for all scenarios. Net effects:
  - High electrification scenarios lower rates by up to 1 c/kWh by 2030, 0.6 cents/kWh by 2025
  - Similar rate impacts for “high price” sensitivity for export sales, 1.2 c/kWh by 2030, with no increased electrification (but low export prices increases rates)
  - High CDM scenario increases rates (0.5 c/kWh by 2025, 1.4 c/kWh by 2030)
- Lower average bills with either or both of CDM and electrification, compared to Synapse Base Case
  - High CDM – scenario 6 – monthly bill savings ($6 – 2025, $20 – 2030) even with higher rates
  - New money: oil/gas savings rises to $244 million/year by 2030 in “high” electrification case ($112 million/year, 2025). Electrification: always lower overall bills (electric + oil)
  - Analysis reflects the average customer – potential for disparity across customers should be considered in policy and program implementation stage
- Combined scenarios (CDM and electrification) 20a, 24, best customer bill impact
  - High electrification w/ EV TOU, high CDM, TOU and CPP, DR elements
  - Rates go down through first half of period, increase back towards zero effect in later years. Monthly average bill savings of $75 (2030), $30 (2025) for Sc. 24

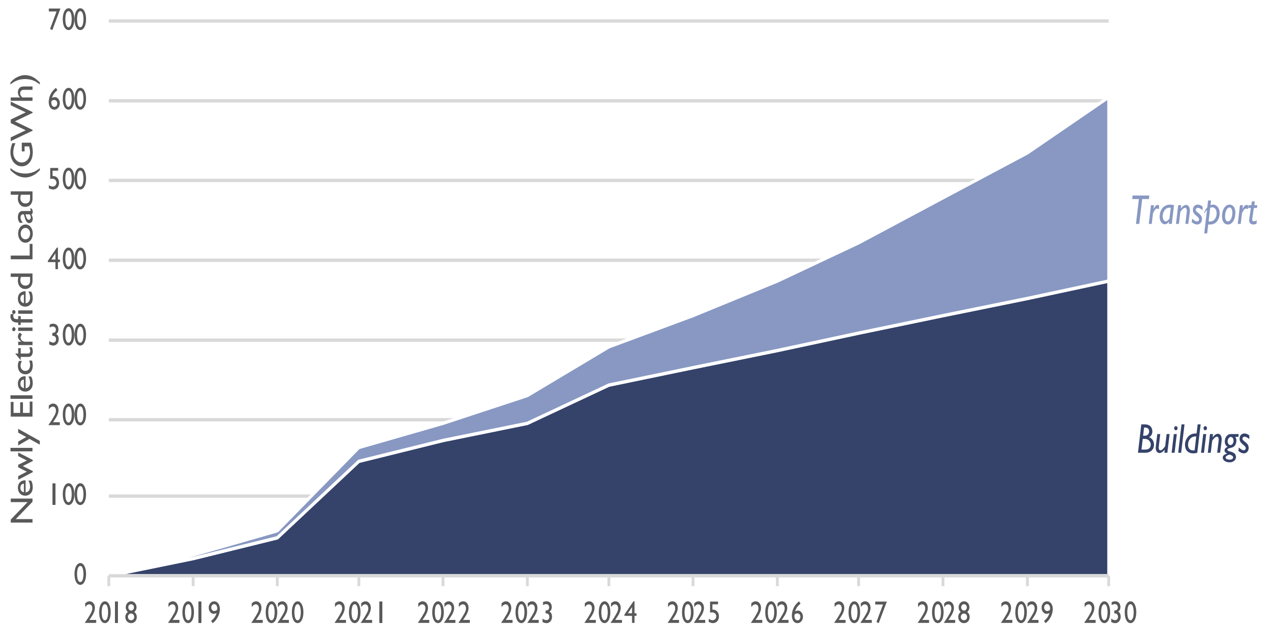
Summary Findings – IIS Energy Balance

- MFP surplus sufficient to meet IIS needs and export sizable surplus; when considered with Recall energy, total export volumes ~ 3.5 TWh/yr. (~1.4 TWh without Recall) Tables 41, 42.

GWh	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
Excluding Recall							
Muskrat Falls Generation Available after Island and Nova Scotia Obligations	**1,771**	**1,975**	**1,970**	**1,933**	**1,989**	**2,069**	**2,123**
Recall Energy Available for Island After Labrador Load Requirement	**1,218**	**1,472**	**1,417**	**1,441**	**1,461**	**1,418**	**1,399**
Including Recall							
Muskrat Falls Available after Island/Nova Scotia Needs, Assuming Recall serves Island	**2,989**	**3,447**	**3,386**	**3,374**	**3,450**	**3,487**	**3,522**

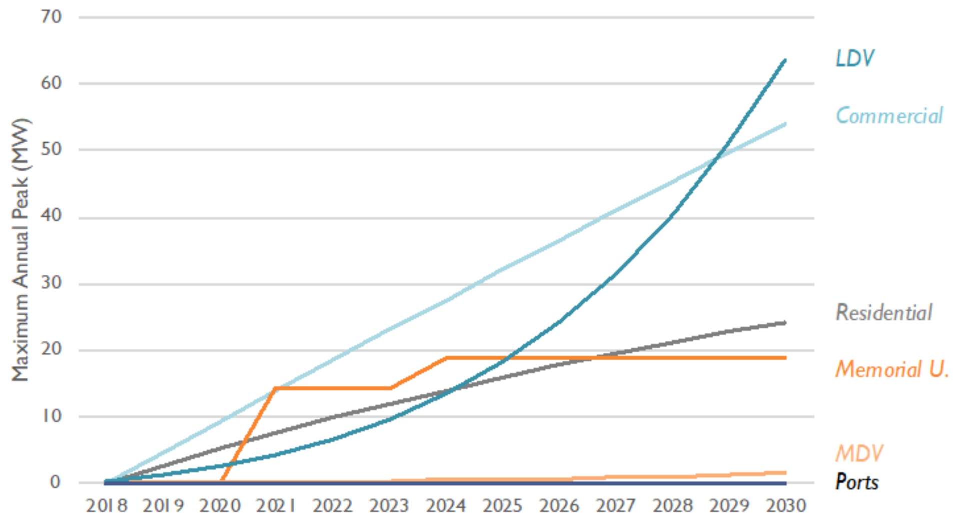
Summary Findings – Electrification

- Electrification effect – "high" scenarios – rises to ~600 GWh/yr. (2030)
    - Avoided oil expenditures of $112 mm/year (by 2025), $244 mm/year (by 2030)
    - Direct contribution to revenues: $67 million/yr (2025), $134 million/yr (2030);
    - Net mitigation (accounting for costs) ranges from $33-40 million/yr (2025), to $52-$55 million/yr (2030)

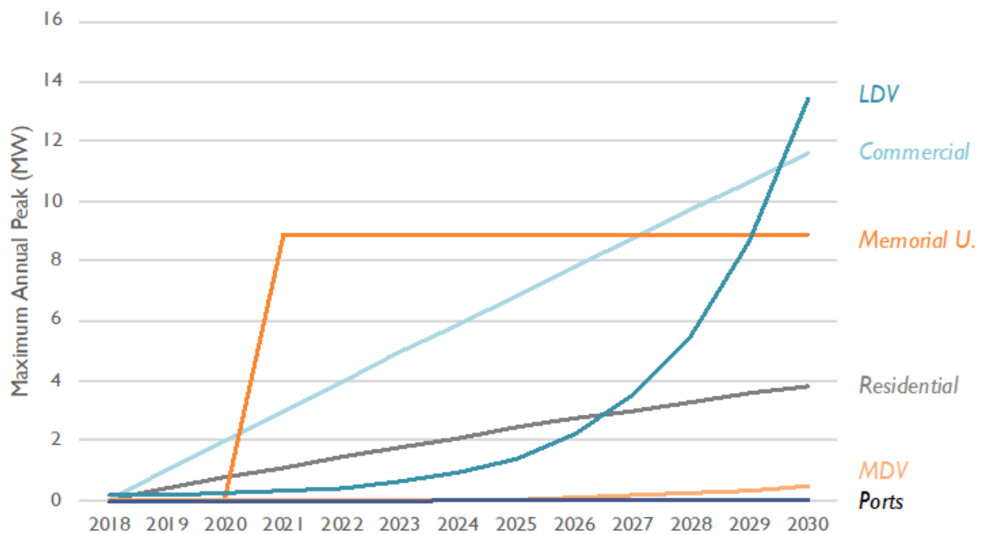


Summary Findings – Electrification Peak Additions

- High scenario: 147 MW peak addition (total) by 2030 - IIS

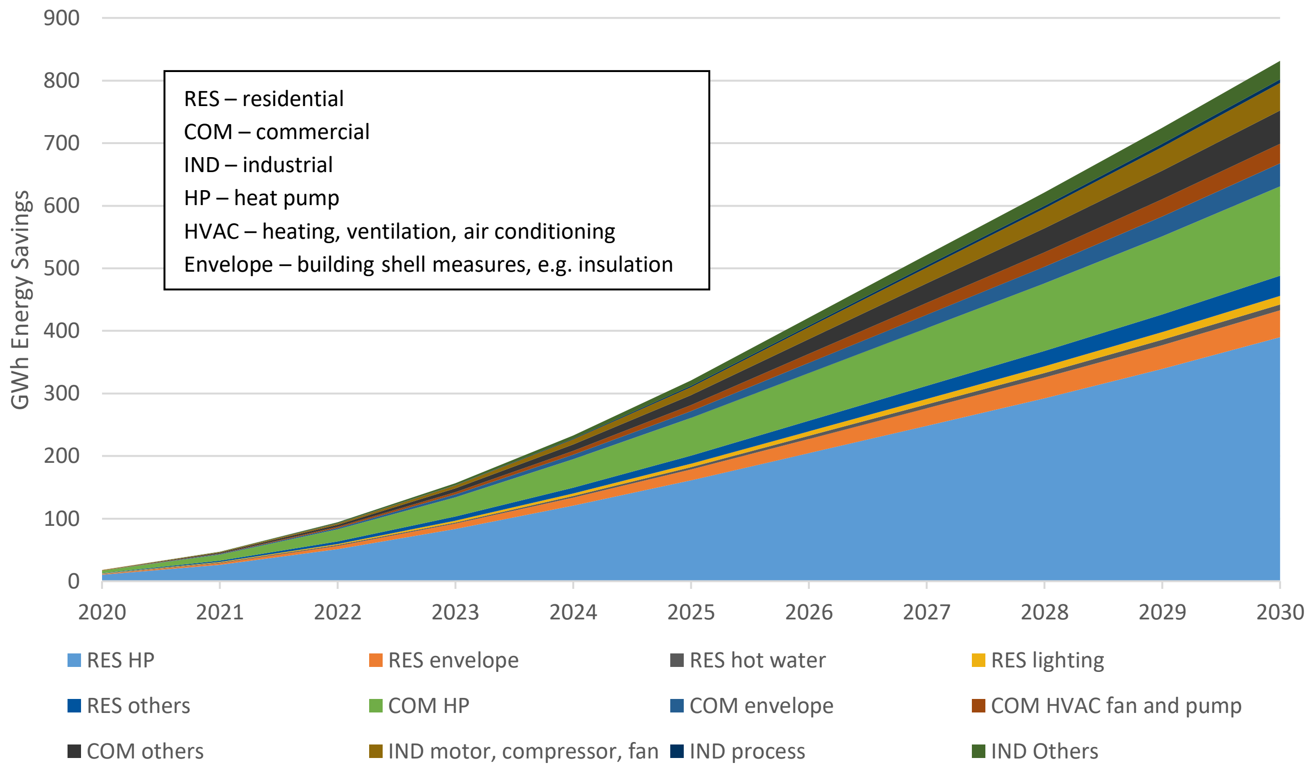


- Low scenario: 37 MW peak addition (total) by 2030 - IIS



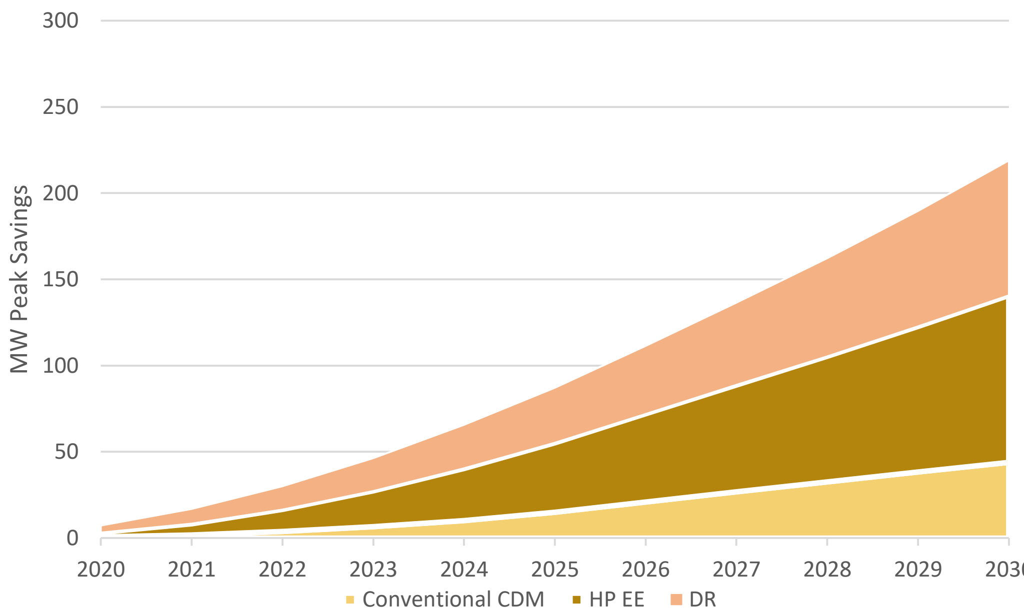
Summary Findings – CDM Energy Savings

- Aggressive CDM programs on Island are economic; across all sectors
  - Estimated savings net of savings already embedded in reference forecast
- Energy savings contribute to additional export sales, capacity need avoidance, and lower bills. “High” CDM case shown below.



Summary Findings - CDM, DR Peak Savings

- CDM including heat pumps, and DR peak savings valued at marginal generation capacity costs.
- Overall contribution to net mitigation significant, as primary benefit from CDM/DR is this potential avoidance of capacity costs.
- Modeled DR increases are in addition to existing industrial curtailment opportunities.



Summary Findings – CDM Program Costs

- CDM on the Island is highly cost-effective;
- Peak shaving value ("Capacity Benefits" below) greater than energy savings alone;
- Steady ramp of Net Peak Savings (Megawatts, MW) seen;
- Relatively high benefit/cost (B/C) ratio indicates value even with lower avoided capacity value, or with higher costs.

Average Avoided Energy Rate ($/MWh)	33
Avoided Cap Value ($/kW-year)	317

Island: High Case: CDM & HP (2019$)

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 ($ r	1	1	3	5	7	10	13	16	18	20	22
BC Ratio	3.1	3.0	3.0	2.9	2.9	2.8	2.8	2.8	2.9	3.1	3.3

Overall Findings re: Reference Questions

- In response to the 1st Question, and based upon our results for the 3rd Question and the bill impact findings:
  - It is more advantageous to Ratepayers for the Province to:
    - increase load through electrification, which saves on oil/gasoline expenses while providing electric system revenue; and simultaneously
    - improve energy efficiency (and, critically, utilize forms of demand response) to primarily lower peak load,
    - thereby allowing for the inadvertent and incidental peak demand increases from newly-electrifying load, while still reducing future capacity expansion costs; and secondarily to
    - allow for sale of remaining MFP surplus (energy, and if/as available, capacity) to external markets.
  - Our summary findings thus reflect the best customer outcomes in scenarios with
    - High levels of electrification; <u>and</u>
    - High levels of CDM, and use of some form of demand response; <u>and</u>
    - Rate design that allows for employment of time-of-use principles for at least new electric vehicle (EV) load and potentially allows for expanded use of time-of-use rates employing AMI and some form of critical peak pricing to shave peak demands.

- Concerning the 2nd Question:
  - The amount of surplus available from MFP can be used to both fully support electrification needs (energy and peak additions) and increase export sales of surplus energy (and potentially capacity).
  - The levels available will be influenced by the extent of CDM and electrification that is achieved in the Province; a larger “buffer” is available to meet electrification peak loads when CDM is maximized.

Detailed Results: Rate and Bill Mitigation

Scenarios Modeled

- Series of scenarios defined to allow examination of combined effects
- Results highlighted for a few representative scenarios
  - High electrification
  - High CDM
  - Combination of high CDM and high electrification, with and without full AMI/TOU
- Major drivers for scenarios:
  - Level of increased load through electrification
  - Amount of energy and peak savings through CDM and DR
  - Mix of different amounts of electrification and CDM
  - Rate design layering:
    - Allow time-of-use for EVs only, to show effect of no AMI, but TOU for some new load
    - Allow DR for peak reduction, without any commensurate energy savings
    - Allow full AMI to reduce peak load and shift energy with TOU rates
  - Combinations of electrification, CDM, DR and rate design effect to determine mitigation possibilities.
- Roughly 38 scenarios ultimately modeled for rate and bill effect, to discern differences.

Table 1 Mitigation Results

- All values are relative to the Synapse Base Case (or reference scenario).
- Net mitigation (“Delta Utility Revenues”) and the associated average rate mitigation (c/kWh) and change in average monthly electric bill are shown below. Net mitigation is defined as the sum of cost and revenue effect components, which are shown on Table 2 (next slide).
- Table 1 also includes the change in total energy expenditures based on the combination of reduced (or increased) electric consumption, and (for electrification scenarios) reduced oil consumption.

	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	($35.0)	($83.8)	0.549	1.431	($6)	($20)	($35.0)	($83.8)	($6)	($20)
10. High Elec	$32.6	$52.1	(0.490)	(0.799)	$9	$21	($79.5)	($191.4)	($22)	($46)
12. High Elec w/EV TOU	$33.5	$55.3	(0.505)	(0.847)	$9	$20	($78.5)	($188.3)	($22)	($47)
12a. High Elec w/EV TOU w/DR	$39.8	$69.8	(0.600)	(1.070)	$7	$16	($72.2)	($173.7)	($24)	($52)
20. High Elec w/EV TOU, High CDM	$2.5	($18.1)	(0.039)	0.310	$2	($1)	($109.6)	($261.6)	($29)	($69)
20a. High Elec w/EV TOU, High CDM w/DR	$8.7	($4.1)	(0.136)	0.069	$1	($6)	($103.4)	($247.6)	($31)	($73)
24. High Elec w/EV TOU, High CDM w/TOU+CPP	$6.9	$2.2	(0.108)	(0.038)	$1	($8)	($105.2)	($241.3)	($30)	($75)

Table 2 Mitigation Results – By Component

- All values are relative to the Synapse Base Case (or reference scenario).
- Net mitigation (revenues minus costs) is composed of:
  - Revenue changes from increased or decreased energy consumption (Delta Internal Revenues).
  - Revenue changes from increased or decreased export revenues;
  - CDM, DR, TOU and/or electrification costs (annualized); and
  - Capacity benefits or costs associated with peak savings or increased peak load (annualized).

	Delta Internal Revenues (Millions)		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	($55.5)	($155.9)	$14.3	$45.1	$9.4	$22.7	($15.6)	($49.8)	($35.0)	($83.8)
10. High Elec	$65.5	$129.2	($12.6)	($28.7)	$3.5	$11.8	$16.9	$36.7	$32.6	$52.1
12. High Elec w/EV TOU	$65.4	$129.0	($11.8)	($28.6)	$4.6	$15.4	$15.4	$29.7	$33.5	$55.3
12a. High Elec w/EV TOU w/DR	$65.1	$127.7	($11.8)	($28.6)	$6.7	$23.0	$6.8	$6.3	$39.8	$69.8
20. High Elec w/EV TOU, High CDM	$11.0	($22.8)	$2.0	$19.5	$14.0	$38.1	($3.5)	($23.3)	$2.5	($18.1)
20a. High Elec w/EV TOU, High CDM w/DR	$10.7	($24.2)	$2.0	$19.5	$16.1	$45.7	($12.1)	($46.4)	$8.7	($4.1)
24. High Elec w/EV TOU, High CDM w/TOU+CPP	$10.8	($24.8)	$2.3	$19.1	$22.4	$42.5	($16.3)	($50.4)	$6.9	$2.2

Load Forecasts

Load Forecast – Price Response

- Forecast trajectories uncertain –use of econometric specifications based on historical response to small changes in price no longer directly applicable.
- Nature and extent of price response effect can vary widely – short term options to significantly reduce usage are limited, longer term options include CDM.
    - Significant switching to other fuels from electricity for heating unlikely
    - Heat Pump installations more likely, and already an observed response before rate increases
    - Shell measures (insulation) and other CDM, and some behavioral response probable
- Price elasticity of -0.3 reflected in Hydro low rate forecast not unreasonable, given limited substitution options.
    - Effect of greater price response would result in increased exports, reduced capacity need, higher rates, but lower average bills.
- Extreme Load sensitivity (~0.6 elasticity) to Synapse Base Case:
    - Higher export sales, higher rates

Load Forecast – Synapse Base Case

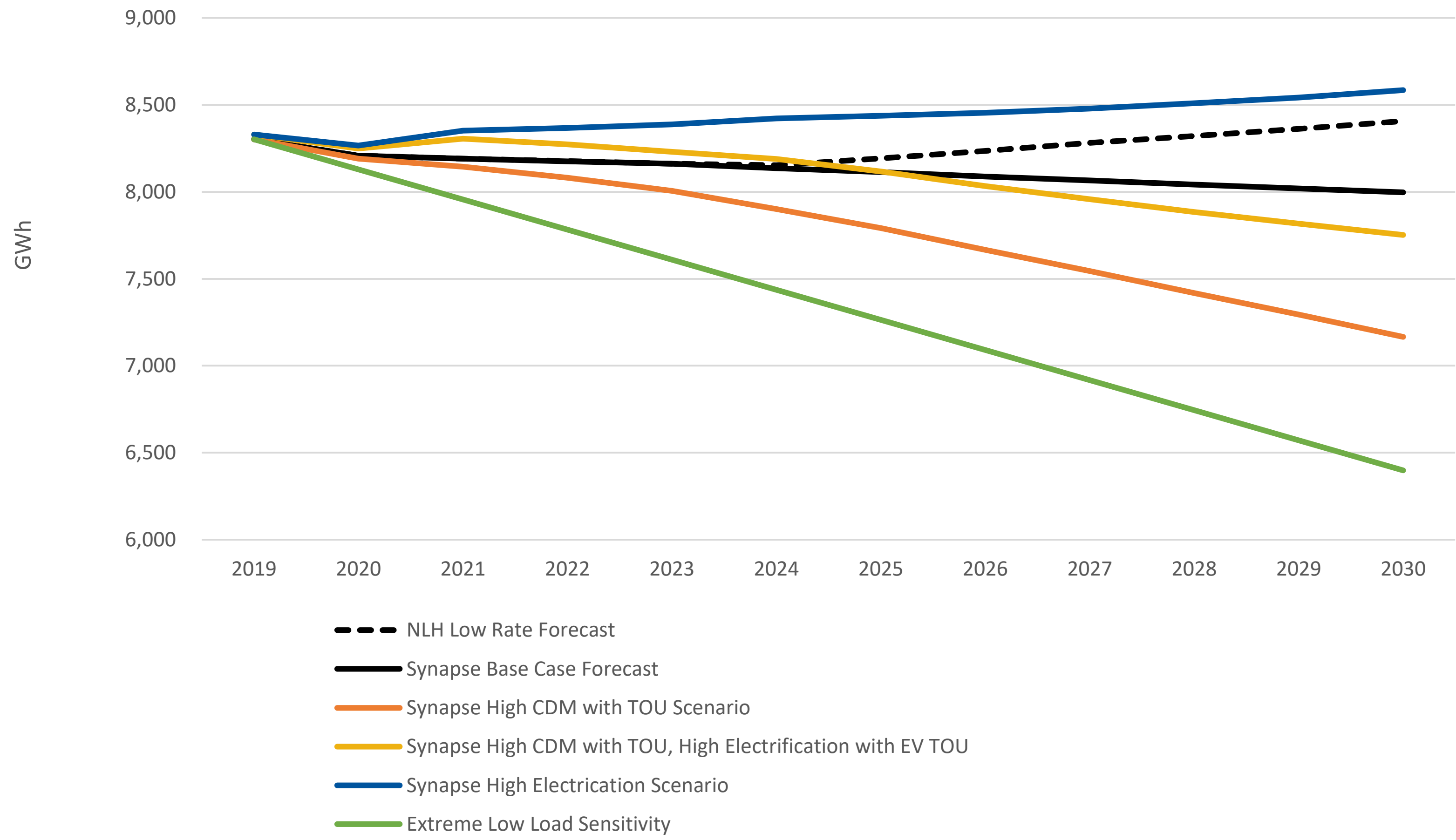
- Based on Hydro's "low rate" forecast, with out-years adjustments reflecting flatter load trend based on Newfoundland Power's near-term forecast, reflecting, for example, price response (including heat pump installations).

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
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

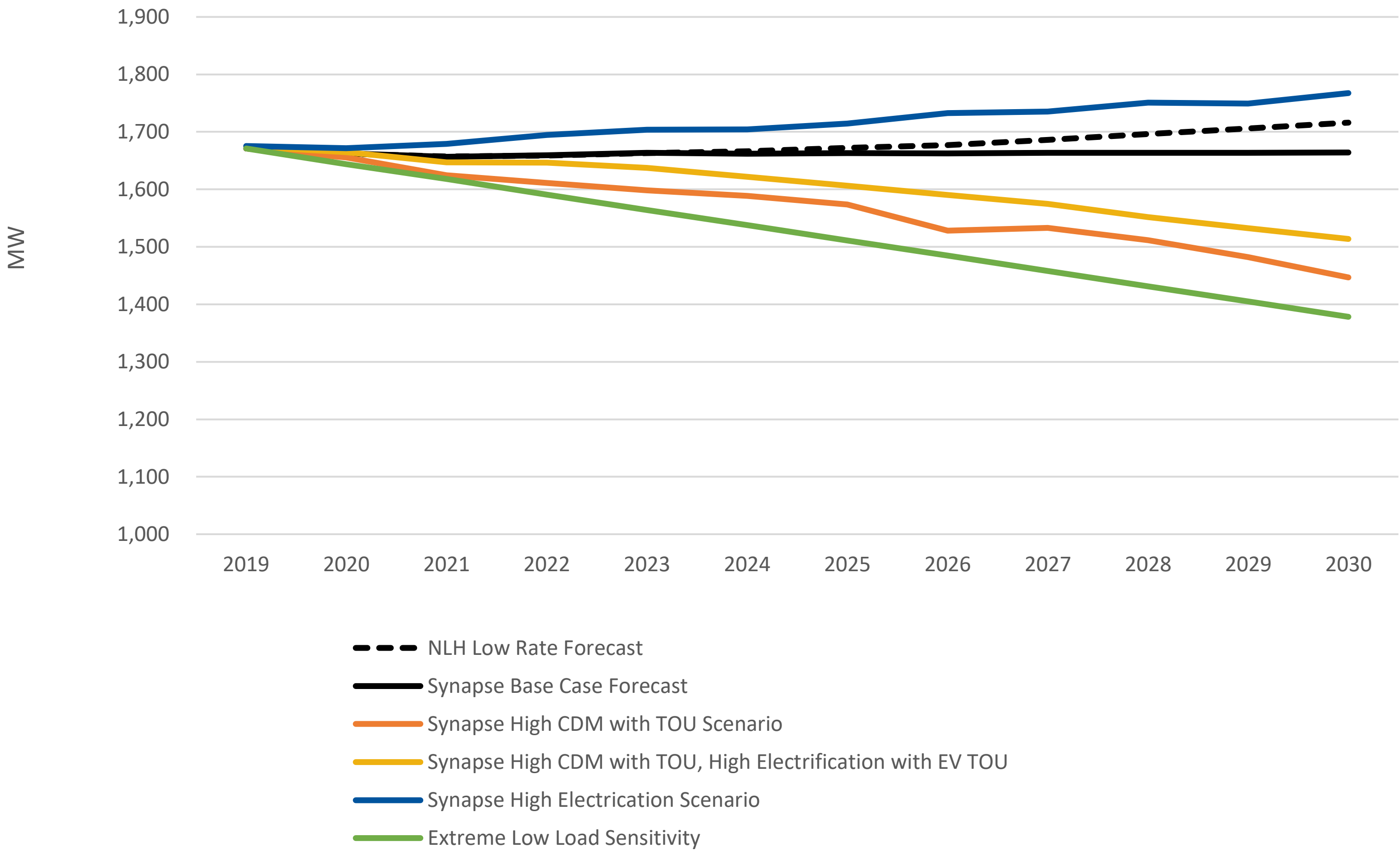
IIS Energy Requirement – Selected Scenarios

- Synapse Base Case, Selected Scenarios, NLH Low Rate Forecast, and Extreme Load Sensitivity – IIS Energy Requirement (excluding NLH island and LIL losses)

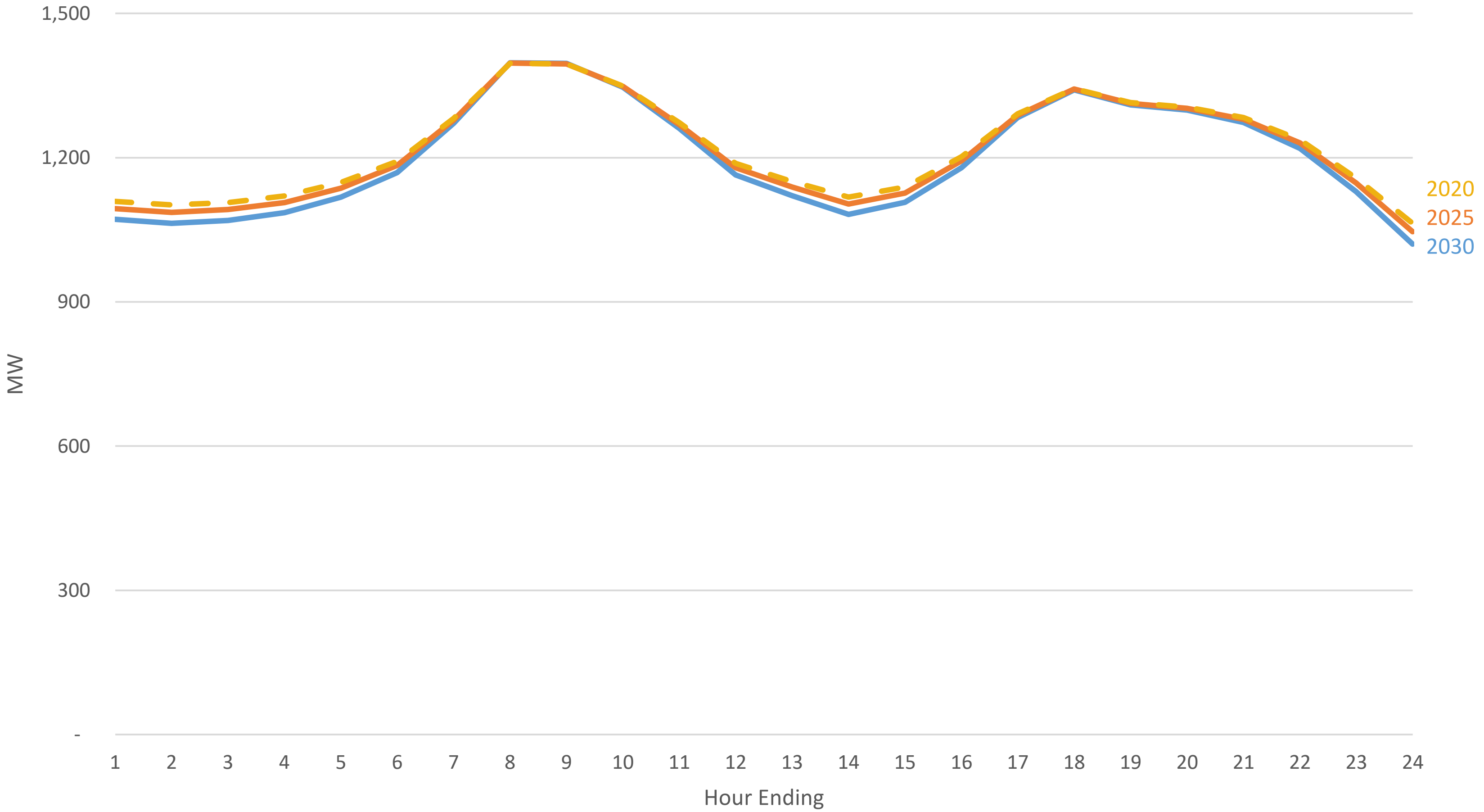


IIS Peak Demand Forecast – Selected Scenarios

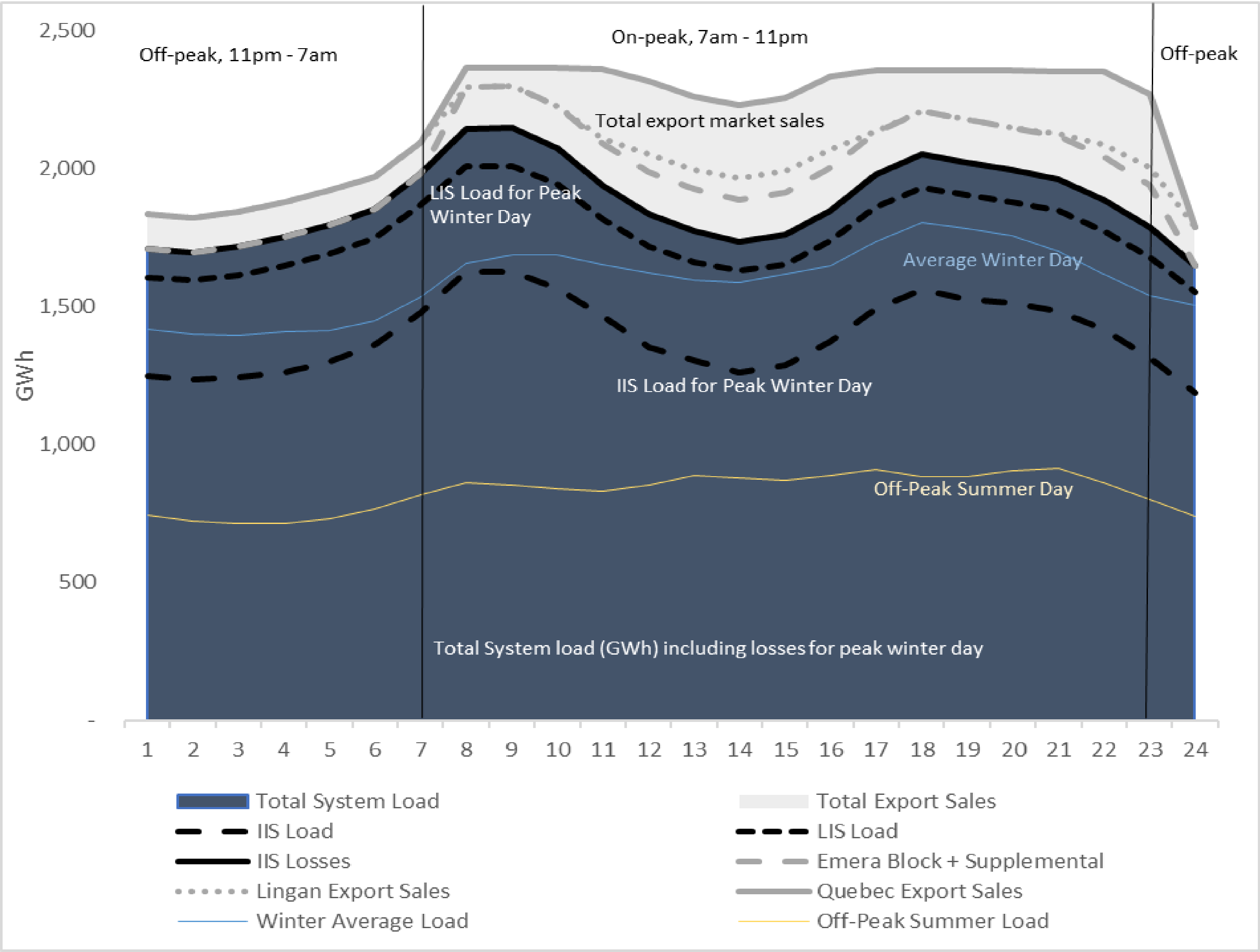
- Synapse Base Case, Selected Scenarios, NLH Low Rate Forecast, and Extreme Load Sensitivity – Peak Demand Forecast (excluding NLH island and LIL losses)



Reference Case IIS Load – Peak Winter Day



Peak, Average Winter, and Summer Day Profile



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Electrification

Electrification Analysis Overview

- Sectors analyzed:
  - **Transportation electrification**:
    - Replacement of gasoline and diesel vehicles with electric vehicles (EVs)
      - Light- and medium-duty vehicles (LDV and MDV) only
      - MDVs include delivery vehicles and buses (school and transit)
    - Addition of more electrified berths to St. John's port
  - **Building electrification**:
    - Conversion from oil heating to electric heating
      - Residential: conversion to heat pumps
      - Small and large commercial: conversion to heat pumps
      - Institutional and Memorial University: conversion to electric resistance boilers
- Developed a **low** and **high** electrification scenario for each sector

Building Electrification Assumptions

- Low Scenario:
  - Annual adoption of heat pumps: 0.5%
  - Assumes all buildings retain oil heating as back-up for peak days

- High Scenario:
  - Annual adoption of heat pumps: 2.0%
  - Assumes no buildings retain oil heating as back-up for peak days

- Threshold for back-up oil heating system: 20°F / -7°C

- Load assumptions:
  - Residential and small/large commercial building heat pump load is entirely weather-dependent
  - Institutional building ER boiler load is 40% baseload / 60% weather-based
  - Memorial University ER boiler load is 60% baseload / 40% weather-based

Transportation Electrification Assumptions

- Low Scenario:
  - Newfoundland EV adoption trajectory achieves 2025 all-Canada goal (of reaching 10% EV sales) five years late, in 2030.
  - Annual port electrification increase of 6%

- High Scenario:
  - Newfoundland EV adoption trajectory achieves 2030 all-Canada goal of 30% EV sales.
  - Annual port electrification increase of 12%

- Quarterly vehicle kilometers traveled (VKT) were used to estimate monthly impacts from EVs

- Hueneme Port in California used as a proxy for St. John's (similar port cargo load)

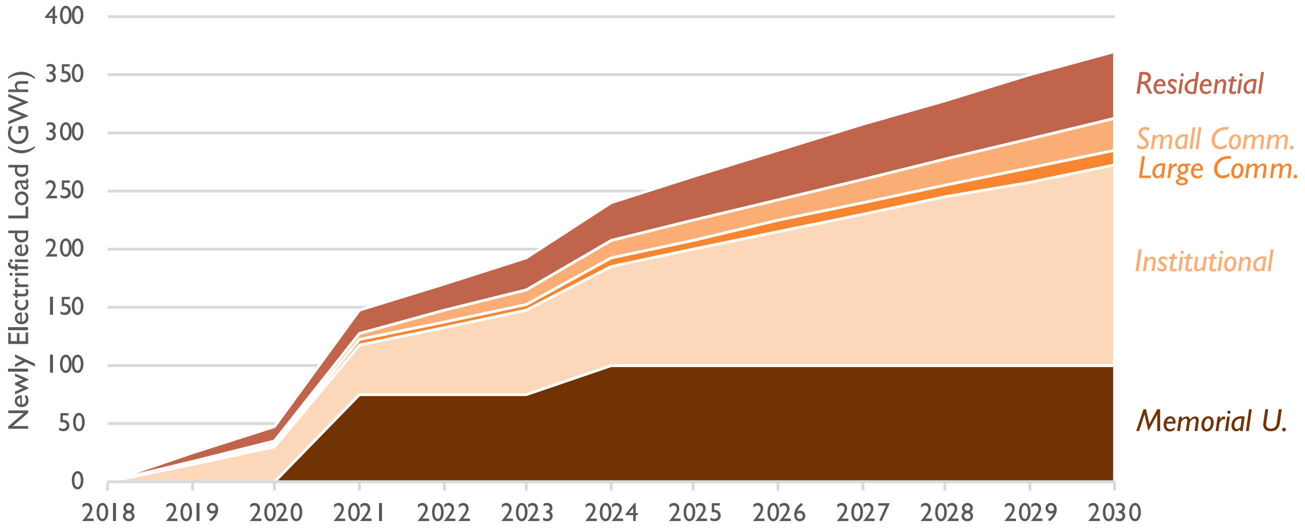
- Impacts to Island Interconnected and Labrador Interconnected systems scaled by population

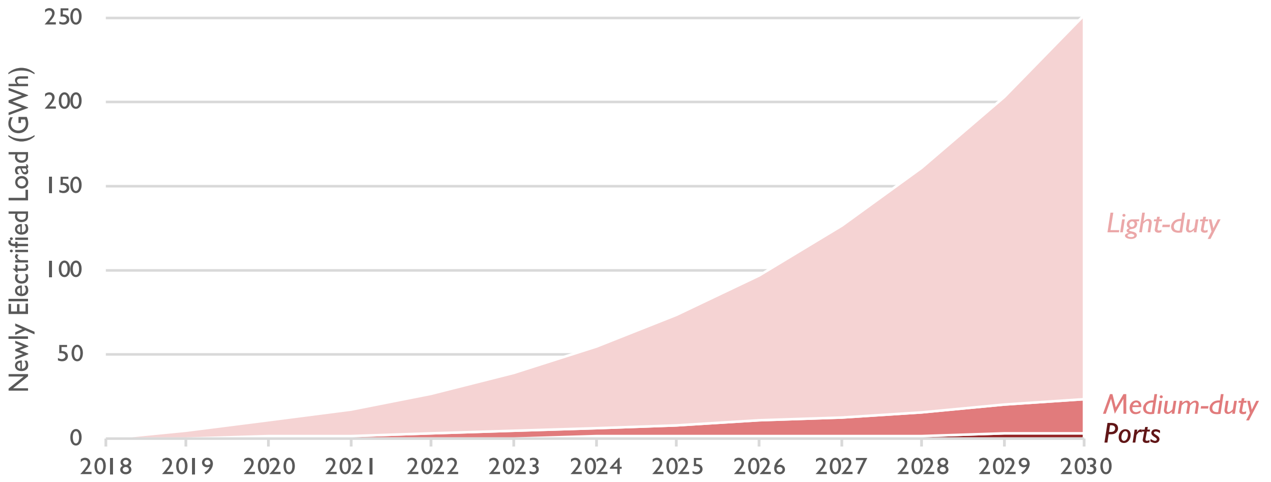
Electrification Cost Assumptions

- Calculation:
  - Mitigation is [electricity revenue minus utility program incentive costs (heat pumps and EVs) minus EV charging station costs]
  - Customer economics and overall energy expenditures also account for avoided fuel savings (oil and gasoline/diesel)
  - Non-inclusive of customer equipment costs

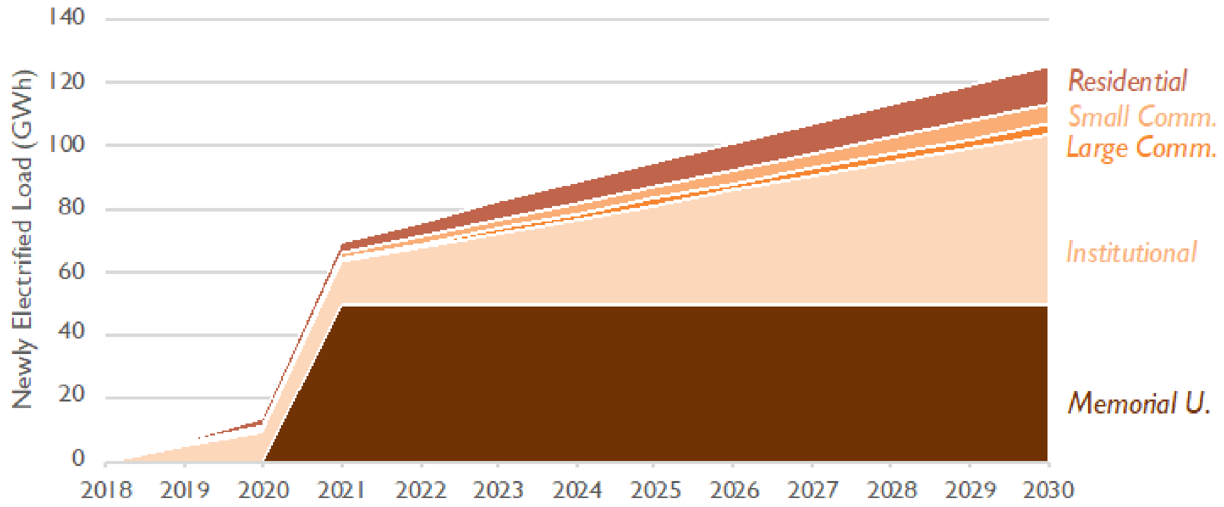
- Non-customer costs:
  - *Existing* federal EV incentive: $5,000 per EV
    - *Assumed* incentive step-downs after EVs reach 3% of LDV sales
  - *Assumed* heat pump incentive: $1,000 per ton (paid by utility and/or provincial government)
    - *Assumed* additional incentive for back-up heating system retention and integrated controls: $500 per ton (low scenario only)
  - Charging station costs (from Information Requests):
    - Level 2: $16,000 per charger
    - Fast-chargers: $150,000 per charger

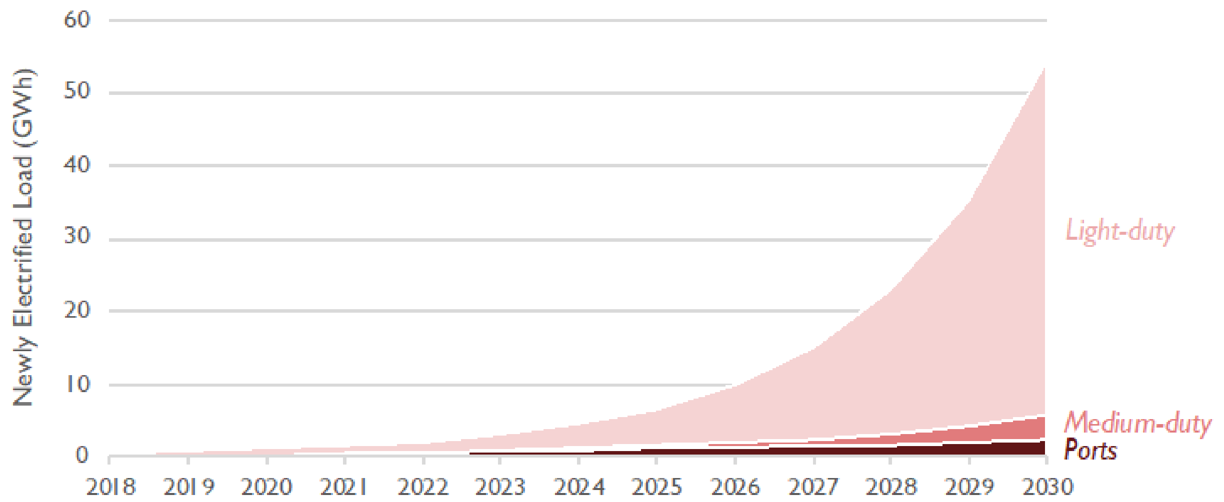
Electrification – Buildings and Transport, High Scenario





Electrification – Buildings and Transport, Low Scenario

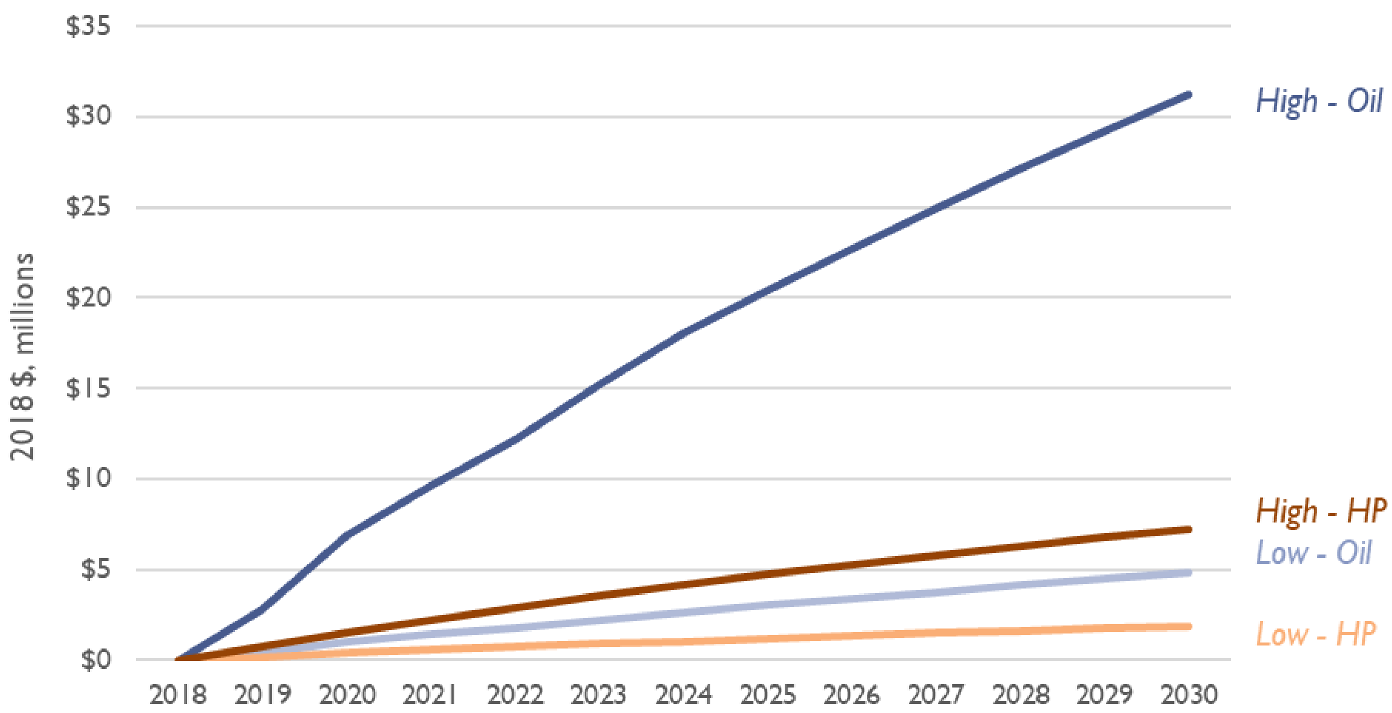




Cost Impacts to Residential Customers

- High scenario: high adoption of heat pumps (HP) and high cost of fuel (heating oil or electricity)
- Low scenario: low adoption of HPs and low cost of fuel

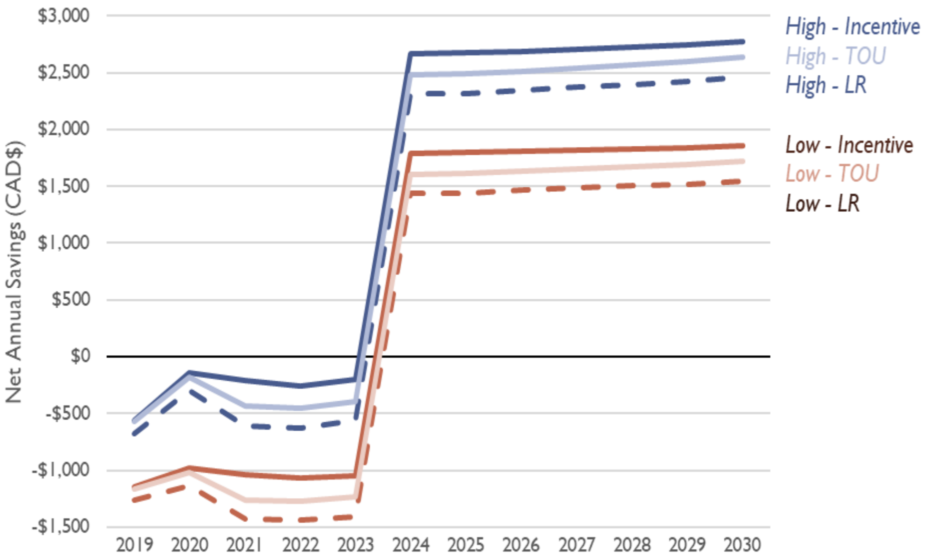
- In either scenario, HPs are less costly than oil heating for homeowners



Typical Single-EV Savings by Scenario and Rate Type

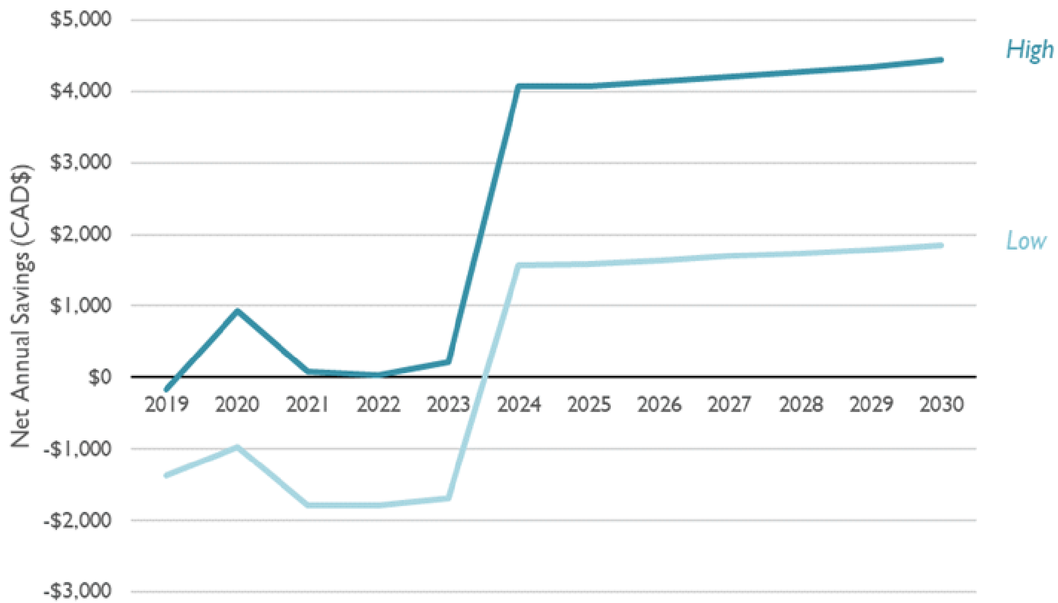
- Finance a new EV over 5 years at 5% interest

- High/low cases: High/low cost of gasoline
- Electric rate design or incentive rates have moderate impact on customer economics
- Does not include the $5,000 Federal EV incentive
- In either scenario, EVs offer lifetime savings to customers



Typical Single-Home Heat Pump Savings

- Finance a HP purchase over 5 years with NP loan product
- With high oil prices, net energy bill savings balance the loan payment, then customers see savings
- With low oil prices, it's closer to break-even over the life of the heating system



CDM and DR

CDM and Demand Response

- Key contribution of CDM and DR is to lower peak load and avoid capacity expansion (or retention) costs.
  - Peak load reduction directly valued in modeling, based on Hydro's marginal generation cost study.
- "Baseline" CDM reflects no change to current programs, minimal progression of heat pump uptake, savings embedded in Synapse forecast
  - Low and High Cases reflect incremental CDM and HP installation – GWh, MW peak savings estimates
- DR peak savings estimation separate – low and high
- All CDM and HP savings based on end-use model characterizing sectors and aggregate end uses, with technical savings and participation/adoption rates
  - RES, COM, IND sectors: dwelling type and comm. bldg. classification subsector
    - RES end uses: space heating, DHW, lighting, refrigeration, other
    - COM end uses: space heating, DHW, lighting, HVAC fans/pumps, other
    - IND end uses: motor/compressor/pump/fan, process, HVAC, lighting, other
- Costs
  - 7-year amortization
  - Based on estimated 1st year costs/kWh by end-use category, DR as $/kW
  - B/C estimates based on low avoided energy, high avoided capacity

CDM – Adoption Rates of Technologies, Low and High Scenarios

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

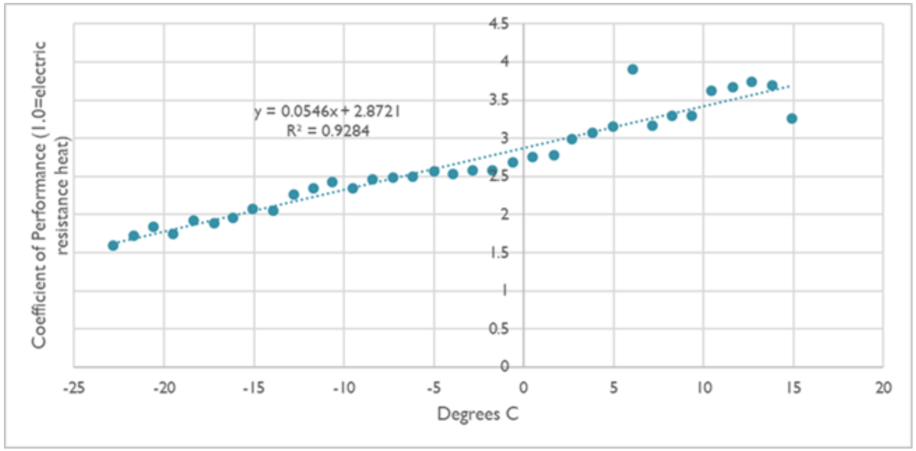
	Base		Low		High	
	2020	2030	2020	2030	2020	2030
Island						
RES	3.5%	39.5%	3.5%	44.0%	3.9%	52.6%
COM	1.6%	18.5%	1.6%	32.2%	1.8%	49.3%
IND	1.3%	14.5%	1.3%	25.8%	1.4%	40.1%
Labrador						
RES	2.0%	22.6%	2.0%	29.9%	2.0%	36.0%
COM	1.1%	12.7%	1.1%	22.1%	1.2%	33.9%
IND	1.3%	14.5%	1.3%	25.8%	1.4%	40.1%

Annual CDM Measure Adoption Rates for Residential CDM in IIS

Heat Pump Performance and Savings

- Heat pump characteristics and their contribution to total home heating needs are a critically important component of overall CDM effect.

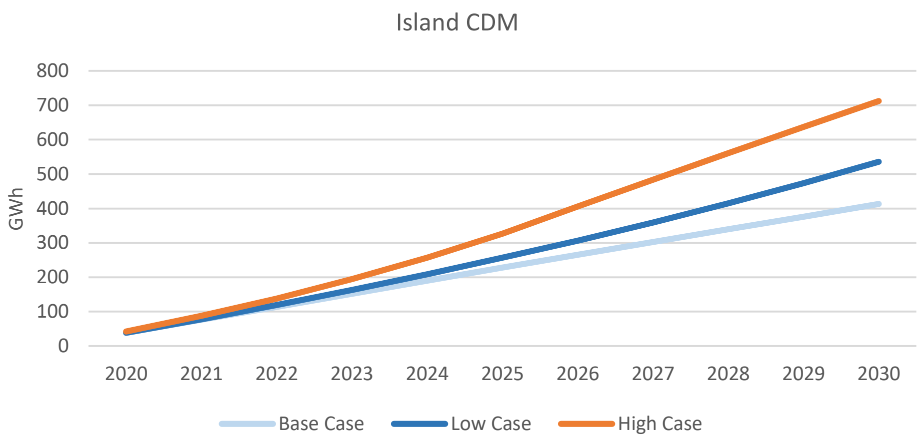
Cold climate heat pump COP - temperature curve

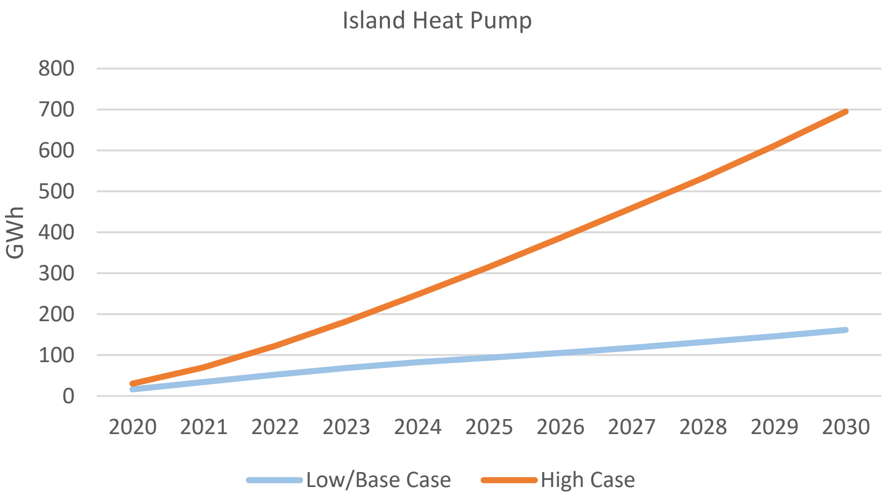


Heat Pump Savings Factors by Region

	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%

CDM and Heat Pump Summary Savings





IIS Capacity Balance and Export Sales

IIS Capacity Balance – Excluding Recall for IIS

- Balance without Recall Capacity available to IIS:

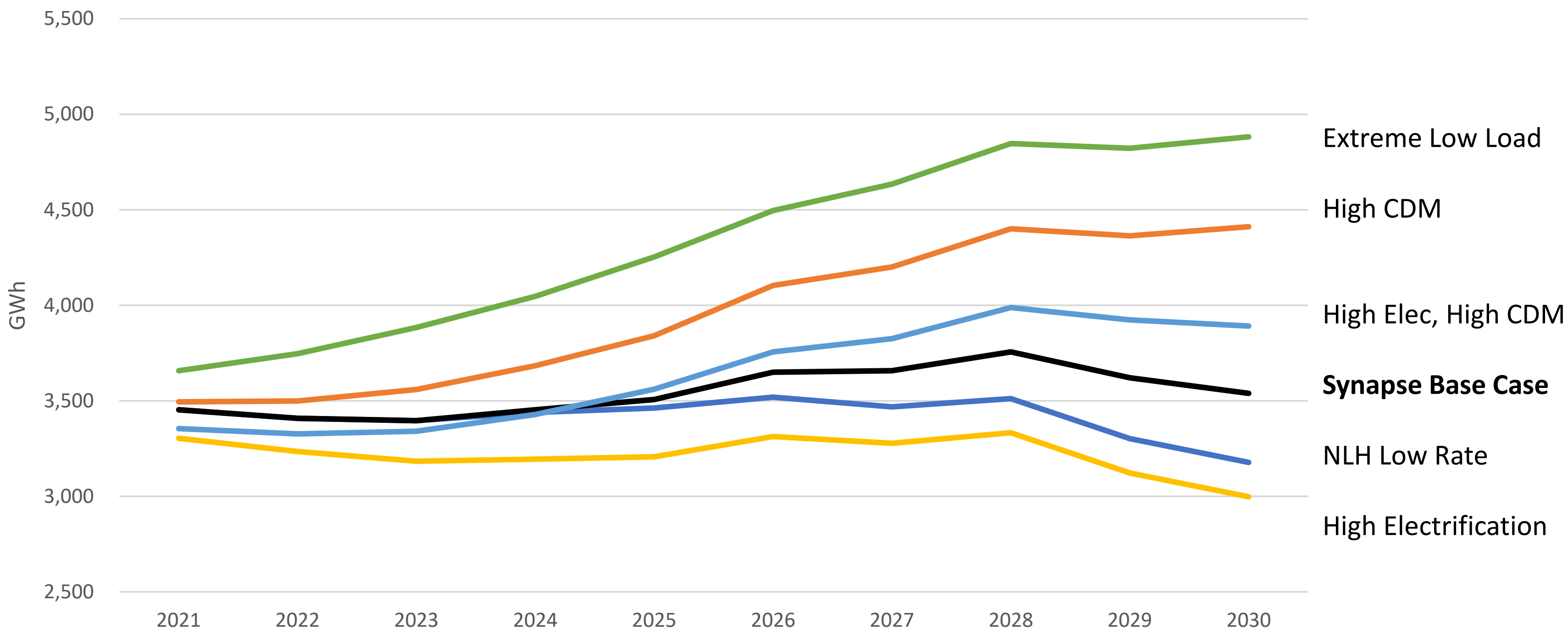
Island Load, Losses, Generation, and Labrador Island Link at Peak	Beginning of Year						
	2020	2021	2022	2023	2024	2025	2030
Island Peak Load (including self-supplied load)	1,662	1,657	1,659	1,663	1,662	1,663	1,664
Island Transmission Losses	141	141	141	141	141	141	141
Total Capacity Requirement	1,804	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

IIS Capacity Balance – Including Recall for IIS

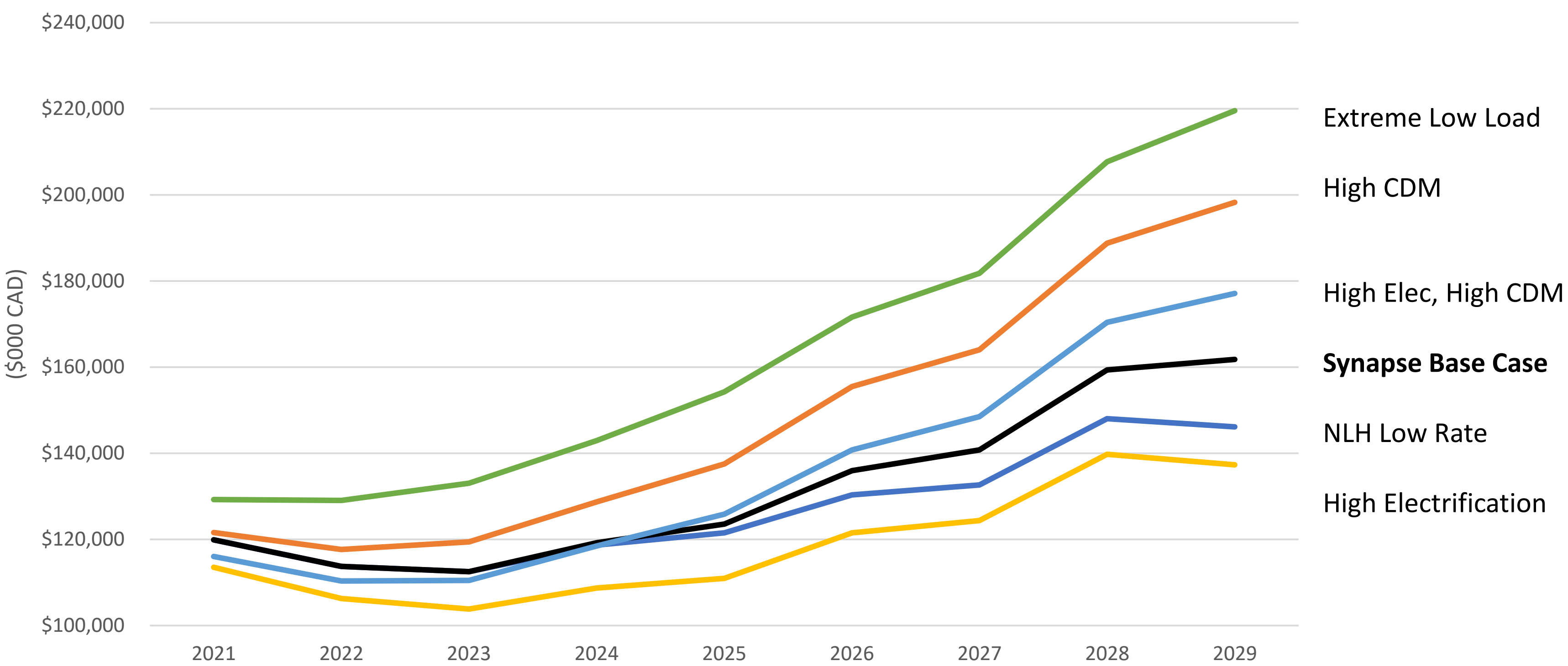
- Balance with Recall Capacity Available to IIS:

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

Export Sales Volumes by Selected Scenario



Export Sales Revenues by Selected Scenario



Rate Design

Rate Design

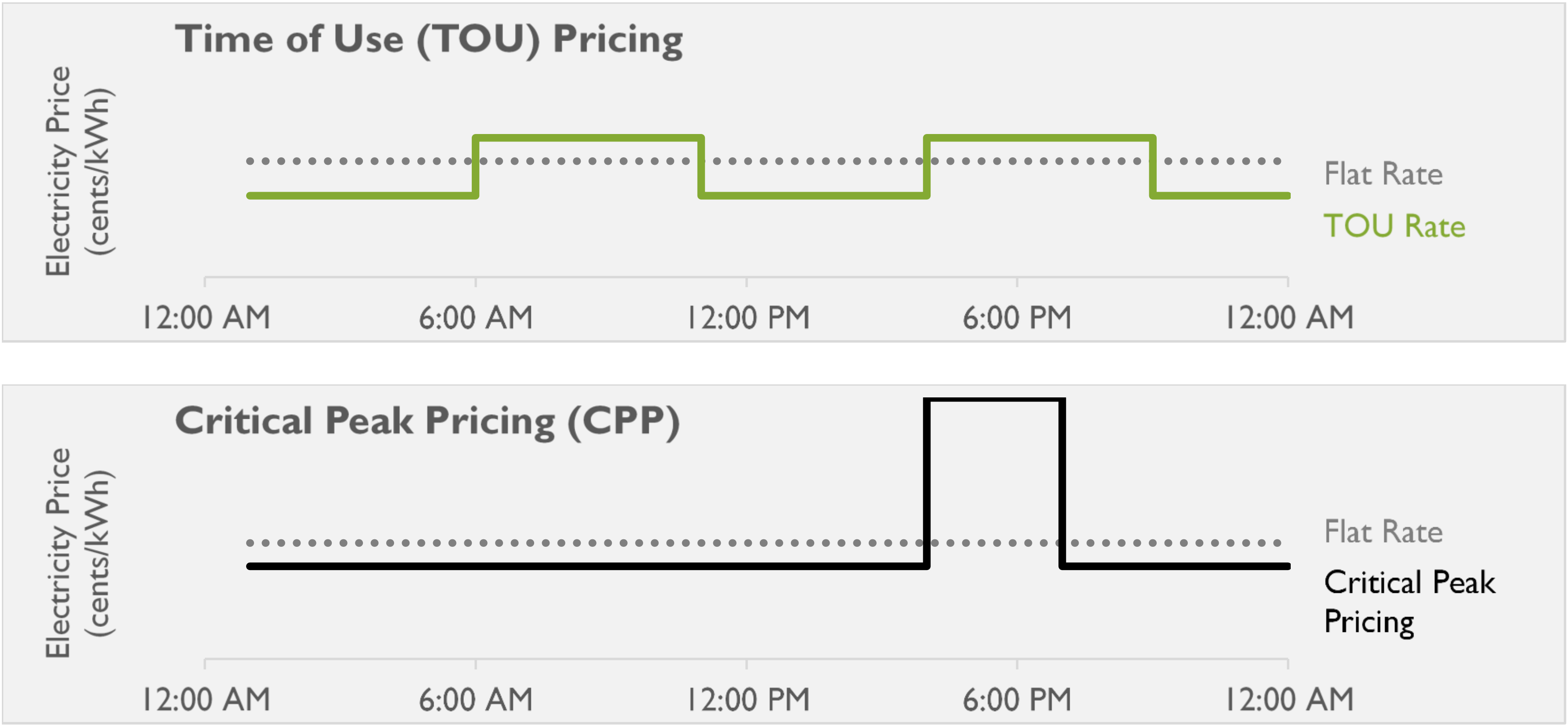
- Purpose of time-varying rates is to shape electricity loads to:
  - **<u>Maximize</u>** export revenues when market prices are high
  - **<u>Minimize</u>** peak demand to avoid the need to add capacity
  - **<u>Incent</u>** newly electrified load to consume off-peak

- Electricity prices should reflect marginal costs
  - Marginal cost of energy is based on the <u>opportunity cost</u> of selling in the export market
  - Marginal generation capacity and transmission capacity reflect cost of expanding system capacity to serve increased peak demand

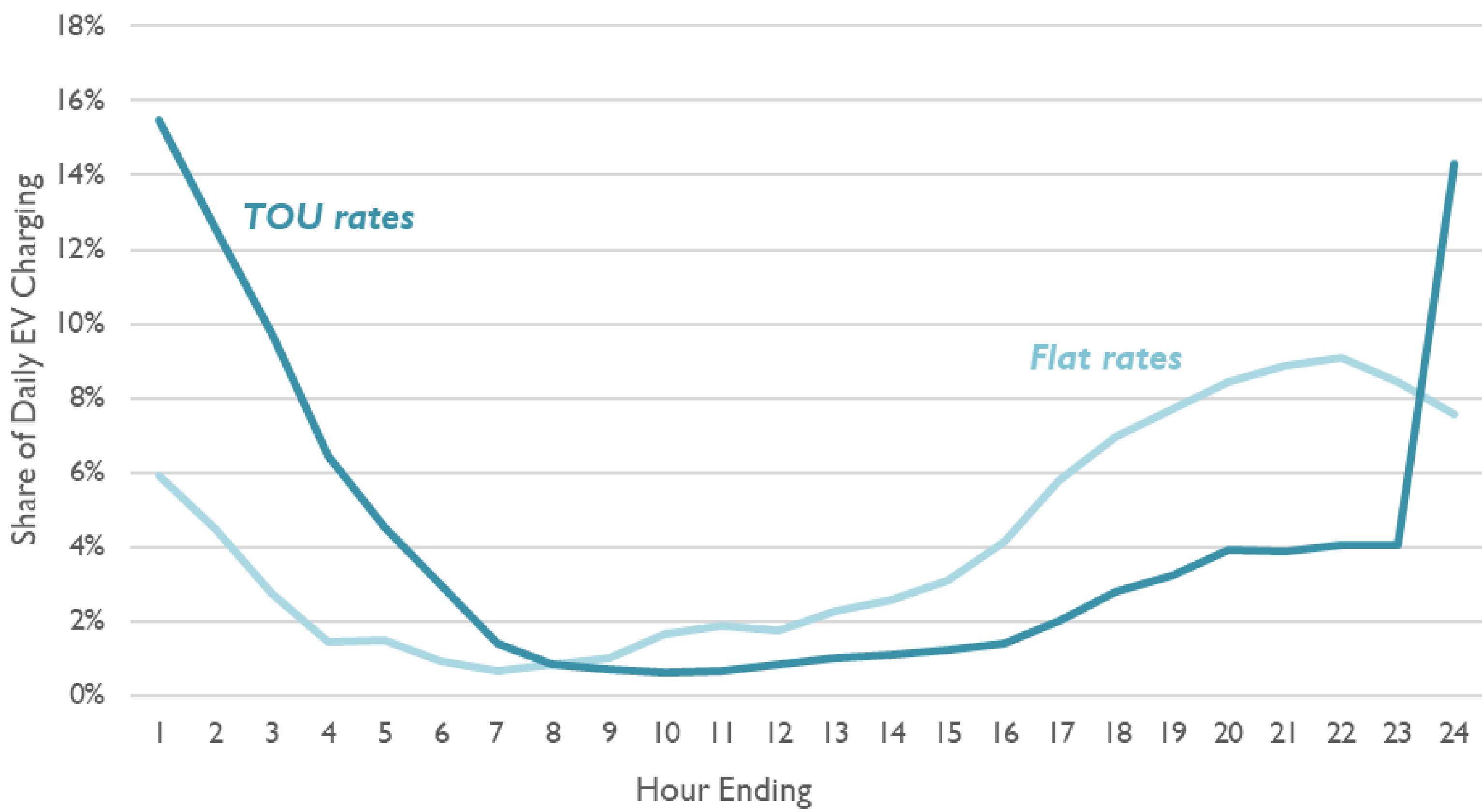
Rate Design in Analysis

- Rate Design - 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.
- Rate Options Considered:
  - TOU rates with CPP for all customers;
  - TOU rates for electric vehicle customers only using smart chargers; and
  - Lower-priced flat rates for charging electric vehicles to encourage transportation electrification.

Stylized TOU and CPP Pricing



EV Charging Profile – Flat and TOU Rates



Rate Design Observations

- TOU rates through smart charging infrastructure for EVs initially
  - No-regrets action:
    - EV load is substantial and easily shifted to off-peak hours.
    - Smart chargers are relatively low-cost.
    - Can help to incentivize transportation electrification.
- Eventually, could move to full AMI to broadly implement time-of-use rates.
  - Initial results show potential for net benefits.
  - A more detailed review of the costs and benefits of TOU with CPP is required to better gauge overall economics.
    - Obtain a more accurate, current estimate for AMI costs.
    - Determine and estimate value of other benefits are provided by AMI over current metering
    - Use pilots to test actual load responsiveness under both TOU and CPP.

Overall Observations & Next Steps

Overall Observations

1. High levels of policy-supported electrification & enhanced CDM: best overall rate and bill mitigation effect.
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 (cars, batteries, heat pumps).
3. CDM on the IIS complements and supports the electrification elements because it allows increases in export sales and mitigates the peak-load-increasing effect of electrification consumption in peak periods.
4. Rate design at the sectoral level (guided by high-level analyses here) – can lead to efficient price signaling.
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.
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.
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. However, closer examination of costs and benefits (relative to alternatives) is warranted.
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.

Next Steps

- The logical next steps, aligned with our major findings and observations, would include more detailed analysis on:
  - Development of electrification policies,
    - Including specific rate structures and levels that would apply for newly-electrifying load, and
    - The form of incentives that could be used for new equipment such as heat pumps, and
    - Plans to install EV chargers in a logical fashion across the Island.
  - Development of CDM programs, including initiatives to most efficiently and effectively increase the activity in the Province, e.g.,
    - Including standard approaches to enhancing CDM effects with careful attention to program design and equity across all customers;
    - Including demand response mechanisms – conventional industrial curtailment, and incremental peak load shaving using enabling control technologies (e.g., thermostats) and/or rate drivers such as CPP (for all, if AMI is developed); and
    - Including potential incentives for heat pumps that demonstrate increased performance, and/or for other technologies that can potentially be deployed to reduce peak load.
  - Investigation of rate design approaches that introduce at least an initial form of TOU pricing for new EV load and considers more extensive TOU and CPP approaches; and
  - Attention to Federal and Provincial policies that provide funding for building energy efficiency, fuel switching, and electric vehicle rebates.