Q. **Reference: Application, para. 8**

Regarding the $190,404,301 grant from the provincial government to Hydro for rate mitigation:

a) How does that grant show up, if at all, in Hydro's income/earnings statement or balance sheet?

b) Please provide Hydro's annual earnings for 2020, 2021 and 2022 in total and by business segment. If final figures are not yet available for 2022 then please provide estimates.

A. **a)** The grant from the provincial government has been included in the Rate Mitigation Fund Component of the Supply Cost Variance Deferral Account reducing the balance owing from customers.[1] The balance in the Supply Cost Variance Deferral Account is grouped with Regulatory Assets on the balance sheet, reducing the Regulatory Asset balance and increasing the cash balance.[2] There is no regulated Newfoundland and Labrador Hydro ("Hydro") income statement impact as a result of the receipt of the government grant.

b) Please refer to CA-NLH-005, Attachments 1 and 2 for a copy of Hydro's Annual Returns for 2020 and 2021, respectively. Hydro's Annual Return for 2022 is confidential pending its presentation in the House of Assembly of Newfoundland and Labrador, after which it will be provided to the required parties.

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[1] Please refer to CA-NLH-003, Attachment 2 for the March 2023 balances within the Supply Cost Variance Deferral Account.
[2] The cash will reduce future short-term borrowing requirements.

newfoundland labrador hydro
a nalcor energy company

Hydro Place. 500 Columbus Drive.
P.O. Box 12400. St. John's. NL
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April 1, 2021

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro's 2020 Annual Return

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") 2020 Annual Return filed pursuant to Section 59(2) of the *Public Utilities Act*.

Hydro's 2020 Annual Return is confidential pending its presentation in the House of Assembly of Newfoundland and Labrador. Once that presentation has occurred, Hydro will provide the documents to the required parties.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

ecc: **Board of Commissioners of Public Utilities**
Jacqui Glynn
PUB Official Email

2020 Annual Return

(Return 20 pursuant to Section 59(20) of the *Public Utilities Act)*

April 1, 2021

A report to the Board of Commissioners of Public Utilities

Contents

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2020

Deloitte.

Deloitte LLP
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St. John's NL A1E 0E4
Canada

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Independent Auditor's Report

To the Directors of Newfoundland and Labrador Hydro

Opinion

We have audited the non-consolidated financial statements of Newfoundland and Labrador Hydro (the "Company"), which comprise the non-consolidated statement of financial position as at December 31, 2020, and the non-consolidated statements of profit and comprehensive income, changes in equity and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying non-consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2020, and the results of its financial performance and its cash flows for the year then ended in accordance with the financial reporting provisions of Section 59 of the Public Utilities Act.

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Accounting

We draw attention to Note 2 to the non-consolidated financial statements, which describes the basis of accounting. The non-consolidated financial statements are prepared to assist the Company in complying with the financial reporting provisions of Section 59 of the Public Utilities Act. As a result, the non-consolidated financial statements may not be suitable for another purpose.

Other Matter

Newfoundland and Labrador Hydro has prepared separate consolidated financial statements for the year ended December 31, 2020 in accordance with International Financial Reporting Standards on which we issued an unmodified auditor's report to the Lieutenant-Governor in Council, Province of Newfoundland and Labrador dated March 5, 2021.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with the financial reporting provisions of Section 59 of the Public Utilities Act, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements
Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Deloitte LLP

Chartered Professional Accountants
March 5, 2021

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31 (millions of Canadian dollars)	Notes	**2020**	2019
ASSETS			
Current assets			
Cash		**28**	8
Trade and other receivables	5	**97**	131
Inventories	6	**92**	103
Prepayments		**8**	6
Deferred asset	7	**23**	9
Total current assets		**248**	257
Non-current assets			
Property, plant and equipment	8	**2,206**	2,199
Intangible assets	9	**7**	5
Right-of-use assets		**2**	2
Sinking fund investments	10	**183**	174
Investments in joint arrangements	11	**610**	584
Total assets		**3,256**	3,221
Regulatory deferrals	12	**172**	123
Total assets and regulatory deferrals		**3,428**	3,344
LIABILITIES AND EQUITY			
Current liabilities			
Short-term borrowings	14	**262**	233
Trade and other payables	13	**119**	143
Current portion of long-term debt	14	**7**	7
Derivative liability	23	**23**	9
Other current liabilities		**2**	2
Total current liabilities		**413**	394
Non-current liabilities			
Long-term debt	14	**1,765**	1,776
Deferred contributions	15	**21**	19
Decommissioning liabilities	16	**15**	14
Employee future benefits	18	**107**	101
Other long-term liabilities		**4**	2
Total liabilities		**2,325**	2,306
Shareholder's equity			
Share capital	19	**23**	23
Contributed capital	19	**146**	147
Reserves		**(22)**	(22)
Retained earnings		**939**	877
Total equity		**1,086**	1,025
Total liabilities and equity		**3,411**	3,331
Regulatory deferrals	12	**17**	13
Total liabilities, equity and regulatory deferrals		**3,428**	3,344

Commitments and contingencies (Note 25)

See accompanying notes

On behalf of the Board

DIRECTOR

DIRECTOR

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF PROFIT AND COMPREHENSIVE INCOME

For the year ended December 31 (millions of Canadian dollars)	Notes	**2020**	2019
Energy sales		**611**	657
Other revenue		**26**	25
Revenue		**637**	682
Fuels		**158**	217
Power purchased		**122**	130
Operating costs	20	**136**	141
Transmission rental		**21**	22
Depreciation and amortization		**79**	83
Net finance expense	21	**90**	90
Other expense	22	**4**	8
Expenses		**610**	691
Profit (loss) for the year from operations		**27**	(9)
Share of profit of joint arrangement	11	**25**	27
Preferred dividends		**8**	8
Profit before regulatory adjustments		**60**	26
Regulatory adjustments	12	**(15)**	(37)
Profit for the year		**75**	63
Other comprehensive income			
Items that may or have been reclassified to profit or loss			
Items related to employee future benefits		**(1)**	(8)
Total items that may be reclassified subsequently to profit or loss		**(1)**	(8)
Items that will not be reclassified subsequently to profit or loss			
Share of other comprehensive gain (loss) for the year		**1**	(1)
Total items that will not be reclassified subsequently to profit or loss		**1**	(1)
Other comprehensive income (loss) for the year		**-**	(9)
Total comprehensive income for the year		**75**	54

See accompanying notes

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(millions of Canadian dollars)	Note	Share Capital	Contributed Capital	Reserves	Retained Earnings	Total
Balance at January 1, 2020		**23**	**147**	**(22)**	**877**	**1,025**
Profit for the year		**-**	**-**	**-**	**75**	**75**
Total comprehensive income for the year		**-**	**-**	**-**	**75**	**75**
Regulatory adjustment	**19**	**-**	**(1)**	**-**	**-**	**(1)**
Dividends	**19**	**-**	**-**	**-**	**(13)**	**(13)**
Balance at December 31, 2020		**23**	**146**	**(22)**	**939**	**1,086**
Balance at January 1, 2019		23	147	(13)	822	979
Profit for the year		-	-	-	63	63
Other comprehensive loss		-	-	(9)	-	(9)
Total comprehensive (loss) income for the year		-	-	(9)	63	54
Contributed capital	19	-	1	-	-	1
Regulatory adjustment	19	-	(1)	-	-	(1)
Dividends	19	-	-	-	(8)	(8)
Balance at December 31, 2019		23	147	(22)	877	1,025

See accompanying notes

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31 (millions of Canadian dollars)	Notes	**2020**	2019
Operating activities			
Profit for the year		**75**	63
Adjustments to reconcile profit to cash provided from operating activities:			
Depreciation and amortization		**79**	83
Regulatory adjustments	12	**(15)**	(37)
Amortization of rate stabilization plan fuel credit		**24**	-
Share of profit of joint arrangement	11	**(25)**	(27)
Finance income	21	**(13)**	(12)
Finance expense	21	**103**	102
Other		**6**	14
		234	186
Changes in non-cash working capital balances	27	**21**	26
Interest received		**1**	1
Interest paid		**(103)**	(104)
Net cash provided from operating activities		**153**	109
Investing activities			
Additions to property, plant and equipment		**(88)**	(126)
Contributions to sinking funds	10	**(7)**	(7)
Changes in non-cash working capital balances	27	**(2)**	(5)
Net cash used in investing activities		**(97)**	(138)
Financing activities			
Dividends paid	19	**(13)**	(8)
Rate stabilization plan fuel credit		**(55)**	-
Increase in short-term borrowings		**29**	44
Other		**3**	1
Net cash (used in) provided from financing activities		**(36)**	37
Net increase in cash		**20**	8
Cash, beginning of the year		**8**	-
Cash, end of the year		**28**	8

See accompanying notes

1. DESCRIPTION OF BUSINESS

Newfoundland and Labrador Hydro (Hydro or the Company) is incorporated under a special act of the Legislature of the Province of Newfoundland and Labrador (the Province). The principal activity of Hydro is the generation, transmission and sale of electricity. Hydro's operations include both regulated and non-regulated activities. Hydro is a 100% owned subsidiary of Nalcor Energy (Nalcor). Hydro's head office is located at 500 Columbus Drive in St. John's, Newfoundland and Labrador, A1B 0C9, Canada.

Hydro holds interests in the following entities:

A 65.8% interest in Churchill Falls (Labrador) Corporation Limited (Churchill Falls). Churchill Falls is incorporated under the laws of Canada and owns and operates a hydroelectric generating plant and related transmission facilities situated in Labrador which has a rated capacity of 5,428 megawatts (MW).

A 51.0% interest in Lower Churchill Development Corporation (LCDC), an inactive subsidiary. LCDC is incorporated under the laws of Newfoundland and Labrador and was established with the objective of developing all or part of the hydroelectric potential of the Lower Churchill River.

2. SIGNIFICANT ACCOUNTING POLICIES

2.1 Statement of Compliance and Basis of Measurement

These annual audited non-consolidated financial statements (financial statements) have been prepared in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB) with the exception of Hydro's investments in joint arrangements and related disclosures. These statements are non-consolidated as the investments in joint arrangements have been accounted for using the equity method of accounting, as described in Note 2.8. Consolidated statements for the same period have been prepared for presentation to the Lieutenant Governor in Council of the Province.

These financial statements have been prepared on a historical cost basis, except for financial instruments at fair value through profit or loss (FVTPL) which have been measured at fair value. The financial statements are presented in Canadian Dollars (CAD) and all values rounded to the nearest million, except when otherwise noted. The financial statements were approved by Hydro's Board of Directors (the Board) on March 5, 2021.

2.2 Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents consist of amounts on deposit with Schedule 1 Canadian Chartered banks, as well as highly liquid investments with maturities of three months or less. Investments with maturities greater than three months and less than twelve months are classified as short-term investments.

2.3 Inventories

Inventories are carried at the lower of cost and net realizable value. Cost is determined on a weighted average basis and includes expenditures incurred in acquiring inventories and bringing them to their existing condition and location. Net realizable value represents the estimated selling price for inventories less all estimated costs of completion and costs necessary to make the sale.

2.4 Property, Plant and Equipment

Items of property, plant and equipment are recognized at cost less accumulated depreciation and accumulated impairment losses. Cost includes materials, labour, contracted services, professional fees and, for qualifying assets, borrowing costs capitalized in accordance with Hydro's accounting policy outlined in Note 2.6. Costs capitalized with the related asset include all those costs directly attributable to bringing the asset into operation.

When significant parts of property, plant and equipment are required to be replaced at intervals, Hydro recognizes such parts as individual assets with specific useful lives and depreciation rates. Likewise, when a major inspection is performed, its cost is recognized in the carrying amount of the asset as a replacement if the recognition criteria are satisfied. All other repairs and maintenance costs are recognized in profit or loss as incurred.

Depreciation commences when the assets are ready for their intended use. Residual values and useful lives are reviewed at the end of each year and adjusted prospectively, if appropriate. As per Board Order P.U. 30 (2019), Hydro was approved to recover gains and losses through accumulated amortization and to record removal costs through depreciation. To comply with International Accounting Standard (IAS) - 16, the adjustments related to the recovery of gains and losses through accumulated amortization and removal depreciation are presented as a regulatory adjustment in Note 12. The depreciation rates used are as follows:

Generation plant	
Hydroelectric	25 to 110 years
Thermal	20 to 70 years
Diesel	3 to 70 years
Transmission	
Lines	26 to 65 years
Terminal stations	20 to 60 years
Distribution system	20 to 60 years
Other assets	5 to 70 years

Hydroelectric generation plant includes the powerhouse, turbines, governors and generators, as well as water conveying and control structures, including dams, dikes, tailraces, penstocks and intake structures. Thermal generation plant is comprised of the powerhouse, turbines and generators, boilers, oil storage tanks, stacks, and auxiliary systems. Diesel generation plant includes the buildings, engines, generators, switchgear, fuel storage and transfer systems, dikes and liners and cooling systems.

Transmission lines include the support structures, foundations and insulators associated with lines at voltages of 230, 138 and 69 kilovolt (kV). Terminal station assets are used to step up voltages of electricity for transmission and to step down voltages for distribution. Distribution system assets include poles, transformers, insulators, and conductors.

Other assets include telecontrol, buildings, vehicles, furniture, tools and equipment.

2.5 Intangible Assets

Intangible assets that are expected to generate future economic benefit and are measurable, including computer software costs and feasibility studies, are capitalized as intangible assets in accordance with IAS 38.

Intangible assets with finite useful lives are carried at cost less accumulated amortization and accumulated impairment losses. The estimated useful life and amortization method are reviewed at the end of each year with the effect of any changes in estimate being accounted for on a prospective basis. Intangible assets with indefinite useful lives are carried at cost less accumulated impairment losses.

Amortization is calculated on a straight-line basis over the estimated useful lives of the assets as follows:

Feasibility studies	22 years
Computer software	7 years

2.6 Borrowing Costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale. Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization. All other borrowing costs are recognized in the Non-Consolidated Statement of Profit and Comprehensive Income in the period in which they are incurred.

2.7 Impairment of Non-Financial Assets

Property, plant and equipment and other non-financial assets are reviewed for impairment losses whenever events or changes in circumstances indicate that the carrying amount may not be recoverable.

Where it is not possible to estimate the recoverable amount of an individual asset, Hydro estimates the recoverable amount of the cash generating unit (CGU) to which the asset belongs. The recoverable amount is the higher of fair value less costs of disposal and value in use. Value in use is generally computed by reference to the present value of future cash flows expected to be derived from non-financial assets. In assessing value in use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset or CGU is estimated to be less than its carrying amount, the carrying amount of the asset or CGU is reduced to its recoverable amount and an impairment loss is recognized immediately in the Non-Consolidated Statement of Profit and Comprehensive Income.

2.8 Investments in Joint Arrangements

A joint arrangement is an arrangement in which two or more parties involved have joint control. Control exists when Hydro has the power, directly or indirectly, to govern the financial and operating policies of another entity, so as to obtain benefits from its activities. A joint arrangement is either classified as a joint operation or a joint venture based on the rights of the parties involved. Hydro's investment in Churchill Falls is classified as a joint operation.

Hydro's investment in Churchill Falls is recorded using the equity method of accounting. Under the equity method, the interest in the investment is carried in the Non-Consolidated Statement of Financial Position at cost plus post acquisition changes in Hydro's share of net assets of the investment. The Non-Consolidated Statement of Profit and Comprehensive Income reflects the share of the profit or loss of the joint operation.

2.9 Employee Future Benefits

(i) Pension Plan

Employees participate in the Province's Public Service Pension Plan (Plan), a multi-employer defined benefit plan. Contributions by Hydro to this Plan are recognized as an expense when employees have rendered service entitling them to the contributions. Liabilities associated with this Plan are held with the Province.

(ii) Other Benefits

Hydro provides group life insurance and health care benefits on a cost-shared basis to retired employees, in addition to a retirement allowance.

The cost of providing these benefits is determined using the projected unit credit method, with actuarial valuations being completed on an annual basis, based on service and Management's best estimate of salary escalation, retirement ages of employees and expected health care costs.

Actuarial gains and losses on Hydro's defined benefit obligation are recognized in reserves in the period in which they occur. Past service costs are recognized in operating costs as incurred. Pursuant to Board Order No. P.U. 36 (2015), Hydro recognizes the amortization of employee future benefit actuarial gains and losses in the Non-Consolidated Statement of Profit and Comprehensive Income as a regulatory adjustment.

The retirement benefit obligation recognized in the Non-Consolidated Statement of Financial Position represents the present value of the defined benefit obligation.

2.10 Provisions

A provision is a liability of uncertain timing or amount. A provision is recognized if Hydro has a present legal obligation or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount can be reliably estimated. Provisions are not recognized for future operating losses. The provision is measured at the present value of the best estimate of the expenditures expected to be required to settle the obligation using a discount rate that reflects the current market assessments of the time value of money and the risks specific to the obligation. Provisions are re-measured at each Non-Consolidated Statement of Financial Position date using the current discount rate.

2.11 Decommissioning, Restoration and Environmental Liabilities

Legal and constructive obligations associated with the retirement of property, plant and equipment are recorded as liabilities when those obligations are incurred and are measured as the present value of the expected costs to settle the liability, discounted at a rate specific to the liability. The liability is accreted up to the date the liability will be incurred with a corresponding charge to net finance expense. The carrying amount of decommissioning, restoration and environmental liabilities is reviewed annually with changes in the estimates of timing or amount of cash flows added to or deducted from the cost of the related asset or expensed in the Non-Consolidated Statement of Profit and Comprehensive Income if the liability is short-term in nature.

2.12 Revenue from Contracts with Customers

Hydro recognizes revenue from contracts with customers related to the sale of electricity to regulated Provincial industrial, utility and direct customers in rural Newfoundland and Labrador and to non-regulated industrial, utility and external market customers.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Hydro recognizes revenue when it transfers control of a product or service to a customer.

Revenue from the sale of energy is recognized when Hydro satisfies its performance obligation by transferring energy to the customer. Sales within the Province are primarily at rates approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB), whereas export sales and sales to other certain major industrial customers are either at rates under the terms of the applicable contracts, or at market rates. Hydro recognizes revenue at the amount to which it has the right to invoice, which corresponds directly to the value of Hydro’s performance to date.

2.13 Leasing

<u>Lessee Accounting</u>

Hydro assesses whether a contract is or contains a lease, at inception of a contract. Hydro recognizes a right-of-use asset and a corresponding lease liability with respect to all lease agreements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low-value assets. For these leases, Hydro recognizes the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, Hydro uses its incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise:

- Fixed (and in-substance) lease payments less any lease incentives;
- variable lease payments that depend on an index or rate; and
- payments expected under residual value guarantees and payments relating to purchase options and renewal option periods that are reasonably certain to be exercised (or periods subject to termination options that are not reasonably certain to be exercised).

The lease liability is subsequently measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured, with a corresponding adjustment to the related right-of-use assets, when there is a change in variable lease payments arising from a change in an index or rate, or when Hydro changes its assessment of whether purchase, renewal or termination options will be exercised. Hydro did not make any such adjustments during the periods presented.

The right-of-use assets comprise the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and accumulated impairment losses.

Whenever Hydro incurs an obligation for costs to dismantle and remove a leased asset, restore the site on which it is located or restore the underlying asset to the condition required by the terms and conditions of the lease, a provision is recognized and measured under *IAS 37 – Provisions, Contingent Liabilities and Contingent Assets*. The costs are included in the related right-of-use asset.

Right-of-use assets are depreciated over the shorter period of the lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that Hydro expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. Depreciation starts at the commencement date of the lease.

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognized as an expense in operating costs in the period in which the event or condition that triggers those payments occurs.

As a practical expedient, IFRS 16 permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement. Hydro has elected to apply this practical expedient.

2.14 Foreign Currencies

Transactions in currencies other than Hydro’s functional currency (foreign currencies) are recognized using the exchange rate in effect at the date of transaction, approximated by the prior month end close rate. At the end of each reporting period, monetary items denominated in foreign currencies are translated at the rates of exchange in effect at the period end date. Foreign exchange gains and losses not included in regulatory deferrals are recorded in the Non-Consolidated Statement of Profit and Comprehensive Income as other expense.

2.15 Income Taxes

Hydro is exempt from paying income taxes under Section 149(1) (d.2) of the Income Tax Act.

2.16 Financial Instruments

Classification and Initial Measurement
Financial assets and financial liabilities are recognized in the Non-Consolidated Statement of Financial Position when Hydro becomes a party to the contractual provisions of the instrument and are initially measured at fair value.

Financial assets are classified at amortized cost, fair value through other comprehensive income (FVTOCI), FVTPL or as derivatives designated as hedging instruments in an effective hedge. Financial liabilities are classified at FVTPL, amortized cost or as derivatives designated as hedging instruments in an effective hedge. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities (other than financial assets and financial liabilities at FVTPL) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at FVTPL are recognized immediately in profit or loss.

Financial Assets at Amortized Cost
Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows are subsequently measured at amortized cost using the effective interest rate method and are subject to impairment. Gains and losses are recognized in profit or loss when the asset is derecognized, modified or impaired.

Hydro's financial assets at amortized cost include cash, trade and other receivables and sinking fund investments.

Financial assets at FVTPL
Financial assets that do not meet the criteria for being measured at amortized cost or FVTOCI are measured at FVTPL. Financial assets at FVTPL are measured at fair value at the end of each reporting period, with any fair value gains or losses recognized in profit or loss to the extent they are not part of a designated hedging relationship.

Financial Liabilities at Amortized Cost
Hydro subsequently measures all financial liabilities at amortized cost using the effective interest method. Gains and losses are recognized in profit or loss when the liability is derecognized.

Hydro's financial liabilities at amortized cost include trade and other payables, short-term borrowings and long-term debt.

Derivative Instruments
Derivative instruments are utilized by Hydro to manage risk. Hydro's policy is not to utilize derivative instruments for speculative purposes. Derivatives are initially measured at fair value at the date the derivative contracts are entered into and are subsequently measured at their fair value at the end of each reporting period. The resulting gain or loss is recognized in profit or loss immediately unless the derivative is designed and effective as a hedging relationship.

Derecognition of Financial Instruments
Hydro derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another party.

Hydro derecognizes financial liabilities when, and only when, its obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognized and the consideration paid and payable is recognized in profit or loss.

Impairment of Financial Assets
Hydro recognizes a loss allowance for expected credit losses (ECL) on investments in debt instruments that are measured at amortized cost or at FVTOCI. The amount of ECL is updated at each reporting date to reflect changes in credit risk since initial recognition of the respective financial instrument.

Hydro always recognizes lifetime ECL for trade and other receivables. The ECL on these financial assets are estimated based on Hydro's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate. Hydro also records 12-month ECL for those financial assets which have low credit risk and where the low credit risk exemption has been applied. The classes of financial assets that have been identified to have low credit risk are cash and sinking funds.

For all other financial instruments, Hydro recognizes lifetime ECL when there has been a significant increase in credit risk since initial recognition. If, on the other hand, the credit risk on the financial instrument has not increased significantly since initial recognition, Hydro measures the loss allowance for that financial instrument at an amount equal to 12-month ECL. The assessment of whether lifetime ECL should be recognized is based on significant increases in the likelihood or risk of a default occurring since initial recognition instead of on evidence of a financial asset being credit-impaired at the reporting date or an actual default occurring.

Lifetime ECL represents the ECL that will result from all possible default events over the expected life of a financial instrument. In contrast, 12-month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

2.17 Government Grants

Government grants are recognized when there is reasonable assurance that Hydro will comply with the associated conditions and that the grants will be received.

Government grants are recognized in profit or loss on a systematic basis over the periods in which Hydro recognizes as expenses the related costs for which the grants are intended to compensate. Specifically, government grants whose primary condition is that Hydro should purchase, construct or otherwise acquire non-current assets are recognized as deferred revenue in the Non-Consolidated Statement of Financial Position and transferred to the Non-Consolidated Statement of Profit and Comprehensive Income on a systematic and rational basis over the useful lives of the related assets.

Government grants that are receivable as compensation for expenses or losses already incurred or for the purpose of giving immediate financial support to Hydro with no future related costs are recognized in the Non-Consolidated Statement of Profit and Comprehensive Income in the period in which they become receivable.

2.18 Regulatory Deferrals

Hydro's revenues from its electrical sales to most customers within the Province are subject to rate regulation by the PUB. Hydro's borrowing and capital expenditure programs are also subject to review and approval by the PUB. Rates are set through periodic general rate applications utilizing a cost of service methodology. Hydro's allowed rate of return on rate base based upon Board Order No. P.U. 30 (2019) is 5.4% in 2020 and 5.4% in 2019. Hydro applies various regulator approved accounting policies that differ from enterprises that do not operate in a rate regulated environment. Generally, these policies result in the deferral and amortization of costs or credits which are expected to be recovered or refunded in future rates. In the absence of rate regulation, these amounts would be included in the determination of profit or loss in the year the amounts are incurred. The effects of rate regulation on the financial statements are disclosed in Note 12.

3. SIGNIFICANT ACCOUNTING JUDGMENTS, ESTIMATES AND ASSUMPTIONS

The preparation of the financial statements in conformity with IFRS requires Management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ materially from these estimates, including changes as a result of future decisions made by the PUB. The estimates and underlying assumptions are reviewed on an on-going basis. Revisions to accounting estimates are recognized in the period in which the estimate is reviewed if the revision affects only that period or future periods.

The World Health Organization declared the Coronavirus disease (COVID-19) outbreak a Public Health Emergency of International Concern on January 30, 2020 and a pandemic on March 11, 2020. In order to mitigate the spread of COVID-19 there have been global restrictions on travel, quarantines, self-isolation, social and physical distancing and forced closure of certain types of public places and non-essential businesses. These actions have caused and continue to cause disruption to operations and economic uncertainty.

COVID-19 is an evolving situation that may have widespread implications for the Company's environment, operations and financial results. For the year ended December 31, 2020, COVID-19 did not have a significant impact on the Company's results of operations, but has resulted in delays in capital spending. At this time, Management cannot reasonably estimate the duration and magnitude of the COVID-19 impact on the economy and future effect on the Company.

3.1 Use of Judgments

(i) Property, Plant and Equipment
Hydro's accounting policy relating to property, plant and equipment is described in Note 2.4. In applying this policy, judgment is used in determining whether certain costs are additions to the carrying amount of the property, plant and equipment as opposed to repairs and maintenance. If an asset has been developed, judgment is required to identify the point at which the asset is capable of being used as intended and to identify the directly attributable borrowing costs to be included in the carrying value of the development asset. Judgment is also used in determining the appropriate componentization structure for Hydro's property, plant and equipment.

(ii) Revenue
Management exercises judgment in estimating the value of electricity consumed by retail customers in the period, but billed subsequent to the end of the reporting period. Specifically, this involves an estimate of consumption for each retail customer, based on the customer's past consumption history.

When recognizing deferrals and related amortization of costs or credits in Hydro Regulated, Management assumes that such costs or credits will be recovered or refunded through customer rates in future years. Recovery of some of these deferrals is subject to a future PUB order. As such, there is a risk that some or all of the regulatory deferrals will not be approved by the PUB which could have a material impact on Hydro Regulated's profit or loss in the year the order is received.

(iii) Determination of CGUs
Hydro's accounting policy relating to impairment of non-financial assets is described in Note 2.7. In applying this policy, Hydro groups assets into the smallest identifiable group for which cash flows are largely independent of the cash flows from other assets or groups of assets. Judgment is used in determining the level at which cash flows are largely independent of other assets or groups of assets.

(iv) Discount Rates
Certain of Hydro's financial liabilities are discounted using discount rates that are subject to Management's judgment.

(v) Leases

Definition of a lease
At inception of a contract, Hydro assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, Hydro assesses whether the contract involves the use of an identified asset, Hydro has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use and Hydro has the right to direct the use of the asset.

Lease extension and termination options
In determining the lease term, Hydro considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. The assessment is reviewed if a significant event or a significant change in circumstances occurs within its control. The assessment requires the consideration of facts and circumstances such as contractual terms and conditions for option periods, significant leasehold improvements undertaken, costs to terminate the lease, the importance of the asset to the lessee's operations and past practice.

(vi) Regulatory adjustments
Regulatory assets and liabilities recorded in Hydro arise due to the rate setting process for regulated utilities governed by the PUB. The amounts relate to costs or credits which Management believes will be recovered or settled through customer rates in future periods, pursuant to the proceedings and outcomes of future PUB orders. Certain estimates are necessary since the regulatory environment often requires amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the PUB for deferral as regulatory assets and liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates could have a material impact and are recognized in profit or loss in the period in which they become known.

3.2 Use of Estimates

(i) Property, Plant and Equipment
Amounts recorded for depreciation are based on the useful lives of Hydro's assets. The useful lives of property, plant and equipment are determined by independent specialists and reviewed annually by Hydro. These useful lives are Management's best estimate of the service lives of these assets. Changes to these lives could materially affect the amount of depreciation recorded.

(ii) Decommissioning Liabilities
Hydro recognizes a liability for the fair value of the future expenditures required to settle obligations associated with the retirement of property, plant and equipment. Decommissioning liabilities are recorded as a liability at fair value, with a corresponding increase to property, plant and equipment. Accretion of decommissioning liabilities is included in the Non-Consolidated Statement of Profit and Comprehensive Income through net finance expense. Differences between the recorded decommissioning liabilities and the actual decommissioning costs incurred are recorded as a gain or loss in the settlement period.

(iii) Employee Future Benefits
Hydro provides group life insurance and health care benefits on a cost-shared basis to retired employees, in addition to a severance payment upon retirement. The expected cost of providing these other employee benefits is accounted for on an accrual basis, and has been actuarially determined using the projected unit credit method prorated on service, and Management's best estimate of salary escalation, retirement ages of employees and expected health care costs.

(iv) Leases incremental borrowing rate
Hydro uses its incremental borrowing rates in measuring its lease liabilities. The incremental borrowing rate is the rate of interest that a lessee would have to pay to borrow over a similar term, and with a similar security, the funds necessary to obtain an asset of a similar value to the right-of-use asset in a similar economic environment. The determination of the incremental borrowing rate requires the consideration of different components, all of which are to incorporate a number of important lease characteristics.

3.3 Use of Assumptions

Deferred Assets and Derivative Liabilities

Effective October 1, 2015, Hydro entered into a power purchase agreement (PPA) with Nalcor Energy Marketing Corporation (Energy Marketing) which allows for the purchase of available recapture energy from Hydro for resale by Energy Marketing in export markets or through agreements with counterparties. Additionally, the PPA allows for the use of Hydro's transmission service rights by Energy Marketing to deliver electricity, through rights which are provided to Hydro pursuant to a Transmission Service Agreement with Hydro-Québec dated April 1, 2009. In September 2016, the terms of the PPA were amended to require a 60 day termination notice by either party. This replaced the previous termination clause of 90 days prior to the end of the operating year. Management's assumption is that the term of the PPA at December 31, 2020, will continue for at least the next 9 months.

Fair values relating to Hydro's financial instruments and derivatives that have been classified as Level 3 have been determined using inputs for the assets or liabilities that are not readily observable. Certain of these fair values are classified as Level 3 as the transactions do not occur in an active market, or the terms extend beyond the period for which a quoted price is available.

Hydro's PPA with Energy Marketing is accounted for as a derivative instrument, where Hydro determines that the fair value at initial recognition differs from the transaction price and the fair value is evidenced neither by a quoted price in an active market for an identical asset or liability nor based on a valuation technique that uses only data from observable markets. These derivative transactions are initially measured at fair value and the expected difference is deferred. Subsequently, the deferred difference is recognized in other comprehensive income (loss) on an appropriate basis over the life of the related derivative instrument but not later than when the valuation is wholly supported by observable market data or the transaction has occurred.

Hydro has elected to defer the difference between the fair value of the power purchase derivative liability upon initial recognition and the transaction price of the power purchase derivative liability and to amortize the deferred asset on a straight-line basis over its effective term (Note 7). These methods, when compared with alternatives, were determined by Management to most accurately reflect the nature and substance of the transactions.

4. CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

The following is a list of standards/interpretations that have been issued and are effective for accounting periods commencing on or after January 1, 2020, as specified.

- *IAS 1 – Presentation of Financial Statements*[1] *and IAS 8 – Accounting Policies, Changes in Accounting Estimates and Errors*[1] *(Amendments to IAS 1 and IAS 8)*
- *IFRS 16 – Leases – COVID-19 Related Rent Concessions (Amendment to IFRS 16)*[2]
- *IAS 16 – Property, Plant and Equipment – Proceeds before Intended Use (Amendments to IAS 16)*[3]
- *IAS 37 – Provisions, Contingent Liabilities and Contingent Assets – Onerous Contracts – Costs of Fulfilling a Contract (Amendments to IAS 37)*[3]
- *IAS 1 – Presentation of Financial Statements – Classification of Liabilities as Current or Non-Current (Amendments to IAS 15)*[4]

[1] Effective for annual periods beginning on or after January 1, 2020.
[2] Effective for annual periods beginning on or after June 1, 2020.
[3] Effective for annual periods beginning on or after January 1, 2022, with earlier application permitted.
[4] Effective for annual periods beginning on or after January 1, 2023, with earlier application permitted.

4.1 IAS 1 – Presentation of Financial Statements and IAS 8 – Accounting Policies, Changes in Accounting Estimates and Errors (Amendments to IAS 1 and IAS 8)

Effective January 1, 2020, Hydro adopted the amendments to IAS 1 and IAS 8 to align the definition of 'material' across the standards and to clarify certain aspects of the definition and to include the concept of 'obscuring information'. The amendments are intended to improve the understanding of the existing requirements rather than to significantly impact Hydro's materiality judgments.

4.2 IFRS 16 – Leases – COVID-19 Related Rent Concessions (Amendment to IFRS 16)

The IASB issued an amendment to IFRS 16 that provides lessees with an exemption from assessing whether a COVID-19-related rent concession is a lease modification. Since Hydro does not have any COVID-19 related rent concessions, the application of this amendment did not have an impact on Hydro's financial statements.

4.3 IAS 16 – Property, Plant and Equipment – Proceeds before Intended Use (Amendments to IAS 16)

The IASB issued amendments to IAS 16 relating to proceeds before intended use. The amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. The amendments also clarify the meaning of 'testing whether an asset is functioning properly'. IAS 16 now specifies this as assessing whether the technical and physical performance of the asset is such that it is capable of being used in the production or supply of goods or services, for rental to others, or for administrative purposes.

These amendments are applied retrospectively, but only to items of property, plant and equipment that are brought to the location and condition necessary for them to be capable of operating in the manner intended by management on or after the beginning of the earliest period presented in the financial statements in which the entity first applies the amendments. Hydro early adopted the amendments to IAS 16 as of January 1, 2020, with retrospective application as of January 1, 2019. The application of these amendments to IAS 16 did not have any transitional impact on Hydro's financial statements.

4.4 IAS 37 – Provisions, Contingent Liabilities and Contingent Assets – Onerous Contracts – Costs of Fulfilling a Contract (Amendments to IAS 37)

The amendments to IAS 37 specify that the cost of fulfilling a contract comprises the costs that relate directly to the contract. Costs that relate directly to a contract can either be incremental costs of fulfilling that contract, such as direct labour and materials, or an allocation of other costs that relate directly to fulfilling contracts, such as the allocation of the depreciation charge for an item of property, plant and equipment used in fulfilling the contract. These amendments apply to contracts for which the entity has not yet fulfilled all its obligations at the beginning of the annual reporting period in which the entity first applies the amendments and are currently not applicable to Hydro, however, may apply to future transactions.

4.5 IAS 1 – Presentation of Financial Statements – Classification of Liabilities as Current or Non-Current (Amendments to IAS 1)

The IASB issued amendments to IAS 1 to promote consistency in applying the requirements by helping companies determine whether, in the statement of financial position, debt and other liabilities with an uncertain settlement date should be classified as current (due or potentially due to be settled within one year) or non-current. The classification is based on rights that are in existence at the end of the reporting period and specify that classification is unaffected by expectations about whether an entity will exercise its right to defer settlement of a liability. The amendments are applied retrospectively upon adoption.

5. TRADE AND OTHER RECEIVABLES

As at December 31 (millions of Canadian dollars)	**2020**	2019
Trade receivables	**97**	117
Other receivables	**10**	23
Due from related parties	**7**	5
Allowance for doubtful accounts	**(17)**	(14)
	97	131

As at December 31 (millions of Canadian dollars)	**2020**	2019
0-60 days	**95**	120
60+ days	**2**	11
	97	131

As at December 31 (millions of Canadian dollars)	**2020**	2019
Allowance for doubtful accounts, beginning of the year	**(14)**	(17)
Change in balance during the year	**(3)**	3
Allowance for doubtful accounts, end of the year	**(17)**	(14)

6. INVENTORIES

As at December 31 (millions of Canadian dollars)	**2020**	2019
Fuel	**54**	65
Materials and other	**38**	38
	92	103

Fuel inventory includes No. 6 fuel in the amount of $43.6 million (2019 - $53.4 million). The cost of inventories recognized as an expense during the year is $160.8 million (2019 - $220.2 million) and is included in operating costs and fuels.

7. DEFERRED ASSET

The deferred asset related to Hydro's PPA with Energy Marketing was amortized into income on a straight-line basis over the assumed five month term of the contract, which commenced on January 1, 2020. Subsequently, in June and September 2020, Management reassessed the anticipated contract term and determined that a new deferred asset and derivative liability was required resulting in a deferred asset addition of $7.9 million and $7.5 million, respectively. These balances were fully amortized at September 30, 2020 and December 31, 2020. In December 2020, Management assessed the anticipated contract term and determined that a new deferred asset and derivative liability was required. This resulted in a deferred asset addition of $22.7 million to be amortized into income on a straight-line basis over the assumed nine month term, commencing on January 1, 2021. The components of change are as follows:

As at December 31 (millions of Canadian dollars)	**2020**	2019
Deferred asset, beginning of the year	**9**	21
Additions	**38**	9
Amortization	**(24)**	(21)
Deferred asset, end of the year	**23**	9

8. PROPERTY, PLANT AND EQUIPMENT

(millions of Canadian dollars)	Generation Plant	Transmission and Distribution	Other	Assets Under Development	Total
Cost					
Balance at January 1, 2019	1,269	1,091	125	40	2,525
Additions	-	-	-	129	129
Disposals	(4)	(2)	(3)	-	(9)
Transfers	64	52	9	(126)	(1)
Balance at December 31, 2019	1,329	1,141	131	43	2,644
Additions	**-**	**-**	**-**	**90**	**90**
Disposals	**(6)**	**(1)**	**(3)**	**-**	**(10)**
Transfers	**39**	**56**	**8**	**(103)**	**-**
Decommissioning liabilities and revisions	**1**	**-**	**-**	**-**	**1**
Other adjustments	**-**	**-**	**-**	**(3)**	**(3)**
Balance at December 31, 2020	**1,363**	**1,196**	**136**	**27**	**2,722**
Depreciation					
Balance at January 1, 2019	214	126	41	-	381
Depreciation	49	26	6	-	81
Disposals	(1)	(1)	(1)	-	(3)
Other adjustments [1]	(6)	(6)	(2)	-	(14)
Balance at December 31, 2019	256	145	44	-	445
Depreciation	**44**	**27**	**6**	**-**	**77**
Disposals	**(4)**	**-**	**(2)**	**-**	**(6)**
Balance at December 31, 2020	**296**	**172**	**48**	**-**	**516**
Carrying value					
Balance at January 1, 2019	1,055	965	84	40	2,144
Balance at December 31, 2019	1,073	996	87	43	2,199
Balance at December 31, 2020	**1,067**	**1,024**	**88**	**27**	**2,206**

[1] In Board Order No. P.U. 48 (2018), the PUB approved a 2018 cost deferral of $18.5 million related to the differential in the 2018 depreciation expense associated with the proposed change in depreciation methodology. Pursuant to Board Order No. P.U. 30 (2019), the PUB approved Hydro’s proposed depreciation methodology and the reclassification of $13.6 million of the 2018 cost deferral to property, plant and equipment.

Capitalized interest for the year ended December 31, 2020 was $1.5 million (2019 - $2.0 million) related to assets under development.

9. INTANGIBLE ASSETS

(millions of Canadian dollars)	Computer Software	Feasibility Studies	Assets Under Development	Total
Cost				
Balance at January 1, 2019	13	2	-	15
Transfers	1	-	-	1
Balance at December 31, 2019	14	2	-	16
Disposals	**-**	**(1)**	**-**	**(1)**
Transfers	**4**	**-**	**(4)**	**-**
Other adjustments	**-**	**-**	**4**	**4**
Balance at December 31, 2020	**18**	**1**	**-**	**19**
Amortization				
Balance at January 1, 2019	8	1	-	9
Amortization	2	-	-	2
Balance at December 31, 2019	10	1	-	11
Amortization	**1**	**1**	**-**	**2**
Disposals	**-**	**(1)**	**-**	**(1)**
Balance at December 31, 2020	**11**	**1**	**-**	**12**
Carrying value				
Balance at January 1, 2019	5	1	-	6
Balance at December 31, 2019	4	1	-	5
Balance at December 31, 2020	**7**	**-**	**-**	**7**

10. SINKING FUND INVESTMENTS

As at December 31, 2020, sinking funds include $182.6 million (2019 - $174.0 million) related to repayment of Hydro's long-term debt. Sinking fund investments consist of bonds, debentures, short-term borrowings and coupons issued by, or guaranteed by, the Government of Canada, provincial governments or Schedule 1 banks, and have maturity dates ranging from 2022 to 2033.

Hydro debentures, which are intended to be held to maturity, are deducted from debt while all other sinking fund investments are shown separately on the Non-Consolidated Statement of Financial Position as assets. Annual contributions to the various sinking funds are in accordance with bond indenture terms, and are structured to ensure the availability of adequate funds at the time of expected bond redemption. Effective yields range from 1.52% to 6.82% (2019 - 2.51% to 6.82%).

Sinking funds consist of the following:

As at December 31 (millions of Canadian dollars)	**2020**	2019
Sinking funds, beginning of the year	**174**	164
Contributions	**7**	7
Change in sinking fund investments in own debentures	**(10)**	(8)
Earnings	**12**	11
Sinking funds, end of the year	**183**	174

Sinking fund instalments due over the next five years are as follows:

(millions of Canadian dollars)	2021	2022	2023	2024	2025
Sinking fund instalments	7	7	7	7	7

11. INVESTMENTS IN JOINT ARRANGEMENTS

As at December 31 (millions of Canadian dollars)	**Ownership Interest**	**2020**	2019
Churchill Falls	65.8%		
Shares, at cost		**167**	167
Equity in retained earnings, beginning of the year		**421**	394
Accumulated other comprehensive loss, beginning of the year		**(4)**	(3)
Other comprehensive gain (loss)		**1**	(1)
Equity in profit for the year		**25**	27
		610	584

12. REGULATORY DEFERRALS

(millions of Canadian dollars)		January 1 2020	Reclass & Disposition	Regulatory Activity	**December 31 2020**	Remaining Recovery Settlement Period (years)
Regulatory asset deferrals						
Supply deferrals	(a)	35	(20)	44	**59**	n/a
Deferred energy conservation costs	(b)	9	-	(1)	**8**	n/a
Foreign exchange losses	(c)	48	-	(2)	**46**	21
Rate stabilization plan (RSP)	(d)	16	49	(25)	**40**	n/a
Retirement asset pool	(e)	11	-	2	**13**	n/a
Business system transformation program	(f)	3	-	1	**4**	n/a
Other	(i-v)	1	-	1	**2**	n/a
		123	29	20	**172**	
Regulatory liability deferrals						
Insurance amortization and proceeds	(g)	(3)	-	-	**(3)**	n/a
Removal provision	(h)	(8)	-	(4)	**(12)**	n/a
Other	(i-v)	(2)	1	(1)	**(2)**	n/a
		(13)	1	(5)	**(17)**	

12.1 Regulatory Adjustments Recorded in the Non-Consolidated Statement of Profit and Comprehensive Income

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
RSP amortization	**(32)**	4
RSP fuel deferral	**57**	34
RSP interest	**(2)**	2
Rural rate adjustment	**2**	1
Total RSP activity	**25**	41
Supply deferral recovery	**11**	3
Supply deferrals	**(55)**	(30)
Total supply deferrals	**(44)**	(27)
2019 revenue deficiency	**-**	(52)
Removal provision	**4**	4
Other	**-**	(3)
	(15)	(37)

The following section describes Hydro's regulatory assets and liabilities which will be, or are expected to be, reflected in customer rates in future periods and have been established through the rate setting process. In the absence of rate regulation, these amounts would be reflected in operating results in the year and profit for 2020 would have decreased by $15.1 million (2019 – $36.7 million).

12.(a) Supply Deferrals

Pursuant to Board Order No. P.U. 22 (2017), the Board approved the deferral of Energy Supply costs using three specific deferral accounts: the Energy Supply, Holyrood Conversion and Isolated Systems Supply cost deferrals. In 2020, Hydro recorded a net increase to the deferrals of $55.0 million (2019 - $29.6 million) with recovery determined through an annual application process. Board Order No. P.U. (2019) approved the recovery from customers of $18.4 million over a 20 month period; of which, in 2020 Hydro recovered $10.9 million (2019 - $2.7 million). In Board Order No. P.U. 13 (2020), the Board approved the recovery of the 2019 supply cost deferral of $19.8 million from the RSP.

12.(b) Deferred Energy Conservation Costs

In 2020, Hydro deferred $0.6 million (2019 - $1.5 million) in Energy Conservation Costs associated with an electrical conservation demand management program for residential, industrial, and commercial sectors. As per Board Order No. P.U. 22 (2017), Hydro recovered $1.5 million (2019 – $1.4 million) of the balance through a rate rider.

12.(c) Foreign Exchange Losses

In 2002, the PUB ordered Hydro to defer realized foreign exchange losses related to the issuance of Swiss Franc and Japanese Yen denominated debt and amortize the balance over a 40 year period. Accordingly, these costs were recognized as a regulatory asset. During 2020, amortization expense of $2.2 million (2019 - $2.2 million) was recorded.

12.(d) RSP

In 1986, the PUB ordered Hydro to implement the RSP which primarily provides for the deferral of fuel expense variances resulting from changes in fuel prices, hydrology, load and associated interest. Adjustments required in utility rates to cover the amortization of the balance are implemented on July 1 of each year. Similar adjustments required in industrial rates are implemented on January 1 of each year.

Hydro recorded a net increase in the RSP balance in 2020 of $23.7 million (2019 - decrease of $89.9 million) resulting in a balance from customers of $39.9 million (2019 - $16.2 million). The increase in the RSP asset is primarily due to Board Order P.U. 16 (2020) which approved a one-time bill credit resulting in a net increase to the RSP of $30.8 million; Board Order P.U. 13 (2020) which approved the recovery of the 2019 supply cost deferrals of $19.8 million resulting in an increase to the RSP; partially offset by normal operation of the RSP which resulted in a net decrease to the RSP of $25.4 million (2019 - $40.7 million) and Board Order P.U. 29 (2019) which approved the refund of the firm energy savings deferral resulting in a decrease of $1.5 million from the RSP.

12.(e) Retirement Asset Pool

As per Board Order No. P.U. 30 (2019), the Board approved Hydro's proposed depreciation methodology which includes the deferral of gains and losses on retirement of assets. The deferral will be recovered through future depreciation expense. The depreciation methodology and corresponding retirement asset pool was approved effective January 1, 2018. In 2020, Hydro deferred $2.1 million (2019 - $1.9 million) of retirement asset activity resulting in a total balance of $13.2 million.

12.(f) Business System Transformation Program

As per Board Order No.'s P.U. 23 (2019) and P.U. 30 (2019), the Board approved the deferral of business system transformation program costs commencing in 2018. The recovery of the deferral is subject to a future Board order. During the year, Hydro deferred $1.1 million (2019 – $2.5 million).

12.(g) Insurance Amortization and Proceeds

Pursuant to Board Order No. P.U. 13 (2012), Hydro records net insurance proceeds against the capital costs and amortizes the balance over the life of the asset. Under IFRS, Hydro is required to recognize the insurance proceeds and corresponding amortization in regulatory liabilities. During 2020, Hydro recorded a decrease to regulatory liabilities resulting from amortization of $nil (2019 - $0.6 million) related to the assets.

12.(h) Removal Provision

As per Board Order No. P.U. 30 (2019), the Board approved Hydro's proposed depreciation methodology which includes the provision for removal costs. The depreciation methodology and corresponding removal provision was approved effective January 1, 2018. Hydro recorded a net increase to the provision relating to 2020 activity of $4.1 million (2019 - $4.1 million) resulting in a total balance of $12.0 million.

12.(i) Hearing Costs

As per Board Order No. P.U. 30 (2019), the Board approved the deferral of $1.7 million in hearing costs relating to the 2017 General Rate Application hearing and the Cost of Service hearing to be amortized over a three year period commencing 2018. In 2020, Hydro recorded amortization of $0.6 million (2019 - $1.1 million) resulting in a net balance of $nil.

12.(j) 2018 Revenue Deficiency

In Board Order P.U. 30 (2019), the Board approved the 2018 Revenue Deficiency of $0.8 million. The Revenue Deficiency consists of $2.3 million which was approved to be recovered through a transfer to the RSP and a refund to customers of $1.5 million. A refund of $0.6 million was paid to industrial customers in 2019 with the remaining balance of $0.9 million refunded to the Labrador Rural Interconnected customers in 2020.

12.(k) 2019 Revenue Deficiency

In Board Order P.U. 30 (2019), the Board approved the 2019 Revenue Deficiency of $51.8 million. The Revenue Deficiency consists of $52.6 million which was approved to be recovered through a transfer to the RSP, $0.1 million to be recovered over a 20 month period and a refund to customers of $0.9 million. A refund of $0.3 million was paid to Industrial customers in 2019 which resulted in a December 31, 2019 balance in the 2019 Revenue Deficiency of $0.6 million. The remaining refund of $0.6 million to the Labrador Rural Interconnected customers was paid in 2020.

12.(l) Deferred Lease Costs

In Board Order No's. P.U. 17 (2016), P.U. 23 (2016) and No. P.U. 49 (2016) the Board approved amortization of lease costs associated with mobile diesel units at Holyrood Thermal Generating Station (HTGS) over a period of five years. In 2020, Hydro recorded amortization of $0.3 million (2019 - $1.3 million) of the deferred lease costs.

12.(m) Deferred Foreign Exchange on Fuel

Hydro purchases fuel for HTGS in USD. The RSP allows Hydro to defer variances in fuel prices (including foreign exchange fluctuations). During 2020, Hydro recognized a reduction to regulatory assets foreign exchange gains on fuel purchases of $0.2 million (2019 - $1.0 million).

12.(n)Phase Two Hearing Costs

Pursuant to Board Order No. P.U. 13 (2016), Hydro received approval to defer consulting fees and salary related costs relating to Phase Two of the investigation into the reliability and adequacy of power on the Island Interconnected system after the interconnection with the Muskrat Falls generating station. As a result, Hydro recorded a net increase to regulatory assets of $nil million (2019 - $0.2 million) for a total deferred balance of $1.4 million (2019 - $1.4 million).

12.(o) Asset Disposal

As per Board Order No. P.U. 49 (2016), the Board ordered that Hydro recognize a regulatory asset of $0.4 million related to the Sunnyside transformer that was disposed of in 2014. Hydro is required to recover the deferred asset in rate base and amortize the asset for 22.4 years commencing in 2015. Hydro is required to exclude the new Sunnyside transformer from rate base until the Sunnyside transformer original asset deferral has been fully amortized.

12.(p) Firm Energy Purchase

Pursuant to Board Order No. P.U. 3 (2020), the Board approved the deferral of savings associated with firm energy power purchases. Hydro recorded a regulatory liability of $1.5 million in 2019. In 2020, pursuant to Board Order No. 29 (2020), the balance of $1.5 million was refunded through the RSP.

12.(q) Hydraulic Resources Optimization Deferral Account

In Board Order P.U. 49 (2018), a deferral account to capture the revenues and costs associated with the hydraulic optimization activities was approved. For the year ended December 31, 2020, the balance of hydraulic optimization activities is a net gain of $1.0 million (2019 - $0.3 million) recorded as a deferred liability.

12.(r) Deferred Purchased Power Savings

In 1997, the PUB ordered Hydro to defer $1.1 million related to reduced purchased power rates resulting from the interconnection of communities in the area of L'Anse au Clair to Red Bay to the Hydro-Québec system and amortize the balance over a 30 year period. The remaining unamortized savings in the amount of $0.2 million (2019 - $0.3 million) are deferred as a regulatory liability.

12.(s) Non-Customer Contributions in Aid of Construction

Pursuant to Board Order No. P.U. 1 (2017), Hydro recognized amortization of deferred contributions in aid of construction (CIAC) from entities which are not customers in profit or loss. During 2020, Hydro recorded $0.9 million (2019 - $0.7 million) non-customer CIAC amortization as a regulatory adjustment. In the absence of rate regulation, IFRS requires non-customer CIACs to be recorded as contributed capital with no corresponding amortization. As a result, during 2020 Hydro also recorded an increase of $0.9 million (2019 - $0.7 million) to contributed capital to recognize the amount that was reclassified to profit or loss.

12.(t) Employee Future Benefits Actuarial Loss

Pursuant to Board Order No. P.U. 36 (2015), Hydro has recognized the amortization of employee future benefit actuarial gains and losses in net income. During 2020 Hydro recorded $0.1 million (2019 - $nil) employee future benefits losses as a regulatory adjustment. In the absence of rate regulation, IFRS would require Hydro to include employee future benefits actuarial gains and losses in other comprehensive income. As a result, during 2020 Hydro also recorded a decrease of $0.1 million (2019 - $nil) to other comprehensive income to recognize the amount that was reclassified to profit or loss.

12.(u) Reliability and Resource Adequacy Study

Pursuant to Board Order No. P.U. 29 (2019), the Board approved the deferral of costs associated with the Reliability and Resource Adequacy proceeding. Hydro deferred $0.6 million in 2020 (2019 - $0.2 million). The recovery of the balance is to be determined in a future Board Order.

12.(v) Frequency Converter Revenue Deferral Account

In Board Order P.U. 35 (2020), the Board approved the deferral of the cumulative revenue requirement impact associated with the loss on the sale of a frequency converter, commencing December, 2019. The disposition of the cumulative revenue requirement impact included in the deferral account balance will be addressed as part of Hydro’s next general rate application. During 2020, Hydro deferred $0.2 million as a regulatory liability (2019 - $nil).

13. TRADE AND OTHER PAYABLES

As at December 31 (millions of Canadian dollars)	**2020**	2019
Trade payables	**72**	82
Accrued interest payable	**25**	25
Due to related parties	**7**	7
Other payables	**15**	29
	119	143

14. DEBT

14.1 Short-term Borrowings

Hydro utilized its $300.0 million government guaranteed promissory note program to fulfil its short-term funding requirements. As at December 31, 2020, there were three promissory notes outstanding for a total of $262.0 million with a maturity date of January 4, 2021 bearing an average interest rate of 0.17% (2019 - $233.0 million bearing an average interest rate of 1.82%). Upon maturity, the promissory notes were reissued.

Hydro maintains a $200.0 million CAD or USD equivalent committed revolving term credit facility maturing on July 27, 2021. As at December 31, 2020, there were no amounts drawn on the facility (2019 - $nil). Borrowings in CAD may take the form of Prime Rate Advances, Bankers’ Acceptances (BAs), and letters of credit, with interest calculated at the Prime Rate or prevailing Government BA fee. Borrowings in USD may take the form of Base Rate Advances and letters of credit. The facility also provides coverage for overdrafts on Hydro's bank accounts, with interest calculated at the Prime Rate.

On April 17, 2020, Hydro obtained additional credit through establishment of a committed credit facility with its banker in the amount of $300.0 million with a maturity date of April 17, 2021. As at December 31, 2020, there were no amounts drawn on this facility. Borrowings in CAD may take the form of BAs and, in certain circumstances, Prime Rate advances. The facility also provides coverage for overdrafts on Hydro’s bank accounts, with interest calculated at the Prime Rate.

14.2 Long-term Debt

The following table represents the value of long-term debt measured at amortized cost:

As at December 31 (millions of Canadian dollars)	Face Value	Coupon Rate %	Year of Issue	Year of Maturity	**2020**	2019
Hydro						
Y *	300	8.40	1996	2026	**297**	296
AB *	300	6.65	2001	2031	**304**	305
AD *	125	5.70	2003	2033	**124**	124
AF	500	3.60	2014/2017	2045	**481**	481
1A	600	3.70	2017/2018	2048	**639**	640
Total	1,825				**1,845**	1,846
Less: Sinking fund investments in own debentures					**73**	63
					1,772	1,783
Less: Sinking fund payments due within one year					**7**	7
Total					**1,765**	1,776

*Sinking funds have been established for these issues.

Hydro's promissory notes and debentures are unsecured and unconditionally guaranteed as to principal and interest and, where applicable, sinking fund payments, by the Province, with exception of Series 1A which is borrowed directly from the Province. The Province charges Hydro a guarantee fee of 25 basis points annually on the total debt (net of sinking funds) with a remaining term to maturity of less than or equal to 10 years and 50 basis points annually on total debt (net of sinking funds) with a remaining term to maturity greater than 10 years for debt outstanding as of December 31, 2010. For debt issued subsequent to December 31, 2010, the guarantee rate is 25 basis points annually on the total debt (net of sinking funds) with an original term to maturity of less than or equal to 10 years and 50 basis points annually on total debt (net of sinking funds) with an original term to maturity greater than 10 years. The guarantee fee recorded for the year ended December 31, 2020 was $8.6 million (2019 - $8.6 million).

On December 18, 2020, Hydro received approval from the Board of Public Utilities to issue debt with a face value of up to $300.0 million (Board Order No. P.U. 40 (2020)) on or before April 30, 2021.

15. DEFERRED CONTRIBUTIONS

Hydro has received contributions in aid of construction of property, plant and equipment. These contributions are deferred and amortized to other revenue over the life of the related property, plant and equipment asset.

As at December 31 (millions of Canadian dollars)	**2020**	2019
Deferred contributions, beginning of the year	**20**	19
Additions	**3**	1
Other adjustments	**-**	1
Amortization	**(1)**	(1)
Deferred contributions, end of the year	**22**	20
Less: current portion	**(1)**	(1)
	21	19

16. DECOMMISSIONING LIABILITIES

Hydro has recognized liabilities associated with the retirement of portions of the HTGS and the disposal of Polychlorinated Biphenyls (PCB).

The reconciliation of the beginning and ending carrying amounts of decommissioning liabilities for December 31, 2020 are as follows:

As at December 31 (millions of Canadian dollars)	**2020**	2019
Decommissioning liabilities, beginning of the year	**14**	14
Accretion	**-**	-
Revisions	**1**	-
Decommissioning liabilities, end of the year	**15**	14

The total estimated undiscounted cash flows required to settle the HTGS obligations at December 31, 2020 are $15.2 million (2019 - $15.2 million). Payments to settle the liability are expected to occur between 2021 and 2025. The fair value of the decommissioning liabilities was determined using the present value of future cash flows discounted at Hydro's credit adjusted risk free rate of 0.5% (2019 - 2.0%). Hydro has recorded $14.8 million (2019 - $14.1 million) related to HTGS obligations.

The total estimated undiscounted cash flows required to settle the PCB obligations at December 31, 2020 are $0.3 million (2019 - $0.4 million). Payments to settle the liability are expected to occur between 2021 and 2025. The fair value of the decommissioning liabilities was determined using the present value of future cash flows discounted at Hydro's credit adjusted risk free rate of 0.5% (2019 - 2.1%). Hydro has recorded $0.3 million (2019 - $0.4 million) related to PCB obligations.

Hydro's assets include generation plants, transmission assets and distribution systems. These assets can continue to run indefinitely with ongoing maintenance activities. As it is expected that Hydro's assets will be used for an indefinite period, no removal date can be determined and consequently, a reasonable estimate of the fair value of any related decommissioning liability cannot be determined at this time. If it becomes possible to estimate the fair value of the cost of removing assets that Hydro is required to remove, a decommissioning liability for those assets will be recognized at that time.

17. LEASE LIABILITIES

AMOUNTS RECOGNIZED IN THE NON-CONSOLIDATED STATEMENT OF PROFIT AND COMPREHENSIVE INCOME

For the year ended December 31 (millions of Canadian dollars)		**2020**	2019
Variable lease payments not included in the measurement of leases	(a)	**28**	28

(a) Variable lease payments not included in the measurement of leases include payments made to Nalcor for power generated from assets which are owned by the Province. These variable lease payments are included in power purchased in the Non-Consolidated Statement of Profit and Comprehensive Income.

The total cash outflow for leases for the year ended December 31, 2020 amount to $28.3 million (2019 - $28.2 million).

18. EMPLOYEE FUTURE BENEFITS

18.1 Pension Plan

Employees participate in the Province's Public Service Pension Plan, a multi-employer defined benefit plan. The employer's contributions for the year ended December 31, 2020 of $7.8 million (2019 - $8.0 million) are expensed as incurred.

18.2 Other Benefits

Hydro provides group life insurance and health care benefits on a cost shared basis to retired employees, and in certain cases their surviving spouses, in addition to a retirement allowance upon retirement. In 2020, cash payments to beneficiaries for its unfunded other employee future benefits were $3.1 million (2019 - $2.9 million). An actuarial valuation was performed as at December 31, 2020.

As at December 31 (millions of Canadian dollars)	**2020**	2019
Accrued benefit obligation, beginning of the year	**101**	86
Current service cost	**4**	4
Past service cost	**-**	2
Interest cost	**3**	4
Benefits paid	**(3)**	(3)
Actuarial loss	**2**	8
Accrued benefit obligation, end of the year	**107**	101

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
Component of benefit cost		
Current service cost	**4**	4
Past service cost	**-**	2
Interest cost	**3**	4
Total benefit expense for the year	**7**	10

The significant actuarial assumptions used in measuring the accrued benefit obligations and benefit expenses are as follows:

	2020	2019
Discount rate - benefit cost	**3.20%**	3.90%
Discount rate - accrued benefit obligation	**2.70%**	3.20%
Rate of compensation increase	**3.50%**	3.50%

Assumed healthcare trend rates:

	2020	2019
Initial health care expense trend rate	**5.64%**	5.85%
Cost trend decline to	**3.60%**	3.60%

Current rate 5.64%, reducing linearly to 3.6% in 2040 and thereafter.

A 1% change in assumed health care trend rates would have had the following effects:

Increase (millions of Canadian dollars)	**2020**	2019
Current service and interest cost	**2**	1
Accrued benefit obligation	**18**	16

Decrease (millions of Canadian dollars)	**2020**	2019
Current service and interest cost	**(1)**	(1)
Accrued benefit obligation	**(13)**	(13)

19. SHAREHOLDER'S EQUITY

19.1 Share Capital

As at December 31 (millions of Canadian dollars)	**2020**	2019
Common shares of par value of $1 each		
Authorized: 25,000,000		
Issued, paid and outstanding: 22,503,942	**23**	23

19.2 Contributed Capital

As at December 31 (millions of Canadian dollars)	**2020**	2019
Contributed capital, beginning of the year	**147**	147
Additions	**-**	1
Amortization	**(1)**	(1)
Contributed capital, end of the year	**146**	147

During 2020, Lower Churchill Management Corporation contributed $0.2 million (2019 - $0.7 million) in addition to property, plant and equipment. Pursuant to Board Order No. P.U. 1 (2017), Hydro recognized $0.9 million (2019 - $0.7 million) in amortization as a regulatory adjustment.

19.3 Dividends

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
Declared during the year		
Final dividend for prior year: $0.03 per share (2019 - $0.05)	**1**	1
Interim dividend for current year: $0.31 per share (2019 - $0.29)	**12**	7
	13	8

20. OPERATING COSTS

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
Salaries and benefits	**87**	88
Maintenance and materials	**21**	24
Professional services	**8**	8
Insurance	**4**	4
Travel and transportation	**3**	4
Municipal taxes	**2**	2
Equipment rental	**2**	2
Office supplies	**2**	2
Other operating costs	**7**	7
	136	141

21. NET FINANCE EXPENSE

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
Finance income		
Interest on sinking fund	**12**	11
Other interest income	**1**	1
	13	12
Finance expense		
Long-term debt	**92**	92
Debt guarantee fee	**9**	9
Other	**4**	3
	105	104
Interest capitalized during construction	**(2)**	(2)
	103	102
Net finance expense	**90**	90

22. OTHER EXPENSE

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
Loss on disposal of property, plant and equipment	**2**	6
Other	**2**	2
Other expense	**4**	8

23. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

23.1 Fair Value

The estimated fair values of financial instruments as at December 31, 2020 and 2019 are based on relevant market prices and information available at the time. Fair value estimates are based on valuation techniques which are significantly affected by the assumptions used including the amount and timing of future cash flows and discount rates reflecting various degrees of risk. As such, the fair value estimates below are not necessarily indicative of the amounts that Hydro might receive or incur in actual market transactions.

As a significant number of Hydro's assets and liabilities do not meet the definition of a financial instrument, the fair value estimates below do not reflect the fair value of Hydro as a whole.

Establishing Fair Value

Financial instruments recorded at fair value are classified using a fair value hierarchy that reflects the nature of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices).

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value. For assets and liabilities that are recognized at fair value on a recurring basis, Hydro determines whether transfers have occurred between levels in the hierarchy by reassessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period. There were no transfers between Level 1, 2 and 3 fair value measurement for the years ended December 31, 2020 and 2019.

	Level	Carrying Value	Fair Value	Carrying Value	Fair Value
As at (millions of Canadian dollars)		**December 31, 2020**		December 31, 2019	
Financial assets					
Sinking funds - investments in Hydro debt issue	**2**	**73**	**88**	63	75
Sinking funds - other investments	**2**	**183**	**234**	174	211
Financial liabilities					
Derivative liability	**3**	**23**	**23**	9	9
Long-term debt including amount due within one year (before sinking funds)	**2**	**1,845**	**2,394**	1,846	2,242

The fair value of cash, trade and other receivables, short-term borrowings, and trade and other payables approximates their carrying values due to their short-term maturity.

The fair values of Level 2 financial instruments are determined using quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability. Level 2 derivative instruments are valued based on observable commodity future curves, broker quotes or other publicly available data. Level 2 fair values of other risk management assets and liabilities and long-term debt are determined using observable inputs other than unadjusted quoted prices, such as interest rate yield curves and currency rates.

Level 3 financial instruments include the derivative liability relating to the PPA with Energy Marketing and represents the future value provided to Energy Marketing through the contract.

The following table summarizes quantitative information about the valuation techniques and unobservable inputs used in the fair value measurement of Level 3 financial instruments as at December 31, 2020:

(millions of Canadian dollars)	Carrying Value	Valuation Techniques	Significant Unobservable Input(s)	Range
Derivative liability (PPA)	23	Modelled pricing	Volumes (MWh)	28-32% of available generation

The derivative liability arising under the PPA is designated as a Level 3 instrument as certain forward market prices and related volumes are not readily determinable to estimate a portion of the fair value of the derivative liability. Hence, fair value measurement of this instrument is based upon a combination of internal and external pricing and volume estimates. As at December 31, 2020, the effect of using reasonably possible alternative assumptions for volume inputs to valuation techniques may have resulted in a -$0.1 million to +$0.7 million change in the carrying value of the power purchase derivative liability.

23.2 Risk Management

Hydro is exposed to certain credit, liquidity and market risks through its operating, investing and financing activities. Financial risk is managed in accordance with Hydro's Board approved Financial Risk Management Policy, which outlines the objectives and strategies for the management of financial risk, including the use of derivative contracts. Permitted financial risk management strategies are aimed at minimizing the volatility of Hydro's expected future cash flows.

Credit Risk

Hydro's expected future cash flow is exposed to credit risk through its operating activities, primarily due to the potential for non-performance by its customers, and through its financing and investing activities, based on the risk of non-performance by counterparties to its financial instruments. The degree of exposure to credit risk on cash and derivative assets as well as from the sale of electricity to customers, including the associated accounts receivable, is determined by the financial capacity and stability of those customers and counterparties. The maximum exposure to credit risk on these financial instruments is represented by their carrying values on the Non-Consolidated Statement of Financial Position at the reporting date.

The COVID-19 pandemic has increased the credit risk of the Company, as the potential risk for non-performance of the Company's customers has increased with the current economic slowdown. Hydro had established flexible collection practices during the COVID-19 pandemic for its customers including flexible bill payment arrangements and waiving interest on overdue accounts for residential and general service customers, which is recoverable from the Province. In September 2020, Hydro returned to its normal customer collections practices, but continues to waive interest on overdue accounts, which is recoverable from the Province. Hydro is continuing to monitor the risk of non-performance by its customers and as at December 31, 2020 the impact on the Company's expected credit loss allowance is not considered material. As well, Hydro is continuing to monitor the implications of COVID-19, including the risk of credit losses, pronouncements from governments and regulators and, if required, will make adjustments to the expected credit loss allowance in future periods.

Credit risk on cash is minimal, as Hydro's cash deposits are held by a Schedule 1 Canadian Chartered Bank with a rating of A+ (Standard and Poor's).

Credit exposure on Hydro's sinking funds is limited by restricting the holdings to long-term debt instruments issued by the Government of Canada or any province of Canada, Crown corporations and Schedule 1 Canadian Chartered Banks. The following credit risk table provides information on credit exposures according to issuer type and credit rating for the remainder of the sinking funds portfolio:

	Issuer Credit Rating	**Fair Value of Portfolio (%)**	Issuer Credit Rating	Fair Value of Portfolio (%)
	2020		2019	
Provincial Governments	**AA- to AAA**	**17.10%**	AA- to AAA	17.30%
Provincial Governments	**A- to A+**	**26.53%**	A- to A+	27.16%
Provincially owned utilities	**AA- to AAA**	**24.03%**	AA- to AAA	26.00%
Provincially owned utilities	**A- to A+**	**32.34%**	A- to A+	29.54%
		100.00%		100.00%

Credit exposure on derivative assets is limited by the Financial Risk Management Policy, which restricts available counterparties for hedge transactions to Schedule 1 Canadian Chartered Banks, and Federally Chartered US Banks.

Hydro's exposure to credit risk on its energy sales and associated accounts receivable is determined by the credit quality of its customers. Hydro's three largest customers account for 81.3% (2019 - 82.3%) of total energy sales and 63.0% (2019 - 63.4%) of accounts receivable. Energy sales for the three largest customers include $455.0 million (2019 - $501.2 million) for Regulated Hydro, as well as $41.4 million (2019 - $39.8 million) for Non-Regulated Hydro.

Liquidity Risk
Hydro is exposed to liquidity risk with respect to its contractual obligations and financial liabilities, including any derivative liabilities related to hedging activities. Liquidity risk management is aimed at ensuring cash is available to meet those obligations as they become due.

Short-term liquidity is mainly provided through cash on hand, funds from operations and a $300.0 million promissory note program. In addition, Hydro maintains a $200.0 million (2019 - $200.0 million) committed revolving term credit facility with its primary banker. On April 17, 2020, Hydro signed a credit agreement with its primary banker to establish an additional credit facility in the amount of $300.0 million with a maturity date of April 17, 2021. These credit facilities are held with its primary banker in order to meet any requirements beyond those forecasted for a given period. Long-term liquidity risk is managed by the issuance of a portfolio of debentures with maturity dates ranging from 2026 to 2048. Sinking funds have been established for these issues, with the exception of the issues maturing in 2045 and 2048.

The following are the contractual maturities of Hydro's financial liabilities, including principal and interest, as at December 31, 2020:

(millions of Canadian dollars)	< 1 Year	1-3 Years	3-5 Years	> 5 Years	Total
Trade and other payables	119	-	-	-	119
Short-term borrowings	262	-	-	-	262
Derivative liability	23	-	-	-	23
Debt guarantee fee	9	17	16	143	185
Long-term debt including sinking funds	7	13	13	1,792	1,825
Interest	93	185	185	1,035	1,498
	513	215	214	2,970	3,912

Market Risk
In the course of carrying out its operating, financing and investing activities, Hydro is exposed to possible market price movements that could impact expected future cash flow and the carrying value of certain financial assets and liabilities. Market price movements to which Hydro has significant exposure include those relating to prevailing interest rates, foreign exchange rates, most notably the USD/CAD, and current commodity prices, most notably the spot prices for fuel, electricity, and No. 6 fuel. These exposures are addressed as part of the Financial Risk Management Policy.

Interest Rates
Changes in prevailing interest rates will impact the fair value of financial assets and liabilities, which includes Hydro's cash and sinking funds. Expected future cash flows associated with those financial instruments can also be impacted. The impact of a 0.5% change in interest rates on net income and other comprehensive income associated with cash and short-term debt was negligible throughout 2020 due to the short time period to maturity. There was no impact on profit and other comprehensive income associated with long-term debt as all of Hydro's long-term debt has fixed interest rates.

Foreign Currency and Commodity Exposure
Hydro's primary exposure to both foreign exchange and commodity price risk arises from its purchases of No. 6 fuel for consumption at the HTGS, and these risks are mitigated through the operation of the RSP.

As at December 31, 2020 trade and other payables included balances of $0.1 million (2019 - $0.2 million) denominated in United States Dollars (USD).

The components of the change impacting the carrying value of the derivative asset and derivative liability for the years ended December 31, 2020 and 2019 are as follows:

(millions of Canadian dollars)	**(Level 3)**
Balance at January 1, 2020	**(9)**
Purchases	**(38)**
Changes in profit or loss	
Mark-to-market	**1**
Settlements	**23**
Total	**24**
Balance at December 31, 2020	**(23)**

(millions of Canadian dollars)	(Level 3)
Balance at January 1, 2019	(21)
Purchases	(9)
Changes in profit or loss	
Mark-to-market	(5)
Settlements	26
Total	21
Balance at December 31, 2019	(9)

24. RELATED PARTY TRANSACTIONS

Hydro enters into various transactions with its parent and other affiliates. These transactions occur within the normal course of operations and are measured at the exchange amount, which is the amount of consideration agreed to by the related parties. Related parties with which Hydro transacts are as follows:

Related Party	Relationship
Nalcor	100% shareholder of Hydro
The Province	100% shareholder of Nalcor
Churchill Falls	Joint arrangement of Hydro
Twin Falls	Joint venture of Churchill Falls
Energy Marketing	Wholly-owned subsidiary of Nalcor
Lower Churchill Management Corporation	Wholly-owned subsidiary of Nalcor
Labrador-Island Link Operating Corporation (LIL Opco)	Wholly-owned subsidiary of Nalcor
Muskrat Falls Corporation (Muskrat Falls)	Wholly-owned subsidiary of Nalcor
Nalcor Energy – Oil and Gas Inc.	Wholly-owned subsidiary of Nalcor
Board of Commissioners of Public Utilities (PUB)	Agency of the Province

Routine operating transactions with related parties are settled at prevailing market prices under normal trade terms. Outstanding balances due to or from related parties are non-interest bearing with settlement within 30 days, unless otherwise stated.

(a) For the year ended December 31, 2020, Lower Churchill Management Corporation contributed $0.2 million (2019 - $0.7 million) in addition to property, plant and equipment.

(b) For the year ended December 31, 2020, Hydro purchased $48.2 million (2019 - $47.2 million) of power produced by Churchill Falls under long-term power contracts.

(c) Hydro incurs certain costs of operations, hearings and application costs of the PUB. During 2020, Hydro incurred $1.1 million (2019 - $2.1 million) in costs related to the PUB and has included $0.9 million (2019 - $0.7 million) in trade and other payables.

(d) As at December 31, 2020, Hydro has a payable to related parties of $7.1 million (2019 - $6.8 million) and a receivable from related parties for $6.8 million (2019 - $4.9 million). This payable/receivable consists of various intercompany operating costs and power purchases.

(e) The debt guarantee fee paid to the Province for 2020 was $8.6 million (2019 - $8.6 million). Interest paid to the Province on Series 1A long-term debt for 2020 was $22.2 million (2019 - $22.2 million).

(f) For the year ended December 31, 2020, Hydro recovered $2.1 million (2019 - $2.0 million) of operating costs from related parties representing the provision of administrative services.

(g) For the year ended December 31, 2020, Hydro incurred $6.9 million (2019 - $6.7 million) in operating costs from related parties representing the provision of administrative services.

(h) For the year ended December 31, 2020, Hydro has purchased $28.0 million (2019 - $28.0 million) of power generated from assets related to Exploits Generation, which are owned by the Province. In addition, Hydro operates these assets on behalf of Nalcor and recovered costs in the amount of $25.6 million (2019 - $26.2 million).

(i) For the year ended December 31, 2020, Hydro has recovered net intercompany labour related expenses of $1.3 million (2019 - $0.6 million).

(j) Hydro received $1.0 million (2019 - $1.0 million) from Nalcor associated with the Upper Churchill Redress Agreement to be used to provide a rebate to residential customers in Innu Communities and to the Mushuau Innu First Nation.

(k) Hydro recorded $2.3 million (2019 - $2.2 million) as an energy rebate from the Province to offset the cost of basic electricity consumption for Labrador rural isolated residential customers under the Northern Strategic Plan. As at December 31, 2020, there is a balance of $0.2 million (2019 - $0.4 million) outstanding in trade and other receivables.

(l) Hydro recorded $2.6 million (2019 - $nil) as sales to Lower Churchill Management Corporation to reimburse costs of electricity used at Soldier’s Pond.

24.1 Key Management Personnel Compensation

Compensation for key management personnel, which Hydro defines as its executives who have the primary authority and responsibility in planning, directing and controlling the activities of the entity, includes compensation for senior executives. Salaries and employee benefits include base salaries, performance contract payments, vehicle allowances and contributions to employee benefit plans. Post-employment benefits include contributions to the Province’s Public Service Pension Plan in the amount of $0.2 million (2019 – $0.1 million).

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
Salaries and employee benefits	**2**	2

25. COMMITMENTS AND CONTINGENCIES

(a) Hydro is subject to various legal proceedings and claims in the normal course of business. Although the outcomes of such actions cannot be predicted with certainty, Management believes the Company's exposure to such claims and litigation will not materially affect its financial position or results of operations.

(b) Outstanding commitments for capital projects total approximately $21.6 million as at December 31, 2020 (2019 - $16.7 million).

(c) Hydro has entered into a number of long-term power purchase agreements as follows:

Type	Rating	Effective Date	Term
Hydroelectric	3 MW	1995	25 years*
Hydroelectric	4 MW	1998	25 years
Hydroelectric	300 MW	1998	43 years
Cogeneration	15 MW	2003	20 years
Wind	390 kW	2004	Continual
Wind	27 MW	2008	20 years
Wind	27 MW	2009	20 years
Wind	300 kW	2010	Continual
Hydroelectric	225 MW	2015	25 years
Hydroelectric	175 kW	2019	15 years
Biomass	450 kW	2018	1 year post in-service of Muskrat Falls in-service date

*This agreement is currently in discussion for renewal

Estimated payments due in each of the next five years are as follows:

(millions of Canadian dollars)	2021	2022	2023	2024	2025
Power purchases	79.1	80.3	70.3	70.1	70.8

(d) Through a power purchase agreement signed October 1, 2015, with Energy Marketing, Hydro maintains the transmission services contract it entered into with Hydro-Québec TransÉnergie which concludes in 2024.

The transmission rental payments for the next four years are estimated to be as follows:

2021	$20.6 million
2022	$20.8 million
2023	$21.0 million
2024	$5.3 million

(e) In 2013, Hydro entered into a Power Purchase Agreement with Muskrat Falls for the purchase of energy and capacity from the Muskrat Falls Plant. The supply period under the agreement is 50 years and commences at the date of commissioning of the Muskrat Falls Plant. Estimated payments for the next five years have not yet been determined as they may be impacted by the Province's rate mitigation plan.

(f) In 2013, Hydro entered into the Transmission Funding Agreement (TFA) with LIL Opco, in which Hydro has committed to make payments which will be sufficient for LIL Opco to recover all costs associated with rent payments under the LIL Lease and payments to cover operating and maintenance costs incurred by LIL Opco. Hydro will be required to begin mandatory payments associated with the TFA upon commissioning of the Lower Churchill Project assets. The term of the TFA is anticipated to continue until the service life of the LIL assets has expired.

(g) In 2018, Hydro entered into three additional agreements in order to enable transmission of energy from Labrador to the island; the Labrador Island Link Interim Transmission Funding Agreement (LIL interim TFA); Labrador Transmission Assets Interim Transmission Funding Agreement (LTA interim TFA); and a Minimum Performance Guarantee (the Guarantee). The LIL Interim TFA is between the Labrador Island Link Limited Partnership (Partnership) and Hydro to provide for cost reimbursement, from Hydro to the Partnership, for operating and maintenance costs resulting from the LIL being made available for service earlier than would otherwise be required. The LTA Interim TFA is between the Labrador Transmission Corporation (LTC) and Hydro to provide for cost reimbursement, from Hydro to LTC, for operating and maintenance costs resulting from the LTA being made available for service earlier than would otherwise be required. Both of the Interim TFA's were developed based on the existing long-term Transmission Funding Agreement, executed in 2013. The Guarantee is between Nalcor Energy and Hydro and provides Hydro with guaranteed minimum average availability of the LIL and LTA during the term of the Interim TFA's. Should performance deficiencies by either or both of the LIL and LTA result in Hydro realizing a net loss from the use of off-island purchases, Nalcor will reimburse Hydro, in proportion to the contribution of these deficiencies to the net loss, for the operating and maintenance costs of the LIL and LTA. No payments have been made to date.

(h) In 2014, Hydro entered into three Capacity Assistance Agreements, one with Vale Newfoundland & Labrador Limited (Vale) and two with Corner Brook Pulp and Paper Limited (CBPP) for the purchase of relief power during the winter period. In February 2019, Hydro entered into a revised agreement with CBPP that expires the earlier of April 30, 2022 or the commissioning of the Muskrat Falls plant. In December 2020, Hydro entered into a revised agreement with Vale that expires in March of 2021. Payment for services will be dependent on the successful provision of capacity assistance for the winter period by Vale and CBPP.

26. CAPITAL MANAGEMENT

Hydro's principal business requires ongoing access to capital in order to maintain assets to ensure the continued delivery of safe and reliable service to its customers. Therefore, Hydro's primary objective when managing capital is to ensure ready access to capital at a reasonable cost, to minimize its cost of capital within the confines of established risk parameters, and to safeguard Hydro's ability to continue as a going concern.

The capital managed by Hydro is comprised of debt (long-term debentures, short-term borrowings, bank credit facilities and bank indebtedness) and equity (share capital, shareholder contributions, reserves and retained earnings).

A summary of the capital structure is outlined below:

(millions of Canadian dollars)	**2020**		2019	
Debt				
Sinking funds	**(183)**		(174)	
Short-term borrowings	**262**		233	
Current portion of long-term debt	**7**		7	
Long-term debt	**1,765**		1,776	
	1,851	**63.0%**	1,842	64.2%
Equity				
Share capital	**23**		23	
Contributed capital	**146**		147	
Reserves	**(22)**		(22)	
Retained earnings	**939**		877	
	1,086	**37.0%**	1,025	35.8%
Total Debt and Equity	**2,937**	**100.0%**	2,867	100.0%

Hydro's approach to capital management encompasses various factors including monitoring the percentage of floating rate debt in the total debt portfolio, the weighted average term to maturity of its overall debt portfolio, its percentage of debt to debt plus equity, and its interest coverage.

For the regulated portion of Hydro's operations, Management targets a capital structure comprised of 75% debt and 25% equity, a ratio which Management believes to be optimal with respect to its cost of capital. This capital structure is maintained by a combination of dividend policy, shareholder contributions and debt issuance. The issuance of any new debt with a term greater than one year requires prior approval of the PUB. Hydro's committed operating facility has a covenant requiring Hydro to ensure that its consolidated debt to total capitalization ratio does not exceed 85%. As at December 31, 2020, Hydro was in compliance with this covenant.

Legislation stipulates that the total of the Government guaranteed short-term loans issued by Hydro and outstanding at any time shall not exceed a limit as fixed by the Lieutenant-Governor in Council. Short-term loans are those loans issued with a term not exceeding two years. On February 20, 2020, the Lieutenant-Governor in Council issued Order in Council OC2020-18 to increase the level of short-term borrowings permitted by Hydro from $300 million to $500 million, effective until March 31, 2022. As a result, the current limit is now $500.0 million and $262.0 million is outstanding as at December 31, 2020 (2019 - $233.0 million). The Hydro Corporation Act, 2007 (the Act) limits Hydro's total borrowings outstanding at any point in time, which includes both short-term borrowings and long-term debt. Bill 33, passed on March 26, 2020, increased Hydro's total borrowing limit under the Act from $2.1 billion to $2.6 billion.

Historically, Hydro Regulated addressed longer-term capital funding requirements by issuing government guaranteed long-term debt in the domestic capital markets. However, in December 2017, Hydro Regulated's process changed; the Province now issues debt in the domestic capital markets, on Hydro Regulated's behalf, and in turn loans the funds to Hydro Regulated on a cost recovery basis. Any additional funding to address long-term capital funding requirements will require approval from the Province and the PUB.

27. SUPPLEMENTARY CASH FLOW INFORMATION

For the year ended December 31 (millions of Canadian dollars)	**2020**	2019
Trade and other receivables	**34**	5
Inventories	**11**	(9)
Prepayments	**(2)**	-
Trade and other payables	**(24)**	25
Changes in non-cash working capital balances	**19**	21
Related to:		
Operating activities	**21**	26
Investing activities	**(2)**	(5)
	19	21

28. SEGMENT INFORMATION

Hydro operates in three business segments. The designation of segments is based on a combination of regulatory status and management accountability.

Hydro Regulated activities encompass sales of electricity to customers within the Province that are regulated by the PUB. Hydro Non-Regulated activities include the sale of energy, purchased from Churchill Falls, to mining operations in Labrador West as well as costs of Hydro that are excluded from the determination of customer rates. Energy Marketing includes the sale of electricity and transmission to Energy Marketing.

	Hydro Regulated	Non-Regulated Activities	Energy Marketing	Total
(millions of Canadian dollars)	For the year ended December 31, 2020			
Energy sales	**557**	**50**	**4**	**611**
Other revenue	**6**	**-**	**20**	**26**
Revenue	**563**	**50**	**24**	**637**
Fuels	**158**	**-**	**-**	**158**
Power purchased	**75**	**43**	**4**	**122**
Operating costs	**135**	**1**	**-**	**136**
Transmission rental	**1**	**-**	**20**	**21**
Depreciation and amortization	**79**	**-**	**-**	**79**
Net finance expense	**90**	**-**	**-**	**90**
Other expense	**4**	**-**	**-**	**4**
Expenses	**542**	**44**	**24**	**610**
Profit for the year from operations	**21**	**6**	**-**	**27**
Share of profit of joint arrangement	**-**	**25**	**-**	**25**
Preferred dividends	**-**	**8**	**-**	**8**
Profit before regulatory adjustments	**21**	**39**	**-**	**60**
Regulatory adjustments	**(15)**	**-**	**-**	**(15)**
Profit for the year	**36**	**39**	**-**	**75**
Capital expenditures*	**90**	**-**	**-**	**90**
Total assets	**2,780**	**622**	**26**	**3,428**

***Capital expenditures include non-cash additions of $0.2 million contributed by Lower Churchill Management Corporation and $1.5 million of interest capitalized during construction.**

NEWFOUNDLAND AND LABRADOR HYDRO
NOTES TO THE NON-CONSOLIDATED FINANCIAL STATEMENTS

(millions of Canadian dollars)	Hydro Regulated	Non-Regulated Activities	Energy Marketing	Total
	For the year ended December 31, 2019			
Energy sales	608	44	5	657
Other revenue	5	(1)	21	25
Revenue	613	43	26	682
Fuels	217	-	-	217
Power purchased	84	42	4	130
Operating costs	136	5	-	141
Transmission rental	1	-	21	22
Depreciation and amortization	83	-	-	83
Net finance expense (income)	91	(1)	-	90
Other expense	8	-	-	8
Expenses	620	46	25	691
(Loss) profit for the year from operations	(7)	(3)	1	(9)
Share of profit of joint arrangement	-	27	-	27
Preferred dividends	-	8	-	8
(Loss) profit before regulatory adjustments	(7)	32	1	26
Regulatory adjustments	(37)	-	-	(37)
Profit for the year	30	32	1	63
Capital expenditures*	129	-	-	129
Total assets	2,735	597	12	3,344

*Capital expenditures include non-cash additions of $0.7 million contributed by Lower Churchill Management Corporation and $2.0 million of interest capitalized during construction.

Newfoundland and Labrador Hydro

Directors[1]	Officers
John Green Chairperson, NL Hydro Lawyer, McInnes Cooper	**Stan Marshall** Chief Executive Officer
Donna Brewer Retired Deputy Minister of Finance	**Jennifer Williams** President
Chris Loomis Professor (Retired) Memorial University of Newfoundland and Labrador	**Kevin Fagan** Vice President, Regulatory Affairs and Customer Service
Stan Marshall Chief Executive Officer, NL Hydro President and Chief Executive Officer, Nalcor Energy	**Terry Gardiner** Vice President, Engineering and Technology
Brendan Paddick (on leave of absence) CEO Columbus Capital Corp.	**Lisa Hutchens** Vice President, Financial Services
David Oake President Invenio Consulting Inc.	**Ronald LeBlanc** Vice President, Operations and NLSO
Fraser Edison President and CEO, Rutter Inc.	**Michael Ladha** Vice President, General Counsel, Corporate Secretary and Commercial
John Mallam Retired NL Hydro Executive	
William Nippard Director of Operations, Qulliq Energy Corporation	
Brian Walsh Retired FortisTCI Executive	
Head Office Newfoundland and Labrador Hydro PO Box 12400 Hydro Place, 500 Columbus Drive St. John’s, NL Canada A1B 4K7	

[1] Newfoundland and Labrador Hydro Board of Directors as at December 31, 2020.

Newfoundland and Labrador Hydro
Computation of Rate Base
Year Ended December 31, 2020
($000)

	2020	**2019**
Capital Assets - Return 4	2,708,003	2,610,468
Work in Progress [1]	24,988	37,417
	2,732,991	2,647,885
Deduct:		
Accumulated Depreciation - Return 6 [2]	523,797	449,739
Contributions in Aid of Construction - Return 7 [1]	50,680	45,593
Total Capital Assets	2,158,515	2,152,552
Deduct Items Excluded from Rate Base:		
Work in Progress [1]	(24,988)	(37,417)
Asset Retirement Obligations (net of amortization)	(768)	(67)
Net Capital Assets	2,132,758	2,115,068
Net Capital Assets, Previous Year	2,115,068	2,083,539
Unadjusted Average Capital Assets	2,123,913	2,099,304
Deduct:		
Average Net Capital Assets Excluded from Rate Base	(8,257)	(9,679)
Average Capital Assets	2,115,656	2,089,625
Cash Working Capital Allowance - Return 8	1,409	1,299
Fuel Inventory - Return 10	54,075	57,611
Supplies Inventory - Return 10	38,438	37,701
Average Deferred Charges - Return 11	100,981	119,811
Average Rate Base at Year-End - Return 12	**2,310,559**	**2,306,047**

[1] Contributions of $1.9 million (2019 - $5.9 million) related to capital assets not in service have been net in work in progress.

[2] Accumulated amortization is net of the Retirement Asset Pool and Removal Provision. Please refer to Return 6 for further details.

Newfoundland and Labrador Hydro
Capital Assets - Original Cost
Year Ended December 31, 2020
($000)

	Balance 31-Dec-2019	Adjustments During 2020	Additions During 2020	Retirements During 2020	Balance 31-Dec-2020
Power Generation					
Steam	178,499	439	10,281	(4,065)	185,153
Hydro	865,192	384	9,176	(353)	874,401
Diesel	96,916	306	15,705	(1,228)	111,699
Gas Turbine	184,754	16	3,310	-	188,079
	1,325,361	**1,145**	**38,472**	**(5,646)**	**1,359,332**
Substations	338,302	(357)	35,064	(510)	372,499
Transmission	554,359	(76)	7,412	(31)	561,664
Distribution	240,568	(69)	14,171	(197)	254,472
General Plant	79,196	7	4,362	(1,037)	82,528
Telecontrol	51,697	(140)	3,751	(1,869)	53,438
Total Depreciable Plant	**2,589,484**	**510**	**103,232**	**(9,290)**	**2,683,934**
Non-Depreciable Land	5,072	-	-	-	5,072
Plant Investment	2,594,556	510	103,232	(9,290)	2,689,007
Intangible	15,912	-	3,805	(721)	18,996
Total - Return 3	**2,610,468**	**510**	**107,037**	**(10,011)**	**2,708,003**

Newfoundland and Labrador Hydro
Capital Expenditures - Overview
Year Ended December 31, 2020
($000)

	Total P.U. Board Approved Expenditures for 2020	Total Actual Expenditures for 2020	Variance from 2020 Budget
Generation	26,860	16,935	9,925
Transmission and Rural Operations	92,352	57,333	35,019
General Properties	6,314	4,817	1,497
Allowance for Unforeseen Events	1,216	218	998
Supplemental Projects	7,911	8,166	(256)
New Projects less than $50,000 Approved by Hydro	100	87	14
Total Capital Budget	**134,752**	**87,555**	**47,197**

2020 Capital Budget Approved by Board Order No. P.U. 6(2020)	107,576
New Project Approved by Board Order No. P.U. 39(2019)	244
New Project Approved by Board Order No. P.U. 39(2019)	(193)
New Project Approved by Board Order No. P.U. 7(2020)	2,059
New Project Approved by Board Order No. P.U. 7(2020)	(1,800)
New Project Approved by Board Order No. P.U. 14(2020)	7,638
New Project Approved by Board Order No. P.U. 25(2020)	333
New Project Approved by Board Order No. P.U. 25(2020)	(333)
New Project Approved by Board Order No. P.U. 26(2020)	44
New Project Approved by Board Order No. P.U. 26(2020)	(44)
New Project Approved by Board Order No. P.U. 32(2020)	216
2020 New Projects under $50,000 Approved by Hydro	100
Total Approved Capital Budget Before Carryovers	**115,842**
Carryover Projects 2019 to 2020	18,910
Total Approved Capital Budget	**134,752**

Newfoundland and Labrador Hydro
Accumulated Depreciation
Year Ended December 31, 2020
($000)

	Property, Plant and Equipment	Intangible	Total
Balance, December 31, 2019	441,622	11,180	452,802
Add:			
Depreciation	77,794	1,508	79,302
Deduct:			
Retirements, Transfers and Adjustments	(6,536)	(722)	(7,258)
Accumulated Amortization Balance, December 31, 2020	512,880	11,966	524,846
Retirement Asset Pool			
Balance, December 31, 2019	(11,054)	-	(11,054)
Add:			
Net Loss on Retirement	(2,573)	-	(2,573)
Disposal Proceeds	510	-	510
	(13,117)	-	(13,117)
Removal Provision			
Balance, December 31, 2019	7,992	-	7,992
Add:			
Removal Depreciation	5,054	-	5,054
Less:			
Removal Costs	(978)	-	(978)
	12,068	-	12,068
Total Accumulated Amortization Balance, December 31, 2020	511,831	11,967	523,797

Depreciation Rates - 2020

Depreciation is calculated on a straight-line basis over the estimated useful lives of the assets as follows:

Generation Plant	
Hydroelectric	25 to 110 years
Thermal	20 and 70 years
Diesel	3 to 70 years
Transmission	
Lines	26 and 65 years
Terminal Stations	20 to 60 years
Distribution System	20 to 60 years
Other Assets	5 to 70 years

Newfoundland and Labrador Hydro
Contributions in Aid of Construction
Year Ended December 31, 2020
($000)

	Customers	Province/ Nalcor	Total
Gross Contributions			
December 31, 2019	18,995	33,306	52,301
2020 Additions[1]	924	6,116	7,040
December 31, 2020	19,919	39,423	59,341
Less:			
Accumulated Amortization			(8,662)
Net Balance December 31, 2020 - Return 3			**50,680**

[1] Contributions of $5.5 million (2019 - $6.0 million) that are related to capital assets that are in work in progress have been excluded from Contributions in Aid of Construction and included in work in progress.

Newfoundland and Labrador Hydro
Working Capital
Year Ended December 31, 2020
($000)

	2020	**2019** [1]
Calculation of Cash Working Capital Allowance		
Operating Expenses for the Year - Return 9	133,514	135,442
Add: Power Purchases [1]	74,689	83,537
Add: Transmission Expenses [1]	1,429	1,406
Total	209,632	220,386
Net Lag %[2]	2.41%	1.86%
Working Capital Allowance	5,052	4,099
Deduct: HST Adjustment	3,643	2,800
Working Capital Allowance - Return 3	1,409	1,299

[1] The power purchases for 2019 included $1.4M of transmission expense which is presented separately in 2020.

[2] Net Lag % is calculated as Net Lag Days (Revenue Lag less Expense Lag) divided by 365 days. In 2020, Hydro's revenue lag was 36 days (2019 - 36 days) and the expense lag was 27 days (2019 - 29 days) resulting in a Net Lag of 9 days (2019 - 7 days).

Newfoundland and Labrador Hydro
Statement of Operating Costs
Year Ended December 31, 2020
($000)

	2020	2019
Salaries and Benefits	84,442	84,589
System Equipment Maintenance	20,489	22,883
Office Supplies and Expenses	2,288	2,243
Professional Services	7,330	8,522
Insurance	3,785	3,507
Equipment Rentals	2,739	3,597
Travel	1,500	2,404
Miscellaneous Expenses	4,570	4,937
Building Rental and Safety	911	979
Transportation	1,215	1,359
Customer Costs	2,908	391
Cost Recoveries	1,337	31
Operating Costs - Return 8	**133,514**	**135,442**

Newfoundland and Labrador Hydro
Significant Operating Expense Variance
Year Ended December 31, 2020
($000)

	2020	2019	Increase (Decrease)
System Equipment Maintenance	**20,489**	**22,883**	**(2,394)**
Primarily due to variations in maintenance work activities year over year.			
Professional Services	**7,330**	**8,522**	**(1,192)**
Primarily due to the GRA and Cost of Service Hearing charges incurred in 2019, lower costs associated with the CDM Program incurred in 2020, partially offset by an increase in engineering consulting in 2020.			
Insurance	**3,785**	**3,507**	**278**
Premium increase in 2020 due to market rate increases.			
Equipment Rentals	**2,739**	**3,597**	**(858)**
Primarily due to lower amortization of the Holyrood Black Start Diesel lease costs.			
Travel	**1,500**	**2,404**	**(904)**
Primarily related to variations in work activities and travel restrictions associated with COVID-19 Health and Safety protocols.			
Miscellaneous Expenses	**4,570**	**4,937**	**(367)**
Primarily related to reduced training expenses in 2020 due to COVID-19 Health and Safety protocols.			
Customer Costs	**2,908**	**391**	**2,517**
Increased bad debt expense in 2020 associated with a general service customer.			
Other Cost (Recoveries) Charge	**1,337**	**31**	**1,306**
Primarily due to a lower CDM deferral in 2020 as a result of a reduction in CDM Program costs (attributed to COVID-19) along with higher Intercompany Admin fees.			

Newfoundland and Labrador Hydro
Inventory
Year Ended December 31, 2020
($000)

	Fuel		Supplies	
	2020	**2019**	**2020**	**2019**
Opening Balance	65,834	56,995	37,414	36,736
January	55,987	44,771	38,670	37,210
February	47,661	52,575	37,751	37,470
March	51,270	52,373	38,200	37,659
April	50,019	61,537	38,894	37,757
May	43,590	68,557	38,871	38,208
June	58,565	65,402	38,662	38,525
July	57,765	66,492	38,764	38,163
August	57,109	66,283	38,632	37,622
September	56,435	54,315	38,509	37,752
October	51,932	47,825	38,248	37,736
November	53,089	45,981	38,463	37,863
December	53,721	65,834	38,622	37,414
13-Month Average - Return 3	**54,075**	**57,611**	**38,438**	**37,701**

Newfoundland and Labrador Hydro
Deferred Charges
Year Ended December 31, 2020
($000)

	Board Order No.	2020	2019
Foreign Exchange Losses	P.U. 7(2002–2003)	45,296	47,453
Foreign Exchange On Fuel	P.U. 30(2019)	(656)	(444)
Conservation Demand Program	P.U. 30(2019)	8,750	9,683
Phase II Hearing Costs	P.U. 13(2016)	1,364	1,351
Asset Disposal	P.U. 13(2016)	311	330
Deferred Lease Costs	P.U. 38(2013)	132	449
Supply Deferrals	P.U. 30(2019)	59,703	35,452
Deferred Power Purchases	P.U. 5(1996–1997)	(213)	(244)
2018 Revenue Deficiency	P.U. 30(2019)	(1)	(891)
2019 Revenue Deficiency	P.U. 30(2019)	77	(515)
Hearing Costs	P.U. 16(2019)	-	550
Business System Transformation Program	P.U. 16(2019)	3,585	2,465
Reliability And Resource Adequacy	P.U. 29(2019)	765	179
Firm Energy Purchase	P.U. 3(2020)	-	(1,476)
Hydraulic Resource Optimization	P.U. 49(2018)	(1,268)	(272)
Frequency Converter	P.U. 35(2020)	(244)	-
Deferred Charges		117,601	94,070
Deduct:			
Deferred Charges Excluded From Rate Base [1]		(5,714)	(3,995)
Deferred Charges, End Of Current Year		111,887	90,075
Deferred Charges, End Of Prior Year		90,075	149,546
Average Deferred Charges For Rate Base - Return 3		**100,981**	**119,811**

[1] The calculation of Deferred Charges for Rate Base excludes Phase Two Hearing Costs of $1.4 million (2019 - $1.4 million), the Business System Transformation Deferral of $3.6 million (2019 - $2.5 million), as well as Reliability and Resource Adequacy Study Review of $0.8 million (2019 - $0.2). Recovery of these expenditures are subject to approval by the Board.

2020 Annual Return
Return 12: Return on Rate Base
Page 1 of 1

Newfoundland and Labrador Hydro
Return on Rate Base
Year Ended December 31, 2020
($000)

		2020	2019
(a)	Corporate Net Income - Return 1	74,092	63,255
	Deduct: Unregulated Earnings	38,064	34,053
	Regulated Net Income	36,028	29,202
	Add: Compliance Adjustments	-	(6,779)
	Add: Cost of Service Exclusions[1, 2]	7,311	12,256
	Add: Regulated Interest - Return 16	83,143	87,685
(b)	Regulated Return	126,482	122,364
(c)	Average Rate Base - Return 3	2,310,559	2,306,046
(d)	Rate of Return on Average Rate Base	5.47%	5.31%
	Lower end of Approved Range - 0.20	5.23%	5.23%
	Higher end of Approved Range + 0.20	5.63%	5.63%

[1] The Cost of Service Exclusions are comprised of the disallowed portion of the debt guarantee fee of $6.3 million (2019 - $6.3 million), depreciation on assets excluded from rate base of $1.0 million (2019 - $1.7 million) and the write off of the CBPP frequency converter of $Nil (2019 - $4.2 million).

[2] An adjustment was made to the Cost of Service Exclusions for 2019 due to Board Order P.U. 38(2019), where the Board found that the loss on the sale of the frequency converter to its customer of approximately $4.2 million shall not be recovered from Hydro's other customers.

Newfoundland and Labrador Hydro
Return on Regulated Average Retained Earnings
Year Ended December 31, 2020
($000)

		2020		2019
Total Equity - Hydro as per Balance Sheet, Return 1		1,085,560		1,025,082
Add: Compliance Adjustments		-		-
		1,085,560		1,025,082
Deduct: Share Capital		22,504		22,504
Contributed Surplus		146,243		146,861
Accumulated OCI		(22,073)		(21,834)
Ending Retained Earnings as per Balance Sheet, Return 1		938,886		877,551
Deduct: Non-Regulated Retained Earnings				
Beginning Non-Regulated Retained Earnings	537,774		511,374	
Non-Regulated Net Income for the Year	38,064		34,053	
Non-Regulated Dividends for the Year	(12,760)		(7,653)	
Ending Non-Regulated Retained Earnings		563,078		537,774
Regulated Retained Earnings, end of year		375,807		339,777
Add:				
Regulated Contributed Surplus		100,000		100,000
Retained Earnings Cost of Service Exclusions [1]		43,113		35,802
Total Regulated Equity, end of year [1]		518,920		475,579
Regulated Equity, beginning of year		475,579		440,913
Regulated Average Equity [1]		497,250		458,246
Net Income - Return 1		74,092		63,255
Add: Compliance Adjustments		-		(6,779)
Deduct: Non-Regulated Net Income		38,064		34,053
Hydro Regulated Earnings		36,028		22,423
Cost of Service Exclusions [1]		7,311		12,256
Regulated Earnings [1]		43,339		34,679
Rate of Return on Regulated Equity [1]		8.72%		7.57%

[1] Refer to Note 2 in Return 12.

Newfoundland and Labrador Hydro
Capital Structure
Year Ended December 31, 2020
($000)

	2020		2019		Average	
	Amount	Percent	Amount	Percent	Amount	Percent
Hydro						
Debt (Return 15)	1,851,431	63.0%	1,841,568	64.2%	1,846,500	63.6%
Equity (Return 13)	1,085,560	37.0%	1,025,082	35.8%	1,055,321	36.4%
	2,936,991	**100.0%**	**2,866,651**	**100.0%**	**2,901,821**	**100.0%**
Hydro Regulated						
Debt (Return 15)	1,836,875	74.9%	1,824,835	76.2%	1,830,855	75.5%
Funded Employee Future Benefits	83,790	3.4%	79,680	3.3%	81,735	3.4%
Funded Asset Retirement Obligation	14,276	0.6%	14,366	0.6%	14,321	0.6%
Equity (Return 13)[1]	518,920	21.1%	475,579	19.9%	497,250	20.5%
	2,453,861	**100.0%**	**2,394,461**	**100.0%**	**2,424,161**	**100.0%**

[1] Refer to Note 2 in Return 12.

Newfoundland and Labrador Hydro
Cost of Debt
Year Ended December 31, 2020
($000)

	2020	2019	Average
Long-Term Debt	1,772,001	1,782,533	1,777,267
Promissory Notes	262,000	233,000	247,500
Sinking Funds	(182,570)	(173,965)	(178,267)
Total Debt	**1,851,431**	**1,841,568**	**1,846,500**
Add back Mark to Market Value	-	-	-
Net Debt	1,851,431	1,841,568	1,846,500
Non-Regulated Debt Pool	(14,556)	(16,733)	(15,645)
Total Regulated Debt - Return 14	**1,836,875**	**1,824,835**	**1,830,855**
Current Year Interest Expense - Return 16			86,556
Cost of Debt			4.73%

Newfoundland and Labrador Hydro
Interest Expense
Year Ended December 31, 2020
($000)

	2020	2019
Gross Interest		
Long-Term Debt	92,475	92,475
Promissory Notes and Short Term	2,741	3,709
	95,216	96,184
Amortization of Debt Discount and Financing Expenses	(156)	(170)
Provision for Foreign Exchange	2,157	2,157
Interest Earned	(13,029)	(12,324)
Debt Guarantee Fee - Hydro[1]	8,624	8,605
Other	179	(224)
	92,991	94,228
(Deduct):		
Cost of Service Exclusions[1]	(6,348)	(6,348)
Non Regulated Interest	(87)	306
Interest for Cost of Debt - Return 15	86,556	88,186
(Deduct):		
Interest Capitalized During Construction	(1,516)	(1,989)
Add:		
Interest charged on RSP	(1,897)	1,488
Regulated Net Interest - Return 12	83,143	87,685
(Deduct):		
Provision for Foreign Exchange	(2,157)	(2,157)
Add:		
Cost of Service Exclusions [1]	6,348	6,348
Accretion of ARO	289	338
Regulated Interest (PUB Quarterly)	87,623	92,214
(Deduct):		
Interest charged on RSP	1,897	(1,488)
Add:		
Non Regulated Interest	87	(306)
Interest - Return 1	89,607	90,420

[1] As per Board Order No. P.U. 49(2016), Hydro has excluded the disallowed portion of the debt guarantee fee.

Newfoundland and Labrador Hydro
Rate Stabilization Plan - Activity
Year Ended December 31, 2020
($000)

	Utility						Industrial						
Month	**Load Variation**	**Allocation Fuel Variation**	**Allocation Rural Rate Alteration**	**Financing Charges**	**Adjustment**	**Transfers**	**Cumulative Net Balance**	**Load Variation**	**Allocation Fuel Variation**	**Financing Charges**	**Adjustment**	**Transfers**	**Cumulative Net Balance**
Opening Balance							(3,487)						2,722
Adjustment							79						6
Adjusted Opening Balance							(3,408)						2,728
January	(2,875)	(2,234)	(401)	(15)	1,333	-	(7,600)	(271)	(210)	12	-	-	2,260
February	(1,007)	(1,513)	(363)	(34)	1,243	-	(9,274)	(97)	(144)	10	(85)	-	1,944
March	(1,608)	(4,071)	(365)	(41)	1,237	17,990	3,868	(148)	(379)	9	(85)	1,773	3,114
April	(3,702)	(4,892)	(316)	17	926	-	(4,098)	(327)	(431)	14	(54)	-	2,316
May	(3,404)	(2,819)	(298)	(18)	761	-	(9,875)	(287)	(228)	10	(61)	-	1,749
June	(3,192)	(194)	(269)	(44)	542	50,576	37,545	(278)	(9)	8	(59)	-	1,411
July	(3,370)	(79)	2,486	(58)	546	-	37,071	(259)	27	6	(61)	-	1,124
August	(3,759)	88	848	164	540	-	34,952	(258)	55	5	(56)	-	871
September	(3,273)	(49)	(244)	154	544	(1,342)	30,742	(238)	18	4	(59)	-	595
October	(4,780)	(2,123)	(283)	142	713	-	24,411	(325)	(135)	3	(43)	(130)	(35)
November	(3,969)	(6,892)	(321)	108	949	-	14,287	(215)	(480)	(0)	(59)	-	(789)
December	(3,386)	(7,866)	(396)	63	1,060	-	3,763	(206)	(561)	(3)	(64)	-	(1,622)
Year-to-Date	**(38,323)**	**(32,644)**	**80**	**439**	**10,395**	**67,224**	**3,763**	**(2,908)**	**(2,477)**	**76**	**(686)**	**1,643**	**(1,622)**
Hydraulic Allocation							9,691						735
Total							**13,454**						**(887)**
							To Return 18						To Return 18

Newfoundland and Labrador Hydro
Rate Stabilization Plan - Balances
Year Ended December 31, 2020
($000)

	Hydraulic				From Return 17		
Month	**Net Hydraulic Production Variation**	**Financing Charges**	**Transfers**	**Cumulative Variance and Financing Charges**	**Utility Balance**	**Industrial Balance**	**Cumulative Net Balance**
Opening Balance	-	-	-	16,930	(3,487)	2,721	16,164
Adjustment	-	-	-	-	79	6	85
Adjusted Opening Balance	-	-	-	16,930	(3,408)	2,728	16,250
January	(14,382)	75	-	2,623	(7,600)	2,260	(2,717)
February	(1,664)	12	-	970	(9,274)	1,944	(6,360)
March	6,957	4	-	7,931	3,868	3,114	14,914
April	6,873	35	-	14,839	(4,098)	2,316	13,057
May	9,500	66	-	24,405	(9,875)	1,749	16,279
June	9,650	108	-	34,163	37,545	1,411	73,119
July	5,226	151	-	39,540	37,071	1,124	77,735
August	4,827	175	-	44,541	34,952	871	80,364
September	1,162	197	-	45,900	30,742	595	77,237
October	745	203	-	46,848	24,411	(35)	71,224
November	(18,393)	207	-	28,662	14,287	(789)	42,160
December	8,961	127	-	37,749	3,763	(1,622)	39,890
Year-to-Date	19,462	1,357	-	20,819	7,171	(4,350)	23,639
Hydraulic Allocation	(9,098)	(1,357)	-	(10,455)	9,691	735	(28)
Total	**10,364**	**-**	**-**	**27,293**	**13,454**	**(887)**	**39,861**

Newfoundland and Labrador Hydro
Assessable Revenue
Year Ended December 31, 2020
($000)

	2020	2019
Electricity Sales [1]	631,064	649,745
Rate Stabilization (Return 17) [2]	(31,553)	3,955
CDM Rider	1,489	1,432
Energy Supply Deferral & Revenue Deficiency[1]	9,536	1,841
Energy Sales (Return 1)	610,536	656,973
Other Revenue [3]	25,937	25,365
Total Revenue (Return 1)	636,473	682,337
Deduct Regulated Hydro Revenue That Is Not Assessable:		
Input Tax Credits	131	162
Contribution in Aid of Construction	1,087	1,170
Supplier Discounts[3]	-	-
Rural Rate Alteration[4]	2,009	1,035
CBPP Frequency Converter Revenue Adjustment	243	-
Ponding Revenue Deferral[5]	1,528	866
Deduct Non-Regulated Revenue:		
Recall/Export[5]	3,624	4,950
Iron Ore Company of Canada	41,316	39,751
Tacora/Wabush Mines	8,546	3,865
Other Revenue	20,443	20,679
	78,927	72,479
Assessable Revenue	557,546	609,859

[1] The 2019 Return has been restated for presentation purposes.

[2] Includes Utility adjustment ($10,395) (2019 - $2,543) and Industrial adjustment $686 (2019 - $1,411) from Return 17.

[3] Adjustments have been made to 2019 Other Revenue to exclude Supplier Discounts and Misc Recoveries as these are included with O&M.

[4] Rural Rate Alteration was excluded from the 2019 Assessable Revenue.

[5] The Recall/Export for 2019 included $0.9M of Ponding Revenue Deferral which is presented separately in 2020.

Newfoundland and Labrador Hydro
2020 Annual Report on the Rural Deficit

	2020 [1]			
Rural Deficit Areas	**Revenues ($)**	**Cost of Service before Deficit and Revenue Allocation ($)**	**Revenue Credits ($)**	**Deficit ($)**
Island Interconnected	54,792,068	68,574,245	-	(13,782,177)
Island Isolated	1,391,617	9,631,323	-	(8,239,706)
Labrador Isolated	9,243,697	33,327,718	-	(24,084,021)
L'Anse au Loup	2,903,269	5,864,895	-	(2,961,626)
DND Revenue Credit[2]	-	-	-	-
Total	68,330,652	117,398,181	-	(49,067,529)

	2020				
Rural Deficit Areas	**Number of Communities[3]**	**Number of Customers**	**Cost per kWh ($)**	**Deficit per Customer ($)**	**Cost Recovery Ratio**
Island Interconnected	146	22,998	0.16	(599)	0.80
Island Isolated	6	775	1.68	(10,632)	0.14
Labrador Isolated	15	2,719	0.80	(8,858)	0.28
L'Anse au Loup	8	1,042	0.24	(2,842)	0.50
Total	**175**	**27,534**	**0.24**	**(1,782)**	**0.58**

	Forecast Deficit ($)				
Rural Deficit Areas	**2021[1]**	**2022[4]**	**2023[4]**	**2024[4]**	**2025[4]**
Island Interconnected	(14,148,021)	-	-	-	-
Isolated Systems	(35,073,209)	-	-	-	-
DND Revenue Credit	-	-	-	-	-
Total	(49,221,230)	**-**	**-**	**-**	**-**

[1] The 2020 Rural Deficit and the 2021 Forecast Rural Deficit calculations are based on proforma Cost of Service Studies. The 2021 Forecast Rural Deficit excludes any impacts of commissioning of the Muskrat Falls Project.

[2] Hydro did not receive DND Revenue Credit in 2020.

[3] Hydro's definition of Community corresponds to the "Town Code" in its customer information system. Some smaller communities may be combined if they share a single postal code.

[4] Hydro has not provided forecast deficit figures for 2022–2025 due to the uncertainty regarding post-Muskrat Falls rates.

2020 Electrification, Conservation and Demand Management Report

April 1, 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Contents

List of Appendices

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1.0 Introduction

Electrification, Conservation and Demand Management ("CDM") activities undertaken by Newfoundland and Labrador Hydro ("Hydro") include both joint utility programs offered by Hydro and Newfoundland Power ("Utilities") through the takeCHARGE partnership, and programs specifically targeted to Hydro's customers. This report focuses primarily on the costs and initiatives implemented by Hydro, including Hydro's portion of costs related to the delivery of joint initiatives in 2020.

In 2020, CDM activities were impacted by the COVID-19 pandemic. Hydro was required to plan and execute programs while ensuring employee, public, and contractor safety. Program advertising and logistics were adjusted throughout the year to be consistent with COVID-19 safety protocols. Many businesses were impacted by restrictions and closures, leading to feelings of uncertainty and lower customer participation in CDM business programs. Furthermore, the unexpected issuance of a new Request for Proposals ("RFP") and additional safety planning led to delayed execution for the Isolated Systems Community Energy Efficiency Program, resulting in lower savings than previous years. Overall, Hydro's programs have achieved 950 MWh of annual incremental energy savings in 2020 and have accumulated energy savings of 51,731 MWh since 2009.

2.0 Coordination and Context

2.1 Utility Planning

Starting with the initial CDM plan in 2008, Hydro and Newfoundland Power have designed and implemented a joint utility portfolio of programs for electricity customers in Newfoundland and Labrador.[1] Currently, programs offered through the joint utility model are available for residential, commercial, and industrial customers and provide rebate options to address energy savings for electricity customers. In the most recent five-year conservation plan developed by the Utilities, the CDM plan was expanded to include beneficial electrification programming that will be implemented beginning in 2021.

[1] The Five-Year Energy Conservation Plan: 2008–2012 was filed with the Board of Commissioners of Public Utilities ("Board") on June 27, 2008. The Five-Year Energy Conservation Plan: 2012–2016 was filed with the Board on September 14, 2012. The Five-Year Conservation Plan: 2016–2020 was filed with the Board on November 12, 2015. The Five-Year Electrification, Conservation and Demand Management Plan 2021–2025 was filed with the Board by Newfoundland Power on December 16, 2020. Hydro intends to file its application related to the delivery of programs identified in the Five-Year Electrification, Conservation and Demand Management Plan 2021–2025 early in the second quarter of 2021.

Hydro has also been developing programs outside the joint utility process to provide customers with additional opportunities to conserve and to provide feedback for expanded offerings of joint utility programs. For example, Hydro's retailer coupon program offered in 2010–2011 was the impetus for the Instant Rebate Program that was launched provincially in 2014. In 2020, this program continued to provide point-of-purchase rebates for a range of technologies, including LED lighting and draft proofing.

Other CDM activities for 2020 include the continuation of the residential and commercial rebate programs, the Isolated Systems Community Energy Efficiency Program, the custom industrial program, and the delivery of three Government-funded programs. The description of the programs offered during 2020 through both the joint utility partnership and those specific to Hydro's customers is provided as Appendix A to this report.

The Utilities continuously evaluate customer conservation programs and periodically undertake third-party program evaluations to refine program design and support future planning.

2.2 Government Engagement

Hydro continues to have a positive working relationship with the Provincial and Federal Governments, and remains engaged in dialogue on potential programming, policy, and partnership opportunities. In 2020, Hydro delivered three Government-funded programs to customers: the Low Carbon Economy Leadership Funding Program, the Heat Pump Rebate Program, and the Energy Efficient Loan Program.

Hydro continued to deliver the Low Carbon Economy Leadership Funding program to its customers on behalf of the Federal and Provincial Governments through insulation and thermostat rebates to customers in oil-heated homes. Twelve insulation rebates and two thermostat rebates were approved in areas served by Hydro in 2020. The costs associated with these rebates have been fully recovered by Hydro from the Provincial Government.

In 2020, Hydro concluded administration of the Heat Pump Rebate Program on behalf of the Provincial Government. The program provided 848 customers with $1,000 rebates to assist with the cost of installing a high-efficiency heat pump in their homes. Costs associated with this program were fully recovered by Hydro from the Provincial Government.

Hydro also concluded working with the Provincial Government in 2020 to deliver the three-year Energy Efficient Loan Program ("EELP") in March 2020. EELP helped cover upfront costs when purchasing heat pumps, insulation, and home energy assessments. The program offered a reduced interest rate of prime plus 1.5% (versus Hydro's standard financing rate of prime plus 4%). Over the three-year duration of the program, Hydro approved 26 low-interest applications. All costs for this program were fully recovered from the Provincial Government.

3.0 2020 Conservation and Demand Management Program Costs and Energy Savings

3.1 Portfolio Level Program Costs and Energy Savings

Table 1 and Table 2 describe Hydro's total CDM program expenses and energy savings from 2009 to 2020 across all of Hydro's systems. Further detail and a breakdown of the costs that will be recovered through the CDM Deferral Account[2] and the associated energy savings are provided in Section 7, Program Energy Savings and Program Costs.

Table 1: Hydro's CDM Portfolio Spending ($000)[3,4,5]

	2009-2014	2015	2016	2017	2018	2019	2020
Residential							
Windows	496	2	-	-	-	-	-
Insulation	615	70	61	102	88	198	96
Thermostats	196	20	22	55	44	75	41
Residential Benchmarking	-	-	49	45	23	27	9
Coupon Program	275	-	-	-	-	-	-
Block Heater Timer	47	-	-	-	-	-	-
Heat Recovery Ventilator	18	6	6	7	10	11	3
Isolated Systems Community(Residential)	2,344	530	451	936	981	577	239
Instant Rebate	253	239	247	159	169	140	47
Appliance Retirement Pilot	-	56	(12)	-	-	-	-
Isolated Load Control Pilot	-	6	158	17	5	17	-
Commercial							
Isolated System Community(Commercial)	-	-	-	-	-	412	52
Commercial Lighting	148	18	-	-	-	-	-
ISBEP	304	7	45	41	99	24	23
Business Efficiency Program	146	152	205	155	155	118	60
Industrial	1,887	(102)	28	41	20	142	-
Total	**6,729**	**1,004**	**1,260**	**1,559**	**1,593**	**1,741**	**570**

[2] Hydro defers costs associated with delivering CDM programs in the CDM Cost Deferral Account (excludes program costs for the Labrador Interconnected System).
[3] Credits are due to an overstated accrual in a prior year.
[4] Program costs for 2020 were less than previous years due to lower program participation attributed to the COVID-19 pandemic and delayed implementation of the Isolated Systems Community program.
[5] Numbers may not add due to rounding.

Table 2: Hydro's CDM Portfolio Annual Energy Savings (MWh)[6]

	2009-2014	2015	2016	2017	2018	2019	2020	Life to Date
Residential								
Windows	431	10	-	-	-	-	-	441
Insulation	1,884	105	72	155	139	80	156	2,592
Thermostats	189	34	44	59	62	46	60	495
Residential Benchmarking	-	-	-	131	234	155	-	520
Coupon Program	320	-	-	-	-	-	-	320
Block Heater Timer	288	-	-	-	-	-	-	288
Heat Recovery Ventilator	6	5	5	4	12	5	1	38
Isolated Systems Community(Residential)	4,129	1,426	512	1,141	1,064	749	394	9,415
Instant Rebate	148	164	191	90	300	350	95	1,339
Commercial								
Isolated Systems Community(Commercial)	-	-	-	-	-	448	75	523
Commercial Lighting	513	124	-	-	-	-	-	637
ISBEP	140	67	241	24	205	41	49	767
Business Efficiency Program	107	797	735	908	429	234	120	3,330
Industrial	25,595	-	177	-	162	5,092	-	31,026
Total	**33,750**	**2,734**	**1,977**	**2,513**	**2,608**	**7,200**	**950**	**51,731**

3.2 Residential Programs

Hydro's residential portfolio included four programs offered jointly by the Utilities (insulation, thermostats, heat recovery ventilators ("HRV"), and instant rebates) and one offered solely by Hydro (the Isolated Systems Community Energy Efficiency Program). Throughout 2020, Hydro continued to promote the takeCHARGE programs and technologies. Local advertising and building partnerships with retailers remains a priority and is an integral factor in the promotion of customer rebate programs.

3.3 Commercial Programs

Hydro's Business Efficiency Program ("BEP") and Isolated Business Efficiency Program ("ISBEP") include prescriptive product rebates for heating and lighting controls and a custom program for individual customer facilities. Both programs continued to be delivered to business customers in the Hydro's interconnected and isolated areas in 2020. These programs provide technical support to identify economical energy efficiency opportunities and provide financial support for capital upgrades. The total annual energy savings achieved as a result of Hydro's business programs in 2020 was 169 MWh.

[6] Numbers may not add due to rounding.

Hydro continues to engage with lighting distributors to promote the sale of high performance lighting products. In 2020, Hydro expanded its Business Efficiency Program by adding prescriptive rebates for LED luminaires, T5 LED, and LED parking lot lighting.

Commercial facility audits continue to be utilized to engage customers in the Isolated Systems Business Efficiency Program and the Business Efficiency Program. The intent of the audits is to facilitate the identification of opportunities, technical analysis and support, and project completion.[7] In 2020, two commercial facility audits were completed in the interconnected system; however, COVID-19 safety precautions limited the number of customer facilities that could be audited. In addition, six customers completed projects involving upgrades and improvements in lighting, insulation, and refrigeration systems in Hydro's isolated and interconnected service areas.

3.4 Isolated System Community Program

The Isolated Systems Community Energy Efficiency Program is specifically targeted to residential and commercial customers in Hydro's isolated diesel systems. The objective of the program is to provide outreach, education, and energy efficient products free of charge to residential and business customers in the diesel system communities within Newfoundland and Labrador. From 2012 to 2020, the program installed 135,047 energy efficient products, resulted in total energy savings of approximately 10 GWh, and provided employment for over 55 residents of these communities.

The Isolated Systems Community Energy Efficiency Program includes residential and commercial direct installations and focuses on building knowledge and capacity in the communities by hiring and training local representatives. These representatives work within their own communities to promote the program, offer useful information on energy use, and provide direct installation of energy efficient products.

In 2020, the Isolated Systems Community Energy Efficiency Program required a new RFP to be issued that was awarded to EcoFitt. Program implementation was delayed due to the RFP and additional planning requirements to ensure safety when entering customer residences and businesses during the COVID-19 pandemic. Drop-off kits with energy efficient products were added to the existing direct installation framework to reduce comply with COVID-19 safety protocols.

[7] Approximately 130 audits have been conducted in total since 2012.

In 2020, 633 residential and 78 business customers received direct installation or drop-off kits totalling 8,852 products consisting of water saving technologies, LED specialty bulbs, smart power-strips, and weather stripping products. While this work was ongoing, information was collected about the type of lighting, heating, and appliances in the homes and businesses, which will be used for future program planning. A program evaluation strategy was performed to ensure product savings and validation processes are consistent with best practices and future portfolio evaluations.

3.5 Industrial Program

Since 2010, Hydro has delivered the Industrial Energy Efficiency Program, which offers support and financial incentives for Hydro's industrial customers based on projects for lighting retrofits, process improvements, equipment changes, loss prevention (e. g., heat, steam energy), and funding for energy audit consultant reports. Promotion of the Industrial Energy Efficiency Program is facilitated through Hydro's Key Account Management framework to support improved project planning, scheduling, and execution. Within this framework the industrial customers are directly engaged with their Key Accounts Specialist to assist with the Industrial Energy Efficiency Program. This also permits Hydro to better understand customer facilities, processes, plans and schedules for potential efficiency improvement projects. The Industrial Energy Efficiency program had no projects completed in 2020 due to industrial customers reporting they were concentrating work activities on core business operations during the COVID-19 pandemic; however, Hydro's Key Accounts Specialist remains engaged with industrial customer to assist in future projects.

4.0 Electrification

In 2020, the Board recommended the Utilities develop a plan for beneficial electrification to manage future system peak demand and realize rate mitigation benefits. The 2020–2034 Potential Study prepared by Dunsky Energy Consulting was used to evaluate market potential of various electrification technologies and develop programming for which planning is underway.[8] The anticipated timeframe for implementation of the identified electrification programs through takeCHARGE is 2021/2022. The 2020–2034 Potential Study identified high positive potential in the electric vehicle sector, provided customer adoption barriers such as electric vehicle charging station availability and high purchase pricing are reduced.

[8] Subject to regulatory approval.

In 2020, Hydro began construction on the province's first electric vehicle fast-charging network, which is an important first step to making electric vehicles more accessible in the province. The charging network consists of 14 fast charging stations located, on average, every 70 km from St. John's to Port Aux Basques and is anticipated to be completed in 2021. Funding for the network was provided by Hydro, the Provincial Government, and the Federal Government through Natural Resources Canada's Electric Vehicle and Alternative Fuel Infrastructure Deployment Initiative.

5.0 Planning and Evaluation

During 2020, the following external evaluations and surveys were completed to measure customer awareness, interest, and uptake in current programs:

- Socket saturation survey - to determine the prevalence of LEDs used for lighting in customers' homes, as a means of informing future program planning;
- Annual marketing survey - to assess home energy use and energy saving practices, as well as awareness of, and participation in, the takeCHARGE programs; and
- The Electrification, Conservation and Demand Management Plan 2021–2025 (the "2021 Plan") was developed by the Utilities and provided to the Board by Newfoundland Power in December 2020. It introduces customer electrification programs while continuing to facilitate and develop conservation and demand management programs. Electrification programming includes electric vehicle and charging infrastructure rebate programs in addition to a custom electrification program for commercial facilities. The custom demand program will be evaluated along with an electric vehicle demand response pilot program to manage system peaks and realize the rate mitigation benefits of electrification. Long-standing CDM programs will continue and expand to offer incentives for duct insulation, air sealing, and the distribution of energy efficiency kits to low-income customers.

6.0 Outreach and Support

During 2020, Hydro continued to partner with Newfoundland Power to deliver the takeCHARGE program which offers customer education and conservation awareness activities, primarily through promotion of its takeCHARGE rebate programs and outreach activities. Residential and business programs are promoted through activities including mass media marketing, targeted promotions, community outreach, school programming, trade ally development, partnerships, and events.

The advertising campaign includes newspaper, radio, online and social media advertisements. Campaigns run throughout the year for insulation, thermostats, HRVs, instant rebates, heat pump education and the Business Efficiency Program. The media is chosen based on the time of year that programs are in market and consumer purchasing behaviours.

The takeCHARGE team is also active on social media through a joint utility Facebook page which has over 15,000 likes and over 3,100 followers, as well as a YouTube channel, Twitter account, and website. The takeCHARGE website continues to be a leading source of information for customers seeking energy efficiency information. In 2020, there were 672,759 page views, of which 81% were new visitors. The top three pages visited were the insulation rebate, heat pumps and the thermostat rebate.

Hydro engages with retailers, suppliers, students, and other groups through presentations and interactive booth displays to promote programs, answer questions and promote energy conservation. The takeCHARGE Town Challenge initiative invites municipalities to submit proposals that will support their efforts to develop or improve energy conservation or energy efficiency projects. Over the last nine years, winning municipalities have been awarded a total of $115,000 to complete their proposed projects. The takeCHARGE Make the Switch Bulb Giveaway provides LED bulbs to selected non-profit organizations and other groups to help reduce operational lighting costs in their facilities or to help their members/residents be more energy efficient through the use of LED bulbs. In 2020, Hydro distributed 1,000 bulbs to five groups and also worked with Newfoundland Power to distribute 10,000 bulbs to local food banks. The takeCHARGE school contests for kindergarten to grade 6 classes and grade 7 to grade 12 classes were administered to support students' understanding of why saving energy is important and to demonstrate what they can do to conserve energy.

The 12th annual takeCHARGE Energy Efficiency Week was held from September 28 –October 4, 2020 and Business Efficiency Week was held from November 30–December 6, 2020. Both promotional weeks were dedicated to providing customers with information to assist them in saving energy and money through reducing their energy consumption. During each week, a full social media campaign was launched and online webinars were held to engage customers.

In 2020, takeCHARGE was the recipient of two ENERGY STAR Canada Awards. The awards recognized best in class as utility program of the year and promotional campaign of the year.

1 Table 3 shows Hydro's costs to provide education and outreach, support, and planning for its CDM
2 programs from 2009 to 2020.

Table 3: Hydro's Support Costs ($000)[9]

	2009-2014	2015	2016	2017	2018	2019	2020
Education	1,073	154	138	111	63	124	68
Support	276	68	42	40	47	41	46
Planning	1,163	442	250	251	128	178	142
Total	**2,512**	**664**	**429**	**401**	**238**	**343**	**257**

3 7.0 Program Energy Savings and Program Costs

4 Table 4 provides the estimated annual energy savings from programs for which costs are deferred by
5 Hydro in the CDM Cost Deferral Account and recovered from customers following approval of the Board.

Table 4: Energy Savings from Island Interconnected and Isolated Systems CDM Program Activities (MWh)[10,11]

	2009-2014	2015	2016	2017	2018	2019	2020	Life to Date
Residential								
Windows	193	4	-	-	-	-	-	197
Insulation	670	52	40	111	76	54	117	1,121
Thermostats	92	23	33	43	46	34	44	317
Residential Benchmarking	-	-	-	131	234	155	-	520
Coupon Program	213	-	-	-	-	-	-	213
Block Heater Timer	-	-	-	-	-	-	-	-
Heat Recovery Ventilator	2	-	1	-	1	1	-	4
Isolated Systems Community(Residential)	4,129	1,426	512	1,141	1,064	749	394	9,415
Instant Rebate	80	71	21	9	86	153	18	439
Commercial								
Isolated Sytem Community(Commercial)	-	-	-	-	-	448	75	523
Commercial Lighting	161	46	-	-	-	-	-	207
ISBEP	140	67	241	24	205	41	49	767
Business Efficiency Program	73	794	719	601	295	99	97	2,677
Industrial	25,595	-	177	-	162	-	-	25,934
Total	**31,348**	**2,484**	**1,744**	**2,060**	**2,170**	**1,735**	**794**	**42,335**

[9] Numbers may not add due to rounding.
[10] Hydro's CDM Cost Deferral Account does not capture spending associated with CDM programs offered to customers on the Labrador Interconnected system, therefore Table 4 does not reflect energy savings associated with these programs.
[11] Numbers may not add due to rounding.

Table 5 provides a breakdown of annual CDM program costs included in the CDM Cost Deferral Account. Deferred costs associated with the delivery of programs include direct costs for advertising, salaries, rebates and other expenses directly associated with a specific program. The deferred costs are recovered from customers through the CDM Cost Recovery Adjustment and vary depending on the uptake of the program and the number of programs offered.

Table 5: CDM Program Costs Included in the CDM Cost Deferral Account[12,13,14]($000s)

	2009-2014	2015	2016	2017	2018	2019	2020
Residential							
Windows	437	1	-	-	-	-	-
Insulation	516	62	57	93	80	193	88
Thermostats	178	19	21	53	43	75	40
Residential Benchmarking	-	-	49	45	23	27	9
Coupon Program	236	-	-	-	-	-	-
Block Heater Timer							
Heat Recovery Ventilator	11	4	4	5	5	10	3
Isolated Systems Community(Residential)	2,344	530	451	936	981	577	239
Instant Rebate	220	186	143	104	130	108	41
Appliance Retirement Pilot	-	56	(12)	-	-	-	-
Isolated Load Control Pilot	-	6	158	17	5	17	-
Commercial							
Isolated Systems Community(Commercial)	-	-	-	-	-	412	52
Commercial Lighting	93	11	-	-	-	-	-
ISBEP	304	7	45	41	99	24	23
Business Efficiency Program	132	134	207	138	141	100	60
Industrial	1,846	(115)	27	41	20	(30)	-
Total	**6,317**	**902**	**1,152**	**1,474**	**1,528**	**1,512**	**555**

8.0 Program Participation and Savings

Table 6 provides statistics on participation in each of Hydro's programs. The transaction units are specific to each program. The Residential Energy Star Window, Insulation, Thermostat and HRV Programs reflect approved rebates. The Coupon Program reflects numbers of coupons redeemed on energy efficient products. The Commercial Lighting and Instant Rebate Programs reflect the number of products rebated through the programs. The Block Heater Timer Program reflects the number of timers determined to be installed through post-giveaway surveys or coupon redemption. The Isolated Systems Business Efficiency Program, Business Efficiency Program, and Industrial Efficiency Programs reflect the number of completed retrofit projects. The Isolated Systems Program denotes the number of residential

[12] Credits are due to an overstated accrual in a prior year.
[13] Program costs for 2020 were less than previous years due to lower program participation attributed to the COVID-19 pandemic and delayed implementation of the Isolated Systems Community program.
[14] Numbers may not add due to rounding.

and commercial customer premises that received direct installations. Finally, the Residential Benchmarking Program indicates the number of customers included in the treatment group.

Table 6: Life-to-Date Program Participation

	2009-2014	2015	2016	2017	2018	2019	2020	Total
Residential								
Windows	204	7	-	-	-	-	-	211
Insulation	267	35	31	39	42	32	57	503
Thermostats	152	15	63	56	66	46	56	454
Residential Benchmarking	-	-	1,000	1,000	1,000	1,000	-	4,000
Coupon Program	9,010	-	-	-	-	-	-	9,010
Block Heater Timer	629	-	-	-	-	-	-	629
Heat Recovery Ventilator	12	9	8	7	21	8	1	66
Isolated Systems Community(Residential)	3,689	965	345	1,007	727	940	633	8,306
Instant Rebate	6,920	4,551	26,601	9,764	19,285	23,293	2,863	93,277
Commercial								
Isolated Systems Community(Commercial)	-	-	-	-	-	220	87	307
Commercial Lighting	1,607	323	-	-	-	-	-	1,930
ISBEP	6	1	5	3	10	4	2	31
Business Efficiency Program	4	12	23	46	34	13	22	154
Industrial	5	-	1	-	1	2	-	9
Total	**22,505**	**5,918**	**28,077**	**11,922**	**21,186**	**25,558**	**3,721**	**118,887**

9.0 Levelized Utility Costs

Levelized Utility Cost ("LUC") is a method used to compare costs associated with conservation programs to the value of energy saved. The LUC represents the economic cost to the utility (cents per kWh) to achieve those energy savings. LUC is an industry metric which is calculated by discounting future energy savings resulting from conservation programs to a present value. Table 7 provides the LUC for Hydro's 2020 programs. The energy savings represent the annual savings resulting from individual program participation during 2020.

Table 7: Hydro Program Participation, Savings, and Levelized Utility Cost 2020

Program	Participation	Energy Savings (MWh)	Non-coincident Demand Savings (kW)	Levelized Utility Costs(¢/kWh)	Life to date Levelized Utility Cost(¢/kWh)
Windows	-	-	-	-	-
Insulation	57	156	62	6.2	4.4
Thermostats	56	60	2	7.7	10.3
Isolated Systems Community	720	469	145	14.1	14.5
ISBEP	2	49	17	5.9	10.1
Heat Recovery Ventilator	1	1	-	66.8	20.1
Business Efficiency Program (Custom and Prescriptive)	22	120	61	7.7	4.6
Instant Rebate	2,863	95	19	8.5	17.0
Total Programs	**3,721**	**950**	**306**	**9.6**	**5.5**

10.0 Conclusion

In 2020, the Utilities worked closely to develop the 2021 Plan under the takeCHARGE partnership. The 2021–2034 Potential Study was used to analyze the energy efficiency and demand response potential of the province that was both achievable and economical to position the Utilities to provide cost-effective and beneficial programming to customers. Significant effort was undertaken to research new programming, consult key stakeholders, and analyze potential impacts in the local market to develop the 2021 Plan which will introduce electrification programs to customers while continuing long-standing CDM programs.

Hydro continued to promote energy conservation and demand management throughout 2020, including the joint utility programs offered by Hydro and Newfoundland Power through the takeCHARGE partnership while planning for the incorporation of future electrification programming, and beginning construction on the province’s first electric vehicle fast-charging network. The takeCHARGE programs have been successful in providing education and fostering the development of a culture of energy conservation in the province. In addition, Hydro continued to work with its customers to understand needs and drivers of electrical consumption so it could ultimately support the achievement of sustainable energy savings through the various programs described in this report. Overall, Hydro’s efforts supported annual incremental energy savings of 950 MWh in 2020 and cumulative energy savings of 51,731 MWh since 2009. Hydro has also worked in partnership with the Provincial Government on various programs and initiatives to support energy efficiency and a lower carbon economy.

Appendix A

Conservation and Demand Management Program Descriptions

Residential takeCHARGE Rebate Programs

Program incentives are processed primarily through customer applications. The programs are promoted in partnership with trade allies in the retail, home building and renovation industries.

Insulation Rebate Program

The objective of this program is to provide incentives to increase the insulation R-value in residential basements, crawl spaces and attics, thereby increasing the efficiency of the home's building envelope. Eligibility for the programs is limited to electrically heated homes, determined on the basis of annual energy usage. Home retrofit projects are eligible. Customers can receive an incentive of 75% of basement wall and ceiling insulation materials up to $1,000 and 50% of attic insulation material costs up to $1,000.

Thermostat Rebate Program

This program encourages installation of programmable and electronic thermostats to allow customers better control of the temperature in their home and to save energy. These high-performance thermostats provide accurate temperature control while the programmable option allows customers to set back the temperature automatically during the night or when they are away. Eligibility for the program is limited to electrically heated homes, determined on the basis of annual energy usage. Home retrofit projects and new home developments are eligible. Incentives of $10 for each programmable thermostat and $5 for each electronic high-performance thermostat are offered.

HRV Rebate Program

This program encourages customers to purchase a high-efficiency HRV to improve the efficiency of their home. Eligible measures in this program include HRV models that have a Sensible Recovery Efficiency of 70% or more. Customers who purchase a high efficiency HRV can receive a rebate of $175. All customers are eligible for this program regards of the age of the home or its heat source.

Isolated System Community Energy Efficiency Program – Hydro Program

This program includes both residential and commercial components targeting customers in Isolated Diesel communities and L'Anse au Loup. The focus is on residential customers through the direct installation of a kit of technologies, at-cash register coupons on small technologies and mail-in rebates on energy efficient appliances. Commercial customers also receive a direct installation of a kit of technologies. The kit includes items for water savings, draft proofing, lighting and other measures.

Homeowners receive education on energy efficiency and information on the existing takeCHARGE rebate programs. Community events, social media promotions and exchanges are held to promote the program and energy efficiency awareness.

Block Heater Timer Program – Hydro Program

This program targeted customers in the Labrador Interconnected System to encourage the purchase of energy saving Block Heater Timers through in-store discounts offered at partnering retailers. The program launched with a giveaway of the technology to create awareness of the product as there was little or no use of the technology before the program. The incentive was offered over two winter seasons (2012–2013 and 2013–2014) and ended in spring 2014.

Small Technologies Program

Instant Rebates

This program promotes a variety of smaller technologies, such as LED lighting, and smart power bars, through instant rebates available at the cash register of participating retailers. All customers are eligible for this program regardless of the age of the home or its heat source.

Appliances and Electronics

This program encouraged customers to purchase high-efficiency appliances. Participants received incentives of $100 for select energy efficient washers, freezers, and $20 for eligible TVs. All customers were eligible for this program regardless of the age of the home or its heat source. This program ended December 31, 2017.

Residential Benchmarking Program

This program encouraged customers to adopt energy efficient behavioural changes. Participants received Home Energy Reports that provided insight into their homes' electricity use. The reports helped customers understand changes in their usage over time, as well as how they compared to similar homes. They also included practical tips on how to save energy moving forward. The program also included an online component that allowed customers to engage even further through weekly challenges and personalized saving plans. Hydro ended this program in December 2019.

Energy Efficient Loan Program

This program was offered by the Government of Newfoundland and Labrador and takeCHARGE, making it easier to save energy and money. On-bill financing with a 2.5 % interest rate reduction from standard utility financing rates was available for insulation, heat pumps and home energy assessments. Through the Energy Efficient Loan Program, eligible applicants could receive low-interest financing for up to $10,000 over a maximum of five years. This program ended March 31, 2020.

Commercial takeCHARGE Rebate Programs

Business Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency and demand reduction projects.

This program is available for existing commercial facilities that can save energy or reduce demand by installing more efficient equipment and systems. The program includes custom project incentives and prescriptive rebates for specific measures on a per unit basis.

Isolated Systems Business Efficiency Program – Hydro Program

The Isolated Systems Business Efficiency Program was launched in 2012 and targets commercial customers in the Isolated Diesel communities and L'Anse au Loup. The program provides a custom approach to finding energy efficiency solutions and financial assistance for feasibility studies and for retrofit projects. It has the same program design and offerings as the joint utility Business Efficiency Program, but has higher incentive levels for retrofit work because of the higher avoided cost of generation in these systems.

Industrial Energy Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation opportunities. This program is a custom program designed to respond to the unique needs of the industrial market rather than a prescriptive technology approach.

Attachment 1

Electrification, Conservation and Demand Management Plan 2021–2025

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ELECTRIFICATION, CONSERVATION AND DEMAND MANAGEMENT PLAN 2021-2025

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TABLE OF CONTENTS

1.0 EXECUTIVE SUMMARY

The *Electrification, Conservation and Demand Management Plan: 2021-2025* (the "2021 Plan") is the fourth consecutive plan implemented by Newfoundland Power and Newfoundland and Labrador Hydro under the takeCHARGE partnership. The 2021 Plan introduces customer electrification programs and continues long-standing conservation and demand management ("CDM") programs.

Programs included in the 2021 Plan are designed to be cost-effective and responsive to customer expectations. All programs are based on local market research, stakeholder consultations and estimates of long-term energy and demand impacts.

In 2020, the Newfoundland and Labrador Board of Commissioners of Public Utilities (the "Board") recommended the utilities develop a plan for appropriate electrification and CDM programming. The 2021 Plan is consistent with the Board's recommendation.

The cost of implementing the 2021 Plan is forecast to total $73.1 million over the period 2021 to 2025.

Electrification programs are forecast to increase energy usage by 47.1 GWh over the duration of the 2021 Plan. As customers' energy usage increases, the cost of providing service is spread over more kWh. Over the long term, electrification programs are forecast to provide a rate mitigating benefit of 0.5¢/kWh by 2034.

CDM programs are essential to realizing the rate mitigating benefits of electrification. As customers' energy usage increases, it is necessary to manage system peak in order to manage system costs. CDM programs reduce system peak.

Over the duration of the 2021 Plan, CDM programs are forecast to provide energy savings of 1,610 GWh and 82 MW in peak demand reduction. Combined, these energy savings and peak demand reductions are forecast to lower system costs by approximately $113 million.

Both electrification and CDM programs are forecast to result in lower customer costs. Electrification programs will provide savings for participating customers of approximately $27 million, primarily through vehicle fuel savings. CDM programs will provide electricity bill savings for participating customers of approximately $203 million.

The 2021 Plan is consistent with sound public utility practice and is designed to be flexible to respond to shifts in customer expectations, market trends and access to government funding.

2.0 BACKGROUND

2.1 Customer Program Delivery

Newfoundland Power and Newfoundland and Labrador Hydro ("Hydro" and, collectively, the "Utilities") have offered customer programming under takeCHARGE since 2009. The Utilities have successfully implemented three multi-year plans as part of the takeCHARGE partnership.

All programs implemented since 2009 have been responsive to customers' expectations and consistent with the provision of least-cost, reliable service. Over 60,000 customers have participated in programs since 2009. These customers have saved approximately $131 million on their electricity bills. System costs have been reduced by $142 million since 2009 as a result of these programs.

The most recent five-year plan covered the period 2016 to 2020 (the "2016 Plan"). The 2016 Plan is forecast to exceed target energy savings. Cumulative energy savings are forecast to be 985.8 GWh, compared to a target of 883.2 GWh.

These results have been achieved by strategically removing barriers to energy efficiency in Newfoundland and Labrador. Incentives have addressed customer cost barriers. Education initiatives have addressed gaps in customer awareness and knowledge. By addressing barriers, the Utilities have enabled market transformation for products such as windows to higher efficiency standards.

The 2021 Plan is consistent with the Utilities' long-term history of delivering customer programs.

Schedule A provides a summary of the results and customer benefits delivered from the 2016 Plan.

2.2 Rate Mitigation

Electrification is the process of converting customer end uses from fossil fuels to electricity. Generally, increased sales from electrification provide rate mitigating benefits by spreading the cost of providing service over more kWh.

In the Newfoundland and Labrador context, electrification also provides rate mitigating benefits by maximizing the value of surplus electricity.[1] The provincial retail electricity rate is forecast to exceed the value of export sales over the long term. For example, based on a residential retail rate of 13.5¢/kWh and an export sales value of 4.2¢/kWh, each additional kWh consumed domestically will provide a benefit of 9.3¢.[2]

The rate mitigating value of electrification was confirmed by the Board in the Government of Newfoundland and Labrador reference on rate mitigation options and impacts. In its final report issued in February 2020, the Board stated:

> *Appropriate electrification programs should be pursued by Government and the utilities, taking into account the impact such programs can have on the Island Interconnected system peak through CDM programs. The work being undertaken by Hydro and Newfoundland Power on the potential in the Province for electrification and CDM is critical and this analysis should be completed and made available to the Board and stakeholders as soon as possible.*[3]

The Board encouraged the Utilities and Government to work together on the development of the most appropriate electrification and CDM programs for the province.[4]

The 2021 Plan provides the framework to achieve the rate mitigating benefits described in the Board's final report.[5]

2.3 Current Utility Practice

Electrification is a relatively new trend for North American utilities. However, electrification programs are increasingly part of utility customer energy program portfolios.

Electrification initiatives throughout North America are the result of various public policy objectives. The primary public policy objective driving electrification of the transportation sector is reducing greenhouse gas ("GHG") emissions. This is consistent with the Provincial and

[1] Following commissioning of the Muskrat Falls project, the quantity of electricity generated in the province is forecast to exceed domestic requirements for electricity, resulting in a surplus of approximately 3.5 TWh.

[2] The illustration of the net benefit of electrification does not include utility investments such as distribution system upgrades and supply capacity considerations.

[3] See the Board's final report on *Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, page 63.

[4] See the Board's final report on *Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, page 63.

[5] See the Board's final report on *Rate Mitigation Options and Impacts: Muskrat Falls Project*, February 7, 2020, page 109.

Federal governments' policy objectives for transportation electrification.[6] Utility electrification programs typically work in coordination with government initiatives, such as vehicle incentives.

While public policy objectives differ, a number of commonalities exist in North America. The Utilities researched 43 jurisdictions where utilities offer customer electrification programs. Of these 43 jurisdictions: (i) 32 jurisdictions provide incentives for vehicles or chargers; (ii) 31 jurisdictions invest in charging infrastructure; (iii) 27 jurisdictions provide custom solutions for commercial customers; and (iv) 25 jurisdictions undertake managed charging.

Schedule B provides a review of current North American utility electrification initiatives.

Utility CDM programs continue to be offered to customers throughout North America. Long-standing CDM programs offered throughout North America include energy efficient lighting upgrades, home retrofits and customized commercial supports.[7]

The electrification and CDM programs in the 2021 Plan are consistent with utility offerings in other jurisdictions.

3.0 ELECTRIFICATION & CDM POTENTIAL

All customer programming offered under takeCHARGE since 2009 has been based on comprehensive studies of the market potential of CDM technologies. For the first time, the 2020-2034 Potential Study (the "Study") included the market potential of electrification technologies.

[6] Fully electric vehicles do not produce tailpipe emissions. The Government of Canada considers electrification as key to decarbonizing the transportation sector and transitioning to a low-carbon future. Additionally, the transportation sector in Newfoundland and Labrador represents 32% of provincial GHG emissions (see https://www.turnbackthetide.ca/data.shtml#gge-energy-use). The Government of Newfoundland and Labrador has committed to net-zero emissions by 2050 (see correspondence from Former Premier Ball to Prime Minister Trudeau dated May 25, 2020, regarding the effects of COVID-19 on the economy of Newfoundland and Labrador).

[7] The Utilities confirmed the continuation of CDM programs through a jurisdictional survey conducted in 2019. As examples: (i) Efficiency Nova Scotia, FortisBC, Efficiency Maine and Efficiency Vermont provide energy-efficient lighting programs; (ii) Efficiency Nova Scotia, FortisBC and Efficiency Maine provide home retrofit programs; and (iii) BC Hydro, FortisBC, Efficiency Nova Scotia, Manitoba Hydro, Efficiency Maine and Efficiency Vermont provide customized commercial supports.

The Study was conducted using Newfoundland and Labrador-specific inputs to assess electrification and CDM potential, as well as corresponding opportunities and challenges.[8] Multiple scenarios were considered for electrification and CDM potential. A baseline scenario was assessed based on no additional utility intervention. Upper and lower scenarios were assessed based on varying levels of utility intervention, such as differing levels of customer incentives and education.

The primary outcomes of the Study were identification of: (i) cost-effective electrification and CDM measures; (ii) general parameters for program development; and (iii) energy savings and electrification potential by sector and end-use.[9]

Overall, the results of the Study position the Utilities to provide programming that is least cost for customers.

The Study can be found in Schedule C.

3.1 Electrification

The Study assessed the potential for transportation electrification and electrification of space and water heating for residential and commercial customers.

3.1.1 Transportation Electrification

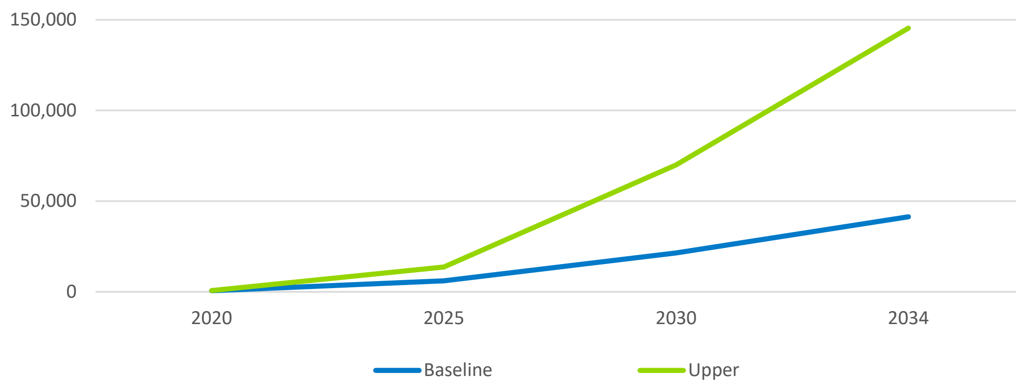
The results of the Study show that there is potential for cost-effective transportation electrification programs.

[8] For example, the fuel switching analysis included an assessment of how many households and businesses can be expected to replace or supplement oil and wood-fired space heating and domestic hot water heating systems with electric heat pump systems under various levels of incentives. The transportation electrification analysis included an assessment of the vehicle market in Newfoundland and Labrador and was divided into the following five categories: personal light-duty vehicles ("LDV"), commercial LDV, medium-duty vehicles, heavy-duty vehicles and buses.

[9] The Study is not intended to give granular information about measures in specific segments, but rather give a macro view of potential. Moreover, it is not a program design document that accurately forecasts energy savings and usage achieved through Utility programs in a given future year, but rather quantifies the total *potential* opportunities that exist under specific parameters.

Figure 1 shows the baseline and upper scenarios for provincial electric vehicle ("EV") adoption forecast for the Study period of 2020 through 2034.

Figure 1
EV Potential
(Total Number of EVs)



The baseline scenario forecasts EV adoption without any additional utility intervention.[10] This scenario forecasts approximately 41,000 EVs on the road by 2034. This level of adoption is forecast to increase retail electricity sales by 266 GWh.

The upper scenario forecasts EV adoption supported by utility investments in charging infrastructure, EV incentives and public education and awareness initiatives. This scenario forecasts approximately 145,000 EVs on the road by 2034. This level of adoption is forecast to increase retail electricity sales by 720 GWh.

EVs represent approximately 40% of annual vehicle sales by 2034 in the upper scenario.[11] This compares to only approximately 10% of annual vehicle sales in the baseline scenario, which is considerably lower than national targets.[12]

The primary difference in EV adoption rates between the baseline and upper scenarios is attributed to variations in access to public charging infrastructure. Under both scenarios,

---

10 The baseline scenario forecasts adoption based on current levels of investment and support. This includes a commitment by Hydro and the Federal and Provincial Government to increase charging infrastructure (estimated to be the installation of 14 direct-current fast chargers and 14 Level 2 ports in 2020).

11 Reflects LDV sales, including personal and commercial cars, trucks and SUVs.

12 The Federal Government has set targets for EVs to reach 10% of LDV sales per year by 2025, 30% by 2030 and 100% by 2040.

direct-current fast charger ("DCFC") deployment has the greatest impact on EV adoption.[13] The Study recommended that DCFC deployment should be prioritized to increase transportation electrification.

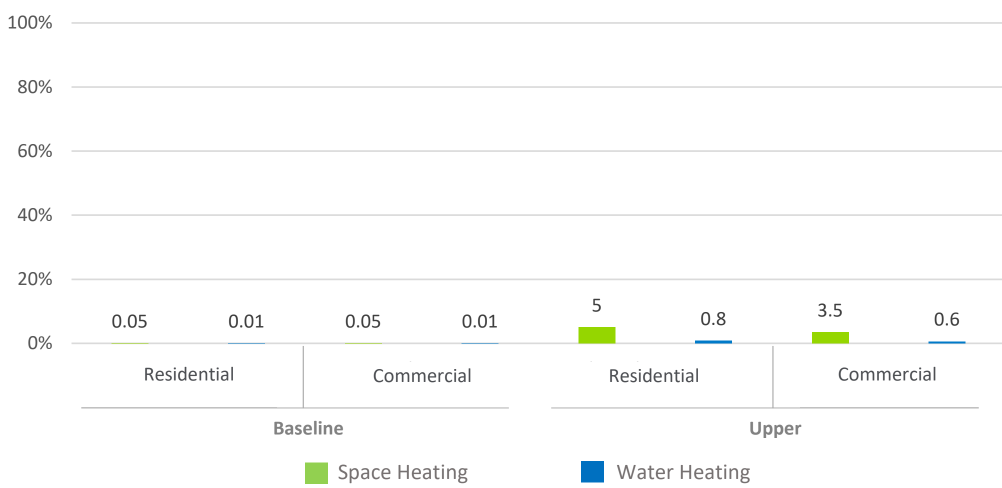
Schedule D provides information on EV technology and global market trends.

3.1.2 Space and Water Heating Electrification

The results of the Study show there is limited potential for electrification of space and water heating in homes and buildings. The limited potential is due to unfavorable customer economics.[14]

Figure 2 shows the Study's baseline and upper achievable scenarios estimated for electrification of space and water heating.[15]

Figure 2
Customers with Non-Electric Space and Water Heating Switching to Electric Heat Pump Systems (%)



[13] DCFCs, commonly referred to as Level 3 or fast chargers, charge an EV in approximately 30 minutes to one hour. Level 2 chargers charge an EV in approximately 9 hours. Level 1 chargers charge an EV in approximately 50 hours.

[14] In most instances, the capital cost of switching from oil or wood space and water heating systems to an electric system outweighs the monetary benefits of the energy savings. See the Study, Volume 1, page 94, "DMSHP measures did not pass TRC cost effectiveness screening."

[15] The baseline scenario forecasts adoption based on current levels of investment and support. The upper potential is defined as the portion of electrification potential that is achievable through utility interventions and programs given institutional, economic and market barriers. For example, increasing incentive levels and enabling activities such as financing and education.

The baseline scenario forecasts no material electrification of space or water heating.[16] This scenario includes no utility intervention. Only a small number of customers are forecast to adopt heat pumps to electrify their space or water heating in this scenario.

The upper scenario forecasts minimal electrification of space and water heating, with an increase in retail electricity sales of approximately 80 GWh. This scenario includes a large financial incentive for non-electrically heated residential and commercial customers. Approximately 5% of residential customers and 3.5% of commercial floor space adopt some form of heat pump system for space heating. With a large financial incentive the adoption of domestic heat pump water heaters is less than 1% for both residential and commercial customers.

3.2 Conservation and Demand Management

The Study estimated the amount of energy and demand savings that could be achieved through CDM programs. It also considered programs that specifically attempt to reduce consumption at times of system peak.

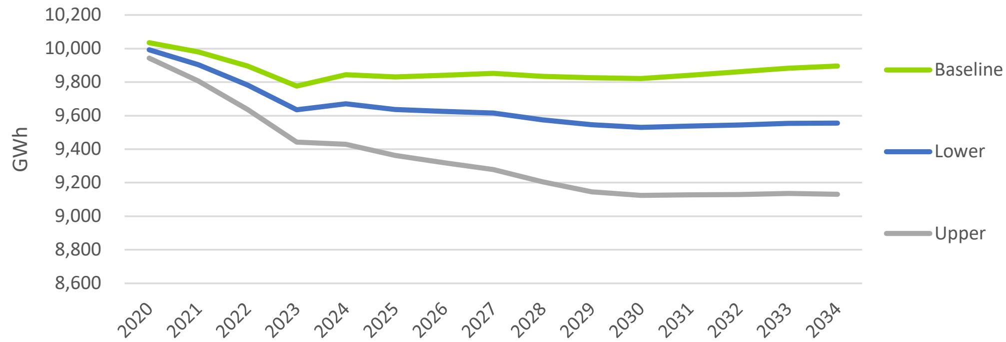
3.2.1 Energy Conservation Potential

The results of the Study show there continues to be potential for cost-effective CDM programs.

[16] This analysis considered potential for fuel switching to electricity amongst customers using oil or wood for space heating and oil for water heating.

Figure 3 shows the baseline provincial energy usage forecast and the lower and upper achievable energy saving potentials estimated by the Study.[17]

Figure 3
Forecast Provincial Electricity Consumption
Conservation Potential Study Results
2020-2034



The province's total potential for energy savings by 2034 is forecast to be 764 GWh in the upper scenario and 340 GWh in the lower scenario.[18] In the short term, energy saving potential is similar across all sectors.[19] Due to the high penetration of electrically heated homes, measures that target space heating such as insulation continue to offer potential in the residential sector, along with Home Energy Reports and smaller upgrades such as lighting. Commercial lighting upgrades represent the largest potential for that sector in the short term. Motor and compressor measures offer the largest energy savings opportunity in the industrial sector.

3.2.2 Demand Reduction Potential

The Study shows that there continues to be potential for demand management in the province, however the existing programs achieve the majority of this potential.

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17 The baseline represents the Utilities' 2019 provincial energy usage forecast. The achievable potential is the portion of new economic conservation potential from 2020 to 2034 achievable through utility interventions and programs given institutional, economic and market barriers. The lower and upper achievable potential include different incentive levels, investments and other enabling activities such as financing and education.

18 In 2034, the baseline is 9,895 GWh. In the upper scenario, the forecast energy consumption is 9,131 GWh. 9,895 GWh - 9,131 GWh = 764 GWh in the upper scenario. Likewise, in the lower scenario, the forecast energy consumption is 9,555 GWh. 9,895 GWh - 9,555 GWh = 340 GWh.

19 The Study forecasts a decline in energy savings through utility programs after 2024 when new lighting and heat pump standards are expected to come into place.

Figures 4 and 5 show the demand reduction potential in the province from specific demand management measures and demand reductions from programs that target energy conservation.[20]

Figure 4
Lower Scenario
Demand Management Potential
2034 (MW)

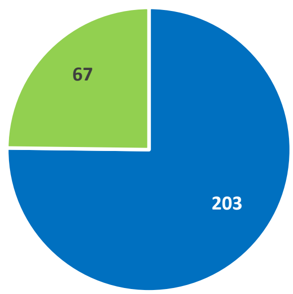
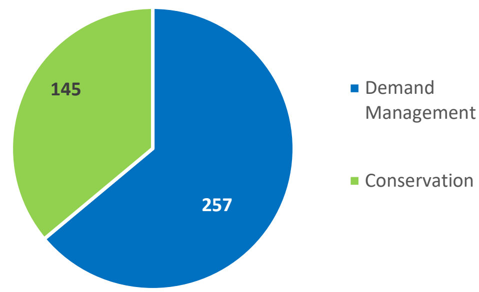


Figure 5
Upper Scenario
Demand Management Potential
2034 (MW)



Demand management potential over the long term is forecast to be achieved through a combination of specific demand management measures and conservation programs.

Figure 4 shows that peak demand reduction of 270 MW could be achieved in the lower scenario.[21] In this scenario, conservation programming accounts for 25% of demand reduction potential and demand management measures account for the remaining 75%.[22] The majority of demand management potential is currently realized through existing industrial and commercial curtailment arrangements.[23]

Figure 5 shows that peak demand reduction of 402 MW could be achieved in the upper scenario by 2034.[24] In this scenario, conservation programming accounts for 36% of demand reduction potential and demand management measures account for the remaining 64%.[25]

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20 The achievable potential is defined as the portion of new economic demand and energy efficiency potential that is achievable from 2021 to 2034 through utility interventions and programs given institutional, economic and market barriers. The lower scenario maximizes the impact of current demand response programs. The upper potential scenario introduces additional rate and direct load control demand response measures.

21 67 + 203 = 270.

22 67/270 = 0.25, or 25%. 203/270 = 0.75, or 75%.

23 For example, curtailment accounts for 76% of demand management potential in the lower scenario. The remainder consists of dual fuel potential, which involves commercial customers switching to an alternate fuel source at times of peak, and current voltage management practices.

24 145 + 257 = 402.

25 145/402 = 0.36, or 36%. 257/402 = 0.64, or 64%.

The Study indicated new demand management measures provide little additional benefit to reducing system peak, including Time of Use ("TOU") rates and Critical Peak Pricing ("CPP").[26]

Both TOU rates and CPP require investment in advanced metering infrastructure ("AMI").[27] TOU rates and CPP are not forecast to provide sufficient benefits to justify the cost of AMI until at least 2030, when EV load management may be required to avoid capacity additions. The Utilities will continue to monitor the impacts of EV load to evaluate the benefits of introducing TOU and CPP in the future.

Schedule E provides additional information regarding demand management potential in the province.

3.2.3 Demand Impacts of EV Adoption

Demand management is essential to realizing the full benefits of EV adoption. Unmanaged EV charging which takes place during on-peak hours, could contribute to capacity-related system costs.[28] Managed EV charging shifts charging to off-peak hours which will have the effect of avoiding capacity-related system costs.

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26 Direct load control (DLC) also offers minimal incremental peak reduction. DLC is forecast to add just 1 MW of savings by 2024, but would include incentive, administration and control infrastructure costs, which offset much of the program benefits.

27 The majority of customers in the province are currently served by automated meter reading ("AMR") technology. AMR allows meters to be read using a radio signal, but is not capable of interval metering for the purpose of implementing time-varying rates.

28 If peak demand is not managed, the Utilities will have to invest in additional generation. High capacity costs, coupled with the coincidence between EV charging and utility load will likely lead to significant increases in peak demand and related system costs if load management is not utilized. December through March is considered the winter peak season and April through November is considered the non-winter off-peak season. Within the winter months, from 7:00 a.m. to 11:00 p.m. on weekdays is considered on-peak. Off-peak hours occur after 11:00 p.m. until 7:00 a.m. and include weekends.

Table 1 shows the net present value ("NPV") impacts of unmanaged versus managed charging of EV load at times of system peak in 2034, as assessed in the Study.

Table 1
EV Demand Management
Benefits and Costs of Unmanaged versus Managed EV Charging[29]
2034

	Unmanaged Charging				Managed Charging			
	MW	Benefits	Costs	NPV	MW	Benefits	Costs	NPV
Baseline	106	$119M	($163M)	($44M)	16	$119M	($52M)	$68M
Upper Scenario	281	$317M	($431M)	($114M)	42	$317M	($147M)	$170M

Unmanaged charging results in a negative NPV of $44 million to $114 million by 2034 due to investments in additional capacity.[30] Managed charging results in a positive NPV of $68 million to $170 million over the same period.

The Study recommends the Utilities pilot managed EV charging to determine the most effective approach at mitigating the impact of EV charging on system peak.

4.0 THE 2021 PLAN

The 2021 Plan introduces programs and education designed to promote electrification of provincial energy use, primarily in transportation. It also continues long-standing CDM programs and education for customers.

[29] The benefits include revenue from incremental energy sales. The costs include: (i) supply costs associated with meeting the incremental load growth and (ii) capital costs associated with charging infrastructure investment.

[30] If load grows at peak times, additional generation will be required to meet customer needs.

Schedule F provides a description of the programs included in the 2021 Plan.

The 2021 Plan is based on the results of the Study, stakeholder consultation and anticipated future customer economics and system dynamics.

Further details on the stakeholder consultation process can be found in Schedule G.

4.1 Program Screening

All programs in the 2021 Plan are screened to ensure they are cost-effective from a utility and customer perspective.

Cost-effectiveness includes consideration of marginal energy and capacity costs.[31] Marginal energy and capacity costs are forecast to change. Marginal energy costs are forecast to decrease from current levels upon commissioning of the Muskrat Falls project. Marginal capacity costs are forecast to increase due to capacity constraints on the Island Interconnected System. The 2021 Plan is based on the latest estimates of future changes in marginal costs.

Schedule H provides the current forecast marginal cost of energy and capacity for 2021-2040.[32]

Cost effectiveness of CDM programs in the 2021 Plan continues to be evaluated using a Total Resource Cost test ("TRC"). The TRC evaluates programs from the perspective of the customer and the utility.[33] It includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants.

Cost effectiveness of electrification programs in the 2021 Plan is evaluated using a Modified Total Resource Cost test ("mTRC"). The mTRC is substantially the same as the TRC used to

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31 Marginal cost is the cost to supply electricity to meet the incremental kW of demand and kWh of energy. The provincial marginal cost of energy is based on the export price of electricity and the marginal cost of capacity is based on the avoided cost of adding generation to meet customer requirements at times of system peak.

32 The average hourly marginal cost was provided by Hydro in their 2020 Marginal Cost Update, April 20, 2020.

33 CDM programs also require a positive result for the Program Administrator Cost ("PAC") test as a secondary screening. The PAC evaluates programs from the perspective of the utility. It includes the costs and benefits experienced by the utility system. Research into Canadian and U.S. utility practice shows that the TRC and PAC tests are still appropriate for measuring the benefits of CDM. Use of the TRC and PAC to evaluate customer conservation programs was approved by the Board in Order No. P.U. 18 (2016).

screen CDM programs, but includes non-electrical customer benefits. Specifically, the mTRC recognizes cost savings for customers as a result of lower fuel and maintenance costs. These benefits are essential to the customer economics of electrification technologies.[34]

Schedule I provides further information regarding practices for cost effectiveness testing of electrification programs.

The Utilities also analyzed the rate mitigation value of its electrification programs, pilot projects and infrastructure investment. This analysis identified the customer rate impact of these electrification initiatives.

Section 5.0 provides the rate mitigation results.

4.2 Electrification

The 2021 Plan outlines strategic initiatives takeCHARGE will implement to address customer barriers to electrification. EVs and other technologies are still emerging. Public awareness and understanding of the benefits of EVs are in formative stages. Additionally, current charging infrastructure is insufficient to increase market adoption of EVs.[35] Action is required to remove these barriers and accelerate EV adoption. These actions include investments in charging infrastructure, financial incentives, and awareness and education initiatives.

4.2.1 Utility Charging Infrastructure Investment

The availability of charging infrastructure is forecast to have the highest impact on EV adoption in both the short and long term.[36] Providing sufficient access to charging infrastructure is necessary to eliminate customers concerns about their ability to reach their destinations and support EV adoption.

[34] In 2019 Econoler, a third party consultant, performed a jurisdictional scan. The results of this study and supplemental utility research show that not all utilities perform cost effectiveness testing for electrification programs. However, the utilities that do, consider the perspectives of the utility, the customer and society, which is captured in the mTRC.

[35] In a 2019 survey completed by MQO, Newfoundland and Labrador residents ranked access to charging and concerns about reliability of range among the highest barriers to EV ownership.

[36] See the Study, Volume 1, page 105, "*Under both the low and high scenarios, DCFC and L2 deployment have the highest impact on adoption in both the short and long terms. The limited availability of charging infrastructure in the province severely constrains market adoption of LDVs under baseline conditions, and any deployment increases both geographical coverage and availability of charging and has a significant impact on the market*."

Currently, the business case for private investment in DCFC charging stations is weak.[37] This indicates that DCFC deployment in the province will be limited in the absence of utility or government intervention. Through appropriate investment, utility involvement can accelerate electrification of the transportation sector.[38]

The 2021 Plan includes charging infrastructure support through two utility investment models: (i) the make-ready model; and (ii) the utility charging network investment model.

The make-ready model includes the installation of electrical infrastructure to enable customers to purchase and install DCFC. The costs to get a site ready for charger installation are typically a large percentage of the capital required for an installation, at approximately 30% to 40%.[39] This model lowers upfront capital costs which, in turn, improves the business case for commercial customers when installing, owning and operating EV charging stations.[40]

The utility charging network investment model includes the installation, operation and maintenance of charging infrastructure directly by the Utilities. Through utility investment in all aspects of DCFC deployment, this model fully mitigates challenges related to the weak business case for private investment in DCFC.

Combined, these investment models will accelerate the availability of DCFC in the province. This is necessary to maximize the potential for transportation electrification, as outlined in the Study. Under both models, utility involvement will ensure the distribution system is adequately designed and constructed to meet required standards. Utility involvement in DCFC site selection will also work to keep investment costs low.[41]

Both investment models are commonplace in North American jurisdictions that are pursuing electrification of the transportation sector.

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[37] Given the large investment required to install DCFC and low number of EVs in the province, it would be difficult for a private charger operator to make a profit in the near term. Third party charging investment and operation will become more feasible as EV uptake increases. Also see the Study, Volume 1, page 116.

[38] MJ Bradley & Associates, *Accelerating the Electric Vehicle Market: Potential Roles of Electric Utilities in the Northeast and Mid-Atlantic States*, March 2017, p.11-12.

[39] Chris Nelder and Emily Rogers, *Reducing EV Charging Infrastructure Costs*, Rocky Mountain Institute, 2019, p. 23.

[40] Under this model, utilities invest in the site's required electrical distribution infrastructure upgrades up to, but not including, the charging infrastructure, thereby making the site ready for charger installation. The Utilities' infrastructure investments typically include transformer and service capacity upgrades, wiring, conduit, metering upgrades and trenching. The customer oversees the procurement, installation, ownership, maintenance and operation of the chargers.

[41] Utility deployment of charging infrastructure will lead to benefits from optimizing station placement within the distribution system to avoid infrastructure upgrades. See the Study, Volume 1, page 111.

Schedule J provides additional information on current utility practice for charging infrastructure investment.

4.2.2 Residential EV & Charging Infrastructure Program

While EVs have lower operating and maintenance costs, they also have a higher upfront purchase cost.[42] The average incremental cost of purchasing an EV compared to a gasoline-powered vehicle is approximately $19,000. EV owners can also incur further costs for the installation of Level 2 charging equipment to ensure timely vehicle charging. This can include the cost of the charger, as well as the cost of upgrading home wiring and electrical capacity.

The Study showed that vehicle purchase incentives can improve the customer business case for EVs. This is forecast to increase the adoption of EVs which, in turn, is forecast to increase EV system load by 16% to 32% by 2025.[43]

The 2021 Plan includes vehicle purchase incentives to address the upfront capital cost of purchasing an EV. The program will work in conjunction with existing Federal rebates to further reduce the capital cost of an EV.[44]

The Study showed managed EV charging will be critical to address the impact of EVs on system peak.[45] Addressing impacts on system peak is necessary to manage capacity-related system costs.

The 2021 Plan includes incentives to address the upfront cost of installing Level 2 chargers. Only Level 2 chargers that are capable of demand management will qualify for these incentives.

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[42] In a 2019 survey completed by MQO, Newfoundland and Labrador residents also ranked cost as one of the highest barriers to EV ownership.

[43] See the Study, Volume 1, page 105, *"Incentives can potentially increase EV load by 16 to 32% in the short-term through improving the business case of EV adoption and bridging the market to cost parity. Incentives contribute to both an increase in the number of EVs on the road as well as the shift from plug-in hybrid ("PHEVs") to battery electric vehicles ("BEVs") in the market, which corresponds to an increase in EV load."*

[44] This assumes the current federal incentive of $5,000 on a BEV and $2,500 on a PHEV which covers a portion of this incremental cost remains in place for the duration of the 2021 Plan.

[45] See the Study, Volume 1, page 150.

4.2.3 Commercial EV & Charging Infrastructure Program

This program provides an incentive to commercial customers looking to replace existing gasoline-powered vehicles with EVs or add an EV to their fleet. As with residential vehicles, there is a higher upfront cost to purchase EVs for commercial use. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV.

This program also offers a rebate for eligible purchase and installation costs for installing a Level 2 charger for workplaces and fleets. Installation costs are highly location-specific and typically require some form of electrical extensions, capacity upgrades and trenching. Eligible chargers will be network enabled, allowing for future commercial demand management initiatives.

4.2.4 Custom Electrification Program

The Custom Electrification Program will offer incentives for commercial customers to replace fossil-fuelled technologies with equivalent electric technologies that are more efficient.[46] Incentives will be provided on an individualized basis for projects that are cost-effective from both the customer and utility perspectives.[47] This is comparable to the customized incentives provided to customers under the current Business Efficiency Program.

The Custom Electrification Program will work in tandem with the existing Business Efficiency Program. The 2021 Plan expands the Business Efficiency Program to include an increased focus on demand management. This is necessary to manage impacts on system peak as commercial customers electrify their business processes.

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[46] Custom commercial programs allow for the economic evaluation of a specific project considering the energy use and demand impacts of the customer's facility. Evaluation is based on detailed costs and benefits unique to the customer's proposed project.

[47] Examples of individualized projects may include: (i) the installation of ductless mini-split heat pumps ("MSHP") for water or space heating; (ii) the electrification of business processes; (iii) dockside electrification; and (iv) the purchase of electric fork lifts.

Table 2 shows forecast customer energy use estimates by sector for 2021 through 2025 resulting from the electrification programs in the 2021 Plan.

Table 2
Energy Usage Estimates
2021 through 2025
(GWh)

	2021	2022	2023	2024	2025	Total
Residential	0.3	1.5	4.3	9.3	17.1	32.5
Commercial	0.2	0.9	2.0	4.1	7.4	14.6
Total	**0.5**	**2.4**	**6.3**	**13.4**	**24.5**	**47.1**

The electrification programs outlined in the 2021 Plan will result in cumulative customer energy usage of 47.1 GWh. The majority of electrification, 69%, will occur in the residential sector through transportation electrification initiatives.[48]

4.3 CDM Programs

CDM programs continue to provide opportunities to customers in all three sectors: residential, commercial and industrial.

Table 3 shows the portfolio of CDM programs to be offered under the 2021 Plan.

Table 3
Conservation and Demand Management Programs
By Sector

Residential	Commercial	Industrial
Benchmarking HRV Instant Rebates Insulation and Air Sealing Isolated Systems Community Program Low Income Kit Program Thermostat	Business Efficiency Program Isolated Business Efficiency Program Isolated Systems Community Program	Industrial Energy Efficiency Program

All current customer CDM programs will continue in the 2021 Plan, with modifications to certain programs.

48 32.5 GWh / 47.1 GWh = 0.69 or 69%

The Instant Rebate program is forecast to end after 2022. At that time, it is expected that regulations[49] may prohibit the manufacturing of certain lower efficiency models of light bulbs, such as halogens.[50] LEDs are expected to become the market standard at that time.

The Insulation program will be expanded to offer incentives for duct insulation and air sealing, helping customers to save further on space heating costs.

A low income program will be introduced providing income-qualified customers with an energy efficiency kit at no cost to the participant.

The Business Efficiency Program demand incentive will be adjusted to better support demand management opportunities in instances where commercial facilities convert space and water heating to electric.

49 Phase two of the Energy Independence and Security Act (EISA) was scheduled to come into effect in the United States ("U.S.") on January 1, 2020, restricting the sale and manufacture of light bulbs that do not meet new minimum energy performance standards for bulb types covered by the regulations. Components of these lighting regulations were delayed by the U.S. Department of Energy. The timing of the implementation of these lighting regulations is uncertain. When implemented, these requirements are anticipated to impact the Canadian market, as the Canadian government has indicated commitments to align efficiency standards with the U.S. The Utilities will monitor changes to these regulations closely.

50 LED light bulbs account for the majority of items rebated through the Instant Rebates program. The Utilities will continue to monitor the saturation of LED bulbs in the marketplace to inform the program end date. Research will be completed through in-store assessments, socket saturation surveys and assessments of free-ridership (an estimate of participants who would have chosen the more efficient product without the program).

Table 4 shows forecast annual customer energy and demand reduction estimates by sector from 2021 through 2025.[51]

Table 4
2021 Plan Annual Energy and Demand Reduction Estimates
2021 through 2025

	2021	2022	2023	2024	2025	Total
Energy (GWh)						
Residential	194.2	212.3	222.9	234.2	246.9	1,110.5
Commercial	53.7	61.0	68.6	76.2	84.7	344.2
Industrial	31.0	31.0	31.0	31.0	31.0	155.0
Total	278.9	304.3	322.5	341.4	362.6	1,609.7
Demand (MW)						
Residential	49.1	53.9	57.5	61.0	65.0	65.0
Commercial	9.8	11.2	12.8	14.5	16.3	16.3
Industrial	0.7	0.7	0.7	0.7	0.7	0.7
Total	59.6	65.8	71.0	76.2	82.0	82.0

The CDM programs in the 2021 Plan are estimated to result in cumulative customer energy savings of approximately 1,610 GWh and achieve peak demand reductions of 82 MW by 2025. The energy savings and demand reduction will occur annually for the life of the installed technologies. The demand reduction will more than offset the increase of 3.2 MW[52] of peak demand resulting from electrification initiatives.[53]

[51] CDM program savings indicated throughout the 2021 Plan are cumulative. The savings reflect all technologies installed since program implementation which have not reached the end of their useful life. For example, LED light bulbs are expected to last for seven years. Therefore, LEDs installed in 2019 will provide savings annually until 2025. CDM program savings indicated throughout the 2021 Plan represent *gross* savings achieved by customers. *Net* savings reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings and (ii) program free ridership.

[52] The increase in peak demand of 3.2 MW is the result of the additional 47.1 GWh in system load created through electrification initiatives in the 2021 Plan.

[53] Demand reduction from the Utilities' curtailment initiatives are reported separately. Results from Newfoundland Power's commercial curtailment program are filed each year with Newfoundland Power's *Curtailable Service Option Report*. Results from Hydro's industrial curtailment program are filed each year with Hydro's *Capacity Assistance Agreement*.

4.4 Customer Education and Research

4.4.1 Customer Education

Over the 2021 Plan period, takeCHARGE will maintain its focus on providing energy saving advice, while expanding its mandate to help inform customer decisions regarding electrification.

Conservation outreach efforts will consider a variety of customer groups, such as those with low income, seniors, renters, students and small businesses. The takeCHARGE website, social media activities and partnerships with industry stakeholders will continue to provide customers with energy efficiency education and support.[54]

Energy efficiency education will focus on helping customers understand and manage their electricity use. Resources will touch on a wide variety of topics, from no-cost ways to save to how to select the most energy efficient technologies for your home or business. takeCHARGE will focus on how to make educational materials more accessible to customers with disabilities, such as vision impairments.

Electrification education will help homeowners and businesses make informed decisions when considering EVs and other fuel switching opportunities.[55] Online resources will outline the benefits and address the barriers to adopting these technologies. EVs will also become a focus of customer outreach activities, including trade shows and employee engagement.

As with past customer conservations efforts, a focus on industry partnerships will be critical in advancing EV adoption. The Utilities will work with key stakeholders, such as automobile dealers, sales staff and current EV owners.[56]

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[54] Education will be delivered virtually due to COVID-19 until it is safe to resume in-person outreach. Webinars have been used to deliver a variety of customer presentations for schools, homeowners and trade allies in 2020.

[55] This type of outreach has been successful for utility education initiatives for CDM, helping customers manage their energy use. For example, in 2016, takeCHARGE expanded its educational focus to ductless MSHP. Since its launch, the heat pump website has received approximately 250,000 views.

[56] In 2020, takeCHARGE launched the Go Electric EV drivers club for local EV owners and a website that focuses on EV education.

4.4.2 Customer Research

In advance of the next Study, planned for 2023, the Utilities will undertake a number of research projects regarding electricity end-use trends and the state of the local market for efficient technologies. For example, efficiency standard changes and increased adoption of lighting, mini-split heat pumps ("MSHP"), and EVs are expected to occur in the coming years. It will be important for the Utilities to understand the market dynamics of these changes and other emerging technologies.

The Utilities will also research the costs and customer benefits of a number of technologies through pilot programs, as described below.

Schedule K provides further information on pilot programs for the 2021-2025 period.

Custom Fleet Pilot Program

A significant portion of the forecast electricity consumption in the Study associated with EVs by 2034 is expected to come from commercial vehicles. EVs such as medium-duty vehicles ("MDVs"), heavy-duty vehicles ("HDVs") and buses offer large potential but have unique barriers to adoption, including model availability.[57] Generally, MDVs, HDVs and buses are found to be more sensitive to economics. Electrification of these vehicle classes will therefore require substantial support in the form of incentives or changes in key market economic factors.[58]

The Custom Fleet Pilot Program will allow the Utilities to investigate how to cost effectively overcome the adoption barriers associated with these fleet vehicles. It will also allow the Utilities to investigate opportunities to monitor and manage system peak impacts associated with electrifying large vehicle loads. Implementation of the pilot program will include engaging fleet managers, providing information on fleet electrification opportunities and offering support through technical advice, feasibility studies and financial incentives.

EV Demand Response Pilot Program

By 2034, EV adoption is forecast to increase electricity use. This could potentially change the overall electricity system load shape. The Study indicates that, in the near term, research and

57 Examples of MDVs include delivery vans, box trucks and utility bucket trucks. Examples of HDVs include long-haul and short-haul semi tractors, garbage trucks and dump trucks.

58 See the Study, Volume 1, page 113. *"Generally, MDV, HDV and buses were found to be more sensitive to economics and will require substantial support in the form of incentives or changes in key market economic factors (electricity rates, fuel prices, etc.) to trigger any significant shift in adoption beyond natural market uptake. Programs targeted towards commercial fleets, awareness campaigns and other initiatives could be potential levers to accelerate the commercial market."*

evaluation should be used to understand these potential impacts and explore mitigation strategies. Managed EV charging will be key to limiting utility system demand impacts. The EV Demand Response Pilot Program will allow the Utilities to assess a number of approaches to control the demand impacts of EVs. Peak demand reduction impacts, cost effectiveness and customer perspectives will be evaluated for each technology, helping to inform the best long-term approach to EV demand management.

The EV Demand Response Pilot Program targets EVs owners who will charge their EV at home using a Level 2 charger. The pilot program will utilize various technologies that help reduce charging at times of system peak such as smart chargers and direct load controllers.

Small Business Direct Install Pilot Program

The Small Business Direct Install Pilot Program will target small business customers, as they are challenged with additional time and financial constraints to making energy efficient upgrades. Energy saving water and lighting measures will be installed at customer facilities. Additionally, the pilot program will help customers identify larger upgrades that can be supported through the Business Efficiency Program, while providing them with other ways to save energy.

The Small Business Direct Install Pilot Program will help inform how these upgrades can be offered to a broad range of customers cost effectively.

Heat Pump Load Research Pilot Program

Due to the increase in adoption of heat pumps and the potential impacts they have on the Utilities' peak load, Newfoundland Power is currently completing load research on MSHPs which is expected to be completed in 2021.[59] The research is being completed over two winter seasons and one summer season and will provide valuable insights into the system impacts of MSHPs, in a time when adoption of this technology is growing.

The Heat Pump Load Research Pilot Program will also provide valuable insights into the demand impacts of ductless MSHPs and how their adoption impacts the energy usage of the whole home.

4.5 Costs and Cost Recovery

Total costs related to customer electrification and CDM initiatives are forecast to be $73.1 million from 2021 through 2025.

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59 As of 2019, there were almost 47,000 heat pumps installed in the province. The Study considered the forecast installation of heat pumps. It was forecast that residential MSHP adoption amongst those with electric heat will continue to grow, reaching close to 70,000 installs by 2034.

Table 5 provides of a summary of the Utilities' total electrification and CDM costs from 2021 through 2025.[60]

Table 5
Electrification and CDM Costs
2021 through 2025
($000s)

	2021	2022	2023	2024	2025	Total
Utility EV Infrastructure Investment	2,095	2,049	903	1,378	1,306	7,731
Electrification Programs	952	1,762	2,634	3,012	4,145	12,505
CDM Programs	8,211	8,688	7,880	7,834	8,327	40,940
Customer Education and Research[61]	1,466	2,681	3,564	2,932	1,306	11,949
Total	**12,724**	**15,180**	**14,981**	**15,156**	**15,084**	**73,125**

The Utilities anticipate investing $7.7 million in EV charging infrastructure.[62] To maximize the value of investments, existing funding programs will be leveraged to reduce utility costs associated with EV infrastructure deployment.[63]

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60 This cost summary does not include costs related to Newfoundland Power's demand management activities (Curtailable Rate Service Option and facilities management) and costs related to Hydro's interruptible load arrangements. The Utilities' curtailment costs and results will continue to be reported separately to the Board.

61 Customer education and research includes the costs associated with the heat pump load research pilot program, the small business direct install pilot program, the custom fleet pilot program and the EV demand response pilot program.

62 Utility EV Infrastructure Investment is higher in the first two years reflecting a larger investment in the Utility DCFC Charging Network. Infrastructure costs stabilize in the final three years reflecting continuing investment in Utility DCFC Charging Network and the Make-Ready Charging Infrastructure program. The Utility Charging Network costs do not include any costs associated with Hydro's construction and operation of 14 DCFC and 14 Level 2 chargers throughout the province. This investment was approved by the Board in Order No. P.U. 7 (2020).

63 The Utilities have applied for approximately $1 million in funding to install 19 DCFC's and 19 Level 2 chargers in the province. The Utilities will continue to take advantage of any federal and provincial funding to lower program costs, where possible. Revenues generated from the Utility owned charging infrastructure will also help offset the costs of operating the Utility DCFC Charging Network.

Electrification program costs increase through the period. Customer program participation levels are expected to increase as the adoption of EVs becomes more prevalent.[64]

The Utilities' costs related to CDM programs in the 2021 Plan are forecast to be approximately $40.9 million over the 5-year planning period.[65] This is consistent with the 2016 Plan CDM program costs, which are forecast to be $39.5 million over five years. Forecast changes in program costs primarily reflect costs associated with implementing and evaluating new programs and the conclusion of certain programs or measures through the planning period.

Customer education and research costs are forecast to be approximately $11.9 million over the 2021 Plan period. This includes the expansion of customer education resources, presentations and implementation of four pilots.[66]

Schedule L provides a summary of forecast energy consumption, energy savings and costs for the 2021 Plan.

The Utilities will continue to recover costs associated with CDM programming and major studies over seven years, consistent with the current practice approved by the Board.[67]

To enable the development and implementation of electrification programs in 2021, cost recovery of electrification initiatives and capital must be addressed for 2021.[68] Cost recovery for 2021 will be addressed by the Utilities in applications to the Board. Specifics of long-term amortizations can be determined in the Utilities' next rate cases.[69]

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64 This reflects increasing customer uptake as the electrification market transforms, driven by the Utilities' investment in EV infrastructure in the province and other enabling activities.

65 Conservation program costs are an average of approximately $8 million annually over the 5-year period.

66 Customer education and research costs are forecast to decline in 2025 to reflect the conclusion of the electrification pilots. Please see Schedule K for further information on the pilot programs in the 2021 Plan.

67 The Utilities have used this approach for customer conservation programs since 2013, based on Order No. P.U. 13 (2013) and Newfoundland and Labrador Hydro – Amended General Rate Application – Parties' Settlement Agreement dated August 14, 2015. The amortization of program costs over a seven-year period remains appropriate because of the extended nature of the electrification and CDM benefits provided by program technologies.

68 Capital investments include costs related to charging infrastructure deployment and information systems enhancements. Supplemental 2021 capital expenditures for the Utilities are estimated to be approximately $2.8 million. The Utilities have applied for approximately $1 million in funding to offset the capital costs required to install 19 DCFC's and 19 Level 2 chargers in the province.

69 The Utilities are examining regulatory approaches in other jurisdictions and their applicability to this jurisdiction.

The Utilities propose to expense annually recurring general electrification and CDM costs, such as education, as they are incurred.[70]

5.0 CUSTOMER BENEFITS

Electrification and CDM provide three principal customer benefits. These customer benefits are outlined in Table 6.

Table 6
Electrification and CDM
Customer Benefits

Benefits	Electrification	CDM
Customer Rate Mitigation	X	
Lower System Costs		X
Customer Cost Savings[71]	X	X

Electrification provides customer rate mitigation benefits.[72] CDM lowers system costs. Both electrification and CDM lower overall costs to customers. Each of these benefits is described below.

Customer Rate Mitigation

Increased electrification in the province provides rate mitigation benefits to customers over the long term.

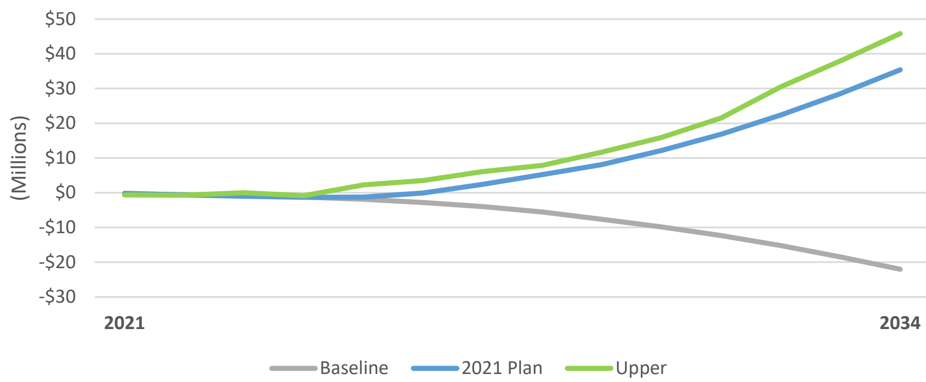
[70] While general customer electrification and CDM costs provide benefits to customers in terms of information, know-how and advice, those benefits are not transparently quantifiable in the same manner as program benefits.

[71] Participation in electrification and conservation programs can also save customers money in areas other than energy. For example, EV drivers will typically save $1,100 on maintenance over the life of the vehicle compared to a gasoline powered vehicle.

[72] In addition to rate mitigating benefits, electrification also benefits customers through reductions in GHG emissions. The electrification initiatives outlined in the 2021 Plan are forecast to reduce GHG emissions by 36,761 megatons of CO^2. Reducing GHG emissions is consistent with federal and provincial policy objectives.

Figure 6 shows the net customer benefits associated with electrification from 2021 to 2034.

Figure 6
Rate Mitigation Benefits from Electrification



In the Study's baseline scenario EV adoption is low.[73] Without any utility intervention system costs will increase. Increased system costs put upward pressure on rates.

The 2021 Plan lays the foundation for increasing electrification over the long term, primarily through EV adoption.[74] Increased electrification is forecast to provide 0.5¢/kWh of rate mitigating benefits by 2034.[75] This is the result of additional net revenue of approximately $127 million over the period 2021 to 2034, or $62 million on a net present value basis.

The 2021 Plan is forecast to achieve approximately 70% of the Study's upper potential in 2034.[76]

[73] Net revenue represents the total additional revenue available through electrification, less the additional system and program costs. The baseline is the net revenue forecast based on the number of EVs projected with unmanaged charging in the baseline scenario of the Study. The differences in net revenues from Table 1 on page 11 primarily reflects updates to customer rate and marginal cost assumptions since the Study was completed.

[74] The 2021 Plan results show the projected outcomes based on the proposed programs and pilots included in the 2021 Plan.

[75] The rate mitigating benefit of 0.5¢/kWh is based on a change from the rates approved by the Board in Order No. P.U. 31 (2019) Amended. For example, this additional net revenue translates into an estimated $100 in lower electricity bill charges for an average all-electric residential customer.

[76] The upper is the net revenue forecast based on the number of EVs projected in the upper scenario of the Study. The differences in the net revenue from Table 1 on page 11 reflects updates to customer rate and marginal cost assumptions since the Study was completed.

Lower System Costs

CDM programing in the 2021 Plan will decrease system costs by approximately $113 million. This includes system energy and capacity costs.

CDM programs are essential to realizing the customer benefits of electrification. As electrification increases, customers' electricity consumption at times of peak also increases. CDM programming reduces peak electricity consumption. This, in turn, helps manage future investments required to meet increases in system capacity.

Customer Cost Savings

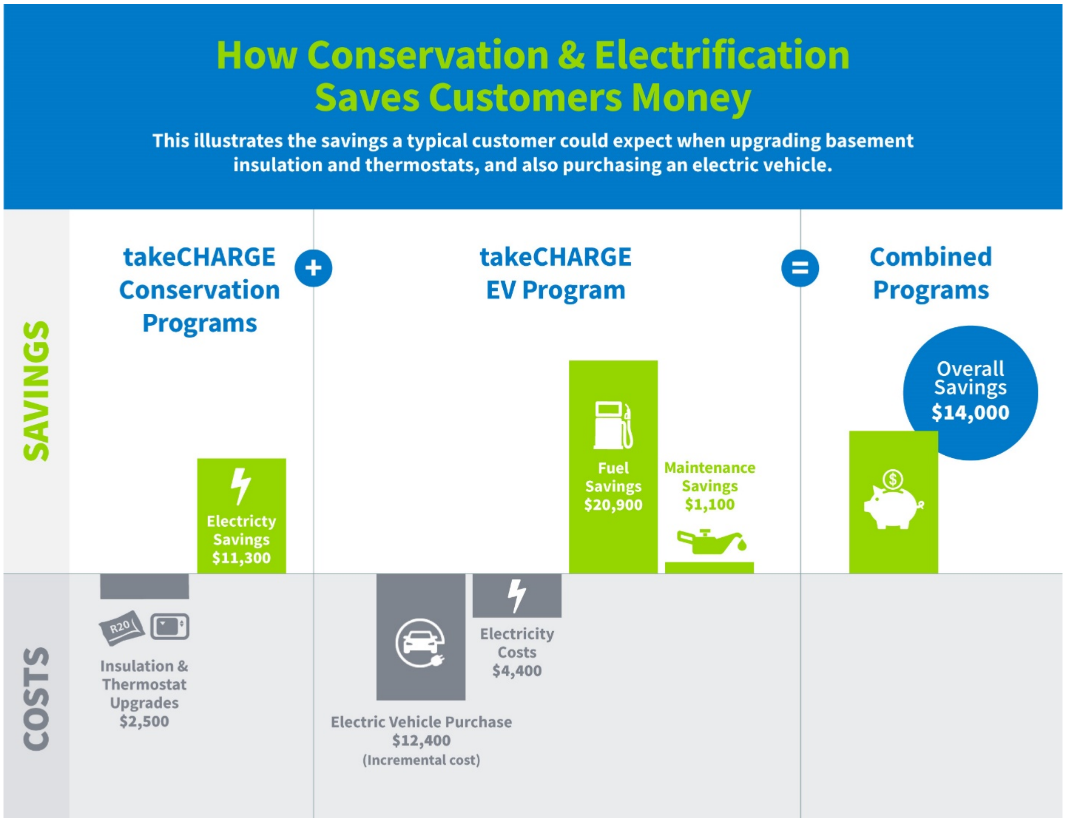
Both electrification and CDM programming will result in cost savings for customers.

Participants in electrification programs will see a reduction in their overall energy costs, primarily through vehicle fuel and maintenance savings. For example, electrification programs will provide fuel savings for customers of approximately $27 million.

Participants in CDM programs will see a reduction in their electricity costs. CDM programs will provide electricity bill savings for customers of approximately $203 million.

Figure 7 provides an illustrative example that demonstrates the cost saving benefits of customer conservation and electrification programs.

Figure 7
Conservation and Electrification Participant Benefits[77]



Following this illustrative example, a customer would incur incremental costs of approximately $19,300 related to conservation upgrades and the purchase of an EV. That same customer would see total cost savings of $33,300 through reduced electricity, fuel and maintenance costs. This results in net cost savings of $14,000.

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77 The overall savings of $14,000 represents the total savings of $23,300 ($11,300 in electricity savings + $20,900 in fuel savings + $1,100 in maintenance savings) expected to be incurred over the life of the insulation (25 years), thermostats (11 years) and EV (10 years) minus the total cost of $19,300 to purchase, install and power these technologies ($2,500 to upgrade to programmable thermostats and insulate a basement + $12,400 in incremental costs to purchase an EV + $4,400 in electricity costs for the EV). The costs to upgrade these technologies represent the costs once the rebate has been provided.

Overall, the combination of electrification and CDM programming proposed in the 2021 Plan will result in rate mitigating benefits for customers, lower system costs, and customer cost savings. This shows that, while electrification and conservation can seem like opposing messages, both have the same fundamental objective – to help customers lower their overall costs, including electricity, fuel and vehicle maintenance costs. Communicating these benefits to customers and stakeholders will be important to the success of the 2021 Plan.

6.0 OUTLOOK

The introduction of electrification programming will lay the foundation for market transformation over time. This will provide long-term rate mitigating benefits for customers.

The 2021 Plan will focus on creating the relationships and environment necessary to increase EV adoption in the province. With the established takeCHARGE partnership and growing customer awareness of electrification, the Utilities will continue to seek opportunities to collaborate with complementary organizations and trade allies for customers' benefit. Information sharing and policy coordination with the Provincial Government will also continue.

Schedule M provides letters of support for the 2021 Plan from stakeholders.

The continuation of CDM programming will maintain support for customers in managing their electricity use. These programs and education initiatives will continue to provide bill savings for customers. Outreach will increasingly target specific customer groups, including seniors and customers with low income. Partnerships with trade allies and community groups will be important to broadening customer reach.

The electrification and CDM initiatives in the 2021 Plan are designed to be flexible to ensure continued cost-effectiveness for customers. This requires responding to changing market and system dynamics. For example, EVs are forecast to reach cost parity with gasoline-powered vehicles in 2025. Recent advancements in battery technology may result in cost parity earlier. Annual cost-effectiveness screening will account for such changes to ensure initiatives remain beneficial for customers.

Schedule A
Five-Year Conservation Plan: 2016-2020 Summary

Five-Year Conservation Plan: 2016-2020 Summary

Conservation and Demand Management Programs

Through the delivery of the *Five-Year Conservation Plan: 2016-2020* (the "2016 Plan"), the Utilities jointly offered customer energy conservation programs providing both education and financial incentives to encourage customer installation of energy efficient technologies and adoption of energy efficient behaviours.[1] In addition, Hydro has offered programming for its customers, such as incentives for commercial customers in its isolated system service territories, where market conditions and system costs differ.

Table A-1 shows, by sector, the portfolio of programs that have been offered under the 2016 Plan.[2]

Table A-1
Conservation Programs by Sector

Residential	Commercial	Industrial
Insulation Thermostat Heat Recovery Ventilator Small Technologies[3] Benchmarking Isolated Systems Community Program	Business Efficiency Program Isolated Business Efficiency Program Isolated Systems Community Program	Industrial Energy Efficiency Program

[1] Once installed, these energy efficient technologies provide energy savings for the customer throughout the life of the product. For example, a heat recovery ventilator has an estimated life of 15 years and will result in energy saving benefits throughout that period.

[2] Detailed program descriptions can be found in Schedule F.

[3] This program provided incentives for two different groups of energy efficient products, appliances and electronics, and smaller technologies rebated by retail partners at the point of purchase. The appliances and electronics program was ended on December 31, 2017. The program originally provided rebates on refrigerators, chest freezers, washing machines and televisions. The Instant Rebate component offers rebates on a variety of low-cost energy efficient products. Products include LED lighting, weather stripping, dehumidifiers, dimmer switches, showerheads, smart power strips and more.

Table A-2 provides a summary of energy savings and demand savings forecast to be achieved through the Utilities' conservation programs from 2016 to 2020F. The energy and demand savings build upon the achievements of the conservation programs since 2009.

Table A-2
Summary of 2016 Plan Results[4]
2016 through 2020F

	2016	2017	2018	2019	2020F	Total
Annual Energy Savings (GWh)						
Residential	89.2	114.5	141.2	165.4	178.5	688.8
Commercial	15.0	24.1	31.8	40.2	46.4	157.5
Industrial	25.8	25.8	25.9	31.0	31.0	139.5
Total Energy Savings	**130.0**	**164.4**	**198.9**	**236.6**	**255.9**	**985.8**
Annual Demand Savings (MW)						
Residential	26.2	32.3	37.6	44.1	45.2	45.2
Commercial	4.0	5.0	6.3	7.1	8.4	8.4
Industrial	-	-	-	0.7	0.7	0.7
Total Demand Savings	**30.2**	**37.3**	**43.9**	**51.9**	**54.3**	**54.3**

Delivery of the 2016 Plan is estimated to result in 985.8 GWh of cumulative energy savings, exceeding the target of 883.2 GWh. The residential programs are the largest contributor to energy savings. Commercial energy savings have grown throughout the plan, and are expected to account for approximately 16% of overall energy savings achieved.

The Utilities continuously review customer energy conservation programs to ensure they provide relevant energy conservation initiatives for customers and are responsive to evolving customer needs

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4 CDM program savings indicated for the 2016 Plan are cumulative. The savings reflect all technologies installed since program implementation which have not reached the end of their useful life. For example LED light bulbs are expected to last for seven years. Therefore LEDs installed in 2014 will provide savings annually until 2020. CDM program savings represent gross savings achieved by customers. Net savings reflect adjustments for: (i) the timing of customer installations giving rise to the energy savings and (ii) program free ridership (an estimate of participants who would have chosen the more efficient product without the program).

and expectations.[5] The Utilities also delivered a number of energy efficiency programs for the Provincial and Federal Governments. A description of these programs is outlined in Table A-3.

Table A-3
takeCHARGE Government Program Delivery

Energy Efficiency in Oil Heated Homes Program	The Government of Canada's Low Carbon Economy Leadership Fund (LCELF) aims to reduce greenhouse gas emissions. In 2019, takeCHARGE extended its Insulation and Thermostat Rebate Programs to customers with oil heat through the LCELF and Provincial Government funding.
Heat Pump Rebate	The Heat Pump Rebate program funded by the Government of Newfoundland and Labrador and administered by Hydro, offered $1,000 rebates to qualified homeowners for mini-split, multi-split and central heat pumps. Rebates were issued to qualified homeowners for heat pumps purchased and installed on or after October 15, 2019 until the program ended on March 15, 2020.
Energy Efficiency Loan Program (EELP)	The Utilities delivered the EELP for the Government of Newfoundland and Labrador from 2017 to 2020. Through EELP, reduced rate financing was provided for insulation, heat pumps and home energy assessments to assist customers with the financial barriers to making their homes more energy efficient.

Education and Support

The Utilities continued to focus on customer education and community outreach in the delivery of the 2016 Plan. Energy conservation education and support was provided through a variety of channels, which include a joint website and social media accounts, outreach activities, school presentations and partnerships with other organizations. Table A-4 shows the number of energy conservation related customer-initiated contacts and outreach events from 2016 to 2020.

[5] Throughout the 2016 Plan, Island Interconnected System residential and commercial programs were reviewed by external third-party evaluators. Programs are evaluated on their energy savings, market impacts and delivery effectiveness. Evaluation findings are used to make necessary adjustments such as energy savings claims and to refine program design and implementation. For example, outcomes of the Instant Rebate evaluations have allowed the Utilities to extend this program beyond its original estimated end date of 2018. Annual market research continued to show significant room for growth in the residential LED market with a study commissioned in 2018 reporting approximately 3.5 million sockets that could be converted to more efficient lighting.

Table A-4
Customer Contacts and Outreach Events
2016 through 2020F

	2016	2017	2018	2019	2020F[6]	Total
Customer Inquiries[7]	8,411	10,170	9,019	9,670	5,430	42,700
Website Visits	241,359	302,909	411,045	376,988	392,049	1,724,350
Outreach Events	194	303	313	298	48	1,156

The Utilities are expected to have over 42,000 customer contacts and over 1.7 million visits to the takeCHARGE website from 2016 through 2020. The majority of customers choose electronic means of communication to obtain information on energy conservation and rebate programs. This is consistent with promotion of the takeCHARGE website as the primary resource for customer inquiries and information.[8]

The Utilities participated in an average of 277 community outreach events each year between 2016 and 2019. Through these events, takeCHARGE assisted customers with their energy efficiency questions, while helping them to take advantage of the takeCHARGE rebate programs. Energy conservation presentations were delivered to retailers, students, community groups and associations.[9] takeCHARGE information booths were displayed at trade fairs, industry conferences and retail stores across the province. The Utilities also offered a number of specialized outreach events such as the takeCHARGE of Your Town Challenge, Make the Switch, Energy Efficiency Week, Customer Energy Forums and the Luminary Awards.[10]

Trade allies, retailers and a variety of partners play an integral role in helping customers make knowledgeable decisions regarding energy efficiency. Trade allies and retail partners share and display information about takeCHARGE programs and promote energy efficiency upgrades during special events. The Utilities continued to develop new partnerships and strengthen existing relationships. Some of these organizations include Seniors NL, the Association of Newfoundland and Labrador Realtors, Empower NL, the Canadian Home Builders Association, Municipalities Newfoundland and

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6 2020 customer engagement results were impacted by the COVID-19 pandemic.

7 Customer inquiries include calls and emails received by the Utilities regarding energy efficiency.

8 The Utilities continued to build upon existing energy conservation resources for commercial and residential customers. New website resources are helping businesses to better understand how their facilities use electricity and suggest low-cost and no-cost ways to save energy. Online content for residents was evolved with a focus on how homes use electricity, no-cost ways to save, and key topics such as heat pumps.

9 Since 2016, over 13,500 students in over 165 schools throughout the province have received presentations about energy conservation through the takeCHARGE *Kids in Charge* K-I-C Start School Program. The program also includes an annual contest and online resources.

10 Each utility provides an annual grant of $7,500 for energy efficient upgrades to a municipality in their service territory through the takeCHARGE of Your Town Challenge. The Make the Switch LED bulb giveaway provides energy efficient light bulbs to non-profit and community organizations. Each annual Energy Efficiency Week reminds customers that takeCHARGE is here to help customers manage their electricity use, while Customer Forums connect residential and commercial customers with energy experts throughout the year. The takeCHARGE Luminary Awards were launched in 2018, providing an opportunity to recognize the progressive work in energy efficiency achieved by utility partners and customers.

Labrador, Newfoundland and Labrador Housing Corporation, the Government of Newfoundland and Labrador and the Government of Canada.

Costs

Table A-5 provides a summary of the research and customer education and conservation and demand management (CDM) program costs incurred by the Utilities from 2016 through 2020.[11]

Table A-5
Conservation Costs
2016 through 2020F
($000s)

	2016	2017	2018	2019	2020F	Total
Research and Customer Education	864	1,022	1,008	1,846	1,296	6,036
CDM Programs	8,320	8,300	7,632	7,631	7,597	39,480
Total	**9,184**	**9,322**	**8,640**	**9,477**	**8,893**	**45,516**[12]

The Utilities' costs related to customer energy conservation programs have remained stable during the 2016 Plan. This is primarily a result of consistent program offerings with fluctuations in research costs for initiatives such as commercial and residential end use surveys and the 2020 – 2034 Potential Study (the "Study").[13] The Utilities each bear the costs related to the provision of customer programming in their own service territory. General conservation and program costs, such as customer rebates and costs related to responding to customer inquiries are incurred directly by each utility. Costs which are incurred jointly, such as provincial mass media advertising, are split on an 85% / 15% basis between Newfoundland Power and Hydro, respectively.[14]

[11] Newfoundland Power's current conservation cost recovery practice reflects Board Order No. P.U. 13 (2013). Conservation program costs are deferred and amortized over a seven-year period. Through annual operation of the Company's Rate Stabilization Adjustment, customer rates are adjusted to reflect any difference between the conservation program costs included in the most recent test year and the costs actually incurred. Newfoundland Power's annually recurring general conservation costs related to providing general customer information, community outreach and planning are expensed in the year in which the costs are incurred. As of August 14, 2015, associated with a general rate application filed by Hydro on July 30, 2013, and an amended general rate application filed by Hydro on November 10, 2014, it was agreed that "Hydro's proposal to defer and amortize annual customer energy conservation program costs, commencing in 2015, over a discrete seven-year period in a Conservation and Demand Management (CDM) Cost Deferral Account should be approved."

[12] The total cost to deliver the 2016 Plan from 2016 through 2020 is forecast to be $45.5 million. The $4.4 million incurred above the plan forecast is primarily due to the extension of the Instant Rebates and Benchmarking programs. The Instant Rebates Program was due to end after 2018, but was continued in 2019 and 2020. The Benchmarking Program was due to end after 2019, but was extended into 2020. Both programs continue to offer cost-effective energy and demand savings.

[13] The Study and commercial and residential end use surveys were completed in preparation for the 2021 Plan.

[14] This approach to division of jointly incurred costs reflects the proportion of customers served by each utility. The Study is an exception to this split, where Newfoundland Power and Hydro split the costs 60%/40%, respectively.

Tables A-6, A-7 and A-8 outline energy savings, demand savings and costs for each energy conservation program by sector from 2016-2020F

Table A-6
Conservation Programs
Energy Reductions: 2016 – 2020F
by Sector
(GWh)

	2016	2017	2018	2019	2020F	Total
Residential						
Insulation Program	29.2	33.1	37.5	42.9	48.4	191.1
Thermostat Program	11.6	15.7	18.9	22.1	24.3	92.6
ENERGY STAR Window Program	9.9	9.9	9.9	9.9	9.9	49.5
Coupon Program	0.2	0.2	0.2	0.2	0.2	1.0
HRV	0.6	0.8	1.1	1.4	1.5	5.4
Small Technologies	31.2	40.4	52.5	63.1	70.5	257.7
Benchmarking	-	6.8	12.4	16.3	14.0	49.5
Isolated Systems Community Program	6.2	7.3	8.4	9.2	9.4	40.5
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**89.2**	**114.5**	**141.2**	**165.4**	**178.5**	**688.8**
Commercial						
Business Efficiency Program	14.6	23.6	31.1	39.1	44.8	153.2
Isolated Systems Business Efficiency Program	0.4	0.5	0.7	0.7	0.8	3.1
Isolated Systems Community Program (Commercial)	-	-	-	0.4	0.8	1.2
Total Commercial Portfolio	**15.0**	**24.1**	**31.8**	**40.2**	**46.4**	**157.5**
Industrial						
Industrial Energy Efficiency Program	25.8	25.8	25.9	31.0	31.0	139.5
Total Portfolio	**130.0**	**164.4**	**198.9**	**236.6**	**255.9**	**985.8**

Table A-7
Conservation Programs
Program Costs: 2016 – 2020F
by Sector
($000s)

	2016	2017	2018	2019	2020F	Total
Residential						
Insulation Program	881	1,184	1,240	1,578	1,281	6,164
Thermostat Program	446	593	456	496	573	2,564
ENERGY STAR Window Program	-	-	-	-	-	-
Coupon Program	-	-	-	-	-	-
HRV	147	132	219	156	239	893
Small Technologies	4,291	2,291	1,911	1,588	950	11,031
Benchmarking	523	883	836	820	862	3,924
Isolated Systems Community Program	451	936	981	577	992	3,937
Block Heater Timer Program	-	-	-	-	-	-
Total Residential Portfolio	**6,739**	**6,019**	**5,643**	**5,215**	**4,897**	**28,513**
Commercial						
Business Efficiency Program	1,508	2,199	1,870	1,805	2,122	9,504
Isolated Systems Business Efficiency Program	45	41	99	24	192	401
Isolated Systems Community Commercial	-	-	-	412	-	412
Total Commercial Portfolio	**1,553**	**2,240**	**1,969**	**2,241**	**2,314**	**10,317**
Industrial						
Industrial Energy Efficiency Program	28	41	20	175	386	650
Total Portfolio	**8,320**	**8,300**	**7,632**	**7,631**	**7,597**	**39,480**

Table A-8
Conservation Programs
Demand Reductions: 2016 – 2020F
By Sector
(MW)

	2016	2017	2018	2019	2020F	Total
Residential						
Insulation Program	8.8	10.5	12.4	14.6	15.8	15.8
Thermostat Program	3.5	3.7	3.8	3.9	4.0	4.0
ENERGY STAR Window Program	3.1	3.1	3.1	3.1	3.1	3.1
Coupon Program	0.1	0.1	0.1	0.1	0.0	0.0
HRV	0.2	0.2	0.3	0.4	0.4	0.4
Small Technologies	8.6	11.1	13.4	15.8	17.1	17.1
Benchmarking	-	1.2	1.9	3.3	1.7	1.7
Isolated Systems Community Program	1.9	2.2	2.6	2.9	3.1	3.1
Block Heater Timer Program	-	-	-	-	-	-
Total Residential Portfolio	**26.2**	**32.1**	**37.6**	**44.1**	**45.2**	**45.2**
Commercial						
Business Efficiency Program	3.7	4.7	5.9	6.7	7.9	7.9
Isolated Systems Business Efficiency Program	0.3	0.3	0.4	0.4	0.4	0.4
Isolated Systems Community Program (Commercial)	-	-	-	-	0.1	0.1
Total Commercial Portfolio	**4.0**	**5.0**	**6.3**	**7.1**	**8.4**	**8.4**
Industrial						
Industrial Energy Efficiency Program	-	-	-	0.7	0.7	**0.7**
Total Portfolio	**30.2**	**37.1**	**43.9**	**51.9**	**54.3**	**54.3**

Schedule B
North American Electrification Initiatives

Table B-1 shows utility electrification initiatives in North America by State and Province.

Table B-1
North American Electrification Initiatives

	Vehicle Incentive[1]	Commercial EV Charger Incentive[2]	Residential EV Charger Incentive[3]	Make Ready Investment[4]	Utility DCFC Investment[5]	Fleet Support[6]	Custom Commercial Incentive[7]	DCFC Incentive[8]	Managed Charging[9]
Alabama									X
Alaska	X								X
Arizona		X	X		X		X		X
Arkansas			X			X	X		
BC	X[10]		X[10]		X[11]				X
California	X	X	X	X	X	X	X	X	X
Colorado			X	X		X			X
Connecticut	X		X						

1 Vehicle incentives include programs where an incentive is paid to customers to reduce the upfront cost of an EV.

2 Commercial EV charger incentives include programs that provide commercial customers with an incentive towards the purchase of a level 2 charger.

3 Residential EV charger incentives include programs that provide residential customers with an incentive towards the purchase of a level 2 charger.

4 Make ready investment includes initiatives to reduce the cost to install EV charger equipment. These programs would typically include a portion of the rebate or investment towards the costs required to install an EV charger.

5 Utility DCFC investment includes initiatives where the utility owns and operates DCFC infrastructure.

6 Fleet support includes initiatives that are focused on supporting commercial customers in converting their vehicle fleet to electric vehicles.

7 Custom commercial incentives include programs that provide incentives towards converting non-electric vehicle technologies to electric, such as forklifts or heat pumps.

8 DCFC incentives include programs that provide incentives off the purchase price of DCFC infrastructure.

9 Managed charging includes initiatives where the utility has a program to encourage off peak charging of EVs, such as managed charging through smart charging or EV off peak incentive rates.

10 The vehicle incentive program in BC and Quebec is funded by the Provincial Government. The vehicle incentive program in New York is funded by the State.

11 Section 18 of British Columbia's Clean Energy Act states that in setting rates under the Utilities Commission Act for a public utility carrying out a prescribed undertaking, the commission must set rates that allow the public utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking. Order in Council No. 339 amended Greenhouse Gas Reduction (Clean Energy) Regulation. B.C. Reg. 102/2012 to include electric vehicle charging stations as a prescribed undertaking under the Clean Energy Act.

Schedule B
Page 2 of 3

Table B-1
North American Electrification Initiatives

	Vehicle Incentive[1]	Commercial EV Charger Incentive[2]	Residential EV Charger Incentive[3]	Make Ready Investment[4]	Utility DCFC Investment[5]	Fleet Support[6]	Custom Commercial Incentive[7]	DCFC Incentive[8]	Managed Charging[9]
District of Columbia				X		X			X
Florida	X				X[12]		X		
Georgia		X	X	X	X				X
Hawaii				X	X	X			X
Illinois							X		X
Indiana					X				X
Iowa		X	X				X		
Kentucky[13]			X		X	X			X
Louisiana							X		
Maine	X								
Maryland		X	X	X	X	X			X
Massachusetts				X	X	X			X
Michigan		X	X					X	X
Minnesota		X	X	X		X	X		X
Missouri		X			X			X	
Nevada		X			X	X			X
New Brunswick					X[14]				
New Mexico[15]				X	X	X			
New York	X[10]		X	X	X	X		X	X
North Carolina		X	X		X	X			

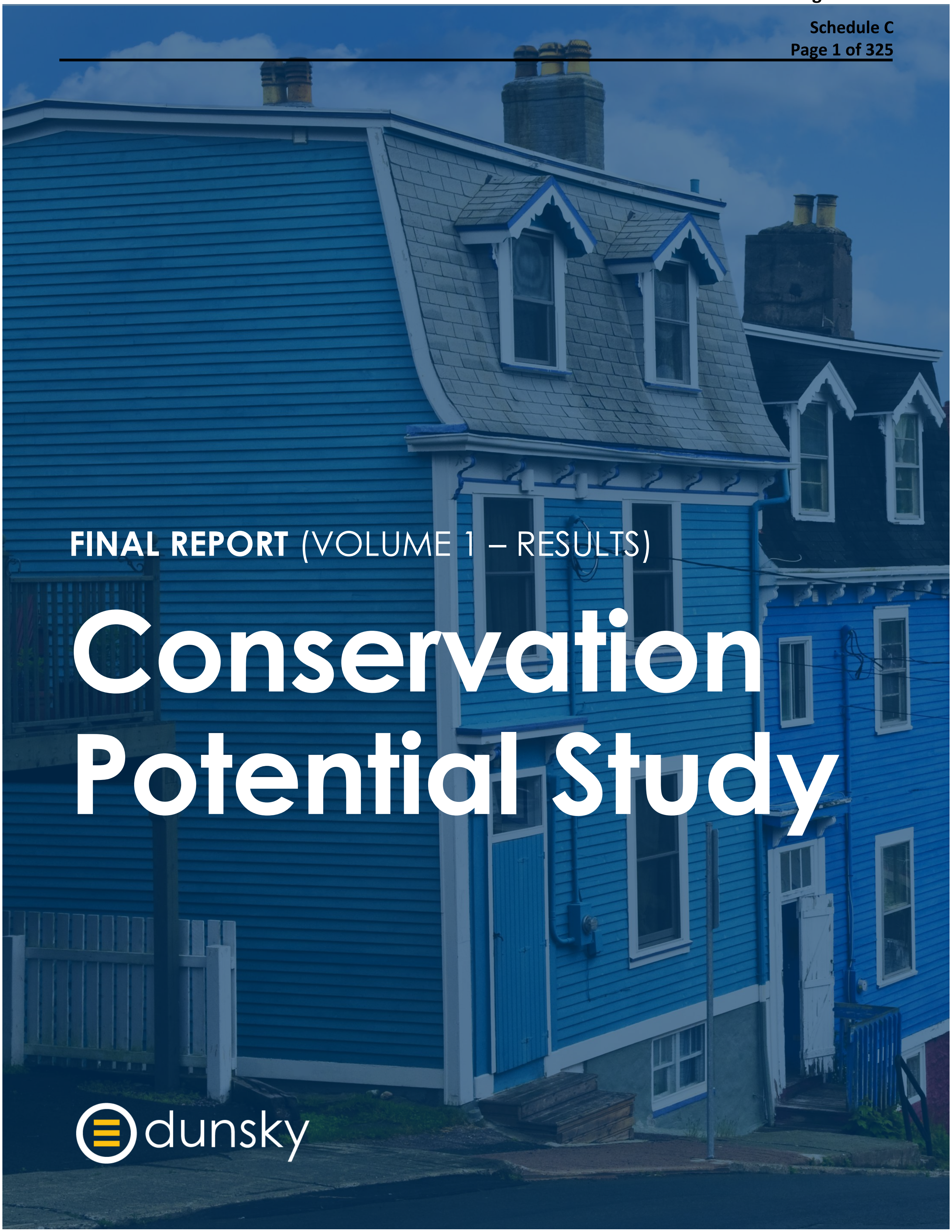
[12] The utility DCFC investment in Florida is pending regulatory approval.
[13] The residential charger incentive, the utility DCFC investment, the fleet support and managed charging in Kentucky are pending regulatory approval.
[14] Utility DCFC investment in New Brunswick, Nova Scotia, Quebec and Rhode Island is unregulated.
[15] The make ready investment, the utility DCFC investment and the fleet support in New Mexico are pending regulatory approval.

Table B-1
North American Electrification Initiatives

	Vehicle Incentive[1]	Commercial EV Charger Incentive[2]	Residential EV Charger Incentive[3]	Make Ready Investment[4]	Utility DCFC Investment[5]	Fleet Support[6]	Custom Commercial Incentive[7]	DCFC Incentive[8]	Managed Charging[9]
North Dakota			X				X		
Nova Scotia					X[14]				
Ohio[16]		X	X	X	X	X		X	X
Oregon		X	X		X	X			X
Pennsylvania	X	X							
Quebec	X[10]		X[10]		X[14]				
Rhode Island				X	X[14]	X		X	X
South Carolina			X		X				X
South Dakota			X				X		
Texas		X	X			X	X	X	X
Utah	X	X	X	X					X
Vermont	X	X	X						
Virginia		X	X		X	X			
Washington		X	X	X[17]	X	X			X
Wisconsin		X	X	X		X			
Total	**11**	**19**	**26**	**15**	**24**	**20**	**11**	**7**	**25**

16 The residential charger incentive, the utility DCFC investment, the fleet support and managed charging in Ohio are pending regulatory approval.
17 The make ready investment in Washington is pending regulatory approval.

Schedule C
2020–2034 Potential Study



FINAL REPORT (VOLUME 1 – RESULTS)

Conservation Potential Study

dunsky

Conservation Potential Study
Final Report (Volume 1 – Results)

Submitted to:

Newfoundland Power Inc.
Newfoundland and Labrador Hydro

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Volume 2

Within the text of the report the reader will find references to specific appendices in which further relevant details are presented. Appendices are included in Volume 2 as follows:

Appendix A: Energy Efficiency modelling methodology

Appendix B: Demand Response modelling methodology

Appendix C: Fuel Switching modelling methodology

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LIST OF ACRONYMS

ASHP – Air Source Heat Pump

BEV – Battery Electric Vehicle

BUG – Backup Generator

CBR – Cost Benefit Ratio

CDM – Conservation and Demand Management

CEUS – Commercial End-Use Survey

CPP – Critical Peak Pricing

CVR – Conservation Voltage Reduction

DCFC – Direct Current Fast Charger

DEEP – Dunsky Energy Efficiency Potential Model

DHW – Domestic Hot Water

DMSHP – Ductless Mini-Split Heat Pump

DR – Demand Response

EE – Energy Efficiency

ER – Early Replacement

EUL – Estimated Useful Life/Effective Useful Life

EVA – Electric Vehicle Adoption Model

RCx – Retro-commissioning

FS – Fuel Switching

GHG – Greenhouse Gas

GWh – Gigawatt Hour

HDV – Heavy Duty Vehicle

HVAC – Heating, Ventilation, and Air-Conditioning

ICE – Internal Combustion Engine

IIC – Island Interconnected System

IOC – Iron Ore Company of Canada

ISO – Isolated Diesel System

ISP – Industry Standard Practice

kWh – Kilowatt Hour

L2 – Level 2

LAB – Labrador Interconnected System

LDV – Light Duty Vehicle

LED – Light-Emitting Diode

MDV – Medium Duty Vehicle

MW - Megawatt

MWh – Megawatt Hour

NTGR – Net-to-Gross Ratio

PACT – Program Administrator Cost Test

PC – Participant Cost

PCT – Participant Cost Test

PHEV – Plug-in Hybrid Electric Vehicle

ROB – Replace on Burnout

RUL – Remaining Useful Life

SCT – Societal Cost Test

SEM – Strategic Energy Management

TCO – Total Cost of Ownership

TOU – Time-of-Use

TRC – Total Resource Cost

TRM – Technical Reference Manual

VFD – Variable Frequency Drive

VRF – Variable Refrigerant Flown

DEFINITIONS

Assessment of potential: The development of energy and capacity savings available from projected customer usage through the application of commercially available, cost-effective technologies and improved operating practices, considering the impacts of market factors.

Achievable potential: The savings from cost-effective opportunities once market barriers have been applied, resulting in an estimate of savings that can be achieved through demand-side management programs. Three achievable potential scenarios were modeled to examine how varying factors such as incentive levels and market barrier reductions impact uptake.

Cumulative savings: A rolling sum of all new savings that will affect energy sales, cumulative savings exclude measure re-participation (i.e. savings toward a measure are counted only once, even if customers can participate again after the measure has reached the end of its useful life) and provide total expected grid-level savings.

Economic potential: The savings opportunities available should customers adopt all cost-effective savings, as established by screening measures against the Total Resource Cost (TRC) test, without consideration of market barriers or adoption limitations.

Energy End-Use: In this study, energy end-uses refer to grouping of energy saving measures related to specific building component (i.e. water heating, HVAC, lighting etc.)**.**

Energy Saving Measure: An energy saving measure (or measure) refers to a specific equipment or building operation improvement that leads to energy savings.

Market Sector: The market of energy using customers in Newfoundland and Labrador is broken down into two sectors based on the primary occupants in the building: Residential (including single family and multi-family buildings) or Commercial (including businesses, institutional and industrial buildings).

Market Segment: Within each Sector, market segments are defined to capture key differences in energy use and savings opportunities that are governed by building use and configuration.

NL Utilities: Refers to the two retail utilities in Newfoundland and Labrador, Newfoundland Power (NF Power) and Newfoundland and Labrador Hydro (NL Hydro).

Program savings: Savings from measures that are incentivized through programs in a given year, including savings from measure re-participation. They are most representative of annual program savings and can be used to improve CDM program planning to help meet savings objectives, and to determine which sectors, end-uses, and measures hold the most potential.

Technical potential: The theoretical maximum savings potential, ignoring constraints such as cost-effectiveness and market barriers.

EXECUTIVE SUMMARY

Dunsky Energy Consulting conducted a Conservation and Demand Management (CDM) potential study for Newfoundland and Labrador over the 2020-2034 timeframe. Detailed bottom-up modeling tools were applied, to quantify energy and demand impacts from multiple CDM sources, including energy efficiency (EE), demand response (DR), heating fuel switching (FS) and electric Vehicles (EVs).

The study covered opportunities in each of the three electricity systems in the province:

- The Island Interconnected (IIC) System: Comprising over 90% of the provinces' residential and commercial customers.
- The Labrador Interconnected System (LAB): On which consumption is dominated by two large industrial customers.
- The Isolated Diesel (ISO) Systems: Which make up a small portion of electricity consumption in the province but have extremely high generation costs and barriers to efficiency.

Table 0- 1 provides a guide of the electricity systems that each study element was applied to.

Table 0- 1. CDM Programing Components Covered in the NL Conservation Study

Study Component	Model Applied	Systems Studied
Energy Efficiency	Dunsky's Energy Efficiency Potential (DEEP) Model	IIC, LAB, ISO
Demand Response	Dunsky's Demand Response (DR) Model	IIC, LAB
Fuel Switching	DEEP Model adapted for Heat Pump adoption	IIC
Electric Vehicles	Dunsky's Electric Vehicle Adoption Model	Province-wide

The study is founded on up-to-date Newfoundland and Labrador-specific market data for both the residential and commercial sectors. This market data provided specific saturation and baseline efficiencies of energy-using equipment in homes and businesses across the province. In addition, the study included a survey to assess customer barriers to the adoption of energy efficiency technologies.

This potential study comes at a transitional time for Newfoundland and Labrador's electric utilities, stemming from changes to the province's generation and transmission systems. This is taking place against disruptions to North America's electricity utility industry as a whole, including a growing focus on customer needs and their opportunities to save energy, shift demand and switch fuels. Specific challenges facing the electric utilities include:

- Changes to Newfoundland and Labrador's energy supply and distribution with the addition of the Muskrat Falls generation facility and Labrador-Island-Link transmission line.
- Changes to marginal costs of energy and peak demand.
- A rapidly transforming lighting market, which is impacting some CDM program top savings measures.
- A growing interest in the electrification of heating and transportation.
- The emergence of peak demand and load management priorities.

These opportunities put growing emphasis on conservation and demand management opportunities that can help utilities balance supply and demand, considering both temporal and locational variations, to maintain electricity service reliability and affordability.

Over the 15-year study period, electricity rates, avoided costs and carbon pricing in the province are subject to notable uncertainty. To capture the impact that changes in these factors could have on the market adoption of the studied technologies, sensitivity analyses were conducted covering these three key economic factors.

USES FOR THIS POTENTIAL STUDY

This potential study is a high-level assessment of electricity impacting opportunities in the Province of Newfoundland and Labrador over the next 15 years. Its main purposes are to support:

- **Resource planning:** Evaluate the impact of Energy Efficiency, Demand Response, Fuel Switching and Codes & Standards on long-term energy consumption and demand needs at the grid/distribution level.

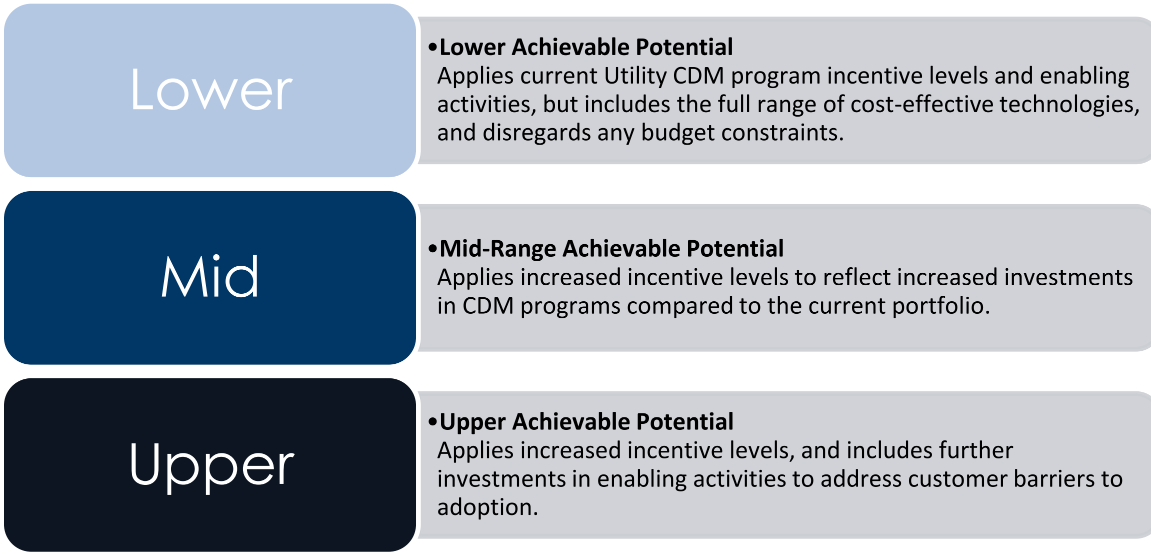
- **Efficiency program planning:** Assess achievable CDM opportunities to improve CDM program planning and help meet long-term savings objectives, and determine which sectors, end-uses and measures hold the most potential.

This potential study is *not* intended to give granular information about measures in specific segments, but rather give a macro view of efficiency potential. Moreover, it is not a program design document that accurately forecast savings achieved through Utility programs in a given future year, but rather quantify the total potential opportunities that exist under specific parameters.

ENERGY EFFICIENCY POTENTIAL

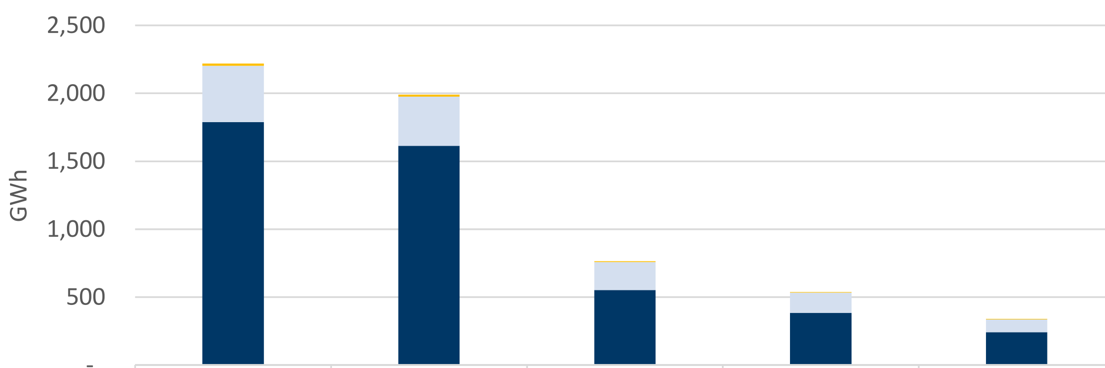
Three levels of savings potential were assessed: Technical, Economic, and Achievable. Within the Achievable potential three scenarios were modeled to examine how CDM program design factors such as incentive levels and investments in enabling activities can impact potential savings. The achievable potential scenarios are defined at the Upper, Mid, and Lower Achievable Potential levels, as described in **Figure 0-1** below.

Figure 0-1. CDM Program Scenarios Applied in this Study



Below, the technical, economic, and achievable savings are presented side-by-side for electric potential savings (**Figure 0-2**) for each system over the study period (2020-2034). Overall these results show that over 95% of the Technical Potential is cost-effective (from a total resource cost (TRC) test perspective) and is therefore captured in the Economic Potential. Moreover, the Achievable Potential scenarios demonstrate the impact of additional investments through higher incentive levels and further enabling strategies.

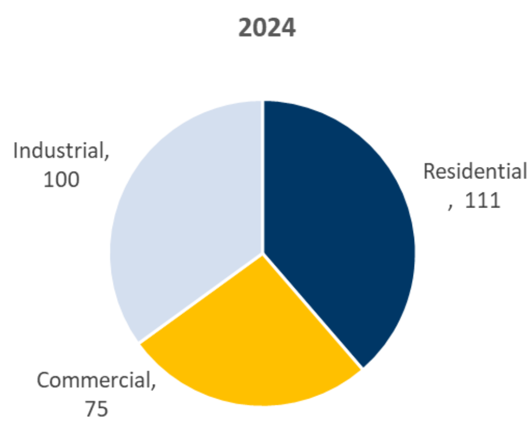
Figure 0-2. Cumulative Electric Potential Savings from Efficiency Under Mid-Rates (2034)

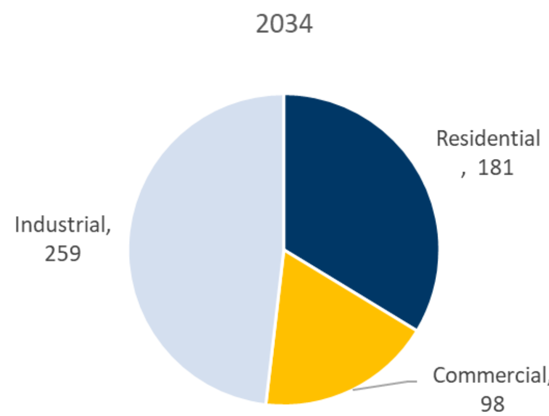


	Technical	Economic	Upper	Mid	Lower
ISO	16	16	6	5	4
LAB	415	363	207	149	94
IIC	1,788	1,613	552	384	242

Below, cumulative savings under the Mid program scenario are presented by sector and time period (**Figure 0-3**). The results presented focus on the Mid program scenario for illustrative purposes, as the proportional amount of savings in each sector are generally consistent under each of the program scenarios. Overall the results show that in the initial years the residential sector offers the greatest savings potential, while the industrial sector offers the greatest potential by the end of the study. This is primarily a result of the residential lighting savings being eliminated after 2025 as the lighting market transforms as result of the new EISA standards that are expected to come into force. It should be noted that the majority of the industrial savings come from the Large Industrial segment, for which a top-down assessment was performed, rather than the bottom-up analysis applied to assess savings in all other segments.

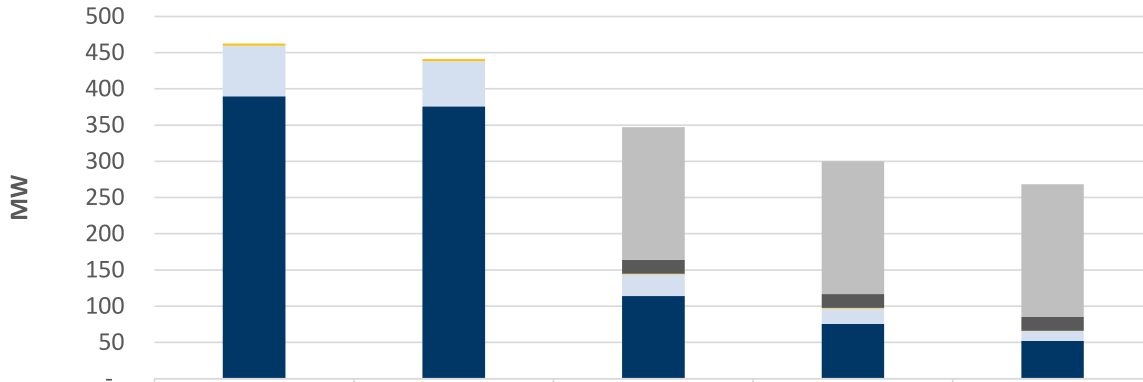
Figure 0-3. Province-Wide Cumulative Achievable Potential (GWh) by sector: Mid Program Scenario





The combined peak demand potential from energy efficiency (EE) and demand response (DR) programs are presented below in **Figure 0-4** below.

Figure 0-4. Peak Demand Potential Savings for DR and EE Programs by System[1] Under Mid-Rates (2034)



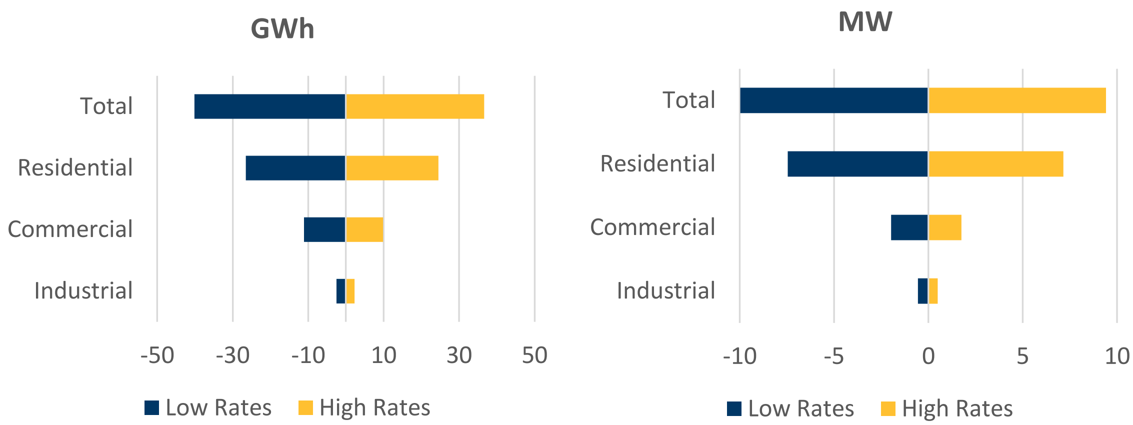
	Technical	Economic	Upper	Mid	Lower
IIC (DR)			183	183	183
LAB (DR)			19	19	19
ISO (EE)	3	3	1	1	1
LAB (EE)	70	63	30	22	14
IIC (EE)	390	375	114	76	52

Overall, from these findings it is evident that EE program scenarios offer significant demand reduction potential, particularly in the IIC system. However, it is also apparent that the DR programs offer more peak demand reductions than any of the EE program scenarios.

Figure 0-5 below shows the impact of the low and high customer rate cases on the Mid Program scenario cumulative achievable potential by 2034. The low customer rate represents customer rates that are fully mitigated from future rises related to the Muskrat Fall generation facility (about 18% less than the Mid-case), while the High rates case represents a scenario where the rates are not mitigated at all (about 20% higher than the Mid rates scenario). Overall it is found that the achievable potential will increase or lower by 10% under each rate case as compared to the mid-rates case. These results are somewhat tempered by the fact that the rate cases were not applied to the Large Industrial sector, which delivers nearly half of the achievable potential by 2034.

[1] DR potentials include existing curtailment and potential peak demand impacts from new measures and programs as described in Chapter 4 of this report. Because the model does not consider interactions among DR measures at the technical and economic potentials level, the results are not considered additive, and are therefore not included in the graph.

Figure 0-5. Impact of Customer Rate Scenarios on Cumulative Achievable Savings by segment: Mid Program Scenario (IIC - 2034)



Finally, the study assessed the annual activity and savings for each of the takeCHARGE programs. The overall results, where savings are expressed as the portion of sales in each year, are presented below for the IIC and LAB systems together **(Figure 0-6**) and the ISO system (**Figure 0-7**). Overall it was found that annual program savings are highest in the initial years, and drop after 2024 when the new EISA lighting standards are expected to come fully into force. Savings in the earlier years contain significant lighting contributions while in the later years, envelope, HVAC and industrial motors and compressors dominate the program savings.

Figure 0-6. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (IIC+LAB)

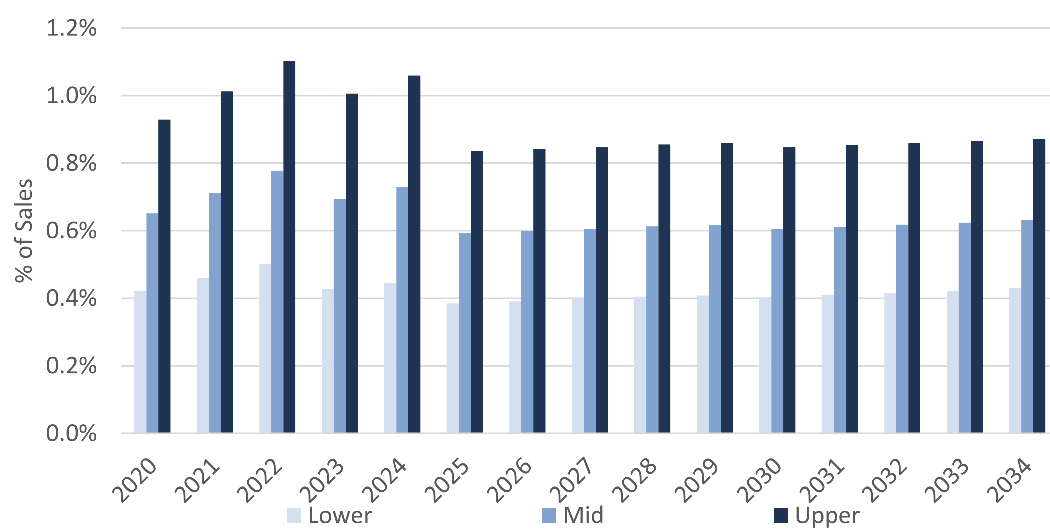
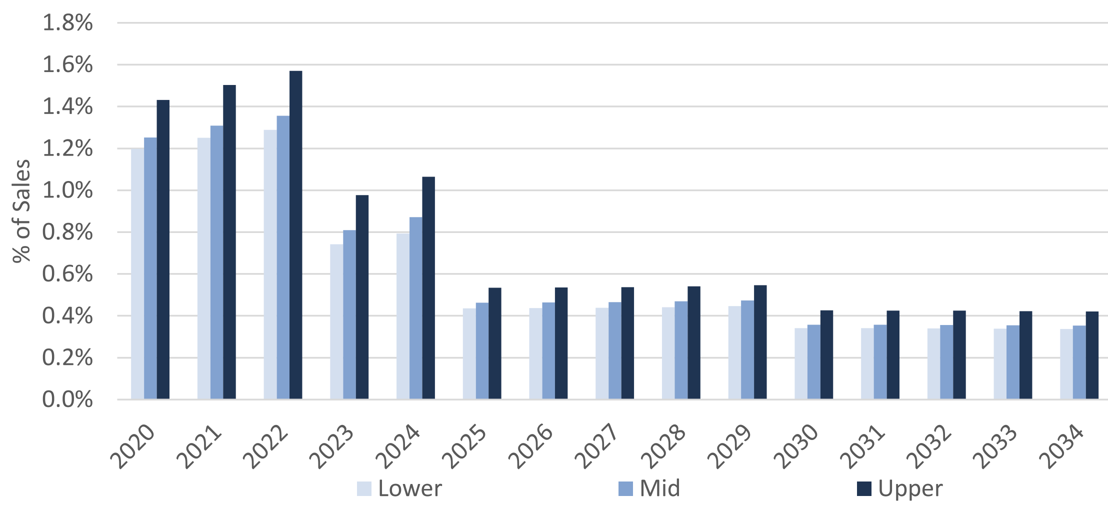


Figure 0-7. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (ISO)



CDM PROGRAMS: KEY TAKE-AWAYS

The following key take-aways emerge from the CDM Program potential analysis:

- **The province-wide savings in the initial study years put the NL Utility CDM programs squarely in the range of savings being achieved by other Canadian utilities**. The Lower program scenario potential would correspond to closely current CDM program savings, but with an increase stemming from the expected increase in customer rates as the Muskrat Falls generation facility comes online. Savings in this period are dominated by substantial lighting savings when summed across all sectors, a trend that is particularly strong in the ISO system.

- **In the residential sector annual savings are highest for Home Energy Reports, but Envelope measures offer the greatest lifetime saving:** As much as 50% of annual savings come from the Home Energy Reports. However, this program offers limited lifetime savings, due to its 1-year EUL. Envelope measures provide significant annual savings and more than half of all lifetime savings by the end of the study period.

- **Commercial sector savings are initially dominated by lighting, but in the later years HVAC measures present a leading opportunity.** With four measures in the top 10 in the latter study years (HVAC Control, HVAC VFD, HVAC Equipment and Heat Pumps), the HVAC end-use shows the second most potential for program savings, starting after EISA standards come into effect (2023). It also has the greatest potential in terms of lifetime savings during the entire study period. This may justify focusing CDM efforts on this end-use.

- **Industrial sector savings are driven by the large industrial segment. Motors and compressor measures related to processes dominate the program savings in all periods.** The industrial sector also offers notable lighting savings, as most industrial lighting is not impacted by the new EISA lighting standards.

Finally, HVAC measures also offer notable savings for industrial facilities where they have high annual hours of use (24-hour operation or shift work).

DEMAND RESPONSE POTENTIAL

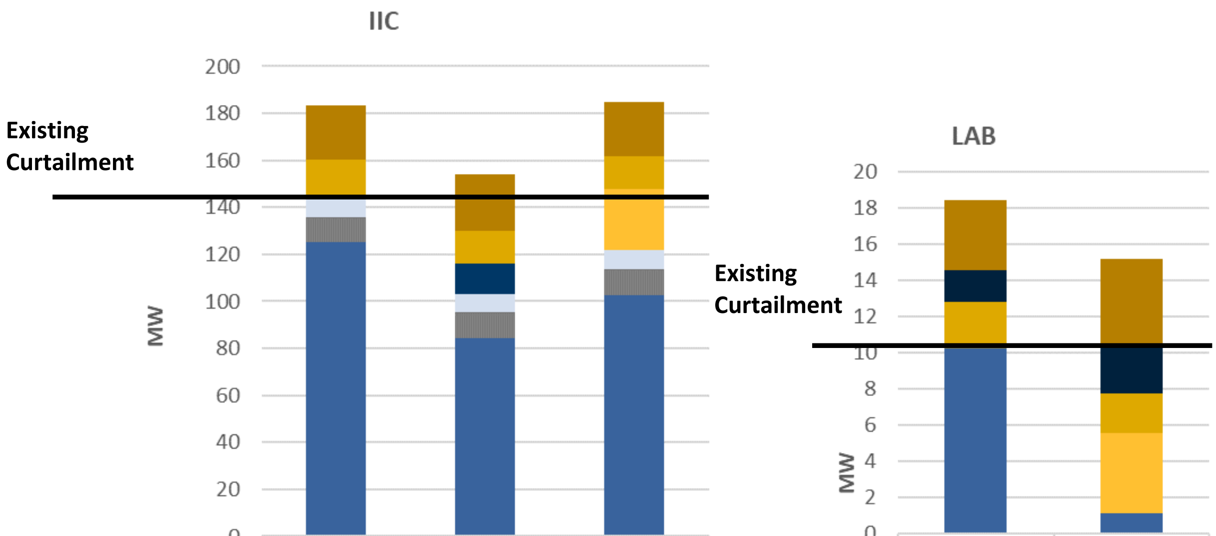
The study includes an assessment of the technical, economic and achievable potentials of a wide range of demand response (DR) measures, and the results are presented for each set of measures under the achievable potential scenario results. Three DR program scenarios were assessed, each based on a specific mix of DR programs to determine which offers the most potential when the net impact on the utility peak demand curve is assessed **(Figure 0-8)**.

Figure 0-8. Demand Response Program Scenarios

Scenario 1	•**Enhanced Current DR Potential** The first scenario focuses on maximizing the impact from current DR programs (i.e. curtailment) and adding further programs that have little or no interactive effects with existing programs.
Scenario 2	•**Rate-Based DR Expansion** The second scenario approach focuses on the DR potential possible via rate-based measures such as Time of Use rates and/or Critical Peak Pricing. These are applied alongside existing curtailment programs.
Scenario 3	•**Equipment Control DR Expansion** The third scenario focuses on an equipment control approach, either through utility direct load control, or manual control of equipment. These are applied alongside existing curtailment programs.

Figure 0-9 and **Table 0-2** below present the peak reduction potential for each scenario assessed for the IIC and LAB systems. A line indicating the peak demand reduction potential from the existing industrial and commercial curtailment as well as conservation voltage reduction (IIC system only) is also included.

Figure 0-9. Demand Response Potential[2] (2034)



IIC	Scenario 1	Scenario 2	Scenario 3
Dual-Fuel	23	24	23
Small/Med Industrials	16	14	14
Equipment	0	0	26
TOU	0	13	0
CVR	8	8	8
Commercial Curtailment	11	11	11
Large Industrials	125	84	103

LAB	Scenario 1	Scenario 3
Dual-Fuel	4	5
BUGs	2	3
Small/Med Industrials	3	2
Equipment	0	4
Large Industrials	10	1

[2] Since dynamic rates have a negative impact on LAB system, Scenario 2 is not present in the LAB analysis. The following sections and Appendix F contain more details on dynamic rates and their impacts on LAB and IIC systems.

Table 0- 2. Existing Curtailment and Scenarios Comparison (2034)

System	Existing potential	Scenario 1:	Scenario 2:	Scenario 3:
IIC	144	183	154	185
LAB	10	19	19[3]	15
Total	**154**	**202**	**173**	**200**

From the above results the following conclusions can be drawn:

- **Scenario 1 - Optimizing the Existing Curtailment is the most advantageous scenario:** Scenario 1 offers the most potential for nearly all years for both IIC and LAB systems. The focus on the existing curtailment approaches carries the least degree of program complexity and cost when compared to Scenarios 2 and 3 that would require adding the program infrastructure for TOU rates and equipment direct load controls respectively.

- **In the IIC systems there is little benefit, or even lowered peak reduction benefits, in adding measures that incur significant bounce back effects:** Under Scenario 2 in the IIC system, the overall potential actually drops when the optimally designed TOU rates program is added to the mix of programs as it undermines the ability for the Industrial Curtailment program by creating new, choppier peaks in the load curve. Scenario 3 in the IIC system does yield a marginally higher overall potential (2 MW higher) than Scenario 1.

- **Existing industrial curtailment potential places Newfoundland and Labrador at the high end of achievable range when benchmarked against other jurisdictions:** The Industrial Curtailment program has significant enrolled capacity that appears to be well suited to reducing peak loads on the IIC system in particular. Further potential may exist to expand this program among more Small and Medium industrial customers as well.

  While TOU Rates, CPP and Equipment Control programs did not appear to offer additional DR potential, adjustments to the existing Industrial Curtailment programs, incorporating more aggressive EV adoption peak load impacts, or adding the Fuel Switching load curve impacts, all may alter conditions such that TOU Rates, CPP and/or Equipment Controls could become effective in the future: Changes to the utility load curve or to the constraints applied in other programs have significantly impacted the interactions among programs. For example, if the NL Utilities are able to negotiate Industrial Curtailment contracts with longer DR event durations, it may be possible that TOU Rates, CPP and Equipment Programs could offer additional potential as compared to the results presented herein.

Overall, it appears that maintaining the Utilities focus on industrial and commercial curtailment is the best option to optimize the DR achievable potential in NL.

[3] Using best scenario (Scenario 1: Optimise Existing Curtailment) since TOU is not improving peak demand savings for LAB system.

Consideration of Curtailment Flexibility and Further Integration of EV Adoption and Fuel Switching Impact

Increased flexibility for the industrial curtailment contracts could increase the potential from other programs. Further analysis of this potential will be undertaken by the Utilities. It should also be noted that the results presented in study indicate that Fuel Switching and EV Adoption could significantly alter the utility load curve shapes, which may create an opening for the TOU Rates, CPP and Equipment Controls programs to add further peak load reduction potentials. As the needed information becomes available, the Utilities will conduct further assessments.

FUEL SWITCHING POTENTIAL

A fuel switching analysis was conducted to assess how many households and businesses can be expected to replace or supplement oil- and wood-fired space heating and domestic hot water (DHW) heating systems with electric heat pump systems under various levels of incentives. The analysis tested three scenarios – one without any incentives (Lower) and two with various levels of utilities incentives to encourage customers to install electric heating and hot water equipment (Mid, Upper) under the Mid-rate scenario with no carbon tax applied to fuel oil for heating. The incentive scenarios also reduce barrier levels in the model to simulate education and outreach efforts that make fuel switching less daunting to consumers. **Figure 0-10** describes each scenario.

Figure 0-10. Fuel Switching Scenarios Applied in this Study

Lower	• **No Incentives** No incentives are offered. Fuel switching is what would be expected without any market intervention.
Mid	• **35% Incentive** An incentive to cover 35% of the incremental cost of the measure is applied, **plus a ½ step reduction in barrier levels**.
Upper	• **70% Incentive** An incentive to cover 70% of the incremental cost of the measure is applied, **plus a full step reduction in barrier levels.**

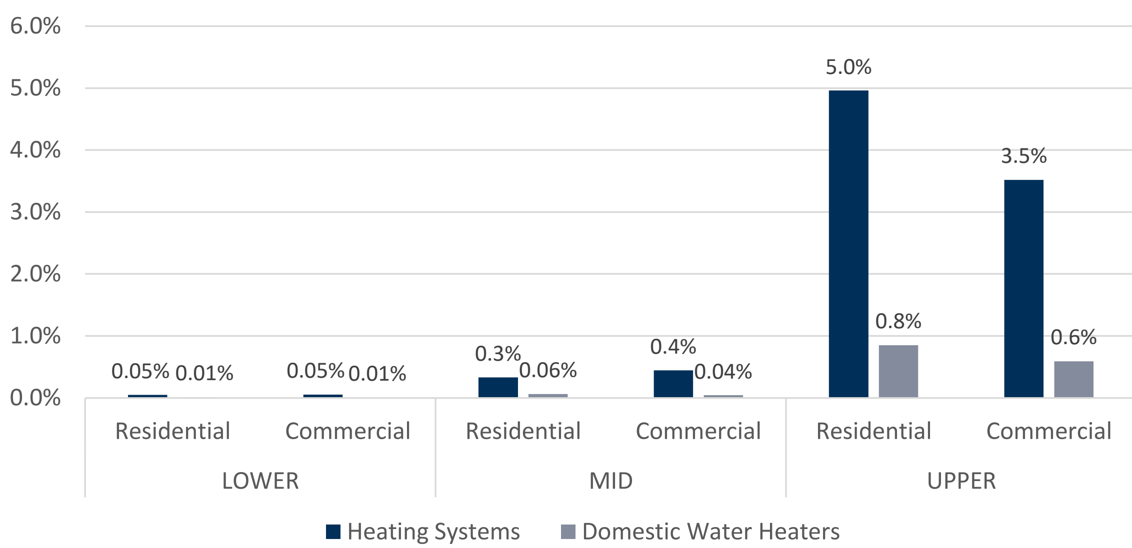
Figure 0-11 shows the portion of customers that would be expected to switch from combustible fuel systems (i.e., oil-fired or wood-fired heating systems) to heat pump systems under each scenario. Ultimately, there is little adoption of heat pump measures by oil-heated households and businesses when no incentives are provided (Lower scenario). Wood-heated households do not adopt heat pump measures under any scenario. The only

significant adoption under the Lower scenario is DMSHPs by households with electric baseboard heating (not shown in figure), which drives significant reductions in energy consumption and demand.[4]

With a smaller incentive (e.g. Mid scenario), oil-heated customers begin to adopt heat pump systems, but the market does not move significantly until large incentives are provided under the Upper scenario. With a 70% incentive (plus full step barrier level reduction by applying enabling strategies such as customer and contractor education), 5.0% of all residential customers and 3.5% of all commercial floor space opt to replace or displace their oil-fired heating system with a central air source heat pump (ASHP) or ductless mini-split heat pump (DMSHP). Nearly all heat pumps adopted by the commercial sector are DMSHP, while roughly 80% of heat pumps adopted by the residential sector are DMSHP – the remainder being central ASHP.

Finally, there is little adoption of heat pump domestic water heaters (DWH) under the Lower and Mid scenarios. Under the Upper scenario, 0.8% of residential and 0.6% of commercial customers switch from oil-fired DWH to heat pump DWH, respectively.

Figure 0-11. Percent of customers switching from combustible fuel systems to heat pump systems (2034)



Note: For heating systems, residential adoption is expressed as a percentage of households, while commercial adoption is expressed as a percent of square footage.

Figure 0-12 and **Figure 0-13** show the energy and demand impacts of fuel switching netted against the energy and demand reductions expected from electric baseboard households adopting DMSHP.

[4] Note: The addition of DMSHP to households with electric baseboard heating is not incentivized under any scenario since there is significant natural adoption without incentives, and this measure would not typically pass utility cost-effectiveness screening.

Figure 0-12. Fuel switching net energy impact (Mid-rates case)

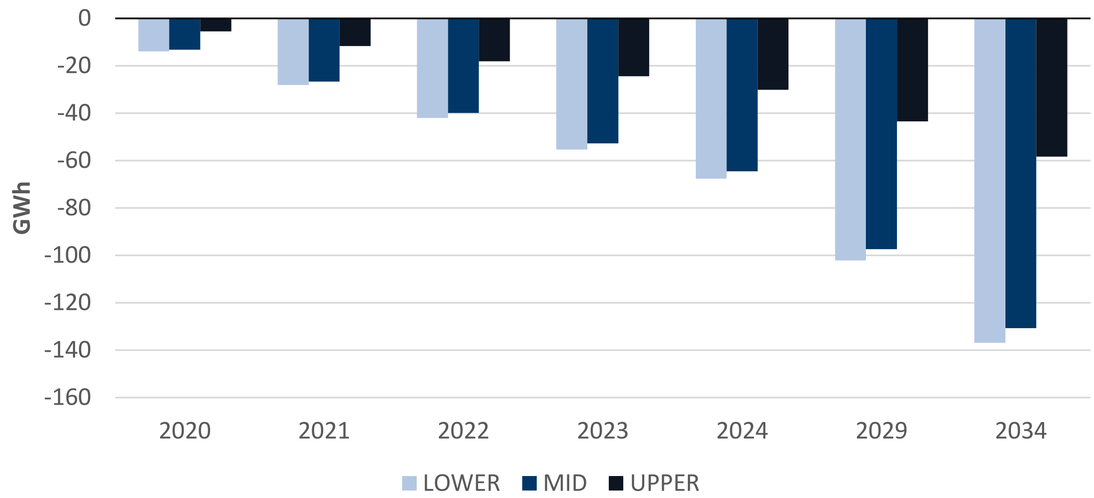
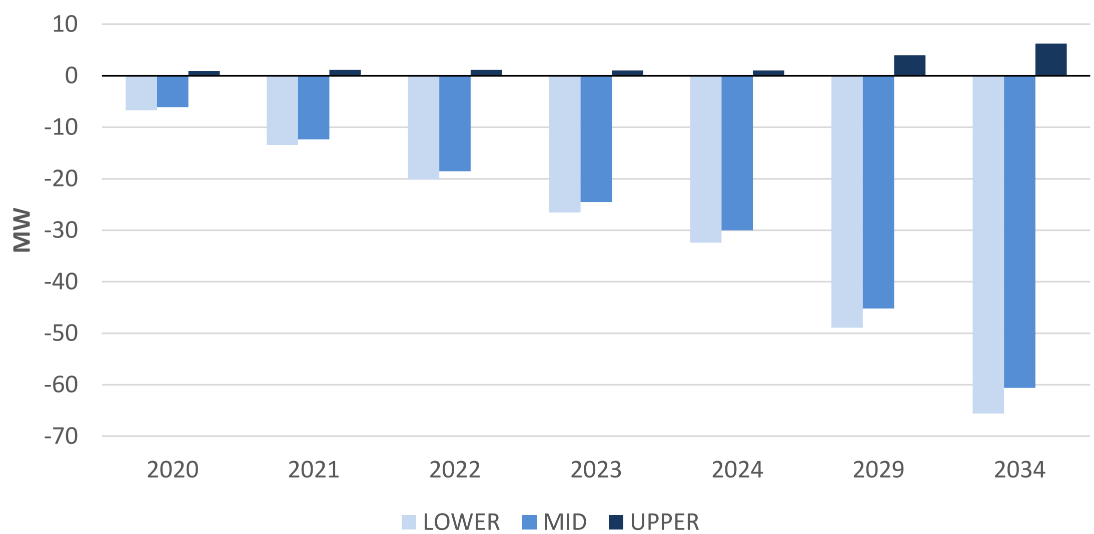


Figure 0-13. Fuel switching net demand impact



Note: Incentives are not provided to households with electric baseboard heating under any scenario.

Based on the fuel switching analysis, the following key findings emerge:

- **The customer's economics *do not* favour fuel switching from oil or wood fired space heating.** For most customers, it does not make sense to adopt electric-based heating systems (space heating or domestic water heating) in favour of existing oil- and wood-fired heating systems – even when the electric systems are high efficiency heat pumps. Without significant incentives, consumers are unlikely to switch from combustible fuel-based systems to any sort of electric heating including heat pumps. This tendency will only be magnified if electricity rates increase faster than assumed under the Mid-rates case.

- **The customer's economics *do* favour heat pumps in existing electric resistance heated households.** The market segment where heat pump systems do show the most economic benefit is households with electric baseboard heating. The analysis mirrors recent market data showing significant adoption of DMSHPs among households with electric baseboard heating, which leads to energy and demand reductions. If electric rates increase, the economics will only improve for these customers leading to additional adoption and additional reductions in electricity sales.

- **Incentivizing the addition of DMSHP to existing oil-fired heating systems offers the most opportunity to increase electricity usage.** Most customers adopted DMSHPs to displace heating from existing oil-fired heating systems, if they adopted anything at all. This choice avoids the costs associated with fully removing the legacy heating systems (e.g. oil tank removal).

ELECTRIC VEHICLE POTENTIAL

This study assesses the potential Electric Vehicle (EV) adoption in Newfoundland and Labrador and the corresponding impacts on electricity consumption in the province. Leveraging Dunsky's Electric Vehicle Adoption (EVA) model, the adoption of EVs within Newfoundland and Labrador is forecasted under several scenarios, energy consumption is assessed, the peak load and financial impacts of EV deployment are quantified and potential strategies for interventions are identified.

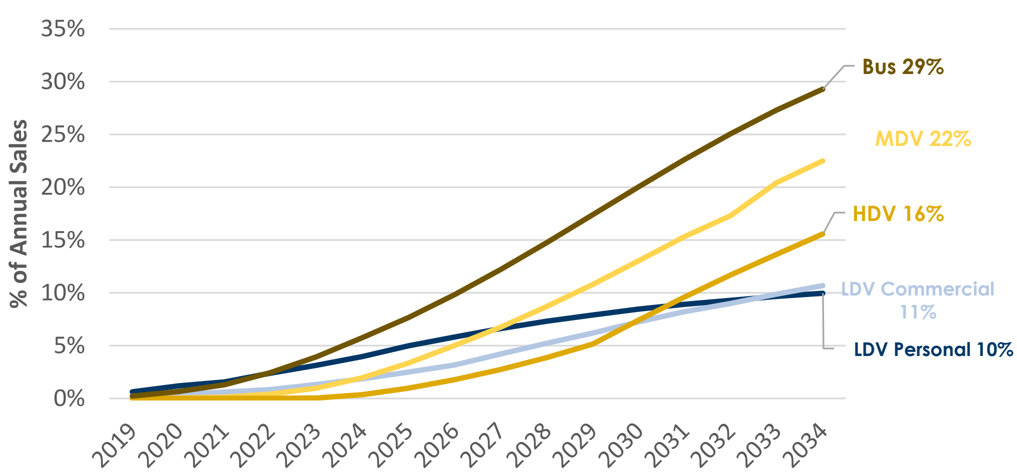
For this assessment the vehicle market in Newfoundland and Labrador was divided into the following five categories: Personal Light-Duty Vehicle (LDV), Commercial Light-Duty Vehicles (LDV), Medium-Duty Vehicles (MDV), Heavy-Duty Vehicles (HDV) and Buses. For each of the modeled vehicle categories, a vehicle archetype capturing representative characteristics (e.g. annual distance traveled, fuel efficiency, battery size, powertrain output, etc.) of a vehicle in that segment was developed.

The study then uses Newfoundland and Labrador specific inputs and assumptions to assess the potential for EVs in each vehicle category and assess corresponding opportunities and challenges. The following scenario analysis was conducted to assess the impact of a range of key factors on EV adoption in the province:

- **Baseline (business-as-usual):** EV adoption under no further action beyond currently planned deployment (i.e. no new installed charging infrastructure or incentives, except those currently committed to by the Utilities and the Provincial Government).
- **Sensitivities:** Impact of factors linked to general competitiveness of the global EV market (battery costs, vehicle availability) and local market conditions (electricity rates, fuel rates and vehicle sales).
- **Levers:** Interventions that the utility, government, or other actors can make to accelerate the deployment of electric vehicles, namely public DC Fast Chargers (DCFC) and Level 2 (L2) charging infrastructure deployment, as well as vehicle purchase incentive programs.

Figure 0-14 provides EV adoption projections under baseline conditions. Approximately 41,400 EVs are expected to be on the road by 2034, representing between 10-29% of annual sales varying by vehicle class.

Figure 0-14. Baseline Percent of Electric New Vehicle Sales by Vehicle Class



Key findings from the Baseline analysis include:

- **The adoption of Light-Duty Vehicles in Newfoundland and Labrador is well below national and global projections** (30% of EV sales by 2030), with only 10% of personal LDV sales and 11% of commercial LDV sales estimated to be EVs by 2034. This is primarily caused by the lack of public charging infrastructure, which is forecast to significantly constrain the growth of the LDV market moving forward. Despite the early lead of personal LDVs, commercial vehicles are expected to significantly increase in share during the study period as a result of improving economics.

- **The forecast uptake of MDVs and HDVs in Newfoundland and Labrador are on par with global projections.** Given lower anticipated dependence of commercial light-duty vehicles on public infrastructure, incremental upfront purchase cost and model availability become the primary barriers to uptake in these segments and as these factors improve over the course of the study period, uptake increases in response.

- **The natural uptake of electric buses significantly exceeds that of all other vehicle classes reaching 29% of sales by 2034.** This is primarily due to high vehicle model availability and high utilization of some bus types which improves the business case from a total cost of ownership perspective.

- **EVs could represent 3% of electricity consumption by 2034:** Despite light-duty personal vehicles representing the majority of EVs on the road at all points in the study period, the majority of load impacts would likely come from the MDV, HDV and Bus classes given the higher utilization and size of these vehicle types and corresponding energy use. Overall under the baseline scenario, EVs are estimated to add 266 GWh of electricity consumption by 2034 (≈ 3% of energy sales) and contribute to a 100 MW increase in the utilities' peak demand (≈ 5% of forecast peak by 2034).

A sensitivity analysis to test the impact of key uncertainties indicates that vehicle model availability in the short-term will be critical for EV adoption. Additionally, commercial segments were found to be more sensitive to economic factors that impact the Total Cost of Ownership (TCO) of vehicles compared to the personal segment; particularly future electricity rates and fuel prices.

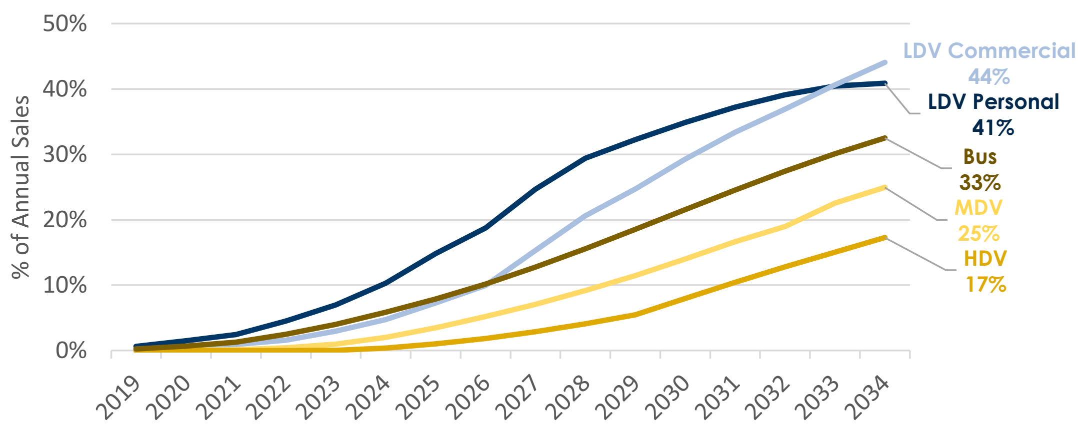
An analysis of the impact and cost-effectiveness of the three investment levers (DCFC, Level 2 and incentives) was conducted, which indicates that:

- **DCFC investments can have a significant impact in accelerating EV adoption and energy sales.** For example, a $20M investment in DCFC infrastructure would result in 132,000 EVs on the road (219% increase from baseline), and 647 GWh of EV load by 2034 (143% increase from baseline). Despite being identified as a priority, investments in DCFC beyond certain thresholds may result in over-saturating the market and are expected to have diminishing returns.
- **Level 2 charger investments were also found to be impactful and cost-effective, however less so than DCFC.** The impact of infrastructure investment could be maximized through leveraging existing federal programs or following a "make-ready" approach rather than self-deployment of charging stations.
- **Incentive programs could accelerate adoption in the short-term,** however they have limited long-term impact on the market compared to infrastructure deployment and may not be a suitable approach for intervention.

- **Investments should be diversified among complementing investments** in DCFC with public L2 deployment, education and awareness initiatives and programs targeted towards commercial fleets. For example, a modeled $20M investment focused on DCFC and L2 infrastructure can significantly increase LDV uptake in Newfoundland and Labrador, from 10% of sales in 2034 under baseline to 41% of sales by 2034; bringing EV adoption in Newfoundland and Labrador on par with Canada-wide and global EV sales targets.
- **The MDV, HDV and bus segments were found to be more sensitive to customer economics and will require substantial support in the form of incentives or changes in key financial factors** (electricity rates, fuel prices, etc.) to trigger any significant shift in adoption beyond natural market uptake.

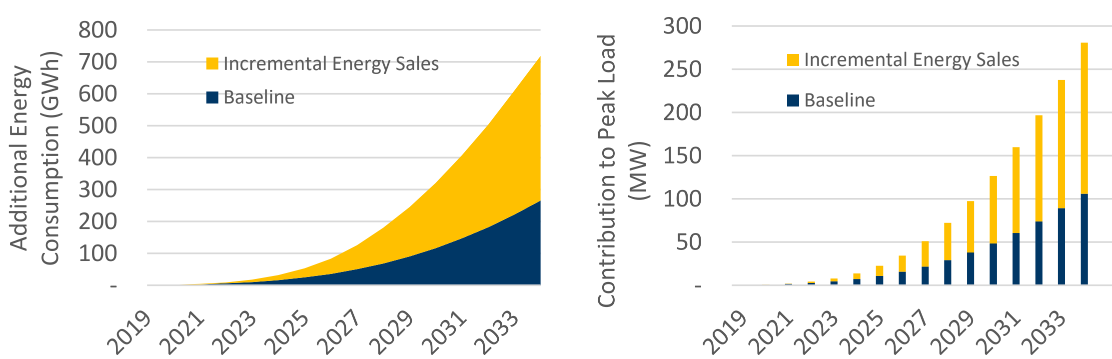
Figure 0-15 and **Figure 0-16** below show the adoption projections and electricity sales impacts of a diversified $20M investment over 10 years to promote EV adoption in the province.

Figure 0-15. Percent of Electric New Vehicle Sales by Vehicle Class Under $20M Investment Scenario



The incremental adoption attributed to the investments can almost triple load growth from EVs relative to baseline to 720 GWh of energy consumption (approximately a 7% increase in 2034 energy consumption) and increase system peak demand by 281 MW (approximately a 13% increase in 2034 peak load) under unmanaged charging, as shown in **Figure 0-16.** EV charging load management could potentially reduce the peak impacts of the forecasted EV adoption to 42 MW (approximately 2% increase in 2034 peak load).

Figure 0-16. Energy and Peak Load Impacts from Electric Vehicle Adoption Under $20M Investment Scenario



Financial Impacts

The Utilities' high capacity costs coupled with the high coincidence between EV charging loads and utility loads are expected to lead to significant peak increases and costs to the Utilities that could result in deficits as well as diminish the value any investment brings. Under the baseline scenario, the Utilities are forecasted to incur losses of $44M by 2034 as a result of EV deployment if no load management is utilized or capacity costs are not reduced.

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.

Table 0- 3.Benefits and Costs of EV Adoption Under Baseline and $20M Investment Scenario By 2034

	Unmanaged Charging			Load Management		
	Benefits	Costs	NPV	Benefits	Costs	NPV
Baseline	$119M	($163M)	**($44M)**	$119M	($51)	**$68M**
$20M Investment	$317M	($359M)	**($113M)**	$317M	($147M)	**$170M**

REPORT STRUCTURE

This report presents the methods, findings and the potential study results from several perspectives, including cumulative savings by system, scenario, sector, segment, and end-use. A brief outline of the report structure is provided below.

VOLUME 1

Chapter 1 – Introduction: This first chapter provides an overview of the study scope and the context against which the study was conducted including the forecast baseline energy sales and peak demand projections. It also provides a description of the program scenarios and sensitivity analysis conducted in the study.

Chapter 2 – Cumulative CDM Program Savings Potential: The first results chapter section outlines cumulative savings over 15 years from CDM programs, expressed as the cumulative impact on sales for each electricity system (IIC, LAB, ISO) under each of the program scenarios (Lower, Mid, Upper). It also includes a sensitivity analysis considering the impact of electricity rate forecasts and avoided costs on the cumulative savings.

Chapters 3 – Program Savings Potential and Analysis: Chapter 3 provides detailed results for CDM program savings, focusing primarily on the Mid scenario[5] (which applies slightly increased incentive levels and expanded eligible measures compared to current CDM programs). Results include average annual program savings, as well as savings by sector, end-use, and segment. Top-10 contributing measures are presented for each sector. Corresponding budget, and savings in percentage of sales are also provided. This chapter also includes an analysis of the specific CDM programs considering their potential savings and cost-effectiveness under each program scenario.

Chapter 4 – Demand Response Potential: Chapter 4 outlines the demand response program potential based on three program combination scenarios for each of the IIC and LAB systems. The chapter describes key DR measures and program interactive effects when multiple new and existing DR measures are applied simultaneously. Finally, the impact and cost-effectiveness of each scenario is provided.

Chapter 5 – Fuel Switching: This chapter presents the results of the fuel switching analysis, which assesses how many households and businesses can be expected to replace or supplement oil- and wood-fired space heating and domestic hot water (DHW) heating systems with electric heat pump systems under various levels of incentives.

Chapter 6 – Electric Vehicle Adoption: This chapter presents results of the Electric Vehicle (EV) Adoption study, highlighting forecasts for EV uptake within Newfoundland and Labrador under several scenarios, assessing the corresponding impacts on the utilities' load and identifying strategies for interventions that can increase EV adoption.

[5] Other scenario results are provided in Appendix F.

VOLUME 2

Within the text of the report the reader will find references to specific appendices in which further relevant details are presented. Appendices are included in Volume 2 as follows:

Appendix A: Energy Efficiency modelling methodology

Appendix B: Demand Response modelling methodology

Appendix C: Fuel Switching modelling methodology

Appendix D: Electric Vehicle adoption modeling methodology

Appendix E: Study inputs and assumptions

Appendix F: Detailed results tables

1. INTRODUCTION

This report presents the results of the Conservation and Demand Management (CDM) Potential Study conducted over the 2020-2034 timeframe for the Newfoundland and Labrador electric utilities. Detailed bottom-up modeling tools were applied, to quantify energy and demand impacts from multiple CDM sources, including energy efficiency (EE), demand response (DR), heating fuel switching (FS) and electric Vehicles (EVs). This report provides an assessment and analysis of the combined CDM potential for Newfoundland and Labrador over the study period, as well as a high-level explanation of the study methods and modelling approach.

THE NEWFOUNDLAND AND LABRADOR ELECTRIC UTILITIES

NEWFOUNDLAND POWER INC.

Newfoundland Power Inc. operates an integrated generation, transmission and distribution system throughout the island portion of Newfoundland and Labrador.

For over 125 years, Newfoundland Power has provided customers with safe, reliable electricity in the most cost-efficient manner possible. Newfoundland Power serves over 265,000 customers, about 90% of all electricity consumers in the province.

Newfoundland Power purchases approximately 93% of the electricity it sells from the Crown Corporation, Newfoundland and Labrador Hydro. Newfoundland and Labrador Hydro are the primary generation utility on the island interconnected system. Newfoundland Power generates the balance from its generation facilities, primarily smaller hydroelectric stations located across the island.

All the common shares of Newfoundland Power are owned by Fortis Inc. (NYSE/TSX: FTS), the largest investor-owned distribution utility in Canada, which serves approximately 3,200,000 gas and electric customers, with total assets of approximately $49 billion.

NEWFOUNDLAND AND LABRADOR HYDRO

Newfoundland & Labrador Hydro is a fully regulated, crown-owned electric utility that owns and operates facilities for the generation, transmission and distribution of electricity to utility, industrial and retail customers in the Province of Newfoundland and Labrador. At Hydro, we recognize a dependable source of electricity as an essential part of daily life, and have provided safe and reliable electricity for over 50 years.

Hydro has an installed generating capacity of 1,763 megawatts (MW) and generates and transmits over 80 per cent of the electricity consumed by Newfoundlanders and Labradorians every year. Hydro has locations throughout the province including nine hydroelectric generating stations, one oil-fired plant, four gas turbines, and 25 diesel plants. Hydro also maintains 54 high-voltage terminal stations, 25 lower-voltage interconnected distribution stations, and thousands of kilometers of transmission and distribution lines. Hydro has also recognized wind as a valuable energy source and has developed a strategy to leverage this source of clean, renewable energy.

Hydro is focused on long-term strategic planning to ensure a continued reliable source of electricity. Continuous infrastructure upgrades and use of new technology is one way we commit to providing excellent customer service. Hydro continues to search for the best way to provide power that is cost efficient, sustainable and environmentally sound.

OVERVIEW OF THE TAKECHARGE PARTNERSHIP

Since 2008, the Newfoundland Power and Newfoundland and Labrador Hydro have offered customer energy conservation information and programming on a joint and coordinated basis under the takeCHARGE energy conservation brand. The Utilities' provision of energy conservation programming is responsive to customer expectations, supports efforts to be responsible stewards of electrical energy resources and is consistent with provision of least cost, reliable electricity service.

STUDY CONTEXT

This potential study comes at a transitional time for Newfoundland and Labrador's electric utilities, stemming from changes to the province's generation and transmission systems. This is taking place against disruptions to North America's electricity utility industry as a whole, including a growing focus on customer needs and their opportunities to save energy, shift demand and switch fuels. These opportunities – driven by rapidly evolving technology, policies and consumer preferences – put more emphasis than ever on conservation and demand management opportunities that can help utilities balance supply and demand, considering both time and locational variations, to maintain electricity service reliability and affordability.

Changes to Newfoundland and Labrador's Energy Supply

This study provides a forecast of CDM Program potentials over the 2020-2034 period during which Newfoundland and Labrador's electricity system will undergo significant changes. Primary among these will be the Muskrat Falls hydro-electric generation facility which is expected to be fully commissioned by 2020. Other changes include the recent 900 MW expansion of the Labrador-Island link transmission system that will offset new industrial loads and retiring thermal generation facilities on the island. Finally, NL Hydro will soon be able to participate in local energy markets as it becomes interconnected to the North American grid.[6]

As a result of the combined impact of these changes, NL Hydro faces a challenge to maximize the value of energy exports and off-peak sales to mitigate customer rates, while reducing winter peak demand, particularly on the IIC system where winter peak marginal costs are particularly high. CDM offers an opportunity to reduce on-peak sales and peak demand in a cost-effective manner, thereby supporting NL Utilities' efforts to mitigate rates. Moreover, fuel switching to electric heating and electric vehicle adoption can further increase electricity usage,[7] but considerations must be made to ensure that electricity rates are managed to make these options attractive to customers, and that the new demand does not increase IIC winter peaks. This study provides insights into the potential for each of these opportunities considering the consumption and peak load impacts, as well as the cost-effectiveness to the Utilities and customers alike.

New Lighting Standards are Impacting Efficiency Program Focus

Across North America, changes to the standards for lighting are being closely watched by program administrators, as they will largely eliminate residential lighting savings opportunities, along with a significant portion of commercial sector lighting savings, when they come into force. Historically a significant contributor to portfolio savings, lighting is transforming, and electric efficiency programs may seek to invest CDM program budgets in new measures and program delivery strategies to achieve savings. Leveraging a strong foundation of

[6] MARGINAL COST STUDY UPDATE – 2018, Summary Report, NL Hydro, 2018.

[7] The net revenue gained from increased domestic sales can be used to offset the revenue that must be recovered to offset the costs of the Muskrat Falls project, thereby helping to mitigate customer rates.

Newfoundland and Labrador-specific market data, the potential study will be key in planning and optimizing the programs to do just that.

Electrification of Heating and Transportation

As the 2030 deadline for the first of Canada's commitments under the Paris Agreement on Climate Change approaches,[8] increasing attention is being paid to the emissions reduction potentials from electric vehicles and switching heating loads to electricity. When Muskrat Falls achieves full power, the province's generation mix will be 98% supplied by hydroelectricity, however, this may also bring increased customer electricity rates that may dissuade Newfoundland and Labrador homes and businesses from replacing oil heating with electric heat pumps or adopting electric vehicles. Moreover, the Provincial Government has put in place a carbon pricing plan that does not apply to home heating oil, and while it does apply an incremental new tax on gasoline and diesel for transportation, it also replaces an existing tax thereby reducing the carbon price impact to customers by nearly half.[9] While electric heating and EVs offer significant potential to reduce GHG emissions and increase domestic sales which will help offset the costs of Muskrat Falls, the current fuel pricing signals in the province may hinder the market for customers to adopt these clean energy technologies.

This study includes two chapters that forecast the expected baseline fuel switching and heat pump adoption rates, as well as the baseline adoption of EVs. The study also assesses the potential impact of utility incentives for purchasing electric heating equipment and vehicles, as well as options for investing in enabling strategies and infrastructure.

Demand and Load Management an Emerging Priority

As with many North American utilities, the NL Utilities are increasingly considering energy efficiency and demand response alongside supply-side resource options in addressing system capacity constraints. In particular, NL Utilities sees significant benefits from reducing winter peak loads in the IIC system. The achievable potential quantified in this study will help to support utility decision-makers in considering CDM as an option to address system constraints. Along with CDM programs, the study also forecasts heating fuel switching to electric heating and EV adoption that should be factored into system planning considerations. The projected impact of future codes and standards are also included in the study, to the extent possible considering uncertainties over future lighting standards in the USA, enforcement timelines, and acknowledging long-term changes in codes and standards which are unpredictable to a large extent.

The Need for Newfoundland and Labrador Specific Market Data

Because of these changing conditions, the need for leveraging a wide range of NL-specific sources and recently collected market data was crucial to ensure that the study was reflective of Newfoundland and Labrador's unique market and electric system conditions. This study therefore characterizes the energy-using technologies currently found in the Newfoundland and Labrador market, along with key features of the province's building stock. Leveraging the Utilities' recently conducted end-use surveys that capture Newfoundland and Labrador-

[8] Canada committed to a 30% reduction in GHG emissions relative to 2005, by 2030.

[9] Source: https://www.releases.gov.nl.ca/releases/2018/mae/1023n01.aspx.

specific market data, this study provides an assessment of attainable CDM opportunities. This information was supplemented with further primary data collection from 666 NL homes and 150 businesses to ascertain the barriers to adopting efficiency technologies and participating in CDM programs. Further verification was attained through 15 market actor interviews and residential and commercial stakeholder workshops to capture the perspectives of local players who are actively delivering efficiency technologies to NL homes and businesses. Moving forward, this study will be instrumental in the design of energy efficiency programs that are well-suited to the Newfoundland and Labrador context and will capture savings opportunities.

CDM POTENTIAL STUDY SCOPE

The Newfoundland and Labrador Conservation Potential Study (hereafter called "the Study") provides an assessment of CDM programs savings over a 15-year period, from 2020 to 2034, covering the three electricity systems in the province.

Island Interconnected (IIC) System: Refers to the combined service territories of NF Power and NL Hydro on the island of Newfoundland, including transmission level large industrial customers. The vast majority of electricity customers in NL are located on this system (95% of residential customers and 93% of Commercial and Industrial customers).

Labrador Interconnected (LAB) System: Refers to NL Hydro service territory in Labrador, including transmission level large industrial customers.

Isolated Diesel Generation (ISO) System: Refers to the collection of isolated diesel generators operated by NL Hydro in remote communities across the province.

Figure 1-1. NL Utility Service Territories

Where applicable, individual potential assessment models were created for each system to capture the unique opportunities. This included systems specific market data, avoided costs, customer rates, and energy measure characteristics.

The study assessed the changes in electricity consumption associated with the full range of commercially viable energy efficiency measures, as well as the potential impacts on electric peak demand, both from efficiency measures, and demand response initiatives. Increases in electricity consumption and demand were assessed from primary space and water heating fuel switching (from oil and wood to electricity), as well as electric vehicle adoption.[10]

The Study quantifies the electric system impacts associated with four streams of CDM programming, as laid out in **Table 1-1** below. For each study component, a separated modelling effort was undertaken to accurately

[10] These were treated as parallel studies, and the combined impact of CDM initiatives is presented separately from the fuel switching and electric vehicle adoption impacts in this report.

capture the key inputs and relationships that drive the adoption and impacts of efficiency measures, demand response programs, fuel switching and electric vehicles among the province's homes and businesses.

Table 1-1. CDM Programing Components Covered in the NL Conservation Study

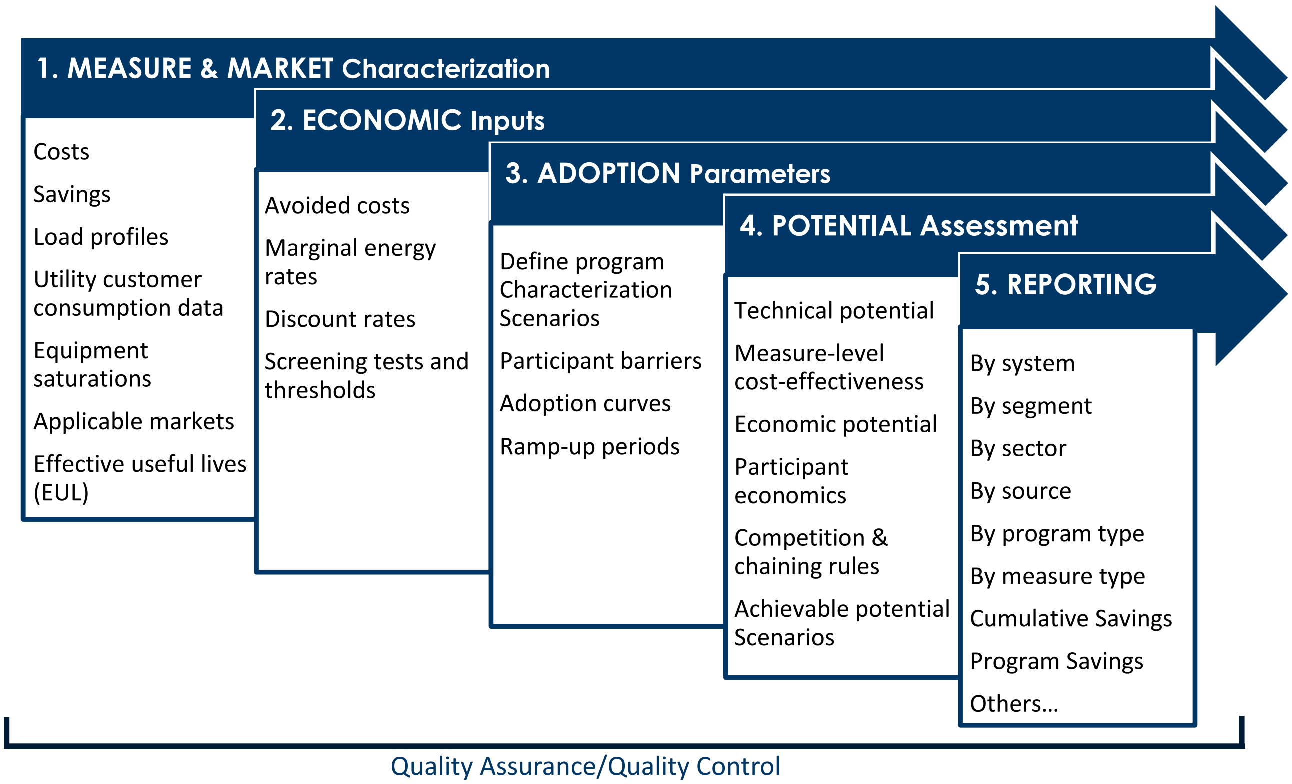
Study Component	Model Applied	Systems Studied	Details
Energy Efficiency	Dunsky's Energy Efficiency Potential (DEEP) Model	IIC, LAB, ISO	Appendix A
Demand Response[11]	Dunsky's Demand Response (DR) Model	IIC, LAB	Appendix B
Fuel Switching[12]	DEEP Model adapted for Heat Pump adoption	IIC	Appendix C
Electric Vehicles	Dunsky's Electric Vehicle Adoption Model	Province-wide	Appendix D

Using Dunsky Energy Consulting's various potential modelling tools, the study applied a granular, bottom-up modelling approach to define the energy savings opportunities for each savings stream, in each market sector based on equipment saturations developed through prior market data collected by the NL Utilities. The detailed methodology for assessing the potential for each savings stream is outlined in the Appendices found in Volume 2 of this report. The high-level study process flow is outlined below (**Figure 1-2**).

[11] Demand response programs were assessed only for the interconnected systems due to the limited applicability of active demand management in the small diesel generated systems that characterize the ISO.

[12] The fuel switching analysis focuses on the projected uptake of heat pumps to replace oil, wood or electric resistance as the primary space and water heating source in the province's homes and businesses. The Fuel Switching study focused on the IIC system as the opportunities for heat pump adoption in the other systems are minimal.

Figure 1-2. Potential Study Modelling Process Flow



USES FOR THIS POTENTIAL STUDY

This potential study is a high-level assessment of electricity impacting opportunities in the Province of Newfoundland and Labrador over the next 15 years. Its main purposes are to support:

- **Resource planning:** Evaluate the impact of Energy Efficiency, Demand Response, Fuel Switching and Codes & Standards on long-term energy consumption and demand needs at the grid/distribution level.
- **Efficiency program planning:** Assess achievable CDM opportunities to improve CDM program planning and help meet long-term savings objectives, and determine which sectors, end-uses and measures hold the most potential.

This potential study is *not* intended to give granular information about measures in specific segments, but rather give a macro view of efficiency potential. Moreover, it is not a program design document that accurately forecast savings achieved through Utility programs in a given future year, but rather quantify the total potential opportunities that exist under specific parameters.

DATA SOURCES AND USES IN STUDY

The CDM Potential Study leveraged a pool of NL-specific data to prepare potential models that are representative of each electricity system. This was supplemented with primary research through phone and web surveys with NL businesses and homeowners to collect further details related to their buildings and the barriers they face in adopting energy efficiency measures or joining DR programs. **Table 1-2** provides an overview of the key data sources used in the study, and a more detailed description of the sources, inputs and assumptions can be found in Appendix E.

Table 1-2. Newfoundland and Labrador Specific Data Sources used in the Conservation Potential Study

Data source	Application in study
Utility Customer data	The utilities provided historical electricity consumption data and customer counts for each market segment. These were used to fix total consumption and number of customers in each market segment.
End-Use surveys	A Commercial End-Use Survey (CEUS) and a Residential End-Use Survey (REUS) were conducted by the utilities in 2018 and 2017 respectively. These results were applied to establish equipment saturations in the model.
Economic data	Customer rates, avoided costs and discount rates were used to calculate TRC, PACT and PCT benefits.
CDM program data	Program evaluation reports and CDM plans were provided by the Utilities. These were used to characterize CDM programs for model (incentive level, administration costs), and benchmark model findings.
Baseline EV adoption projection	Used to define market for EV smart charging DR measure.
2015 CDM Potential Study[13]	Used to supplement market and measure characterization data for the model where there are gaps in the Dunsky measure database and/or the end use survey data.
Historical utility load curve	Hourly system load curves for IIC and LAB were used to establish DR addressable peak and define standard peak day.

[13] Reference: Newfoundland and Labrador Conservation and Demand Management Potential Study: 2015, ICF International.

Consumption and demand forecasts	Used to assess % savings in each period of the study and determine DR addressable peak forecast.

MARKET SEGMENTATION

Based on the review of NL Utilities' customer data and discussions with the utilities, Dunsky divided the customer bases into the market sectors and segments as presented below (**Table 1-3**). Overall, the study assesses both residential and commercial sectors, with specific considerations for a range of segments within each, including single detached, attached and apartments in the residential sector, and twelve commercial segments such as offices, grocery stores and restaurants, industrial, and others. Developing results for each segment, the study modeled the cumulative savings over the 2020-2034 period to arrive at the assessment of the technical, economic and achievable potentials.

Table 1-3. Sectors and Segments Included in the Study (Both Utilities Combined)

Sector	Segment	Customers	2018 Consumption (MWh)
Residential	Single Detached	191,338	3,362,706
	Attached	29,345	466,251
	Apartments	30,071	290,509
Commercial	Office	5,495	464,442
	Retail	3,321	260,363
	Grocery/Restaurant	1,904	271,514
	Health Services	820	179,979
	Education	738	312,206
	Warehouse	653	78,467
	Lodging/Hospitality	1,440	105,196
	Other Commercial	7,058	462,767
Industrial	Fishing	626	115,718
	Manufacturing	1,216	141,986
	Sm./Med. Industrial	4,781	312,330
	Large Industrial	6	3,628,000[14]

[14] Large Industrial annual consumption in the IIC system is projected to drop from 1,479 GWh in 2018, to 613 GWh by 2020 as transmission level customers increase self-generation.

Top-Down Assessment of Large Industrial Customers (Transmission-Level)

The Large Industrial Segment did not lend itself to the bottom-up adoption modelling approach applied for the other segments as it has such a small number of customers and no CEUS data was available to determine the saturation of specific equipment in each facility. For this segment the study applies a top-down approach to assess the potential efficiency and peak demand savings based on the best available projections from past studies and current curtailment contracts. An outline of the efficiency modelling approach applied for this segment can be found in Appendix E.

CUSTOMER BARRIERS SURVEY AND ADOPTION BARRIER-LEVEL SETTING

To support the application of adoption curves in the Potential Model, two barriers surveys were conducted as part of the study:

Residential Web Survey: Using email addresses associated with residential customers, a web survey (666 completes) was conducted. Results were stratified by building type. The survey covered barriers to adopting the following categories of energy efficiency measures:

- Insulation
- Air sealing
- Heating systems
- Heat pumps
- Appliances
- Smart thermostats

In addition, the survey assessed residential customer considerations to participating in demand response/demand control and fuel switching initiatives.

Commercial Telephone Survey: 150 Commercial customers completed a 15-minute telephone survey. Results were stratified by each of the eight commercial segments, as well as the fishing and manufacturing industrial segments.

Each survey included a series of questions pertaining to decision-making factors and barriers faced by customers when they consider adopting energy efficiency measures. The survey captured responses from each of the customer segments, and differentiated responses for the following six major end-uses:

- Lighting
- HVAC
- Commercial refrigeration equipment
- Commercial kitchen equipment
- Water heating equipment
- Motors and compressed air systems

The survey also asked respondents about the financial factors they consider when purchasing or replacing energy-using equipment, and how varying levels of incentives may influence their purchasing decisions. The survey results were treated to establish a baseline barrier level for each market segment / end-use combination. These were then mapped to each measure in the model, adjusting for measure-specific factors, such as installation complexity or time in the market. Finally, the barrier analysis applied system-wide barrier increases for the LAB and ISO systems to account for the additional barriers faced in the province's remote communities. These were then used as inputs to the Potential Model which determined which adoption curve is applied to each measure-market segment combination. Further details on the barrier survey and the barrier level setting can be found in Appendix E.

MEASURE CHARACTERIZATION

Comprehensive lists of efficiency and demand response measures applicable to each market sector were provided to the NL Utilities early in the project for approval. These lists were expanded and adapted based on feedback from the NL Utilities, and the final approved measure list was compiled. Further details on the measures applied in the study can be found in Appendix F.

Basic assumptions related to energy savings or impact factors were characterized for each measure using published Technical Reference Manuals (TRMs) from NL and other relevant jurisdictions, NL Utility program evaluation measure savings findings, NL climate data to determine effective full load heating and cooling hours, and other public and in-house data sources. The detailed measure lists and sources used for input characterization can be found in Appendix E. Measure details characterized for model inputs include:

- **Annual gross savings:** Per-unit electric savings are included, including consumption and demand values.
- **Incremental costs:** The incremental installed cost of the efficient technology as compared to the baseline option.
- **Load factors:** This category addresses summer and winter peak coincidence factors, seasonal savings distributions, as well as monthly peak load impacts for commercial customers.
- **Measure life:** This category addresses the EUL of each measure and baseline technology.
- **Installation Schedule:** For each measure the study determines the installation timing relative to the EUL of the existing equipment, and its attribute as either replacing existing equipment, or being a newly added piece of equipment.

Treatment of EISA 2020 Standards for Lighting in this Study

Phase two of the Energy Independence and Security Act (EISA) is scheduled to come into effect in the United States on January 1, 2020, restricting the sale and manufacture of light bulbs that do not meet new minimum energy performance standards for bulb types covered by the regulations. These requirements are also anticipated to impact the Canadian market, as the Canadian government has indicated commitments to align efficiency standards with the U.S. By increasing baseline energy performance requirements, the new standards will reduce the savings that can be claimed by lighting efficiency programs.

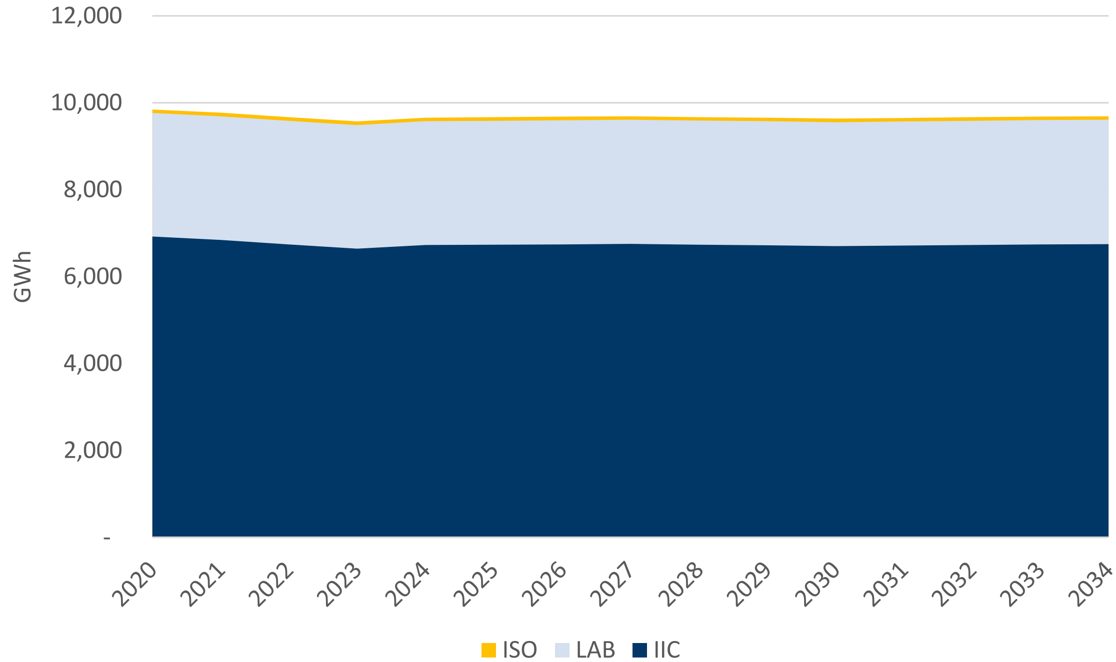
Informed by the timeline of previous amendments to the Canadian Energy Efficiency Regulations, the study assumes that the new lighting standards will be enforced in Canada beginning January 1, 2022 for standard screw-in type bulbs (referred to as A-Lamps in this study). The study applies an additional year of savings to be counted beyond the date of enforcement, assuming that stocks of incandescent and halogen bulbs will take approximately one year to deplete, and therefore will be available for sale until the end of 2022. Starting January 1, 2023, savings from the purchase of new bulbs covered by the regulation are no longer counted towards programs in the model.

On February 6, 2019, the US Department of Energy (DOE) announced plans to withdraw the expansion of energy efficiency standards for specialty lamps (referred to as Reflectors in this study). To account for this uncertainty, the study assumes that the market for specialty lamps will transform either through a change in standards or through a shift driven by manufacturers by 2025. As a result, the study does not apply any specialty lamp savings starting January 1, 2025.

NEWFOUNDLAND AND LABRADOR ENERGY USE BASELINE

Establishing the baseline energy consumption over the study period provides a valuable benchmark to the savings potentials in the study and facilitates an assessment of the impact that CDM programs can have on energy sales in the province. Baseline electricity use was provided by NL Utilities, and the values were then adjusted by Dunsky to remove the projected impact of efficiency programs post-2020 and included the impact of expected codes and standards changes. Below, the forecasted energy use in Newfoundland and Labrador is presented by sector and energy type for the years 2020-2034.

Figure 1-3. Forecasted Newfoundland and Labrador Energy Use Baseline for 2020-2034



Overall the sales projections indicate that annual consumption is expected to drop in the initial years then remain steady in the IIC system. This is due primarily to customer price sensitivity to the anticipated potential rate increases associated with the commissioning of the Muskrat Falls Project. For the LAB and ISO systems, the sales are expected to remain steady over the study period. Demographic data provided by the Utilities indicates the population in NL is expected to somewhat decline in the coming years. Moreover, expected changes to lighting standards leading to the transformation of standard and specialty bulbs in the early 2020s is expected to further contribute to a slight reduction in the forecasted baseline energy consumption, even before energy efficiency programs are considered.

Figure 1-4 and **Figure 1-5** present the breakdown of energy consumption in each of the three systems by sector and by end-use respectively. From these it can be seen that the IIC and ISO systems are dominated by residential and commercial consumption, while the LAB system is dominated by industrial consumption.

Figure 1-4. Newfoundland and Labrador 2018 Energy End-Use Breakdown by Sector – All Systems (GWh)

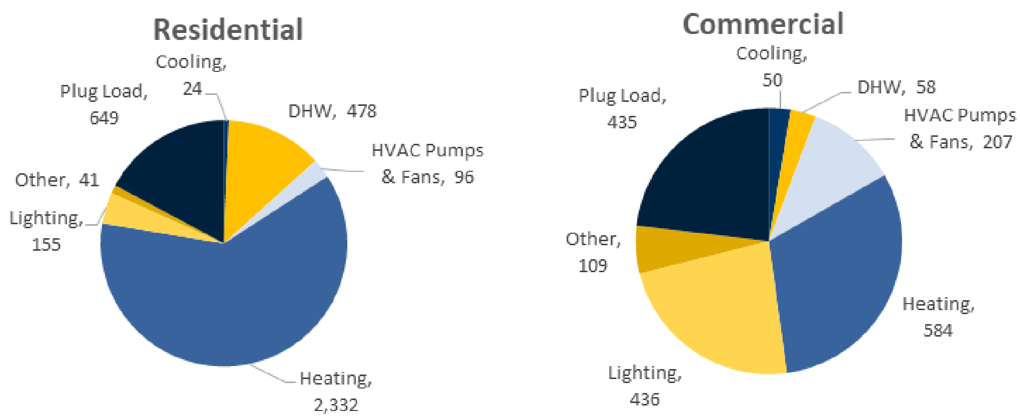
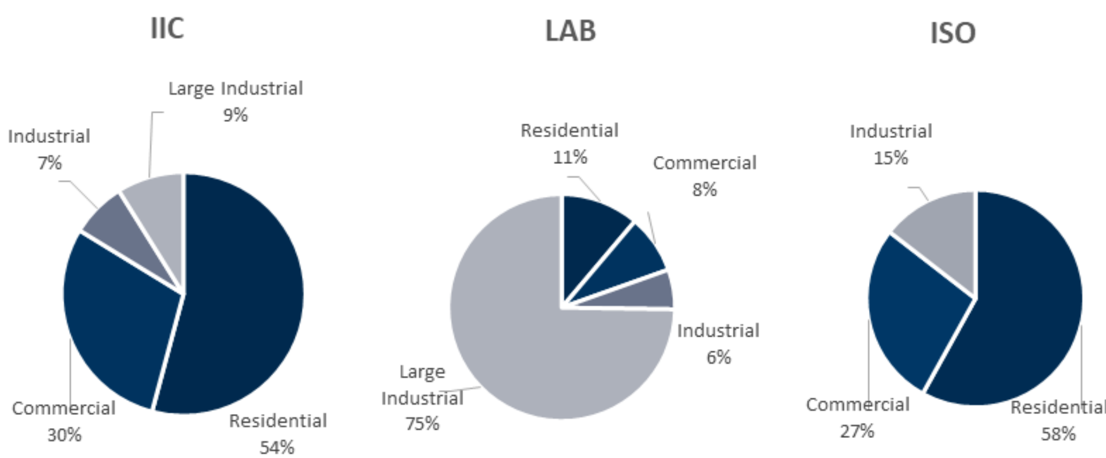


Figure 1-5. Newfoundland and Labrador Projected Energy Use Breakdown by Sector 2020

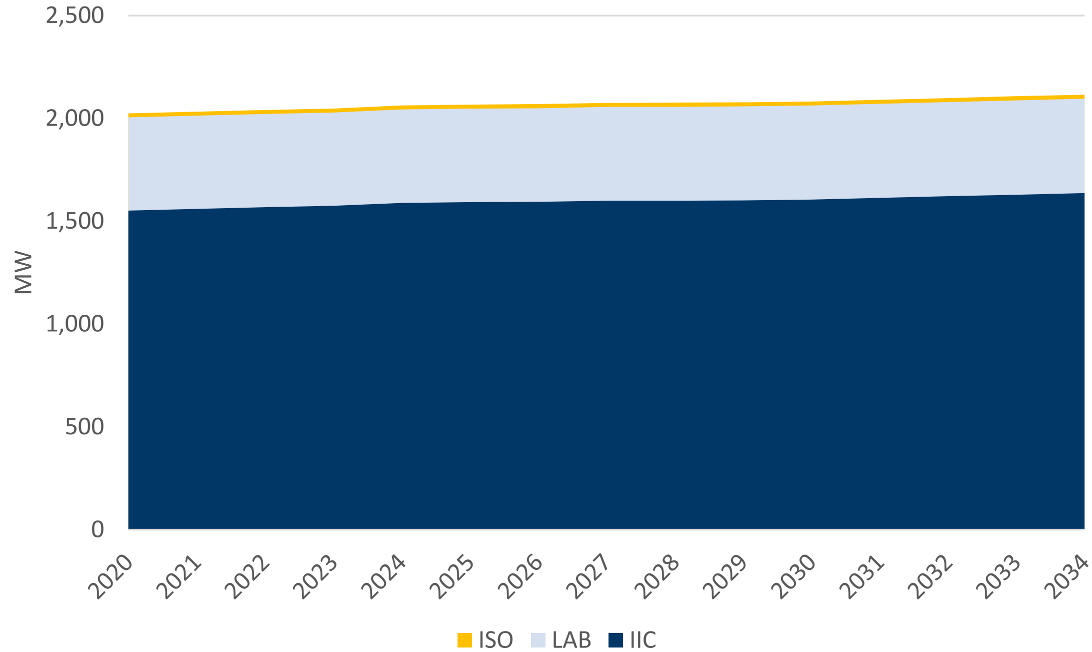


Note: Large Industrial refers to transmission-level industrial customers.

Based on the end-use breakdowns, it can be seen that residential heating dominates among all non-industrial loads, representing 23% of the overall province-wide electrical consumption load. By comparison, all industrial sector facilities together represent just 33% of the province-wide annual consumption. Plug load and lighting represent the next two largest non-industrial loads, representing 12% and 6% of the overall province-wide annual consumption respectively.

Figure 1-6 below provides the baseline demand projections for the three systems. Over the study period there is an expected steady rise in the IIC system annual peak demand, which is an opposite trend to the consumption projections provided above. Given the high avoided costs of capacity for the IIC system, this indicates that measures and programs that can mitigate demand increases may offer particular value in the CDM program portfolio.

Figure 1-6. Forecast Newfoundland and Labrador Annual Peak Demand by System



CDM PROGRAM SCENARIOS

As is standard practice in potential studies, the study assesses electric efficiency savings potentials at the technical, economic and achievable levels. For the achievable potential, which is the primary focus of the analysis, the study assesses savings resulting from potential program scenarios in order to determine how various levels of CDM investment and programming approaches can impact the achieved savings (see **Figure 1-7** below).

Figure 1-7. CDM Program Scenarios Used to Assess Achievable Savings

Lower	•**Lower Achievable Potential** Applies current Utility CDM program incentive levels and enabling activities, but includes the full range of cost-effective technologies, and disregards any budget constraints.
Mid	•**Mid-Range Achievable Potential** Applies increased incentive levels to reflect increased investments in CDM programs compared to the current portfolio.
Upper	•**Upper Achievable Potential** Applies increased incentive levels, and includes further investments in enabling activities to address customer barriers to adoption.

The Lower scenario indicates the level of savings that may be reached with current programs including additional technologies and if no budget limitations were applied.[15] The Mid scenario indicates how much additional savings could be achieved by increasing incentives and expanding programs to include new construction (NC), appliance recycling, and incentives to encourage customers to purchase higher efficiency cold-climate heat pumps. Finally, the Upper scenario provides an assessment of the combined impact of the increased incentive levels applied in the Mid scenario, along with further investments in enabling strategies to lower barriers to adoption (such as contractor training, consumer education or midstream initiatives).[16] These scenarios provide hypothetical impacts of high-level CDM program features. Developing detailed program designs including specific annual budgets and administration costs are beyond the scope of this study.

[15] New measures, not currently offered in the CDM programs, include commercial building insulation measures, some new lighting types (such as pole mounted LEDs), cooling equipment and chillers, retro-commissioning, compressor efficiency measures, and a range of residential appliances and envelope measures. A full list of all measures considered in the study, along with which would be new to the CDM programs can be found in Appendix E.

[16] Midstream refers to offering incentives to contractors or suppliers, rather than customers.

Enabling Strategies: Options for Reducing Customer Barriers

To optimize achievable potential savings, programs must go beyond incentives to address other non-economic barriers to customer participation. Barrier reductions can be achieved through enabling activities such as consumer education, contractor training and support, market research, program design and enhancements, marketing strategies, program evaluation (which can identify barriers to participation), and others.
(See Appendix A for a description of how Adoption Curves and Barriers are applied in this study).

The program scenarios assessed in this study capture the impact of current enabling strategies applied by the NL Utilities by calibrating the Lower program scenario achievable potentials to current CDM portfolio savings. The potential impact of investing further in enabling strategies is assessed under the Upper program scenario, where a half step reduction in barrier levels is applied over and above the Mid program scenario. While the potential study does not identify the specific enabling strategies engaged or the associated barriers addressed, the results are intended to provide a quantitative assessment of additional savings that can be unlocked through enabling strategies.

From there, program design analysis can be applied along with the Barrier Survey results from this study, to identify specific actions that would be appropriate for each measure and market segment.

CUMULATIVE AND PROGRAM EFFICIENCY SAVINGS

Study results are presented in two different ways, each serving a specific purpose and providing a different insight into potential savings.

Cumulative savings are covered in Chapter 2 and provide a rolling sum of all new savings that will affect energy sales. Cumulative savings provide the total expected impact on utility sales in each electricity system and should be used to determine the impact of CDM programs on long-term energy consumption and peak demand at the grid/distribution level.

Program savings are presented in Chapter 3 and provide the level of savings from measures that are incentivized through programs in a given year. Program savings should be used to assess achievable CDM program opportunities to improve CDM program planning and help meet short and long-term savings objectives and determine which sectors, end-uses and measures hold the most potential.

DEMAND RESPONSE PROGRAM SCENARIOS

The study includes an assessment of the technical, economic and achievable potentials of a wide range of demand response (DR) measures, and the results are presented for each set of measures under the achievable potential scenario results. It should be noted that aggregate results for the technical and economic potentials of all DR measures are not presented in this report. The study includes assessments of the technical and economic potential for each individual measure however, these are not considered additive due to the high degree of interaction among programs and the utility load curve. Measure-level Technical and Economic potential details are provided on a measure-by-measure level in Appendix F.

Furthermore, because the mix of DR programs has more of an impact than the incentive levels applied (provided that base case incentive levels are set high enough to attract a sufficient pool of participants), the study presents scenarios based on program mixes and approaches as outlined in **Figure 1-8** below. Because the interactions among programs and the utility load curve are complex and unpredictable before running the DR model, it is only apparent after the scenarios have been analysed which provides higher or lower DR potentials, and thus the scenarios are described by the program mix they contain, rather than their expected level of impact.

Figure 1-8. Demand Response Program Scenarios

Scenario 1	•**Enhanced Current DR Potential** The first scenario focuses on maximizing the impact from current DR programs (i.e. curtailment) and adding further programs that have little or no interactive effects with existing programs.
Scenario 2	•**Rate-Based DR Expansion** The second scenario approach focuses on the DR potential possible via rate-based measures such as Time of Use rates and/or Critical Peak Pricing. These are applied alongside existing curtailment programs.
Scenario 3	•**Equipment Control DR Expansion** The third scenario focuses on an equipment control approach, either through utility direct load control, or manual control of equipment. These are applied alongside existing curtailment programs.

COST AND RATE SENSITIVITY

The Newfoundland and Labrador CDM Potential study covers a 15-year study period, during which electricity rates, avoided costs and carbon pricing in the province are subject to notable uncertainty. To capture the impact that changes in these factors could have on the market adoption of the studied technologies, sensitivity analysis was conducted covering these three key economic factors. **Table 1-4** provides a guide to the sensitivity ranges applied in the study and the base case values applied throughout the presentation of results. Detailed electricity rates and carbon pricing tables are provided in Appendix E.

Table 1-4. Rate, Cost and Price Sensitivity Ranges Applied in the Potential Study

	LOW	MID	HIGH
Electricity Rates: Electricity rate scenarios were provided by the utilities based on likely mitigated or unmitigated rate scenarios that account for the rate impacts from the Muskrat Fall generation facility.	Mitigated rates that exhibit little or no increase as compared to current rates when adjusted for inflation.	Mid-point between mitigated and unmitigated rates.	Unmitigated rate projections wherein the Muskrat Falls financing costs will be recovered through customer rate increases.[17]
Avoided Costs: Current and projected avoided costs of peak capacity in NL are high compared to neighbouring provinces and may be subject to revision. As such the Utilities provided avoided cost scenarios to test the impact of lower avoided costs.	60% of currently projected avoided capacity costs.	80% of currently projected avoided capacity costs.	Currently projected avoided cost for IIC provided by the Utilities. LAB avoided costs of capacity set to 90% of IIC avoided costs.
Carbon Pricing: The Provincial Government's carbon pricing plan has been accepted by the Federal Government, but future evolutions in GHG emissions policy could lead to an increase in carbon pricing on heating oil and transportation fuels.	Current NL Carbon Pricing Plan. No carbon price on heating oil, and a 9.79% carbon tax on gasoline and diesel.	Federal Government Backstop Carbon Pricing starting at $20 per tonne in 2019 and rising $10 per year to $50 per tonne in 2022.[18]	The social cost of carbon is a monetary measure of the climate change impact from emitting an additional tonne of carbon dioxide (CO2). [19]

Note: Light-blue shaded cells indicate the base-case for each sensitivity factor.

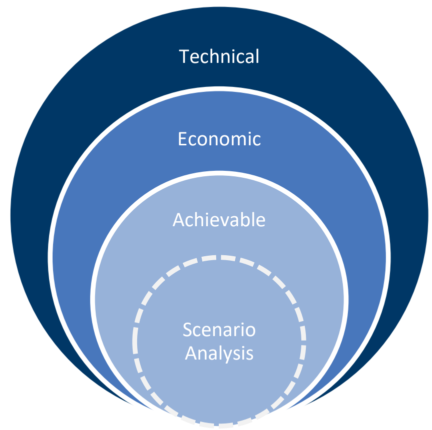
[17] Methodology Review Report, the estimated residential rate is projected to be approximately 21¢ per kWh without additional rate mitigation beyond Hydro's forecast export revenues.

[18] Source: Government of Canada, Technical Paper on the Federal Carbon Pricing Backstop, https://www.canada.ca/content/dam/eccc/documents/pdf/20170518-2-en.pdf.

[19] Source: Government of Canada, Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates, https://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1.

2. CUMULATIVE EFFICIENCY SAVINGS POTENTIAL

The following graphs and tables present Newfoundland and Labrador's cumulative savings potentials, covering energy (GWh) and peak demand (MW) as applicable. The results cover the annual cumulative impact on sales in each of the three studied electricity systems: IIC, LAB and ISO. The following sections present the savings potentials at three levels, as described below:



Technical potential: The theoretical maximum savings potential, ignoring constraints such as cost-effectiveness and market barriers.

Economic potential: The savings opportunities available should customers adopt all cost-effective savings, as established by screening measures against the Total Resource Cost (TRC) test.[20]

Achievable potential: The savings from cost-effective opportunities once market barriers have been applied, resulting in an estimate of savings that can be achieved through CDM programs. Three achievable potential scenarios were modeled to examine how varying factors such as incentive levels and market barrier reductions impact uptake:

- **Lower:** Applies current Utility CDM program incentive levels and enabling activities, including an expanded range of cost-effective technologies and without any program budget constraints.
- **Mid-range:** Applies increased incentive levels to reflect increased investments in CDM programs compared to the current portfolio. Also adds new construction, appliance recycling, and heat pump programs.
- **Upper:** Applies same increased incentive levels as in the Mid scenario, but with further investments in enabling activities to address customer barriers to adoption.

Throughout the following presentation of results and analysis, the reader should be aware of the following:

- **Achievable potential is presented under the Mid scenario**, except where otherwise specified.
- **All savings are expressed in at-the-meter terms**, rather than at-the-generator terms. The savings results therefore do not include line-losses in the transmission and distribution network. Line losses are added

[20] As is standard practice in potential studies, the TRC calculation applied to assess the Economic screening considers the costs and benefits of each measure, but does not include program costs such as administration or start-up costs. In this study, efficiency measures with a TRC of 0.8 or higher were retained in the Economic Potential.

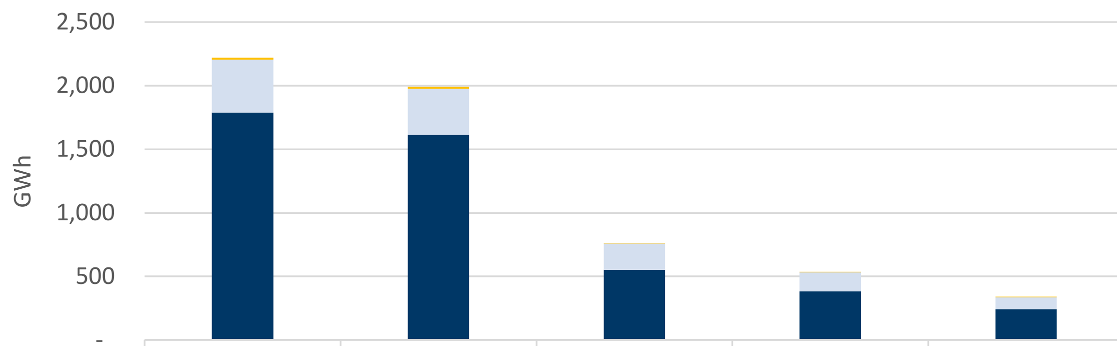
to the at-the-meter savings to calculate at-the-generator savings (to reflect the true avoided costs of generation) and these are used in the TRC calculations.

- **All savings are calculated under the Mid customer rates scenario:** Unless otherwise stated, the results in this section were generated using the mid customer rates scenario that assumes a mid-point in the rates between the mitigated and unmitigated rate projections. Details on the customer rates are provided in Appendix E.

ELECTRIC ENERGY SAVINGS POTENTIAL

Below, the technical, economic, and achievable savings are presented side-by-side for electric potential savings (**Figure 2-1** and **Table 2-1**) for each system over the study period (2020-2034).

Figure 2-1. Cumulative Electric Potential Savings from Efficiency Under Mid Rates (2034)



	Technical	Economic	Upper	Mid	Lower
ISO	16	16	6	5	4
LAB	415	363	207	149	94
IIC	1,788	1,613	552	384	242

Table 2-1. Cumulative Potential as a Portion of Sales (2034)

Study Component	Economic Potential	Lower	Mid	Upper
IIC	24%	3.6%	5.7%	8.2%
LAB	13%	3.3%	5.2%	7.2%
ISO	19%	5.4%	5.8%	6.8%
Total (Province-wide)	21%	3.5%	5.5%	7.9%

From these results, the following observations can be made:

- **Technical and economic potential are close in magnitude.** More than 95% of the technical potential is considered cost-effective. This is a consequence of three factors:
    - The avoided costs of generation for the IIC and LAB system are extremely high ($420/kW and higher). Thus, measures that offer significant peak savings impacts can quickly become cost-effective as they accrue peak savings benefits.

- As per the Utilities instruction, the study applied a TRC screen of 0.8, meaning that all measures whose lifetime benefits are equal to or higher than 80% of the lifetime costs are included in the economic potential. This allows for marginally cost-effective measures to be combined with other more cost-effective measures to be considered for inclusion in the CDM programs, as long as the overall program or portfolio can achieve a TRC of 1.0 or higher. Some measures may not be able to be combined cost effectively therefore reducing the total achievable potential that is shown in this report.
- Finally, measures that are currently not commercially available, and are not expected to become available within next 15 years, were excluded from the measure list.[21] This reduces the technical potential but has no impact on the economic or achievable potential scenario outcomes.

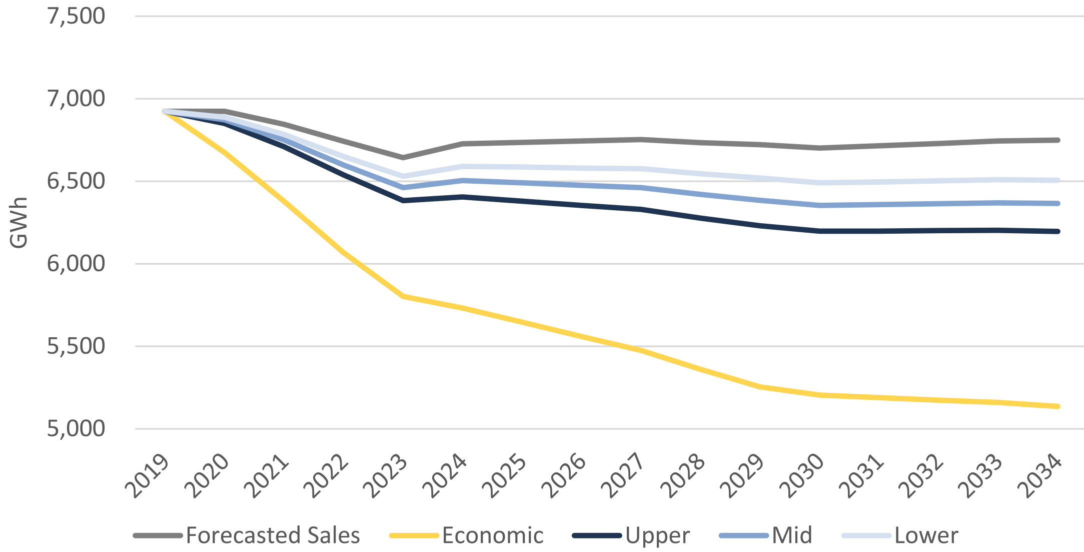
- **The achievable potential scenarios are all significantly lower than the economic potential.** This is largely attributed to market barriers such as customer knowledge, technology availability, the perceived higher cost of energy efficient equipment and uncertainty about the savings from efficiency improvements.
- **Investing in barrier reductions can increase achievable potential over and above raising incentives alone.** The combination of increased incentive levels and enabling strategies that can reduce customer barriers, as applied under the Upper program scenario more than doubles the incremental savings increase over the Lower program scenario.

IMPACT ON ELECTRICITY SALES

The graphs below illustrate the impact on annual savings under each achievable program scenario and the economic potential for each system (**Figure 2-2** to **Figure 2-4**). In each case it can be seen that the reduction in sales is steepest in the initial five years while lighting savings continue, and new programs and new measures ramp up. In the later years, the projected impact on savings flattens as the new equipment standards take hold for lighting and heat-pumps and the number of available opportunities for replace-on-burnout measures (replacement of a piece of equipment that has reached the end of its useful life with a more efficient option) go down until the market is depleted. Subsequent equipment replacements thereby are counted as re-participation and are not included as additional cumulative savings.

[21] The commercial availability and viability of measures was assessed through the market actor interviews, and a review of available secondary sources such as technical reference manuals, as well as Dunsky's professional judgment. A list of considered measures that were not retained for inclusion in the model is provided in Appendix E.

Figure 2-2. Cumulative Electric Potential: Mid Scenario Impact on Sales Under Mid-Rates (IIC)

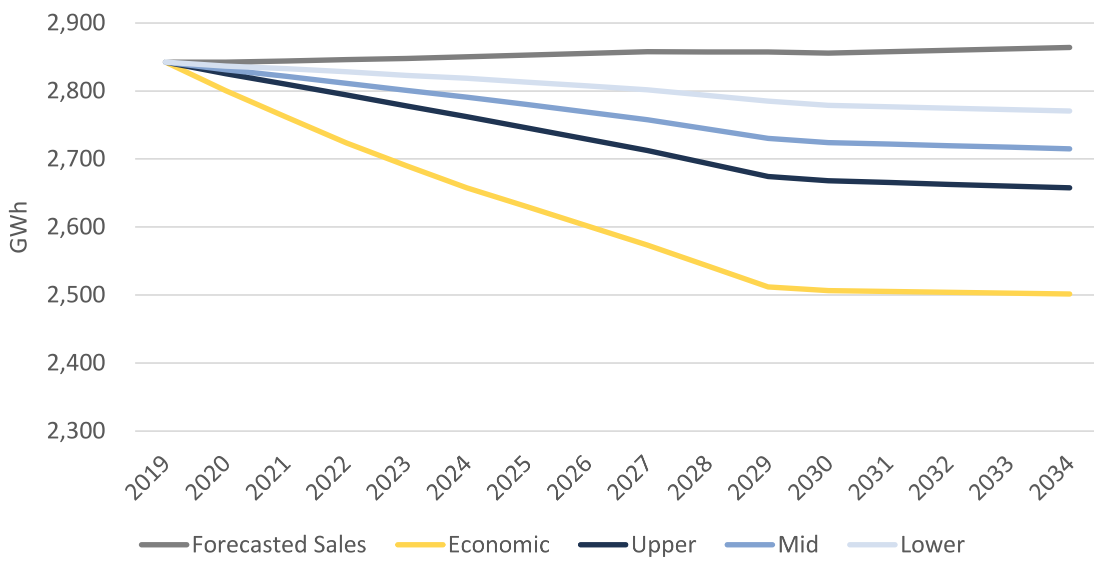


Note: Y axis does not start at zero in order to show trends more clearly.

The potential impact on electricity sales in the IIC system reveals the following:

- **Economic Potential:** Savings from economically viable measures could reduce sales by as much as 24% over the study period. This is mostly accomplished in the first 10 years, after which programs would maintain slightly decreasing annual sales.
- **Achievable Potential:** Savings from the program scenarios can achieve up to an 8.2% reduction in sales by 2034 under the Upper scenario, or a 3.6% reduction in sales by 2034 under the Lower program scenario.

Figure 2-3. Cumulative Electric Potential: Mid Scenario Impact on Sales Under Mid Rates (LAB)

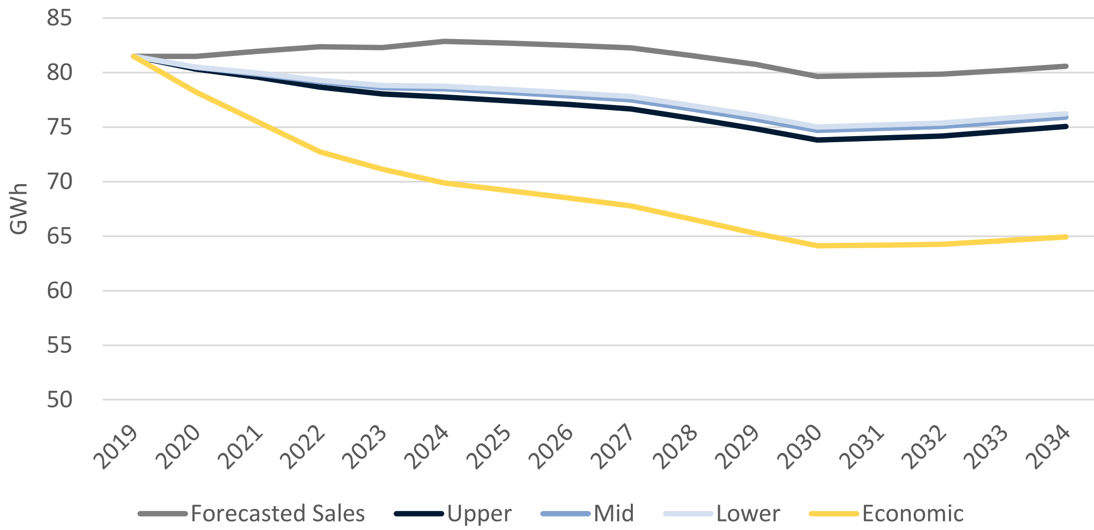


Note: Y axis does not start at zero in order to show trends more clearly.

The potential impact on electricity sales in the LAB system reveals the following:

- **Economic Potential:** Savings from economically viable measures could reduce sales by as much as 13% by the end of the study period. This is largely accomplished in the first 10 years, after which programs would maintain slightly decreasing annual sales.
- **Achievable Potential:** Savings from the program scenarios can achieve up to a 7.2% reduction in sales by 2034 under the Upper scenario, or a 3.3% reduction in sales by 2034 under the Lower program scenario. Similar to the economic potential, these impacts are largely accomplished in the first 10 years, after which the programs would maintain savings levels through re-participation. In all achievable program scenarios, any growth in projected sales in the LAB system may be offset by efficiency savings.

Figure 2-4. Cumulative Electric Potential: Mid Scenario Impact on Sales Under Mid Rates (ISO)



Note: Y axis does not start at zero in order to show trends more clearly.

The potential impact on electricity sales in the ISO system reveals the following

- **Economic Potential:** Savings from economically viable measures could reduce sales by as much as 19% by the end of the study period. This is largely accomplished in the first five years, after which programs would maintain slightly decreasing annual sales.
- **Achievable Potential:** Savings from the program scenarios can achieve up to a 6.8% reduction in sales by 2034 under the Upper scenario, or a 5.4% reduction in sales by 2034 under the Lower program scenario. Similar to the economic potential, these impacts are largely accomplished in the first five years, after which the programs would maintain savings levels through re-participation. Moreover, the spread among the program scenarios is small compared to the IIC and LAB systems. This is due to the current ISO system programs that offer high incentives and apply enabling strategies such as direct install for residential programs which leaves little room for increasing savings through raised incentives in the residential sector.

SAVINGS POTENTIAL BY SECTOR AND SEGMENT

Below, cumulative savings under the Mid program scenario are presented by system, sector and time period (**Figure 2-5** and **Figure 2-6**). The results presented focus on the Mid program scenario for illustrative purposes, as the proportional amount of savings in each sector are generally consistent under each of the program scenarios. For further details, tables of cumulative savings by sector and end-use can be found in Appendix F for all program scenarios.

Figure 2-5. Province-Wide Cumulative Achievable Potential (GWh) by sector: Mid Program Scenario Under Mid Rates

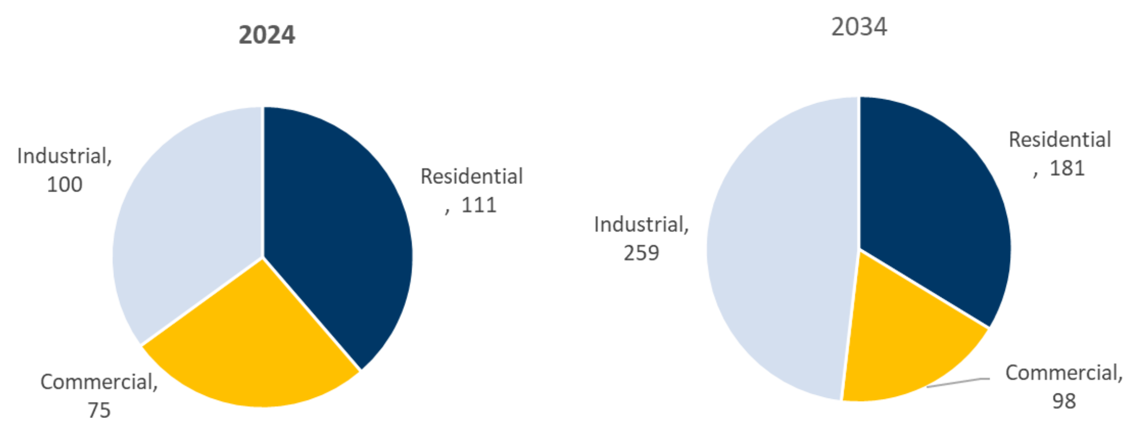
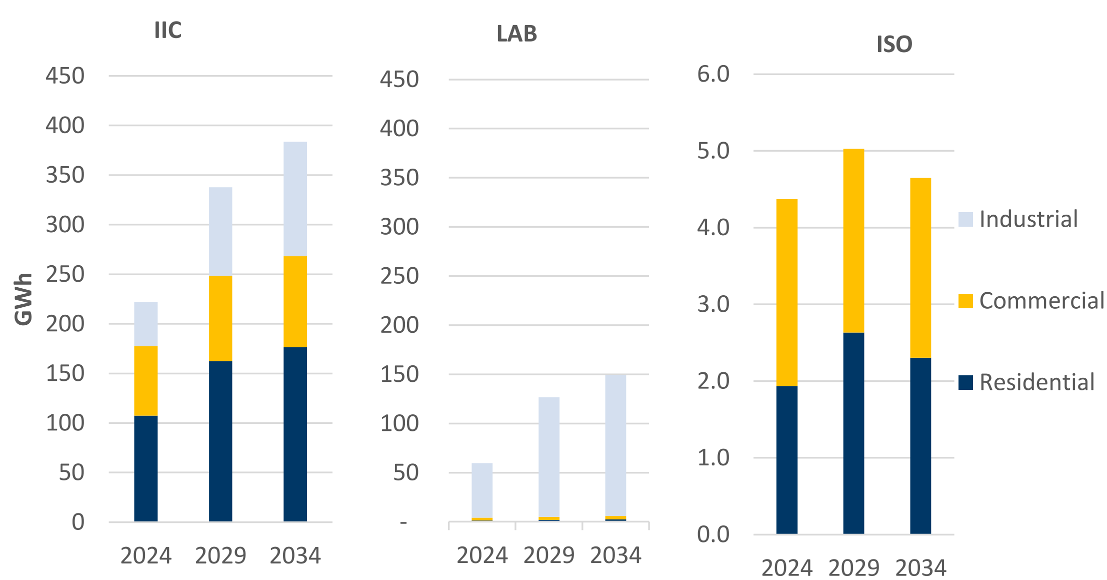


Figure 2-6. Cumulative Achievable Potential by System, Sector, and Time Period: Mid Program Scenario Under Mid Rates



Note: The Y axis differs for the ISO system to make the presentation clearer

From the results presented above, the following observations can be made:

- **Province-wide, the residential sector offers the highest savings potential in the initial five years, while the industrial sector appears to offer the highest savings potential by the end of the study period:** In the initial years, residential savings comprise over 40% of the potential, which is greater than either of the other sectors. However, by the end of the study period, the industrial sector offers nearly half of all savings potential in the province (47%), which is approximately split evenly between the IIC and LAB systems. It should be noted that the majority of these savings stem from the six transmission-level customers for whom a top-down analysis of the savings was applied, rather than the bottom-up analysis applied in all other segments. A key difference is that in the residential and commercial sectors cumulative savings taper off later in the study period due to lighting and heat pump standards changes, program participation and market transformation.

- **The IIC system residential sector savings are substantial due to the high penetration of electrically heated homes:** More than half of the savings in the IIC stem from the residential sector, and these savings grow throughout the study period. This indicates that savings are not coming from lighting measures alone, as residential lighting opportunities are expected to be largely eliminated by the EISA standards changes and market transformation effects by 2025.

- **Commercial sector savings in the ISO system make up over half of the remaining savings potential in that system:** While the commercial savings are curtailed in the initial years due to lighting market transformation, there remains significant commercial sector potential in the ISO system by the end of the study period.

The average annual savings by segment are presented below for the first five years (**Figure 2-7)** and the last ten years (**Figure 2-8**) of the study period. Residential segments are coloured dark blue, commercial segments are yellow, and industrial segments are light blue. The grey line provides a rolling total as a percent of overall savings.

Figure 2-7. Province-Wide Achievable by Segment (GWh): Mid Scenario Under Mid Rates, Average Annual (2020-2024)

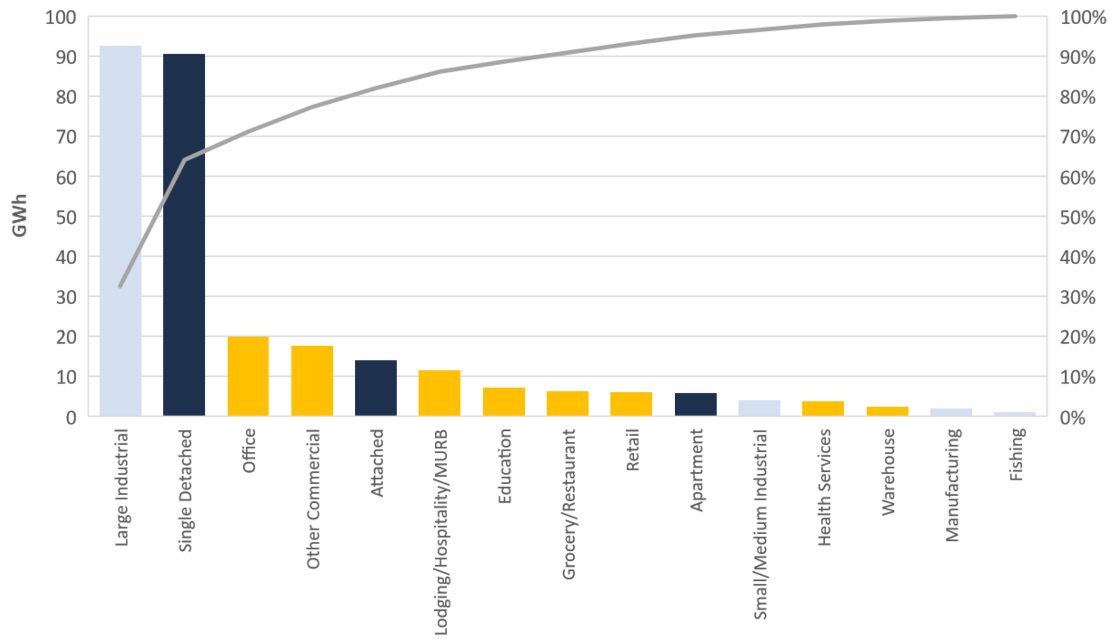
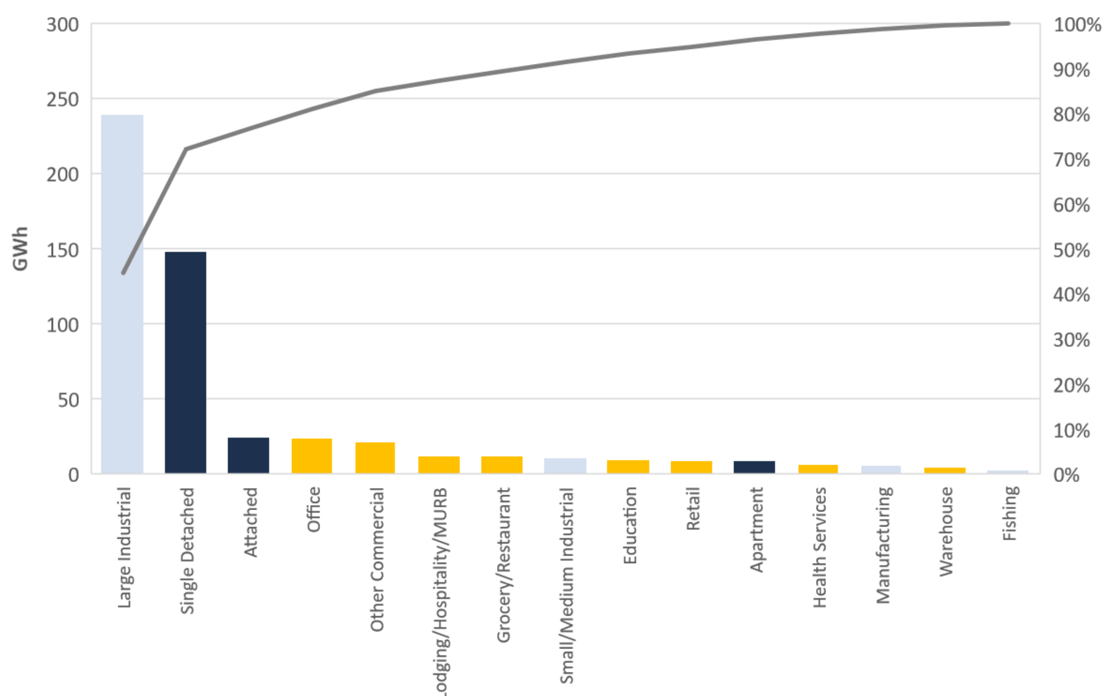


Figure 2-8. Province-Wide Achievable by Segment (GWh): Mid Scenario Under Mid Rates, Average Annual (2025-2034)



Inspection of the segment level cumulative savings reveals the following:

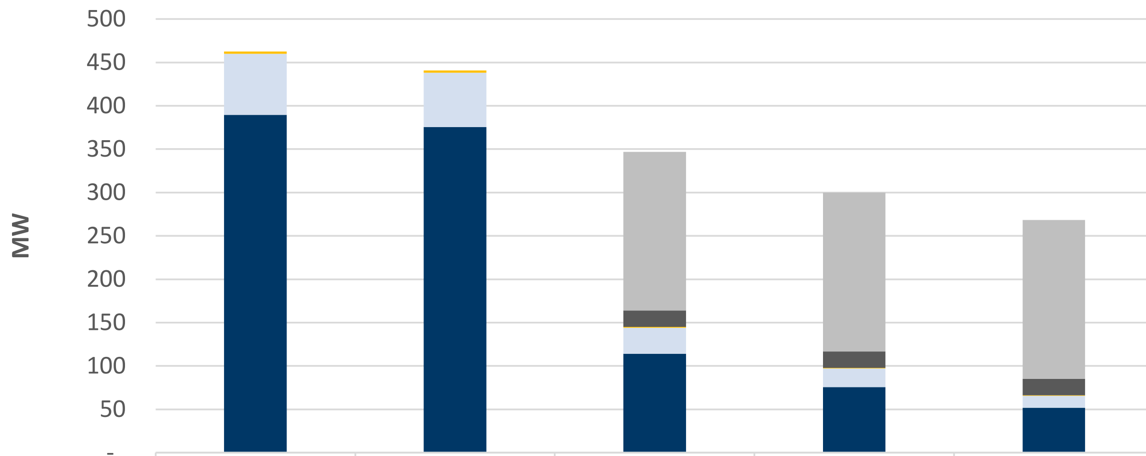
- **Large industrial has the most potential throughout the study period, and its portion of the overall potential grows even larger by the end of the study period:** The high energy usage per facility in the segment makes for significant potential savings. Once again, it should be noted that the top-down analysis did not reveal which measures drive these savings, thus there could be value in further studying this segment to verify these savings levels on a facility-by-facility basis, and to determine the key savings technologies.
- **A substantial portion of annual savings in the initial years are found in the single-family home segment**: Although the savings in this segment remain high throughout the study period, they are lower in the later years of the study as lighting savings drop out. Savings in other residential segments are much lower due to the lower number of customers in the apartments and attached homes segments, in addition to the higher barriers to many efficiency measures faced by these customers.
- **The top five segments represent more than 80% of the potential annual savings**, which may justify focusing CDM program efforts on these segments.

PEAK DEMAND REDUCTION POTENTIALS

The combined peak demand potential from energy efficiency (EE) and demand response (DR) programs are presented below in **Figure 2-9**. The efficiency program savings were assessed using the DEEP model first, and then the utility load curve was adjusted to account for these peak demand savings. These new utility load curves were then applied in the DR Model to arrive at the DR potential.

For the DR potential, only the highest yielding scenario for each of the systems (IIC and LAB) is presented in the results as these scenarios best capture the existing curtailment potential (please see Chapter 4 for further details on the DR Scenario results). The DR savings for the ISO system were not assessed due to the complexities of applying demand response programs to small local generation systems.

Figure 2-9. Peak Demand Potential Savings for DR and EE Programs by System Under Mid Rates[22] (2034)



	Technical	Economic	Upper	Mid	Lower
IIC (DR)			183	183	183
LAB (DR)			19	19	19
ISO (EE)	3	3	1	1	1
LAB (EE)	70	63	30	22	14
IIC (EE)	390	375	114	76	52

From these results, the following observations on demand reduction potential can be made:

- **The demand response programs offer higher demand reduction impacts than the efficiency measures under all EE program scenarios:** Demand response potential in the province is high when benchmarked

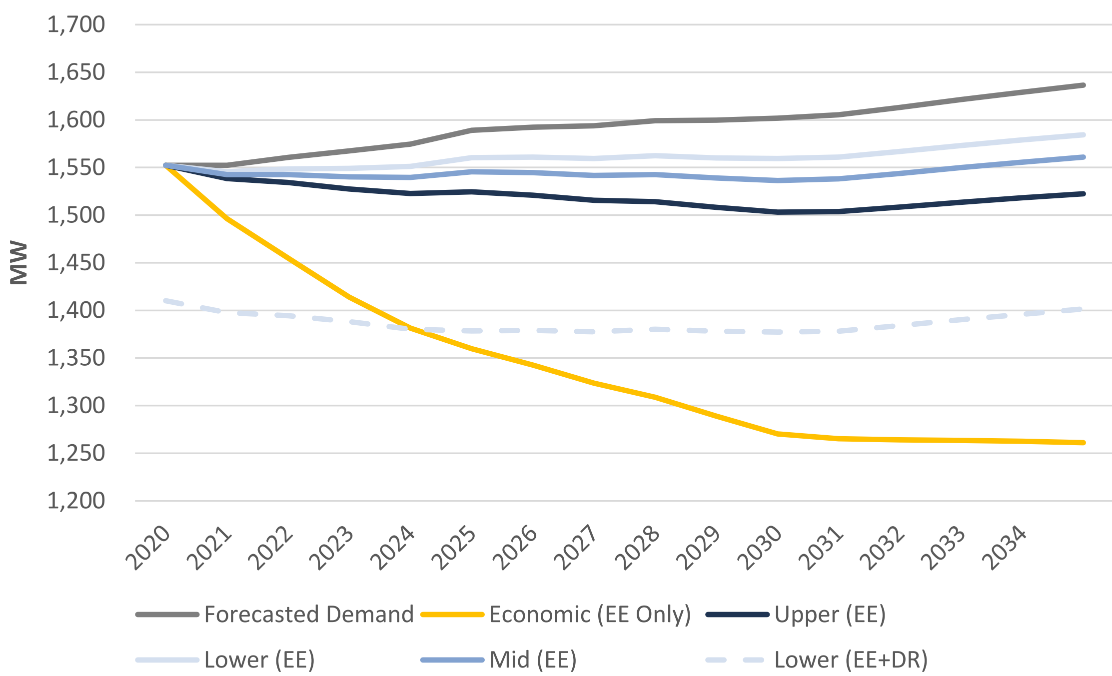
[22] DR potentials include existing and potential peak demand impacts as assessed in the DR model and described in Chapter 4 of this report. Because the model does not consider interactions among DR measures at the technical and economic potentials level, the results are not considered additive, and are therefore not included in the graph.

against other jurisdictions (see Chapter 4 for more details), and it delivers more demand reduction than any of the all efficiency program scenarios.

- **The Mid and Upper EE program scenarios offer significant increases to peak demand reduction potential, particularly in the IIC system:** While all EE program scenarios offer notable peak demand reductions, the Upper and Mid EE program scenarios offer significantly higher peak demand potentials than the Lower scenario, as was the case for consumption savings. Nonetheless, the EE peak demand potential remains much lower than the economic potential. If the NL Utilities continue to seek demand savings in the IIC system, there may be opportunities to tune higher program incentives on EE measures that offer the highest peak demand savings.

Figure 2-10 and **Figure 2-11** below show the peak demand impacts from EE and DR in the IIC and LAB systems respectively.

Figure 2-10. Peak Demand Potential Savings for DR and EE Programs Under Mid Rates (IIC)

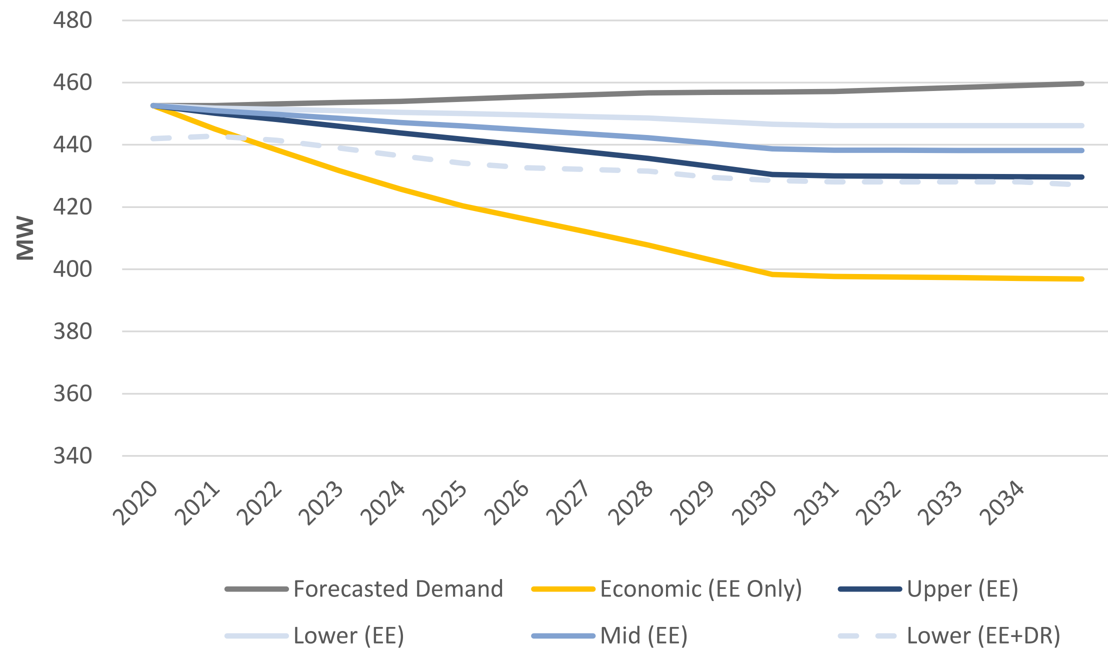


From the above figure it can be seen that the DR peak demand reduction far outweighs the EE peak demand potential in all years.

- **Much of the DR potential is already captured in the current industrial and commercial curtailment programs:** The dashed grey line reveals a slight dip in the initial years as expansion of the DR programs offsets overall system peak demand growth. Chapter 4 provides further details on the DR potential.

- **The combination of expanded DR programs and EE programs can effectively offset peak demand growth in the IIC system:** The dashed grey line remains at or below 1,400 MW for most of the study period, except the final years. This represents the combined impact of the DR programs and the Lower EE program potential, suggesting that a modest increase in EE programs potential by strategically targeting peak demand reducing efficiency measures could help ensure stable peak demand in the IIC system throughout the study period. The initial dip in peak demand in the initial years in the dashed Lower EE programs + DR line is caused by an overall projected dip in forecast peak demand combined with a ramp up in new DR program potential, over and above current curtailment (see Chapter 4 for details on the additional DR potential).

Figure 2-11. Peak Demand Potential Savings for DR and EE Programs Under Mid Rates (LAB)

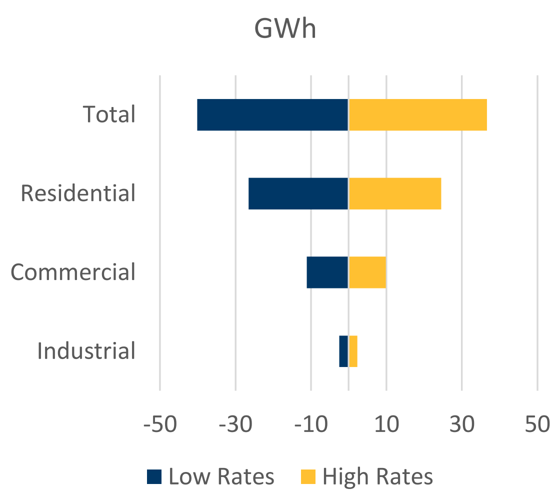


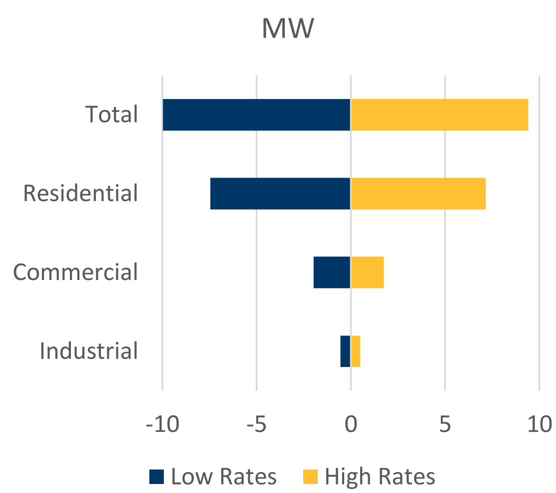
From this chart it can be seen that the LAB system has less DR potential than in the IIC system, and that current peak demand can be maintained or reduced through either EE or DR programs. Further details on the LAB DR program potential can be found in Chapter 4.

IIC SYSTEM SAVINGS SENSITIVITY ANALYSIS

The NL Utilities provided three customer rate scenarios for the IIC system to reflect uncertainty over future rates for commercial and residential customers after the Muskrat Falls generation facility becomes fully commissioned. In the following charts, the impact of the rate sensitivity cases is presented for achievable efficiency program savings.[23] Detailed results tables for the cumulative savings potential for the Upper and Lower program scenarios under the High, Mid and Low rates cases are provided in Appendix F. Overall the achievable potential for the Low-rates case was on average 18% lower than the Mid rates, while the achievable potential for the High-rates case was 20% higher than the Mid-rates case. It should be noted that the sensitivity analysis was not applied to the Large Industrials segment, as customer rates were not an input to the top-down analysis performed for that sector.

Figure 2-12. Impact of Customer Rate Scenarios on Cumulative Achievable Savings by segment: Mid Program Scenario (IIC - 2034)





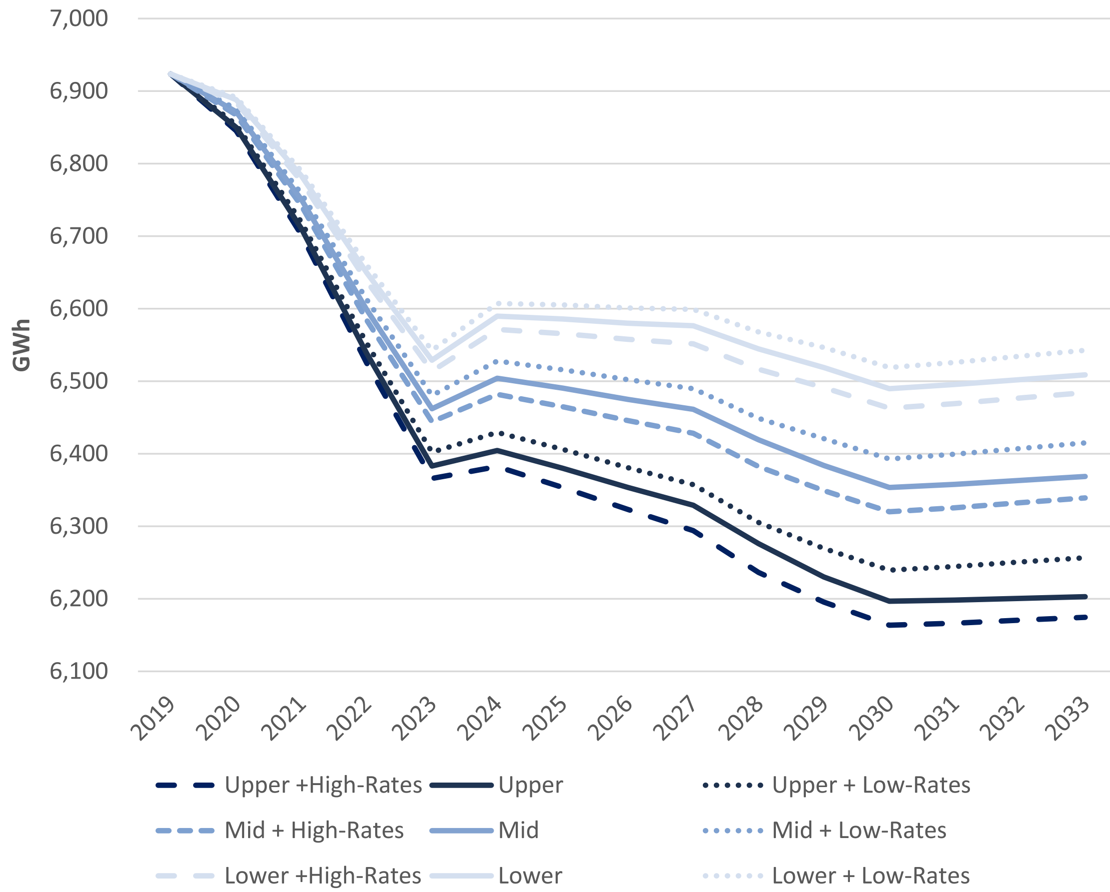
From the tornado graphs above, it can be seen that the High-rates case results in a greater adoption of efficiency measures, while Low-rates reduces the uptake of efficiency measures. Proportionally the increase from raising rates appears to be similar to the decreases when rates are lowered. Overall the majority of the impact is seen in the residential sector.

Below, the impact of the various rate scenarios on the progression of cumulative savings in the IIC system is presented (**Figure 2-13**). The following figure illustrates how the various rate scenarios would impact cumulative

[23] The DR program savings are not sensitive to absolute customer rates (Time of Use rates are assessed based on-to off-peak ratios) so the sensitivity analysis is limited to the EE program potentials. Further details on the DR potential findings are provided in Chapter 4 of this study.

savings under the Lower and Upper program scenarios. The annual savings for each customer rate scenario broken down by sector is provided in the appendix.

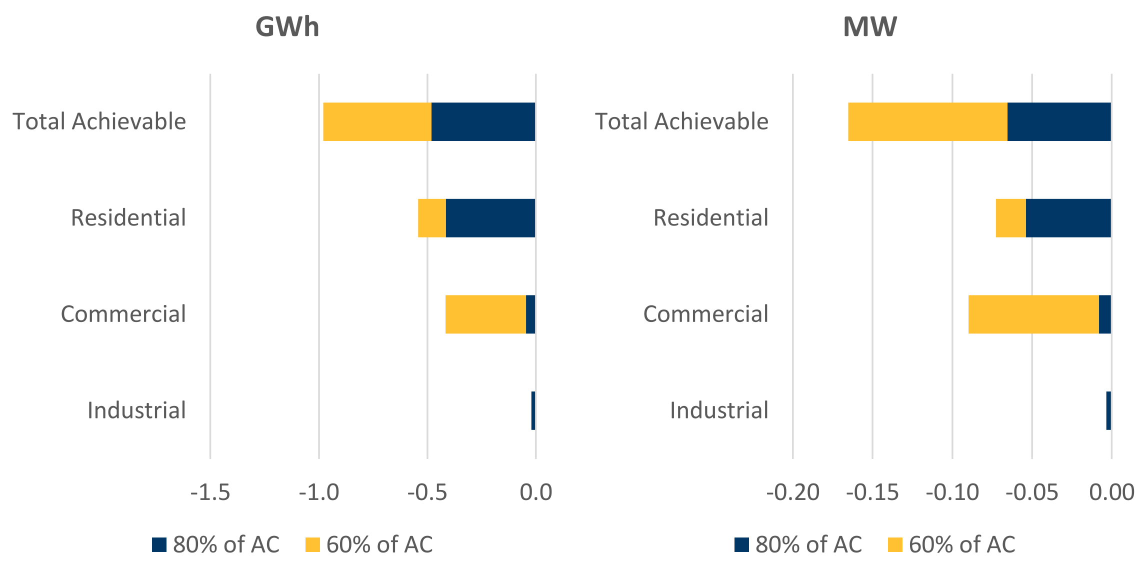
Figure 2-13. Impact of Customer Rates on the Cumulative Achievable Potential (IIC)



From the above figure it is clear that achievable savings are only marginally sensitive to the customer rate cases applied. Overall it is found that the achievable potential will increase or lower by 10% under each rate case as compared to the mid-rates case, which is attributed to two key reasons. First, the rate scenarios were not applied in the Large Industrial Segment analysis, which account for close to half of the overall cumulative savings by the end of the study period. Second, while customer rates are an important factor in determining the economics for adopting efficiency measures, market barriers also play a key role, tempering the sensitivity of the program savings to the various rate scenarios.

Finally, the impact of reduced avoided costs of capacity on the cumulative potential in the IIC system was assessed and the results are presented in **Figure 2-14** below. As discussed previously, the avoided costs of capacity for the IIC system range between $420 to $440 per MW over the study period, which helps most measures to be cost-effective under the TRC screen applied in the DEEP model. The following figure illustrates how reduced avoided capacity costs would impact cumulative savings (**Figure 2-14**).

Figure 2-14. Impact of Avoided Costs of Capacity Scenarios on Cumulative Achievable Savings: Mid Program Scenario (IIC – 2034)



From the above figure, the following observations are made:

- **The cumulative achievable potentials are much more sensitive to changes in customer rates than they are to changes in the avoided costs of capacity: Figure 2-14** and **Figure 2-12** reveal that changes to the avoided costs have much less impact on the achievable potential than changes to customer rates. This is a logical finding, as the achievable potential is driven by customer economics, which is directly affected by changes to customer rates (higher electricity rates increase benefits to customers from EE measures). On the other hand, customers are not directly exposed to avoided costs, and so avoided costs changes impact only customer adoption when they alter the range of measures included in the economic potential; measures that are not included in the economic potential are not considered for customer adoption under the achievable potential.
- **The range of tested avoided costs does not significantly impact the achievable potential:** Reducing the avoided costs of capacity impacts the achievable potential when they cause a measure to fail the TRC screen. Even at 60% of the currently projected avoided costs, the IIC system avoided costs of capacity remain relatively high compared to other jurisdictions. As a result, the reductions in avoided costs of capacity are insufficient enough to cause many measures to fail the TRC screen (which was set at 0.8). Thus, the vast majority of measures remain within the economic potential, making them available under the achievable potential scenarios.

3. EFFICIENCY PROGRAM SAVINGS POTENTIAL

The following graphs and tables present Newfoundland and Labrador's CDM program efficiency savings potential. Program savings refer to the savings from measures that are incentivized through programs in a given year. They are most representative of annual program savings and can be used as an input to CDM program planning to help establish savings objectives, and to determine which sectors, end-uses, and measures hold the most potential.

Three achievable potential scenarios were assessed in this potential study: Lower, Mid, and Upper. By varying factors such as incentive levels[24] and barrier reduction strategies between scenarios, the study offers insights into their respective impacts on program savings. A summary of the assumptions associated with each scenario are presented below (**Figure 3-1**). Detailed tables of the input assumptions applied for each program can be found in Appendix E.

Figure 3-1. Program Scenario Assumptions

Lower	•**Lower Achievable Potential** Applies current Utility CDM program incentive levels and enabling activities, but includes the full range of cost-effective technologies, and disregards any budget constraints.
Mid	•**Mid-Range Achievable Potential** Applies increased incentive levels to reflect increased investments in CDM programs compared to the current portfolio.
Upper	•**Upper Achievable Potential** Applies increased incentive levels, and includes further investments in enabling activities to address customer barriers to adoption.

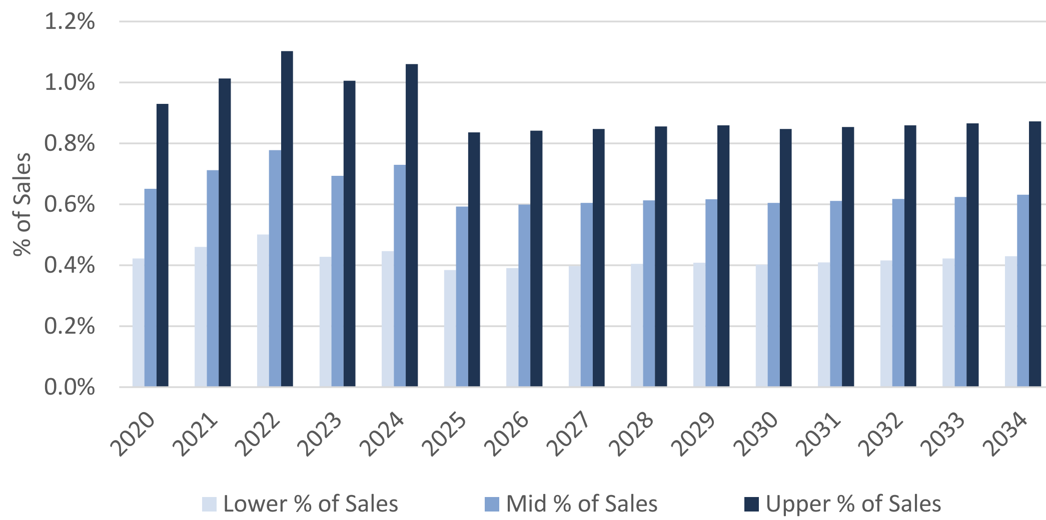
The results that follow highlight the achievable potential savings under each scenario, for each of the current takeCHARGE programs, as well as for potential new programs. Results are presented for each program under each scenario, as well as breakdowns of program savings by end-use and the top ten measures in each sector. All results were generated under the Mid-rates case, representing a middle point escalation of customer rates between the mitigated and unmitigated rate projections.

[24] Incentive levels refer to the portion of a measure's incremental cost is covered by a program incentive.

ANNUAL PROGRAM SAVINGS

Forecasted annual program savings for all programs are expressed as the portion of annual sales in each year of the study period for each of the program scenarios below (**Figure 3-2**). We present IIC + LAB savings together as the takeCHARGE programs are delivered consistently throughout these two systems. Due to the extremely high avoided costs of generation and subsidized rates for customers in ISO system, NL Hydro offers tailored programs for the ISO system with elevated incentive levels and enabling strategies (such as direct install program implementation) to address the specific challenges of these remote communities. The annual savings are provided as a portion of overall ISO system sales in a separate chart (**Figure 3-3**).

Figure 3-2. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (IIC+LAB)



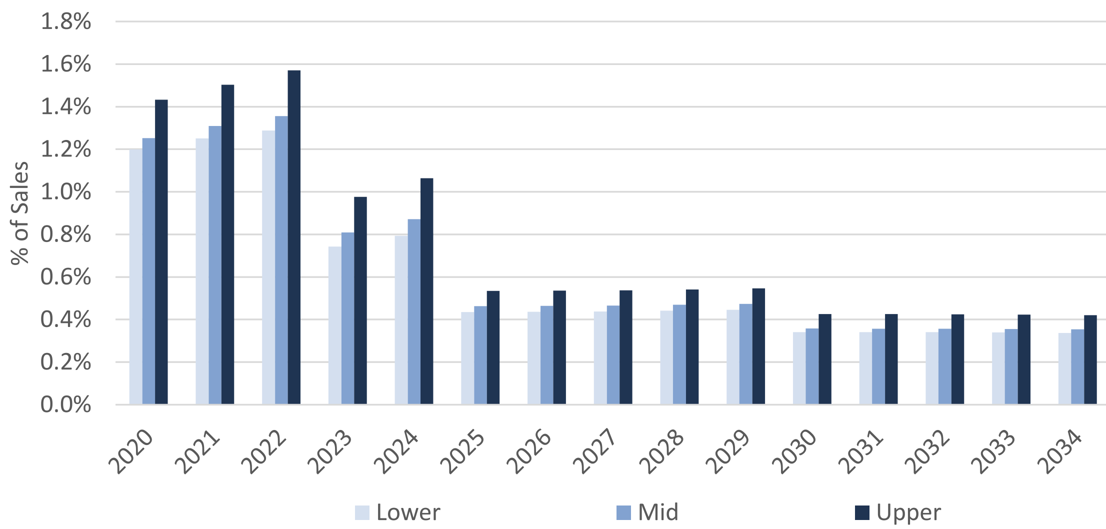
From these results, the following observations can be made:

- **Savings range from 0.4% to 1.1% of sales in the initial five years of the study period:** Savings under all program scenarios are highest in the initial five years. The Lower program scenario achieve 0.4%-0.5% savings per year in this period, while the Upper scenario savings exceed 1.1% of sales, reaching a peak in 2022 and 2024. Starting in 2025 the annual program savings drop significantly as almost all residential lighting and a significant portion of commercial lighting savings are eliminated by the 2023 and 2025 standards updates. Also, heat pump standards improve in 2023 and 2025, further cutting savings from those measures. However, it should be noted that there is an increase in savings between 2023 and 2024 as rates rise and new measures and programs added in 2020 complete their ramp up period.

- **After a steep drop between 2024 and 2025, program savings remain stable for the remainder of the study period.** Once residential and standard commercial lighting has been removed from the programs, annual savings drop to a lower level. As commercial lighting equipment are gradually replaced with long life expectancy LEDs, the number of replacement opportunities declines and with it, savings that can be achieved through programs. However, as customer rates gradually increase, a steady flow of HVAC and envelope improvement opportunities persists over the remainder of the study period.

The ISO system exhibits a similar pattern, with a steep drop in program savings between 2024 and 2025, although the reduction is much more pronounced (**Figure 3-3**).

Figure 3-3. Program Savings as a Portion of Annual Sales: Lower, Mid and Upper Program Scenarios Under Mid Rates (ISO)



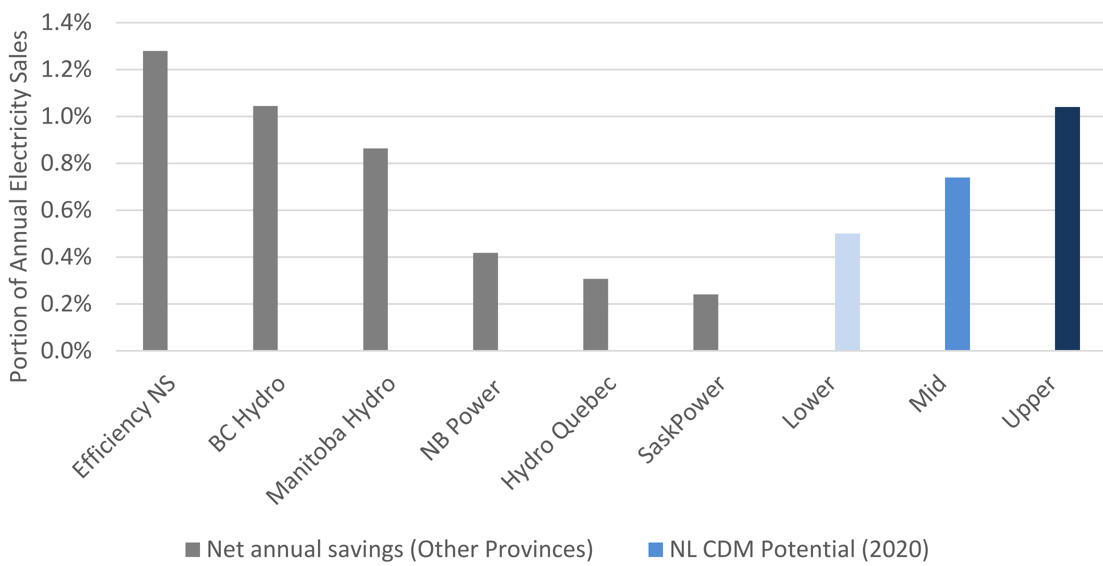
The follow observations are made from the figure above:

- **ISO savings in the initial years are higher than for the later years, and the program scenarios show much less spread in their results:** Savings in the initial years range from 1.2% to 1.6%, peaking in 2020 before the first EISA standards updates take effect. The high savings are driven by the high incentive levels and enabling strategies employed in the Isolated Residential Program (100% incentives and direct install implementation). With the high incentives in the residential program, there is little impact under the Mid program scenario, and the Upper program scenario applies just a barrier reduction impact in the residential program, thus the program scenario results are closely grouped, suggesting it would be a challenge for NL Hydro to generate significantly higher savings than the current ISO system programs deliver.

- **ISO savings are highly driven by lighting measures in the initial years, and envelope and HVAC measures in the later years:** The high incentives offered for ISO customers and enabling strategies cause these programs to be very sensitive to lighting savings, which leads to notable drops in annual savings in 2023 and 2025 as each phase of the EISA standards is applied. Moreover, due to the low penetration of electric heating among ISO system customers, there are fewer HVAC and envelope measure savings available to the programs from 2025 to 2034, and thus the annual savings drop. However, it should be noted that there is an increase in savings between 2024 and 2023 as rates rise and new measures and programs added in 2020 complete their ramp up period.

For comparison, the CDM program scenario savings in 2020 are compared to a selection of other Canadian Province electric efficiency program savings (**Figure 3-4**), where results were available. Further details and references for the data from other provinces can be found in Appendix E (see **Table E-31**).

Figure 3-4. Annual CDM Program Potential (2020) and recent Electric Efficiency Performance in Other Canadian Provinces

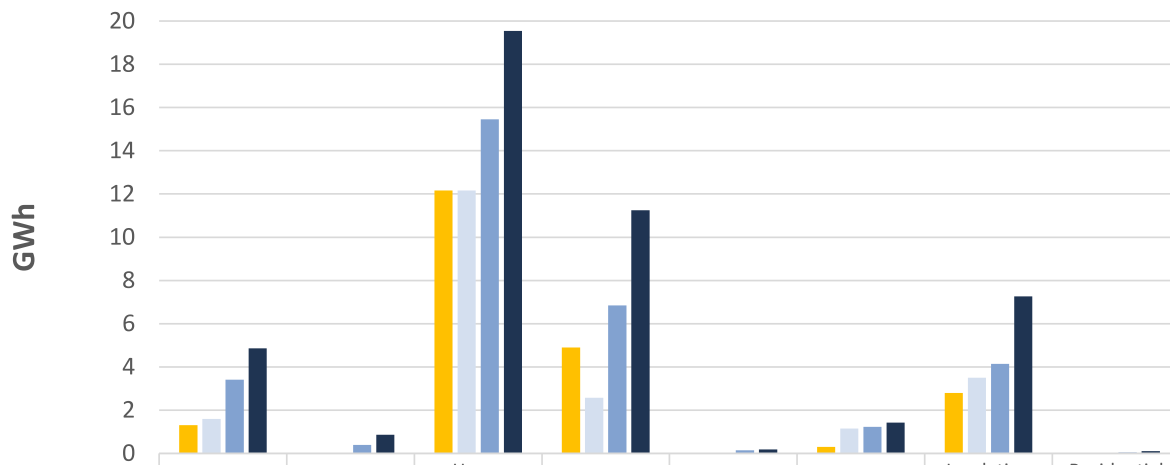


Overall the results indicate that the NL CDM Potential in 2020 places NL within the middle range of savings when compared to other provinces. The Lower program scenario delivers savings that are comparable, but exceed, the lesser performing provinces (New Brunswick, Quebec and Saskatchewan), which all exhibit low electricity rates for customers. The Upper program scenario would place NL within Canada's leading provinces for efficiency programs. While this figure offers a useful comparison, it is important to note that energy prices and fuel mixes vary by province, which have a significant influence on the annual savings achieved.

RESIDENTIAL PROGRAMS

Below, current residential program savings[25] are presented alongside modeled potential savings for each program scenario for 2020 under the Mid-rates case (**Figure 3-5**) for the takeCHARGE programs covering the IIC and LAB systems collectively. Current values are compared for the first year of the study (2020) as CDM program numbers are not available for later years. Program savings potentials for the initial five years (2020-2024) are also presented to show expected program savings evolutions (**Figure 3-6)**.

Figure 3-5. Comparison of Residential Program Savings: Current programs, Lower, Mid and Upper Program Scenarios Under Mid Rates (2020)



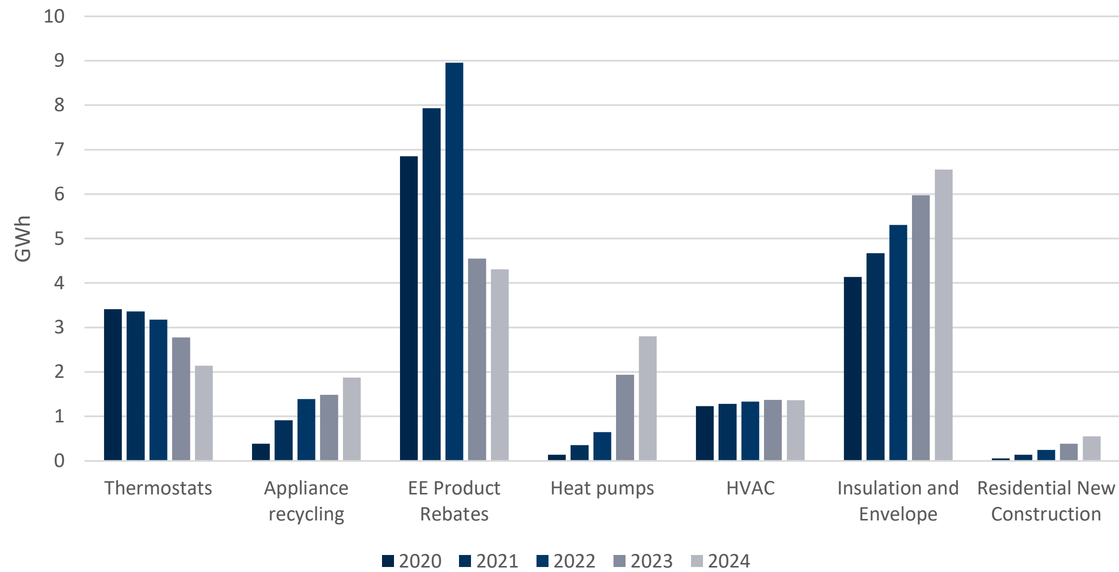
	Thermostats	Appliance recycling	Home Energy Report	EE Product Rebates	Heat pumps	HVAC	Insulation and Envelope	Residential New Construction
Current Prog.	1.30		12.16	4.90		0.30	2.80	
Lower	1.59	0.00	12.16	2.57	0.00	1.15	3.51	0.00
Mid	3.41	0.39	15.45	6.85	0.14	1.23	4.14	0.05
Upper	4.85	0.86	19.55	11.24	0.18	1.43	7.27	0.10

Note: Current Program savings are derived from either the 2019 CDM Program Plan for 2019, or evaluated program savings from 2017 and/or 2018 where available.

From the residential program comparisons, it can be seen that some programs exhibit a somewhat larger potential in 2020 than in the current plans or evaluation report: This is largely because the results shown apply the Mid-rates case, which are higher than current customer rates, thereby they increase the efficiency benefits to customers which drives increased adoption. The model was calibrated under the Low-rates case (fully mitigated) and the results are provided in Appendix F.

[25] Current Program savings are derived from recent CDM program evaluation reports or the 2016-2020 Energy Conservation Plan (2015, NL Hydro and NF Power) using 2019 planned savings where recent evaluations were not available.

Figure 3-6. Residential Program Savings Evolution (2020-2024): Mid Program Scenario Under Mid Rates



Note: Home Energy Reports are not presented in the above graph as the savings do not change by year.

A review and comparison of the above figures reveals a few key trends:

- **New programs and programs with measures not currently offered in the takeCHARGE portfolio show notable growth over the 2020-2024 period: Figure 3-6** presents annual program savings for each residential program over the 2020-2024 period. To account for the expected ramp-up in demand attributed to growing awareness and program effectiveness for newly offered programs and measures, the model applied a program uptake growth factor in the initial years (Appendix E Measure Lists provides details which measures in the model are not currently offered in the takeCHARGE programs.) The impact of new programs and measure incentives can be seen on the Appliance Recycling, Heat Pumps, HVAC, Insulation and Envelope, and Residential New Construction programs.

- **Thermostats Program:** The Thermostats program captures a significant amount of savings under the Lower program scenario, and shows substantial growth when incentives are increased and enabling strategies are employed under the Mid and Upper program scenarios. The program evolution **in Figure 3-6** indicates that thermostat program savings will drop with time as the market for programmable and electronic thermostats becomes saturated.

- **Appliance Recycling:** The NL Utilities do not currently offer an appliance recycling program, primarily due to the lack of consistent provincial appliance recycling and Freon removal facilities that prevent a province wide program being offered at this time. This program was added under the Mid and Upper program scenarios, and demonstrates marginal potential in 2020, but with a significant ramp up in the initial years.

- **Home Energy Reports:** This program applied the average savings per home from the 2018 program evaluation report, which is the same values as presented under the Current program savings. The model was set to reach 30%, 40%, and 50% of residential customers in the IIC and LAB systems. Overall, the ratios of the three program scenarios largely follows the program coverage on the basis of the portion of single family and attached homes that receive reports under each scenario. The model did not account for any changes in savings per home or program growth by year, and thus this program is not included in **Figure 3-6** as the savings remain constant in each year.

- **EE Product Rebates:** The EE Rebates Program includes residential lighting and efficient appliance measures (See Appendix E for a full measure list). This program exhibits lower savings in 2020 than were achieved in past years (current value is taken from the last available data in the 2016-2020 Plan). Lighting savings appear to be dropping as compared to past years as the market transforms and saturates and efficient product performance evolves, which may impact the expected uptake and savings as compared to the last NL Utility projections. A possible explanation of the drop in residential lighting savings is provided below in a call-out box.

Residential Lighting Savings

This study shows a notable drop in lighting savings compared to recent CDM program performance. While there are still many sockets in NL that contain halogen or incandescent bulbs, the market is transforming as LEDs become more and more common, which may reduce the opportunities for CDM programs to influence LED bulb purchases. A number of factors lead to uncertainty over LED savings in the coming years.

First, as the market transforms, free ridership could rise in lighting programs. The model applied a 0.76 NTGR for residential lighting, which was taken from the 2017-18 program evaluation. Given the fast pace of lighting transformation this NTGR may drop in the next evaluation. Moreover, due to the changing existing bulb mix in homes, this study used a lower average savings per bulb than past program evaluations (See Appendix E for further details). This is further supported by preliminary result from a recent socket study performed in 2019 which indicates that the saturation of LEDs in NL homes has jumped from 42% in 2018 to 51% in 2019

While the lighting savings in this report may be lower than in past program years, the results still show significant potential, which suggest that residential lighting may still offer a valid, albeit somewhat reduced, contributor to residential CDM program savings in the coming years before possible standards changes are enforced.

- **Heat Pumps:** Currently, NL Utilities offer financing for customers who wish to install heat pumps, but no incentives. This approach was taken due to the high levels of natural adoption already occurring in the market. It should be pointed out that the Heat Pumps program characterized in the analysis would incentivise customers to install a better than standard efficiency model, and only counts the incremental costs and savings as compared to a standard heat pump. Under the Mid and Upper scenarios, the model applied a 50% incentive and increasing barrier reductions. Chapter 5 includes a separate analysis of heat pump adoption in general for customers switching from electric baseboard heating, oil heating or wood stoves. While the savings from this program are insignificant in 2020, **Figure 3-6** reveals that if incentives were offered to efficient heat pumps the program savings could increase steeply between 2020 and 2024 as the program ramps up and customer rates potentially rise.

- **Heating Ventilation and Air-Conditioning (HVAC):** The HVAC program shows a significant bump in savings as a result of the increased customer rates under the mid-rates case. Customer rates have a significant impact on measures with long EULs, such as HVAC equipment. Moreover, the modelled program includes a wide variety of equipment options covering all commercially available opportunities which may have further led to higher savings than the current HVAC CDM program (See the detailed measure list in Appendix E for a full list of HVAC measures in the model).

- **Insulation and Envelope:** As with the HVAC program, the Insulation and Envelope program offers a notable increase in savings potential as compared to the current CDM program, as a result of the increasing customer rates, additional measures being incorporated, and the long EULs for measures in this program. There is little difference between the Lower and Mid program scenarios as the incentive levels were changed only from 60% to 65% respectively under the scenarios. This program does exhibit a significant jump in the Upper scenario, suggesting that investing in enabling strategies could be an effective way to expand the market for envelop upgrades. Moreover, as electricity prices rise and a handful of new measures become cost-effective and are included in the program (such as professional air-sealing and efficient windows), the savings ramp up significantly over the initial five years of the study period.

- **Residential New Construction (NC):** The NL Utilities do not currently offer a Residential NC program, so this program was added only under the Mid and Upper program scenarios. Results indicate that the savings from ENERGY STAR certified homes would be insignificant in 2020, but may grow steadily up to 2024.

END-USE BREAKDOWN AND TOP SAVINGS MEASURES

This section presents a breakdown of residential savings opportunities by end-use and lists the top-saving measures under the Mid program scenario, applying the Mid-rates case. Both the end-use breakdown and the summary of top measures are quantified using averages of annual program savings for the initial five-year period (2020-2024), as well as the average over the later ten-year period (2025-2034). Lifetime savings are presented by end-use and for each of the top measures to provide further context concerning the persistence of savings.

The top electrical savings measures in the residential sector are presented below (**Table 3-1**).They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on an annual savings basis as compared to the lifetime savings basis. The top residential savings measures ranked by total lifetime savings over the full study period is also provided (**Table 3-2**).

A measure's annual program savings will be counted each year towards the CDM program performance, but its impact on cumulative savings will vary greatly depending on each measure's EUL.[26] Presenting the measure

[26] For example, a measure with a 10-year EUL will be incentivized once and generate savings for 10 years, whereas a measure with a 1-year EUL (e.g. Home Energy Report) needs to be incentivized each year to maintain its impact on the cumulative savings at the grid level.

lifetime savings helps to illustrate which savings offer the most long-term benefits, even after an incentive program may be retired.

Table 3-1. Residential Top 10 Efficiency Measures: Mid Program Scenario Under Mid Rates

2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
Home Energy Report	15	**Home Energy Report**	15
Insulation	3.6	**Insulation**	1.9
Thermostats	3.0	**Mini-split Ductless Heat Pump (DMSHP)**	1.4
LED (Interior)	2.1	**Thermostats**	1.3
Low Flow Shower Head	1.4	**Efficient Windows**	1.1
Faucet Aerators	1.4	**Air Sealing**	1.1
Mini-split Ductless Heat Pump (DMSHP)	1.2	**ENERGY STAR Clothes Dryer**	0.66
Heat Recovery Ventilator	1.1	**ENERGY STAR Refrigerators**	0.62
Air Sealing	1.1	**Low Flow Shower Head**	0.59
Freezer Recycling	0.92	**Faucet Aerators**	0.58

Table 3-2. Residential Top 10 Efficiency Measures by Total Lifetime Savings: Mid Program Scenario Under Mid Rates

Measure	Total Lifetime Savings (GWh)
Insulation	978
Thermostats	356
Mini-split Ductless Heat Pump (DMSHP)	288
Efficient Windows	257
Air Sealing	246
Home Energy Report	220
Heat Recovery Ventilator	188
New Construction	155
Low Flow Shower Head	148
Faucet Aerators	145

A breakdown of residential average annual savings by end-use[27] is presented below (**Figure 3-7**) followed by lifetime savings (**Figure 3-8**), for comparison purposes.

Figure 3-7. Residential Annual Savings by End-Use (GWh): Mid Program Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates

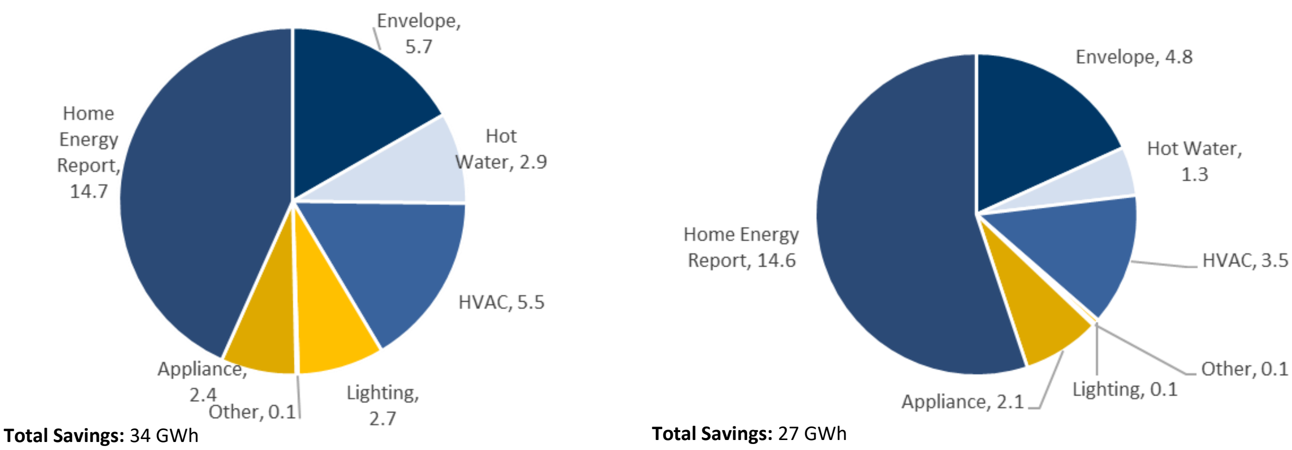
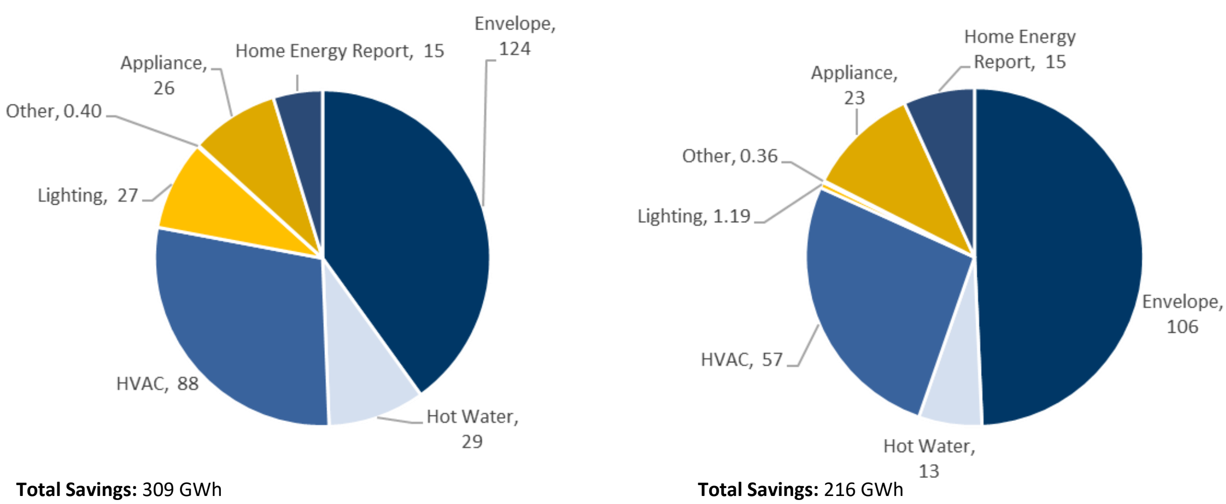


Figure 3-8. Residential Lifetime Electricity Savings by End-Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates



[27] A complete list of the measures included within each end use is provided in Appendix E.

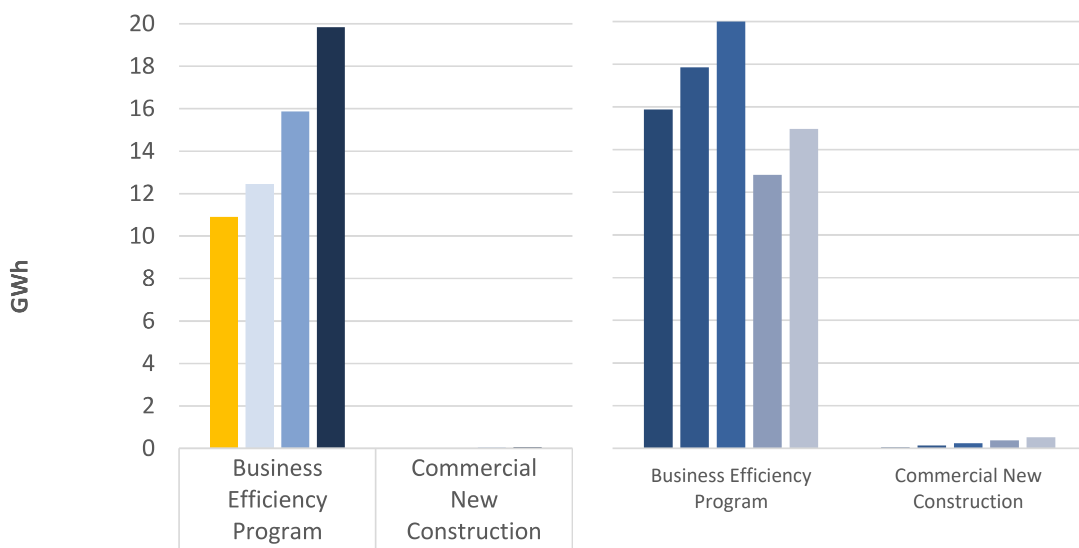
From these results, the following observations can be made:

- **Envelope measures provide significant annual savings and more than half of all lifetime savings by the end of the study period.** Contrary to the Home Energy Reports, envelope measures (with insulation, air sealing and efficient windows leading the group) contribute slightly more than 20% of annual program savings by the end of the study, but due to their long EULs they generate over 40% of lifetime savings in the initial 5 years (2020-2024), and close to 50% in the 2025-2034 period. This end-use shows constant growth in savings throughout the study period. These results demonstrate the value of investing in barrier and cost reducing efforts to promote envelope upgrades in new and existing homes in Newfoundland and Labrador.
- **Lighting measures only provide savings during the first five years.** Due to the assumption that future EISA lighting standards will come into effect in January 2023 (for Standard A-Lamps) and in January 2025 (for Specialty Reflector bulbs), no more savings from replacing A-lamps and reflector lamps with LEDs can be counted towards programs starting on these dates respectively. Overall program savings decline due to the loss of these measures. However, if the announced rollback on applying EISA standards to specialty lamps is enforced, or if the Canada does not adopt the same lighting standards as the US, there could be opportunities to promote efficient lighting in Newfoundland and Labrador homes beyond 2024.
- **As much as 50% of annual savings come from Home Energy Report (behavioural measure)**. This measure offers the single most important source of annual savings across the study period, and increasingly over time, reaching more than 50% of residential savings in the final years of the study. However, this end-use is among the lowest in terms of lifetime savings, due to its 1-year EUL. This means that if the program is discontinued, the savings would not persist in future years.
- **High Efficiency Mini-Split Heat Pumps show increasing savings if included in programs.** Heat pump adoption in NL has been growing considerably in the past few years, and the combination of possible electricity rate increases, and the high penetration of electric heating suggests that this will continue. Offering incentives for customers to adopt higher efficiency heat pump models jumps from the 8th most important saving measure in the first five years to the 5th in the later study years.

COMMERCIAL PROGRAMS ANALYSIS

Below, current commercial program savings[28] are presented alongside modeled savings under each program scenario for 2020 under the Mid-rates case (**Figure 3-9)** for the IIC and LAB systems collectively. Current values are compared for the first year of the study (2020) as CDM program numbers are not available for later years. The evolution of the annual savings for the initial five years under the Mid program scenario (2020-2024) are also presented. The Business Efficiency Program covers all non-residential customers (the commercial and industrial segments in this study) with the exclusion of the transmission-level (Large Industrial segment) customers.

Figure 3-9. Comparison of Commercial Program Savings (Left - 2020) and Program Savings Evolution (Right – Mid Scenario) Under Mid Rates



	Business Efficiency Program	Commercial New Construction
Current Prog.	11	
Lower	12	0.00
Mid	16	0.05
Upper	20	0.08

Note: Current Program savings are derived from either the 2019 CDM Program Plan for 2019, or evaluated program savings from 2017 and/or 2018 where available.

Observation of the above figure reveals the following:

- **Business Efficiency Program:** From the commercial program comparisons, it can be seen that the Business Efficiency Program exhibits a somewhat larger potential in 2020 than in the current plan. This

[28] Current Program savings are derived from recent CDM program evaluation reports or the 2016-2020 Energy Conservation Plan (2015, NL Hydro and NF Power) using 2019 planned savings where recent evaluations were not available.

is largely because the results shown apply the Mid-rates case, which are higher than current customer rates, thereby they increase the efficiency benefits to customers which drives increased adoption. The model was calibrated under the Low-rates case (fully mitigated) and the results are provided in Appendix F. The savings evolution reveals that lighting measures have a significant impact on this program's annual savings, as there is a notable drop in savings in 2023 when new standards for A-lamps are expected to take effect. It should be noted that unlike in the residential lighting, no socket study was available for commercial lighting, so the savings per bulb reflect past evaluation savings.

- **Commercial New Construction (NC):** The NL Utilities do not currently offer a Commercial NC program, so this program was added only under the Mid and Upper program scenarios. Results indicate that the savings will be insignificant in 2020, and despite steady growth up to 2024, the barriers to obtaining LEED and Net-Zero-Energy Ready building certification along with the limited rate of new construction in the province limit the savings for this program.

COMMERCIAL SECTOR END-USE BREAKDOWN AND TOP SAVINGS MEASURES

This section presents a breakdown of commercial savings opportunities by end-use and lists the top-saving measures under the Mid program scenario, applying the Mid-rates case. Both the end-use breakdown and the summary of top measures are quantified using averages of annual program savings for the initial five-year period (2020-2024), as well as the average over the later ten-year period (2025-2034). Lifetime savings are presented by end-use and for each of the top measures to provide further context concerning the persistence of savings.

The top electrical savings measures in the commercial sector are presented below (**Table 3-3**). They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on an annual savings basis as compared to the lifetime savings basis. A measure's annual program savings will be counted each year towards the CDM program performance, but its impact on cumulative savings will vary greatly depending on each measure's EUL.[29] Presenting the measure lifetime savings helps to illustrate which savings offer the most long-term benefits, even after an incentive program may be retired. The top commercial savings measures ranked by total lifetime savings over the full study period is also provided (**Table 3-4)**.

[29] For example, a measure with a 10-year EUL will be incentivized once and generate savings for 10 years, whereas a measure with a 5-year EUL (e.g. Recommissioning and Strategic Energy Management (RCx-SEM)) needs to be incentivized more frequently to maintain its impact on the cumulative savings at the grid level.

Table 3-3. Commercial Top 10 Efficiency Measures: Mid Program Scenario Under Mid Rates

2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
LED (Interior)	11	**LED (Interior)**	1.3
Heat Pumps	0.67	**Heat Pumps**	0.94
HVAC Control	0.61	**HVAC Control**	0.62
HVAC VFD	0.58	**HVAC VFD**	0.60
LED (Exterior)	0.52	**New Construction**	0.53
Low Flow Fixtures	0.35	**RCx-SEM**	0.51
RCx-SEM	0.30	**Food Services**	0.37
New Construction	0.26	**Low Flow Fixtures**	0.35
Lighting Controls (Interior)	0.26	**HVAC Equipment**	0.30
Food Services	0.18	**Insulation**	0.18

Table 3-4. Commercial Top 10 Efficiency Measures by Total Lifetime Savings: Mid Program Scenario 2020-2034 Under Mid Rates

Measure	Sum of Total Lifetime Savings (GWh)
LED (Interior)	867
New Construction	296
Heat Pumps	181
HVAC VFD	133
HVAC Control	94
RCx-SEM	89
Insulation	67
HVAC Equipment	60
Food Services	48
Low Flow Fixtures	39

A breakdown of commercial average annual savings by end-use[30] is presented below (**Figure 3-10**) followed by lifetime savings (**Figure 3-11**), for comparison purposes.

Figure 3-10. Commercial Annual Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates

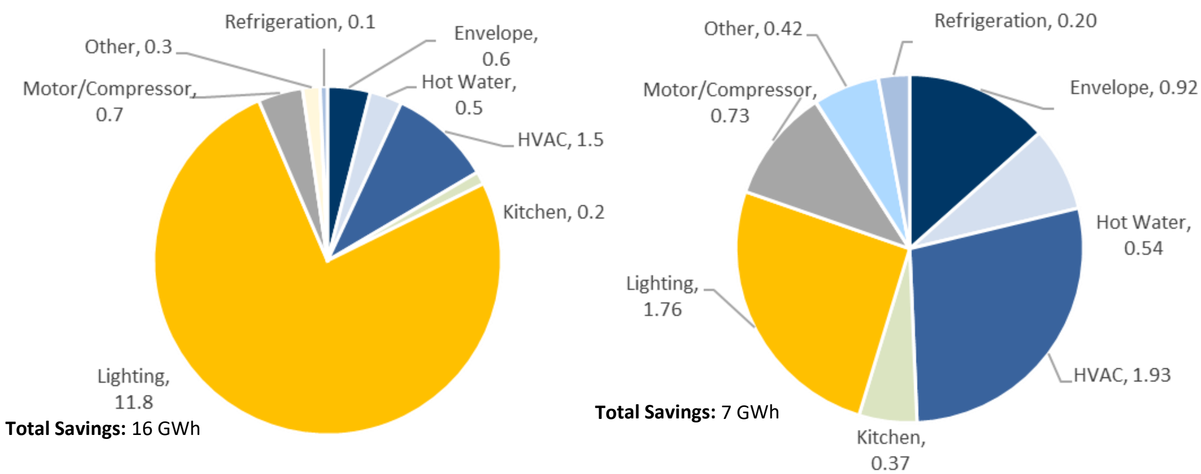
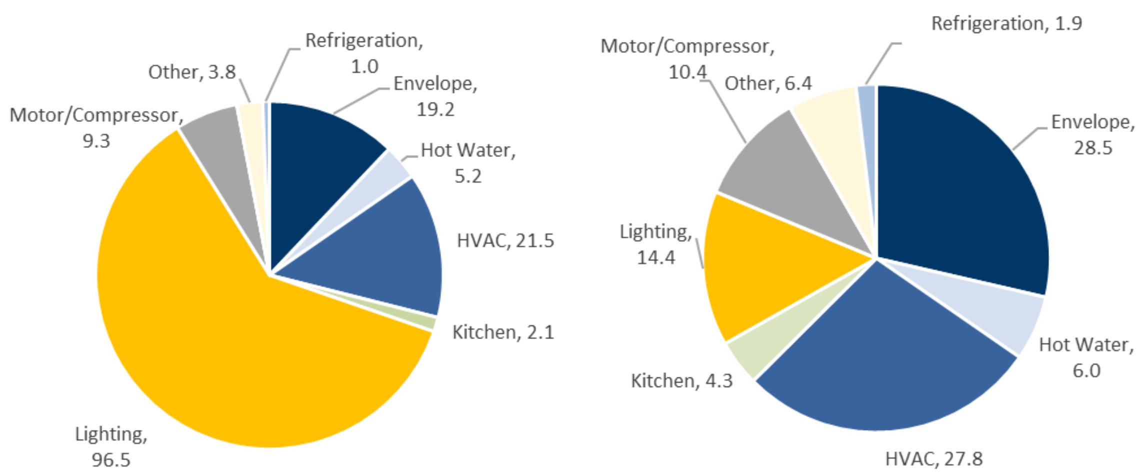


Figure 3-11. Commercial Lifetime Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates



Total Savings: 159 GWh

Total Savings: 100 GWh

[30] A complete list of the measures included within each end use is provided in Appendix E.

From these results, the following observations can be made:

- **Commercial lighting savings dominate in the initial years, but are expected to decline by over 85% in the later years of the study period.** As in the residential sector, the loss of lighting measures due to future EISA lighting standards causes a steep decline in savings. However, LED replacement of lighting equipment not targeted by the standards, such as fluorescent tubes, high bay fixtures and exterior lights, still provide important savings in the later years of the study.
- **HVAC measures presents a leading opportunity for the commercial sector over study period.** With four measures in the top 10 in the latter study years (HVAC Control, HVAC VFD, HVAC Equipment and Heat Pumps), the HVAC end-use shows the second most potential for program savings, starting after EISA standards come into effect (2023), and as a result also shows the second greatest potential in terms of lifetime savings during the later years of the study period (2025-2034). This may justify focusing CDM efforts on this end-use.
- **Envelope measures offer substantial lifetime savings:** While envelope measures do not show up in the top ten annual savings lists, the end-use breakdowns show that envelope savings offer substantial savings over the study period, due to their long EULs compare to other measures.
- **Recommissioning and Strategic Energy Management (RCx-SEM) is a top measure throughout the study period:** As electricity prices continue to rise, and many lighting measures drop out of the potential, the importance of RCx-SEM grows in importance for the commercial sector.
- **While LEED and Net-Zero-Ready New Construction measures offer too few annual savings in the initial years, they emerge as a top 10 measure in the later years, and offer the second highest lifetime savings overall:** The extremely long EUL of new construction measures (35 years) allows them to deliver significant lifetime savings.

INDUSTRIAL CUSTOMER END-USE BREAKDOWN AND TOP SAVINGS MEASURES

This section presents a breakdown of industrial savings opportunities (**excluding Large Industrial segment savings**[31]) by end-use and lists the top-saving measures under the Mid program scenario, applying the Mid-rates case. Both the end-use breakdown and the summary of top measures are quantified using averages of annual program savings for the initial five-year period (2020-2024), as well as the average over the later ten-year period (2025-2034). Lifetime savings are presented by end-use and for each of the top measures to provide further context concerning the persistence of savings.

The top electrical savings measures in the Industrial sector are presented below (**Table 3-5**). They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on an annual savings basis as compared to the lifetime savings basis. Presenting the measure lifetime savings helps to illustrate which savings offer the most long-term benefits, even after an incentive program may be retired. In

[31] Includes savings from Small and Medium Industrials, Fishing and Manufacturing, but excludes savings from Large Industrials which were analysed through a top-down approach and no end-use or equipment saturation data was available.

the following table, the top industrial savings measures by total lifetime savings over the full study period are provided (**Table 3-6**).

Table 3-5. Industrial Top 10 Efficiency Measures: Mid Scenario, 2020-2024 and 2025-2034 Under Mid Rates

2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
Motor Controls	0.65	**Motor Controls**	0.69
LED (Interior)	0.28	**Motor/Compressor**	0.11
HVAC Control	0.086	**Heat Pumps**	0.11
Heat Pumps	0.066	**HVAC Control**	0.090
Low Flow Fixtures	0.064	**RCx-SEM**	0.086
HVAC VFD	0.063	**LED (Interior)**	0.068
Motor/Compressor	0.056	**HVAC VFD**	0.066
RCx-SEM	0.049	**Low Flow Fixtures**	0.064
Refrigeration Heat Recovery	0.038	**Refrigeration Heat Recovery**	0.040
Insulation	0.026	**Insulation**	0.027

Table 3-6. Industrial Top 10 Efficiency Measures by Total Lifetime Savings: Mid Program Scenario Under Mid Rates

Measure	Sum of Total Lifetime Savings (GWh)
Motor Controls	150
LED (Interior)	21
Heat Pumps	20
Motor/Compressor	18
RCx-SEM	15
HVAC VFD	15
HVAC Control	13
Insulation	9.9
Refrigeration Heat Recovery	8.7
Low Flow Fixtures	7.3

A breakdown of industrial average annual savings by end-use is presented below (**Figure 3-12**) followed by lifetime savings (**Figure 3-13**), for comparison purposes.

Figure 3-12. Industrial Annual Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates

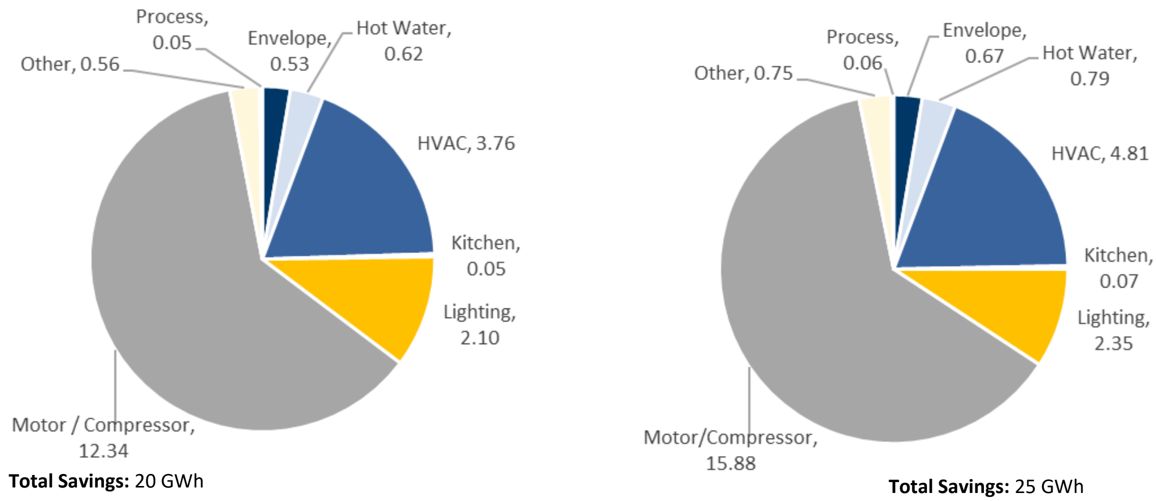
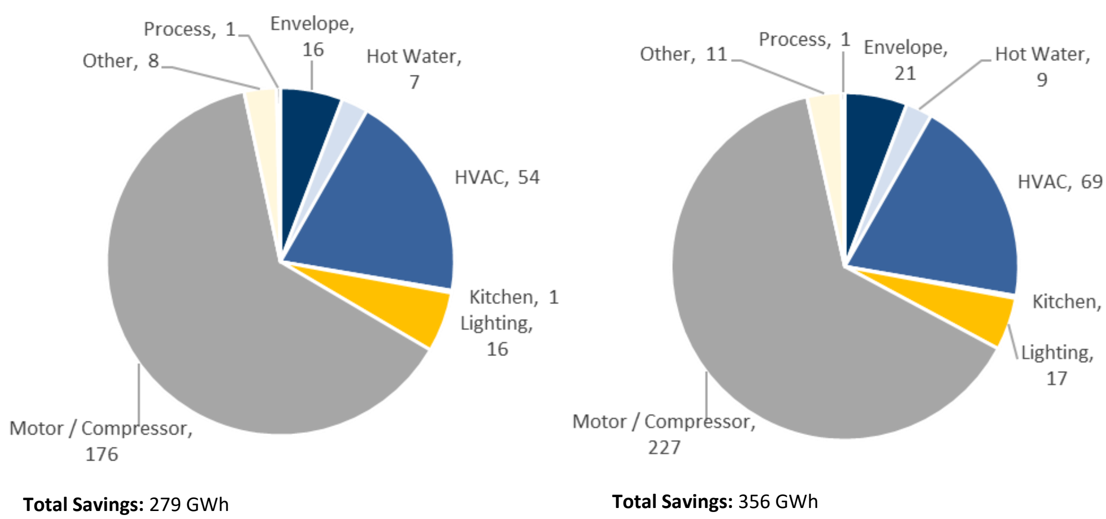


Figure 3-13. Industrial Lifetime Electricity Savings by End Use (GWh): Mid Scenario, 2020-2024 (left) and 2025-2034 (right) Under Mid Rates



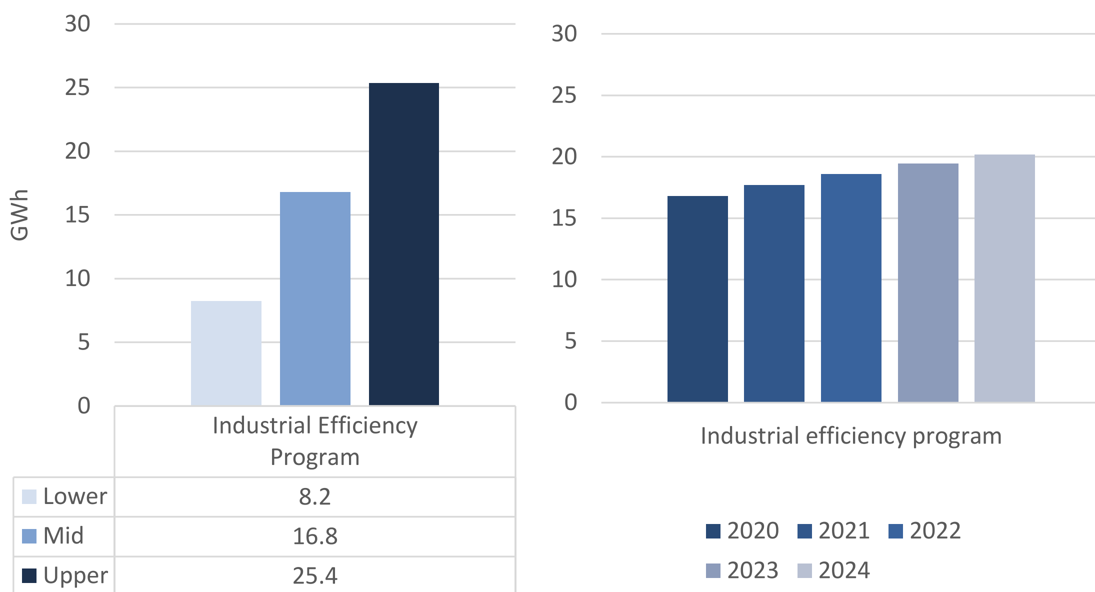
From these results, the following observations can be made:

- **Motors and Compressors dominate the industrial savings over the whole study period on both annual and lifetime terms**: Motor controls and efficient motors offer substantial savings opportunities and are predominant in industrial processes. Although not assessed in this study, presumably these measures would also offer substantial savings potential in the large Industrial segment.
- **HVAC measures present an important opportunity for the industrial sector over the study period.** Efficient heating and ventilation measures also offer significant opportunities in the industrial sector, given the number of facilities that operate year-round and have high annual hours of heating demand.
- **Industrial lighting savings are significant throughout the study period:** Industrial lighting uses few A-Lamp or Reflector bulbs, instead it applies more high-bay and linear lighting, neither of which are impacted by the projected lighting standards updates in 2023 and 2025.

INDUSTRIAL EFFICIENCY PROGRAM

Below, Industrial Efficiency Program savings for large industrial customers are presented under each program scenario for 2020 under the Mid-rates case **(Figure 3-14**) for the IIC and LAB systems collectively. The evolution of the annual savings over the initial five years for the Mid scenario (2020-2024) are also presented. This program covers Hydro's six transmission-level industrial customers which were treated outside of the DEEP model through a top-down analysis (see Appendix E for further details). The other Industrial customer segments savings are captured under the Business Efficiency Program.

Figure 3-14. Comparison of Industrial Efficiency Program Savings (Left – 2020) and Program Savings Evolution (Right – Mid Scenario) Under Mid Rates



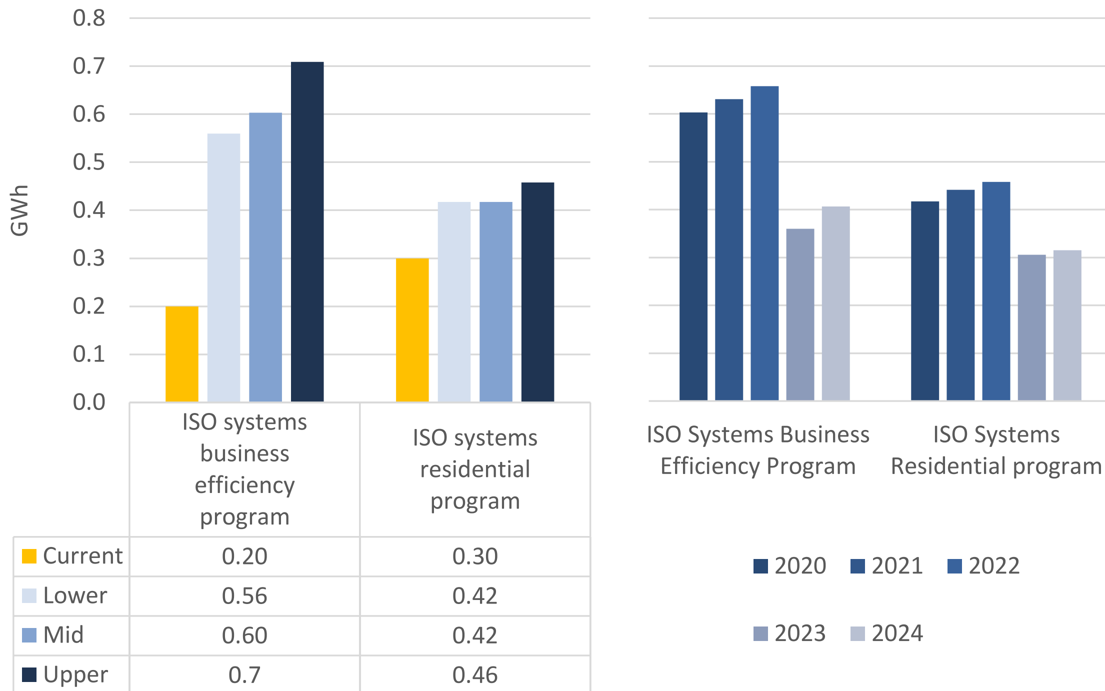
Observation of the above figure reveals the following:

- **Large Industrial program could dominate industrial savings opportunities:** Given the relative size of the energy demand from the six transmission-level customers to the other industrial segments, it is logical that these facilities would offer the most savings opportunities. Unfortunately, the top-down analysis performed for this segment does not provide details on the measures and end-uses that offer the greatest opportunities. Deeper exploration of current energy use at these facilities, and the efficiency performance of installed equipment may prove beneficial for pursuing savings in this important segment.
- **The Industrial programs exhibit steady growth in the initial study years:** The Utilities have offered industrial programs for the past few years, with little uptake, as a result there could be an increase in the savings potentials if the industrial programs begin to gain traction starting in 2020.

ISOLATED SYSTEM PROGRAMS

Below, current ISO system program savings[32] are presented alongside modeled savings under each program scenario for 2020 under the Mid-rates case (**Figure 3-15**). Current values are compared for the first year of the study (2020) as CDM program numbers are not available for later years. The program savings potentials for the initial five years (2020-2024) are also presented to show expected program savings evolutions.

Figure 3-15. Comparison of Isolated Program Savings (Left - 2020) and Program Savings Evolution (Right – Mid Scenario) Under Mid Rates



Observation of the above charts show that the residential program is expected to closely match past program results. However, the commercial program shows the potential for a notable jump in savings. Discussion with NL Hydro indicates that this is well recognized and new enabling strategies are currently being employed to increase savings from the ISO system Business Efficiency Program.

Moreover, the drop in savings for both the commercial and residential programs in 2023 the above figure indicates that much of these savings stem from A-Lamps, which are expected to be subject to new standards starting in 2023.

[32] Current Program savings are derived from recent CDM program evaluation reports or the 2016-2020 Energy Conservation Plan (2015, NL Hydro and NF Power) using 2019 planned savings where recent evaluations were not available.

END-USE SAVINGS AND TOP-10 MEASURES

This section presents a list of the top-saving measures in the ISO systems for both the residential and commercial sectors. The top electrical savings measures in the residential and commercial sectors are presented in the tables below (**Table 3-7** and **Table 3-8**). They are ranked by the average annual savings, and observation of the table shows an important difference in the ranking on a lifetime savings basis. The top residential and commercial savings measures ranked by total lifetime savings over the full study period are also provided (**Table 3-9**).

Table 3-7. ISO System Residential Top 10 Efficiency Measures: Mid Scenario 2020-2024 and 2025-2034 Under Mid Rates

2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
LED (Interior)	0.092	**ENERGY STAR Clothes Dryer**	0.037
Insulation	0.038	**Advanced Smart Strips**	0.024
Advanced Smart Strips	0.038	**Insulation**	0.019
Low Flow Shower Head	0.032	**ENERGY STAR Refrigerators**	0.017
Lighting Controls (Interior)	0.025	**Low Flow Shower Head**	0.013
Thermostats	0.023	**Efficient Windows**	0.012
Freezer Recycling	0.022	**Lighting Controls (Interior)**	0.011
Refrigerator Recycling	0.021	**Thermostats**	0.010
ENERGY START Clothes Dryer	0.020	**Faucet Aerators**	0.007
Faucet Aerators	0.020	**New Construction**	0.006

Table 3-8. ISO System Top 10 Commercial Efficiency Measures: Mid Scenario, 2020-2024 and 2025-2034 Under Mid Rates

2020-2024		2025-2034	
Measure	**Average Annual Savings (GWh)**	**Measure**	**Average Annual Savings (GWh)**
LED (Interior)	0.245	**LED (Interior)**	0.063
LED (Exterior)	0.040	**Motor/Compressor**	0.022
Motor/Compressor	0.017	**LED (Exterior)**	0.018
RCx-SEM	0.013	**RCx-SEM**	0.017
Lighting Controls (Interior)	0.010	**Lighting Controls (Interior)**	0.007
Food Services	0.002	**Food Services**	0.003
Air Sealing	0.002	**Air Sealing**	0.002
HVAC Control	0.002	**HVAC Control**	0.002
Insulation	0.001	**Faucet Aerators**	0.001
Faucet Aerators	0.001	**Insulation**	0.001

From these results, the following observations can be made:

- **Lighting measures dominate both commercial and residential sectors in the ISO system:** As noted, in the next five years lighting measures offer an important savings opportunity in the ISO system.
- **There is a wide diversity of measures in the top savings list, which is a result of almost all measures passing the cost-effective screen for the ISO system:** while customer prices are subsidized, the avoided costs of generation are extremely high in the ISO system, which makes almost all measure pass the TRC screen, making them available for inclusion in CDM programs.

Table 3-9. ISO System Top 10 Efficiency Measures by Lifetime Savings: Mid Scenario, 2020-2024 Under Mid Rates

RESIDENTIAL		COMMERCIAL	
Measure	**Sum of Total Lifetime Savings (GWh)**	**Measure**	**Sum of Total Lifetime Savings (GWh)**
Insulation	0.68	**LED (Interior)**	2.4
ENERGY STAR Clothes Dryer	0.40	**LED (Exterior)**	0.26
LED (Interior)	0.32	**Motor/Compressor**	0.23
Low Flow Shower Head	0.23	**RCx-SEM**	0.19
Advanced Smart Strips	0.20	**Lighting Controls (Interior)**	0.090
Efficient Windows	0.18	**Insulation**	0.030
Thermostats	0.18	**Air Sealing**	0.028
Lighting Controls (Interior)	0.17	**Food Services**	0.025
ENERGY STAR Refrigerators, Most Efficient	0.16	**HVAC Control**	0.017
Faucet Aerators	0.14	**Motor Controls**	0.016

CDM PROGRAMS: KEY TAKE-AWAYS

Based on the results presented in this chapter, the following key take-aways emerge from the CDM Program potential analysis:

- **CDM Program savings in the initial five-year period (2020-2024) range from 0.5% to 1.1% of sales under the Lower to Upper Scenarios (for the IIC + LAB systems):** These ranges put the NL Utility CDM programs squarely in the range of savings being achieved by other Canadian utilities. The Lower program scenario potential would correspond to current CDM program savings, but with a marginal increase in some programs stemming from the expected increase in customer rates as the Muskrat Falls generation facility comes on line. Savings in this period are dominated by substantial lighting savings when summed across all sectors, a trend that is particularly strong in the ISO system.

- **Annual savings potentials are expected to drop by nearly 50% in all systems after 2024:** This is driven by standards changes in lighting primarily, that eliminate savings from A-Lamps and Reflectors (specialty bulbs) which are projected to take effect, or lead to market transformation to LEDs, in 2023 and 2025. Once residential and standard commercial lighting has been removed from the programs, annual savings drop to a lower level. Commercial lighting savings dominate in the initial years, but are expected to decline by over 85% during the study period.

- **Residential sector annual savings are highest for Home Energy Reports, but envelope measures offer the greatest lifetime saving:** As much as 50% of annual savings come from Home Energy Report However, this program offers limited lifetime savings, due to its 1-year EUL. Envelope measures provide significant annual savings and almost half of all lifetime savings by the end of the study period. Contrary to the Home Energy Reports, envelope measures (with insulation, air sealing and efficient windows leading the group) contribute slightly more than 20% of annual program savings by the end of the study, but due to their long EULs they generate close to half of the overall lifetime savings. These results demonstrate the value of investing in barrier and cost reducing efforts to promote envelope upgrades in new and existing homes in Newfoundland and Labrador.

- **Commercial sector savings are initially dominated by lighting, but in the later years HVAC measures presents a leading opportunity.** With four measures in the top 10 in the latter study year (HVAC Control, HVAC VFD, HVAC Equipment and Heat Pumps), the HVAC end-use shows the second most potential for program savings, starting after EISA standards come into effect (2023). It also has the greatest potential in terms of lifetime savings during the entire study period. This may justify focusing CDM efforts on this end-use.

- **Industrial sector savings are driven by the large industrial segment. Motors and compressor measures related to processes dominate the program savings in all periods.** The industrial sector also offers notable lighting savings; as most industrial lighting is not impacted by the new EISA lighting standards. Finally, HVAC measures also offer notable savings for industrial facilities where they have high annual hours of use (24-hour operation or shift work).

4. DEMAND RESPONSE POTENTIAL

The Demand Response (DR) potential was assessed by analysing the ability for electricity rate designs, equipment controls and industrial and commercial curtailment to reduce the annual peak demand in each of the two interconnected systems (IIC and LAB). Because the IIC system includes 90% of all NL electricity customers, demand response programs were first assessed on this system, and then programs that offered significant potential were assessed for expansion to the LAB system customers to determine the impact on that system's annual peak.

To evaluate DR program potential, a standard peak day, which was identified and adjusted to account for load growth and efficiency program impacts over the study period, was created based on NL Utilities' historical hourly annual load curves. The DR potential was also analysed across five years of NL Utilities' historical hourly annual load curves to simulate year-long measure deployment. To ensure that the combined achievable potential results were truly additive in their ability to reduce annual peak loads, combinations of programs were assessed against each system's annual hourly load curve to capture inter-program interactions that could effect the net impact of each program. Further details of this approach are provided in Appendix B.

There are a few key differences between the DR potential assessment and the efficiency potential assessment that are important when reviewing the results:

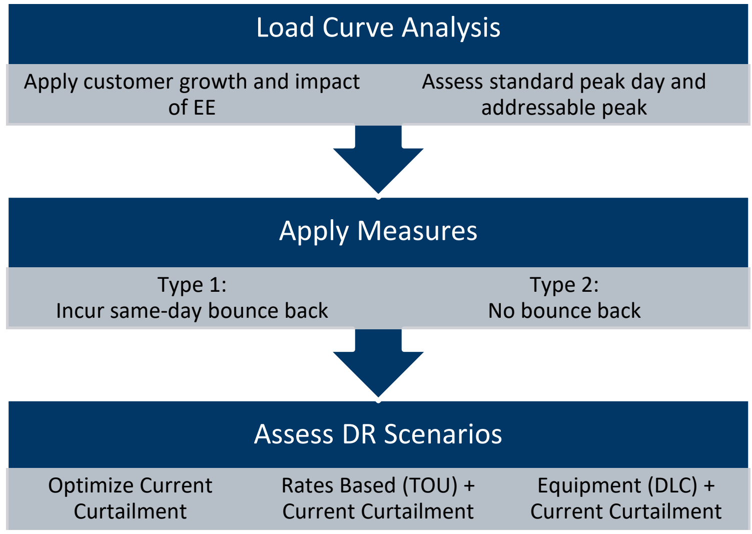
- **The technical and economic potentials were assessed for each measure individually.** Because measures can interact with each-other's ability to create a net reduction in the utility load peak and demand curve profile, technical and economic potentials for DR measures are not considered to be additive, and are therefore not presented in aggregate in this report.
- **The three achievable DR scenario tests represent three program strategies** for actively reducing demand: optimizing current curtailment, expanding to time of use rates, or adding called equipment controls (manual or direct by utility).
- **For each period, the DR potential is expressed as the potential for programs that began in that year**. Unlike many efficiency programs, the DR peak savings only persist as long as the program is active. Factors, such as program roll-out and recruitment of participants may affect the actual achievable peak impacts, especially for newly offered programs.

OVERVIEW OF DEMAND RESPONSE MODELLING APPROACH

Figure 4-1 below presents an overview of the analysis steps applied to assess the DR potential in this study. For each step, system-specific inputs were identified and incorporated into the model. Key to this assessment of the DR potential is the treatment and consideration of the system hourly load curve on the peak day, as well as over the entire years (using historical 8,760 hourly peak load curves). This allows the model to assess the impact of each measure or program on the utility load curve considering key constraints, and the interactive effects among DR programs.

As will be presented in the following chapter, this may lead in some cases to results that are contrary to initial expectations, especially when DR programs such as time-of-use (TOU) rates or equipment direct load control (DLC) are looked at only from the perspective of how they may impact individual customer peak loads, and not the overall interaction with the utility load curve and other DR programs. A more detailed description of the DR modeling approach applied in this study can be found in Appendix B, and Appendix E.

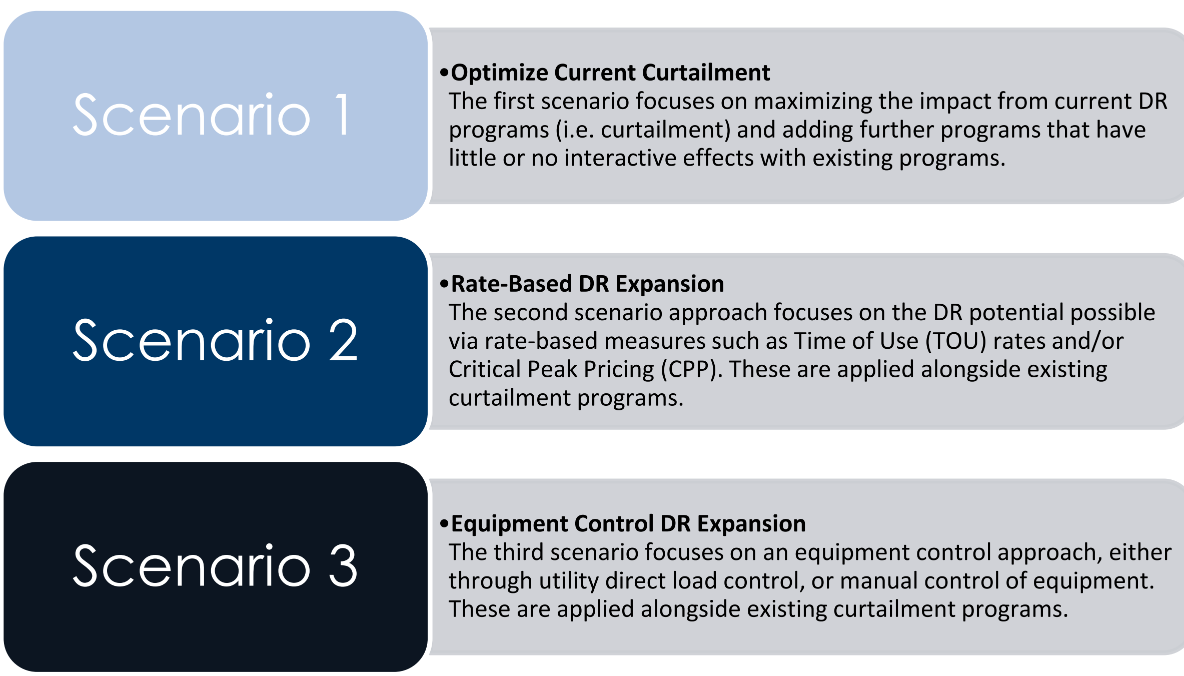
Figure 4-1. Demand Response Potential Assessment Approach



DEMAND RESPONSE SCENARIOS

The study assessed the DR potential under three scenarios corresponding to varied DR approaches or strategies. These scenarios deliver varying benefits covering a range of peak demand impacts. Further details on the specific programs and the related inputs modeled for each scenario are presented in Appendix E and Appendix F.

Figure 4-2. Demand Response Program Scenarios



LOAD CURVE ANALYSIS

The first step in the DR potential analysis was to identify the standard peak day for each of the interconnected systems (IIC and LAB), and apply load growth and efficiency impacts to develop a projection of the peak day 24-hour load curve for each year in the study period. The standard peak day load curve provides a representative load shape that was then used to characterize measures and assess the measure-specific peak demand reduction potentials at the technical and economic potential levels. Achievable peak demand reduction potentials were further verified against five-years of historical hourly load data to assess the impact of annual DR measure deployment constraints.

IIC SYSTEM

The standard peak day for the IIC system was identified as the 97.5th percentile peak load, based on taking the load shape from the top ten peak days in each of five years of historical hourly load data provided by the NL Utilities (**Figure 4-3**). The standard peak day curve was then adjusted to match the projected annual peak demand in each year, as provided by the utilities. **Table 4-1** provides key metrics to describe the peak day shape from a DR potential perspective.

Figure 4-3. IIC Standard Peak Day

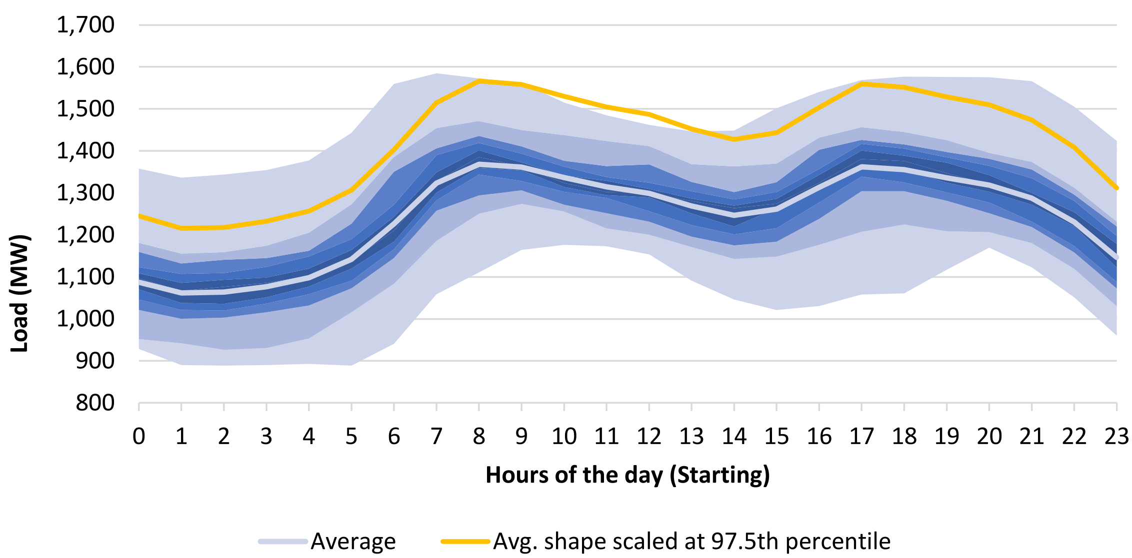


Table 4-1. IIC Standard Peak Day Key Metrics

Peak hours	Peak to Average Difference	Peak to Average Ratio	Number of hours within 10% of peak	Primary End-Use
Morning 7:00 – 10:59 **Evening** 16:00 – 20:59	141 MW	1.10	14 hours	**Morning:** Heating – 67% **Evening:** Heating – 54%

It was found that the IIC system has two extended peaks, which are driven predominantly by residential heating. The narrow margin between the peak and the daily average load indicates that measures with significant bounce-back or pre-charge effects will likely have limited potential to reduce the peak, as they risk creating new peaks by shifting load from one hour to another.

LAB SYSTEM

The standard peak day for the LAB system was identified as the 97.5th percentile peak load, based on taking the load shape from the top ten peak days in each of five years of historical hourly load data provided by the NL Utilities (**Figure 4-4**). The standard peak day curve was then adjusted to match the projected annual peak demand in each year, as provided by the utilities. **Table 4-2** provides key metrics to describe the peak day shape from a DR potential perspective.

Figure 4-4. LAB Standard Peak Day

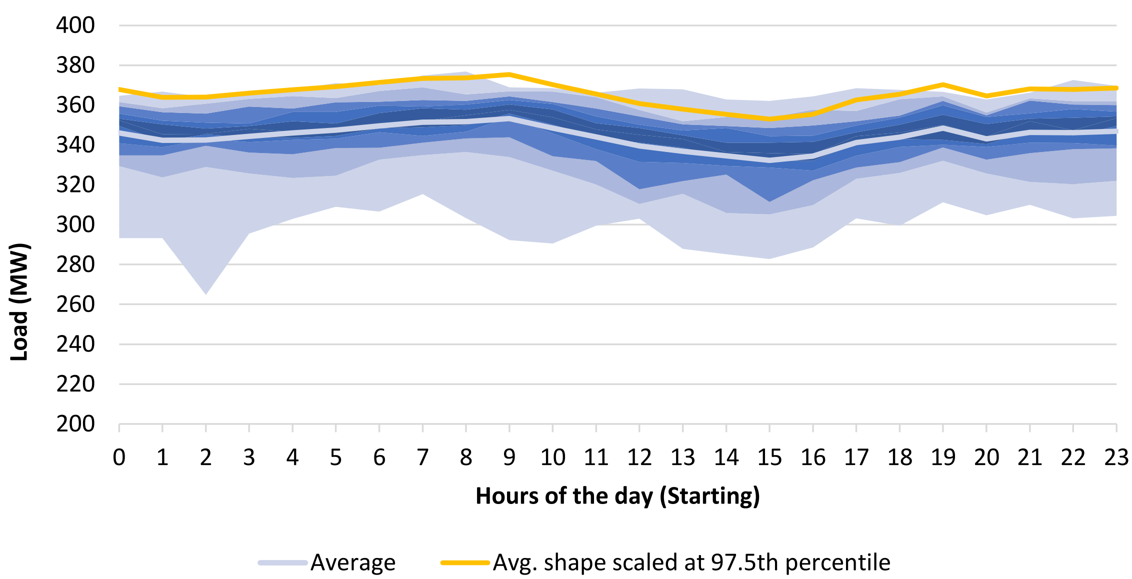


Table 4-2. LAB Standard Peak Day Key Metrics

Peak hours	Peak to Average Difference	Peak to Average Ratio	Number of hours within 10% of peak	Primary End-Use
Morning: 7:00 – 9:59 **Evening:** 18:00 – 20:59	10 MW	1.03	24 hours	**Morning:** Industrial – 52% **Evening:** Industrial – 56%

The results show that LAB system nearly as a perfectly flat load shape. This would be expected to greatly limit measures with bounce-back or pre-charge effects as they risk creating new peaks by shifting load from one hour to another. Type 2 measures, with no bounce-back or pre-charge are more adapted to LAB system.

INDIVIDUAL MEASURE IMPACTS

The analysis applied a range of existing curtailment and new DR programs, assessing the ability of each to address the annual peak on their own, and then assessed the achievable potential in each achievable scenario program grouping to determine the combined effect of each set of programs on the utility load curve. A description of each individual program assessed follows. More details on the specific measures and input assumptions can be found in Appendix E.

It is important to note that in this section all potentials presented are for individual measures when applied to each system load curve. Measures that delivered notable peak load reductions individually were then retained and applied in the achievable scenario analysis to determine their true achievable potential when interacting with other programs and measure combinations, the results of which are presented later in this Chapter.

INDUSTRIAL CURTAILMENT

The NL Utilities have identified a significant amount of industrial curtailment potential through the large industrial customers. This is comprised of self-generation capacity, as well as load curtailment that can be engaged when a DR event is called by the NL Utilities. Collectively the NL Utilities have 133MW of industrial curtailment capacity under contract, which represents 8% of each system peak. A further 18MW of potential has been identified by the Utilities but is not yet included under the existing contracts. A summary of the industrial curtailment potential is presented below in **Table 4-3** below.

Table 4-3. Large industrial under curtailment program

Provider (System)	Contracted Capacity	Assessed Potential	Constraints to Curtailment Contract
Corner Brook (IIC)	105 MW	105 MW	*Period:* 4 to 6 hours, *Request:* 2 per day max, 60 per year, *Total period:* 250 h
Vale – Generation (IIC)	8 MW	8 MW	*Period:* up to 6 hours, *Request:* 2 per day max, 20 per year, *Total period:* 100 h
Vale – Curtailment (IIC)	12 MW	12 MW	*Period:* 3 to 6 hours, *Request:* 2 per day max, 10 per year, *Total period:* 50 h
IOC (LAB)	30 MW	8 MW	No yet completely defined. Corner Brook constraints were used for the purpose of this analysis.
Total (Large Industrials)	**155 MW**	**133MW**	133 MW currently enrolled
Small and Medium Industrials (IIC)	0 MW	14–17 MW	Requires expansion of the industrial curtailment program to these customers.
Small and Medium Industrials (LAB)	0 MW	2–3 MW	Requires expansion of the industrial curtailment program to these customers.

After adjusting the Utility load curves to account for the impact of efficiency programs, and assessing the industrial curtailment in the IIC system over a 5-year period (based on historical 8,760 hour load curve) and accounting for the contract constraints (see **Table 4-3**), it was found that the full 125MW of contracted Industrial Curtailment is directly translated into Achievable Potential.

For the LAB system, when the 30MW Industrial Curtailment contract was applied over a 5-year set of hourly loads, the analysis revealed that the net impact drops to 8MW due to the contract constrains that lead to new peaks occurring at times when the Industrial Curtailment is not available. Further details of this analysis are provided in Appendix F.

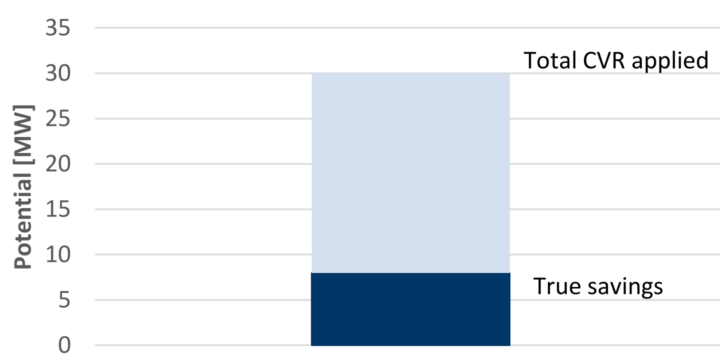
The analysis also explored the potential for expanding industrial curtailment to more small and medium industrial customers would allow a potential increase in demand savings by 16–20 MW. Small and medium industrial curtailment was assumed to focus on a 3-6 hour interruption window with no demand rebound or production shifted to weekends.

CONSERVATION VOLTAGE REDUCTION

NF Power currently reports having the capacity to apply 30MW of conservation voltage reduction (CVR) on the IIC system.[33] The impact of the applied CVR varies depending on the mix of loads within the system. To capture this effect, a CVR factor was calculated that relates the applied CVR capacity to the net load reduction on the system (the amount that persists after intermittent resistive loads have adjusted to the lowered system voltage).

Based on the mix of residential, commercial and industrial loads during the annual winter peak hour, a CVR factor of 0.27 was calculated to represent the CVR impact on the IIC system.[34] This results in 8MW of net CVR potential when 30MW are applied.

Figure 4-5. Conservation Voltage Reduction – Average winter savings



[33] NL Hydro does not currently have any CVR capacity on the LAB system.

[34] CVR factors were assessed from "Measuring the efficiency of voltage reduction at Hydro-Québec distribution", S. Lefebvre ; G. Gaba ; A-O. Ba ; D. Asber ; A. Ricard ; C. Perreault ; D. Chartrand. IEEE, 2008. Further details found in Appendix E.

COMMERICAL CURTAILMENT

NF Power currently offers a commercial curtailment program that has 11 MW of potential currently enrolled. This is comprised primarily of back-up generators (BUGs), which makes up 10 MW of the total program capacity. One enrolled customer provides a further 1 MW of interruptible loads in their facility. Based on NL commercial end-use survey, 10% of commercial customers would likely have BUGs to supply, on average, 47% of their building load. This leads to a maximum technical potential of 15 MW for the IIC system. It was assumed for this analysis that the current 10 MW of BUGs enrolled represents the full achievable potential, since this portion falls outside of the commercial sector propensity curves applied to determine achievable potentials in the study. Further commercial curtailment was assessed in the model, specifically through manual or automated controls of HVAC and lighting systems in commercial facilities.

Because the questions concerning BUGs in the NL commercial end-use received only ten responses in the LAB system, it was judged to not be statistically representative. Instead, an assumption that 8% of commercial customers would likely have BUGs to supply the heating load of the building was used.[35] The LAB system shows a maximum potential of 3 MW. There was no modification to the maximum potential since there's no commercial curtailment program in place in Labrador.

RATE-BASED MEASURES

The NL Utilities do not currently offer a Time of Use (TOU) rate program or a Critical Peak Pricing (CPP) program. The analysis tested a range of TOU rate designs in the IIC systems, starting with the two-tier and three-tier models presented in the recent NL Hydro marginal cost study.[36] The TOU rates program was characterized as an opt-out program to maximize its potential impact, and various rate designs were assessed against the IIC system curve to determine the optimal TOU rate design to lower the annual peaks. TOU rates were designed to reduce the standard peak day load and were tested over 5 years of historical hourly load data to determine the net impact.

Ultimately a two-tier, 2:1 peak to off-peak TOU rate design, applied to both residential and commercial customers, was found to deliver the highest peak demand reduction potential on the IIC system, when applied in the absence of other DR programs and measures (**Figure 4-6**). The same TOU ratio is applied to both residential and commercial sectors. **Figure 4-6** presents this TOU rate structure as well as the normalized energy redistribution profiles from the TOU demand savings.

In the following TOU figures, bounce-back effects are indicated by the times that the yellow or blue impact lines cross into positive values, which implies an increase in the demand at those times. These account for the times when customers will use more electricity just prior to, or after, the high rates periods. Peak savings times are indicated when the yellow or blue line cross into negative values. These indicate times where customers would use less electricity than their habitual usage to avoid the peak rate periods.

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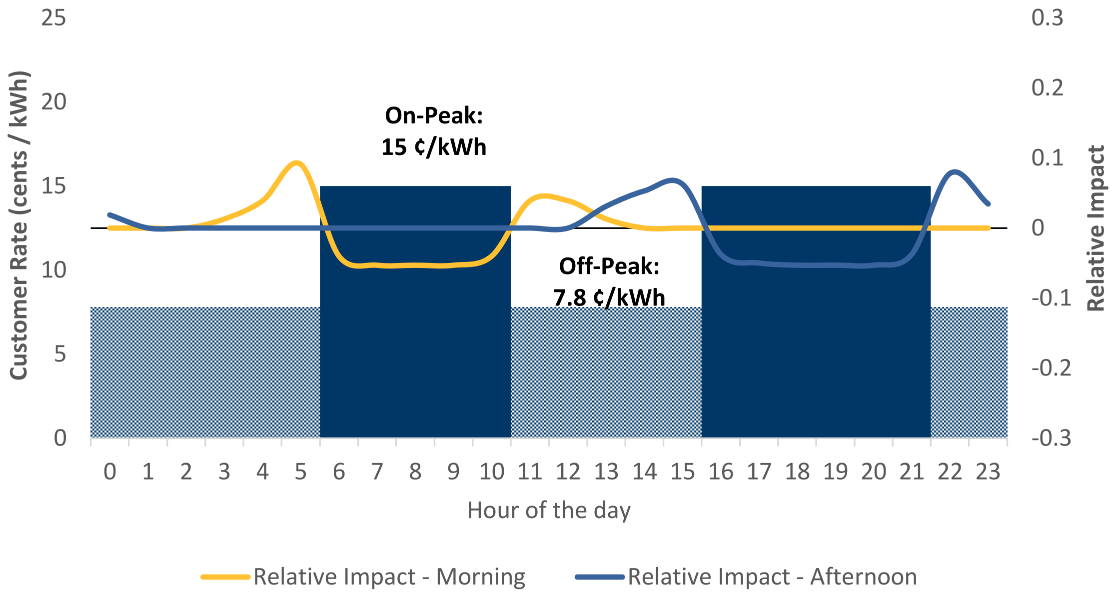
[35] Source: "Commercial Building Energy Consumption Survey", 2012, U.S. Energy Information Agency

[36] Source: "Marginal Cost Study Update – 2018", Nov. 15, 2018, NL Hydro

Figure 4-6. Residential TOU Rate Design and Corresponding Demand Redistribution Effects

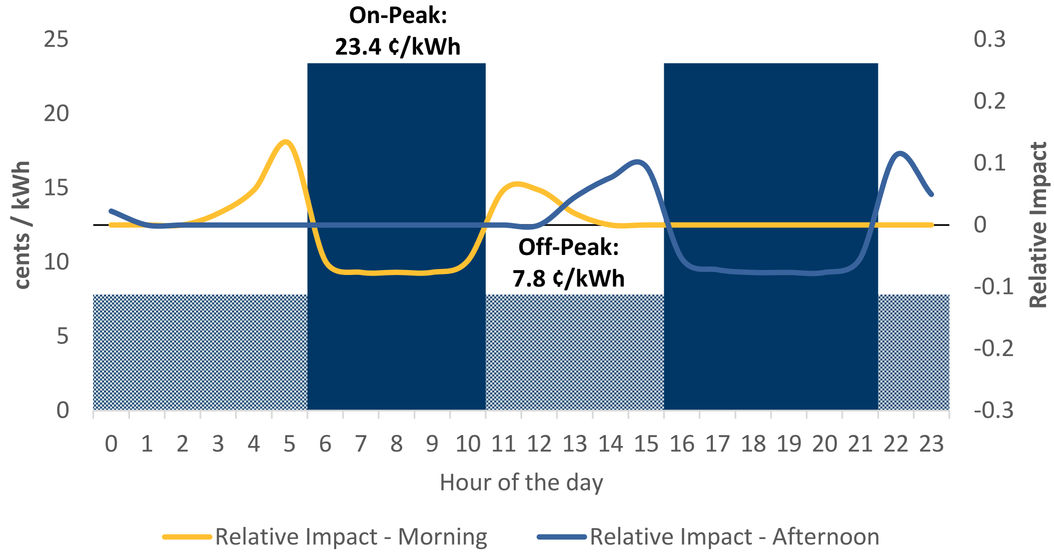


Note: The Residential TOU rate structures are shown here for illustrative purposes. The same on-to off peak ratios would apply to commercial customers applied to all the various commercial rate classes and tiers.

The two-tier 2:1 TOU Rate design was applied to both systems, and while it reduced the peak demand in the IIC by 14MW, it led to a net increase of 7 MW in the LAB system. Overall, the relatively flat peak day load shape in the IIC and LAB systems were an important factor that limited the TOU rates potential. As will be seen later, this impact was further exacerbated when it was found that the application of a TOU Rates program reduced the existing industrial curtailment program potential by more than the TOU rate potential reduction, thereby leading to a net increase in the annual peak. Details on this analysis can be found in Appendix F.

A CPP program was also modelled as it generally exhibits higher demand saving than TOU. The advantage of the CPP program over the TOU program is that it is applied only for specific DR event calls eliciting customer driven load reduction only when needed. On the other hand, TOU rates are applied consistently over the year which reshapes customer behaviour to reduce peak loads. However, for the IIC system it was found that a 3:1 CPP ratio (as presented in **Figure 4-7**) would increase peak demand by 16 MW. Therefore, this measure was not retained for further consideration in the study.

Figure 4-7. Residential CPP Rate Design and Corresponding Demand Redistribution Effects



EQUIPMENT CONTROL MEASURES

An extensive list of DR equipment control measures was considered for the Equipment Control programs (see Appendix E). From the initial list of equipment control measures, only a few were found to offer the potential for reducing the system load when assessed against the IIC and LAB peak day load curves. Given the high avoided costs for both IIC and LAB, most measures are cost-effective.

The analysis revealed that for both systems (IIC and LAB) the relatively flat system load shape on the peak day was a key limiting factor. As a result, the majority of measures tested, actually created new higher peaks. A handful of measures did provide a degree of peak load reduction, when run individually against the utility load curve. These are listed below (**Table 4-3**).

Table 4-3. Effective Equipment Control Measures for IIC System: Economic Potential

RESIDENTIAL			COMMERCIAL		
Measure (End-Use Impact)	**IIC 2034 Potential (MW)**	**LAB 2034 Potential (MW)**	**Measure (End-Use Impact)**	**IIC 2034 Potential (MW)**	**LAB 2034 Potential (MW)**
Setpoint control (Heating)	25	3.5	Setpoint control (Educational – Heating)	2.7	0
Water Heaters (Domestic Hot Water)	26	3.5	Reduction of fresh air flow (HVAC Pump/Fans & Heating)	3.9	0
Clothes Dryer (Plug load)	20	2.0			

Overall, the analysis revealed that:

- **Any of the three residential-sector measures could potentially offer enough savings to sustain a program.** On the other hand, the savings from the commercial measures did not appear to be sufficient to build a new program but may offer potential if added under the existing Commercial Curtailment program. The IIC load shape allows for 26 MW of equipment control demand savings. LAB also show similar results, although with a lower demand saving potential of 4 MW.
- **However, Equipment Controls measures change the utility curve such that they significantly reduce the potential from the existing curtailment programs:** The impact of the equipment program on the utility curve creates peaks that cannot be as effectively addressed by the currently deployed industrial and commercial curtailment. Thus, the net benefit of the equipment controls program is greatly reduced or eliminated in most years, and as a result it does not appear that investing in the additional program infrastructure to offer equipment controls DR would be warranted, given that the same savings could be achieved using currently enrolled curtailment.

DUAL-FUEL HEATING

The potential for Dual Fuel heating was assessed by applying it to homes and businesses with existing central electric heating systems. This program entails installing a back-up oil heater in buildings with central electric heating, along with controls that allow the NL Utilities to switch the heating system from the electric to the oil-fired system during DR events. This measure does not exhibit any bounce-back effects, and was found to offer significant potential when applied against the utility load curves in both systems. Two program options were assessed, one that placed a constraint of 12 DR event calls per year, and one unconstrained option where the NL Utilities can call on the oil-fired heating systems as many times and for as much duration as needed to reduce peaks (**Table 4-4**). Dual-fuel potential is divided between the residential (43%) and commercial (57%) sectors.

Table 4-4. Dual-Fuel Heating Potential by System (2034)

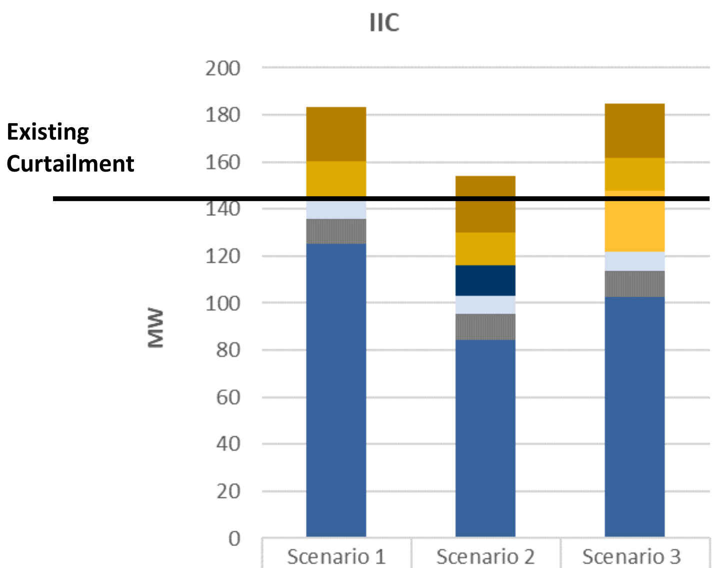
	Potential with Constraints	Unconstrained Potential
IIC Dual Fuel Potential	23 MW	72 MW
LAB Dual Fuel Potential	4.6 MW	14 MW

The constrained Dual-Fuel program potential was retained for further assessment in the achievable potential assessment, as it offers a balance between encouraging peak load reduction, without switching a significant portion of electric heating consumption to oil heating.

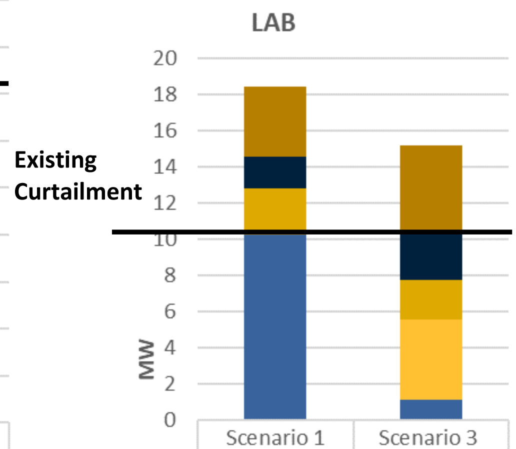
ACHIEVABLE POTENTIAL RESULTS

The overall achievable potential in each system is presented below (**Figure 4-8** and **Table 4-5**). It highlights each achievable scenarios' overall peak load reduction potential when all the constituent programs are assessed together against the utility load curve, accounting for the combined interactions among programs. A line indicating the potential from existing commercial and industrial curtailment and CVR (IIC only), is also indicated for comparison.

Figure 4-8. Demand Response Potential[37] (2034)



	Scenario 1	Scenario 2	Scenario 3
Dual-Fuel	23	24	23
Small/Med Industrials	16	14	14
Equipment	0	0	26
TOU	0	13	0
CVR	8	8	8
Commercial Curtailment	11	11	11
Large Industrials	125	84	103



	Scenario 1	Scenario 3
Dual-Fuel	4	5
BUGs	2	3
Small/Med Industrials	3	2
Equipment	0	4
Large Industrials	10	1

[37] Since dynamic rates have a negative impact on LAB system, Scenario 2 is not present in the LAB analysis. The following sections and Appendix F contain more details on dynamic rates and their impacts on LAB and IIC systems.

Table 4-5. Existing Curtailment and Scenarios Comparison (2034)

System	Existing potential	Scenario 1:	Scenario 2:	Scenario 3:
IIC	144	183	154	185
LAB	10	19	19[38]	15
Total	**154**	**202**	**173**	**200**

From the above results the following conclusions can be drawn:

- **Scenario 1 - Optimizing the Existing Curtailment is the most advantageous scenario for both systems:** Scenario 1 offers the most potential in almost all years for both IIC and LAB systems. The focus on the existing curtailment approaches carries the least degree of program complexity and cost when compared to scenarios 2 and 3 that would require adding the program infrastructure for TOU Rates, CPP and equipment direct load controls respectively.

- **In the IIC systems there is little benefit, or even a reduction in peak reduction benefits, by adding measures that incur significant bounce back effects:** Under Scenario 2 in the IIC system, the overall potential actually drops when the optimally designed TOU rates program is added to the mix of programs as it undermines the ability for the Industrial Curtailment program by creating new, choppier peaks in the load curve (further details on this analysis are provided in Appendix F). Scenario 3 in the IIC system does yield a marginally higher overall potential (2MW higher). However, this net increase is much smaller than the 26MW peak reduction from the Equipment Controls program, because the Equipment Controls program also undermines the Industrial Curtailment program potential.

- **In the LAB system focusing on the current Industrial Curtailment also offers the higher potential:** In the LAB system, the optimized two-tier, 2:1 TOU rate design led to a net increase on the peak when applied alone, and thus Scenario 2 was not assessed. When the Equipment Controls program was added, the shifted peaks once again undermined the ability of the Industrial Curtailment to reduce peak loads, resulting in an overall lowering of the peak demand reduction potential as compared to Scenario 1.

- **Industrial Curtailment provides the bulk of the peak reduction potential, and there is a great deal of potential already under contract. Further study is required to determine if adjusting the Industrial contracts may allow the Utilities to leverage TOU Rates, CPP or Equipment Controls Program Potentials:** Expanding industrial curtailment may offer potential to pursue further demand response. It is also important to note, that all Industrial Curtailment was applied in the analysis under the current contract constraints. Considering the apparent conflict between the TOU Rates, CPP and Equipment programs and the Industrial Curtailment, it may be possible to renegotiate the Industrial Curtailment contracts to cover more facilities, extend over longer periods of time, or allow for more events per year.

[38] Using best scenario (Scenario 1: Optimise Existing Curtailment) since TOU is not improving peak demand savings for LAB system.

With fewer constraints on the Industrial Curtailment, it may be possible for the TOU Rates, CPP and Equipment Controls program to add incremental peak demand reduction over and above the current program scenario potentials. The Utilities will explore this possibility in another study.

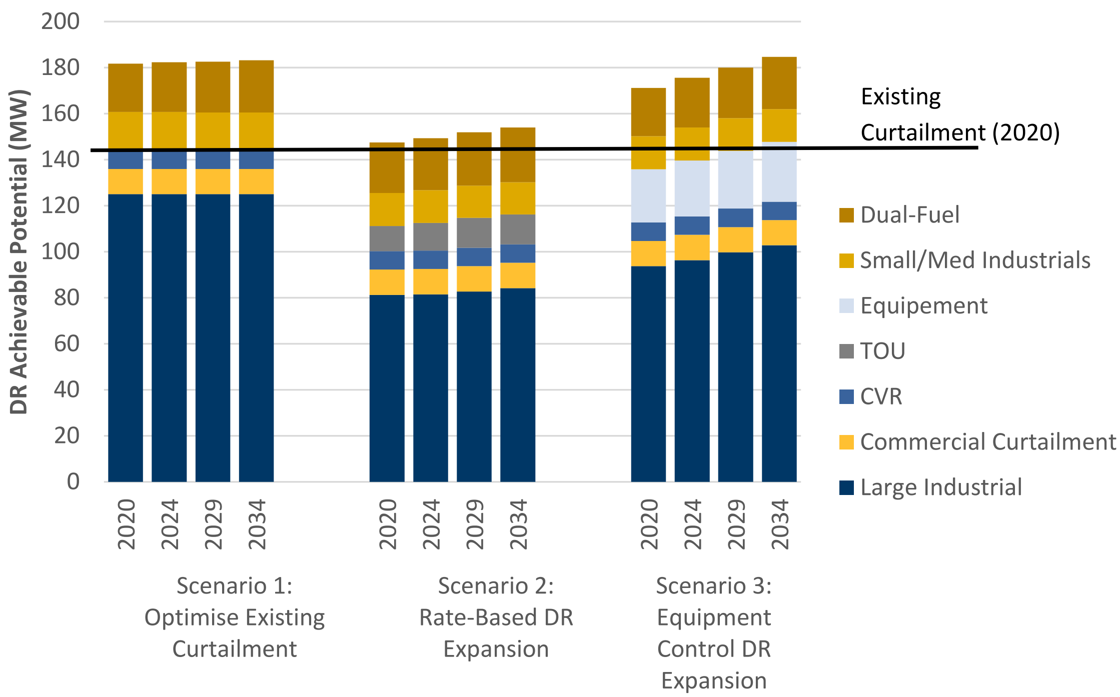
Additional DR Potential is Constrained by the Current DR Programs and Flat Utility Load Curve

Our analysis shows that NL's high avoided costs of capacity allow for many DR measures to be cost-effective when assessed individually. However, the flat utility load shape limits additional potential for any measures with rebound effects when they are run alongside existing curtailment program. This is because the current Industrial Curtailment contracts are generally constrained to 4-6 hour windows, twice a day, based on the current utility peak load profiles (morning and evening). When TOU Rates, CPP and Equipment Controls are added to the program mix, they tend to reduce the existing morning and evening peak, but create three new and sharper peaks: early morning, mid-day, and late night. As a result, the Industrial Curtailment program is not able to effectively address the altered peak day load curve, thereby reducing its overall effectiveness. This means that any additional potential is highly constrained by the load shape, rather than the program cost-effectiveness or market size.

IIC: DEMAND RESPONSE ACHIEVABLE POTENTIAL SAVINGS

The three DR achievable potential scenarios were assessed, each including the measures and programs that fit the scenario DR strategy, lowered peak demand, and were found to achieve a PACT result of greater than or equal to 1.0. **Figure 4-9** presents achievable potential through each scenario, but does not account for program ramp-up for new programs. Further details on program ramp up and costs can be found in Appendix F.

Figure 4-9. IIC Achievable Peak Savings Scenario Results Based on Program Start Year



SCENARIO 1: OPTIMISE EXISTING CURTAILMENT

Currently the NL Utilities have 125 MW enrolled under a large industrial curtailment program in the IIC system, which represents a little above 60% of the coincident peak load from this segment. The analysis assumed that further enrollment of industrial curtailment could be achieved and assessed the degree to which further enrollment would reduce the utility peak.

- **Expanding small and medium industrial customer participation in curtailment programs may offer a streamlined approach to achieve significant peak demand savings:** To further increase potential, enrollment can be expanded among the remaining industrial customers, including small and medium industrials. This approach alone could offer as much peak load savings as the multi-sector approaches assessed in the other scenarios. Under the Industrial Only scenario, around 70% of the industrial customer peak load would be curtailed. Other jurisdictions achieved an upper limit of large industrial around 80%.

- **Additional Potential can be achieved through a Dual-Fuel Program:** Dual-Fuel heating for residential and commercial customers who currently have central electric heating could offer an additional potential of up to 24 MW of peak demand reduction.

- **Further study may be warranted to determine the degree of enrollment possible among industrial customers:** The industrial segment technical potential was determined based on a high-level assumption that NL Utilities have already enrolled key large industrial curtailment and applying professional judgement to the portion of additional small and medium industrial curtailable load that could be achievable based on previous assessments performed in Atlantic Canada. NL Utilities may wish to further assess the costs and feasibility of achieving the levels of large industrial segment enrollment in DR programs, and perform a comparative analysis of the costs and reliability of these peak demand reductions vis-à-vis other high potential opportunities, such as residential domestic setpoint control or hot water direct load controls.

SCENARIO 2: RATE-BASED DR EXPANSION

Scenario 2 analysed the achievable potential when rates-based measures are added to the current program mix. This analysis focused on the optimized two-tier, 2:1 TOU rate program described earlier. From this analysis the following is observed:

- **The optimised two-tier 2:1 TOU Rates program applied to all residential and commercial customers offers limited peak reductions:** We assessed TOU savings assuming a high retention in an opt-out program, and a low peak to off-peak ratio (≈2:1). This results in less savings than is achievable under the Equipment Controls and Optimized Current Curtailment only scenarios, as the TOU impacts do not blend well with the current constraints on large industrial programs (notably, Corner Brook Pulp & Paper Ltd.).

- **The TOU rates program changes the utility curve such that it leads to reduced Industrial Curtailment program effectiveness, thereby leading to a net reduction in the overall achievable potential in Scenario 2:** TOU Rates programs applied in the residential and commercial sectors help to flatten the peak day load curve and displace the demand savings from the initial DR windows. This conflicts with the Industrial Curtailment contract constraints thereby reducing the large industrial segment savings potential. Further details and explanation of why this occurs is provided in Appendix F.

SCENARIO 3: EQUIPMENT CONTROL DR EXPANSION

In the third program scenario, the Equipment Control and Dual Fuels programs were added to the existing programs and the overall achievable potential was assessed, leading to the following observations:

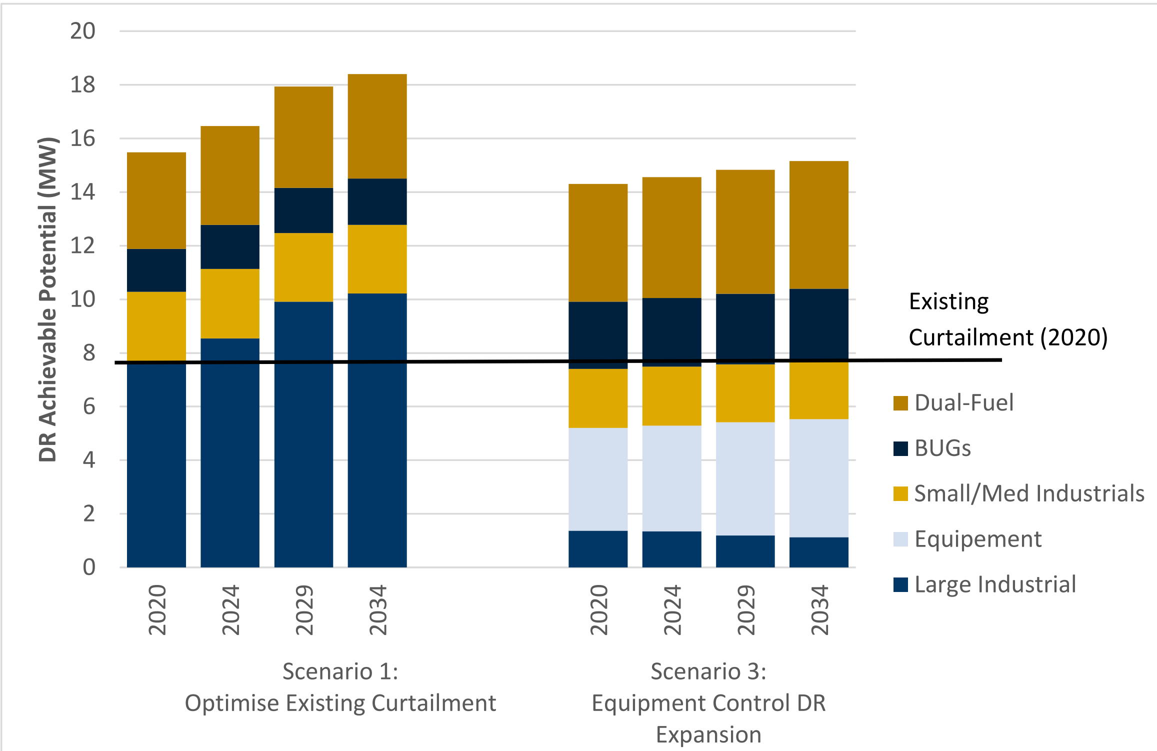
- **The prevalence of electric heating and water heaters allows residential setpoint control and domestic water heater controls may offer the only notable peak load reductions out of all Equipment Control options:** Up to 26 MW of Equipment Control achievable potential was assessed, primarily stemming from direct utility control of electric water heaters and space-heating for residential customers. Water heaters exhibit a high coincident demand with the utility peak (early mornings) and can typically be controlled remotely to reduce demand without disrupting customer comfort. Residential space heating exhibits a lower coincident factor, but the importance of the residential space heating load during peak event allows savings that are close to water heaters.

- **The Equipment Controls program changes the utility curve such that it leads to reduced Industrial Curtailment program effectiveness, thereby leading to a net reduction in the overall achievable potential in Scenario 3:** As with TOU, adding the Equipment Control program undermines the achievable potential from the Industrial Curtailment program, thereby offering a reduction in the overall achievable potential in the early years, and a slight increase by 2034. Given these findings, it is hard to see a justification for investing in Equipment Control program infrastructure, unless adjusting the Industrial Curtailment contracts proves to alter the DR potential of other measures. The Utilities will complete this analysis.

LAB: DEMAND RESPONSE ACHIEVABLE POTENTIAL SAVINGS

The three DR achievable potential scenarios were assessed, each including the measures and programs that fit the scenario DR strategy, lowered peak demand, and were found to achieve a PACT result of greater than or equal to 1.0. For the LAB system, TOU rate design increased the standard peak day load, and therefore it was not retained for further analysis. **Figure 4-10** presents achievable potential through each scenario, but does not account for program ramp-up for new programs. Further details on program ramp up and costs can be found in Appendix F.

Figure 4-10. LAB Achievable Peak Savings Scenario Results Based on Program Start Year



SCENARIO 1: OPTIMISE EXISTING CURTAILMENT

Currently LAB system has 30 MW enrolled under large industrial curtailment, which represents a little above 15% of the coincident peak load from this segment. The analysis assumed that further enrollment of industrial curtailment could be achieved, and then assessed the degree to which further enrollment could be applied against the utility peak.

- **Large industrial curtailment expansion in the LAB is dependent on IOC:** IOC operations are responsible for over 50% of the peak demand in Labrador. NL Utilities already have enrolled IOC in a large industrial curtailment program. As IOC is responsible for such a large share of the system demand, it brings challenges to system load management. Communication with IOC is key in order to be aware of modifications in energy consumption regime.

- **Extending the industrial curtailment program to include the small and medium industrials may offer a streamlined approach to achieve significant peak demand savings:** Similar to IIC, enrollment in curtailment programs can be expanded among the remaining industrial customers, including small and medium industrials. This approach alone could offer as much peak load savings as the multi-sector approaches assessed in the other scenarios. Under the Industrial Only scenario, around 5% of the industrial customer peak load would be curtailed.

- **Adding Dual-Fuel and BUGs Programs could offer further potential:** Adding Dual-Fuel and BUGs programs could offer a further 6 MW of achievable peak load reduction potential. This would ideally be carried out as an extension of the IIC programs, as 6 MW may not be sufficient to justify a program for LAB system customers alone.

SCENARIO 2: RATE-BASED DR EXPANSION

The optimized two-tier, 2:1 TOU Rates program design led to an increase in the annual peak for the LAB system, and therefore Scenario 2 program was not assessed: Based on these results it is concluded that there is little potential for TOU Rates to have a beneficial impact in the LAB system, even if Industrial Curtailment contracts can be adjusted. This scenario was therefore not assessed further.

SCENARIO 3: EQUIPMENT CONTROL DR EXPANSION

Finally, Scenario 3 included an Equipment Controls Program, along with Dual-Fuel and BUGs programs to assess the overall achievable potential from this mix. The follow results emerged:

- **The prevalence of electric heating and water heaters allows residential setpoint control and domestic water heater controls to be the most significant single peak demand reducing measure:** Around 80% of residential heating systems and water heaters in the LAB system are electric-powered. The potential from equipment control is limited by LAB load shape, but equipment control from IIC could be extended to LAB, offering 4 MW of achievable potential peak load reductions.

- **Adding the Equipment Controls Program undermines the current industrial curtailment potential, leading to an overall reduction in the achievable potential as compared to Scenario 1:** As for IIC, equipment program generally creates a negative impact on industrial curtailment, reducing its net peak load reduction impact from 8 MW to 1 MW in 2020. Since the IOC curtailment contract constraints have not yet been established, NL Hydro may want to request longer curtailment event durations than are currently applied in the IIC contracts, thereby minimizing the negative interactions with a possible Equipment Control program in the future.

DR POTENTIAL: KEY TAKE-AWAYS

Based on the results of assessing the DR potential from three program scenarios, there is an apparent 202 MW of demand response potential in the LAB and IIC systems, representing 9.2% of the annual peak load. Much of this potential is already being accessed through the existing Industrial and Commercial Programs and CVR (IIC only), but this study assessed that a further 48 MW may be possible through existing program expansion, and adding a Dual-Fuel heating program for residential and commercial customers with central electric heating.

Table 4-6. Existing Curtailment and Scenarios Comparison (2034)

System	Existing potential	Scenario 1:	Scenario 2:	Scenario 3:
IIC	144	183	154	185
LAB	10	19	19[39]	15
Total	**154**	**202**	**173**	**200**

While there is a limited pool of DR potential assessments conducted for winter-peaking utility DR programs, a handful of studies were identified to benchmark the DR potential assessment for Newfoundland and Labrador (**Table 4-7** below).

Table 4-7. Benchmarking Newfoundland and Labrador DR Potential to Other Jurisdictions

	Newfoundland and Labrador (IIC and LAB combined)	Michigan [40]	Northwest Power & Cons. Council[41]	Puget Sound Energy[42]
Potential as a portion of Peak Load	10.4% (Winter peak) (9.2% in existing curtailment)	4.4%-7.7% (Summer peak)	8.8% (Winter peak)	3.7% (Winter peak)
Avoided Costs	$430 / kW	$140 / kW	n/a	$290 / kW

[39] Using best scenario (Scenario 1: Optimise Existing Curtailment) since TOU is not improving peak demand savings for LAB system.

[40] State of Michigan Demand Response Potential Study, AEG (2017).

[41] Assessing Demand Response (DR) Program Potential for The Seventh Power Plan, Navigant (2014).

[42] Puget Sound Energy Demand Response Potential Assessment (2017)

Based on the findings in this report three key take-aways emerge:

- **Existing industrial curtailment contracts place Newfoundland and Labrador at the high end of achievable range when benchmarked against other jurisdictions:** The Industrial Curtailment program has significant enrolled capacity that appears to be well suited to reducing peak loads on the IIC system in particular. Further potential may exist to expand this program among more Small and Medium industrial customers as well. A dual-fuel heating program for residential and commercial customers could also add notably to the DR potential in both systems.

- **Newfoundland and Labrador's relatively flat peak-day load shape limits DR potential in residential and commercial buildings:** Utilities that experience peak demand resulting from electric resistance heating typically exhibit high inter-seasonal and day-to-day variation, but the load curve on the actual peak days tends to be relatively flat compared to summer peaking utility load curves. This limits the ability for measures that tend to shift loads to other times of the day, like TOU rates, water heating and HVAC controls, to reduce peak demand, as they can quickly create a new peak from the bounce-back demand experienced after the DR event. Our results indicate that this limits the potential from residential and commercial buildings to just 23 MW, which represents just 1.5% of the annual peak load. Moreover, an equipment control program could negatively impact the potential from industrial curtailment, thereby reducing or eliminating its net benefit to the system. Instead measures such as dual-fuel heating or activating BUGs, which have no rebound peak effects, may provide the best option to include commercial and residential customers in DR programs.

- **While TOU Rates and Equipment Control programs did not appear to offer additional DR potential, adjustments to the existing Industrial Curtailment programs, incorporating more aggressive EV adoption peak load impacts, or adding the Fuel Switching load curve impacts, all may alter conditions such that TOU Rates, CPP and/or Equipment Controls could become effective in the future:** Changes to the utility load curve or to the constraints applied in other programs have significantly impacted the interactions among programs. For example, if the NL Utilities are able to negotiate Industrial Curtailment contracts with longer DR event durations, it may be possible that TOU Rates, CPP and Equipment Program could offer additional potential as compared to the results presented herein. The Utilities will undertake a study to complete this analysis.

Overall, it appears that maintaining the utilities focus on industrial and commercial curtailment is the best option to optimize the DR achievable potential in NL.

Consideration of Curtailment Flexibility and Further Integration of EV Adoption and Fuel Switching Impact

Increased flexibility for the industrial curtailment contracts could increase the potential from other programs. Further analysis of this potential will be undertaken by the Utilities. It should also be noted that the results presented in study indicate that Fuel Switching and EV Adoption could significantly alter the utility load curve shapes, which may create an opening for the TOU Rates, CPP and Equipment Controls programs to add further peak load reduction potentials. As the needed information becomes available, the Utilities will conduct further assessments.

5. FUEL SWITCHING POTENTIAL

A fuel switching analysis was conducted to assess how many households and businesses can be expected to replace or supplement oil- and wood-fired space heating and domestic hot water (DHW) heating systems with electric heat pump systems under various levels of incentives. The analysis tests three scenarios – one without any incentives (Lower) and two with various levels of incentives (Mid, Upper). The latter two scenarios provide financial incentives to reduce the upfront costs associated with fuel switching (e.g. the incremental cost of buying a central air source heat pump instead of an oil furnace or the full cost of adding a ductless mini-split heat pump to an existing heat system). The incentive scenarios also reduce barrier levels in the model to simulate education and outreach efforts that make fuel switching less daunting to consumers. **Figure 5-1** describes each scenario.

Figure 5-1. Fuel Switching Scenarios Applied in this Study

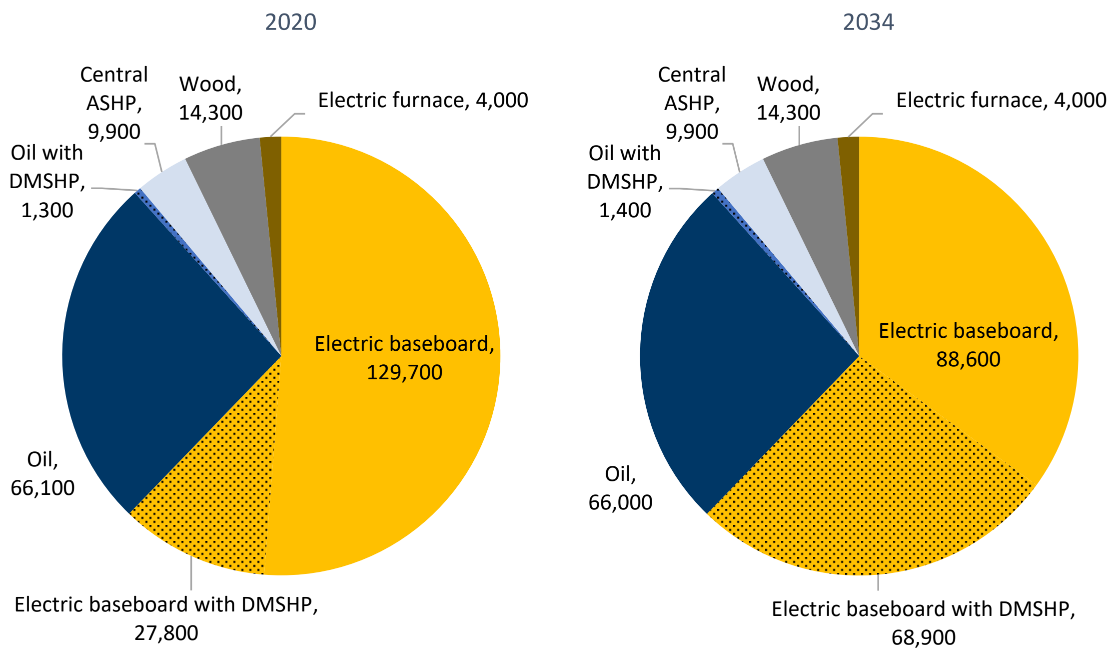
Lower	• **No Incentives** No incentives are offered. Fuel switching is what would be expected without any market intervention.
Mid	• **35% Incentive** An incentive to cover 35% of the incremental cost of the measure is applied, **plus a ½ step reduction in barrier levels**.
Upper	• **70% Incentive** An incentive to cover 70% of the incremental cost of the measure is applied, **plus a full step reduction in barrier levels.**

For each scenario, the analysis assumes Mid-rates and no carbon tax applied to fuel oil for heating. While the adoption of DMSHPs by electric baseboard households is characterized as part of the analysis, the measure **does not receive incentives under any scenario** since there is significant natural adoption of DMSHPs by these households already**.** Appendix C describes the fuel switching modelling methodology in detail. Details on the input and assumptions behind the analysis presented in this chapter can be found in Appendix E, and detailed results are included in Appendix F. The remainder of this chapter describes the results of the analysis.

LOWER SCENARIO – NO UTILITY INCENTIVES

Under the Lower scenario, where no incentives are offered to encourage oil and wood heated homes to switch to electric heat pumps, there is little to no expected fuel switching in both residential and commercial sectors. The only significant change is in residential households with existing electric baseboard heating. Of these homes, an additional 41,000 households (approximately 16% of all households) are expected to add DMSHPs to their baseboard heating systems between 2020 and 2034. In comparison, roughly 100 additional households with oil heating are projected to add DMSHPs, and no homes with wood heating adopt heat pumps. No households completely replace their heating systems with central air source heat pumps (ASHP). Additionally, almost no households and businesses with oil-fired domestic water heating would be expected to switch to heat pump water heaters. **Figure 5-2** shows the number of households with various heating systems at the beginning and end of the study period under the Lower scenario.

Figure 5-2. Residential heating systems under business-as-usual conditions (number of households)



The adoption of DMSHP by electric baseboard households leads to significant net energy and demand reductions as shown in **Figure 5-3** and **Figure 5-4**, respectively. By 2034 under the Mid rate scenario, electric sales will be reduced by nearly 140 GWh annually, and peak demand will be reduced by approximately 80 MW. Compared to forecasted electric sales and demand, these represent decreases in sales and demand of approximately 2.1% and 3.8%, respectively. There is a greater proportional impact on demand due to the larger contribution of residential heating load to system-wide peak demand relative to its contribution to system-wide electricity consumption (for assumptions regarding DMSHP peak demand impacts, see Appendix E). Higher electricity rates would likely drive even greater adoption of DMSHP by electric baseboard households leading to larger net energy and demand reductions, while lower rates will reduce adoption.

Figure 5-3. Net energy impact from Heat Pump adoption: Lower Scenario

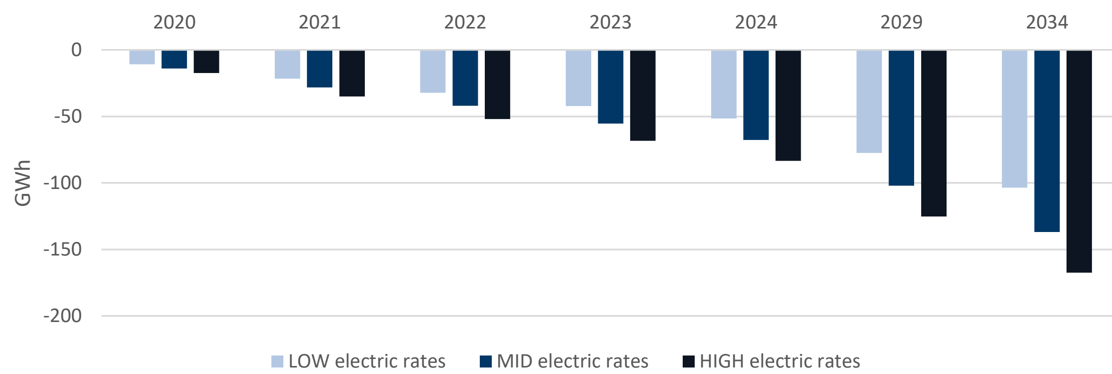
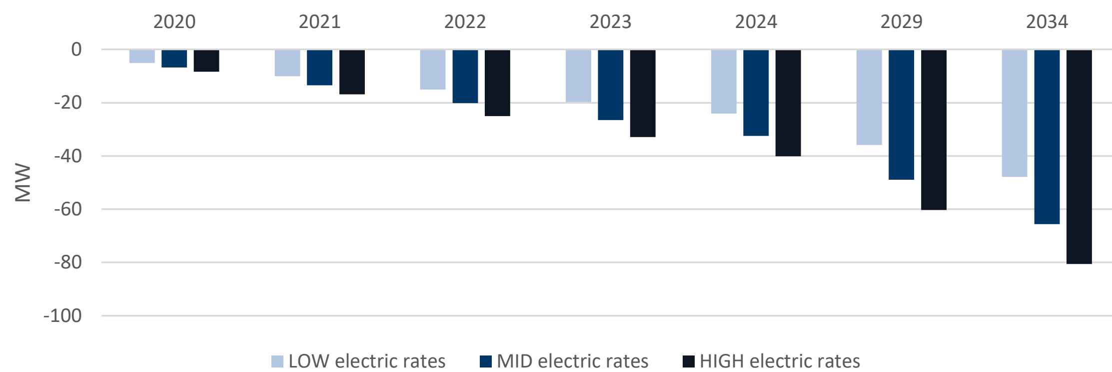


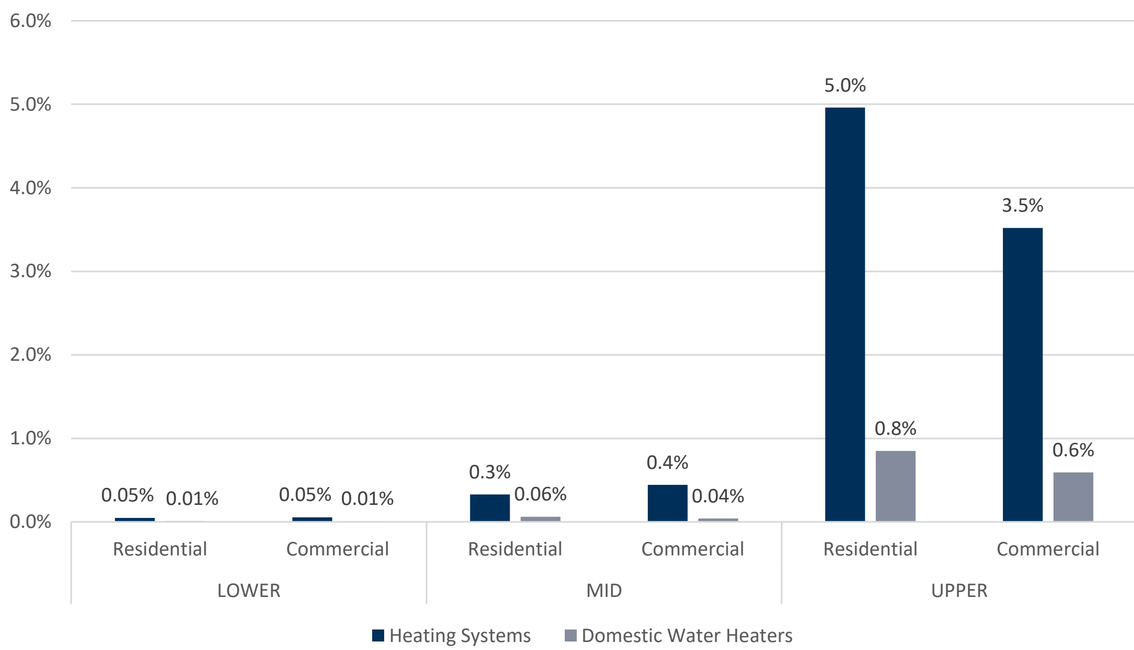
Figure 5-4. Net demand impact from Heat Pump adoption: Lower Scenario



INCENTIVIZING FUEL SWITCHING

Providing incentives for customers to adopt heat pumps for space heating and domestic water heating can help move the market if the incentives are large enough. Overall, the analysis only finds significant fuel switching in the Upper scenario. As shown in **Figure 5-5**, when customers are provided a 70% incentive (plus full-step barrier reduction), approximately 5% of all residential customers and 3.5% of all commercial floor space opt to replace their oil-fired heating system with a central ASHP or add a DMSHP to an existing oil-fired heating system. Since approximately 26.6% of homes and 22.3% of commercial floor space is heated with oil, this translates to roughly 19% of residential households and 16% of commercial floor space with oil heating opting for a heat pump heating system. Less than 1% of all residential and commercial customers replace oil-fired domestic water heaters with heat pump domestic water heaters in the Upper scenario, which translates to approximately 3% and 1% of residential and commercial customers with oil-fired domestic water heating making the switch, respectively.[43]

Figure 5-5. Percent of customers switching from combustible fuel systems to heat pump systems (2034)



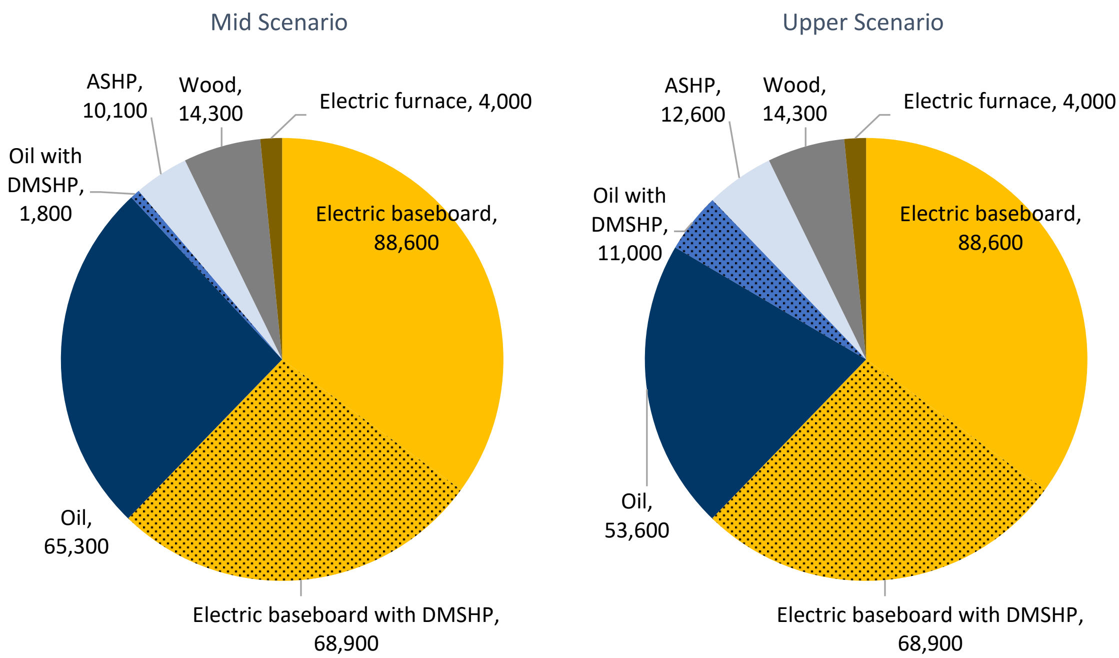
Note: For heating systems, residential adoption is expressed as a percentage of households, while commercial adoption is expressed as a percent of square footage.

[43] Note: Switching from electric resistance to heat pump domestic water heaters is characterized in the CDM portion of this study.

RESIDENTIAL SECTOR

In the residential sector, some households with oil-fired heating systems are likely to adopt heat pumps to replace their current heating system under both incentive scenarios. Households with wood-fired heating systems are not expected to switch to heat pumps primarily due to the low cost of wood fuel compared to electricity. **Figure 5-6** shows the projected breakdown in residential heating systems in 2034 under each scenario. In both cases, more customers are expected to be heated by air source heat pumps (ASHP) or DMSHPs. Under the Mid scenario, approximately 800 households (0.3% of all residential customers) with oil-fired heating adopt heat pumps between 2020 and 2034, while under the Upper scenario, approximately 12,500 oil-fired heating households (5% of all residential customers) adopt heat pumps.

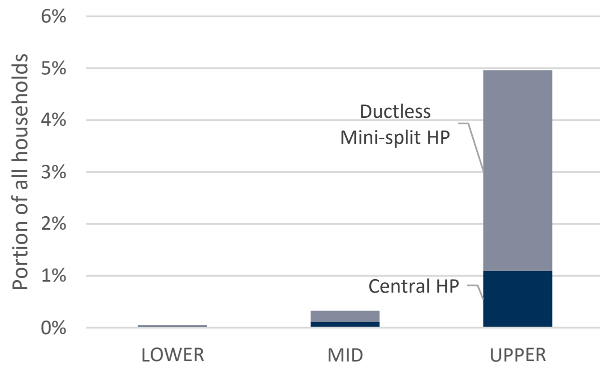
Figure 5-6. Residential heating systems in 2034 under incentive scenarios (number of households)



Note: Incentives are not provided to households with electric baseboard heating under any scenario.

Most households adopting heat pumps choose to add DMSHPs to their existing system over full replacement with a central heat pump (e.g. ASHP). **Figure 5-7** shows the breakdown between the adoption of central heat pumps and DMSHPs.

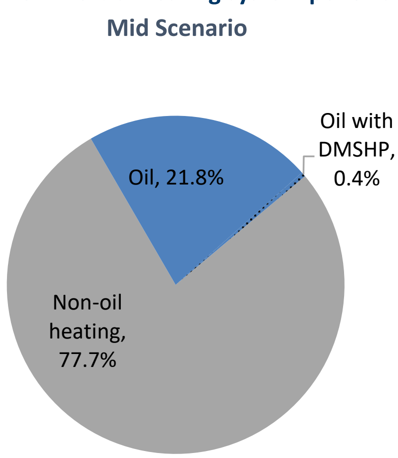
Figure 5-7. Adoption of heat pumps by oil-heated homes, by heat pump technology (2034)

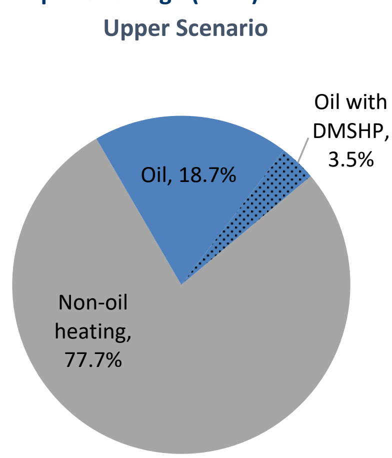


COMMERCIAL SECTOR

In the commercial sector, some businesses will likely be willing to adopt DMSHPs to supplement existing oil-fired heating systems under all incentive scenarios. However, there is no projected adoption of central ASHPs to replace central oil-heating systems due to higher incremental costs for these systems. Under the Upper incentive scenario, 3.5% of commercial square footage is covered by DMSHPs by the end of the study period (see **Figure 5-8**).

Figure 5-8. Commercial heating system penetration, by percent of square footage (2034)



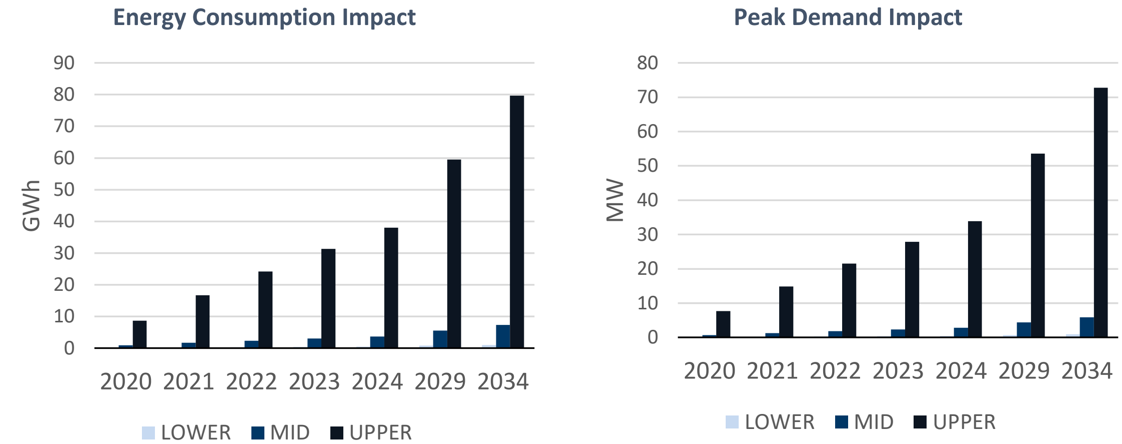


ENERGY AND DEMAND IMPACTS

The energy and demand impacts of customer fuel switching are displayed in **Figure 5-9**. Under the Upper incentive scenario, the adoption of heat pump technologies (for both spacing and domestic water heating) by oil-fired heating customers increases electricity consumption by approximately 80 GWh and peak demand by 70

MW by the end of the study period. There are minimal energy and demand impacts under the Mid incentive scenario due to low adoption.

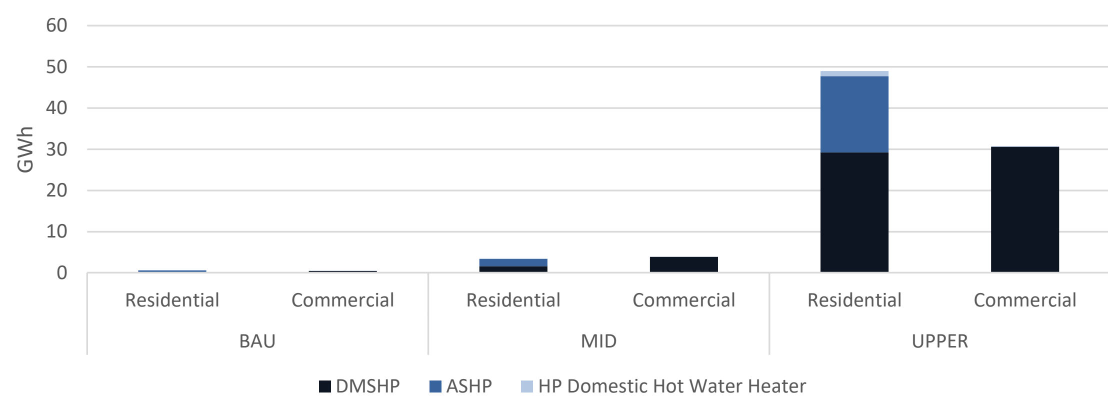
Figure 5-9. Fuel switching energy consumption and peak demand impacts



Note: Energy and demand impacts do not include energy savings from electric baseboard households adopting DMSHPs.

Under the Upper incentive scenario, the majority of energy impacts occur in the residential sector (approximately 61%), with significant energy impacts from the adoption of both DMSHP and ASHPs (see **Figure 5-10**). Approximately 39% of energy impacts occur in the commercial sector with almost all impacts from the adoption of DMSHP under the Upper incentive scenario.

Figure 5-10. Fuel switching energy impacts by sector and technology

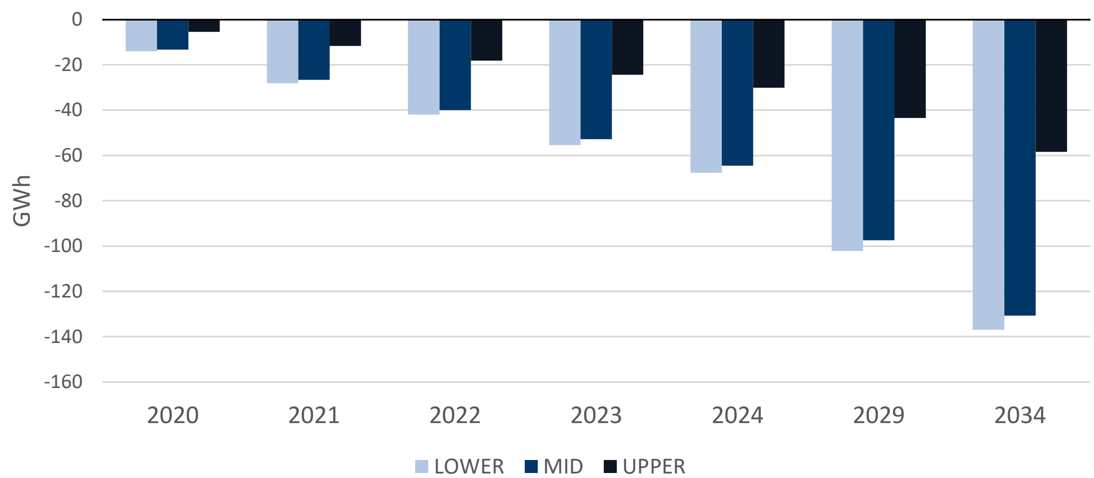


Note: Energy impacts do not include energy savings from electric baseboard households adopting DMSHPs.

NET ENERGY AND DEMAND IMPACTS

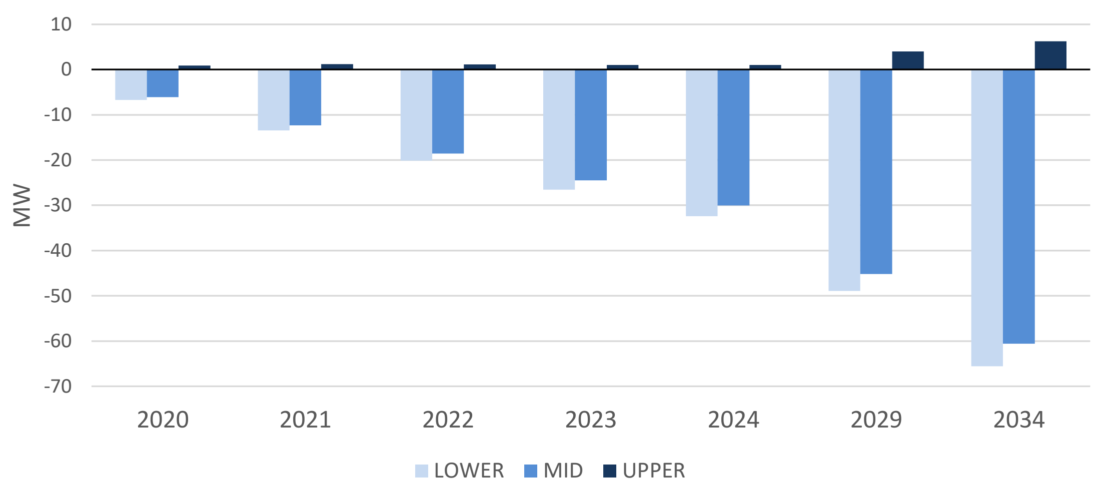
The increase in energy consumption due to oil-fired heating customers adopting heat pumps under the Upper incentive scenario offsets over half of the expected energy consumption reductions resulting from electric baseboard household adoption of DMSHPs as shown in **Figure 5-11**.

Figure 5-11. Fuel switching net energy impact (Mid-rates case)



For peak demand, however, the increase under the Upper incentive scenario more than offsets the expected demand reductions as shown in **Figure 5-12**. By 2034, there is a net increase in demand due to oil-fired customers adopting heat pumps – even when considering demand reductions from electric baseboard households adopting DMSHP. Fuel switching has a greater proportional impact on demand due to lower heat pump capacity and efficiency during peak hours, as is discussed in the call out box that follows **Figure 5-12**.

Figure 5-12. Fuel switching net demand impact



The Peak Demand Impacts of Heat Pump Adoption

The adoption of heat pumps by oil-heated customers has a bigger impact on net demand relative to net energy for two reasons:

1. DMSHPs have a muted demand reduction impact for electric baseboard households. When peak hours occur, generally during cold outdoor temperatures, DMSHPs will run at reduced efficiency and capacity. For electric baseboard homes, this means electric resistance heating will continue to pick up roughly half of the heating load normally covered by DMSHPs during these specific hours, thus reducing demand impacts.

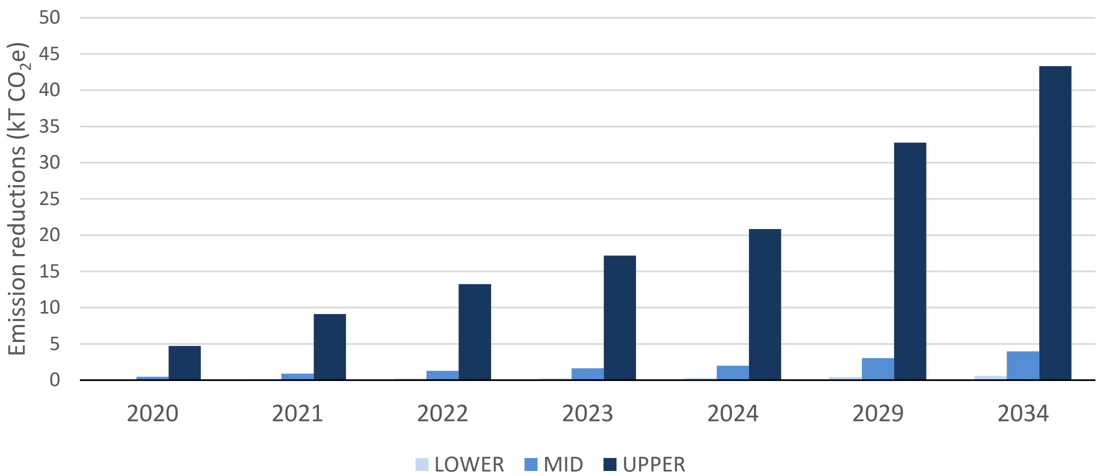
2. Replacing combustible fuel heating systems with a central heat pump (e.g. ASHP) can lead to significant demand increases. Like DMSHPs, these heat pumps will also operate at reduced efficiency and capacity during peak hours and will then rely on electric resistance back-up heating. This, in effect, replaces a heating system with no demand impacts (e.g. oil-fired furnace) with one with significant impacts (e.g. electric resistance heater) during peak hours. For the addition of DMSHP to oil-fired heating systems, there is no electric resistance backup, but these systems will still run during peak hours albeit at reduced capacity – thus contributing to demand impacts as well.

Further details on the Peak Demand assumptions applied in this analysis can be found in Appendix E.

GREENHOUSE GAS IMPACTS

Under the Upper incentive scenario, the reduction in oil consumption results in emission reductions of approximately 40 thousand tonnes of CO_2 equivalent (kT CO_2e) per year by 2034. There are relatively little emission reductions under the Mid incentive scenario due to low rates of fuel switching.

Figure 5-13. Fuel switching greenhouse gas emission reductions



INCENTIVE COSTS

Average annual incentive costs under the Mid incentive scenario are low due to low customer participation. Costs increase to just over $4.5 million per year on average under the Upper incentive scenario as the incentives make it more attractive for customers to fuel switch. In addition to relatively large incentives (i.e. 35% and 70%), the average incentive cost per customer is high because customers may adopt more than one DMSHP, effectively receiving multiple incentives per customer. Additionally, the average cost per customer does not double between scenarios (even though the incentive doubles) due to higher adoption of residential ASHPs, which are provided smaller incentives in the model due to smaller incremental costs. There are currently no utility programs to incentivize fuel switching, and potential programs have not been proposed. The costs in this section are based solely on the incentives paid to consumers within the model. They do not include any program administration costs or other ancillary costs.

Table 5-1. Fuel switching incentive costs

Scenario	Average annual incentive costs	Average cost per customer	Average cost per additional MWh in 2034
Mid	$177,000	$3,100	$360
Upper	$4,660,000	$4,500	$880

Note: Costs estimates include incentives for all measures and do not consider any program administration costs or other ancillary costs.

SENSITIVITY TO ELECTRICITY RATES AND CARBON PRICES

The fuel switching analysis results were tested for their sensitivity to both electricity rates and carbon pricing scenarios since both parameters can have significant impacts on the economics of fuel switching for consumers. Additionally, the utility incentive scenarios were tested for sensitivity to screening for the total resource cost (TRC) test.[44] **Table 5-2** describes each sensitivity scenario.

Table 5-2. Fuel switching sensitivity scenarios

Sensitivity	Description
Federal Government of Canada backstop carbon pricing plan (Fed. Backstop)	Oil rates include a carbon levy set at the Federal Government Backstop Carbon Pricing, which starts at $20 per tonne in 2019 and rising $10 per year to $50 per tonne in 2022.[45]
Social cost of carbon (SCC)	Oil rates include a carbon levy set at the upper bound of the social cost of carbon as estimated by Environment and Climate Change Canada.[46]
Unmitigated electricity rates (HIGH rates)	Retail electricity rates are assumed to be at the HIGH level.
Mitigated rates (LOW rates)	Retail electricity rates are assumed to be at the LOW level.

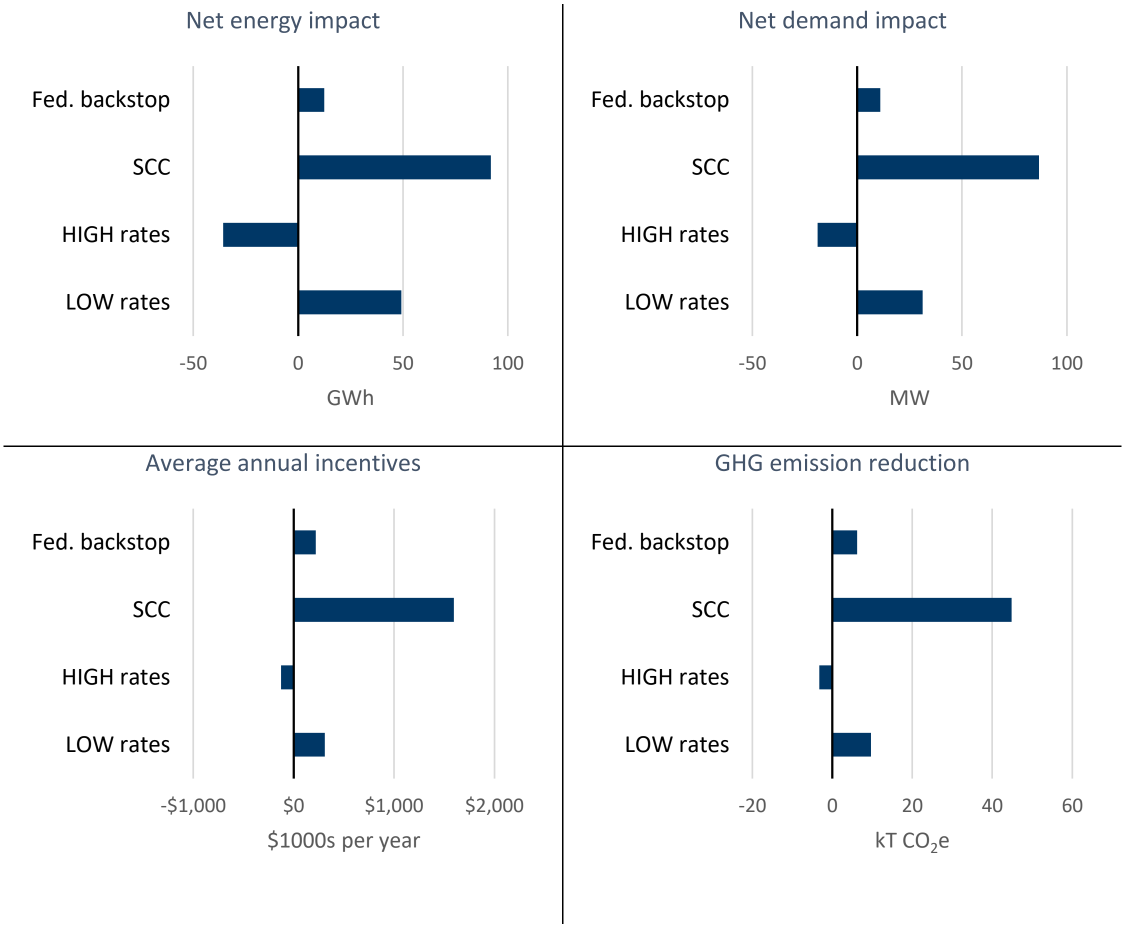
Figure 5-14 shows the difference in net energy impact, net demand impact, average annual incentives and GHG emission reductions for each sensitivity parameter except the TRC screening, which is described qualitatively. **Sensitivity scenarios are compared to a baseline scenario with Mid electric rates, no carbon levy on fuel oil, and under the Mid incentive level.**

[44] The TRC screening excludes measures that do not pass the TRC test. The TRC test determines the net cost of each as a function of increased or decreased avoided costs of electricity and oil/wood consumption and electricity demand as well as the incremental costs of the measures regardless of who pays (e.g. the customer or the utility via incentives). This applied just to the modeled Incentive Scenarios, because the baseline scenario does not include for any utility intervention, but instead captures natural market adoption. Applying the TRC to control natural market adoption is not appropriate.

[45] Source: Government of Canada, Technical Paper on the Federal Carbon Pricing Backstop, https://www.canada.ca/content/dam/eccc/documents/pdf/20170518-2-en.pdf.

[46] Source: Government of Canada, Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates, https://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1.

Figure 5-14. Fuel switching sensitivity analysis: Mid incentive scenario, 2034



Overall, the sensitivity analysis did not produce surprising results. When oil rates increase due to a carbon levy, there is a greater incentive to switch from oil to electric-based technologies. A larger carbon levy drives significantly greater fuel switching, but even a modest carbon levy increases fuel switching.

Conversely, when electricity rates are higher, there is less incentive to move away from oil-fired heating, but there is more incentive to add a DMSHP in electric baseboard households. This can be seen by the significant reduction in net energy and demand impacts under the High-rates case with a relatively smaller impact on average annual incentive payments.

When TRC screening is applied, only measures for domestic heat pump water heaters pass the cost-effectiveness screen to be included in the analysis. All measures for space heating fuel switching from oil are screened out. This is primarily due to the costs associated with increasing peak demand. For all measures, the value of displaced oil consumption is greater than the increase in costs for electricity consumption (set at the avoided cost rate). However, the increase in costs for electricity demand drives the TRC cost-benefit ratio below 0.8 for all measures except domestic heat pump water heaters.

FUEL SWITCHING: KEY TAKE-AWAYS

With a large incentive – 70% of incremental costs – along with enabling strategies that help reduce or remove customer barriers to adoption, approximately 5% of households and 3.5% commercial floor space adopts some form of heat pump heating system to displace oil-fired heating, while only marginal amounts of customers adopt heat pump domestic water heaters over oil-fired heating systems. At lower incentive levels, only a small number of customers with oil-fired heating systems make the switch, and with no incentives, almost no customers adopt heat pumps.

Based on the fuel switching analysis, the following key findings emerge:

- **The customer's economics *do not* favour fuel switching from oil or wood fired space heating.** For most customers, it does not make sense to adopt electric-based heating systems (space heating or domestic water heating) in favour of existing oil- and wood-fired heating systems – even when the electric systems are high efficiency heat pumps. Without significant incentives, consumers are unlikely to switch from combustible fuel-based systems to any sort of electric heating including heat pumps. This tendency will only be magnified if electric rates increase faster than assumed under the Mid-rates case.

- **The customer's economics *do* favour heat pumps in existing electric resistance heated households.** The market segment where heat pump systems do show the most economic benefits is households with electric baseboard heating. The analysis mirrors recent market data showing significant adoption of DMSHPs among households with electric baseboard heating, which leads to energy and demand reductions. If electricity rates increase, the economics will only improve for these customers leading to additional adoption and additional reductions in electricity sales.

- **Incentivizing the addition of DMSHP to existing oil-fired heating systems offers the most opportunity to increase electricity sales for the utilities.** Most customers adopted DMSHPs to displace heating from existing oil-fired heating systems, if they adopted anything at all. This choice avoids the costs associated with fully removing the legacy heating systems (e.g. oil tank removal). However, it should be noted that DMSHP measures did not pass TRC cost-effectiveness screening – mostly due to modeled increases in peak demand. Prior to any considerations to encourage fuel-switching to heat pumps, the peak demand impacts of heat pumps in Newfoundland and Labrador should be verified as this study used several non-jurisdictional specific assumptions to determine peak demand.

6. ELECTRIC VEHICLE ADOPTION

As the electric vehicle (EV) market continues to grow and evolve, utilities, governments, and private sector actors are beginning to take note and plan for increasing EV market shares. From a utility perspective, the electrical loads associated with EV adoption bring both opportunities and challenges; making them a critical element in future resource and program planning.

This section presents the results of projected EV uptake in Newfoundland and Labrador and corresponding impacts to the utilities.

APPROACH

This study leverages Dunsky's Electric Vehicle Adoption (EVA) model to forecast the adoption of Electric Vehicles (EVs) within Newfoundland and Labrador under several scenarios, assess the corresponding impacts of EV deployment on the Newfoundland and Labrador systems and identify strategies for interventions using the following approach:

- **Market Characterization:** Break down the market into vehicle segments and develop representative vehicle archetypes.
- **Model Calibration:** Benchmark Dunsky's EVA model to historical adoption in NL in order to calibrate key model parameters to local market conditions.
- **Scenario Analysis:** Use the calibrated model to assess the impacts of market and technology sensitivities, as well as key levers and interventions.
- **Utility Impacts:** Assess the energy consumption, load and financial impacts associated with the forecasted EV deployment.

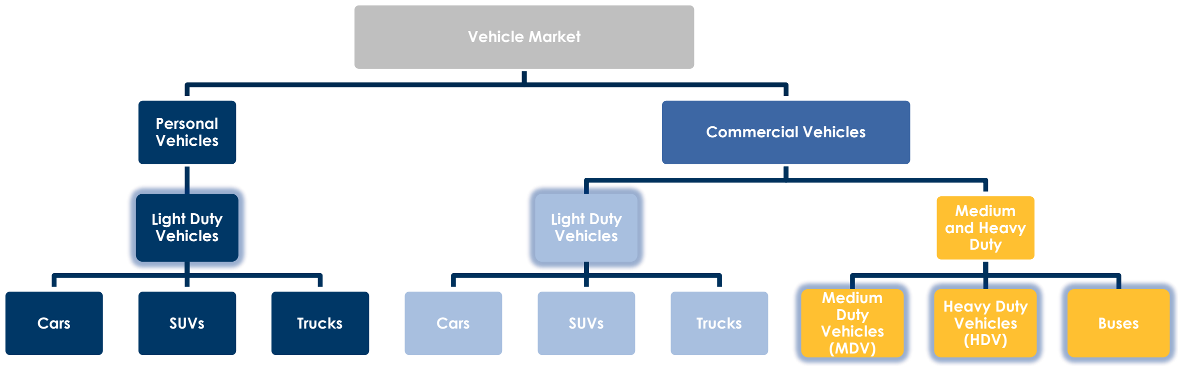
The study uses Newfoundland and Labrador specific inputs and assumptions to assess the potential for EVs in the province and assess corresponding opportunities and challenges. A more detailed description of the modeling approach, as well as key inputs and assumptions, are presented in Appendix D of the report.

MARKET AND VEHICLE CHARACTERIZATION

Due to differences in utilization and customer decision-making thresholds, the vehicle market in Newfoundland and Labrador was divided into personal and commercial vehicles. Additionally, the market was further segmented into vehicle classes that capture key differences between vehicle types, availability of EV models and utilization. As shown in **Figure 6- 1** below, the study captures nine distinct vehicle segments, however results are presented at the following levels:

- **Personal Light-Duty Vehicle (LDV)** including passenger cars, crossovers/SUVs and pickup-trucks.
- **Commercial Light-Duty Vehicles (LDV)** such as taxis, corporate and government fleet vehicles.
- **Medium-Duty Vehicles (MDV)** such as delivery vans, box trucks, utility bucket trucks.
- **Heavy-Duty Vehicles (HDV)** such as long-haul and short-haul semi tractors, garbage trucks, dump trucks.
- **Buses** including transit buses, school buses, coach buses.

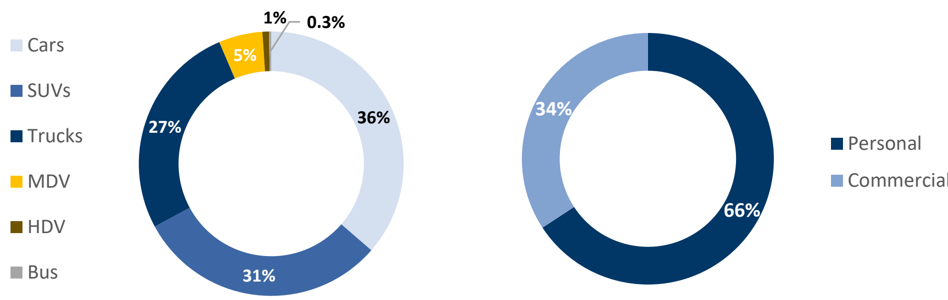
Figure 6- 1. Newfoundland and Labrador Vehicle Segmentation



For each of the modeled segments, a vehicle archetype capturing representative characteristics (e.g. annual distance traveled, fuel efficiency, battery size, powertrain output, etc.) of the average vehicle in that segment was developed. Key inputs and assumptions are presented in Appendix D. The medium-duty vehicles, heavy-duty vehicles and buses categories are a generalization of vehicles within this space to simplify the analysis. While vehicle characteristics of vehicles within each segment may vary significantly within depending on vehicle size, utilization and application, a representative average vehicle for each category was developed for the purpose of assessing the uptake within the category. Furthermore, medium- and heavy-duty categories are not always consistently defined within vehicle classification systems (i.e. some systems define medium-duty as classes 3 to 6, while other use classes 3 to 7) and certain vehicles straddle both the medium- and heavy-duty classifications. For example, refuse trucks can commonly range between Class 6 and Class 8. Likewise, short-haul freight semi-tractors can include both Class 7 and Class 8 trucks.

Based on publicly available data, annual vehicle sales in Newfoundland and Labrador were estimated at approximately 37,000 vehicles. As of 2019, approximately 410,000 on-road vehicles were registered in the province. 94% of vehicles in the province are estimated to be LDVs (i.e. cars, SUVs, trucks, etc.), with the remaining 6% being primarily MDVs as well as HDVs and buses. Additionally, 66% of vehicles are estimated to be primarily for personal use, with the remaining being commercial (i.e. non-personal use including corporates, governments, utilities, etc.).

Figure 6- 2. Distribution of Vehicle Sales in Newfoundland and Labrador



SCENARIO ANALYSIS

In this section, key results from the scenario analysis are presented with a focus on:

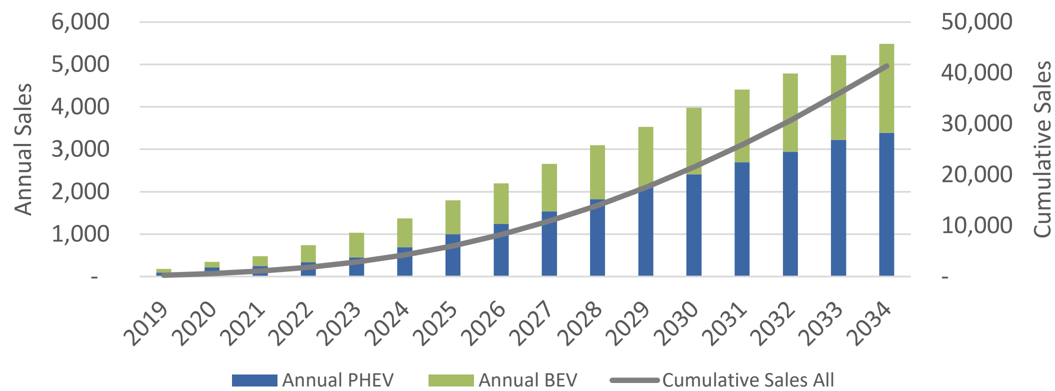
- **Baseline (business-as-usual):** A theoretical baseline which forecasts EV adoption under no further action beyond currently planned deployment (i.e. no new installed charging infrastructure, no incentives, etc.).[47] This baseline is primarily used to get insights into natural uptake of EVs in the province as well as to serve as a benchmark for assessing the impact of sensitivities and levers.
- **Sensitivities:** Assess the sensitivity of projections to factors linked to general competitiveness of the global EV market (lithium-ion battery costs, vehicle availability and technology advancements) and local market conditions (electricity rates, fuel rates and vehicle sales).
- **Levers:** Interventions that the utility, government, or other actors can make to accelerate the deployment of electric vehicles, namely public charging deployment (including DC Fast Chargers (DCFC) and Level 2 (L2)), home charging programs, and incentive programs.

BASELINE

As a first step, the adoption of EVs in Newfoundland and Labrador was forecasted under the assumption of no further program activity (i.e., – current levels of charging infrastructure, no incentives, etc.) in order to develop a theoretical baseline, presented in **Figure 6- 3, Figure 6- 4** and **Figure 6- 5**.

[47] Assuming existing committed actions by the utilities and government (estimated to be the installation of 14 DCFC and 30 Level 2 Ports in 2019/20)

Figure 6- 3. Baseline Annual and Cumulative Sales of Electric Vehicles in Newfoundland and Labrador, All Vehicle Classes



Under baseline conditions, the uptake of EVs is limited in the province. Approximately 41,400 EVs are expected to be on the road by 2034, representing between 10-29% of annual sales (varying by vehicle class), as seen in **Figure 6- 4**. In early years, BEVs have a higher purchase cost to their internal combustion engine (ICE) equivalent across all segments, ranging from 35% higher for Car BEV segment to 240% for the HDV BEV segment.[48] Additionally, the cost of a home/depot charger and installation further increases the incremental cost of an EV over an ICE. The high incremental cost of EVs over ICE equivalents results in limited market adoption across all vehicle class in early years, with EV adoption mostly composed of early adopter demographics whose decision to adopt is largely driven by non-financial considerations. With declining battery costs, the economic barrier facing EV adoption declines steadily, however the market remains significantly constrained by the limited availability of public charging infrastructure.

Throughout the study period, the market is dominated by plug-in hybrids electric vehicles (PHEVs) (62% by 2034). This trend can be attributed to range anxiety of EV purchasers coupled with low levels of public charging infrastructure in the province. PHEVs have the ability to use either an electric or internal combustion powertrain, typically providing sufficient electric mode range for daily driving distances while eliminating the range anxiety concerns associated with pure electric vehicles and increasing their popularity in jurisdictions with a limited public charging network.

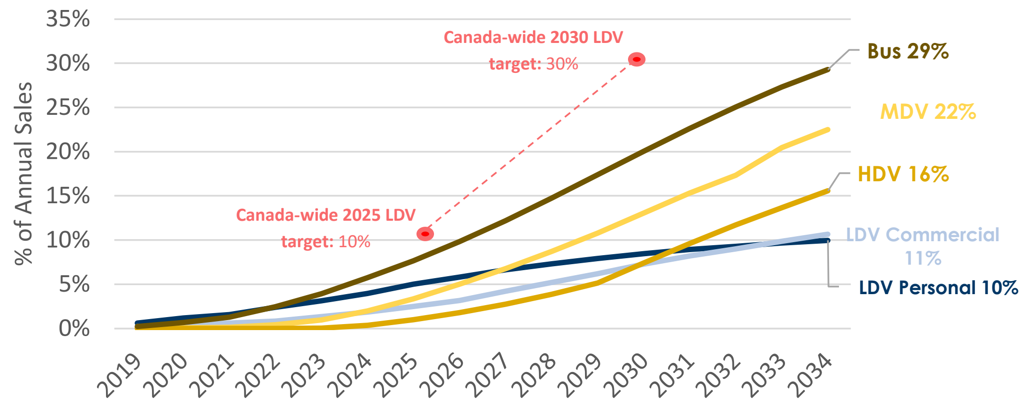
While the number of EVs on the road give a sense of the magnitude of adoption locally, EV projections and targets are often indicated in percentage of new annual vehicle sales. This metric serves as a normalized benchmark point for comparing adoption under different scenarios as well as across jurisdictions. The federal government has set Canada-wide targets for light-duty vehicles of 10% of electric new vehicle sales by 2025, 30% by 2030, and 100% by 2040. Similarly, global projections for the electrification of LDV are 30% of sales by 2030.[49] Under baseline conditions, uptake in Newfoundland and Labrador is forecasted to be much lower than

[48] Estimated vehicle purchase costs for ICE, PHEV and BEV models for each vehicle segment is presented in Appendix E.

[49] Bloomberg New Energy Finance. (2019). Electric Vehicle Outlook 2019. Available online: https://about.bnef.com/electric-vehicle-outlook/#toc-viewreport

these national and global targets, primarily due to charging infrastructure barriers, with only 10% of personal LDV sales and 11% of commercial LDV sales estimated to be EV by 2034.

Figure 6- 4. Baseline Percent of Electric New Vehicle Sales by Vehicle Class



Despite an early lead of personal light-duty vehicles, commercial vehicle segments reach a higher market share by the end of the study. Given lower anticipated dependence of commercial light-duty vehicles on public infrastructure, incremental upfront purchase cost and model availability become the primary barriers to uptake in these segments. As these factors improve over the course of the study period, uptake increases in response. In early years, medium- and heavy-duty vehicle uptake lags due to low model availability and high incremental costs of BEV models compared to their ICE equivalent, mirroring global forecasts.[50] However, over time, declining battery costs and increasing fuel costs improve total cost of ownership (TCO) and the business case for electric MDVs, particularly for urban delivery trucks and other return-to-base MDV fleets where battery size is not a constraining factor. By 2034, 22% of new MDV sales in Newfoundland and Labrador are projected to be EVs, on par with global projections of 20% by 2035. Adoption of electric HDV is likely to lag that of MDVs by a number of years, with nearly-zero uptake forecasted until 2025. Early adopters of EVs in the HDV segment are likely to be short-haul trucks and other vehicles that do not have significant range requirements.

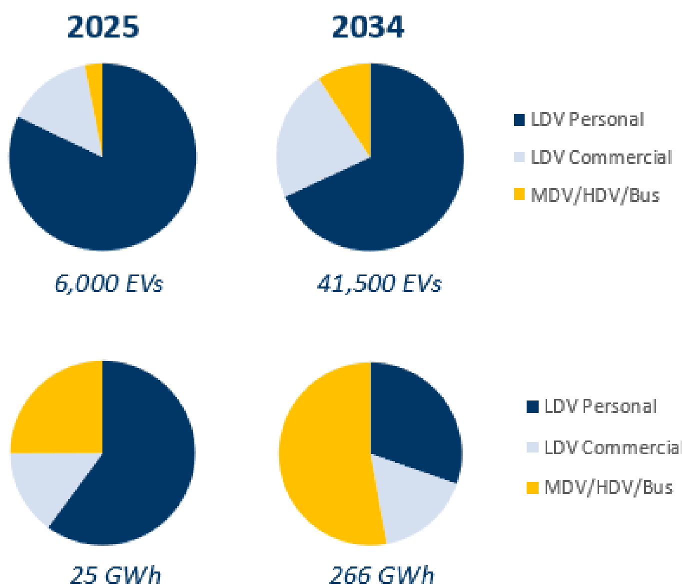
Most notably, natural uptake of electric buses significantly exceeds that of all other vehicle classes reaching 29% of sales by 2034. This is primarily due to high vehicle model availability and high utilization of some bus types, primarily transit, which improves the business case from a total cost of ownership perspective. A high portion of Newfoundland's buses are school buses, which typically have lower utilization and therefore lower potential for fuel savings than transit and other high-utilization bus fleets, resulting in lower uptake of buses overall than seen in global projections.

Despite light-duty personal vehicles representing the majority of EVs on the road at all points in the study period, as shown in **Figure 6- 5**, the majority of load impacts come from the medium-duty, heavy-duty, and bus vehicle classes given the higher utilization and size of these vehicle types and corresponding energy use. By 2034, EVs

[50] Ibid

are estimated to add 266 GWh of energy consumption to the utility's load; corresponding to roughly 5% of projected energy sales by 2034.

Figure 6- 5. Baseline Electric Vehicles and Electric Load by Vehicle Class



A diversified charging load profile was developed for each vehicle segment, leveraging data sets from a range of government and utility-led pilot programs. While the maximum rated power consumption of a single vehicle is important for considering the electrical load on a given home or even the impact on local distribution infrastructure due to clustering of EV adoption, system-wide impacts are best assessed using a diversified charging load profile which accounts for typical charging patterns across a larger population of EVs. For example, while a single LDV EV may be charged at a mix of Level 2 chargers (7 kW) and DCFC (50 kW+), considering the diversity in vehicle utilization and charging patterns, the system-wide peak load impact of the total LDV EV population is estimated at 1.5 kW per EV.[51] Using these diversified charging loads for each vehicle segment, a combined load profile for EV charging in Newfoundland and Labrador was developed, shown in **Figure 6- 6**.

Figure 6- 7 shows the energy impacts and peak load impacts of baseline levels of adoption throughout the study period. By 2034, the forecasted EV adoption would result in an additional 266 GWh of energy consumption (3% increase of 2034 energy consumption). Assuming no load management (i.e. no controlled charging, peak reduction programs or other interventions to shift EV charging), the high coincidence between the charging load

[51] Developed diversified charging load profiles are shown in Appendix D.

and the projected 2034 utility load curve results in an increase in peak load by 106 MW (5% increase of peak load in 2034).[52]

Figure 6- 6. 2034 Load Profile with and without Electric Vehicles, Assuming Unmanaged Charging

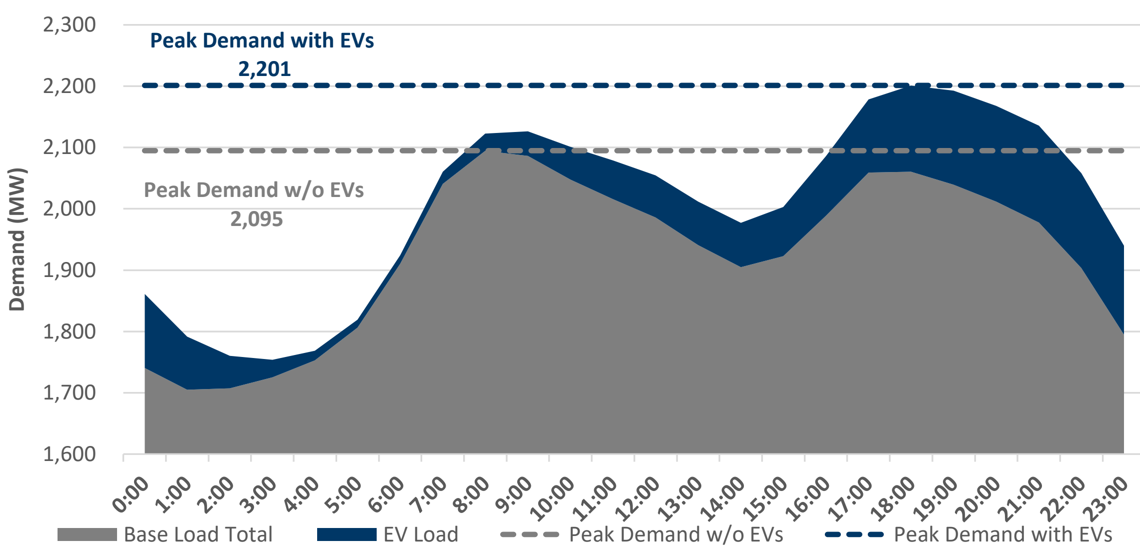
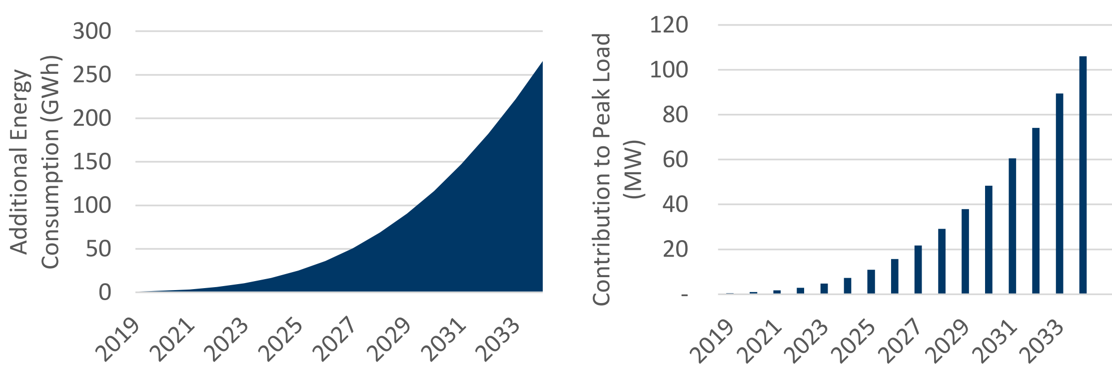


Figure 6- 7. Baseline Energy and Peak Load Impacts from Electric Vehicle Adoption



[52] Does not account for changes in load projections as resulting from Efficiency, DR or Fuel Switching potentials assessed elsewhere in this study.

SENSITIVITIES

Market realities often differ from projections due to changes in key market factors. Given uncertainties in both global factors (vehicle availability, battery costs) and local factors (number of vehicles sold, fuel prices, electricity rates) impacting EV adoption, low and high levels were developed for those key factors[53] and assessed for their impact on the energy consumption from EVs.[54] The results of the sensitivity analysis are shown in **Figure 6- 8**, **Figure 6- 9**, and **Figure 6- 10**, highlighting the impact of each factor on energy consumption in the short and long terms, with dark blue bars indicating an increase in the factor, and light blue indicating a decrease.

A number of key trends can be observed from the results:

- **Future vehicles sales will have a significant impact on the number of EVs on the road and load growth**. Although vehicle sales have traditionally been growing year-over-year, trends of declining vehicle sales are a disruption to the global mobility sector particularly with the advent of shared and autonomous vehicles. Additionally, vehicles sales are often tied to local characteristics such as population growth and economic development.
- **Vehicle availability is critical for EV adoption in the short-term across all vehicle segments:** Consumers are accustomed to having many options with respect to models, colours, and features when purchasing a new vehicle, and the limited variety of EV models currently being manufactured, and those available at dealerships even more so, constrain adoption of EVs. Additionally, EV models of medium and heavy-duty vehicles remain in early stage development, with only a handful of models available on the market today. An increase in the pace at which EV models become widely available has potential to increase market adoption across all segments. Similarly, a lag in availability will constrain the market in both the short and long terms.
- **Electricity rates and fuel costs have limited impact on the uptake of EVs in the personal segment**. Research indicates that consumers in the personal LDV segment are more likely to consider the upfront cost rather than TCO of EVs when making a purchase decision. The sensitivity of uptake in this segment to battery costs, which are tied directly to upfront costs, remains constant throughout the study period.
- **Commercial segments are sensitive to economic factors compared to the personal vehicle segment.** Changes to projected battery costs have a higher impact in the commercial segment, particularly medium and heavy-duty vehicles, due to the large battery sizes in the vehicles. Additionally, commercial operators are more likely to use more sophisticated financial assessments when making a purchase and consider TCO of vehicles rather than just the upfront costs. Particularly for medium and heavy-duty vehicles, which have very high utilization, changes in electricity rates or fuel prices have a substantial impact on the business case for EV adoption.

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[53] Assumptions used for low, medium and high level of each factor are presented in Appendix E.

[54] The results show impacts on energy consumption from EVs (GWh) rather than impacts on adoption (number of cars), as energy sales is a more relevant metric for the utilities. Additionally, using energy sales as a proxy for assessing the impact on adoption of EVs captures the impact of factors on increasing the total number of EVs sales as well as in increasing the market share of BEVs relative to PHEVs. The cumulative EV sales data is provided in Appendix F.

Figure 6- 8. Sensitivity of Personal Light-Duty Vehicle Adoption to Key Market Factors

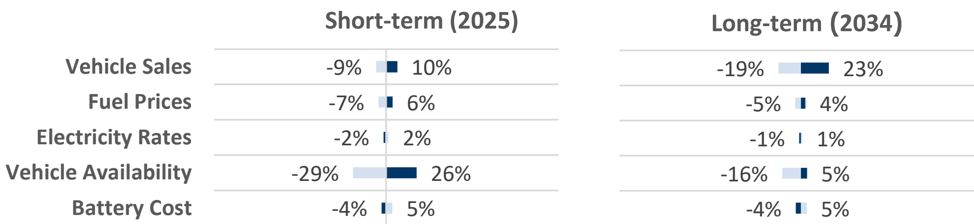


Figure 6- 9. Sensitivity of Commercial Light-Duty Vehicle Adoption to Key Market Factors

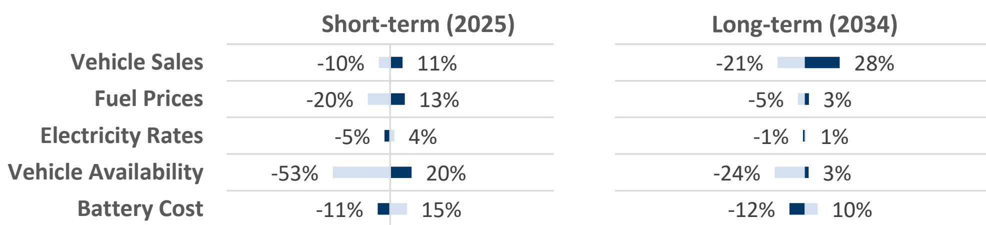
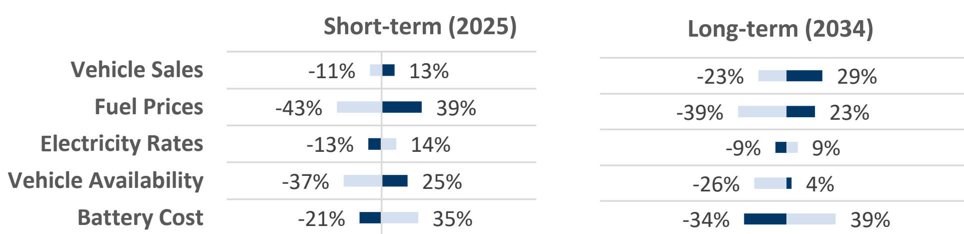


Figure 6- 10. Sensitivity of Medium-Duty, Heavy-Duty, and Bus Vehicle Adoption to Key Market Factors



Market dynamics are often linked, and several factors can change simultaneously. Therefore, in addition to investigating the impact of each factor in isolation, the analysis included an assessment of adoption and energy impacts under a “best-case” and “worst-case” scenario. Results show that energy load impacts of EVs under a low baseline and high baseline scenario range from 107 GWh to 448 GWh respectively, relative to 266 GWh under the assumed baseline.

MARKET LEVERS

Support and interventions from utilities, and governments and other market actors can have a significant impact on the growth of the EV market. In this section, three key levers commonly used to accelerate EV adoption are assessed for their impact to accelerate EV adoption in Newfoundland and Labrador.[55] For each factor, low and high investment scenarios were developed which correspond to investments of approximately $5M and $20M respectively over a 10-year period, as shown in the table below. To properly assess and attribute the impacts on adoption to a specific lever, **the levers are assessed in isolation** (i.e. the entire investment amount is assumed to be allocated to one lever only).

The modeled scenarios are not necessarily proposed investments by the utilities, but rather are designed to show the impacts of different levers on the market and determine what an appropriate investment strategy could be. The scenarios also do not represent all possible intervention options, however ones that are most relevant and likely to have an impact on market adoption by addressing key barriers to adoption. For example, a number of utilities offer incentive programs for the installation of home charging stations, however these strategies are usually not effective at driving additional EV adoption and mostly benefit existing EV adopters and increase free ridership. That said, incentives for home chargers can be used to cover the incremental cost of smart chargers for EV adopters to enable networking and load management functionalities.

Federal Incentives

The 2019 Federal Budget included $300 million in funding to be allocated over three years towards electric vehicle purchase incentives. At the time of writing, the incentive is in place across the country and available as a direct purchase incentive of up to $5,000 for eligible vehicle models. Due to uncertainty around future availability of the incentive, the federal EV incentives are not included in the baseline scenario. The Low Incentive Investment Scenario was developed to resemble the federal rebate levels (i.e. Modeled Incentives – Low can be interpreted as impact of federal incentives). The modeled Incentives – High scenario can be interpreted as the federal incentive in addition to an incentive top-up by the utilities or government.

[55] In addition to the levers indicated in the table below, Dunsky assessed the impacts of investments in a program to retrofit Multi-Unit Residential Buildings (MURBs) and install Level 2 Charging infrastructure in a portion of parking stalls in the province. Limited charging infrastructure in MURBs represents a key barrier to adoption in some jurisdictions, however the results indicated that this was not impactful nor cost-effective due to the housing composition of Newfoundland and Labrador market (i.e. less than 15% of the population residing in MURBs).

Table 6- 1. Levers Applied to the Newfoundland EV Adoption Scenarios (Under budget constraints)

Lever	Description	Low Scenario (≈ $5M investment)	High Scenario (≈ $20M investment)
DCFC deployment	Deployment of Public Direct Current Fast Chargers (DCFC) on highway corridors and in population centres	25 Stations (50 ports)	100 Stations (200 Ports)
L2 deployment	Deployment of Public Level 2 (L2) Charging in population centres	125 Stations (500 ports)	500 Stations (2000 ports)
Vehicle Incentives[56]	Rebates to customers to offset a portion of the upfront cost of an EV purchase	$5K incentive for LDVs, 10% incentive for MDV, HDV, Bus	$7.5K incentive for LDVs, 25% incentive for MDV, HDV, Bus

Figure 6- 11 and **Figure 6- 12** show the impact of the Low and High Investment of each lever on energy consumption compared to baseline,[57] and highlight the following takeaways:

- **Under both the low and high scenarios, DCFC and L2 deployment have the highest impact on adoption in both the short and long terms**. The limited availability of charging infrastructure in the province severely constrains market adoption of LDVs under baseline conditions, and any deployment increases both geographical coverage and availability of charging and has a significant impact on the market.
- **Although incentives boost adoption while they are in place, their impact is diminished once they are phased out.** Incentives can potentially increase EV load by 16 to 32% in the short-term through improving the business case of EV adoption and bridging the market to cost parity. Incentives contribute to both an increase in the number of EVs on the road as well as the shift from PHEVs to BEVs in the market, which corresponds to an increase in EV load. However, the results highlight that incentives cause a temporarily boost in adoption in the short-term, with a limited long-term market impact (8 to 9% increase).
- **Multi-unit residential building retrofits have limited impact due to the housing market composition in Newfoundland and Labrador.** Although limited charging infrastructure in MURBs represents a key barrier to adoption in some jurisdictions, the impact is less pronounced in Newfoundland due to less than 15% of the population residing in these housing types.
- **A portion of the impact from improved public charging infrastructure networks and incentives does not increase overall adoption, but rather results in a shift from PHEVs to BEVs.** Given this, the impact of investment on adoption is not proportional to impact on energy consumption.
- **Higher investments in DCFC and L2 Deployment can further increase market uptake of EVs in the province.** Expansion of public charging infrastructure has the potential to more than triple the number

[56] Incentives were assumed to step down gradually over time. Detailed assumptions can be found in Appendix D.

[57] Additional results in the appendix highlight the impact on EV adoption (i.e. number of vehicles on the road).

of EVs on the road to 132,000 EVs by 2034. This expansion is especially important as the EV population in the province grows in order to avoid congestion (i.e. lineups) at public charging stations.

Figure 6- 11. Impacts of Low Investment Scenario on EV Energy Sales ($5M)

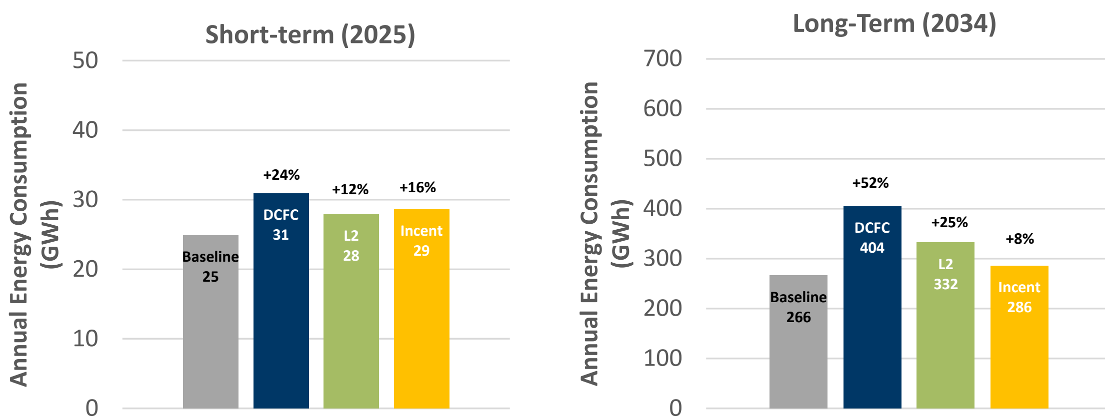
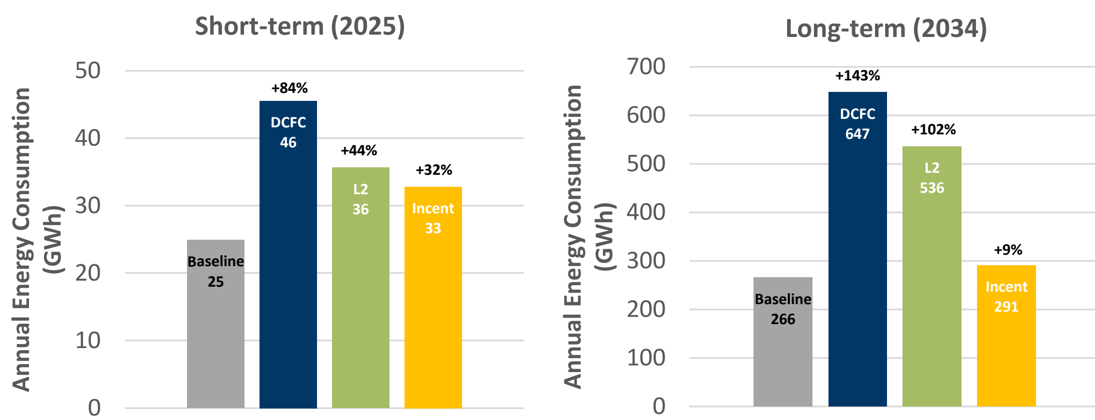


Figure 6- 12. Impacts of High Investment Scenario on EV Energy Sales ($20M)



COST-EFFECTIVENESS ASSESSMENT

For each of the modeled scenarios, the cost-effectiveness of an investment in the specified lever was calculated from the utilities' perspective.[58] The investments in these scenarios are assumed to take place over a 10-year period. To properly assess the financial feasibility of each option, however, the revenues and costs associated with the vehicles over the entire study-period (2020–2034) was used to capture the long-term cost-effectiveness of each initiative in a way that recognizes the life-time of the incremental sales revenues from supported EVs.

The impacts attributed to each scenario are assumed to be the incremental energy sales and peak capacity over the baseline scenario. The cost-effectiveness analysis then considered the following value-streams:

- **Benefits:** Revenues from incremental electricity sales based on forecasted electricity rates (mid scenario).[59]
- **Costs:**
    - Investment costs associated with each scenario
    - Cost of energy supply
    - Cost of capacity

Value streams were then discounted at the utilities' discount rate, and the Benefit to Cost Ratio (BCR) and Net Present Value (NPV) were calculated in order to assess cost-effectiveness from the utilities' perspective. Those scenarios with a BCR greater than 1 or a NPV greater than 0 are considered cost-effective. To obtain insights into the drivers behind cost-effectiveness of the different levers, cost-effectiveness was calculated under two cases:

- **Case 1**: Considering sales revenues and program and utility costs with <u>unmanaged charging load</u>
- **Case 2:** Considering sales revenues and program and utility costs with <u>charging load management</u>

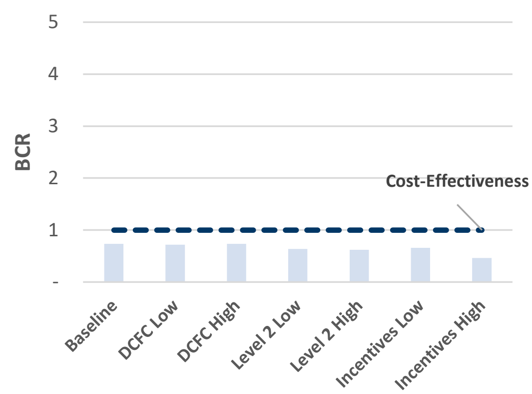
[58] Investments in MURB home charging programs were found not to be impactful or cost-effective in Newfoundland and Labrador, and were therefore removed from consideration in this section.

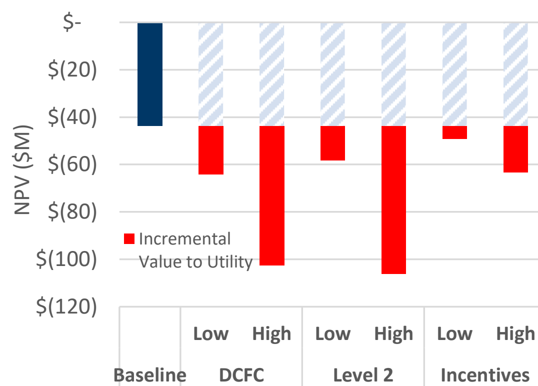
[59] The revenue calculations are based on the assumption that all the charging happens within the utilities' service territories. Additionally, charging rate is assumed to be a blended average of residential and commercial electricity rate projections under the mid scenario.

CASE 1

Considering utility revenues and costs, none of the levers were found to be cost-effective as shown **Figure 6- 13.** This is primarily due to high capacity costs, which diminish all revenue benefits that EVs bring to the utilities. Under baseline, the projected EV adoption is expected to result in -$44M value to the utilities. Any incremental investments that accelerate EV adoption result in a negative business case for the utilities and increase deficits.

Figure 6- 13. Cost-Effectiveness of Levers Assuming Unmanaged Charging Load



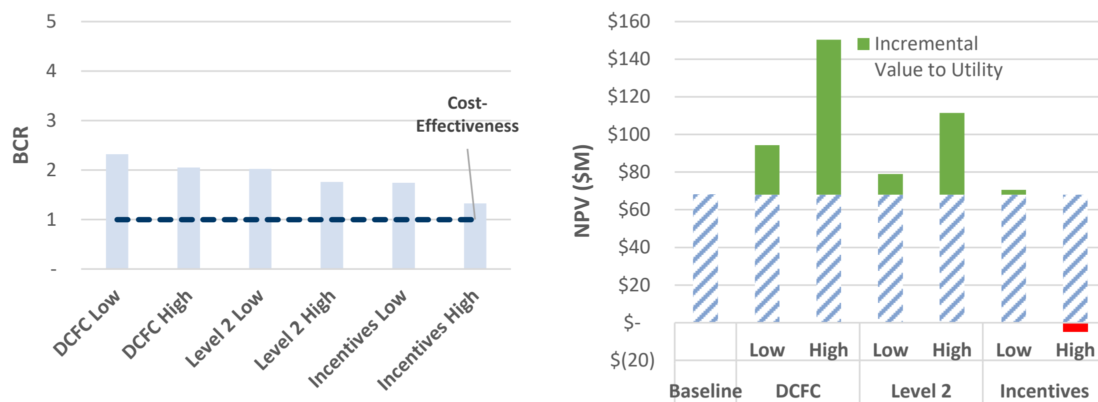


CASE 2

Contrary to findings under case 1, assuming load management is in place (which could reduce peak impacts of EV charging load by 85%) results in most levers being cost-effective from the utilities' perspective.[60] Under baseline conditions, EVs are estimated to increase energy sales nearly $70M in value by 2034. Investments can significantly increase that value. For example, a $20M DCFC deployment can bring in an additional $82M in additional value by 2034.

As shown in **Figure 6- 14**, DCFC and Level 2 infrastructure deployment are the most cost-effective options. The limited long-term market impacts of incentives result in significantly lower cost-effectiveness than infrastructure deployment. Additionally, the results show that over-investment in some interventions beyond a certain threshold (for ex: incentives or DCFC) may have diminishing returns. These impacts result in a lower BCR and NPV, as highlighted by the reduction in the BCR of the Incentives High Scenario relative to the Incentives Low Scenario; resulting in the lever not being cost-effective. The same trend is observed for DCFC investments, which had lower BCR for higher investments, suggesting that investments in infrastructure once the market is saturated have diminishing returns.

Figure 6- 14. Cost-Effectiveness of Levers Assuming Charging Load Management



[60] The cost- analysis does not consider the costs of managing and implementing an EV load management program.

SENSITIVITY TO CAPACITY COSTS

The tables below show results of the sensitivity analysis around capacity costs (considering 100%, 80% and 60% of costs) as well as the use of load management for the low and high investment scenarios respectively. The results confirm that reducing capacity load impacts of EVs will be critical to benefit from EV uptake in Newfoundland and Labrador. Even with a 40% reduction in capacity costs (i.e. 60% of current costs); some levers do have a slightly positive NPV, however have no or limited incremental value above baseline. Applying load management at the full capacity costs (i.e. Case 2 as shown earlier) results in significant cost reductions and maximizes the value of any investment the utilities make. Further capacity cost reductions under load management increase the value any investment can bring to the utilities.

Table 6- 2. Low Investment Scenario Sensitivity to Capacity Costs

NPV of Low Investment Scenarios						
Type of Charging	Unmanaged Charging			Load Management [61]		
Cost of Capacity (2019)	$430/kW (100%)	$340/kW (80%)	$250/kW (60%)	$430/kW (100%)	$340/kW (80%)	$250/kW (60%)
Baseline	($ 44M)	($ 17M)	$ 9M	$ 68M	$ 72M	$ 76M
DCFC	($ 64M)	($ 27M)	$ 10M	$ 94M	$ 100M	$ 106M
Level 2	($ 58M)	($ 26M)	$ 6M	$ 79M	$ 84M	$ 89M
Incentives	($ 49M)	($ 21M)	$ 7M	$ 71M	$ 75M	$ 79M

Table 6- 3. High Investment Scenario Sensitivity to Capacity Costs

NPV of High Investment Scenarios						
Type of Charging	Unmanaged Charging			Load Management [61]		
Cost of Capacity (2019)	$430/kW	$340/kW (-20%)	$250/kW (-40%)	$430/kW (100%)	$340/kW (80%)	$250/kW (60%)
Baseline	($ 44M)	($ 17M)	$ 9M	$ 68M	$ 72M	$ 76M
DCFC	($ 103M)	($ 43M)	$ 16M	$ 150M	$ 159M	$ 168M
Level 2	($ 106M)	($ 55M)	($ 4M)	$ 111M	$ 119M	$ 127M
Incentives	($ 63M)	($ 34M)	($ 4M)	$ 63M	$ 67M	$ 72M

[61] Assuming 85% of peak demand from EV charging load can be avoided.

CONSIDERATIONS FOR MARKET INTERVENTION

The results of the scenario analysis and estimation of impacts of each lever on adoption, load growth, and corresponding cost-effectiveness highlight the following key considerations for investments:

- **Market interventions can have a significant impact** on market uptake of EVs and bring load growth opportunities.
- **The commercial EV market is forecasted to be significant** with improving economics and will contribute to the majority of EV load in Newfoundland and Labrador.
- **High capacity costs coupled with the high coincidence between EV charging loads will result in significant deficits to the utility if load management is not utilized** to reduce peak charging and associated capacity costs.

ASSESSMENT OF INTERVENTION LEVERS

The assessment of the impact, cost-effectiveness and need for intervention for the four key intervention levers assessed in the scenario analysis highlights the following key considerations for investments:

- **DCFC Deployment:** Because the LDV market is severely constrained by the lack of public charging infrastructure, investments in DCFC will be the most impactful and cost-effective lever. The current lack of a solid business case for DCFC charging stations for third-party market actors suggests that DCFC deployment in the province will be limited in the absence of utility or government intervention. Despite the significant impact of DCFC deployment, the results highlight that over-investments in DCFC may have diminishing returns after the market is saturated, therefore DCFC investments should be prioritized while supporting the market through other levers. Additionally, utility deployment of charging infrastructure would also lead to benefits from optimizing station placement within the distribution system to avoid infrastructure upgrades.

- **L2 Deployment:** Although less effective than DCFC deployment in increasing adoption of EVs, public L2 deployment can support the increase of geographic coverage and availability of charging, helping to build confidence among potential EV buyers. A number of businesses across the province have already started deploying L2 charging stations at their facilities to attract EV drivers. Due to the lower installation and operational costs of L2 compared to DCFC, third-party deployment of L2 infrastructure faces fewer barriers and is likely to see more natural uptake. However, interventions may be needed to accelerate the pace of deployment of L2 in the short-term in order to alleviate charging barriers.

- **Vehicle Incentives:** The Federal EV purchase incentives are expected to support the growth of EVs in the province, however incremental incentives for LDVs may not have as significant of an impact on the market. Additionally, EV incentives are typically provided at the federal or provincial level and limited case studies of utilities providing EV purchase incentives are available.

- **MURB Home Charging:** Due to the housing market composition in the province and limited portion of the market living in MURBs, programs targeting retrofitting parking stalls in MURBs with home charging will have limited impact and likely not be cost-effective, and should therefore not be pursued. The upcoming Zero Emission Vehicle Infrastructure Program from NRCan can be leveraged by local governments and building owners to address this barrier.

SUGGESTED PRIORITY AREAS

The results clearly highlight that DCFC deployment should be a priority as a means of accelerating EV adoption in Newfoundland and Labrador, increasing EV load growth**. Figure 6- 15** shows a sample investment strategy for a $5M and $20M investment options over a 10-year period.

Early investments should be mostly – if not fully – dedicated to DCFC deployment to ensure sufficient geographical coverage and availability of a charging network on key highway corridors and population centres across the province. **To maximize impacts of investments, existing federal programs can be leveraged (which currently offer up to 50% cost contribution)[62] to jump-start deployment of DCFC in the province. Additionally, rather than self-deployment of charging stations, the utilities can follow a "make-ready" approach where they develop infrastructure to enable the installations of DCFCs by third-parties (private corporations, municipalities, etc.) and potentially provide incentives to support the build-out of the charging stations.**

As indicated earlier, over-investments in DCFC deployment may have diminishing returns, therefore if a larger investment amount is available, investments should be diversified by complementing DCFC investments with Level 2 Infrastructure deployment and other initiatives including:

- **Load management programs:** Given the utilities' high capacity cost and high coincidence between charging load and utility peak, shifting charging load to off-peak hours will be critical to benefitting from the financial value that EV adoption can bring. The utilities can launch initiatives to encourage off-peak charging through smart charging (i.e. demand response with direct load control), Time-of-Use (TOU) rates, or other approaches.
- **Public marketing initiatives** to educate and raise awareness of the public about EVs and their benefits.
- **Commercial fleet programs:** A significant portion of the forecasted EV load growth in the province is expected come from commercial vehicles. The utilities can engage with fleet managers through utility account managers to inform about opportunities associated with fleet electrification and offer support through feasibility studies, financial support, and other means.

Figure 6- 15: Sample Investment Strategy

$5M Investment

DCFC Deployment and Programs
($4M - $5M)

Load Management
($0M - $1M)[63]

$20M Investment

DCFC Deployment and Programs
($10M - $15M)

Level 2 Deployment and Program
($2M - $4M)

Ancillary Investments ($1M - $5M)
- Load Management
- Public Education and Awareness
- Commercial Fleet Programs

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[62] Natural Resources Canada (NRCAN) Electric Vehicle and Alternative Fuel Infrastructure Deployment Initiative (EVAFIDI) and Zero Emission Vehicle Infrastructure Program (ZEVIP).

[63] Further analysis is required to assess the potential and costs of implementing different EV load management strategies under the forecasted adoption in Newfoundland and Labrador.

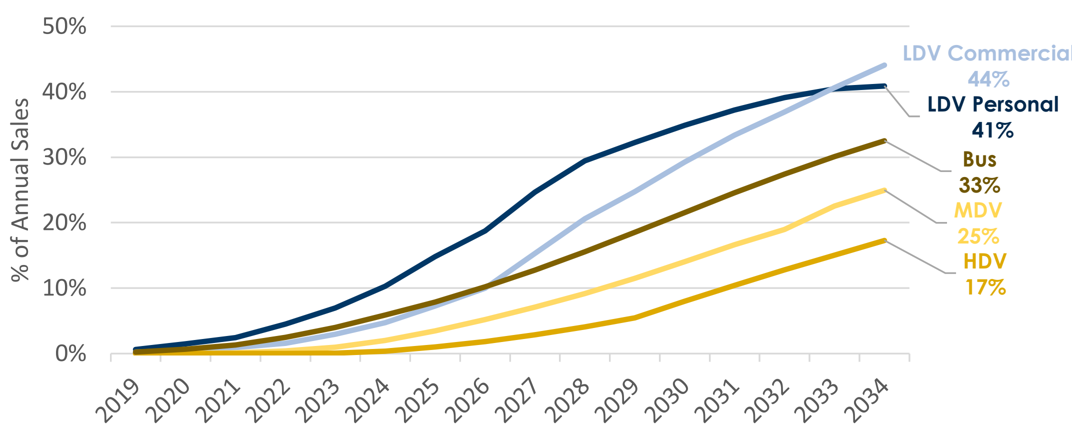
IMPACTS OF INVESTMENTS

Below, the potential impacts of the assumed $20M investments[64] on EV adoption are presented along with utility load and financial impacts.

Impact on Adoption: Compared to uptake under the baseline scenario shown earlier in **Figure 6- 4, Figure 6- 16** below shows that the modeled investment scenario will significantly increase LDV uptake in Newfoundland and Labrador, from 10% of sales in 2034 under baseline to 38% of sales by 2034. Under this scenario, EV adoption in Newfoundland and Labrador is on par with Canada-wide and global EV sales targets of 30% of sales by 2030. Investments can be scaled accordingly to reach more appropriate or desired levels of adoption in the province.

Interventions through public charging infrastructure deployment are not expected to move the medium- and heavy-duty vehicle market. With the exception of long-haul trucking that may depend on a network of charging stations, MDV and HDV segments are mostly expected to rely on depot charging. Generally, MDV, HDV and buses were found to be more sensitive to economics and will require substantial support in the form of incentives or changes in key market economic factors (electricity rates, fuel prices, etc.) to trigger any significant shift in adoption beyond natural market uptake. Programs targeted towards commercial fleets, awareness campaigns and other initiatives could be potential levers to accelerate the commercial market.

Figure 6- 16. Percent of Electric New Vehicle Sales by Vehicle Class Under $20M Investment Scenario

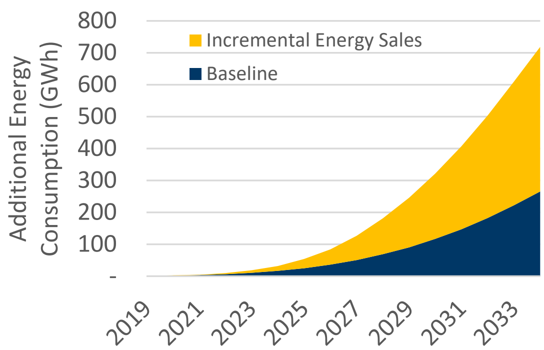


Load Impacts: As shown in **Figure 6-17**, the incremental adoption attributed to the investments can almost triple load growth from EVs relative to baseline (+175%) to 720 GWh of energy consumption (approximately a 7% increase in 2034 energy consumption). Under unmanaged charging, EV charging is expected to increase system peak demand by 281 MW (approximately a 13% increase in 2034 peak load). EV charging is an inherently flexible

[64] The proposed $20M investment scenario assumes utilities only cover 50% of the cost of DCFC and L2 deployment, either through leveraging external funding for 50% of project costs or supporting third-parties through a 50% incentive. Additional results in Appendix F show the impact of the proposed $5M investment focused on DCFC that assumes the same 50% utility contribution to costs.

load and can be managed to a large extent through load management and smart charging techniques. At least one smart charging pilot conducted by a Canadian electric utility demonstrated that 85% of charging load could be consistently shifted to off-peak hours, even while providing EV drivers the opportunity to override utility requests.[65] More granular analysis is required to assess the potential for shifting EV load in the Newfoundland and Labrador system, however assuming 85% of peak charging can be mitigated, only a 42 MW increase in peak demand will be observed as a result of EV charging as shown in **Figure 6- 18.**[66]

Figure 6- 17. Energy and Peak Load Impacts from Electric Vehicle Adoption Under $20M Investment Scenario



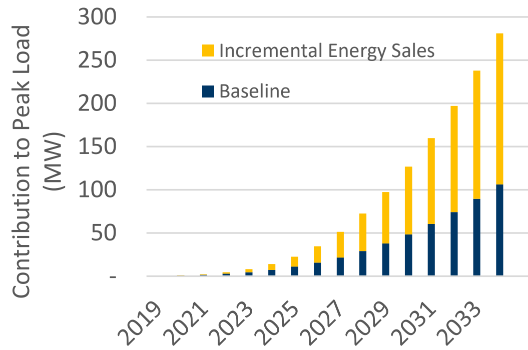
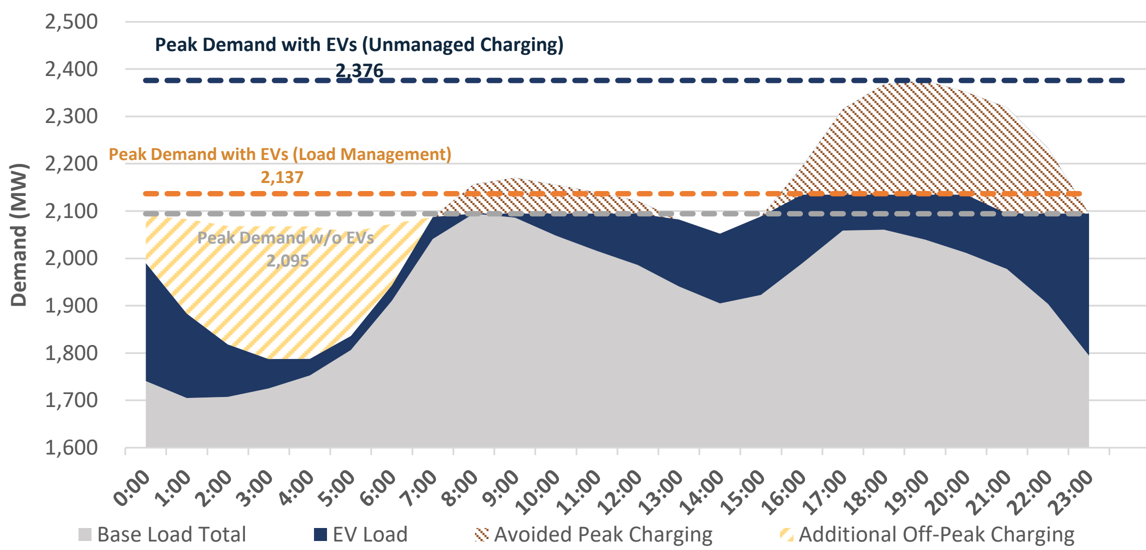


Figure 6- 18. Peak Load Impacts Under $20M Investment Scenario



[65] Final report for the "ChargeTO" Residential Smart Charging Pilot in Toronto, conducted by FleetCarma in partnership with Toronto Hydro. https://www.fleetcarma.com/resources/chargeto/

[66] The shown charging load shifting to off-peak hours is for illustration purposes only. A more detailed analysis of the potential for load shifting in the Newfoundland and Labrador Systems is required to identify the magnitude of peak reduction can be achieved.

Financial Impacts: By 2034, the modeled $20M would nearly triple revenues from EV deployment, from $119M under baseline to $317M. However, without load management, the additional revenue is diminished by the high peak impacts and capacity costs, resulting in a net loss of $44M. Load management can allow the utilities to benefit from the revenue generated from EV energy sales while reducing capacity costs significantly. The modeled $20M would increase the value of EV deployment to the utility to $170M ($102M over baseline). This net revenue gain to the utilities may contribute to Utility efforts to mitigate projected electricity rate increases stemming from the Muskrat Falls generation facility.

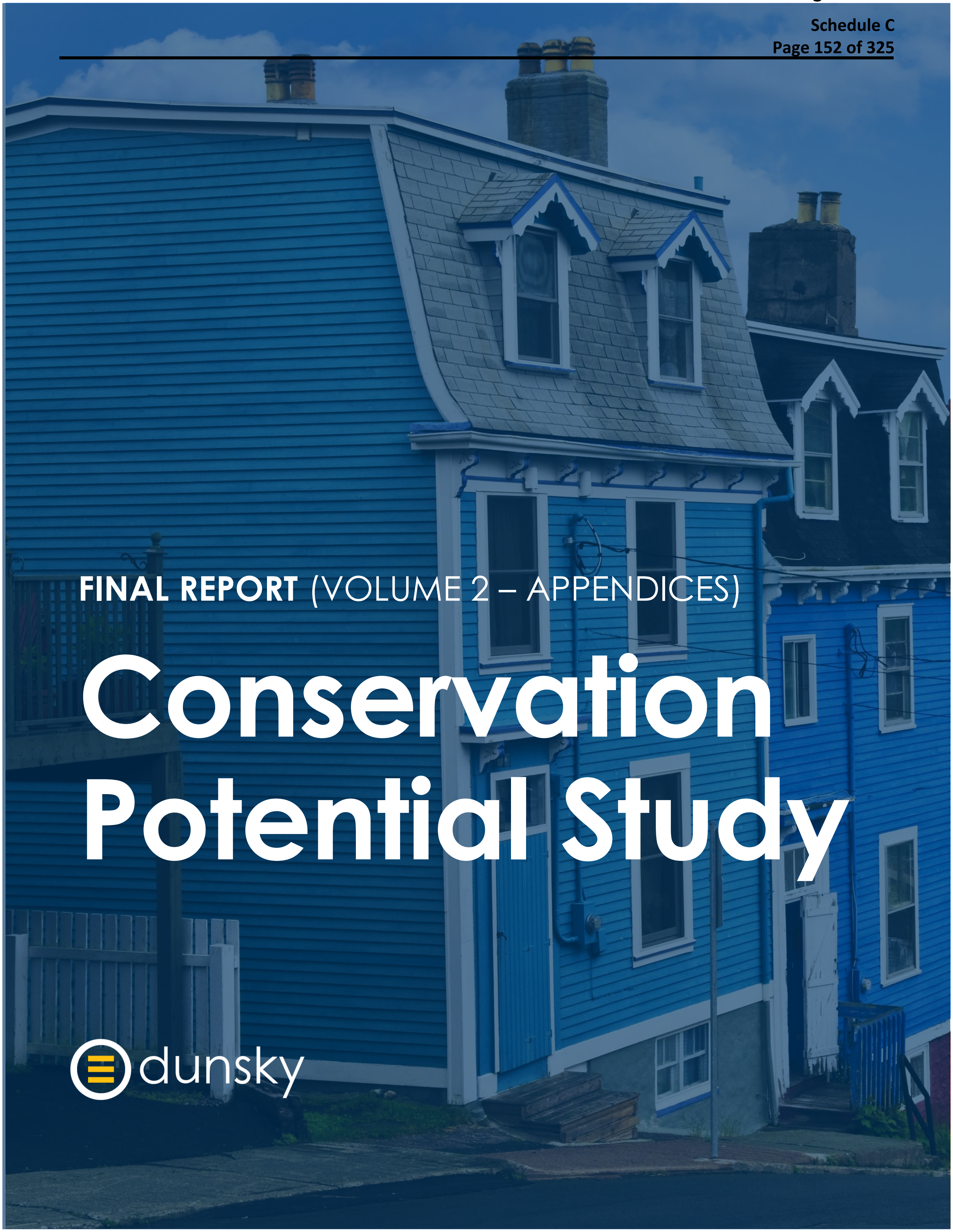
Table 6- 4. Benefits and Costs of EV Adoption Under Baseline and $20M Investment Scenario By 2034

	Unmanaged Charging			Load Management		
	Benefits	Costs	NPV	Benefits	Costs	NPV
Baseline	$119M	($163M)	**($44M)**	$119M	($51)	**$68M**
$20M Investment	$317M	($359M)	**($113M)**	$317M	($147M)	**$170M**

EV ADOPTION: KEY TAKE-AWAYS

The study of the potential and impacts of EVs in Newfoundland and Labrador highlights the following key takeaways:

- **Under baseline, adoption of EVs in Newfoundland and Labrador by 2034 is forecasted to be limited with approximately 41,400 EVs on the road by 2034**. Particularly, projections for LDVs sales in Newfoundland and Labrador are well below national and global projections. This is primarily caused by lack of public charging infrastructure, which is forecast to significantly constrain the growth of the LDV market moving forward. Despite the early lead of personal LDVs, commercial vehicles are expected to significantly increase in share during the study period as a result of improving economics. As opposed to LDV projections, the forecast uptake of MDVs and HDVs in Newfoundland and Labrador are on par with global ones. Overall, under the baseline scenario EVs are estimated to add 266 GWh of electricity consumption by 2034 (≈ 3% of energy sales) and contribute to a 106 MW increase in the utilities' peak demand (≈ 5% of forecast peak by 2034). The majority of the forecast load impacts are attributed to the commercial EVs on the road.
- **Investments can have a significant impact on accelerating EV adoption and corresponding energy sales, as much as tripling load growth from EVs by 2034 under the modeled hybrid $20M investment.** DCFC deployment has been identified as a priority for any investment, as it is the most impactful and cost-effective lever. For example, a $20M investment in DCFC infrastructure would result in 132,000 EVs on the road (219% increase from baseline), and 647 GWh of EV load by 2034 (143% increase from baseline). However, investments in DCFC beyond certain thresholds may result in over-saturation and are expected to have diminishing returns. This suggests that investments should be diversified by complementing investments in DCFC with public L2 deployment, education and awareness initiatives and programs targeted towards commercial fleets. Although incentive programs could accelerate adoption in the short-term, they have limited long-term impact on the market and may not be a suitable approach for intervention.
- **The utilities' high capacity costs coupled with the coincidence between EV charging and utility loads will likely lead to significant peak increases and costs to the utilities if load management is not utilized or capacity costs are not reduced.** Under baseline conditions, the utilities are forecast to incur losses of $44M by 2034 as a result of EV deployment. Additionally, most investments that accelerate EV adoption (i.e. DCFC deployment, etc.) will have negative returns under the existing capacity costs and unmanaged charging loads and will further increase losses. This is primarily due to the utilities' high capacity costs¸ and if EV load management can be deployed the financial impacts could change significantly.
- **EV charging load management will be critical to handle the system impacts of EVs and benefit financially from EV adoption under baseline scenario as well as any investment scenario.** With load management, 85% of peak charging is estimated to be shifted to off-peak hours. A modeled $20M investment focused on DCFC and L2 infrastructure can bring more than $170M in additional value by 2034 in the presence of load management versus a loss of $113M under an unmanaged charging scenario. This corresponds to an increase in peak demand of 42 MW under a load management scenario (approximately 2% of forecast 2034 peak demand), whereas unmanaged load scenario would contribute to 281 MW of additional peak load (13% of forecasted 2034 peak demand). The utility should thus prioritize initiatives that can reduce peak impacts of EV loads and consider more granular analysis to assess the specific potential and costs associated with shifting EV load in the Newfoundland and Labrador system.



FINAL REPORT (VOLUME 2 – APPENDICES)

Conservation Potential Study

dunsky

Conservation Potential Study
Final Report, Volume 2

Submitted to:

Newfoundland Power Inc.
Newfoundland and Labrador Hydro

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LIST OF ACRONYMS

ASHP – Air Source Heat Pump

BEV – Battery Electric Vehicle

BUG – Backup Generator

CBR – Cost Benefit Ratio

CDM – Conservation and Demand Management

CEUS – Commercial End-Use Survey

CPP – Critical Peak Pricing

CVR – Conservation Voltage Reduction

DCFC – Direct Current Fast Charger

DEEP – Dunsky Energy Efficiency Potential Model

DHW – Domestic Hot Water

DMSHP – Ductless Mini-Split Heat Pump

DR – Demand Response

EE – Energy Efficiency

ER – Early Replacement

EUL – Estimated Useful Life/Effective Useful Life

EVA – Electric Vehicle Adoption Model

RCx – Retro-commissioning

FS – Fuel Switching

GHG – Greenhouse Gas

GWh – Gigawatt Hour

HDV – Heavy Duty Vehicle

HVAC – Heating, Ventilation, and Air-Conditioning

ICE – Internal Combustion Engine

IIC – Island Interconnected System

IOC – Iron Ore Company of Canada

ISO – Isolated Diesel System

ISP – Industry Standard Practice

kWh – Kilowatt Hour

L2 – Level 2

LAB – Labrador Interconnected System

LDV – Light Duty Vehicle

LED – Light-Emitting Diode

MDV – Medium Duty Vehicle

MW - Megawatt

MWh – Megawatt Hour

NTGR – Net-to-Gross Ratio

PACT – Program Administrator Cost Test

PC – Participant Cost

PCT – Participant Cost Test

PHEV – Plug-in Hybrid Electric Vehicle

ROB – Replace on Burnout

RUL – Remaining Useful Life

SCT – Societal Cost Test

SEM – Strategic Energy Management

TCO – Total Cost of Ownership

TOU – Time-of-Use

TRC – Total Resource Cost

TRM – Technical Reference Manual

VFD – Variable Frequency Drive

VRF – Variable Refrigerant Flown

DEFINITIONS

Assessment of potential: The development of energy and capacity savings available from projected customer usage through the application of commercially available, cost-effective technologies and improved operating practices, considering the impacts of market factors.

Achievable potential: The savings from cost-effective opportunities once market barriers have been applied, resulting in an estimate of savings that can be achieved through demand-side management programs. Three achievable potential scenarios were modeled to examine how varying factors such as incentive levels and market barrier reductions impact uptake.

Cumulative savings: A rolling sum of all new savings that will affect energy sales, cumulative savings exclude measure re-participation (i.e. savings toward a measure are counted only once, even if customers can participate again after the measure has reached the end of its useful life) and provide total expected grid-level savings.

Economic potential: The savings opportunities available should customers adopt all cost-effective savings, as established by screening measures against the Total Resource Cost (TRC) test, without consideration of market barriers or adoption limitations.

Energy End-Use: In this study, energy end-uses refer to grouping of energy saving measures related to specific building component (i.e. water heating, HVAC, lighting etc.)**.**

Energy Saving Measure: An energy saving measure (or measure) refers to a specific equipment or building operation improvement that leads to energy savings.

Market Sector: The market of energy using customers in Newfoundland and Labrador is broken down into two sectors based on the primary occupants in the building: Residential (including single family and multi-family buildings) or Commercial (including businesses, institutional and industrial buildings).

Market Segment: Within each Sector, market segments are defined to capture key differences in energy use and savings opportunities that are governed by building use and configuration.

NL Utilities: Refers to the two retail utilities in Newfoundland and Labrador, Newfoundland Power (NF Power) and Newfoundland and Labrador Hydro (NL Hydro).

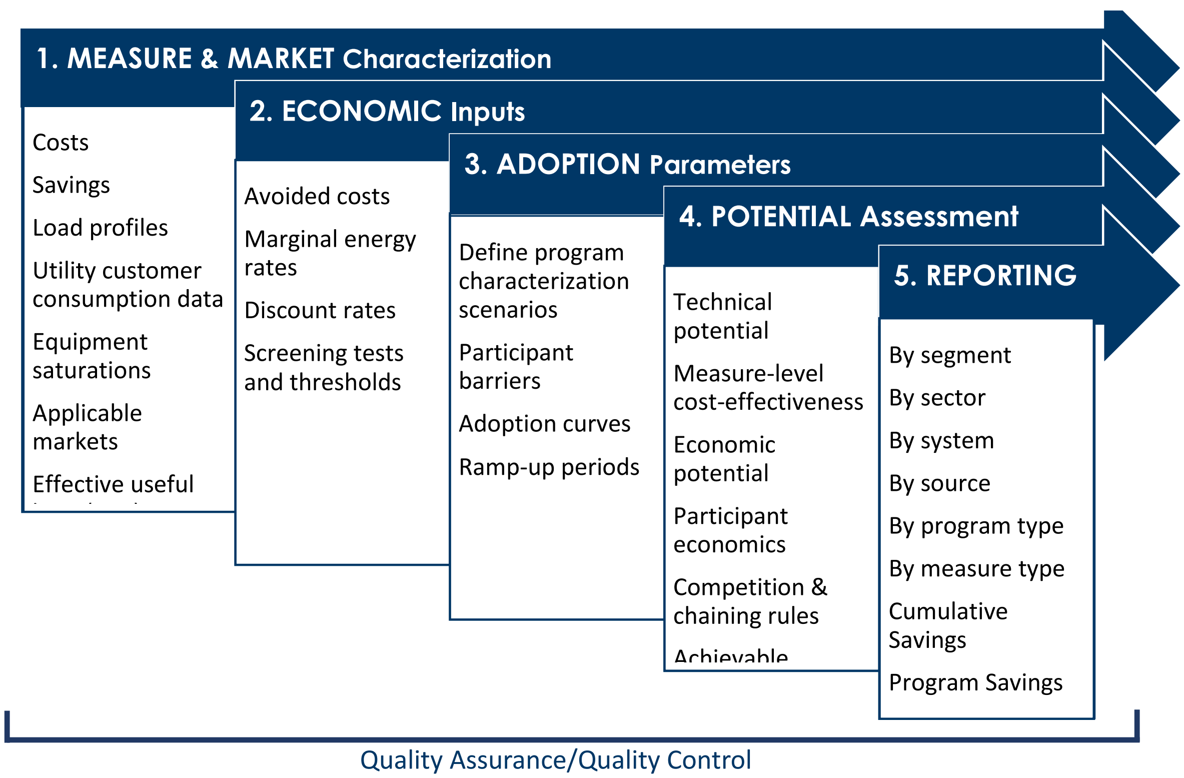
Program savings: Savings from measures that are incentivized through programs in a given year, including savings from measure re-participation. They are most representative of annual program savings and can be used to improve CDM program planning to help meet savings objectives, and to determine which sectors, end-uses, and measures hold the most potential.

Technical potential: The theoretical maximum savings potential, ignoring constraints such as cost-effectiveness and market barriers.

APPENDIX A: DUNSKY ENERGY EFFICIENCY POTENTIAL (DEEP) MODEL METHODOLOGY

The Dunsky Energy Efficiency Potential (DEEP) model employs a multi-step process to develop a bottom-up assessment of the Technical, Economic and Achievable Potentials. The process begins by establishing a comprehensive set of inputs related to energy savings measures, markets, equipment saturations, and economic factors, which are then applied in the model to assess energy savings potential. This appendix outlines the key features of the modelling technique, including the calculation methodologies employed, and the steps taken to ensure the accuracy and quality of the final results and reporting. **Figure A- 1** below provides a high-level overview of the key assessment steps and inputs, followed by more details throughout this appendix.

Figure A- 1. Key steps and inputs in study methodology



The key steps in the DEEP modelling process are:

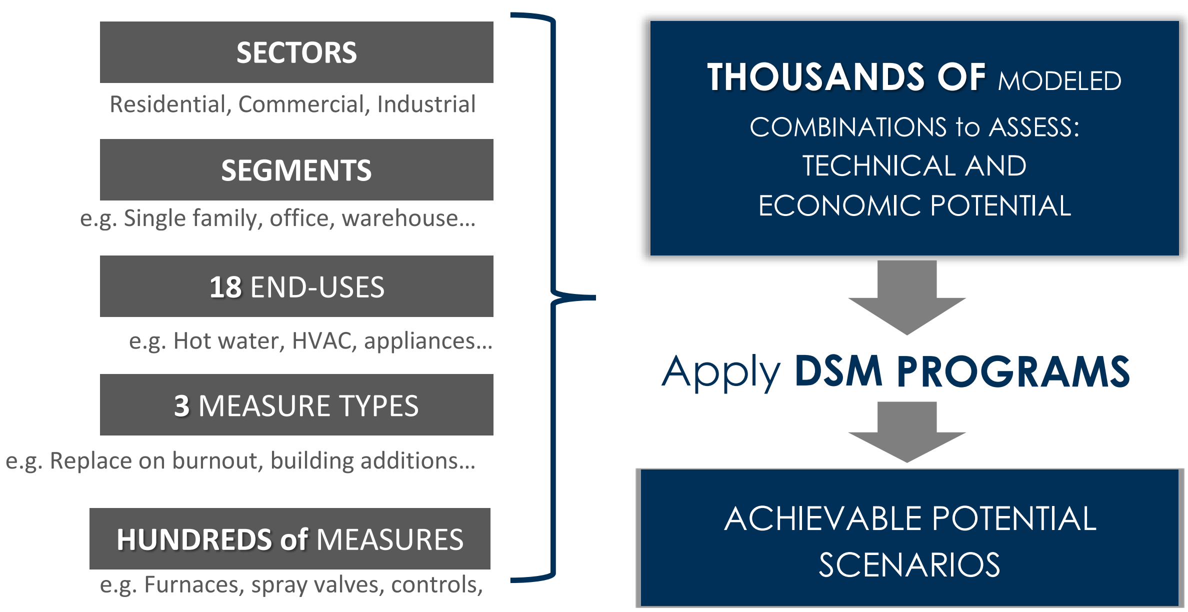
- **Characterize Measures and Their Applicable Markets:** A comprehensive list of energy saving measures is characterized by applying jurisdiction-specific data and assumptions to each measure and market segment. Primary and secondary data are compiled (as available) to establish an assessment of the market baseline, detailing the current saturation of energy using equipment in each market sector and segment. Markets for energy measures are then assessed by combining utility customer counts with market growth factors, equipment turnover rates, and the market baseline results.
- **Economic Inputs:** The model harnesses key economic inputs to assess the measure cost-effectiveness and benefits. Utility avoided costs, customer discount rates, energy rates, and the utility cost of capital are captured and entered into the model in real dollars based on the study period start year. The cost-effectiveness test that will be applied for economic screening is selected, as well as the other test that will be calculated to benchmark program performance.
- **Adoption Parameters:** For each measure-market combination adoption curves are assigned based on customer barrier level assessments. Customer economics inputs such as measure savings, marginal electricity rates and other secondary energy sources are applied to calculate the participant cost test (PCT), the key driver of adoption levels in each adoption curve. Finally, program characterizations are entered into the model by defining the fixed and variable program costs, incentive levels, and enabling activity impacts on customer barriers.
- **Potential Assessment:** The DEEP model assesses the technical potential by combining the measure characterization with the market baseline inputs to determine the theoretical maximum amount of savings possible for each measure-market combination, in each year, over the study period. Measures-market combinations that pass the cost-effectiveness threshold are counted in the economic potential. Achievable potential scenarios are applied by calculating the customer economics, under various incentive program scenarios, and applying adoption curves as described later in this Appendix. At each level, the model applies chaining factors to account for interactive effects among measures and assigns the appropriate market portion in places where multiple measures may compete for the same market (e.g., Tier 1 and Tier 2 efficiency heat pumps).
- **Reporting:** Reporting is conducted in four steps, from the presentation of the initial Draft Results to the Final Report, each with an increasing level of precision and detail. Each report is vetted by the relevant parties, and all feedback is considered and incorporated into the model and reporting before proceeding to the next step.
- **Quality Assurance / Quality Control (QA/QC):** Throughout the modeling process, a rigorous QA/QC process is applied to ensure the inputs reflect the energy using equipment in the studied jurisdiction, and that the results provide an accurate assessment of the energy savings potential. The model is calibrated to past DSM program performance and benchmarked to the baseline energy sales projections and individual energy end-uses, to ensure that the technical, economic and market factors align with the local reality.

DEEP'S BOTTOM-UP ASSESSMENT OF POTENTIAL

DEEP's bottom-up modelling approach assesses each measure-market segment combination, applying CDM programs to arrive at a fulsome assessment of the energy savings potentials. Rather than estimating potentials based on the portion of each end use that can be reduced by energy saving measures and strategies (often referred to as a Top-Down analysis), the DEEP model's Bottom-Up approach applies a highly granular calculation methodology to assess the energy savings opportunity for each measure-market segment opportunity in each year. Key features of this assessment include:

- **Measure-Market Combinations:** Equipment saturations, utility customer counts, and demographic data are applied to create "markets" for each individual measure. The savings per year, and the market size are unique for each measure-market segment combination, thereby increasing the accuracy of the results.
- **Phase-In Potential:** The DEEP model applies the equipment expected useful life (EUL) and market growth factors to determine the number of energy savings opportunities for each measure-market combination in a given year. This provides an important time series for each energy savings measure, upon which estimated annual achievable program volumes (measure counts and savings) can be calculated in the model, as well as phase-in technical and economic potentials.
- **Annual and Lifetime Savings:** For each measure-market combination in each year, DEEP calculates the annual savings as well as the lifetime savings, accounting for mid-life baseline adjustments where appropriate. This provides a read on the cumulative savings (above and beyond natural uptake), as well as the annual savings that will pass through DSM portfolios.

Figure A- 2.Bottom-up Combinations in the DEEP Model (A Separate Model was Created for Each NL Electric System)



OVERVIEW OF MODELLING CALCULATIONS

The DEEP model assesses three levels of energy savings potential: technical, economic, and achievable. In each case, these levels are defined based on the governing regulations and practice in the modeled jurisdiction, such as applying the appropriate cost-effectiveness tests, and applying the relevant benefit streams and net-to-gross (NTG) ratios to ensure consistency with evaluated past program performance.

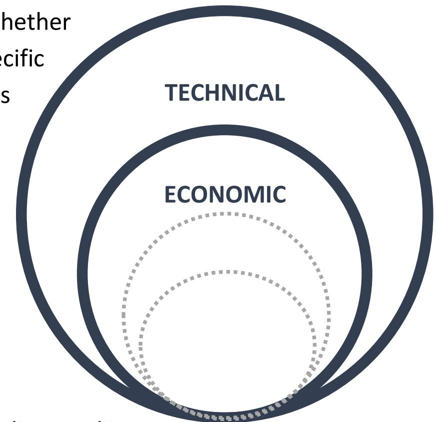
- **Technical Potential:** The technical potential accounts for all theoretically possible energy savings stemming from the applied measures. In markets where multiple measures may compete,[1] the measure procuring the most energy savings per unit is selected.
- **Economic Potential:** The economic potential includes all measures that pass the cost-effectiveness test screen. Economic screening is performed at the measure level, and only accounts for direct costs related to the measure, not including general DSM program costs.
- **Achievable Potential:** The achievable potential considers customer barriers and economics to assess the annual adoption of measures within DSM programs. Achievable potential scenarios are applied based on the removal of barriers (incentives and enabling activities).

Figure A- 3.Bottom-up combinations in the DEEP Model

APPLIED CALCULATION	TECHNICAL POTENTIAL	ECONOMIC POTENTIAL	ACHIEVABLE POTENTIAL
1. ECONOMIC SCREENING	No Screen	Cost-Effectiveness (TRC)	Cost-Effectiveness (TRC and PCT)
2. MARKET BARRIERS	No Barriers (100% Inclusion)	No Barriers (100% Inclusion)	Market Barriers (Adoption Curves)
3. COMPETING MEASURES	Winner takes all	Winner takes all	Competition Groups Applied
4. MEASURES INTERACTIONS	Chaining Adjustment	Chaining Adjustment	Chaining Adjustment
5. NET SAVINGS	Not Considered	Not Considered	Program NTGR

[1] The words “market” or “market size” are used to describe the number of baseline equipment or buildings in a given segment that capture the opportunity for specific energy-efficient measures. For example, the number of sockets with incandescent bulbs in the single-family residential sector would be an example of a “market” for CFLs or LEDs.

CALCULATION OF TECHNICAL AND ECONOMIC POTENTIAL



Various calculation methods are applied at different levels of potential, whether technical, economic, or achievable. These are based on each measure's specific characterization (cost-effectiveness, market applicability), as well as interactive and competition effects among measures.

The calculations applied at the technical and economic levels of potential assessment are outlined below. Calculations are conducted independently at each level to account for shifting and dynamic measure mixes and interactive effects at each level.

TECHNICAL POTENTIAL

Technical potential is the theoretical maximum savings opportunity, disregarding constraints such as cost-effectiveness and market barriers. This excludes early replacement and retirement opportunities, which are to be addressed in the subsequent *achievable* potential analysis.

The measure procuring the most energy savings per unit for each sub-sector and end-use is selected, which maximizes overall energy savings. The focus of the technical potential is on energy savings (e.g., the measures selected are based on energy savings, although demand savings are also calculated). The measures applied in the model are outlined in the approved study measure list (included in Appendix E).

Phase-in Technical Potential: The technical potential, and all other potential levels are calculated on an annual phase-in basis to determine the size of the available market in each year. For each measure for each year, the calculation applies the market size and growth factors, measure type, early and natural replacement rates of existing equipment, and the maximum number of units that could be replaced or installed for a given measure.

ECONOMIC POTENTIAL

Economic potential is determined by screening technical potential measures – or bundles of measures – against the applicable standard cost-effectiveness tests. It disregards market barriers to adoption.

The model can apply any standard cost-effectiveness test, and adaptations are made to follow local jurisdiction cost-effectiveness testing requirements. The threshold for screening is set at 0.8 for the TRC (i.e., measures that achieve a higher cost-effectiveness test result are counted in the economic potential) but can be adjusted in the model to test various screening regimes. Tests included in the model are:

- **Total Resource Cost (TRC) Test**
- **Program Administrator Cost Test (PACT)**
- **Participant Cost Test (PCT)**

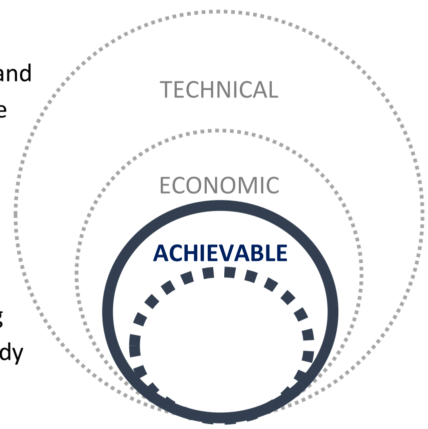
Table A- 1: Costs and Benefits that May be Applied for Cost-Effectiveness Screening

Benefits	Costs
• Utility avoided costs (TRC, PACT) • Customer avoided energy costs (PCT)	• Incremental measure costs (TRC, PCT) • Incentive Costs (PACT)

When calculating the inputs above, and indeed throughout the DEEP model, Dunsky applies the following:

- **Lifetime Benefits:** All benefits applied in the cost-effectiveness test are multiplied by their corresponding cumulative discounted avoided costs to get a present value ($) of lifetime benefits.
- **Real Dollar Accounting:** All benefits and costs are adjusted to real dollars, expressed in the first year of the study (unless otherwise requested).

ACHIEVABLE POTENTIAL SCENARIO ASSESSMENT



The achievable potential is the estimated amount of energy and demand savings that can be achieved by the portfolio of DSM programs applied to the market. **Market adoption is assessed by applying the PCT along with the market adoption curve** associated with the assigned market barrier level for each measure.

Various scenarios are applied by modifying the enabling activities, specifically the incentive levels and barrier reductions from enabling activities. Achievable potential scenarios are defined according to the study requirements.

DSM PROGRAM ARCHETYPES

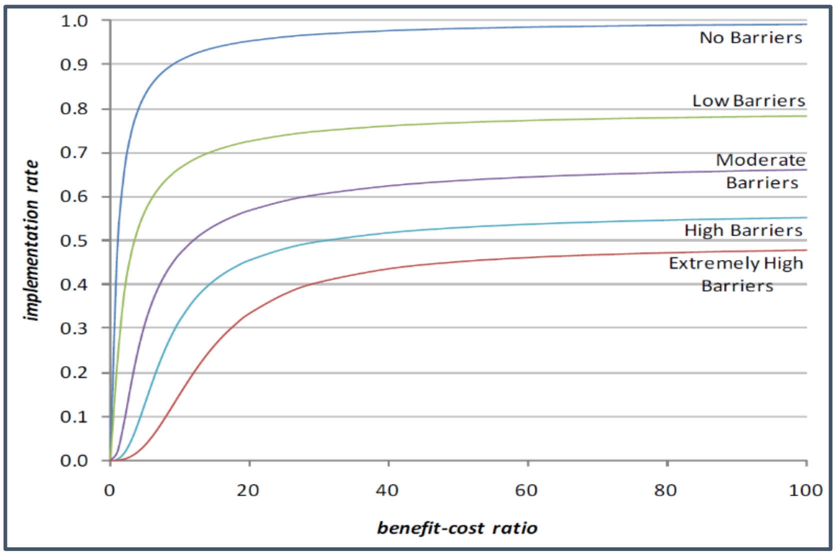
The achievable potential scenarios are assessed by applying DSM program archetypes that are developed based on an analysis of local DSM program evaluation reports, best practices from other jurisdictions, and through discussion with the DSM program administration team(s). Characterization of each program includes translating enabling strategies into customer barrier reduction impacts, incentive levels, cost structure, and applicable measures; those measures are mapped into the potential model. The model's bottom-up calculation approach is used to obtain costs, savings and average persistence of energy savings at the program level by aggregating measures by program archetypes using program assumptions.[2]

[2] While these high level assumptions are used in the model, the Utilities will complete detailed program design after the study is completed, and some programs may be screened out based or deemed not cost effective based on this

DEEP'S REFINED ADOPTION RATE METHODOLOGY

Rooted in the United States' Department of Energy (U.S. DOE) adoption curves,[3] the model methodology sets adoption rates based on a combination of customer cost-effectiveness – applied differently for each sector – and levels of market barriers. **Figure A- 4** presents a schematic view of resulting adoption curves. Five levels of barriers, to which measure categories are assigned based on market research or professional experience, define the maximum adoption curves. Different end-uses and segments exhibit different barriers.

Figure A- 4.Adoption Curves Used in the Study



The DEEP model applies five steps to determine the achievable potential:

1. **Barriers:** Assign each measure category, within each segment, to one of five adoption curves based on its assumed market barrier level (these can change over time if market transformation effects are anticipated).
2. **Drivers:** Assign cost-effectiveness metrics to each sector based on market research into economic drivers or professional experience.
3. **Incentives:** Assign assumed incentive levels.
4. **Economics:** Calculate customer cost effectiveness expressed by the PCT.

in-depth program design.

[3] The USDOE uses this model in several regulatory impact analyses. An example can be found in http://www.regulations.gov/contentStreamer?objectId=090000648106c003&disposition=attachment&contentType=pdf, section 17-A.4.

5. **Adoption:** Calculate resulting adoption rates and adjust as needed based on other external influences such as the ramp-up period (see *Refinement #2* in the call-out box below).

While this methodology is rooted in the U.S. DOE's extensive work on adoption curves, it applies two important refinements, as described in the call-out box below.

Refinements to U.S. DOE Adoption Curves

Refinement #1: Choice of the cost-benefit criteria. The DOE model assumes that participants make their decisions based on a benefit-cost ratio calculated using discounted values. While this may be true for a select number of large, more sophisticated customers, experience shows that most consumers use simpler estimates, including payback periods. This has implications for the choice and adoption of measures, since payback period ignores the time value of money as well as savings after the break-even point. The model converts DOE's discount rate-driven curves to equivalent curves for payback periods.

Refinement #2: Ramp-up. Two key factors – measure awareness and program delivery structure – can in theory limit program participation, especially during the first few years after a program's launch, and result in lower participation than DOE's achievable rates would suggest. For example, a new home retrofit program that requires the enrollment and training of skilled auditors and contractors by program vendors could take some time to achieve the uptake assumed using DOE's curves. In this study, we have therefore applied an adjustment to select programs on a case-by-case basis.

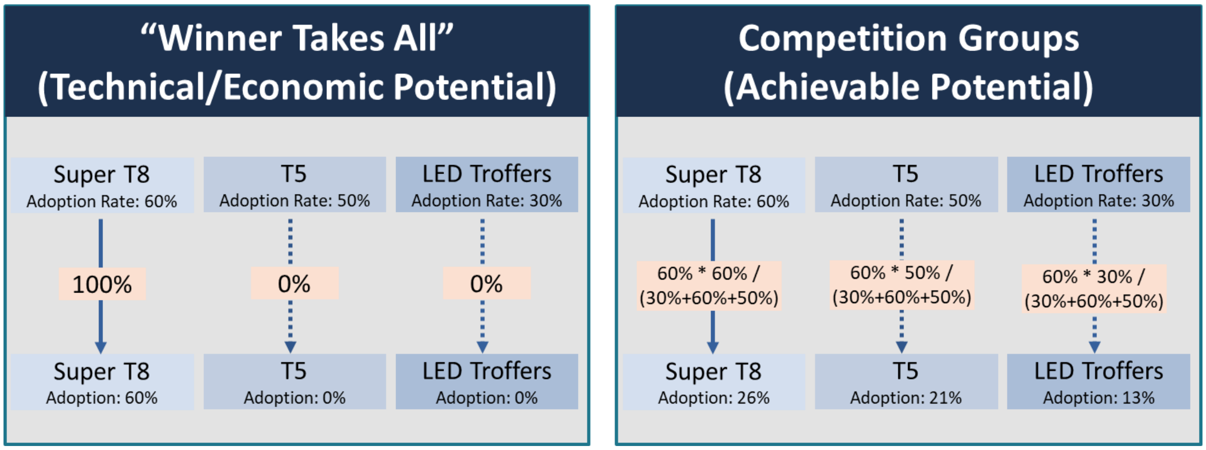
COMPETING MEASURES

Competing measures share the same market opportunity but are mutually exclusive. Examples include ground-source heat pumps vs. air-source heat pumps, or LED troffers vs. T5 lamps. In these cases, the DEEP model assesses the market for each depending on the potential level as follows:

- **TECHNICAL POTENTIAL**: 100% of the market is applied to the measure with the highest savings.
- **ECONOMIC POTENTIAL**: 100% of the market is applied to the *cost-effective* measure with the highest savings.
- **ACHIEVABLE POTENTIAL**: All cost-effective measures compete for the same market. Assuming that all measures are cost-effective, each adoption rate will be a pro-rated value based on the maximum adoption rate and each of the measures' respective adoption rates.

Below is an example where three measures compete: LED troffers, Super T8 and T5 lamps. First, the adoption rate is calculated for each measure independent of any competing measures, as outlined in the figure below.

Figure A- 5. Competing Measures Overview



From this assessment, the maximum adoption rate is assessed at 60%, corresponding to the measure with the highest potential adoption. From this, measures adoptions are pro-rated based on their relative independent adoption rates, to arrive at each measure's share of the 60% total adoption rate. As a result, the total adoption rate is still 60%, but it is shared by three different measures.

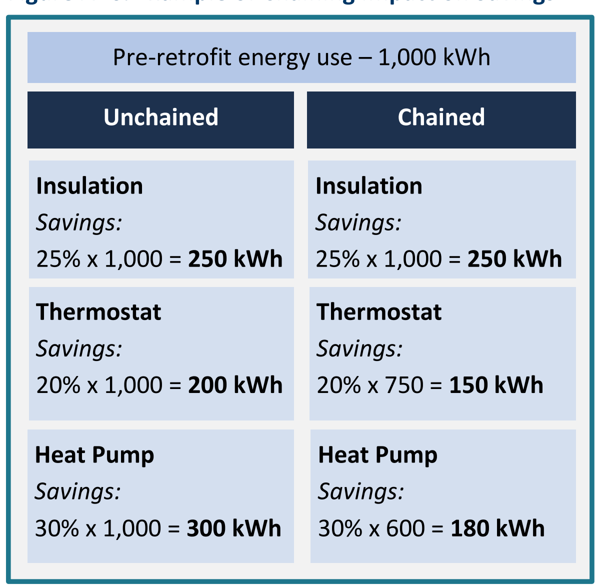
MEASURE INTERACTIONS - CHAINING

Chained measures are subject to adjustment when other measures are also installed in the same segment (see **Figure A- 6** below). Chaining is applied at all potential levels (technical, economic and achievable), and these interactive effects are automatically calculated according to measure screening and uptake at each potential level.

The DEEP model applies a hierarchy of measures in the chain, reducing the savings from each measure that is lower down the chain. The DEEP model adjusts the chained measures' savings for each individual measure, with the final adjustment calculated based on the likelihood that measures will be chained together (determined by their respective adoption rates), and the collective interactive effects of all measures higher in the chain.

An example is provided where insulation is added in a given segment in addition to a smart thermostat and a heat pump. **Figure A- 6** highlights the calculations used when

Figure A- 6. Example of Chaining Impact on Savings



incorporating adoption rates to calculate chaining effects.

In the above example, the percentage of total measures adopted is calculated by taking into account the fact that some participants will adopt multiple measures. For example, for insulation alone, a 50% adoption rate is calculated when considered in isolation, and 40% is calculated for heat pumps. When chaining is considered, the adoption is distributed between those that would happen with chaining and those that happen in isolation. Therefore the assumption in this example is that 40% of the participants adopting insulation will also install a heat pump, and that 50% of the participants adopting a heat pump will also improve their insulation levels.

CUMULATIVE SAVINGS AND AGGREGATE RESULTS

To calculate the cumulative savings and report aggregate savings for each electricity system by measure, end-use, segment and sector, the following approaches are applied to roll up and adjust annual measure savings.

- **Cumulative Annual Savings**: Cumulative savings are calculated for each potential type and each year, using incremental savings potentials. Savings from individual measures are removed from the cumulative savings at the end of their effective useful life (EUL). For instance, a measure installed in Year one and with a EUL of two years would not be recounted in the cumulative potential starting in Year three.

- **Aggregate Results and Reporting**: Measure-level consumption and demand savings-related costs, and benefits are aggregated by sector, segment, end-use, measure-type, or program.

ITERATIVE QA/QC AND REFINEMENTS

To ensure that the DEEP model provides valid results for assessing the potential at all levels, a rigorous QA/QC process is applied throughout all steps in the study. This includes industry best-practices including:

- QA/QC checklists for all modelling processes
- Issue identification and trackers to ensure all items are addressed
- Data cleaning and input benchmarking to ensure all inputs
- Automated input compiling to avoid human error when loading model with study data
- Vetting with internal senior research leads, and relevant client/utility experts
- Model calibration to past program performance
- Feedback QA assessments, wherein model outputs are benchmarked to baseline sales data, and inputs are reviewed where anomalous outputs are observed
- Vetting of model with client/utility via sharing of DEEPs transparent input and calculation sheets

The DEEP model draws its inputs from a detailed measure, market, program and economic databases that are developed using jurisdiction specific data, as follows:

- **Measure Inputs:** Each measure is characterized for the specific jurisdiction being studied (i.e., all parameters are updated to reflect local climate, equipment availability and costs). Then measure costs, savings, EULs and market applicability are benchmarked against Dunsky's internal database of over 15 past potential study inputs to ensure that no values fall outside of the expected ranges, and that the inputs are adjusted or updated accordingly.
- **Market Inputs:** Detailed saturation tables are created for each measure-segment combination (referred to as markets in DEEP's modeling process). These are then benchmarked against recognized building energy thresholds (lighting densities, energy use intensities, cooling and heating capacity per unit condition floor area, average floor area per business etc.). Finally, the individual equipment saturations are benchmarked against Dunsky's internal database of equipment saturation tables, to identify any inputs that may be out of acceptable ranges or anomalous.
- **Economic Inputs:** All economic inputs are converted to real dollar terms based on the study start year, and adapted to fit the model input table formats. These are vetted internally and with the client who provided the sales projections and local economic settings to ensure consistency with internal planning values.
- **Program Inputs:** Program characterizations are developed based on a detailed study of current DSM programs in the jurisdiction, and recent evaluation reports. These are then vetted internally against our internal program characterization database and provided to utility DSM program administration representatives to ensure consistency with current program approaches, costs and incentive levels.

Once the inputs have been prepared and quality checked, a characterization database employs an automated script to assemble the input sheets and avoid any human transfer errors.

MODEL CALIBRATION

Model calibration ensures that the overall estimated energy and demand savings levels are in line with utility electricity forecasts. Because the bottom-up potential methodology is based on baseline equipment saturation data, the focus of the study calibration is on the validation of the market adoption forecast model, and to ensure that the collective inputs provide valid ranges for measure savings, costs and markets.

The study is refined using the most recent completed year of program activity available, using energy savings, demand savings, and costs. This step is more of a quick quality check on results than an actual model calibration, as there might be good reasons for the potential to be materially different from the last annual DSM results. For instance, some programs may be underperforming what is possible for such programs to achieve, or some other anomaly may impact achieved savings.

To account for these factors, calibration is performed at two levels: the overall program by program comparison, as well as at the measure level for a handful of the most influential technologies (i.e. standard LED lightbulb counts in the residential sector) that are typically not impacted by differences in program scope or program underperformance.

The calibration exercise identifies the extent to which the assessment of adoption rates – based on a combination of economic drivers and assumed market barrier levels – appears consistent with recent achievements. Large discrepancies are then reviewed and classified with one (or a combination) of four findings:

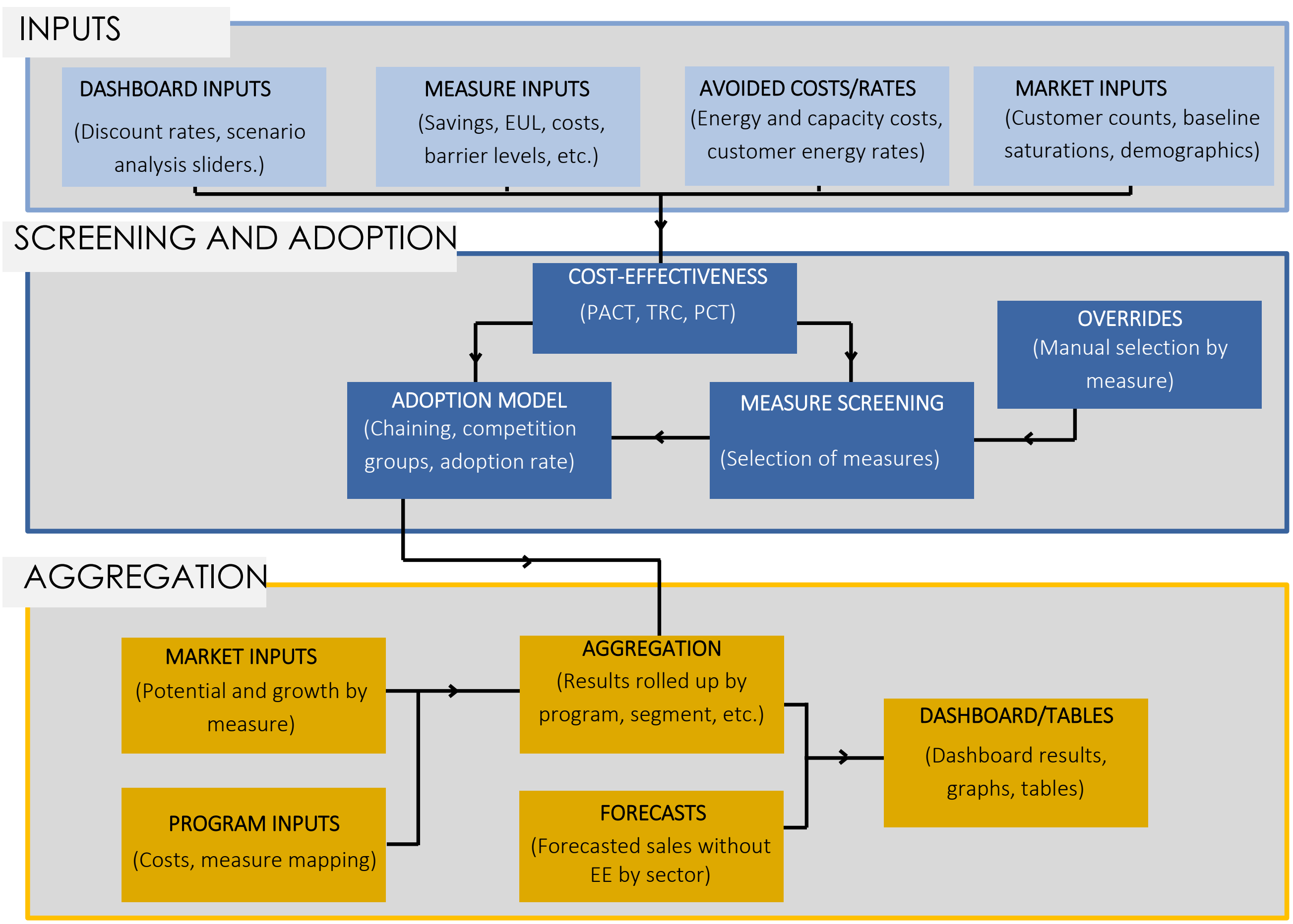
(1) The model is consistent with expected results;
(2) The market adoption algorithm needs to be revisited;
(3) Barrier levels for market adoption need to be revisited; or
(4) An anomaly likely explains an inconsistency, so no change is required.

These findings then inform iterative adjustments to the model inputs and settings before draft and final results are generated and shared with the client and/or stakeholders.

MODEL ARCHITECTURE

Figure A- 7 below presents an overview of the DEEP model's computational structure, including inputs, calculations, and aggregation. The methodology uses a bottom-up approach, beginning at the measure level with individual measure characterization (the top-most row in **Figure A- 7**). The measures are then screened and adoption rates are calculated based on cost-effectiveness results (middle row below). Measure results are then rolled-up by program, segment, sector, energy source, and end use for each electricity system.

Figure A- 7. DEEP model structure



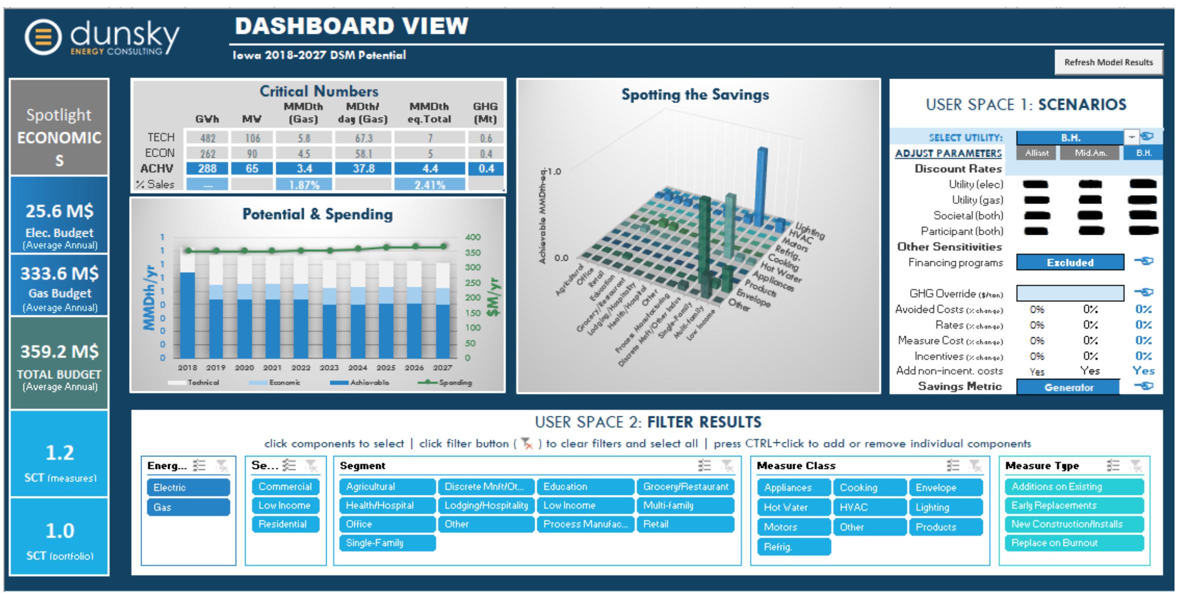
SCENARIO ANALYSIS DASHBOARD

The DEEP model can be delivered for use by the Utilities to run further what-if scenarios. To facilitate this, DEEP is equipped with a dashboard that provides a summary of the model outputs (results), and a range of user-input fields to adjust the model settings to test further scenarios. The model comes equipped with all input data and can be run on a PC equipped with MS Excel 2013 or later.

The Utilities also have access to measure and program input and output tables. Core input assumptions in the model are clearly defined and can be easily changed to conduct sensitivity analysis for efficiency measures, and adjust to changing market conditions (e.g. energy prices, economic growth) as well as recent program and evaluation results.

Figure A- 8 below shows a snapshot of the DEEP dashboard, which is the main entry point to use the model's features, run sensitivity analyses, and get high-level results.

Figure A- 8. DEEP Model – Dashboard View



APPENDIX B: DEMAND RESPONSE POTENTIAL METHODOLOGY

Dunsky's approach to analyzing demand response (DR) potential takes into account two specific considerations that differentiate it from energy efficiency potential assessments.

DR Potential is Time-Sensitive

- DR measures are often subject to constraints based on when the affected demand can be reduced and for how long.
- DR measure "bounce-back" effects (caused by shifting loads to another time) can be significant, creating new peaks that limit the achievable potential.
- DR measures impact one another by modifying the System Load Shape – thus the entire pool of measures (at all sites) must be assessed together to capture these interactive effects and provide a true estimate of the achievable potential impact on the system peak.

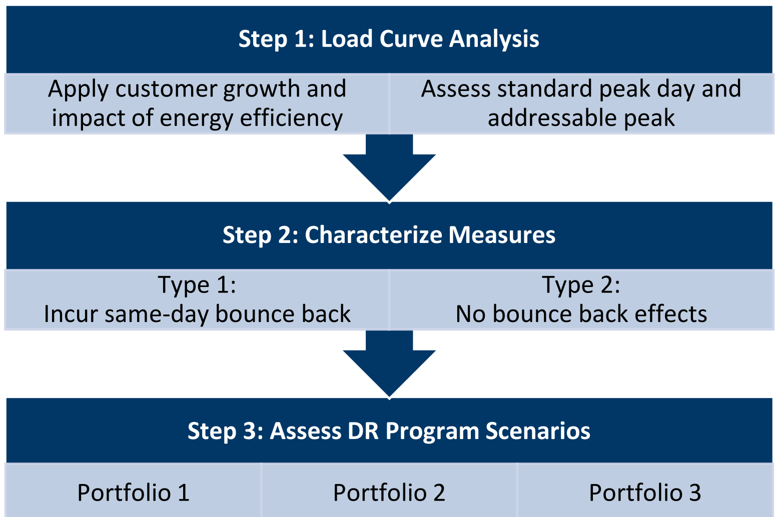
Many DR Measures Offer Little or no Direct Economic Benefits to Customers

- Participants must receive an incentive over and above simply covering the incremental cost associated with installing the DR equipment.
- Incentives can be based on an annual payment basis, a rebate/reduced rate based on a participant agreement to curtail load, or through time-dependent rates that send a price signal encouraging load reduction during anticipated system peak hours.
- Savings are expected to persist only as long as programs remain active.

The following sections outline Dunsky's Demand Response Model methodology, used to assess the technical, economic and achievable peak demand savings from electric demand response programs.

Figure B- 1 presents an overview of the analysis steps applied to assess the DR potential in this study. For each step, system-specific inputs are identified and incorporated into the model. Each step is described below.

Figure B- 1: Demand Response Potential Assessment Steps



STEP 1: LOAD CURVE ANALYSIS

The first modelling step of Dunsky's approach is to define the baseline load forecast and determine the key parameters of the utility load curve that influence the DR potential. The process begins by conducting a statistical analysis of historical utility data to determine the 24-hour load curve for the "Standard Peak Day" against which DR measure impacts are assessed. The utility peak demand forecast period is then applied to adjust the amplitude of the standard peak day curve over the study period. Finally, relative market sector growth factors and efficiency program savings are applied by end-use to further adjust the shape and amplitude of the peak day load curve.

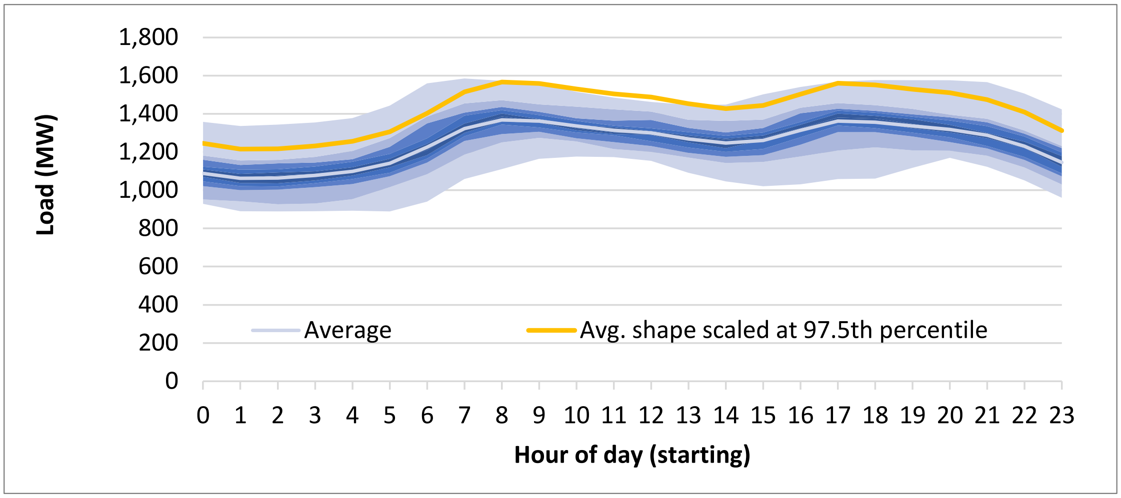
Figure B- 2: Load curve analysis tasks

Once complete, the load curve analysis provides a tool which can assess the individual measure, and combined program impacts against a valid utility peak baseline curve that evolves to reflect market changes over the study period.

IDENTIFY STANDARD PEAK DAY

The **Standard Peak Day** is assessed through an analysis of historical hourly annual load curves. For each year, a sample of the peak days are identified (e.g. 10 top peak demand days in a given year) and a pool of peak days is established. Each peak is normalized in order to compare the shape peaks. From this the average peak day shape is assessed by averaging the hourly shape. The standard peak day load curve is then defined by raising the average peak day load curve such that the peak moment matches the peak demand on the 97.5th percentile peak day (keeping the shape consistent with the average curve), as shown in **Figure B- 3** below.

Figure B- 3: Standard Peak Day Selection Curve (IIC)



Note: each blue shading area represents a 10 percentile gradient.

From the standard peak day curve, two DR windows were identified which represent the 3-5 hour time periods that capture the highest demand hours. These are assessed against the historical annual curves to ensure that 90% of DR peak events within a given year fall within the defined DR windows. These are used to characterize certain DR measures, providing guidance on which hours to target for high time of use (TOU) rate tiers, customer driven curtailment periods, and to create pre-charge/reduction/re-charge curves for equipment control measures, as described in the next step.

STEP 2: CHARACTERIZE DR MEASURES

DR potential is assessed drawing on Dunsky's database of over 30 specific demand reducing measures developed from a review of commonly applied approaches in DR programs across North America, and emerging opportunities such as battery storage.[4] Measures are characterized with respect to the local customer load profiles, and the technical and economic potentials are assessed for each measure.

Figure B- 4: DR Measure Characterization Tasks

Once complete, the measure-specific economic potential is assessed, and loaded into the model to assess the achievable potential scenarios when all interactive load curve effects are considered.

MEASURE SPECIFIC MODEL INPUTS

Measures are developed covering all customer segments and end-uses, and can be broadly categorized into two groups:

- **Type 1 DR Measures (typically constrained by demand bounce-back and/or pre-charging):**
    - These measures exhibit notable pre-charging or bounce-back demand profiles within the same day as the DR event is called. This can create new peaks outside of the DR window and may lead to significant interaction effects among measures, when assessed within their combined impact on the utility peak day curve.
    - Typically, Type 1 measures can only be engaged for a limited number of hours before causing participant discomfort or inconvenience. This is reflected in the DR measure load curves developed for each measure-segment combination.

[4] A detailed list of measures applied in this study is provided in Appendix E.

- **Type 2 DR Measures (unconstrained by load curve):**
  - These measures do not exhibit a demand bounce-back and are therefore not constrained by the addressable peak.
  - Some of them can be engaged at any time, for an unlimited duration.
  - These measures tend to not have interactive effects with other measures.

Dunsky's existing library of applicable DR measure characterizations is applied and adjusted to reflect hourly end-use energy profiles for each applicable segment. Key metrics of the characterization are:

1. **Load Shape:** Each measure characterization relies on an estimate of the 24-hour load shape both before and after the demand response event. The load shapes are based on the population of measures within each market segment and are defined as the average aggregate load in each hour across the segment.

2. **Effective Useful Life (EUL):** Effective useful life of the installed equipment/control device. For behavioural measures with no equipment, a one-year EUL is applied.

3. **Costs**: At measure level, the costs include the initial cost of the upgrade and the annual operational cost (costs of AMI installation or program not included).

4. **Constraints:** Some measures are subject to specific constraints such as the number of hours per day or year, maximum number of events per year and event durations.

Once the measures are adapted to the utility customer load profiles and markets, the technical and economic potentials are assessed for each measure independently as outlined below. Because these are assessed independently, the technical and economic potentials are not considered to be additive, but instead provide important measure characterization inputs to assess the collective achievable potential when analyzed together in step 3.

TECHNICAL POTENTIAL (MEASURE SPECIFIC)

The technical potential represents a theoretical assessment of the total universe of controllable loads that could be applicable to a DR program. It is defined as the technically feasible load (kW) impact for each DR measure considering the impact on the controlled equipment power draw coincident with the utility annual peak.

More specifically, the technical potential is calculated from the maximum hourly load impact during a DR event multiplied by the applicable market of the given measure. It is important to note that the technical potential assessment does not consider the utility load curve constraints.

ECONOMIC POTENTIAL (MEASURE SPECIFIC)

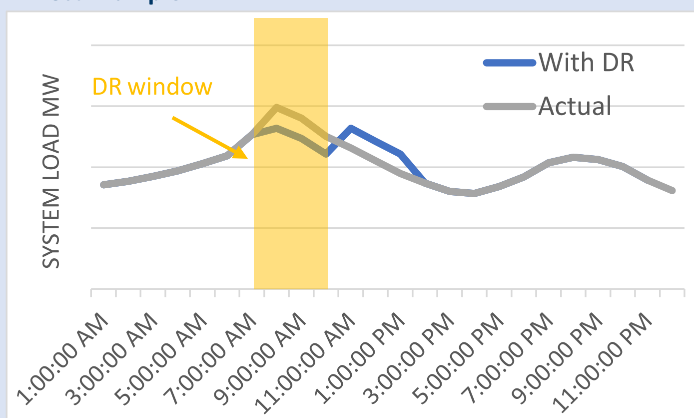
The assessment of each measure's economic potential is conducted in three key steps: adjustment of the technical potential, screening for cost-effectiveness, and adjusting for market adoption limitations.

1. **Technical Potential Adjustment:** The measure's hourly load curve impact is applied to the utility standard peak day load curve, to assess the net impact after pre-charge and bounce-back effects are accounted for. For each individual measure an optimization algorithm that assesses various control schemes and market portions is applied to arrive at the maximum number of participants and impact for the given measure, without creating a new system peak, either during the standard peak day, or over the sample annual hourly load profile.

Load Curve Impact Optimization Example:

By considering the bounce-back effect associated with water heaters recharging their reservoirs after the evening DR window has passed, **Figure B- 5** illustrates how adding too many water heaters to the DR program would risk creating a new peak outside of the DR window. This new peak is used to assess the net impact of the measures, which is determined as the difference between the peak before the DHW controls were applied and the new peak after the DHW controls were applied.

Figure B- 5: Illustrative Domestic Hot Water (DHW) Bounce-Back Effect Example



2. **Cost-Effectiveness Screening:** Once each measure's individual impact on the peak is assessed, it is then screened for cost-effectiveness, retaining just the measures with a PACT > 1 when considering installation costs and baseline incentive costs.[5] The PACT is considered the most appropriate existing test because utilities typically pay all incremental equipment costs in a DR program and because incentives to participants are typically an expense to the utility over and above the incremental

[5] Any measure that cannot achieve a PACT > 1.0 is not retained for further consideration in the model. For customer curtailment measures PACT screening may be assessed under a baseline incentive level (i.e. $20/kW). For equipment control measures the baseline incentive can be set to zero, and then adjusted for measures that return net benefits to the utility.

equipment costs (unlike in efficiency programs where the incentives provided cover a portion of the participant's incremental costs for the efficiency upgrade).

Table B- 1: DR Benefits and Costs Included in Determination of the PACT

Benefits	Costs
• Avoided Capacity Costs • Other ancillary benefits (as applicable)	• Controls equipment installation • Controls equipment Operations and Maintenance (O&M) (if required) • Annual incentives ($/ participant) • Peak reduction incentives ($/kW contracted)

For measures that pass the PACT screening, program incentives can then be set either as a fixed portion of the avoided costs benefits net of measure costs (i.e. 50%) or at the level that maximizes the PACT value for each measure that passes the cost-effectiveness screen.

3. **Market Adoption Adjustment**: The market for a given DR program or measure may be constrained either by the impact on the load curve, or by the expected participation (or adoption) among utility customers.

   In the first case, the economic potential assessment (described above) determines the number of devices needed to achieve the measure's maximum impact on the utility peak load. Adding any further participation will come at a cost to the utility, but with little or no DR impact benefits.

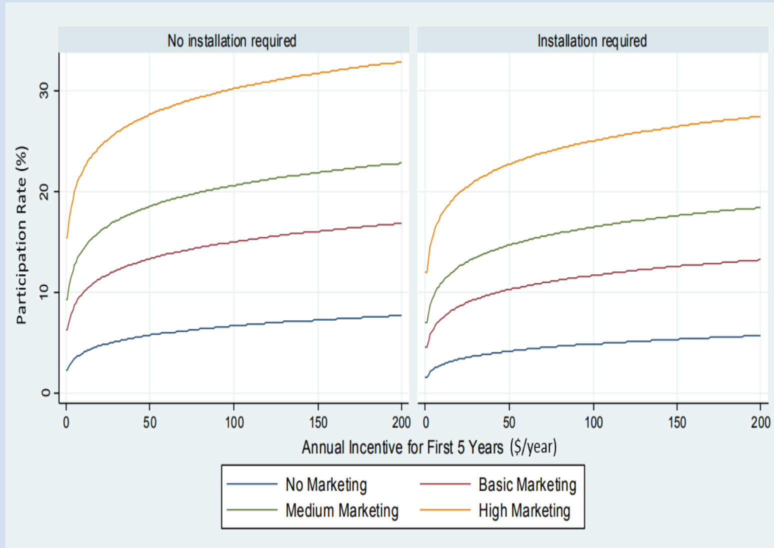
   In the second case, the model determines the expected maximum program participation based on the incentive offered, the need to install controls equipment, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves (described in the call out box below) developed by the Lawrence Berkeley National Laboratory.[6]

[6] Lawrence Berkeley National Laboratory, March 2017. 2025 California Demand Study Potential Study, Phase 2 Appendix F. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

Demand Response Propensity Curves

For each measure the propensity curve methodology, as developed by the Lawrence Berkeley National Laboratory to assess market adoption under various program conditions, is applied. The curves represent achievable enrollment rates as a function of incentive levels, marketing strategy, number of DR calls per year, and the need for controls equipment. Their development is based on empirical studies, calibrated to actual enrollment from utility customer data. Specific curves are available for each sector.

Figure B- 6: Residential Adoption Curves used in the study



The DR model assesses both the utility curve economic potential market and the maximum adoption at the resulting incentive levels, then constrains the market (maximum number of participants) to the lower of the two. This is then applied as a measure input for the achievable potential assessment described in the next step.

STEP 3: ASSESSMENT OF ACHIEVABLE POTENTIAL SCENARIOS

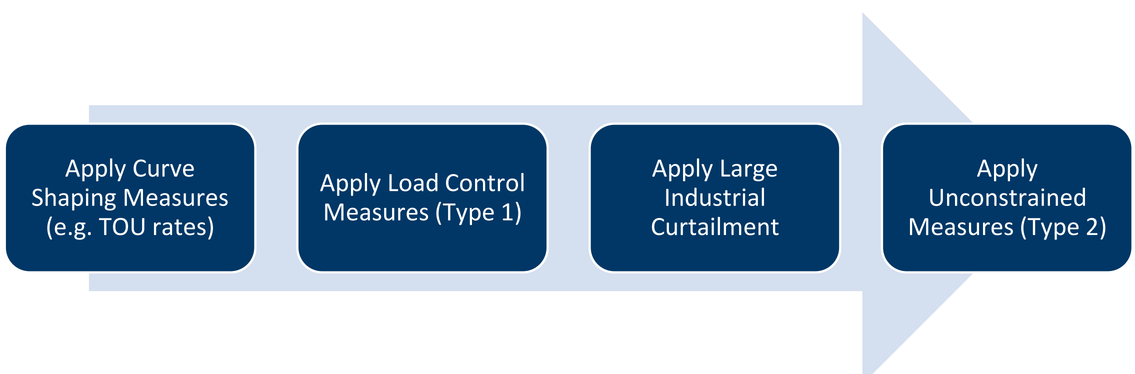
The achievable potential is based on the calibration of each measure's potential using an optimization process that considers market adoption constraints, individual measure constraints, and the combined inter-measure impacts on the utility load curve.

Scenarios are developed to assess the combined impact of selected programs and measures. For example, one scenario may assess the achievable potential of the impact of applying TOU rates and industrial curtailment, while another may assess the combined potential from direct load control of customer equipment and industrial curtailment. This approach recognizes that there can be various approaches to access the demand reduction potentials from the same pool of equipment (i.e. TOU rates can exert a reduction in residential water heating peak demand, thereby reducing or eliminating the potential from a water heater DLC program). The scenarios are assembled from logical combinations of programs and measures designed to test various strategies to maximize the achievable peak load reduction.

ASSESSING ACHIEVABLE POTENTIAL

For each scenario, measures are applied in groups in order starting with the least flexible/most constrained measures and progressing to the measures/groups that are less and less constrained, as per the order illustrated in **Figure B- 7** below.

Figure B- 7: Achievable Potential Assessment Tasks



- **Curve Shaping:** Rates Based Measures (such as time of use rates) are typically applied first as these are designed to alter customer behaviour with time, and are considered the least flexible (i.e. with the exception of critical peak pricing, they cannot be engaged by the utility to respond to a specific DR event, but must be set in place and exert a prolonged effect on the utility load curve shape).
- **Type 1 Load Control Measures:** Direct control of connected loads such as water heaters and thermostats, and customer controlled shut-off or ramp down of commercial HVAC loads are

applied next. These are typically constrained to specific times of day based on the utility peak load shape, and the controlled equipment load shape (i.e. turning of residential water heaters at midday may be feasible but deliver next to no savings as there is minimal hot water demand at that hour). These are assessed against the load curve altered by any shaping measures, and measures that may double count savings are eliminated. A new aggregate utility load curve is then created, applying the achievable load control peak reductions, and bounce-back effect.

- **Industrial / Commercial Curtailment:** Next customer curtailment is applied, which typically carries constraints related to the number of curtailment hours per day (consecutive and total), the number of events per year, and in some cases the time of day that curtailment can be applied. These are applied to the adjusted load curve, after direct load control impacts have been applied, to assess if the changes how the adjusted utility load curve impacts the potential impact of large industrial curtailment measures.
- **Unconstrained Measures:** Finally, the remaining Type 2 measures that have no constraints on the duration, frequency or timing of their application are applied. These may include measures such as dual-fuel heating, back-up generators, and conservation voltage regulation, which can be engaged as needed and whose potential is not impacted by the shape of the utility load curve.

DR PROGRAMS AND SCENARIOS

A set of best-in-class program archetypes is defined in the model based on a review of programs in other jurisdictions and information regarding the current programs in the province. For each program, development, marketing and operating costs have been estimated and applicable measures have been mapped to the corresponding program.

The model first determines the achievable peak demands of the combined measures within all programs, and then assesses the program level cost-effectiveness, combining appropriate measures within a given program, summing all program and measure costs, as well as applicable measure benefits. A minimum 10-year period is assumed for each program, except where the program is based on control devices with a longer EUL, in which case the program is assumed to cover the entire device life. In cases where DR device EULs are shorter than 10 years, re-installation costs are applied.

New measure and program ramp-up: Where applicable, new programs and measures can be ramped up accounting for the time needed to enroll customers and install controls equipment to reach the full achievable potentials. Ramp up trajectories applied to the achievable potential markets after all interactive effects (i.e. new peaks created or program interactions that affect the net impact of any other program) have been assessed.

Program Costs: Table B- 2 below presents the program costs for each major program type applied in the DR potential model. Program costs account for program development (set up), annual management costs, and customer engagement costs. These are added over and above any equipment installation and customer incentive costs to assess the overall program cost-effectiveness. In some cases, a program's constituent measures may be cost-effective, but the program may not pass cost-effectiveness testing due to the additional program costs. Under those scenarios, the measures in the underperforming program are eliminated from the achievable potential measure mix, and the DR potential steps are recalculated to reassess the potential and cost-effectiveness of each measure and program.

Table B- 2: DR Program Administration Costs Applied in Study (excluding DR equipment costs)

Program	Development Complexity	Admin Complexity	Development Costs	Program Fixed Annual Costs (1 FTE = 75,000)	Other Costs ($/customer) for marketing, IT, admin
Residential DLC	Small/Medium	High	$100,000	$75,000	$12
DR Backup Power	Medium	Med	$150,000	$75,000	$1,200
DR Commercial	Medium	Med	$150,000	$75,000	$1,200
Large Industrial Curtailment	Medium	Med	$150,000	$75,000	$3,500
TOU - Residential	Larger (billing system adjustments)	Med	$300,000[7]	$75,000	$90[8]
TOU - Commercial	Larger (billing system adjustments)	Med	$300,000	$75,000	$90
Smart Electric Vehicle Supply Equipment	Medium	Med	$150,000	$75,000	$5

[7] Development costs do not include AMIs. As stated in Appendix E, the costs of a full deployment of AMIs is estimated to be $85M– $105M.

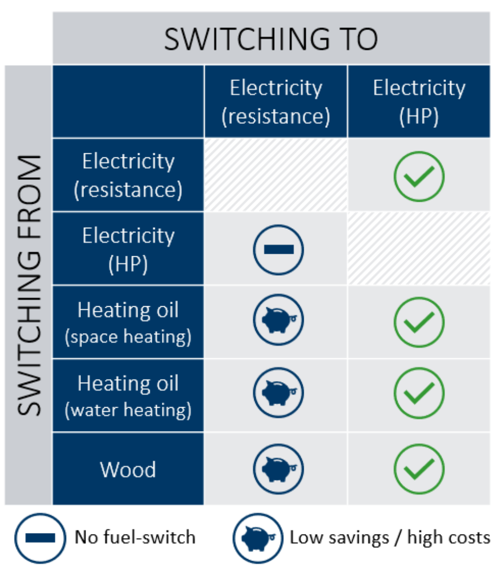
[8] Costs taken from “Decision – Matter No.375”, New Brunswick Energy and Utilities Board, 2018

APPENDIX C: FUEL SWITCHING STUDY METHODOLOGY

The fuel switching analysis assesses how many households and businesses can be expected to replace oil- and wood-fueled space and hot water heating systems with electric heat pumps over the study period under various incentive scenarios. It only considers customers within the Newfoundland Island Interconnected System (IIC).[9]

The analysis focuses on switching from combustible fuel to electricity to estimate the potential to displace heating fuels in favour of electricity consumption. The adoption of fuel switching measures is based on customer economics and barriers, using the same adoption modeling approach described in the DEEP model (see Appendix A). For residential customers, adoption is driven by the simple payback period, which does not discount future costs and savings, while for commercial customers, adoption is driven by the participant cost test (PCT) to account for more sophisticated purchasing practices.

Figure C- 1: Summary of Fuel Switching Combination Screening



Fuel switching measures were identified by comparing retail rates for the available sources of energy and adjusting the number of opportunities for each measure to reflect feasible fuel switching configurations based on cost and complexity. Ultimately, the analysis considered switching from oil and wood-based systems to electric heat pump systems. Switching to electric-resistance systems was excluded due to generally low (or negative) cost savings and/or high installation costs. In order to calibrate findings to overall heat pump market adoption trends an assessment for adding ductless mini-split heat pumps in households with electric resistance baseboards was included.

[9] Labrador Interconnected and Isolated-Diesel Systems are excluded due to limited fuel switching opportunities.

MEASURE CHARACTERIZATION

The identification of specific fuel switch combinations was based on an assessment of the NL market and Residential End Use Survey (REUS)/Commercial End Use Survey (CEUS) results. Full and partial fuel switching options were considered. Measures were characterized for viable fuel switch combinations. Measure characterizations are primarily based on modified algorithms and measure assumptions from published Technical Reference Manuals (TRMs) and supplemented with other sources (e.g. RSMeans data[10], market actor interviews). Measure characterizations include the following parameters:

- Energy and peak demand impacts, costs, effective useful life, etc.
- Marginal retail electricity rates and heating fuel costs (oil and wood)
- Market characterization results (CEUS and REUS)

Air source and ductless mini-split heat pumps are assumed to have efficiencies equivalent to the 2023 federal standard throughout the study period. Baseline oil and wood-fueled technologies are assumed to meet, but not exceed, federal efficiency standards.

The residential and commercial fuel switch measures characterized in this study are listed in **Figure C- 2** and **Figure C- 3** below, respectively.

[10] RSMeans is a database of construction costs including equipment, material and labor costs developed and maintained by Gordian. See: www.rsmeans.com

Figure C- 2: Summary of Fuel Switching by Technology (Residential)

RESIDENTIAL			
SWITCHING FROM	**SWITCHING TO**	**COMMENTS**	**TRM SOURCE**
Oil furnace	Central ducted air source heat pump		Massachusetts Technical Reference Manual (October 2018), 1.4 Air Source Central Heat Pump.
Oil furnace	Ductless mini-split heat pump	Partial switch	Massachusetts Technical Reference Manual (October 2018), 1.25 Ductless Mini-Split Heat Pump.
Oil boiler	Air to water heat pump		Modified from Massachusetts Technical Reference Manual (October 2018), 1.4 Air Source Central Heat Pump.
Oil boiler	Ductless mini-split heat pump	Partial switch	Massachusetts Technical Reference Manual (October 2018), 1.25 Ductless Mini-Split Heat Pump.
Wood furnace	Central ducted air source heat pump		Massachusetts Technical Reference Manual (October 2018), 1.4 Air Source Central Heat Pump.
Wood furnace	Ductless mini-split heat pump	Partial switch	Massachusetts Technical Reference Manual (October 2018), 1.25 Ductless Mini-Split Heat Pump.
Oil hot water heater	Heat pump hot water heater		New York Standard Approach for Estimating Energy Savings from Energy Efficiency Programs – Version 7, Domestic Hot Water, Heat Pump Water Heater (HPWH).

Figure C- 3: Summary of Fuel Switching by Technology (Commercial)

COMMERCIAL			
SWITCHING FROM	**SWITCHING TO**	**COMMENTS**	**TRM SOURCE**
Oil furnace	Central ducted air source heat pump		Mid-Atlantic Technical Reference Manual - Version 8, Unitary HVAC Systems.
Oil furnace	Ductless mini-split heat pump	Partial switch	Mid-Atlantic Technical Reference Manual - Version 8, Ductless Mini-Split Heat Pump.
Oil boiler	Air to water heat pump		Modified from Mid-Atlantic Technical Reference Manual - Version 8, Unitary HVAC Systems.
Oil boiler	Ductless mini-split heat pump	Partial switch	Mid-Atlantic Technical Reference Manual - Version 8, Ductless Mini-Split Heat Pump.
Oil hot water heater	Heat pump hot water heater		Pennsylvania Technical Reference Manual (June 2015), 3.4.2 Heat Pump Water Heaters.

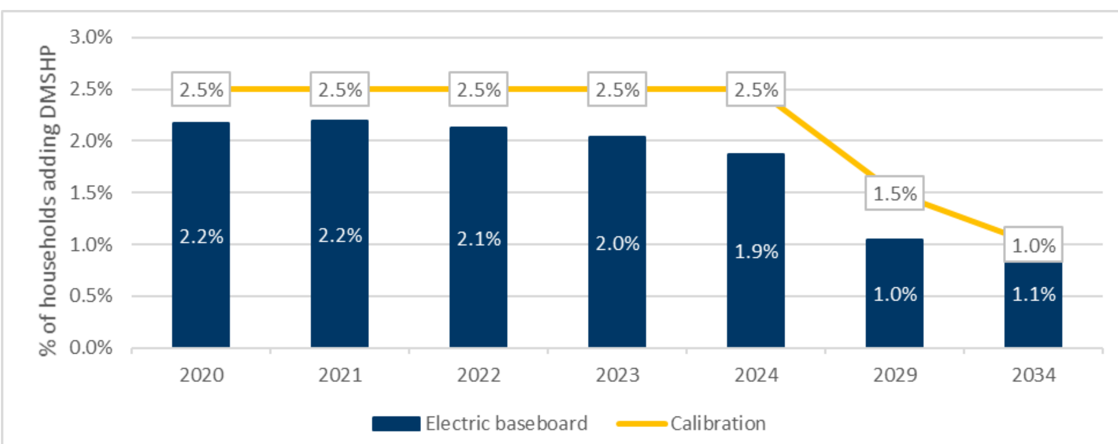
FUEL SWITCHING MODELING

The annual uptake of each fuel switch combination in each year of the study period is modeled and compared to various scenarios considering the impact that incentives and programs can have on the magnitude of fuel switching rates in each market segment. The model produces the following results:

- Annual uptake (number of customers per year)
- Impact on annual electricity sales and annual peak load
- Costs and benefits to customers and utilities
- Net greenhouse gas impacts (based on displacing oil consumption in favour of electricity)

The model was calibrated based on residential heat pump growth factors derived from end-use surveys and the 2018 takeCHARGE Market Study. Based on this information, market adoption of ductless mini-split heat pumps is assumed to be an additional 2.5% of all households annually between 2020 and 2024. This adoption will almost entirely occur among households with electric baseboard heating systems. After 2024, adoption tapers off with 1.5% of households adopting annually between 2025 and 2029 and 1% adoption between 2030 and 2034. The model is calibrated to these assumptions under a scenario with no utility incentives but with HIGH electricity rates to simulate consumer anticipation for higher electricity costs in the future. Ultimately, the model predicts adoption rates similar, but slightly below (roughly 16% below), our baseline adoption assumptions for households with electric baseboard heating. This discrepancy is likely a result of uncertainty over current baseline heat pump adoption, that was determined over just a single 2-year period (the REUS in 2017 and a residential market study conducted in 2018). The results indicate that the assumed baseline heat pump adoption may have been somewhat overestimated, and could possibly decline as the market becomes increasingly saturated. The model found little to no adoption among oil- and wood-heated households, which is aligned with assumptions.

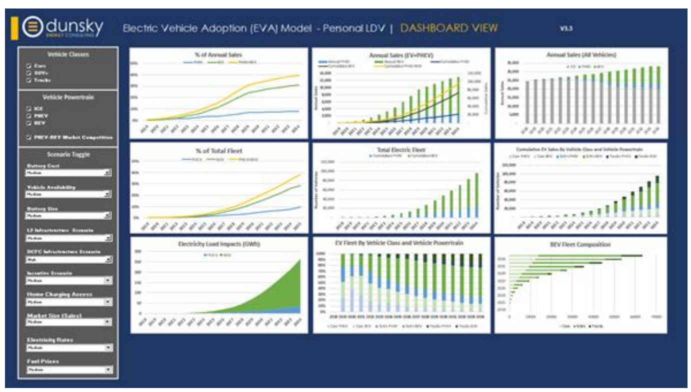
Figure C- 4. Model calibration results: residential adoption of DMSHP



APPENDIX EVA D: ELECTRIC VEHICLE ADOPTION (EVA) MODELING METHODOLOGY

The analysis of Electric Vehicles (EV) leverages Dunsky's Electric Vehicle Adoption (EVA) Model to project EV uptake in Newfoundland Labrador (NL) over the study period. Dunsky's EVA Model was developed in-house to address a growing need by its clients to understand the potential size of the electric vehicle market in their respective jurisdictions and corresponding utility impacts. Based on rigorous review of research from academia and industry, EVA leverages the modeling framework behind Dunsky's Solar Adoption Model (SAM) and builds on the knowledge base and expertise from the company's work with EV modelling.

Figure D - 1. Dashboard View



In addition to providing jurisdiction-specific forecasts for EV adoption, EVA can be used to assess the effectiveness of a range of policy and program options for accelerating EV adoption as well as the sensitivity of EV uptake to key market and technology uncertainties such as battery costs. Results from EVA are then used to assess the impact of the electrical load growth associated with an increasingly electrified transportation sector, helping utilities to plan ahead for this transition and put solutions into place that can help to manage this load growth in the most effective way.

MODEL METHODOLOGY

The model segments the vehicle market into:

- **Vehicle classes:** which are segments of vehicles that share similar characteristics and utilization profiles. For example, cars, SUV, truck, medium-duty, heavy-duty, and buses
- **Vehicle powertrains:** Including Battery Electric Vehicle (BEV), Plug-in Hybrid Electric Vehicle (PHEV), and Internal Combustion Engine (ICE)

EVA model projects market adoption of EVs of each vehicle class within a defined jurisdiction based on several key factors:

- **Technical potential:** The model assumes that annual vehicle sales represent the theoretical potential for EV deployment (i.e. 100% market share). A key consideration in assessing the technical potential is the availability of EV powertrains for the modeled segment. For each vehicle class, the availability of different powertrain types (e.g. plug-in hybrid, battery electric) is assigned a qualitative availability metric (None, Low, Medium or High) based on current availability of models in the market as well as estimated future availability based on industry projections or automakers' announcements; where None indicates no EV choices are available, and High indicates a similar number of EV choices as ICE.

- **Customer economics:** For each vehicle class and powertrain, the model uses key inputs to calculate a bottom-up vehicle cost based on vehicle characteristics (powertrain size, battery size, etc.). Additionally, Total Cost of Ownership (TCO) of each vehicle is calculated using an assumed lifetime and driving distance and considering fuel and operations and maintenance (O&M) costs over the vehicle's lifetime. The incremental upfront cost and Total Cost of Ownership (TCO) of EVs over ICE vehicles are then computed and used to estimate the unconstrained economic potential (i.e. the portion of the market that will opt for EVs at a certain price threshold not considering any other barriers) based on economic adoption curves embedded within the model. These curves are based on consumer willingness-to-pay from consumer choice research and surveys. Consumers in the personal LDV segment are assumed to consider both upfront cost and TCO in their decision-making, whereas commercial consumers are assumed to consider the vehicle's TCO and associated Internal Rate of Return (IRR).

- **Constrained potential:** EVs face several specific barriers that constrain their wide-spread adoption. EVA uses barrier curves along with jurisdiction-specific inputs to assess the impact on key barriers adoption locally. These barrier curves highlight the relationship between metrics that depict the level of each barrier and the portion of the market that is estimated to be willing to adopt EVs at given barrier level. The following barriers are considered within the model:

    - **Range requirement:** A portion of the market is constrained by the limited range of EVs. This barrier is only assumed to affect BEVs and not PHEVs, due to their ability to use ICE powertrain to complement electric driving range.

  - **Home charging access:** Research indicates that the majority of EV charging is expected to happen at home overnight (or in depots for commercial fleets), therefore access to home charging is considered key for enabling EV adoption. While single-family homes often have dedicated parking, residents in Multi-Unit Residential Buildings (MURBs) usually do not. The model uses data on local housing composition (i.e. percentage of population living in single-family homes versus multi-family homes) and assumes the portion of each segment that has dedicated parking. The barrier level can be reduced over time through building code changes that require parking stalls to have EV charging station or incentives and programs to increase home charging access. Additionally, a portion of "garage-orphans"[11] are assumed to consider EVs even given their lack of access to dedicated parking stalls.

  - **Public Charging:** Public charging can be a key enabler or barrier of EV adoption. The model captures two specific characteristics of local charging networks:[12]

    - **Coverage**: The geographical coverage of charging infrastructure considering the required number of stations regionally. Inputs on population, land area, highway length and other regional data are used to determine the required number of DCFC charging stations on highway corridors and in population clusters.

    - **Availability:** An assessment of the number of EVs per port for both Level 2 and DCFC charging stations. The calculated ratios are compared to estimated "ideal ratios". These ideal ratios are dynamic and are recalculated every time-step (i.e. year) based on population density (population per km^2), EV density (EVs per km^2), average year-round temperature, and home charging access.[13] In addition to the number of ports, availability also considers the average charging time given the capacity (kW) of the deployed charging stations and the corresponding charging time for each vehicle.

- **Market dynamics:** Incorporating technology diffusion theory and other market factors to determine rate of adoption and competition between vehicle types.

  - **Competition**: PHEVs and BEVs are assumed to be in competition for the same market. After comparing technical, economic, constrained and market potential of both technologies, a

[11] Garage orphans is a term used to describe residents that do not have access to dedicated off-street garage or parking.

[12] EVA uses the following terminology for charging infrastructure. A **charging station** is assumed to be a facility or location that provides charging services, and can provide charging to one or more EVs at a time depending on the number of ports it includes, whereas a **charging port** is used to refer to a connector that can charge one vehicle at a time. (Note that some "dual port" stations include connectors for different vehicle types, but can only charge one vehicle at a time – considered as a single port in EVA).

[13] The model assumes that the portion of EV drivers who do not have access to home charging impacts the need for public charging (i.e. if EV adopters do not have home charging, they will have a higher reliance on public charging and therefore more charging ports will be required).

probabilistic function is used to represent the portion of the market that will be rational decision-makers and select the superior of the two options (i.e., – the choice that minimizes overall barriers), versus a portion that will adopt the inferior of the two options.

- **Diffusion:** Technology diffusion theory is used to estimate the rate of adoption of EVs. Specifically, the Bass Diffusion curve is used to capture the degree to which the market adopts new innovative technologies over time. This accounts for the demographics and composition of the market through segmenting potential adopters into five categories that vary by motivation for adoption (environmental, economic, etc.), willingness to take risks, technology-savviness, and other factors. The diffusion curve accounts for social interactions and public awareness (or lack of) and the impact of programs on increasing this awareness. Key parameters of the diffusion curve are adjusted to capture the local market characteristics by calibrating the model to historical uptake.

By overlaying the technical potential, customer economics, constrained potential, and market dynamics, EVA is used to model the market share of EVs in the specific segment.

While the treatment of the various vehicle segments is largely the same in EVA, there are a number of differences in in the model's consideration of barriers facing personal LDV, commercial LDV, and commercial MDV/HDV/Bus segments, highlighted in **Table D- 1**.

Table D- 1: Model Treatment of Vehicle Segments, with Differences between Segments in Bold

Barrier	Personal LDV	Commercial LDV	Commercial MDV/HDV/Bus
Technical	Base vehicle assumed to be **gasoline ICE**		Base vehicle assumed to be **diesel ICE**
Economic	**Upfront cost and Total Cost of Ownership (TCO)**	**Internal Rate of Return (IRR)** of the vehicle's upfront and operational costs over its lifetime	
Constraints	• Range Requirement • Charging Time • Public Charging Coverage • **Home Charging Access** • **Public Charging Availability**	• Range Requirement • Charging Time Requirement • Public Charging Coverage	• Range Requirement • Charging Time Requirement
Market	Competition between PHEV and BEVs		**No competition between PHEVs and BEVs (i.e. all assumed to be BEVs)**

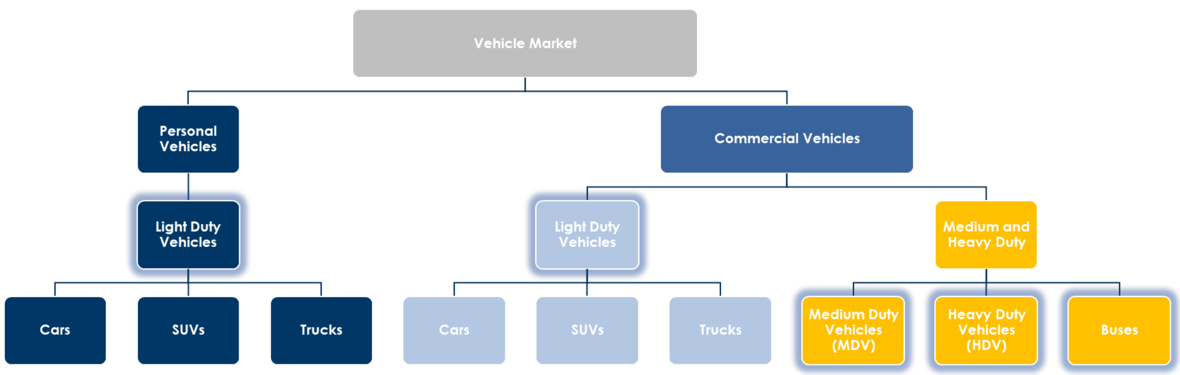
STUDY APPROACH

1. MARKET AND VEHICLE CHARACTERIZATION

To forecast adoption, the vehicle market is segmented and key data on annual vehicle sales, total fleet size, usage patterns, average fuel efficiency and other characteristics is collected for each segment. The analysis covers both personal vehicles and commercial vehicles/fleets, which have significantly different treatment of adoption decision making as a result of differences in economic decision-making thresholds and adoption barriers.

Due to differences in vehicle costs, usage patterns and EV availability, the market is further segmented into Light Duty Vehicles (LDV), Medium Duty Vehicles (MDV) and Heavy-Duty Vehicles (HDV). Where appropriate the market is segmented into more granular vehicle classes. For example, LDVs market is segmented into Cars, SUVs and Trucks. The figure below shows the used market segmentation.

Figure D - 2. Vehicle market segmentation



For each vehicle class, the analysis assumes adopters have a choice between three vehicle powertrains. With the assumption that ICE are the status quo vehicle choice, the model considers the adoption of two EV powertrains, which are defined as any vehicle that plugs in to charge. Specifically, those considered are:

- **BEV:** "Pure" electric vehicles that have only an electric powertrain and plug in to charge (E.g. Chevy Bolt, Nissan Leaf).
- **PHEVs:**[14] Hybrid vehicles that can plug in to charge and operate in electric mode for short distances (e.g. 30 km to 85 km), but that also include a combustion powertrain for longer trips (E.g. Chevy Volt, Toyota Prius Prime).

[14] Non-plug Hybrid Electric Vehicles (HEVs) and Fuel Cell Electric Vehicles (FCEV) are not included in the analysis. Additionally, MDV, HDV, and Bus EVs are only assumed to be BEVs.

For each vehicle class, assumptions on average vehicle characteristics (fuel consumption, powertrain size, battery size, etc.) are used to compile a representative model of vehicles within that segment. Additional assumptions on utilization (i.e. distance traveled) and operational costs are also compiled and used to calculate a bottom-up upfront vehicle cost and TCO for the different vehicle powertrains within each vehicle class.

2. MODEL CALIBRATION

Using data on vehicle sales, costs and other parameters, EVA was benchmarked to historical adoption in the province and key model parameters were calibrated to capture local market characteristics. Calibration parameters include:

- **Technology diffusion parameters**: Which determine rate of adoption of EVs in NL
- **Optimal public charging ratios**: Ideal EV/port ratio for L2 and DCFC infrastructure
- **Economic decision-making threshold**: Adopters' weighting of consideration for upfront cost versus TCO in adoption decision-making
- **PHEV/BEV Competition coefficient**: Level of competition between PHEVs and BEVs

Due to the limited EV deployment to date in NL, trends from the adoption of non-plug-in, hybrid electric vehicles (e.g. Toyota Prius and equivalent models) as well as data from other jurisdictions with similar characteristics and conditions were used to complement the calibration process.

3. MARKET ADOPTION PROJECTIONS

The calibrated version of the model was used to develop future-looking projections. The model was populated with NL-specific market data (see Model Inputs and Assumptions section), such as population density, electricity and fuel prices, local and regional charging infrastructure availability, home charging access, and other local market factors to project uptake of EVs out to 2035.

The model is used to project uptake under the following scenarios:

- **Baseline Projections:** Uptake under business-as-usual conditions[15] [16]
- **Sensitivity Analysis:** Sensitivity to key market, policy and technology uncertainties and risks, specifically
  - i. ***Global market competitiveness factors:*** *Battery costs, vehicle range, availability*
  - ii. ***Local factors:*** *Electricity rates, fuel prices*
- **Impact of Policy/Program Levers:** Key government or utility interventions that can support or accelerate the deployment of EVs in the province including:
  - i. ***Public Charger Deployment:*** *Direct Current Fast Chargers (DCFC) and Level 2 Chargers*
  - ii. ***Home Charging Access:*** *Incentives for home charger installations and programs to accelerate the availability of home charging access in Multi-Unit Residential Building (MURBs)*
  - ***iii.*** ***Vehicle Incentives:*** *Financial rebates for EVs*

For each scenario, the model outputs include both annual and cumulative number of vehicles sold (by vehicle powertrain for each vehicle class) as well as percentage of annual sales and fleet size.

4. UTILITY LOAD IMPACTS

Based on the projected EV adoption, an assessment of the impact of forecasted EVs on utility's load is conducted under different scenarios, each of which assume all charging happens within the Utilities' territories:

- **Annual electricity sales or consumption (GWh)** from EVs based on the assumed vehicle market composition, vehicle utilization, battery size and efficiency.
- **Impact on utility's load patterns and peak demand (MW**) using charging load profiles that consider the diversity of vehicle charging patterns (time and level of charging) and are scaled to match average vehicle utilization and characteristics.
- **Revenue opportunities** associated with EVs based on the increased energy sales and any incremental benefit streams.

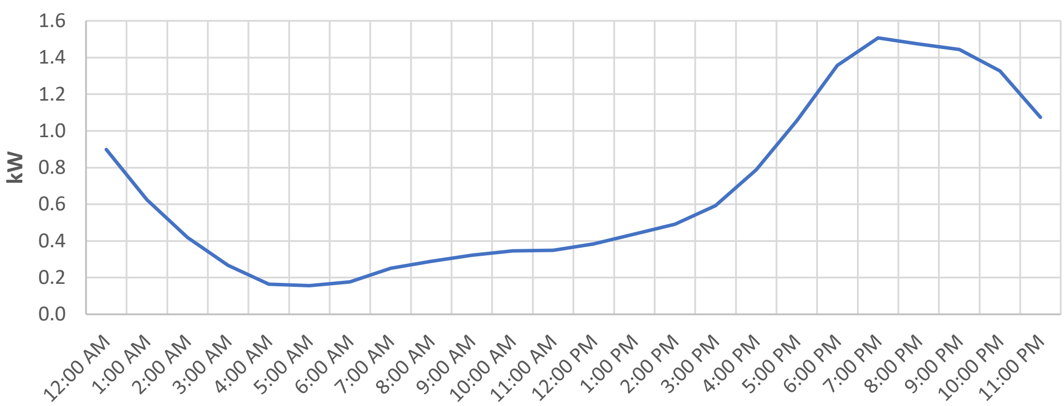
A diversified charging load profile was developed for each vehicle segment, leveraging data sets from a range of government and utility-led pilot programs. While the maximum rated power consumption of a single vehicle is important for considering the electrical load on a given home or even the impact on local

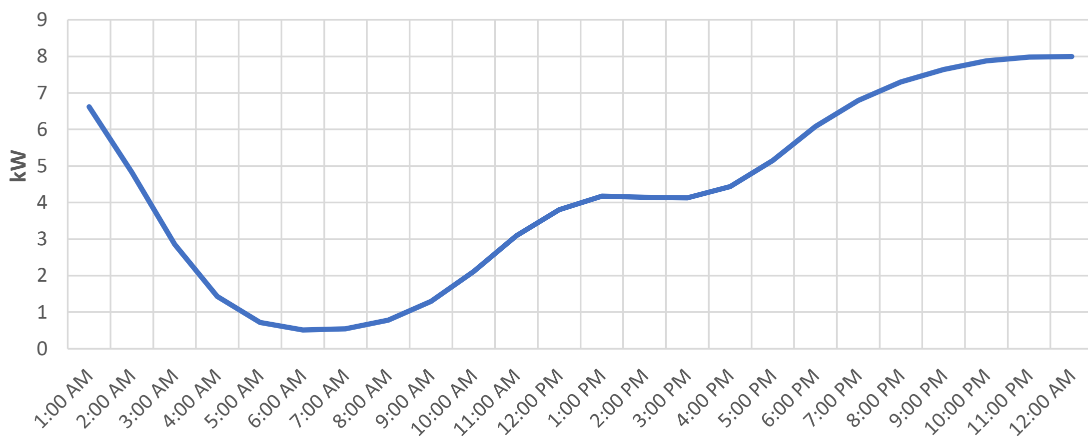
[15] Due to uncertainty around future availability of the incentive, the recently announced federal EV incentives are not included in the baseline scenario. The Low Incentive Investment Scenario was developed to resemble the federal rebate levels (i.e. Modeled Incentives – Low can be interpreted as impact of federal incentives). The modeled Incentives – High scenario can be interpreted as the federal incentive in addition to an incentive top-up by the utilities or government.

[16] Baseline scenario assumes existing committed actions by the utilities and government (estimated to be the installation of 14 DCFC and 30 Level 2 Ports in 2019/20).

distribution infrastructure due to clustering of EV adoption, system-wide impacts are best assessed using a diversified charging load profile which accounts for typical charging patterns across a larger population of EVs. For example, while a single LDV EV may be charged at a mix of Level 2 chargers (7 kW) and DCFC (50 kW+), considering the diversity in vehicle utilization and charging patterns, the system-wide peak load impact of the total LDV EV population is estimated at 1.5 kW of peak load. The load profiles developed for Personal LDVs and Commercial MDVs[17] are presented in **Figure D - 3**.

Figure D - 3. Diversified Charging Load Profiles for Personal Light-Duty Vehicle (Top) and Commercial Medium-Duty Vehicle (Bottom)





[17] Load patterns of medium-duty, heavy-duty, and buses were assumed to be the same, however for each segment a charging load profile was scaled according to the vehicle class-specific average charger power output assumption.

APPENDIX E: STUDY INPUTS AND ASSUMPTIONS

The Newfoundland and Labrador CDM Potential study model was populated with Newfoundland and Labrador-specific inputs to create a representative tool that captures the range and extent of energy saving opportunities in the province.

Key inputs include:

- **Utility Economic Data**: including rate projections; avoided costs of generation and supply; discount rates; inflation rates; number, type and stratified average consumption of customers; and CDM program activities and impacts.
- **Characterized Energy Saving Measures:** including measure costs (full and incremental), energy savings per unit, assumed market barrier level, market growth, replacement schedule, estimated life, applicable segments and populations, among others.
- **NL-Specific Market Data**: A wide range of market data was applied to assess each study element. These include the Commercial and Residential End-Use Surveys conducted in 2018 and 2017 respectively and market studies on various EE equipment and lighting socket studies. As part of this study, primary research was conducted via a barriers survey with 666 residential respondents and 150 commercial respondents, as well as 15 market actor interviews and two stakeholder sessions.

The following chapter provides an overview of the methods applied to characterize the full range of model inputs developed for this study.

UTILITY DATA

Over the course of project development, NL Utilities provided various data in response to a series of data requests. At the highest level, the data was used for the adoption, model inputs and model calibration. **Table E - 1** below details the majority of the data requested from the NL Utilities, and a brief description of how they were applied to the model.

Table E - 1: Utility Data Inputs

Data Provided	Purpose
Discount Rates • Discount rates applicable to CDM investments and savings. ***Utility discount rate:*** 6% Inputs Recommended by Dunsky: ***Participant discount rate:*** 4.95% (Prime Rate of 3.95% + 1%) ***Assumed inflation rate***: 2% - Bank of Canada inflationary targets	Applied to perform present value analysis of CDM investments and savings, which are a key model input for measure screening.
Avoided Costs • Annual avoided costs of electricity generation and demand, and fuel oil by year, including all components normally used in NL utilities' cost-effectiveness calculations. • On- and off-peak electricity avoided costs and other energy source costs provided by NL Utilities. Fuel oil prices were derived from the Board of Commissioners of Public Utilities. • **Demand avoided costs for Labrador Interconnected were estimated at 90% and Isolated Communities were estimated at 25% of the Island Interconnected avoided costs.**	The avoided costs are a principle component of the economic measure screening. Future years (beyond NL utilities' calculations) were extrapolated as necessary.
Marginal Retail Rates • Marginal rate savings – or the rate savings from energy efficiency measures - were calculated by market segment and sector. • For Labrador and Isolated Communities base rates, the following publication was used: Newfoundland and Labrador Hydro Schedule of Rates, Rules and Regulations (Jan 1st, 2019). • For Island Interconnected base rates, the utility provided three scenarios: Low, Mid and High. • To create the marginal customer rates, Dunsky identified the highest usage energy rate tier of each segment using market size and consumption data by segment. The rates were inflated to 2020 dollars. Then economy-wide inflation was removed from the rate escalation as the model takes economic inputs in real dollars. • See the customer rate tables below for the original rates for all three systems and the rates used from the Newfoundland and Labrador Hydro Schedule of Rates.	Energy billing rates were used as one input for calculating achievable potential. For each sector and segment, the most appropriate rate and rate block was selected based on rate definition/structure and customer characteristics (e.g., average consumption). Those rates are used to calculate the total customer bill impacts.

Data Provided	Purpose
Current Measure-Level Assumptions • NL Utilities measure assumptions, including program evaluation reports and program data.	Used for measure characterization development.
Codes and Standards • Codes and Standards assumptions (i.e., new codes and standards that will be enacted in the near future, their estimated year of enactment, and specification assumptions). See **Table E - 8** for specific codes and standards included.	Used to assess baseline conditions to calculate unit savings to be used in the analysis.
Program Data	
• CDM program descriptions, forecasts from NL Utilities' 2016-2020 CDM Plan. • Evaluated NL Utilities program results (2015-2018). • Newfoundland-specific barriers survey research (barriers data at the sector, segment, and end use-level).	Used to complement the measure-level analysis of unit savings and costs and to develop the programs' fixed and variable non-incentive costs.
Additional Information	
• Electricity energy and capacity forecasts (2019-2020) before CDM and codes and standards savings provided by NL Utilities. • Years 2030 and 2044 were forecasted using a linear regression model. • Non-electricity forecasts sourced from National Energy Board of Canada forecasts (https://apps2.neb-one.gc.ca/dvs/?page=landingPage&language=en).	Used to develop energy sales forecast for the 2020-2044 period.
NL Utilities Studies and Reports • Residential efficiency measure adoption.	Used to support measure characterization process and benchmark the adoption model results.
Non-identifying customer information • Contact information for a sample of residential and commercial/industrial customers.	Used to create a sample and obtain responses for the barrier/adoption surveys.

CUSTOMER RATES TABLES

Table E - 2: Island Interconnected - Low Rate Scenario

Year	Domestic Rate	GS Rate 2.1			GS Rate 2.3					GS Rate 2.4			
	All Customers	< 10 kW & 3500 kWh	>3500kWh										
	Energy Only	Energy Only	Demand GT 10 kW		Energy	Demand		Energy		Demand		Energy	
			Winter	Summer		Winter	Summer	1st 150 kWh/kVA & < 50000	excess	Winter	Summer	< 75000	excess
	¢/kWh	¢/kWh	$/kW	$/kW	¢/kWh	$/kVA	$/kVA	¢/kWh	¢/kWh	$/kVA	$/kVA	¢/kWh	¢/kWh
2019	13.78	13.65	11.33	8.30	10.22	9.55	6.52	11.63	9.35	9.18	6.16	11.21	9.26
2020	14.09	13.96	11.58	8.49	10.45	9.76	6.67	11.89	9.56	9.39	6.30	11.46	9.47
2021	14.42	14.29	11.85	8.69	10.70	9.99	6.83	12.17	9.79	9.61	6.45	11.73	9.69
2022	14.75	14.61	12.12	8.88	10.94	10.22	6.98	12.44	10.01	9.83	6.59	12.00	9.91
2023	15.08	14.94	12.39	9.08	11.19	10.45	7.14	12.72	10.23	10.05	6.74	12.27	10.13
2024	15.42	15.27	12.67	9.29	11.44	10.68	7.30	13.01	10.46	10.27	6.89	12.54	10.36
2025	15.77	15.62	12.96	9.50	11.69	10.92	7.46	13.30	10.70	10.51	7.05	12.82	10.59
2026	16.12	15.97	13.25	9.71	11.96	11.17	7.63	13.60	10.94	10.74	7.20	13.11	10.83
2027	16.48	16.33	13.55	9.93	12.23	11.42	7.80	13.91	11.19	10.98	7.37	13.41	11.08
2028	16.86	16.70	13.85	10.15	12.50	11.68	7.98	14.22	11.44	11.23	7.53	13.71	11.33
2029	17.23	17.07	14.16	10.38	12.78	11.94	8.16	14.54	11.69	11.48	7.70	14.02	11.58
2030	17.62	17.46	14.48	10.61	13.07	12.21	8.34	14.87	11.96	11.74	7.87	14.33	11.84
2031	18.02	17.85	14.81	10.85	13.37	12.48	8.53	15.20	12.23	12.01	8.05	14.66	12.11
2032	18.42	18.25	15.14	11.10	13.67	12.76	8.72	15.54	12.50	12.28	8.23	14.99	12.38
2033	18.84	18.66	15.48	11.35	13.97	13.05	8.91	15.89	12.78	12.55	8.42	15.32	12.66
2034	19.26	19.08	15.83	11.60	14.29	13.34	9.11	16.25	13.07	12.84	8.61	15.67	12.94
2035	19.70	19.51	16.18	11.86	14.61	13.64	9.32	16.62	13.36	13.12	8.80	16.02	13.23
2036	20.14	19.95	16.55	12.13	14.94	13.95	9.53	16.99	13.67	13.42	9.00	16.38	13.53

Year	Domestic Rate	GS Rate 2.1			GS Rate 2.3						GS Rate 2.4			
2037	20.59	20.40	16.92	12.40	15.27	14.26	9.74	17.37	13.97	13.72	9.20	16.75	13.84	
2038	21.00	20.81	17.26	12.65	15.58	14.55	9.94	17.72	14.25	14.00	9.39	17.08	14.11	
2039	21.48	21.27	17.65	12.93	15.93	14.88	10.16	18.12	14.57	14.31	9.60	17.47	14.43	
2040	21.91	21.70	18.00	13.19	16.25	15.17	10.37	18.48	14.86	14.60	9.79	17.82	14.72	
2041	22.34	22.13	18.36	13.46	16.57	15.48	10.57	18.85	15.16	14.89	9.98	18.17	15.01	
2042	22.79	22.58	18.73	13.73	16.91	15.79	10.78	19.23	15.46	15.19	10.18	18.54	15.31	
2043	23.25	23.03	19.10	14.00	17.24	16.10	11.00	19.61	15.77	15.49	10.39	18.91	15.62	
2044	23.71	23.49	19.48	14.28	17.59	16.42	11.22	20.01	16.09	15.80	10.60	19.29	15.93	
2045	24.19	23.96	19.87	14.57	17.94	16.75	11.44	20.41	16.41	16.12	10.81	19.67	16.25	
2046	24.67	24.44	20.27	14.86	18.30	17.09	11.67	20.81	16.74	16.44	11.02	20.07	16.58	
2047	25.16	24.93	20.68	15.15	18.66	17.43	11.91	21.23	17.07	16.77	11.24	20.47	16.91	
2048	25.67	25.42	21.09	15.46	19.04	17.78	12.15	21.65	17.42	17.10	11.47	20.88	17.25	
2049	26.18	25.93	21.51	15.77	19.42	18.13	12.39	22.09	17.76	17.44	11.70	21.29	17.59	
2050	26.70	26.45	21.94	16.08	19.81	18.50	12.64	22.53	18.12	17.79	11.93	21.72	17.94	
2051	27.24	26.98	22.38	16.40	20.20	18.87	12.89	22.98	18.48	18.15	12.17	22.15	18.30	
2052	27.78	27.52	22.83	16.73	20.61	19.24	13.15	23.44	18.85	18.51	12.41	22.60	18.67	
2053	28.34	28.07	23.29	17.07	21.02	19.63	13.41	23.91	19.23	18.88	12.66	23.05	19.04	

Table E - 3: Island Interconnected - Mid Rate Scenario

Year	Domestic Rate	GS Rate 2.1				GS Rate 2.3				GS Rate 2.4			
	All Customers	< 10 kW & 3500 kWh	>3500kWh										
	Energy Only	Energy Only	Demand GT 10 kW		Energy	Demand		Energy		Demand		Energy	
			Winter	Summer		Winter	Summer	1st 150 kWh/kVA & < 50000	excess	Winter	Summer	< 75000	excess
	¢/kWh	¢/kWh	$/kW	$/kW	¢/kWh	$/kVA	$/kVA	¢/kWh	¢/kWh	$/kVa	$/kVA	¢/kWh	¢/kWh
2019	13.82	13.69	11.36	8.32	10.25	9.57	6.54	11.66	9.38	9.21	6.18	11.24	9.29
2020	14.55	14.41	11.96	8.76	10.79	10.08	6.89	12.28	9.87	9.70	6.50	11.84	9.78
2021	16.01	15.86	13.15	9.64	11.87	11.09	7.57	13.51	10.86	10.67	7.15	13.02	10.76
2022	17.61	17.44	14.47	10.60	13.06	12.20	8.33	14.86	11.95	11.73	7.87	14.32	11.83
2023	18.94	18.76	15.56	11.41	14.05	13.12	8.96	15.98	12.85	12.62	8.46	15.41	12.73
2024	19.33	19.15	15.89	11.64	14.34	13.39	9.15	16.31	13.12	12.88	8.64	15.73	12.99
2025	19.83	19.64	16.30	11.94	14.71	13.74	9.38	16.73	13.46	13.21	8.86	16.13	13.33
2026	20.09	19.90	16.51	12.10	14.90	13.92	9.51	16.95	13.63	13.39	8.98	16.34	13.50
2027	20.40	20.20	16.76	12.28	15.13	14.13	9.65	17.21	13.84	13.59	9.11	16.59	13.70
2028	20.86	20.66	17.14	12.56	15.47	14.45	9.87	17.60	14.16	13.90	9.32	16.97	14.02
2029	21.23	21.03	17.44	12.78	15.74	14.70	10.04	17.91	14.40	14.14	9.48	17.26	14.26
2030	21.64	21.44	17.78	13.03	16.05	14.99	10.24	18.26	14.69	14.42	9.67	17.60	14.54
2031	22.27	22.05	18.30	13.41	16.51	15.42	10.54	18.78	15.11	14.84	9.95	18.11	14.96
2032	22.63	22.42	18.60	13.63	16.79	15.68	10.71	19.09	15.36	15.08	10.11	18.41	15.21
2033	23.02	22.81	18.92	13.87	17.08	15.95	10.89	19.42	15.62	15.34	10.29	18.73	15.47
2034	23.56	23.34	19.36	14.19	17.47	16.32	11.15	19.88	15.99	15.70	10.53	19.16	15.83
2035	23.98	23.75	19.70	14.44	17.78	16.61	11.35	20.23	16.27	15.98	10.71	19.50	16.11
2036	24.49	24.26	20.12	14.75	18.17	16.96	11.59	20.66	16.62	16.32	10.94	19.92	16.46
2037	25.22	24.98	20.72	15.19	18.71	17.47	11.93	21.28	17.11	16.81	11.27	20.51	16.95
2038	25.89	25.65	21.28	15.59	19.21	17.93	12.25	21.84	17.57	17.25	11.57	21.06	17.40

Year	Domestic Rate	GS Rate 2.1			GS Rate 2.3					GS Rate 2.4			
2039	26.51	26.26	21.78	15.96	19.66	18.36	12.54	22.36	17.99	17.66	11.84	21.56	17.81
2040	27.04	26.78	22.22	16.28	20.05	18.73	12.79	22.81	18.34	18.01	12.08	21.99	18.17
2041	27.58	27.32	22.66	16.61	20.45	19.10	13.05	23.27	18.71	18.38	12.32	22.43	18.53
2042	28.13	27.86	23.11	16.94	20.86	19.48	13.31	23.73	19.09	18.74	12.57	22.88	18.90
2043	28.69	28.42	23.58	17.28	21.28	19.87	13.58	24.21	19.47	19.12	12.82	23.34	19.28
2044	29.27	28.99	24.05	17.62	21.71	20.27	13.85	24.69	19.86	19.50	13.08	23.80	19.66
2045	29.85	29.57	24.53	17.98	22.14	20.68	14.12	25.18	20.25	19.89	13.34	24.28	20.06
2046	30.45	30.16	25.02	18.34	22.58	21.09	14.41	25.69	20.66	20.29	13.61	24.76	20.46
2047	31.06	30.76	25.52	18.70	23.04	21.51	14.70	26.20	21.07	20.69	13.88	25.26	20.87
2048	31.68	31.38	26.03	19.08	23.50	21.94	14.99	26.72	21.49	21.11	14.15	25.77	21.29
2049	32.31	32.00	26.55	19.46	23.97	22.38	15.29	27.26	21.92	21.53	14.44	26.28	21.71
2050	32.96	32.64	27.08	19.85	24.45	22.83	15.59	27.80	22.36	21.96	14.73	26.81	22.15
2051	33.62	33.30	27.62	20.24	24.93	23.28	15.91	28.36	22.81	22.40	15.02	27.34	22.59
2052	34.29	33.96	28.18	20.65	25.43	23.75	16.22	28.93	23.27	22.85	15.32	27.89	23.04
2053	34.97	34.64	28.74	21.06	25.94	24.23	16.55	29.51	23.73	23.30	15.63	28.45	23.50

Table E - 4: Island Interconnected - High Rate Scenario

Year	Domestic Rate	GS Rate 2.1				GS Rate 2.3				GS Rate 2.4			
	All Customers	< 10 kW & 3500 kWh	>3500kWh										
	Energy Only	Energy Only	Demand GT 10 kW		Energy	Demand		Energy		Demand		Energy	
			Winter	Summer		Winter	Summer	1st 150 kWh/kVA & < 50000	excess	Winter	Summer	< 75000	excess
	¢/kWh	¢/kWh	$/kW	$/kW	¢/kWh	$/kVa	$/kVA	¢/kWh	¢/kWh	$/kVa	$/kVA	¢/kWh	¢/kWh
2019	13.10	12.98	10.76	7.89	9.72	9.07	6.20	11.05	8.89	8.73	5.85	10.65	8.80
2020	15.67	15.53	12.88	9.44	11.63	10.86	7.42	13.22	10.64	10.44	7.00	12.75	10.53
2021	22.49	22.28	18.48	13.55	16.68	15.58	10.64	18.98	15.26	14.99	10.05	18.29	15.11
2022	22.59	22.37	18.56	13.60	16.75	15.65	10.69	19.06	15.33	15.05	10.09	18.37	15.18
2023	22.98	22.77	18.89	13.84	17.05	15.92	10.88	19.39	15.59	15.31	10.27	18.69	15.44
2024	23.43	23.21	19.25	14.11	17.38	16.23	11.09	19.77	15.90	15.61	10.47	19.06	15.74
2025	24.08	23.86	19.79	14.50	17.86	16.68	11.40	20.32	16.34	16.05	10.76	19.59	16.18
2026	24.25	24.02	19.93	14.61	17.99	16.80	11.48	20.46	16.46	16.16	10.84	19.73	16.30
2027	24.50	24.27	20.13	14.75	18.17	16.97	11.59	20.67	16.62	16.33	10.95	19.93	16.46
2028	25.07	24.83	20.60	15.10	18.59	17.36	11.86	21.15	17.01	16.70	11.20	20.39	16.84
2029	25.42	25.18	20.89	15.31	18.85	17.61	12.03	21.44	17.25	16.94	11.36	20.68	17.08
2030	25.87	25.62	21.26	15.58	19.19	17.92	12.24	21.82	17.55	17.24	11.56	21.04	17.38
2031	26.72	26.47	21.96	16.09	19.82	18.51	12.64	22.54	18.13	17.81	11.94	21.74	17.96
2032	27.05	26.80	22.23	16.29	20.07	18.74	12.80	22.82	18.36	18.03	12.09	22.00	18.18
2033	27.43	27.17	22.54	16.52	20.34	19.00	12.98	23.14	18.61	18.28	12.26	22.31	18.43
2034	28.08	27.81	23.07	16.91	20.83	19.45	13.29	23.69	19.05	18.71	12.55	22.84	18.87
2035	28.49	28.22	23.41	17.16	21.13	19.73	13.48	24.03	19.33	18.98	12.73	23.17	19.14
2036	29.07	28.80	23.89	17.51	21.56	20.14	13.76	24.53	19.73	19.37	12.99	23.65	19.54
2037	30.09	29.80	24.72	18.12	22.32	20.84	14.24	25.38	20.42	20.05	13.44	24.47	20.22

Year	Domestic Rate	GS Rate 2.1				GS Rate 2.3				GS Rate 2.4			
2038	30.98	30.68	25.45	18.65	22.98	21.46	14.66	26.13	21.02	20.64	13.84	25.19	20.81
2039	31.73	31.43	26.08	19.11	23.54	21.98	15.02	26.77	21.53	21.14	14.18	25.81	21.32
2040	32.37	32.06	26.60	19.49	24.01	22.42	15.32	27.31	21.96	21.57	14.46	26.33	21.75
2041	33.02	32.70	27.13	19.88	24.49	22.87	15.62	27.85	22.40	22.00	14.75	26.85	22.18
2042	33.68	33.36	27.67	20.28	24.98	23.33	15.94	28.41	22.85	22.44	15.05	27.39	22.63
2043	34.35	34.02	28.23	20.69	25.48	23.79	16.25	28.98	23.31	22.89	15.35	27.94	23.08
2044	35.04	34.70	28.79	21.10	25.99	24.27	16.58	29.56	23.77	23.35	15.66	28.50	23.54
2045	35.74	35.40	29.37	21.52	26.51	24.75	16.91	30.15	24.25	23.81	15.97	29.07	24.01
2046	36.45	36.11	29.95	21.95	27.04	25.25	17.25	30.75	24.73	24.29	16.29	29.65	24.49
2047	37.18	36.83	30.55	22.39	27.58	25.75	17.59	31.37	25.23	24.77	16.61	30.24	24.98
2048	37.93	37.57	31.16	22.84	28.13	26.27	17.95	32.00	25.73	25.27	16.95	30.85	25.48
2049	38.68	38.32	31.79	23.30	28.69	26.79	18.30	32.64	26.25	25.78	17.29	31.46	25.99
2050	39.46	39.08	32.42	23.76	29.27	27.33	18.67	33.29	26.77	26.29	17.63	32.09	26.51
2051	40.25	39.86	33.07	24.24	29.85	27.88	19.04	33.95	27.31	26.82	17.98	32.73	27.04
2052	41.05	40.66	33.73	24.72	30.45	28.43	19.42	34.63	27.85	27.35	18.34	33.39	27.58
2053	41.87	41.48	34.41	25.22	31.06	29.00	19.81	35.33	28.41	27.90	18.71	34.06	28.14

The following table describes the original rates used for Labrador Interconnected and the Isolated Communities. These were taken from: Newfoundland and Labrador Hydro, Schedule of Rates, Rules and Regulations, Updated January 1, 2019.[18]

[18] https://nlhydro.com/wp-content/uploads/2019/02/2019-01-01-Complete.pdf

Table E - 5: Labrador Interconnected and Isolated Communities Rates

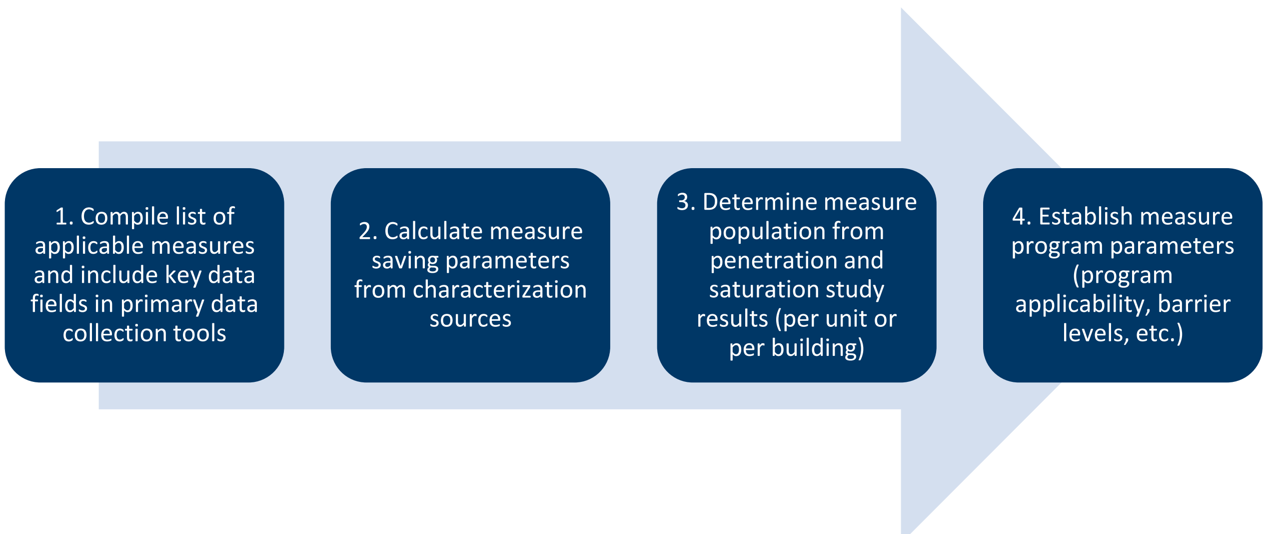
System	Sector	Rate Name	Page in Report	Energy Charge
Isolated Communities	Residential	Rate 1.2D – Domestic Diesel	DSL–NG-1	First Block : 11.391 ¢ per kWh Second Block : 12.838 ¢ per kWh Third Block : 17.408 ¢ per kWh
Isolated Communities	Commercial	Rate 2.1D – General Service Diesel 0-10 kW Rate 2.2D – General Service Diesel over 10 kW	DSL–NG-3 DSL–NG-4	17.250 ¢ per kWh 16.790 ¢ per kWh
Labrador Interconnected	Residential	Rate 1.1L – Domestic	LAB-1	3.255¢ per kWh
Labrador Interconnected	Commercial	Rate 2.1L – General Service 0-10 kW Rate 2.2L – GENERAL SERVICE 10 - 100 kW (110 kVA) Rate 2.3L - GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA RATE No. 2.4L GENERAL SERVICE 1000 kVA AND OVER	LAB-2 LAB-3 LAB-4 LAB-5	5.092 ¢ per kWh 2.417 ¢ per kWh 2.090 ¢ per kWh 1.725¢ per kWh

ENERGY-SAVING MEASURES

The NL Utilities Potential study includes 2,181 measure-market combinations, representing the full range of commercially available technologies (current and emerging). The included measures were characterized using reputable TRMs from other jurisdictions, Dunsky's in-house database of energy efficiency measures in conjunction with market research to determine the population of energy saving opportunities for each measure, and the current baseline technology mix.

The measure characterization process steps outlined in **Figure E - 1** below was applied using a list of measures in consultation with the NL Utilities.

Figure E - 1: Measure Characterization Process



MEASURE CHARACTERIZATION

A list of measure options was presented to NL Utilities early in the project for approval. Basic assumptions related to energy savings or impact factors were developed based on information from TRMs from other jurisdictions, and Newfoundland and Labrador market and climate data.

The list was expanded and adapted based on feedback from NL Utilities, and a final approved measure list was compiled. A full list of measures characterized and their sources are presented in **Table E - 19** and **Table E - 20.**

MEASURE TYPES AND REPLACEMENT SCHEDULES

The model uses four types of measures:

- Replace on Burnout (ROB)
- Early Replacement (ER)
- Addition (ADD)
- New Construction/Installation (NEW)

Each of these measure types requires a different approach for determining the maximum yearly units available for potential calculations. **Table E - 6** provides a guide as to how each measure type is defined and how the replacement or installation schedule is applied within the Potential study to assess the phase-in potentials, year by year.

Table E - 6: Measures Types and Schedules Applied in the Potential study model

Measure Type	Description	Market Base	Yearly Units Calculation
Replace on Burnout (ROB)	Existing units are replaced by efficient units after they fail *Example: Replacing burned out bulbs with LEDs.*	Current Building Code/Equipment Standard or Industry Standard Practice.	Market[19]/Effective Useful Life (EUL) *The EUL is set at a minimum of 3 years[20] to spread installations over the potential study period.*
Early Replacement (ER)	Existing units are replaced by efficient units before burnout *Example: Early replacement of functional but inefficient furnaces.*	Existing (old) Units.	Market (old units)/10 years *The market is defined as the subset of the total number of existing units (e.g., old furnaces that could be retired early).*
Addition (ADD)	An EE measure is applied to existing equipment or structures *Example: Adding controls to existing lighting systems, adding insulation to existing buildings.*	Existing Units.	The eligible market is distributed over the estimated useful life of the measure using an S-curve function.
New Construction/ Installation (NEW)	Measures not related to existing equipment *Example: Installing a heat-pump in a newly constructed building.*	Building Code, equipment standard of Industry Standard Practice.	Market *Market base is measure-specific and defined as new units per year.*

[19] In this table, Market is defined as the number of units to which a specific measure applies.
[20] Note: The Home Energy Report is a special case with an EUL of one year.

For ROB measures, the number of existing equipment in a given year (after applying growth rates) is divided by the effective useful life (EUL) of the measure, to obtain a theoretical maximum number of units per year, which is further adjusted to account for factors such as technical constraints (applicability factor), competition groups, and market adoption rates. In cases for which there is a significant difference between the baseline EUL and the efficient technology EUL, the former is specified in the model and used for unit-per-year calculations. Measures based on a discretionary decision (referred to as an Addition Measure Type in **Table E - 6**) that can be implemented at any given point in time (insulation, controls) have been spread over a period dictated by the measure EUL. For some measures/markets, such as New Construction, the number of units per year is specified directly.

MEASURE MARKETS

Markets were largely determined from primary end use data collection of NL customers by MQO Research for the residential sector and by ICF for commercial sectors. For new construction measures and markets, a projected customer growth rate of 0.4% was applied, which corresponds to NL Utilities' anticipated annual residential and business customer growth rate as calculated from the 2018-2028 Load Forecast.

MEASURE FIELDS

For each measure included in the model, a range of specific fields were defined for entry into the model. These covered the following categories:

- **Applicable segment and sector:** These include the relevant rate class, sector and segment.
- **Measure population:** These fields include the number of buildings and equipment units (e.g. fans) or size units (e.g. horsepower of compressors).
- **Measure descriptions:** The descriptions include overviews of the applicable baseline technology (or technology mix) and efficient technology.
- **Measure annual gross savings:** Per-unit electric, including consumption and demand values.
- **Measure types**: For each measure, the installation timing relative to the EUL of the existing equipment is defined by the following:
    - Replace on Burnout (ROB)
    - Early Replacement (ER)
    - Additional Measures (ADD)
    - New Construction/Installation (NEW)
- **Measure costs:** Costs include both incremental and full costs (where available).
- **Measure life:** This category addresses the EUL of each measure and baseline technology as well as the Remaining Useful Life (RUL) for measures in which early replacement is applicable.
- **Measure adoption factors:** Adoption factors include market applicability factors and assigned barrier levels.
- **Impact factors:** These are factors affecting final savings, including net-to-gross adjustments, in-service factors, persistence factors and realization rates.

- **Load factors:** This category addresses summer and winter peak coincidence factors as well as seasonal savings distributions.

Fields are determined for each measure-segment combination, and the program factors are applied such that each measure is allocated to various programs.

NEW PROGRAM AND MEASURE RAMP-UP

For measures in the model that are not currently part of the CDM programs, the following uptake factor was applied to account for ramping up new programs and measure marketing.

Table E - 7: New Measure Uptake Factor

Program Ramp-up	Adoption	Cumulative
Year 1	10%	10%
Year 2	15%	25%
Year 3	20%	45%
Year 4	25%	70%
Year 5	30%	100%

UPDATED CODES AND STANDARDS

Over the course of the study, a number of new codes and standards will come into force. In some cases, these impact the efficiency of the baseline equipment and thereby can reduce the savings potential for the affected measures. All relevant codes and standards were considered, based on provincial standards in Newfoundland and Labrador, Federal Standards in Canada and upcoming Department of Energy (DOE) standards in the United States. The following details the equipment type, and energy source affected by codes and standards changes within the study.

Table E - 8: Codes and Standards incorporated in the study

Equipment Type	Applicable Code or Standard	Code Change Years
Air Source Heat Pumps	NRCan Standard (and future alignment with 2023 efficiencies in current U.S. DOE standard)	2023/2026
Mini-Split Ductless Heat Pump	NRCan Standard (and future alignment with 2023 efficiencies in current U.S. DOE standard)	2023/2026
LED Lamps and Reflectors	U.S. DOE - EISA	See below

LIGHTING CODES AND STANDARDS

Context

EISA Phase II is planned to come into effect in the United States on January 1, 2020, restricting the sale and manufacture of bulbs that do not meet EISA (US) requirements. These requirements are also anticipated to impact the Canadian market, as the Canadian government has indicated commitments to align efficiency standards with the US. As a result, Dunsky proposes a phase-out approach for affected programs that aligns with expected impacts and timing of the new regulation. Recent development in early February of 2019, namely the release of a *Notice Of Proposed Rulemaking* by the DOE to maintain the existing definitions of General Service Lamps and General Service Incandescent Lamps, will likely create the need to revisit the proposed approach as clarity is gained on future regulations.

EISA Implementation

Natural Resources Canada has provided notice that the minimum energy performance standards for general service and modified spectrum incandescent lighting are being considered for future amendments under the Energy Efficiency Regulations. Lighting products may be included in the next round of amendments, but as of yet these have not been planned. To estimate the process timeline for this amendment – and therefore the anticipated date of enforcement – historic examples were examined. A recent example, amendment 14, took three years to move from pre-consultation to enforcement of a new standard, which provides the basis of the assumption regarding lighting timelines.

It was assumed that the new lighting standards will be enforced in Canada beginning January 1, 2022, and a sell-through period will last through December 31, 2022. Starting January 1, 2023, savings from the purchase of new standard bulbs will no longer be counted towards programs. Starting January 1st, 2025, savings from the purchase of new specialty bulbs will no longer be counted towards programs.

Baseline

To estimate the baseline efficiency for existing bulb types and wattages, survey data that was collected in the Newfoundland and Labrador market for the residential sector was used.

- **Bulb types:** The distribution of bulb types used for the residential lighting measures came from Figure 11 of Newfoundland Power's 2018 Socket Saturation Survey. For commercial lighting measures, in the absence of CEUS market survey data on lighting, evaluated savings were used.
- **Wattages:** An assumed average bulb wattage of 60 Watt equivalents (We) was used (based on 13% of sales being 40We, 71% being 60We and 16% being 75W).

Interactive effects

An interactive effects factor was used to account for the impact of interior lighting measures on heating and cooling loads. For residential interior lighting measures, an interactive effects factor of 36% was applied based on the 2017-2018 Instant Rebates Program Evaluation. For commercial measures, the interactive effects in the 20% range from Table 29 in Econoler's report were used.

Interactive effects account for a portion of the lighting savings that would be made up by heating. These are applied in the model to impact the net savings from lighting measures.

Interactions among efficiency measures are captured in the Chaining function in the model, which assesses the degree to which measure mixes impact each other's savings. This is described in detail in Appendix A.

CLAIMING SAVINGS

In this study, any efficient measure affected by codes and standards but installed through a program before the codes and standards are enforced are attributed to the program throughout the measure lifetime. When the measure burns out and is replaced, the savings are then attributed to codes and standards changes. Savings for measures installed after the codes and standards are enforced are attributed to the codes and standards savings.

MEASURE CHARACTERIZATION INPUTS AND ASSUMPTIONS

The TRMs referenced in the following tables were used to develop measure characterization inputs and assumptions. In addition, the 2015 Potential Study and TRM developed by ICF for all sectors and systems were used for benchmarking purposes to compare current results with the past study.

Table E - 9: TRM versions used for commercial measures

Jurisdiction/TRM Name	Version
Iowa - Volume 3: Nonresidential Measures	Version 2 (July 12th, 2017)
Illinois - Volume 2: Commercial and Industrial Measures	Version 7.0 (Sep. 28th, 2018)
Massachusetts - 2019-2021 Plan Version	October 2018
Maine – Commercial/Industrial/Multifamily	Version 2018.3
Mid-Atlantic (Northeast Energy Efficiency Partnerships (NEEP))	Version 8.0 (May 2018)
New York - Residential, Multi-Family, and Commercial/Industrial Measures	Version 7 (April 15th, 2019)
PSEG Long Island	2019 Version, June 14, 2018
NB Power TRM	September 2017 version
OEB TRM	Version 3.0, December 3rd 2018
Pennsylvania TRM	June 2015 version
California TRM	3rd edition, 2017
Michigan Energy Measures Database	2019 Master Database

Table E - 10: TRM versions used for residential measures

Jurisdiction/TRM Name	Version
Iowa - Volume 2: Residential Measures	Version 2 (July 12th, 2017)
Illinois - Volume 3: Residential Measures	Version 7.0 (Sep. 28th, 2018)
Massachusetts - 2019-2021 Plan Version	October 2018
Maine - Retail/Residential	Version 2018.3
Mid-Atlantic (Northeast Energy Efficiency Partnerships (NEEP))	Version 8.0 (May 2018)
New York - Residential, Multi-Family, and Commercial/Industrial Measures	Version 7 (April 15th, 2019)
PSEG Long Island	2019 Version, June 14, 2018
NB Power TRM	September 2017 version

JURISDICTION SPECIFIC INPUTS

In order to ensure that the results accounted for the specific climatic and equipment usage conditions in each study zone, various measure characterization inputs were tailored to be specific to that zone. The tables below describe which inputs were adjusted, and show what values were used, for both the Commercial/Industrial measures and for the Residential measures.

COMMERCIAL AND INDUSTRIAL SECTOR

Table E - 11: Explanation of headings for jurisdiction specific tables in the C&I sector

Name	Description	Source
HDD_18.3C	Heating degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
CDD_18.3C	Cooling degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
HSPF_zone_IV_to_study_zone	Factor to convert HSPF from standard region IV to region V or VI	Rule of thumb used by NRCan
EFLH_heat <65kBtu/h	Equivalent full load hours for units under 5-tons	Mid-Atlantic methodology. Refer to C&I EFLH Calculations.xlsx
EFLH_heat > 65kBtu/h	Equivalent full load hours for units above 5-tons	Mid-Atlantic methodology. Refer to C&I EFLH Calculations.xlsx
EFLH_cool	Equivalent full load hours	Mid-Atlantic methodology. Refer to C&I EFLH Calculations.xlsx
HOU_lighting	Hours of operation for interior lighting	
HOU_compressor	Hours of operation of compressors	

Table E - 12: Zone 1 - Island Interconnected jurisdiction specific data for C&I sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
4,891	39	0.87

Segment	EFLH_heat_ < 65kBtu/h	EFLH_heat >65kBtu/h	EFLH_cool	HOU_lighting	HOU_compressor
Office	958	697	79	3,610	1,976
Retail	1,416	1,030	119	4,089	1,222
Grocery/Restaurant	2,424	1,763	229	5,592	1,976
Health Services	1,248	907	98	4,018	485
Education	1,427	1,038	115	3,255	520
Warehouse	746	542	58	3,759	1,324
Lodging/Hospitality/ MURB	2,718	1,977	236	1,533	1,976
Other Commercial	1,273	926	97	3,951	2,199
Fishing	1,273	926	97	4,394	1,630
Manufacturing	1,273	926	97	4,394	1,630
Small/Medium Industrial	1,273	926	97	4,394	1,630
Large Industrial	1,273	926	97	4,394	1,630

Table E - 13: Zone 2 - Labrador Interconnected jurisdiction specific data for C&I sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
7,126	28	0.76

Segment	EFLH_heat <65kBtu/h	EFLH_heat >65kBtu/h	EFLH_cool	HOU_lighting	HOU_compressor
Office	1,778	1,015	29	3,610	1,976
Retail	2,629	1,501	43	4,089	1,222
Grocery/Restaurant	4,500	2,568	83	5,592	1,976
Health Services	2,316	1,322	35	4,018	485
Education	2,649	1,512	42	3,255	520
Warehouse	1,384	790	21	3,759	1,324
Lodging/Hospitality/ MURB	5,046	2,880	85	1,533	1,976
Other Commercial	2,363	1,349	35	3,951	2,199
Fishing	2,363	1,349	35	4,394	1,630
Manufacturing	2,363	1,349	35	4,394	1,630
Small/Medium Industrial	2,363	1,349	35	4,394	1,630
Large Industrial	2,363	1,349	35	4,394	1,630

Table E - 14: Zone 3 – Isolated Diesel jurisdiction specific data for C&I sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
6,289	0	0.76

Segment	EFLH_heat_ < 65kBtu/h	EFLH_heat >65kBtu/h	EFLH_cool	HOU_lighting	HOU_compressor
Office	1,232	896	0	3,610	1,976
Retail	1,821	1,324	0	4,089	1,222
Grocery/Restaurant	3,117	2,267	0	5,592	1,976
Health Services	1,604	1,167	0	4,018	485
Education	1,835	1,334	0	3,255	520
Warehouse	959	697	0	3,759	1,324
Lodging/Hospitality/ MURB	3,495	2,542	0	1,533	1,976
Other Commercial	1,637	1,191	0	3,951	2,199
Fishing	1,637	1,191	0	4,394	1,630
Manufacturing	1,637	1,191	0	4,394	1,630
Small/Medium Industrial	1,637	1,191	0	4,394	1,630
Large Industrial	1,637	1,191	0	4,394	1,630

RESIDENTIAL SECTOR

Table E - 15: Explanation of headings for jurisdiction specific tables in the residential sector

Name	Description	Source
HDD_18.3C	Heating degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
CDD_18.3C	Cooling degree days (°C days) with a set point of 18.3°C (65°F)	http://ashrae-meteo.info/index.php?lat=47.620&lng=-52.750&place=''&wmo=718010&si_ip=SI&ashrae_version=2017
HSPF_zone_IV_to_study_zone	Factor to convert HSPF from standard region IV to region V or VI	Rule of thumb used by NRCan
AHL_kWH_out	Annual heating load (kWh) of average building in sector. Heat output of heating system, so independent of heating system efficiency.	NL data (Residential Data - January 27 2019) - processed by Dunsky.
EFLH_heat_hp	Equivalent full load hours of heating with a heat pump - residential sector	http://www.ieppec.org/wp-content/uploads/2018/05/Hamelin_paper_vienna.pdf
EFLH_heat_boiler	Equivalent full load hours of heating with a boiler - residential sector	https://puc.vermont.gov/sites/psbnew/files/doc_library/ev-technical-reference-manual.pdf
EFLH_heat_furnace	Equivalent full load hours of heating with a furnace - residential sector	https://puc.vermont.gov/sites/psbnew/files/doc_library/ev-technical-reference-manual.pdf
EFLH_cool	Equivalent full load hours of cooling - residential sector	https://puc.vermont.gov/sites/psbnew/files/doc_library/ev-technical-reference-manual.pdf
annual_energy_use_kWh_out	Annual electricity usage in an electrically heated building in sector (kWh)	NL data (Residential Data - January 27 2019) - processed by Dunsky.

Table E - 16: Zone 1- Island Interconnected jurisdiction specific data for residential sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
4,891	39	0.87

Segment	AHL _kWH_out	EFLH_heat _hp	EFLH_heat _boiler	EFLH_heat _furnace	EFLH _cool	annual_energy_use _kWh_out
Single Detached	13,507	900	907	1,147	100	23,061
Attached	10,112	900	907	1,147	100	17,733
Apartment	5,658	900	907	1,147	100	10,269

Table E - 17: Zone 2 - Labrador Interconnected jurisdiction specific data for residential sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
7,126	28	0.76

Segment	AHL _kWH_out	EFLH_heat _hp	EFLH_heat _boiler	EFLH_heat _furnace	EFLH _cool	annual_energy_use _kWh_out
Single Detached	19,677	1,311	1,322	1,671	73	29,232
Attached	14,731	1,311	1,322	1,671	73	22,352
Apartment	8,243	1,311	1,322	1,671	73	12,854

Table E - 18: Zone 3 – Isolated Diesel jurisdiction specific data for residential sector

HDD_18.3C	CDD_18.3C	HSPF_zone_IV_to_study_zone
6,289	0	0.76

Segment	AHL _kWH_out	EFLH_heat _hp	EFLH_heat _boiler	EFLH_heat _furnace	EFLH _cool	annual_energy_use _kWh_out
Single Detached	17,366	1,157	1,167	1,475	0	26,920
Attached	13,001	1,157	1,167	1,475	0	20,622
Apartment	7,275	1,157	1,167	1,475	0	11,886

MEASURE LIST AND CHARACTERISATION SOURCES

The measure lists and sources shown in the tables below were used to develop the characterisation algorithms and inputs. The new measure column indicates whether a measure exists in current CDM programs. The table also indicates where the inputs or algorithms were tailored to account for Newfoundland and Labrador-specific conditions.

COMMERCIAL AND INDUSTRIAL SECTOR

Table E - 19: Measure List and Sources for the C&I Sector[21]

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
1	Roof Insulation	Yes	Envelope	NB	2017	HDD/CDD by climate zone for each electricity system
2	Wall Insulation	Yes	Envelope	NB	2017	HDD/CDD by climate zone for each electricity system
3	Building Shell Air Sealing	Yes	Envelope	IA	2017	HDD/CDD by climate zone for each electricity system
4	Efficient Windows	Yes	Envelope	NY	2019	HDD/CDD by climate zone for each electricity system
5	LEED Certified	Yes	Envelope	Custom	Custom	HDD/CDD by climate zone for each electricity system
6	Net-Zero Ready	Yes	Envelope	Custom	Custom	HDD/CDD by climate zone for each electricity system
7	LED A-Lamp (Interior)	No	Lighting	NB	2017	Lighting HOU and interactive effects adapted for NL
8	LED Reflector (Interior)	No	Lighting	NB	2017	Lighting HOU and interactive effects adapted for NL
9	Linear LED Tube	No	Lighting	NB	2017	Lighting HOU and interactive effects adapted for NL
10	LED Luminaire	Yes	Lighting	PSEGLI	2017	Lighting HOU and interactive effects adapted for NL
11	LED High Bay	No	Lighting	NB	2017	Adjusted Savings as per NL Power program evaluation.
12	LED Exit Sign	No	Lighting	NB	2017	Adjusted Savings as per NL Power program evaluation.
13	LED A-Lamp (Exterior)	No	Lighting	NB	2017	Lighting HOU adapted for NL
14	LED Reflector (Exterior)	No	Lighting	NB	2017	Lighting HOU adapted for NL
15	LED Parking Garage (Exterior)	Yes	Lighting	ME	2018	Lighting HOU adapted for NL

[21] All measures outside of new construction are considered under the Utilities Custom Business program if the project is deemed cost effective.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
16	LED Pole Mounted (Exterior)	Yes	Lighting	NB	2017	Lighting HOU adapted for NL
17	LED Wall Pack (Exterior)	No	Lighting	ME	2018	Lighting HOU adapted for NL
18	LED Refrigerated Case Lighting	Yes	Lighting	PSEGLI	2018	Lighting HOU adapted for NL
19	Lighting Controls (Interior), Daylighting	No	Lighting	NB	2017	Lighting HOU adapted for NL
20	Lighting Controls (Interior), Occupancy	No	Lighting	NB	2017	Lighting HOU adapted for NL
21	Lighting Controls (Exterior)	Yes	Lighting	ME	2018	Lighting HOU adapted for NL
22	Unitary Air Conditioner	Yes	HVAC	NEEP	2018	EFLH by climate zone for each electricity system
23	Room/Wall-Mounted Air Conditioner (RAC)	Yes	HVAC	IA	2017	EFLH by climate zone for each electricity system
24	Package Terminal Air Conditioner (PTAC)	Yes	HVAC	PSEGLI	2018	EFLH by climate zone for each electricity system
25	Mini-split Ductless Heat Pump (DHP) - Cold Climate	Yes	HVAC	NEEP	2018	EFLH and equipment efficiencies adapted by climate zone for each electricity system
26	Air Source Heat Pumps (ASHP) - Cold Climate	No	HVAC	NEEP	2018	EFLH and equipment efficiencies adapted by climate zone for each electricity system
27	Air Source Heat Pumps (ASHP)	No	HVAC	NEEP	2018	EFLH and equipment efficiencies adapted by climate zone for each electricity system
28	Ground Source Heat Pump	Yes	HVAC	NB	2017	EFLH and equipment efficiencies adapted by climate zone for each electricity system
29	Package Terminal Heat Pump (PTHP)	Yes	HVAC	PSEGLI	2018	EFLH adapted by climate zone for each electricity system
30	Water Cooled Chiller, Centrifugal	Yes	HVAC	PSEGLI	2018	EFLH adapted by climate zone for each electricity system
31	Air Cooled Chiller	Yes	HVAC	PSEGLI	2018	EFLH adapted by climate zone for each electricity system
32	Energy Recovery Ventilator (ERV)	Yes	HVAC	OEB	2018	EFLH adapted by climate zone for each electricity system
33	Air Curtains	Yes	HVAC	IL	2019	EFLH adapted by climate zone for each electricity system

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
34	HVAC EC Motor	Yes	HVAC	MA	2016	HDD/CDD by climate zone for each electricity system
35	Demand Control Ventilation (DCV)	Yes	HVAC	IL	2017	HDD/CDD by climate zone for each electricity system
36	Kitchen Demand Control Ventilation	Yes	HVAC	IL	2017	Annual heating load adapted by climate zone for each electricity system
37	Dual Enthalpy Economizer Controls	Yes	HVAC	NB	2017	HDD/CDD by climate zone for each electricity system
38	Energy Management System (EMS)	Yes	HVAC	Custom	Custom	Deemed savings adjusted based on energy consumption per business for each electricity system.
39	Guest Room Energy Management	Yes	HVAC	IA	2017	Deemed savings adjusted based on energy consumption per business for each electricity system.
40	Programmable Thermostat	No	HVAC	MA	2017	Savings based on heating equipment and NL climate zones
41	Advanced Thermostat (Wi-Fi Thermostat)	No	HVAC	MA	2017	Savings based on heating equipment and NL climate zones
42	Heat Pump Water Heaters	Yes	Hot Water	PA	2015	Adjusted savings based on estimated hot water consumption of each NL segment.
43	Faucet Aerator	Yes	Hot Water	IA	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
44	Low Flow Shower Head	No	Hot Water	NB	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
45	Pre-Rinse Spray Valve	No	Hot Water	NY	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
46	Thermostatic Restrictor Shower Valve	Yes	Hot Water	NEEP	2018	Adjusted savings based on estimated hot water consumption of each NL segment.
47	Recirculation Pump with Demand Controls	Yes	Hot Water	IA	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
48	Circulator Pump EC Motor	Yes	Hot Water	ME	2018	Adjusted savings based on estimated hot water consumption of each NL segment.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
49	Dishwasher	Yes	Kitchen	IA	2017	Adjusted savings based on estimated hot water consumption of each NL segment.
50	Fryer	Yes	Kitchen	MA	2015	No adjustments made
51	Oven	Yes	Kitchen	MA	2015	No adjustments made
52	Steamer	Yes	Kitchen	MA	2015	No adjustments made
53	Refrigerated Case Anti-Sweat Door Heaters	Yes	Refrigeration	PSEGLI	2018	No adjustments made
54	Refrigerated Case Door Gaskets	Yes	Refrigeration	NY	2017	No adjustments made
55	Refrigerated Case Night Cover	Yes	Refrigeration	MA	2017	No adjustments made
56	Refrigerated Walk-ins Door Strip	Yes	Refrigeration	IA	2017	No adjustments made
57	ENERGY STAR Ice Maker	Yes	Refrigeration	MA	2017	No adjustments made
58	CEE Rated Refrigerators and Freezer - Recycling	Yes	Refrigeration	Custom	Custom	Dropped - Not cost effective
59	Refrigerated Case EC Motor	No	Refrigeration	PSEGLI	2018	No adjustments made
60	Refrigerated Walk-ins EC Motor	No	Refrigeration	PSEGLI	2018	No adjustments made
61	Refrigerated Walk-ins Evaporator Fan Control	Yes	Refrigeration	PSEGLI	2018	No adjustments made
62	Refrigeration Heat Recovery	Yes	HVAC	Custom	Custom	No adjustments made
63	HVAC VFD - Cooling Tower	Yes	Motor/ Compressor	NB	2017	Adjusted kwh/hp based on NL segments
64	HVAC VFD - Fan	Yes	Motor/ Compressor	NB	2017	Adjusted kwh/hp based on NL segments
65	HVAC VFD - Pump	Yes	Motor/ Compressor	NB	2017	Adjusted kwh/hp based on NL segments
66	High Efficiency Air Compressor	Yes	Motor/ Compressor	PSEGLI	2018	Adjusted based on NL compressor HOU for each segment.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
67	Air Receiver for Load/No Load Compressor	Yes	Motor/ Compressor	PSEGLI	2018	Adjusted based on NL compressor HOU for each segment.
68	Low Pressure Drop Filters	Yes	Motor/ Compressor	IL	2018	Adjusted based on NL compressor HOU for each segment.
69	Zero Loss Condensate Drain	Yes	Motor/ Compressor	NB	2017	Adjusted based on NL compressor HOU for each segment.
70	Refrigerated Air Dryer	Yes	Motor/ Compressor	PSEGLI	2019	Adjusted based on NL compressor HOU for each segment.
71	Motor Controls - Process	Yes	Motor/ Compressor	NB	Custom	Applied to Industrial segments
72	Motor Controls - Conveyors	Yes	Motor/ Compressor	Custom	Custom	Applied to Industrial segments
73	Motor Controls - Pumps	Yes	Motor/ Compressor	Custom	Custom	Applied to Industrial segments
74	Custom Processes	No	Process	Custom	Custom	Applied to Industrial segments
75	Advanced Smart Strips	Yes	Office Equipment	PA	2016	No adjustments made
76	ENERGY STAR Uninterruptable Power Supply	Yes	Other	CA	2016	No adjustments made
77	Computer Room Air Conditioner (CRAC)	Yes	Other	MI	2019	EFLH by climate zone for each electricity system
78	Solar Thermal	Yes	Other	Custom	Custom	Savings based on NL climate zones
79	Retro-commissioning Strategic Energy Manager (RCx SEM)	Yes	Other	Custom	Custom	Deemed savings adjusted based on energy consumption per business for each electricity system.

RESIDENTIAL SECTOR

Table E - 20: Measure List and Sources for the Residential Sector

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
1	Air Purifier	Yes	Appliance	blank	blank	No adjustments
2	ENERGY STAR Clothes Dryers	Yes	Appliance	NEEP	2018	No adjustments
3	Clothes Washer	Yes	Appliance	NEEP	2018	Adjusted based on ratio of front to top loading clothes washers in NL.
4	Dehumidifier	No	Appliance	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
5	Dehumidifier Recycle	Yes	Appliance	MA	2019	No adjustments
6	Dishwasher	Yes	Appliance	NEEP	2018	No adjustments
7	Freezer	Yes	Appliance	NEEP	2018	No adjustments
8	Freezer Recycle	Yes	Appliance	California Public Utility Commission Appliance Recycling Program Impact Evaluation	2014	No adjustments
9	Heat Pump Clothes Dryers	Yes	Appliance	NEEP	2018	No adjustments
10	Refrigerator	Yes	Appliance	NEEP	2018	No adjustments
11	Refrigerator Recycle	Yes	Appliance	California Public Utility Commission Appliance Recycling Program Impact Evaluation	2014	No adjustments
12	Home Energy Report	No	Behavioral	NL 2018 Benchmarking Program Evaluation	2019	Used NL evaluated savings
13	Professional Air Sealing	Yes	Envelope	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
14	Attic Insulation	No	Envelope	IL	2019	Used NL evaluated savings

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
15	Basement Insulation	No	Envelope	NL Insulation Rebate Program Evaluation	2017	Used NL evaluated savings
16	Efficient Windows	Yes	Envelope	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
17	New Home Construction	Yes	Envelope	Energy Star Certified Homes, Version 3 (Rev. 08)	2016	Used savings value for NL's climate zone.
18	Wall Insulation	Yes	Envelope	IL	2019	Savings adjusted based on HDD and CDD for each electricity system.
19	Faucet Aerator	No	Hot Water	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
20	Heat Pump Water Heater (HPWH)	Yes	Hot Water	NY	2019	Savings adjusted based on HDD and CDD for each electricity system.
21	Low Flow Shower Head	No	Hot Water	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
22	Thermostatic Restrictor Shower Valve	Yes	Hot Water	NEEP	2018	Adjusted based on mean number of people and of showerheads in NL.
23	Air Source Heat Pump (ASHP) Tune Up	Yes	HVAC	IA	2017	Adjusted based on heat pump equivalent full load hours for NL.
24	Duct Insulation	Yes	HVAC	ME	2018	Savings adjusted based on HDD and CDD for each electricity system.
25	Duct Sealing	Yes	HVAC	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
26	ENERGY STAR Ceiling Fan	No	HVAC	NEEP	2018	No adjustments
27	Ground Source Heat Pump (GSHP)	Yes	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system.
28	Heat Recovery Ventilator	No	HVAC	Custom	Custom	Used Take Charge program requirement as efficient level SRE.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
29	Mini-split Ductless Heat Pump (DMSHP) - Cold Climate	Yes	HVAC	MA	2019	Savings adjusted based on heat pump equivalent full load hours and on heat pump efficiency in that zone.
30	Thermostat Programmable	No	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system and on average number of thermostats per household.
31	Thermostat Wi-Fi	No	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system and on average number of thermostats per household.
32	LED A-Lamp (exterior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
33	LED A-Lamp (interior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
34	LED Linear Tube	Yes	Lighting	NEEP	2018	No adjustments
35	LED Reflector (exterior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
36	LED Reflector (interior)	No	Lighting	PSEGLI	2018	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
37	Advanced Smart Strips	No	Other	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
38	Convection Oven	Yes	Appliance	Custom	Custom	No adjustments
39	Crawl Space Insulation	No	Envelope	IL	2019	Savings adjusted based on HDD and CDD for each electricity system.
40	ENERGY STAR Doors	Yes	Envelope	IA	2018	Savings adjusted based on HDD and CDD for each electricity system.
41	Air Source Heat Pump (ASHP) - Cold Climate	Yes	HVAC	MA	2019	Savings adjusted based on heat pump equivalent full load hours and on heat pump efficiency in that zone.

#	Measure	New to CDM Programs	End Use	TRM Source	TRM Version	NL Adjustments
42	Electronic Thermostat	No	HVAC	NEEP	2018	Savings adjusted based on average annual heating load for each electricity system.
43	Dimmer Switches	No	Lighting	NL Instant Rebates Program Evaluation	2018	Used NL evaluated savings
44	Lighting Controls (Interior)	No	Lighting	MA	2019	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
45	Lighting Controls (Exterior)	No	Lighting	MA	2019	Baseline bulb power based on NL bulb mix based on 2018 Socket Saturation Survey.
46	Insulated Hot Tub Covers	Yes	Other	Custom	Custom	No adjustments

Additionally, in all cases where NL's programs allow the measure to be implemented in a home with oil space heating/water heating, the space heating/water heating savings were split between electricity and oil according to the ratio of the proportion of buildings heated by each of those fuels in that zone and segment.

The following measures are only applicable for electrically heated homes:

a. Home energy report[22]
b. Air Sealing
c. Attic Insulation
d. Basement Insulation
e. Efficient Windows
f. Wall insulation
g. Crawl space insulation
h. Energy star doors
i. All heat pumps
j. New home construction
k. Electronic, programmable and Wi-Fi thermostats – both room and central

[22] Currently the Newfoundland and Labrador Utilities' customers without electric heat are enrolled in this program.

Custom methods were used when a suitable TRM could not be found. **Table E - 21** below details the assumptions made in the case of the custom measures.

Table E - 21: Assumptions for Custom Measures

Measure	Inputs	Algorithm used
Heat Recovery Ventilator	***Flow rate*** based on ventilation requirements in Canada's 2010 National Building Code from http://rdh.com/wp-content/uploads/2015/12/HRV_Guide_for_Houses.pdf. ***Base SRE level*** from https://www.exec.gov.nl.ca/exec/occ/publications/efficient_home_building_guide.pdf. ***Efficient SRE level*** based on takeCHARGE program requirements. Used average of SRE requirement at 0 and -25 C. ***EUL*** from Wisconsin Focus on Energy 2018 TRM.	Energy saving = energy in exhaust air * difference in SRE between efficient and baseline version * proportion of heating provided by each type of heating system / efficiency of that heating system.
Convection Oven	***Savings percentage*** and ***oven baseline power*** from https://smarterhouse.org/cooking/energy-saving-tips. ***Oven HOU*** based on professional judgement. ***EUL*** from NRCAN's Energy cost calculator for new appliances.	Energy saving = Savings percentage * oven baseline power * oven hours of use per day.
Insulated Hot Tub Covers	***Savings percentage*** based on Analysis of Standards Options for Portable Electric Spas, Davis Energy Group Energy Solutions - 2004. ***Baseline consumption*** from Hydro Quebec's Spa consumption calculator - assumed spa used once or twice a week. Used average of all year consumption and summer only consumption. ***EUL*** from https://lakeshorepoolsandtubs.com/2017/11/08/replacing-your-hot-tub-cover/.	Energy saving = savings percentage * baseline energy use.

FURTHER MEASURES CONSIDERED

A number of measures were considered for the study but were ultimately not retained in the modeling. The table below provides a list of these measures and the rationale behind their omission.

Table E - 22. Omitted Measures and Rationale

Measure	Rationale
	RESIDENTIAL
Downsizing HVAC capacity	Prevalence of central HVAC systems in residential units are low with only 13% of homes in the province having an electric furnace, central air source heat pump or ground source heat pump. High efficiency heat pumps are covered in the study, however additional savings from downsizing HVAC is estimated to be small. As well, cost and comfort are barriers to downsizing HVAC capacity.
Codes support program	Most new home construction is happening in major centres, such as St. John's, Mount Pearl, Paradise and Conception Bay South, where the building code is being enforced. For example, close to 60% of new residential service connections in 2018 were on the Avalon peninsula.
Recirculating shower system	Recirculating shower systems are included as a commercial measure, but not for single family homes, as energy used by the pumps will offset hot water savings.
Tankless water heater	Tankless water heaters could increase peak demand. There are other significant barriers to the installation of this measure, including that many customer electrical panels would require additional amperage.
Water tank insulation / Super insulated tanks	New tanks are typically already well insulated.
Drain Water Heat Recovery	Typically hard to configure for single-family residential and is not cost-effective.
Air conditioners and AC tune-ups	Very low prevalence of AC units in NL.
High-Efficiency Furnace Blower Motor	Almost all savings lost to interactive effects.
Timers for Car Warmers	No REUS data on this was available, and Newfoundland is not typically considered to be cold enough to warrant car block heaters.
Use Sensor for Clothes Dryer	Some new clothes dryers have moisture sensors but this is not a retrofit measure.

Measure	Rationale
High Efficiency Cooktops (Induction)	Minimal evidence of consistent savings.
	COMMERCIAL / INDUSTRIAL
VendingMiser	VendingMiser was considered in Newfoundland and Labrador's 2015 Potential Study. In the study it was identified that savings were not likely to exist past 2023.
Codes support program	In the new Climate Change Action Plan the Provincial Government committed to establish minimum energy efficiency requirements for commercial and institutional buildings, which will help address available savings.
Drain water heat recovery	This is typically just appropriate for NC MURBS - a significant potential for retrofit due to building stack configurations and installation costs/challenges is not seen.
CEE Rated Refrigerators and Freezers	CEE retired its specification for commercial refrigerators and freezers as of March 27, 2017 in order to focus on other opportunities to advance energy savings in commercial foodservice.
Automatic Door Closers (Walk-in Coolers)	Minimal applications and impacts.
Freeze Defrost Controllers	Minimal applications and impacts.
ENERGY STAR computers and office equipment	This is not typically considered to be a decision-making factor for computer purchase. NTGs would be very low.
Phase change materials (PCMs)	The technology is in an early phase and does not have proven savings.
Custom Behavioural	Savings for this type of measure were captured under Retro-commissioning and Strategic Energy Manager (RCx and SEM)
Boiler Reset Controls and Steam Traps	In Dunsky's experience this equipment usually applies to gas or oil-fired boilers.

CONSERVATION DEMAND MANAGEMENT PROGRAMS

The Potential Study organizes measures into CDM programs that are characterized by their applicable market coverage, incentive levels and administrative costs. Wherever possible, the programs were developed based on current NL Utilities' programs. Baseline inputs were created for each program and were used to define scenarios as outlined below.

PROGRAM CHARACTERIZATION METHODOLOGY

Programs were largely characterized based on current NL Utilities' programs, following a series of steps to ensure methodological consistency. The Potential study does include some measures not currently offered within the Utilities' portfolio; however, in these cases additional programs were characterized based on other jurisdictions and discussion with Utility staff.

GATHERING AND COMPILING PROGRAM DATA

As a first step, data was gathered on existing programs from the NL 2016-2020 Five-Year Conservation Demand Management Plan, as well as available program evaluation reports. From the compiled list of programs, the Dunsky team aggregated and extracted expected program net savings and costs. To calculate the program costs, the following cost streams were considered to be administrative:

- Program Planning and Administration
- Marketing and Advertising
- Sales, Technical Assistance and Training
- Evaluation and Market Research

The list in **Table E - 23** below highlights the programs characterized for this Potential study.

Table E - 23: NL Utilities Programs

System(s)	Sector	Program
IIC & LAB	Residential	Insulation and envelope
		Energy efficient product rebates
		Thermostats
		HVAC
		Heat pumps
		Benchmarking
		Residential new construction
		Appliance recycling
	Commercial	Business efficiency program
		Commercial new construction
	Industrial	Industrial efficiency program
ISO	Residential	Isolated systems residential program
	Commercial	Isolated systems business efficiency program

PROGRAM INPUT PARAMETERS

The Dunsky team characterized the programs highlighted above and developed assumptions using a uniform methodology, with final adjustments made based on professional judgement and feedback from NL Utilities.

Each program input (listed below) was characterized based on data received from NL Utilities.

- **Fixed Administration Costs are defined as program costs that do not change with the potential model measure uptake.** Through conversations with NL Utilities staff, the portion of non-incentive administrative costs that are fixed (independent of savings) were identified on a program-by-program basis. Costs were taken from the CDM model and converted to real 2020 dollars, then mapped to each program to produce annual fixed costs.
- **Variable Administration Costs are defined as program costs that change with the potential measure uptake.** Also, through conversations with NL Utilities staff, the portion of non-incentive administrative costs considered to be variable (change in magnitude with savings) were identified on a program-by-program basis. Costs were taken from the CDM model and converted to real 2020 dollars, then mapped to each program to produce variable costs by program ($/kWh).
- **Incentive levels are the portion of measure incremental costs that are covered by program incentives.** These incentive levels vary by scenario to assess the ability for higher incentive levels to drive participation:
    - Where available, current NL Utilities incentive levels were calculated using reported participant incentive and participant cost values:

I = Incentive (%)

PI = Participant Incentive ($)

IC = Measure Incremental Cost ($)

$$\boldsymbol{I = \frac{PI}{(PI + IC)}}$$

In cases where data was not available, incentive levels were identified in conversation with the Utilities' staff.

- **Barrier Reductions refer to the ability of programs to reduce market barriers through effective marketing and delivery.**[23] Barrier reductions via program enabling strategies were defined for each scenario. Further discussion of the barrier levels and their impact on adoption is included in Appendix A.
- **The Cost-Effectiveness Threshold indicates the minimum TRC ratio for which a measure can be included in the program**. This can be lowered to allow non-cost-effective measures to be included into the programs. For all scenarios, the default ratio of 0.8 was used.

The program inputs common among all three achievable potential scenarios are provided in **Table E - 24** below.

[23] While the DOE has published 5 different adoption curves for extreme, high, medium, low and no barriers, the Dunsky team's adoption model further provides intermediate barrier curves to provide a more refined analysis. Adjacent DOE barrier levels are considered separated by one step.

Table E - 24: Program Model Inputs by Scenario

	Incentive Level			Barrier Reduction		
Program Name	Lower	Mid	Upper	Lower	Mid	Upper
Insulation and envelope	60%	65%	65%	0	0	0.5
Energy efficient product rebates	20%	35%	35%	0	0	0.5
Thermostats	30%	45%	45%	0	0	0.5
HVAC	50%	60%	60%	0	0	0.5
Heat pumps	0%	50%	50%	0	0	0.5
Benchmarking[24]	30% of homes	40% of homes	50% of homes	n/a	n/a	n/a
Residential new construction[25] **(NEW)**	0%	30%	30%	0	0.5	1
Appliance recycling (NEW)	0%	50%	75%	0	0.5	1
Business efficiency program	20%	30%	30%	0	0	0.5
Commercial new construction (NEW)	0%	30%	30%	0	0.5	1
Industrial efficiency program	30%	50%	50%	0	0	0.5
Isolated systems residential efficiency program	100%	100%	100%	0	0	0.5
Isolated systems business efficiency program	80%	85%	85%	0	0	0.5

[24] The benchmarking program (Home Energy Reports) carries no incremental cost to the customer and its impact is determined by the portion of homes that received the Home Energy Reports. Program incentive levels and barrier reductions used as inputs in the model are defined as work arounds to result in the Lower, Mid and Upper program scenario coverage values of 30%, 40% and 50% respectively.

[25] For new programs (those not currently offered as part of the NL Utilities CDM portfolio) a 0.5 barrier reduction was included for the Mid scenario, and a full barrier level reduction in the Upper scenario to account for the initial barrier reduction from the new program promotional materials.

PRIMARY RESEARCH

DESCRIPTION

In addition to the utility and program data incorporated in the Potential study, the Dunsky team conducted primary research with residential and commercial/industrial (C&I) customers to assess barriers in implementing energy efficiency measures and gain additional market insights where required. Research consisted of surveys for both residential and C&I customers, and market actor interviews with individuals who have subject-matter expertise into particular details required for the study. Results from the surveys and interviews complemented work already conducted by the Utilities to provide a better understanding of technology availabilities and customer behaviours and motivations.

BARRIERS SURVEYS

Residential Survey

The Residential survey was conducted as an online survey with the following parameters:

- A sample of 4,000 customers was selected from all Newfoundland Power and Newfoundland and Labrador Hydro customers for which the Utilities had email addresses.
- The surveys were developed to be 10-12 minutes in length, with a goal of 400 completes.
- The survey was kept open for two weeks to ensure adequate time was available for responses.

By the survey's close, 666 responses were received, with results tabulated by utility and residential segment:

Table E - 25: Breakdown of Residential Survey Responses by Utility and Residential Segments

Data Point	Number of Responses	Breakdown
Total Responses	666	
Segment	533	Single Family Detached
	38	Attached (Duplex or Triplex)
	20	Townhouse or Row House
	27	Apartment or Condo 2-4 Units
	17	Apartment or Condo >5 Units
	9	Mobile Home or Trailer
	22	Other (Vacation Home, Hotel, etc.)
Occupant Status	559	Owners
	96	Renters

The survey covered barriers to adopting the following categories of energy efficiency measures:

- Insulation
- Air sealing
- Heating systems
- Heat pumps
- Appliances
- Smart thermostats

In addition, the survey assessed residential customer considerations to participating in demand response/demand control and fuel switching initiatives.

Commercial/Industrial Survey

The C&I survey was conducted via telephone with the following parameters:

- A random, stratified sample of customers were selected from all Newfoundland Power and Newfoundland and Labrador Hydro customers. Stratification was based on the need for responses from each of the following segments:
    - Office
    - Retail
    - Other
    - Lodging
    - Health
    - Education
    - Warehouse
    - Manufacturing
    - Grocery/Restaurant
    - Fishing
- The surveys were developed to be 10-12 minutes in length, with a goal of 150 completes, with final responses as follows:

Table E - 26: Breakdown of Commercial/Industrial Survey Responses by Utility and Segments

Data Point	Number of Responses	Breakdown
Total Responses	150	
Segment	29	Office
	21	Retail
	20	Other
	16	Lodging
	15	Health
	15	Education
	10	Warehouse
	9	Manufacturing
	8	Grocery/Rest
	7	Fishing

The survey covered barriers to adopting energy efficiency equipment and participating in demand response/demand control and fuel switching initiatives.

BARRIER SETTING FOR MODEL INPUTS

The results of the surveys were used as inputs to the potential study using the following steps:

1. Barriers were set at the segment and end-use level based on the barrier survey results.
2. For each end-use, barriers were established based on the average response on 3-5 specific questions considering key customer constraints that could hinder conducting an energy efficiency upgrade: cost, available time, customer knowledge, project complexity, and uncertainty over the benefits.
3. Global factors were then applied to each segment based on financial decision-making and the proportion of respondents who own or rent the building.
4. Labrador barriers were increased ½ step above the Island Interconnected system.
5. Isolated diesel barriers were increased ½ step above the Island Interconnected system.

MARKET ACTOR INTERVIEWS

Fifteen one-on-one interviews were scheduled with individuals who have subject-matter expertise in the following residential and commercial energy efficiency areas:

- Lighting
- Heat Pumps
- Fish Plants
- Educational Facilities
- Residential Insulation
- Large Industrial
- Commercial New Construction
- Plumbing (Commercial and Residential)
- Mechanical Needs (Commercial and Residential)
- Electric Vehicles
- Fuel Switching

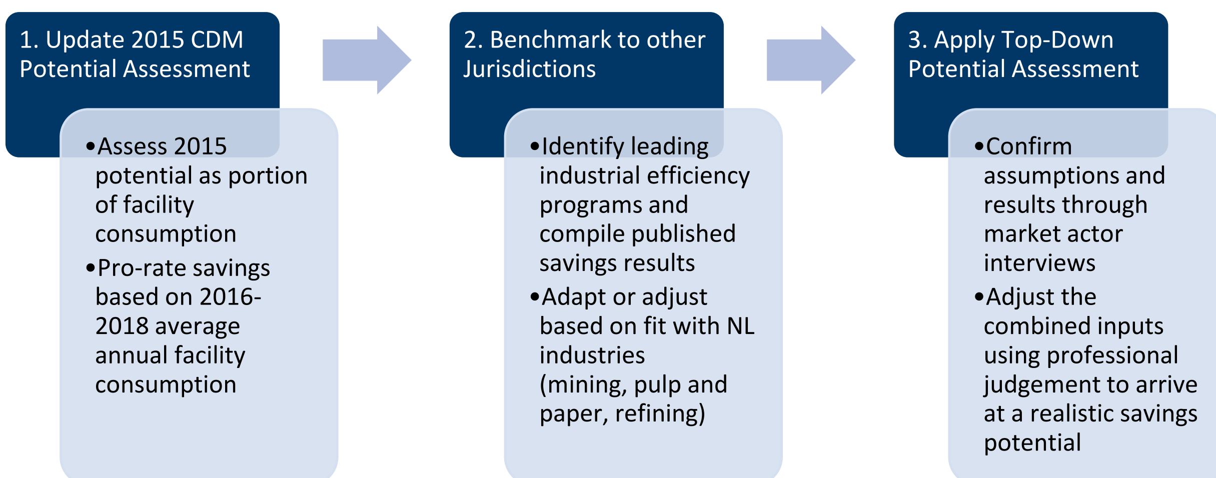
The semi-structured, qualitative interviews were intended to provide supplemental detail on measure and/or market considerations, depending on the specific technologies, sectors, or initiatives identified above. Some examples include Newfoundland and Labrador-specific costs, penetration of given technologies within the provincial market, barriers to adoption, and facility-specific characteristics.

LARGE INDUSTRIAL SECTOR TOP-DOWN ASSESSMENT

As part of the NL Conservation Potential Study, Dunsky attempted to assess the efficiency potential in Newfoundland and Labrador's large industrial segment. This segment is comprised of six transmission-level customers of Newfoundland and Labrador Hydro (two in the LAB system, and four connected to the IIC system) who collectively represent a significant portion of energy consumption in the province (35%).

The utility market data collected through the CEUS did not include these customers, and very little is known about these customers' installed systems, or the penetration of energy efficient equipment. As a result, based on the minimal information available for these customers regarding realistic equipment saturation counts or square footage of operating spaces, this data was not applied in the bottom-up potential model. To address this challenge, a top-down approach was applied to assess the potential among these six transmission-level customers. This is based on the central assumption that because the NL Utilities have not run large industrial CDM programs over the majority of time that has passed since the 2015 CDM Potential study, the overall pool of efficiency opportunities should, in theory, remain largely the same as it was in 2015.

Figure E - 2: Large Industrial Top-Down Potential Assessment Process



LARGE INDUSTRIAL POTENTIAL: TOP-DOWN ASSESSMENT RESULTS AS INPUTS TO STUDY

Because the CEUS did not include the six transmission-level industrial customers, and little is known about the saturation and penetration of energy using equipment in these facilities, it was not possible to include them in Dunsky's bottom-up efficiency potential model. Thus, a top-down assessment of the efficiency savings was performed by extrapolating the findings from the 2015 Newfoundland and Labrador CDM Potential Study. An overview of the top-down assessment results that were included as inputs to the savings and program scenarios in this study is provided in **Table E - 27** below.

Table E - 27: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study (expressed as portion of sales to Transmission Level Customers)

<table>
<tr><th>Scenario</th><th>Technical Potential (2034)</th><th>Economic Potential (2034)</th><th>Cumulative Achievable Savings (2034)</th><th>Annual Program Savings Range</th><th>Annual Average</th></tr>
<tr><td>High (ICF 2015)</td><td rowspan="3">IIC: 33%
LAB: 13%</td><td rowspan="3">IIC: 27%
LAB: 10%</td><td>IIC: 24%
LAB: 9.3%</td><td>0.70% - 1.0%</td><td>0.87%</td></tr>
<tr><td>Mid (New)</td><td>IIC: 18%
LAB: 6.8%</td><td>0.48% - 0.77%</td><td>0.62%</td></tr>
<tr><td>Low (ICF 2015)</td><td>IIC: 11.2%
LAB: 4.4%</td><td>0.23% - 0.53%</td><td>0.38%</td></tr>
</table>

Table E - 28: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study: Consumption (GWh)

Jurisdiction	% Industrial Electricity Savings	Jurisdiction Characteristics [26][27]
NB Power	0.54%-0.58%	Main industries: Paper, wood products, refined petroleum, mining. Industrial electricity rate: ≈6.64¢/kWh[28]
Wisconsin Focus on Energy	0.60%	Main industries: Paper, manufacturing (Food, Plastics, machinery, others). Industrial electricity rate: 10.5¢/kWh 29th place in 2018 ACEEE State Scorecard
IESO (Ontario)	0.76%	Main industries: Mining, metals, manufacturing, food and beverage, automotive. Industrial electricity rate: 12.0¢/kWh[29]
Energy Trust of Oregon	0.79%	Main industries: Wood products, water treatment, laundry, cannabis. 7th place in 2018 ACEEE State Scorecard Industrial electricity rate: 8.7¢/kWh
Efficiency Vermont	1.2%	Main industries: Agriculture/farming, manufacturing (precision machining, plastics, composites, semiconductors, medical devices). Industrial electricity rate: 14.7¢/kWh 4th place in 2018 ACEEE State Scorecard

[26] American Council for an Energy-Efficient Economy (2018), *The 2018 State Energy Efficiency Scorecard*
[27] USA States average industrial electricity rates retrieved from: https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a for February 2019, with an exchange rate of 1.34 CAD/USD
[28] Average of NB Power's small industrial and large industrial rates, assuming a customer capacity factor of 60%
[29] Ontario electricity costs retrieved from http://www.ieso.ca/en/Corporate-IESO/Media/Year-End-Data for supply and https://hydroottawa.com/accounts-and-billing/business/rates-and-conditions for delivery

Table E - 29: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study: Consumption (GWh)

Consumption savings from Efficiency																
Program Savings																
Island Transmission-Level Savings (GWh)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19	19
Economic	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15	15
High	10	11	11	11	12	12	12	12	13	13	13	14	14	14	14	15
Mid	7	7	8	8	8	8	9	9	9	9	10	10	10	11	11	11
Low	3	4	4	4	5	5	5	5	6	6	6	6	7	7	7	8
Labrador Transmission-Level Savings (GWh	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Economic	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	22
High	15	16	16	17	17	18	18	19	19	19	20	20	21	21	21	22
Mid	10	11	11	12	12	12	13	13	14	14	14	15	15	16	16	17
Low	5	5	6	6	7	7	8	8	8	9	9	10	10	11	11	11
Cumulative Savings	**Assumed EUL = 10 years on average for savings**															
Island Transmission-Level Savings (GWh)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	19	37	56	74	93	112	130	149	167	167	167	167	167	167	185	204
Economic	15	30	45	60	75	90	105	120	135	135	135	135	135	135	150	164
High	10	21	32	43	55	67	79	92	105	107	110	113	115	117	132	147
Mid	7	14	21	29	37	46	55	63	73	75	78	81	83	85	96	108
Low	3	7	11	15	20	25	30	35	41	43	46	49	51	54	61	69
Portion of Sales - Island																
Technical	3%	6%	9%	12%	15%	18%	21%	24%	27%	27%	27%	27%	27%	27%	30%	33%
Economic	2%	5%	7%	10%	12%	15%	17%	20%	22%	22%	22%	22%	22%	22%	25%	27%
High	1.7%	3.4%	5.2%	7.1%	9.0%	10.9%	13.0%	15.0%	17.1%	17.6%	18.0%	18.4%	18.9%	19.3%	21.6%	24.0%
Mid	1.1%	2.3%	3.5%	4.8%	6.1%	7.5%	8.9%	10.4%	11.9%	12.4%	12.8%	13.2%	13.6%	14.0%	15.8%	17.6%
Low	0.5%	1.1%	1.8%	2.5%	3.2%	4.0%	4.9%	5.8%	6.7%	7.1%	7.5%	8.0%	8.4%	8.8%	10.0%	11.2%
Labrador Transmission-Level Savings (GWh	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	27	55	82	110	137	165	192	220	247	275	275	275	275	275	275	275
Economic	22	44	67	89	111	133	155	177	200	222	222	222	222	222	222	222
High	15	31	47	64	81	99	117	136	155	174	178	183	187	191	196	200
Mid	10	21	32	43	55	68	81	94	107	122	126	130	135	139	143	147
Low	5	10	16	23	29	36	44	52	60	69	73	78	82	86	90	94
Portion of Sales - Labrador																
Technical	1%	3%	4%	5%	6%	8%	9%	10%	11%	13%	13%	13%	13%	13%	13%	13%
Economic	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	10%	10%	10%	10%	10%	10%
High	0.7%	1.4%	2.2%	3.0%	3.8%	4.6%	5.4%	6.3%	7.2%	8.1%	8.3%	8.5%	8.7%	8.9%	9.1%	9.3%
Mid	0.5%	1.0%	1.5%	2.0%	2.6%	3.1%	3.7%	4.4%	5.0%	5.7%	5.9%	6.1%	6.3%	6.5%	6.7%	6.8%
Low	0.2%	0.5%	0.8%	1.0%	1.4%	1.7%	2.0%	2.4%	2.8%	3.2%	3.4%	3.6%	3.8%	4.0%	4.2%	4.4%

Table E - 30: Top-Down Efficiency Potentials for Transmission Level Industrial Customers Applied in Study: Peak Demand (MW)

Demand Savings from Efficiency																
Cumulative Savings																
Island Transmission-Level Savings (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	2.4	4.9	7.3	9.7	12.1	14.6	16.9	19.2	21.6	21.6	21.6	21.6	21.6	21.6	24.0	26.4
Economic	2.0	3.9	5.9	7.8	9.8	11.8	13.6	15.5	17.5	17.5	17.5	17.5	17.4	17.4	19.4	21.3
High	1.3	2.7	4.2	5.7	7.2	8.7	10.3	11.9	13.5	13.9	14.2	14.6	14.9	15.2	17.1	19.0
Mid	0.9	1.8	2.8	3.8	4.9	6.0	7.1	8.2	9.4	9.8	10.1	10.4	10.8	11.1	12.5	13.9
Low	0.4	0.9	1.4	2.0	2.6	3.2	3.9	4.6	5.3	5.6	6.0	6.3	6.6	6.9	7.9	8.9
Portion of Annual Peak - Island																
Technical	3%	6%	9%	12%	15%	18%	21%	24%	27%	27%	27%	27%	27%	27%	30%	33%
Economic	2%	5%	7%	10%	12%	15%	17%	20%	22%	22%	22%	22%	22%	22%	25%	27%
High	2%	3%	5%	7%	9%	11%	13%	15%	17%	18%	18%	18%	19%	19%	22%	24%
Mid	1.1%	2.3%	3.5%	4.8%	6.1%	7.5%	8.9%	10.4%	11.9%	12.4%	12.8%	13.2%	13.6%	14.0%	15.8%	17.6%
Low	0.5%	1.1%	1.8%	2.5%	3.2%	4.0%	4.9%	5.8%	6.7%	7.1%	7.5%	8.0%	8.4%	8.8%	10.0%	11.2%
Labrador Transmission-Level Savings (MW)	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
Technical	4	8	12	16	19	23	27	31	35	39	39	39	39	39	39	39
Economic	3	6	9	13	16	19	22	25	28	31	31	31	31	31	31	31
High	2	4	7	9	12	14	17	19	22	25	25	26	27	27	28	28
Mid	1	3	4	6	8	10	11	13	15	17	18	18	19	20	20	21
Low	1	1	2	3	4	5	6	7	9	10	10	11	12	12	13	13
Portion of Annual Peak - Labrador																
Technical	1%	3%	4%	5%	6%	8%	9%	10%	11%	13%	13%	13%	13%	13%	13%	13%
Economic	1%	2%	3%	4%	5%	6%	7%	8%	9%	10%	10%	10%	10%	10%	10%	10%
High	1%	1%	2%	3%	4%	5%	5%	6%	7%	8%	8%	9%	9%	9%	9%	9%
Mid	0.5%	1.0%	1.5%	2.0%	2.6%	3.1%	3.7%	4.4%	5.0%	5.7%	5.9%	6.1%	6.3%	6.5%	6.7%	6.8%
Low	0.2%	0.5%	0.8%	1.0%	1.4%	1.7%	2.0%	2.4%	2.8%	3.2%	3.4%	3.6%	3.8%	4.0%	4.2%	4.4%

PORTFOLIO BENCHMARKING INPUTS AND SOURCES

The table below compares savings from efficiency programs from other Canadian provinces across residential, commercial and industrial and cross-cutting sectors.

Table E - 31: Efficiency Program Savings from Other Canadian Provinces (2015-2018 depending on Location)

Programs	NB Power	BC Hydro	Efficiency NS	Hydro Quebec	Manitoba Hydro	SaskPower
Total annual incremental electricity savings from measures installed (% of retail sales)	0.42%	1.0%	1.3%	0.31%	0.86%	0.2%
Total Savings (GWh)	**55**	**602**	**131**	**524**	**190**	**56**
Residential	50	50	54	203	24	25.3
Commercial	5	102	55	321	58	30.8
Industrial	0	166	22		17	
Cross-cutting	0.5	284			91	
Total retail sales (GWh)	**13,170**	**57,652**	**10,245**	**170,703**	**21,966**	**23,282**
Residential	5,100	18,068	4,374	66,111	7,250	3,162
Commercial	2,332	18,968	3,060	45,816	6,873	5,190
Industrial	4,479	13,177	2,466	53,699	7,843	13,722
Other	1,259	7,439	345	5,077		1,208
Total lifetime electricity savings as a % of retail sales	4.8%	12.0%	14.7%	3.5%	9.9%	2.8%
Residential	10.0%	10.1%	13.7%	3.4%	11.0%	7.7%
Commercial & Industrial	0.8%	13.1%	15.5%	3.6%	9.4%	1.8%

Table E - 32: Sources for Data in Table E - 30

NB Power	Savings: 2019/2020 DSM Initiative Update Retail Sales: 2017/2018 Annual Report
BC Hydro	Savings: Report on Demand-Side Management Activities for Fiscal 2017 Retail Sales: 2015-2017 Annual Service Plan Report
Efficiency NS	Savings: Efficiency One 2017 Annual Report Retail Sales: Emera Annual Report 2017
Hydro Quebec	Savings: Sustainability Report 2017 Retail Sales: Annual Report 2017
Manitoba Hydro	Savings: Supplemental Report to the Power Smart Plan 2014 to 2017 - Appendix 8.1 Retail Sales: Annual Report 2016-2017
SaskPower	Savings and Retail Sales: SaskPower 2017-2018 Annual Report Retail Sales:

DEMAND RESPONSE

The demand response potential study branch covers multiples steps. This section focuses on the inputs and assumptions used to complete this study. DR potential methodology was covered in Appendix B.

The demand response modelling used general utility data described in this Appendix (see Utility Data). Key inputs for demand response include:

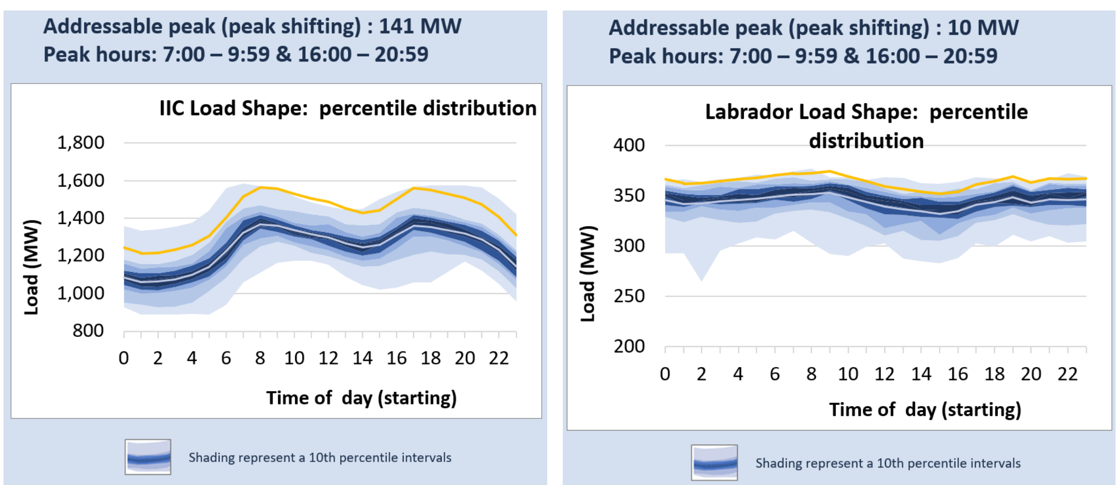
- Avoided costs
- Demand forecast
- Discount rates

STANDARD PEAK DAY

NL Utilities provided Dunsky with hourly historical load data. For the IIC, the data covered January 1st, 2015 to March 31st, 2019 (37,233 data points) and for the LAB, the data covered January 1st, 2015 to December 31st, 2018 (35,064 data points).

This historical data was used to create standard peak days for both systems.

Figure E - 3: Standard Peak Day for IIC and LAB



END-USE BREAKDOWNS

Dunsky developed end-use load curves for each market sector and end-use and where relevant, for individual segments. These provide a basis for four study processes:

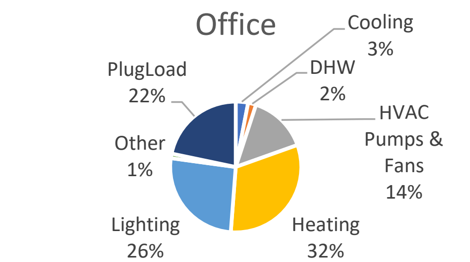
1) They were used to assess standard peak day adjustments for DR addressable peak determination.
2) They were used to develop savings for custom measures, which are expressed as the potential savings as a portion of the associated end-use consumption.
3) They were used to benchmark savings when calibrating the model.
4) They were used to develop winter / summer, on and off-peak savings ratios to apply to seasonal avoided costs in the models.

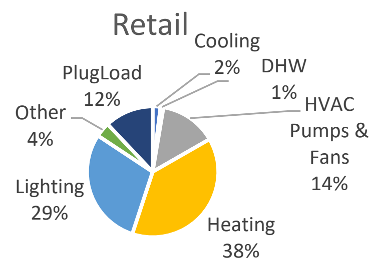
The end-use load curves were developed from the following sources:

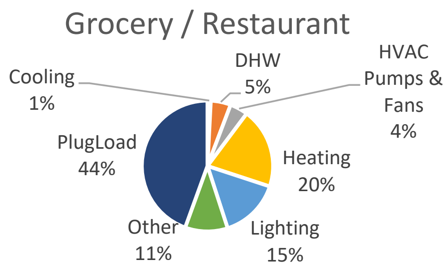
- US Department of Energy (US DOE) published load curves, taken from buildings in comparable climate zones to the Newfoundland and Labrador climate zones, and adjusted to account for heating energy source.
- Engineered load profiles and Dunsky's in-house developed sample consumption profiles.
- Data from the "Newfoundland and Labrador conservation and demand management potential study: 2015".

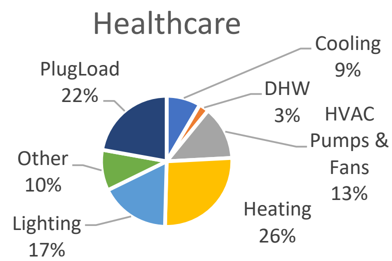
Table E - 33 below presents the end-use consumption for each segment developed from the above sources.

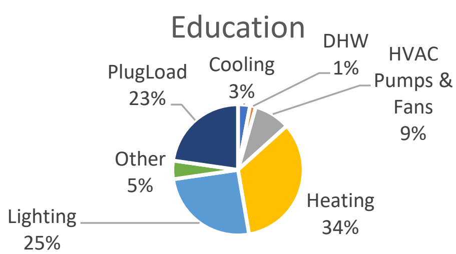
Table E - 33: Annual Consumption: Segment and End-Use Breakdown

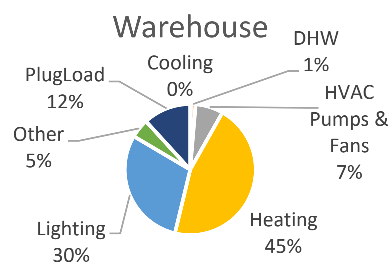


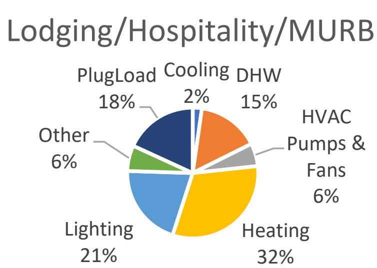


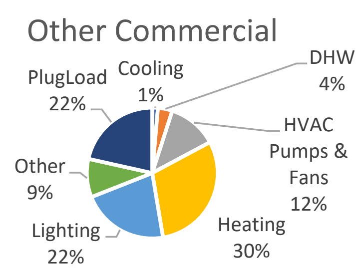


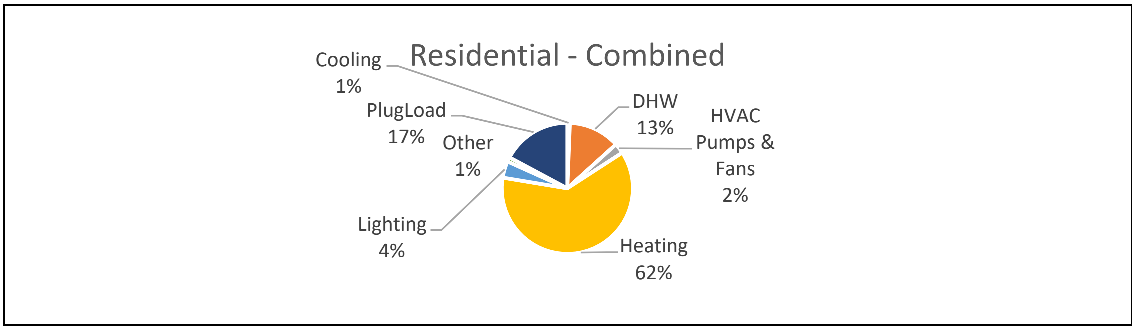












In Newfoundland and Labrador, the Industrial sector is split into four segments: fisheries, manufacturing, small/medium industrial and large industrial. Each segment's consumption was grouped into one industrial end-use ("Industrial"), as seen in **Figure E - 5**. NL Utilities provided Dunsky with data for isolated communities with and without fisheries. Based on this information, data about annual fishery consumption was extracted. Furthermore, NL Utilities also provided large industrial load curves (such as IOC consumption). The last two industrial segments: Manufacturing and Small/Medium Industrials were evaluated using Dunsky's internal datasets. Using the assumptions that commercial and residential buildings are similar in both Labrador and Newfoundland, the same end-use breakdown was scaled to LAB consumption.

Using this annual breakdown and an annual (hourly – 8670 hours) building energy consumption simulation from the US DOE (*Commercial Reference Buildings & Building America House Simulation Protocols*) allowed for the recreation of the end-use breakdown for a standard peak day. The figure below presents the energy and sector breakdown for IIC and LAB systems.

Figure E - 4: IIC Standard peak day – Sector breakdown

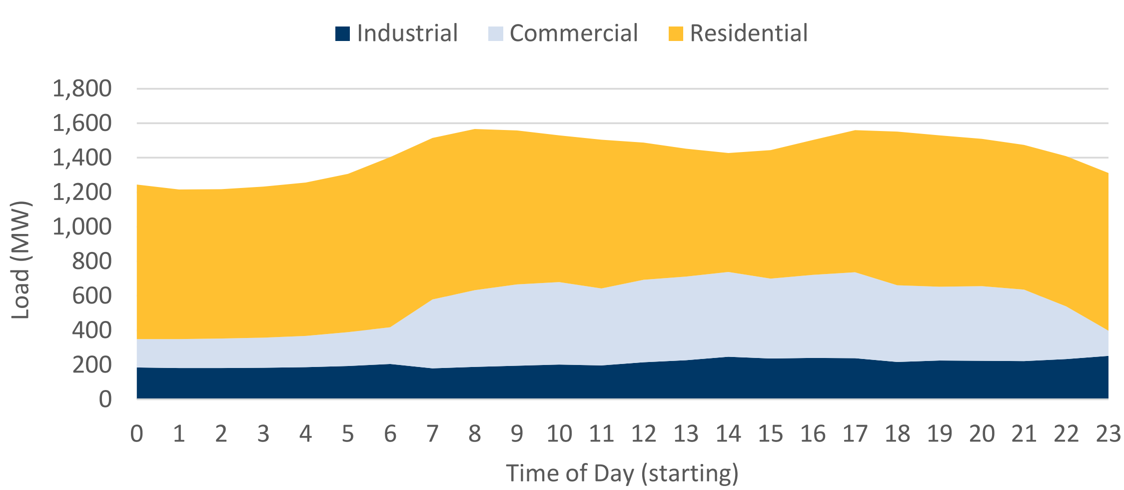


Figure E - 5: IIC Standard peak day – End-use breakdown

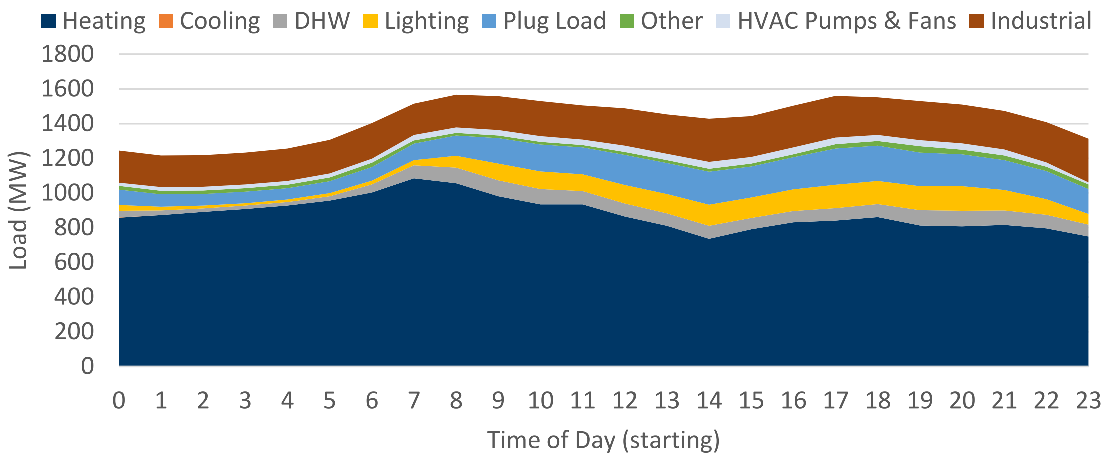


Figure E - 6: LAB Standard peak day – Sector breakdown

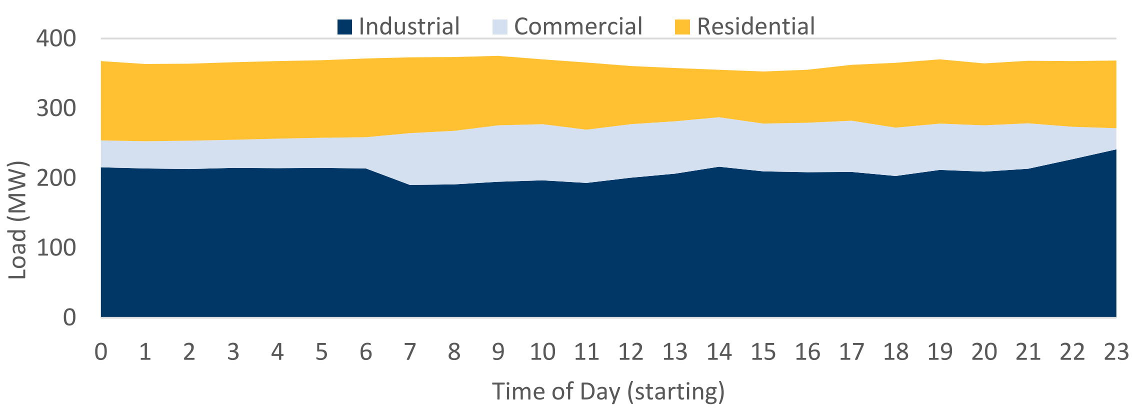
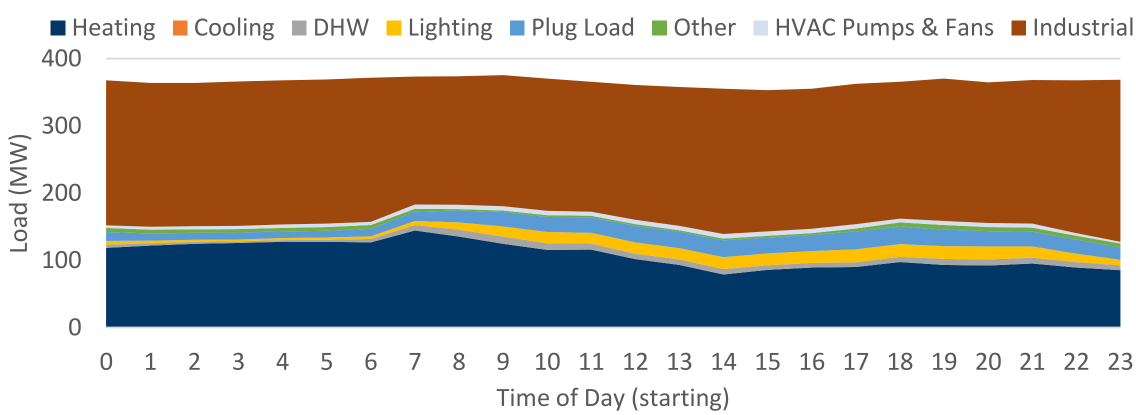


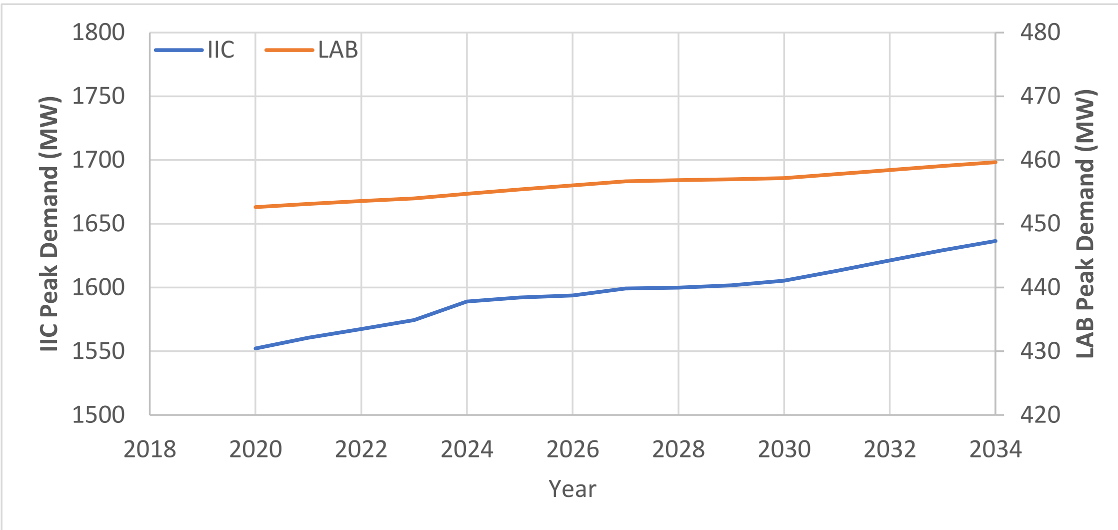
Figure E - 7: LAB Standard peak day – End-use breakdown



FUTURE IMPACTS

The standard peak day was forecasted using the same peak demand forecast as the rest of the potential study. Since no information was available for LAB system, the same growth factors were used for industrial and non-industrial sectors.

Figure E - 8: Newfoundland and Labrador's load forecasting (before EE)



Furthermore, final energy efficiency results from the Lower scenario with mid-rates were combined with the forecast in order to have a better grasp at the future load shape.

Table E - 34: Impact of EE Measures on Demand Response

System	EE impact on Peak-to-average difference (2034)[30]	Peak reduction (2034)	Average hourly EE impact (2034)
IIC	+ 1.6 MW	47 MW	47 MW
LAB	+ 0.6 MW	13 MW	14 MW

[30] Impact of energy efficiency measures on peak to average value. Peak to average is presented, for each system, in the main report. It is a measure of the load curve shape, with lower peak-to-average ratios representing flat load curves, and high ratios representing choppy or high-amplitude peaks.

MEASURES

To assess the DR potential in Newfoundland & Labrador, Dunsky characterized over 25 specific demand reducing measures, based on commonly applied approaches in DR programs across North America, and emerging opportunities such as battery storage. As defined in Appendix B, the measures are covering all customer segments and can be categorized into two groups: Type 1 (constrained by the addressable peak) and type 2 (unconstrained by the addressable peak). Measures of all types have the following key metrics:

- Load shape of the measure
- Constraints
- Measure Effective Useful Life (EUL)
- Costs

Dunsky applied our existing library of applicable DR measure characterizations and adjusted them to reflect end-use energy use profiles in Newfoundland and Labrador's climate. **Table E - 35** and **Table E - 36** provide an overview of each measure characterization and approach.

Table E - 35: Residential Demand Response Measures

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Appliances						
Clothes Washer	Conventional residential clothes washer enabled for Direct Load Control (DLC) by utility	14	Number of clothes washers in the province	Zigbee relay costs (or smart devices)	Fail	Not cost-effective
Clothes Dryer	Conventional residential clothes dryer enabled for DLC by utility	11	Number of clothes dryers in the province	Zigbee relay costs (or smart devices)	Pass	Potential filled by more cost-effective measure
Dishwasher	Conventional residential dishwasher enabled for DLC by utility	11	Number of dishwashers in the province	Zigbee relay costs (or smart devices)	Fail	Not cost-effective
Hot Tubs / Spas	Conventional residential spa enabled for DLC by utility	10	3% of households	Zigbee relay costs	Pass	Potential filled by more cost-effective measure
Refrigerator	Conventional residential refrigerator enabled for DLC by utility	14	Number of residential refrigerators in the province	Zigbee smart plug and hub costs	Fail	Not cost-effective
Hot Water						
Resistance Storage Water Heater	Conventional residential electric water heater enabled for DLC by utility	10	Residential electric water heater (excl. heat pump water heater)	A fast DR enabled control device	Pass	Potential filled by more cost-effective measure
Heat Pump Storage Water Heater	Residential heat-pump water heater enabled for DLC by utility	15	Residential heat pump water heater	A fast DR enabled control device	Fail	Not cost-effective
HVAC						
Space Setpoint Control	Existing Programmable/Manual thermostat enabled for DLC by utility	20	All electric heated households with programmable or manual thermostat	Installation of a communication device or WiFi thermostat	Pass	Utility-wide load curve constraints
Dual Fuel Measure (Fuel switching at peak)	Fuel switching during peak events	20	All electric heated households with central furnace or boiler	Cost of the full equipment ($9,000)	Pass	Utility-wide load curve constraints

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Other						
Electrical Vehicle (EV)	EVs are charged through charging stations (assumed level 2 AC). The measure is applied to existing EV owners who plug for a long period of time. Therefore, the scope is limited to homes.	13	Number of EVs in NL x % charged at home	Incremental cost of a smart charger	Fail	Not cost-effective[31]
Battery Energy Storage	Installation of a Powerwall in household for DR	10	All households	Full cost of the battery	Fail	Not cost-effective
Time-of-Use (TOU)	Implementation of a TOU Rates Program combined with a pricing signal at the peak moment to increase the program efficiency	1	All households	None	Fail[32]	n/a[33]

[31] Residential EV measure is not cost-effective based on the current adoption projections applied by the utilities, as they are insufficient to create an evening peak that exceeds the morning peak. Under the EV penetration levels assessed in Chapter 6 of this study, EV smart charging may become cost-effective.

[32] First year PACT. Does not include negative impact from lost industrial curtailment potential.

[33] TOU rates is a curve shaping mechanism. Therefore, it is applied first to the entire applicable market and does not enter into competition with other measures.

Table E - 36: Non-Residential Demand Response Measures

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Appliances						
Commercial Refrigeration	Commercial refrigeration load shedding through existing BAS	14	Refrigeration load per building x number of buildings (Grocery only)	None	Pass	Potential filled by more cost-effective measure
Hot Water						
Resistance Storage Water Heater	Existing electric water heater enabled for DR	10	C&I electric water heaters (excl. heat pump water heater)	Varies by segments and covers the costs of enabling the system	Fail	Not cost-effective
HVAC						
Space Setpoint Control	Controlling the space setpoint through an existing BAS or Prog/Manual thermostat during peak events	1	All electric heated C&I buildings	None	Pass	Potential filled by more cost-effective measure
Heating Pump Flow Rate Adjustment	Modulation of the heating pump flow rate during peak events	1	Large office, hospital and education buildings (sectors where hydronic heating is more prevalent)	Varies by segment and covers the installation of VFDs on pumps	Fail	Not cost-effective
Interruption of Humidification	Shutting off the electric humidifier in the model, through a schedule, during peak events *Measure divided in two: one at no cost applicable to building with BAS or done manually and one for buildings without a BAS where controls are installed as part of the measure.*	1	C&I buildings with electric humidification	None if through BAS or manual. Varies by building size for the automated measures without BAS.	Pass	Potential filled by more cost-effective measure
Reduction of Fresh Air Flow	Closing the outdoor air dampers during peak events *Measure divided in two: one at no cost applicable to building with BAS or done manually and one for buildings without a BAS where controls are installed as part of the measure.*	1	All electric heated C&I buildings.	None if through BAS or manual. Varies by building size for the automated measures without BAS.	Pass	Potential filled by more cost-effective measure
Reduction of Ventilation Flow	Reducing the static pressure set point for variable air volume (VAV) systems during peak events which results in a fan speed reduction	1	Large office, hospital and education buildings (sectors where VAV are more prevalent)	None	Pass	Potential filled by more cost-effective measure

MEASURE BY END USE	DEMAND RESPONSE STRATEGY	EUL	MARKET SIZE	INITIAL MEASURE COST	PACT	ADOPTION LIMIT
Dual Fuel Measure	Fuel switching during peak events	10	All electric heated C&I buildings with central heating system	Varies by segment and covers the installation of a fuel-fired boiler/furnace	Pass	Utility-wide load curve constraints
Lighting						
Lighting Control (Manual or BAS)	Turning off some of the fixtures using the existing BAS system or manually	1	All fuel heated C&I buildings	None	Pass	Potential filled by more cost-effective measure
Lighting Control	Installation of an addressable dimmable system to reduce level by 30% during peak events	1	All fuel heated C&I buildings	Varies by building size for installing a modulating system	Fail	Not cost-effective
Other						
Electrical Vehicle (EV)	EVs are charged through charging stations (assumed level 2 AC). The measure is applied to existing EV owners who plug for a long period of time. Therefore, the scope is limited to offices.	13	Number of EVs in NL x % charged at the office	Incremental cost of a smart charger	Pass	Potential filled by more cost-effective measure
Backup Generation at Peak Hours	Existing back-up generator enabled for DR	30	IIC: NL CEUS data LAB: 8% of all C&I buildings, based on EIA's CBECs data.	Varies by segment and covers the costs of enabling system	Pass	No more potential
Battery Energy Storage	Installation of a Powerwall/Powerpack enabled for DR	10	All C&I buildings	Full cost of the battery	Fail	Not cost-effective
Industrial Interruptible Load	Load shifting to weekend, via expansion of existing programs or interruptible rates.	1	Large industrial customers not currently enrolled in interruptible rates 7-8% of all Small & Med. Industrials, based on Dunsky internal data from Atlantic Canada	None	Pass	Market constraints
Time-of-Use (TOU) Rates	Implementation of a TOU Rates Program combined with a pricing signal at the peak moment to increase the program efficiency	1	All commercial and institutional buildings	None	Fail[34]	n/a[35]

[34] First year PACT. Does not include negative impact from lost industrial curtailment potential.

[35] TOU rates is a curve shaping mechanism. Therefore, it is applied first to the entire applicable market and does not enter into competition with other measures.

EXISTING CONSERVATION VOLTAGE REDUCTION

NF Power has the possibility to apply 30 MW CVR as a DR measure to reduce load demand. To translate these demand savings to true savings Dunsky used CVR factor for winter load described in the table below. CVR factors for each sector were scaled respectively to the weight of that sector in the peak demand of the IIC system.

Table E - 37: CVR factor per load type[36]

Type	Summer CVR	Winter CVR
Residential, all electric	0.67	0.06
Residential, not all electric	0.67	0.12
Commercial	0.97	0.80
Small Industries	0.10	0.10
Overall	0.61	0.27

DYNAMIC RATES

Dynamic rates impacts were assessed using a peak to off-peak ratio.

Figure E - 9 presents this relationship that was established in a meta-analysis of TOU and dynamic rates by the Brattle Group.[37] This relationship is used to estimate peak savings and the energy shifted outside of the peak hours. Finally, based on Ontario's TOU roll-out few to no energy conservation was reported when implementing TOU rates. For this reason, the study assumes a small 2% savings on the energy displaced over peak hours. Due to the higher response of customers to CPP rates (as it is only a few times per year), savings were assumed to be 20% of the energy displaced during peak hours.

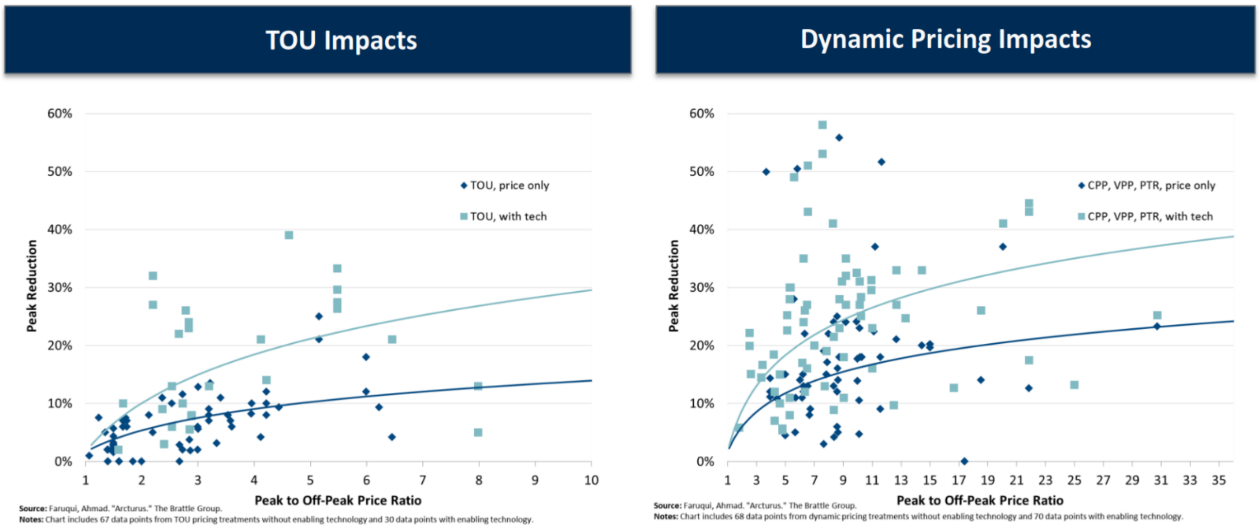
[36] CVR factors were assessed from "Measuring the efficiency of voltage reduction at Hydro-Québec distribution", S. Lefebvre ; G. Gaba ; A-O. Ba ; D. Asber ; A. Ricard ; C. Perreault ; D. Chartrand. IEEE, 2008.

[37] Peak reduction from dynamic rates was assessed from "Arcturus: International Evidence on Dynamic Pricing", A. Faruqui and S. Sergici. 2013.

AMI

An estimate for AMI rollout was also developed to assess cost effectiveness. Using customer data provided by NL Utilities, it was estimated that roughly 275,000 meters would be required to completely convert the actual customers. With an EUL of 15 years, and costs based on NB Power estimates[38] and pro-rated to NL, Dunsky estimates a full-scale AMI deployment would cost $85-$105M.

Figure E - 9: Dynamic Rate Peak Reduction



[38] Costs taken from "Decision – Matter No.375", New Brunswick Energy and Utilities Board, 2018

FUEL SWITCHING

While the fuel switching analysis uses many of the same inputs and assumptions as the CDM Potential analysis, there are multiple distinctive inputs and assumptions due to the unique nature of the analysis. The following section outlines these inputs and assumptions where they differ from the CDM Potential analysis.

INPUTS

Fuel oil and woody biomass costs

To determine the customer economics of switching from oil and wood-based heating systems to electric-based heating systems, the model requires inputs for retail rates for oil and wood heating fuels.

Customer heating oil costs are assumed to be equal to the maximum retail heating fuel cost as set by the NL Board of Commissioners of Public Utilities.[39] Historical maximum prices were analyzed and future oil costs were concluded to increase nominally over time in the absence of intervening policies such as carbon pricing.

Woody biomass costs are based on simple average cost estimates for wood pellets and green wood chips based on price data from Argus Media and J.D. Irving, respectively.[40] Future woody biomass costs are assumed to slightly increase based on annual growth factors taken from a report on energy supply costs in New England.[41]

Carbon pricing

To test fuel switching sensitivity to a carbon price, a carbon-adder is added to fuel oil prices for sensitivity analyses. Woody biomass fuels are excluded from carbon pricing. The sensitivity analyses test the impact of carbon pricing under the federal government's carbon pricing backstop, which starts at \$20 in 2019 and increases to \$50 in 2022, and under a significantly higher carbon price set at the Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates in 2020 at the 95th percentile, which is

[39] Newfoundland and Labrador Board of Commissioners of Public Utilities. "Petroleum Pricing Regulated Fuel Prices". Access at: http://www.pub.nf.ca/ppoprices.htm
[40] Argus Media. "Argus Biomass Markets". Accessed at: https://www.argusmedia.com/en/bioenergy/argus-biomass-markets
Irving Woodlands Division. "Wood Prices". Accessed at: https://irvingwoodlands.com/jdi-woodlands-wood-producers-wood-prices.aspx
[41] Synapse Energy Economics. "Avoided Energy Supply Components in New England: 2018 Report". Access at: https://www.synapse-energy.com/sites/default/files/AESC-2018-17-080.pdf

approximately $213.36 in current dollars.[42] **Table E - 38** shows these carbon prices in dollar per litre of fuel oil equivalents.

Table E - 38: Fuel oil carbon-adders

	Federal backstop		Social cost of carbon	
Year	$ per tonne	$ per litre fuel oil equivalent	$ per tonne	$ per litre fuel oil equivalent
2020	$30	$0.0821	$213	$0.58
2025	$50	$0.1369	$239	$0.65
2030	$50	$0.1369	$264	$0.72
2035	$50	$0.1369	$290	$0.79

ASSUMPTIONS

Measure characterization

The heat pump components of fuel switching measures were generally adapted from the most similar measures characterized as part of the CDM Potential analysis. The analysis assumes customers adopt heat pumps that conform to the U.S. Department of Energy's 2023 efficiency standards for air source heat pumps and ductless mini-split heat pumps, which NRCan is anticipated to align with in the future. The efficiency of base technologies (e.g. combustible fuel systems) are assumed to be at federal standards or average installed efficiency, where appropriate. Incremental costs are the additional cost of installing a heat pump technology instead of a combustible-fuel based technology for replace on burnout (ROB) measures. For additional (ADD) measures, the incremental cost is the total cost of the heat pump technology.

Table E - 39 and **Table E - 40** list the incremental cost and efficiency assumptions for each measure.

Table E - 39: Fuel switching: residential measure assumptions

Measure	Measure Type	Base Unit	Incremental Costs	Heat Pump Efficiency	Base technology efficiency
Oil Furnace to ASHP	ROB	per unit	$1,600	7.65 (HSPF)	0.83 (COP)
Oil Furnace to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	0.83 (COP)
Oil Boiler to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	0.84 (COP)
Wood Stove to ASHP	ROB	per unit	$5,400	7.65 (HSPF)	0.66 (COP)

[42] Technical Update to Environment and Climate Change Canada's Social Cost of Greenhouse Gas Estimates (March 2016). Accessed at: https://ec.gc.ca/cc/default.asp?lang=En&n=BE705779-1#SCC-Sec1

Wood Stove to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	0.53 (COP)
Electric Resistance to DMSHP	ADD	per unit	$5,250	7.65 (HSPF)	1 (COP)
Oil Hot Water to Heat Pump Hot Water Heater	ROB	per unit	$3,300	2 (EF)	0.6 (EF)

Table E - 40: Fuel switching: commercial measure assumptions

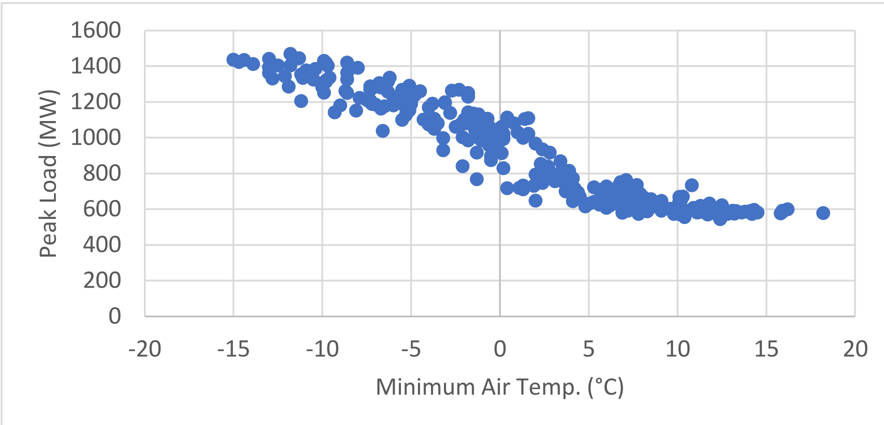
Measure	Measure Type	Base Unit	Incremental Costs	Heat Pump Efficiency	Base technology efficiency
Oil Furnace to ASHP	ROB	per ton	$2,200 to $2,600	7.46 (HSPF)	0.78 (COP)
Oil Furnace to DMSHP	ADD	per ton	$3,600	7.65 (HSPF)	0.78 (COP)
Oil Boiler to DMSHP	ADD	per ton	$3,600	7.65 (HSPF)	0.84 (COP)
Oil Hot Water to Heat Pump Hot Water Heater	ROB	per unit	$3,900 to $5,000	2.2 (EF)	0.6 (EF)

The demand impacts of heat pumps are determined by assuming these systems will be operational at peak hours albeit at a reduced efficiency and capacity. Since peak demand hours tend to occur when minimum outside temperatures are between -10°C and -15°C (see **Figure E - 10**), heat pumps are assumed to have a coefficient of performance (COP) of 1.75 during peak hours.[43] Additionally, heat pumps are assumed to operate at a de-rated capacity of approximately 63%.[44] However, not all households that install heat pumps are expected to run them during peak hours due to various factors such as control settings and other behavioral reasons. Since no NL specific study is available, professional judgement was applied in the analysis to assume 85% of heat pumps will be operating during peak hours for an effective capacity de-rate of 53.5%.

[43] Minnesota Commerce Department. “Cold Climate Air Source Heat Pump.” (2017). Accessed at: https://www.mncee.org/MNCEE/media/PDFs/86417-Cold-Climate-Air-Source-Heat-Pump-(CARD-Final-Report-2018).pdf

[44] Minnesota Commerce Department. “Cold Climate Air Source Heat Pump.” (2017). Accessed at: https://www.mncee.org/MNCEE/media/PDFs/86417-Cold-Climate-Air-Source-Heat-Pump-(CARD-Final-Report-2018).pdf

Figure E - 10: IIC Peak Load Versus Minimum Air Temperature



For the combustible fuel components of the fuel switching measures, units are assumed to conform to federal baseline efficiency standards. Energy impacts are determined using algorithms that take into consideration system efficiencies, sizes and annual heating load. Incremental costs are modified to account for differences in equipment costs as well as ancillary costs such as oil tank removal and backup heating system costs.

Since heat pumps can provide both heating and cooling energy, this additional benefit (relative to combustible fuel systems that only provide heating energy) is accounted for by adding a non-energy benefit to measures that provide cooling services. Additionally, this non-energy benefit ensures that the cost of cooling related energy does not reduce customer economics. For residential systems, the benefit is equivalent to approximately 2 times the annual cost of energy (kWh) consumed to provide cooling. Since there are few cooling hours in Newfoundland, this non-energy benefit is between $30 and $80 per year. For commercial systems, the benefit is equivalent to approximately 1.25 times the annual cost of energy consumed to provide cooling, plus 50% of the incremental cost of the heat pump system. Non-energy benefits for the commercial sector account for incremental system costs due to the higher likelihood the commercial customer would purchase an air conditioning system in the absence of the heat pump system.

Heat pump markets

The technical potential for central heat pumps in residential households is assumed to be one per household. For ductless mini-split heat pumps, customers are assumed to be able to adopt more than one per household. Based on the average size of installed DMSHP in each residential segment, this translates a maximum of roughly two 1.5-ton DMSHP per single detached household as shown in **Table E - 41**. Offsetting 100% of annual heating load is not assumed to account for distribution and behaviour effects.

Table E - 41: Maximum Number of DMSHP per Household

Segment	Max number of DMSHP per household
Single detached	2.0
Attached	1.5
Apartment	1.3

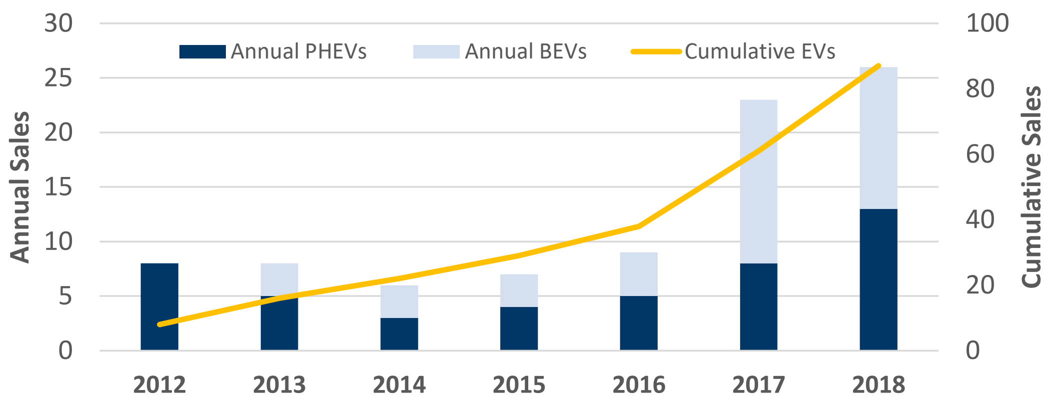
ELECTRIC VEHICLES

MODEL INPUTS

HISTORICAL EV ADOPTION

Historical EV adoption data was determined using a consolidation of data from the Utilities, ServiceNL, and IHS Markit. Approximately 90 EVs are estimated to have been registered in NL by the end of 2018, with a roughly equal split between BEVs and PHEVs.

Figure E - 11. Historic EV Adoption in Newfoundland and Labrador



VEHICLE SALES AND FLEET SIZE

Data on fleet size and annual vehicle sales for Newfoundland and Labrador-specific assumptions were gathered[45] to assess the current composition of vehicle market in the province. Additional assumptions were used to develop estimates of different vehicles classes and the split between personal and commercial sectors. **Table E - 42** show the final assumed market size for the modeled vehicle segments.

Table E - 42: Vehicle Sales and Fleet Size by Vehicle Class and Sector

Segment	Vehicle Class	Fleet Size	Annual Sales
Personal	**Cars**	148,310	11,000
	Trucks	88,480	9,400
	SUVs	39,750	4,200
Commercial	**Cars**	34,300	2,600
	Trucks	19,510	2,100
	SUVs	53,920	5,700
	MDV	17,350	2,000
	HDV	4,900	300

[45] Natural Resources Canada (NRCan). Comprehensive Energy Use Database – Transportation Sector

	Bus	1,370	100

VEHICLE ARCHETYPES

For each vehicle class and drivetrain combination, a representative vehicle archetype was defined. Light-duty vehicle archetypes are common between personal and commercial use and are presented in **Table E - 43**. Medium-duty vehicle, heavy-duty vehicle, and bus archetypes are presented in **Table E - 44**. For each vehicle, the input characteristics were used to develop a bottom-up vehicle cost that accounts for baseline vehicle cost, ICE and electric powertrain costs and battery costs. Additionally, data on O&M costs, average fuel efficiency, driving distance and assumed lifetime were used to calculate the vehicle's Total Cost of Ownership (TCO). Additionally, for BEVs and PHEVs, the cost of a home or depot charger was also added to the vehicle cost.

Table E - 43: Light-Duty Vehicle Model Inputs

	Car			SUV			Truck		
	BEV	**PHEV**	**ICE**	**BEV**	**PHEV**	**ICE**	**BEV**	**PHEV**	**ICE**
Battery size (kWh)	58	12	N/A	72	14	N/A	80	16	N/A
Electric powertrain output (kW)	150	135	N/A	200	180	N/A	200	180	N/A
ICE powertrain output (kW)	N/A	75	150	N/A	100	200	N/A	100	200
Vehicle efficiency electric (kWh/km)	0.18	0.18	N/A	0.23	0.23	N/A	0.25	0.25	N/A
Vehicle efficiency ICE (L/km)	N/A	0.10	0.10	N/A	0.11	0.11	N/A	0.13	0.13
Vehicle Utilization[46]	**Personal LDV:** 20,000 km per year, 5-year lifetime **Commercial LDV:** 30,000 km per year, 4-year lifetime								
% Vehicle electric drive	100%	50%	N/A	100%	50%	N/A	100%	50%	N/A
Annual Non-Fuel O&M Costs	$20	$70	$140	$20	$70	$140	$20	$70	$140
Home charger power (kW)	7	7	N/A	7	7	N/A	7	7	N/A

[46] The vehicle utilization represents the distance driven and duration of time that is assumed to be taken into consideration when calculating the vehicle's total cost of ownership (TCO), rather than the actual expected life of the vehicle.

	Car			SUV			Truck		
	BEV	PHEV	ICE	BEV	PHEV	ICE	BEV	PHEV	ICE
Annual Energy Consumption (kWh)[47]	3,500 – 5,250	1,750 – 2,625	N/A	4,400 - 6,600	2,220 – 3,300	N/A	2,450 – 3,700	4,900 – 7,400	N/A
Vehicle Purchase Cost (2019) – Baseline Scenario	$38,300	$31,300	$28,300	$53,300	$44,900	$41,100	$50,100	$40,200	$36,100
Home/Depot Charger Cost and Installation	$1000	$1000	N/A	$1000	$1000	N/A	$1000	$1000	N/A

[47] Lower and upper range represent the annual consumption of a personal LDV and a commercial LDV respectively.

Table E - 44: Medium-Duty Vehicle, Heavy-Duty Vehicle, and Bus Vehicle Model Inputs

	Medium-Duty Vehicle		Heavy-Duty Vehicle		Bus	
	BEV	ICE	BEV	ICE	BEV	ICE
Battery size (kWh)	100	N/A	750	N/A	270	N/A
Powertrain output (kW)	175	175	540	540	300	300
Vehicle efficiency electric (kWh/km)	0.9	N/A	1.3	N/A	0.9	N/A
Vehicle efficiency ICE (L/km)	N/A	0.3	N/A	0.4	N/A	0.6
Vehicle Utilization[46]	25,000 km per year 12-year lifetime		130,000 km per year 12-year lifetime		65,000 km per year 12-year lifetime	
Annual O&M costs	$940	$1,880	$4,880	$9,760	$35,100	$49,500
Depot charger power (kW)[48]	20 kW	N/A	150 (*2020*) – 2000 (*2029*)	N/A	50 kW	N/A
Annual Energy Consumption (kWh)	22,500	N/A	162,500	N/A	81,000	N/A
Vehicle Purchase Cost (2019) – Baseline Scenario	$140,200	$88,700	$568,600	$167,600	$368,400	$232,000
Depot Charger Cost and Installation	$15,000	N/A	$75,000	N/A	$35,000	N/A

NON-VEHICLE ASSUMPTIONS

Additional, non-vehicle assumptions are used in the model to assess barriers associated with both home and public charging. These assumptions are presented in **Table E - 45**.

[48] Assume overnight charging for MDV and bus, and a combination of overnight and on-route fast charging for HDV. It is also assumed that the average power of on-route HDV charging increases overtime, so high and low average power (with year expected) is provided.

Table E - 45: Non-Vehicle Assumptions

General Model Inputs		Province-Wide	Population Clusters[49]
Newfoundland Population		525,000	301,000
Newfoundland Area (km^2)		405,000	357
Newfoundland highway length (km)		2,500	N/A
Housing Composition	**Single Family Homes**	75%	N/A
	Multi-Family Homes	25%	N/A
Home Charging Access	**Single Family Homes**	85%	N/A
	Multi-Family Homes	0%[50]	N/A

SENSITIVITY FACTOR INPUTS

Given uncertainty with respect to the evolution of both local and global factors that are expected to influence EV adoption, a range of values were defined for each factor and sensitivity tests were completed. Local factors that were assessed include electricity rates, fuel prices, and vehicle sales (volumes and vehicle class composition). The results of the sensitivity analyses are provided in the body of the report. The range of values defined for each factor are presented here. The electricity rates used in the sensitivity analysis are the utilities' low, mid and high scenarios; highlighted in the Customer Rates Tables section in Appendix E.

Table E - 46: Gasoline and Diesel Price Assumptions ($/Litre)[51] [52]

	2020	2025	2034
Gasoline			
Low	1.36	1.36	1.50
Mid	1.66	1.62	1.81
High	1.89	1.91	2.12
Diesel			
Low	1.11	1.10	1.23
Mid	1.39	1.35	1.52
High	1.61	1.63	1.82

[49] Population clusters are defined as areas with populations over 1,000 people. There are 28 population clusters in Newfoundland and Labrador based on data from Statistics Canada (2017). *Population and Dwelling Count Highlight Tables, 2016 Census.*

[50] See assumptions for MURB retrofit program scenarios.

[51] National Energy Board (NEB), 2018. Canada's Energy Future 2018 – Macro Indicators.

[52] Low, medium and high cases from indicated source were converted from 2018 dollars to nominal dollars.

Table E - 47: Annual Vehicle Sales Assumptions (Number of Vehicles)

	2020	2025	2034
Car			
Low	9,700	6,760	3,300
Mid	10,000	7,760	4,540
High	10,490	8,890	6,200
SUV			
Low	10,300	12,330	14,380
Mid	10,710	14,170	19,750
High	11,140	16,230	26,950
Truck			
Low	4,600	5,510	6,420
Mid	4,790	6,330	8,820
High	4,980	7,250	12,040

Table E - 48: Battery Cost Assumptions ($/kWh)

	2020	2025	2034
Light-duty vehicles			
Low	202	127	55
Mid	219	169	105
High	230	199	154
Medium-duty vehicles, heavy-duty vehicles, buses[53]			
Low	337	127	55
Mid	366	169	105
High	384	199	154

SCENARIO INPUTS

Scenarios were defined and analyzed to assess the impact of four types of program levers that could be employed by Utilities, governments, and other market actors to influence adoption. The levers included in the assessment were public DCFC charging infrastructure deployment, public L2 charging infrastructure deployment, vehicle purchase incentives, and increasing access to charging in multi-unit residential buildings (MURBs). High and low investment scenarios were assessed for each lever, corresponding to

[53] Based on feedback from manufacturers, a multiplier was added to the battery costs for medium-duty vehicles, heavy-duty vehicles, and buses for years 2020-2024 to account for low production volumes resulting in limited economies of scale and higher battery prices.

investments of $5 million and $20 million, respectively. These scenarios are summarized in **Table E - 49** below.

Table E - 49: Summary of Levers and Investment Scenarios Assessed

Lever	Description	Low Scenario (≈ $5M investment)	High Scenario (≈ $20M investment)
DCFC deployment	**Deployment of Public Direct Current Fast Chargers (DCFC) on highway corridors and in population centres**	**25 Stations (50 ports)**	**100 Stations (200 Ports)**
L2 deployment	Deployment of Public Level 2 (L2) Charging in population centres	125 Stations (500 ports)	500 Stations (2000 ports)
Vehicle Incentives[54]	Rebates to customers to offset a portion of the upfront cost of an EV purchase	$5K incentive for LDVs, 10% incentive for MDV, HDV, Bus	$7.5K incentive for LDVs, 25% incentive for MDV, HDV, Bus

SCENARIO ASSUMPTIONS

For each lever, a baseline scenario was established which assumed no further program action alongside the high and low scenarios. Below, the baseline, high, and low scenario assumptions are presented for each level.

Table E - 50: DCFC Charging Infrastructure Deployment Scenario Assumptions

		2020	2025	2034
Baseline	**Number of Stations**	14	14	14
	Average ports per station	1	1	1
	Average Power (kW)	50	50	50
Low Scenario	**Number of Stations**	16	21	64
	Average ports per station	1	1	2
	Average Power (kW)	53	75	138
High Scenario	**Number of Stations**	22	42	114
	Average ports per station	1	2	2
	Average Power (kW)	60	90	145

[54] Incentives were assumed to step down gradually over time. Detailed assumptions can be found in Appendix C.

Table E - 51: L2 Charging Infrastructure Deployment Scenario Assumptions

		2020	2025	2034
Baseline	Number of Stations	44	44	44
	Average ports per station	1.3	1.3	1.3
	Average Power (kW)	7	7	7
Low Scenario	Number of Stations	54	94	169
	Average ports per station	1.4	2.7	3.3
	Average Power (kW)	7	7	7
High Scenario	Number of Stations	64	244	544
	Average ports per station	1.5	3.2	3.8
	Average Power (kW)	7	7	7

Table E - 52: Purchase Incentive Scenario Assumptions

			2020	2021	2022	2023	2024	2025	2026 - 2034
Baseline	All Segments		$0	$0	$0	$0	$0	$0	$0
Low Scenario	LDV	PHEVs	$2,500	$2,000	$1,600	$1,300	$1,000	$800	$0
		BEVs	$5,000	$4,000	$3,200	$2,600	$2,000	$1,600	$0
	MDV/HDV/Bus[55]	BEVs	10%	10%	10%	8%	6%	5%	0%
High Scenario	LDV	PHEVs	$3,750	$3,750	$3,750	$3,000	$3,000	$2400	$0
		BEVs	$7,500	$7,500	$7,500	$6,000	$6,000	$4,800	$0
	MDV/HDV/Bus	BEVs	20%	20%	15%	12%	10%	8%	0%

[55] Incentive amount stated as percentage of vehicle cost

APPENDIX F: DETAILED RESULTS TABLES

BASELINE CONSUMPTION

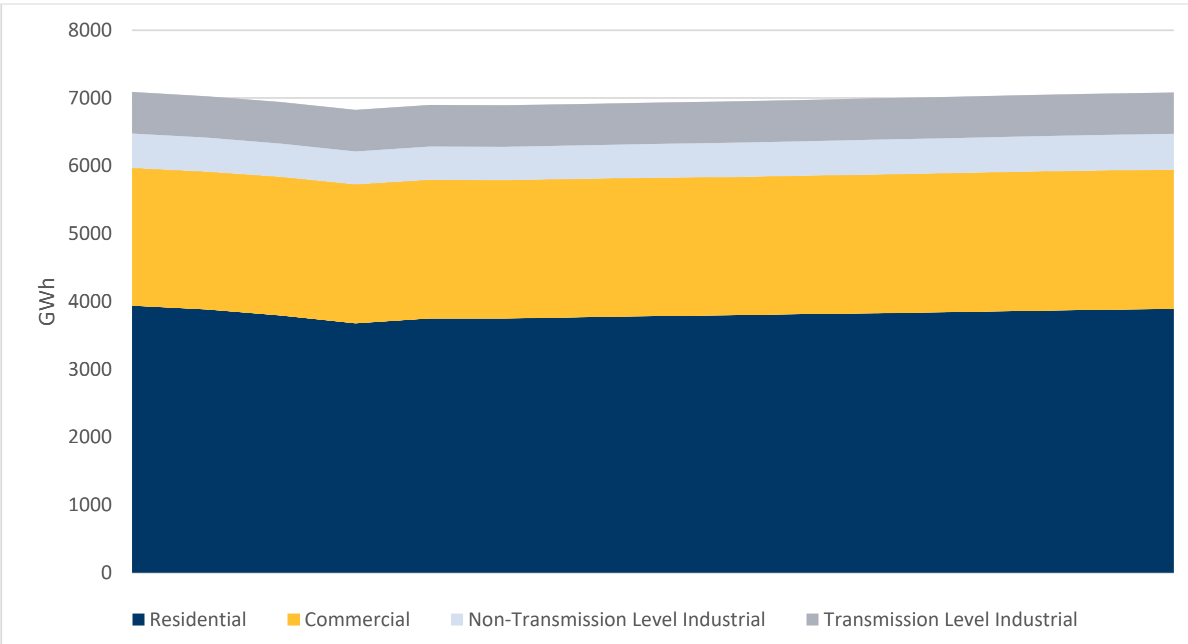
The consumption and demand baseline projection is used to benchmark the effectiveness of an energy efficiency and demand response program portfolio over time. In addition, it is used to generate metrics and perform model calibration.

The consumption and demand baseline were calculated using electric sales forecasts provided by each of the utilities. The consumption forecasts included the effects of naturally occurring savings (e.g. codes and standard changes) as well as projected program savings. Using details provided by the utilities for the project period, the consumption forecast was adjusted to remove the impact of future program savings and naturally occurring savings. Below are more specifics on the process:

- Where applicable, Dunsky removed sectors from the raw forecasts that were not included in the potential model, such as street lighting and electric vehicle charging.
- The following naturally occurring adjustments were explicit in the forecast: lighting and heat pump codes and standards changes. Dunsky removed these standards adjustments from NL Utilities' electricity forecast. If the standards impacted measures in the model, they were considered at the measure level.
- For lighting and heat pump measures, if there was customer adoption due to programs before the codes and standards took effect, the savings for the measures were attributed to the utility through the measure lifetime. For these measures, when replacement occurred, the savings from the replacement was attributed to codes and standards and removed from the baseline.
- The system-wide forecasts for Island Interconnected System were calculated by aggregating the NL Hydro forecasts and the NF Power forecasts for this system. The other systems were calculated using only NL Hydro data.
- Customers under general service rate class 2.4 were considered industrial customers in the baseline. Transmission-level customers were treated separately outside of the model.
- The utilities provided forecasts with implicit utility-based program energy efficiency reductions. Dunsky removed the efficiency program savings from the baseline consumption, using the NL 5-year 2016-2020 Conservation Plan, Table E-1 data.

Additionally, Dunsky calculated an estimate of heating oil consumption in the province using National Energy Board[56] and National Resource Canada[57] data. To calculate the heating oil consumption by system, Dunsky took the total consumption in the province and weighed it by the total electricity consumption in each system.

Figure F- 1: Island Interconnected Electricity Consumption Forecast by Sector



[56]https://apps2.neb-one.gc.ca/dvs/?page=viz2&sector=commercial&unit=petajoules&scenario=reference&sources=solarWindGeothermal,coal,naturalGas,bio,oilProducts,electricity&sourcesInOrder=solarWindGeothermal,coal,naturalGas,bio,oilProducts,electricity&province=NL&dataset=oct2018&language=en

[57]http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=com&juris=atl&rn=1&page=0

Figure F- 2: Labrador Interconnected Electricity Consumption Forecast by Sector

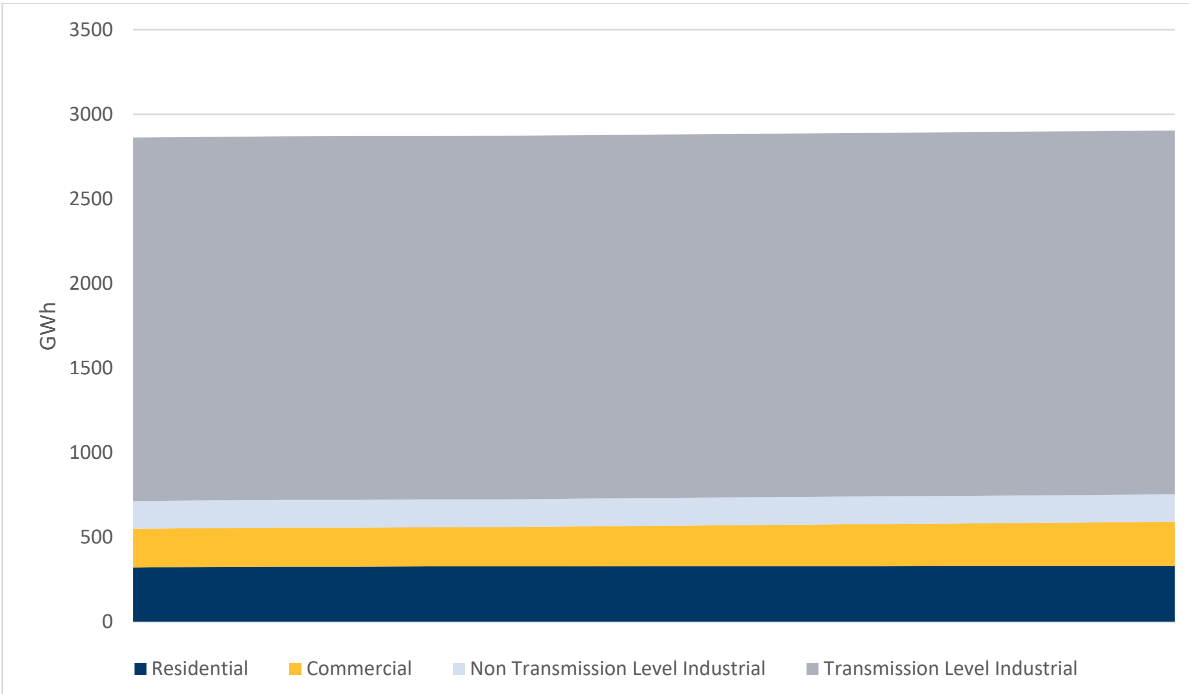
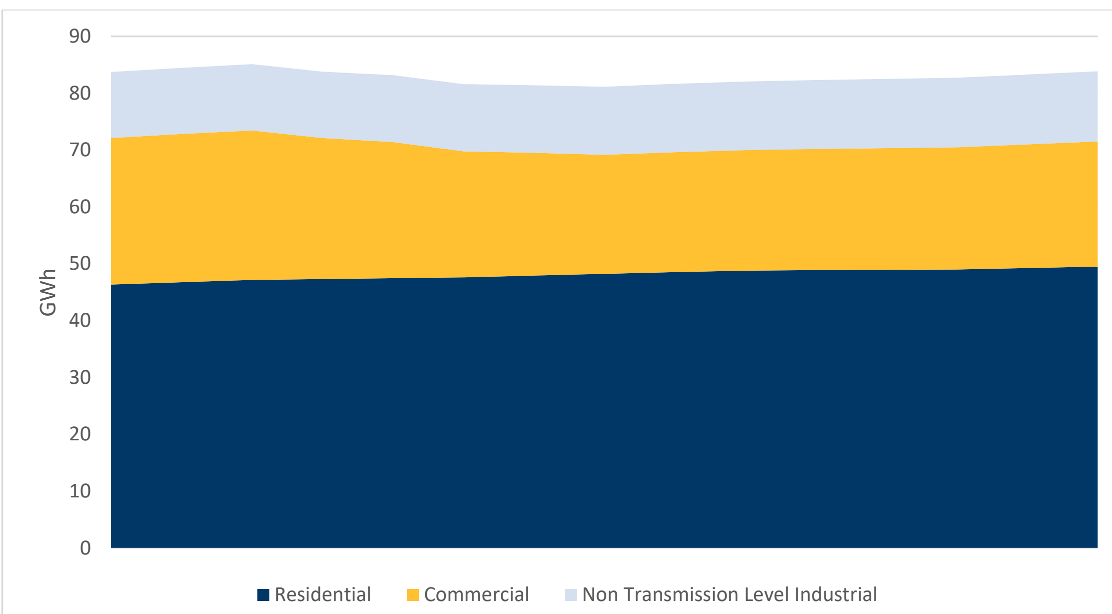


Figure F- 3: Isolated Communities Electricity Consumption Forecast by Sector



DETAILED CUMULATIVE SAVINGS TABLES

This section presents detailed results by sector and end use for each system under the lower, mid, and upper scenarios using the mid- rate case.

LOWER PROGRAM SCENARIO – MID-RATES CASE

Table F- 1: Cumulative Savings by End-Use: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**19.98**	**29.79**	**40.76**	**50.51**	**60.39**	**66.90**	**73.40**	**79.90**	**86.41**	**92.91**	**96.18**	**99.46**	**102.73**	**106.01**	**109.29**
Appliance	0.17	0.49	1.00	1.76	2.80	3.83	4.87	5.91	6.95	7.98	8.87	9.75	10.63	11.51	12.40
Behavioral	11.22	11.22	11.21	11.21	11.21	11.21	11.21	11.20	11.20	11.20	11.20	11.20	11.19	11.19	11.19
Envelope	3.49	7.46	11.98	17.09	22.72	26.34	29.96	33.58	37.20	40.82	44.46	48.10	51.74	55.37	59.01
Hot Water	1.47	2.93	4.30	5.45	6.26	6.81	7.36	7.91	8.46	9.02	8.32	7.62	6.93	6.23	5.54
HVAC	2.71	5.46	8.18	10.76	13.03	14.36	15.69	17.02	18.35	19.69	19.84	20.00	20.15	20.31	20.46
Lighting	0.91	2.23	4.07	4.22	4.35	4.31	4.27	4.23	4.20	4.16	3.45	2.75	2.04	1.33	0.63
Other	0.00	0.01	0.02	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.05	0.06	0.06
Commercial	**11.78**	**24.68**	**38.69**	**44.40**	**51.58**	**52.69**	**53.81**	**54.92**	**56.03**	**57.14**	**57.54**	**57.93**	**58.33**	**58.72**	**59.11**
Envelope	0.04	0.14	0.33	0.60	0.97	1.18	1.39	1.60	1.82	2.03	2.24	2.46	2.67	2.88	3.10
Hot Water	0.32	0.65	1.02	1.40	1.80	2.02	2.25	2.47	2.69	2.92	2.95	2.98	3.01	3.04	3.07
HVAC	0.39	1.04	1.98	3.15	4.51	5.63	6.75	7.87	8.99	10.11	10.83	11.56	12.29	13.02	13.74
Kitchen	0.03	0.09	0.21	0.40	0.66	0.93	1.19	1.46	1.72	1.99	2.17	2.36	2.54	2.73	2.91
Lighting	10.86	22.27	34.08	36.93	40.61	39.24	37.87	36.50	35.14	33.77	32.44	31.12	29.79	28.47	27.14
Motor/Compressor	0.10	0.33	0.75	1.37	2.20	2.67	3.14	3.62	4.09	4.57	5.04	5.52	5.99	6.47	6.94
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.03	0.10	0.22	0.37	0.56	0.67	0.78	0.89	1.00	1.11	1.17	1.23	1.29	1.36	1.42
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.01	0.05	0.10	0.18	0.28	0.36	0.43	0.51	0.58	0.65	0.68	0.70	0.73	0.76	0.78
Industrial	**0.40**	**1.05**	**1.99**	**3.24**	**4.80**	**5.70**	**6.60**	**7.50**	**8.40**	**9.30**	**9.98**	**10.67**	**11.35**	**12.03**	**12.71**
Envelope	0.01	0.02	0.05	0.09	0.14	0.17	0.20	0.23	0.26	0.29	0.32	0.35	0.38	0.41	0.44
Hot Water	0.06	0.12	0.18	0.24	0.30	0.31	0.33	0.34	0.35	0.37	0.37	0.37	0.37	0.37	0.37
HVAC	0.04	0.11	0.22	0.37	0.55	0.68	0.81	0.94	1.07	1.20	1.28	1.37	1.46	1.55	1.64
Kitchen	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03
Lighting	0.18	0.36	0.56	0.75	0.95	1.06	1.16	1.27	1.37	1.48	1.43	1.39	1.34	1.29	1.25
Motor/Compressor	0.12	0.41	0.92	1.70	2.71	3.30	3.89	4.47	5.06	5.65	6.23	6.82	7.41	8.00	8.59
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.01	0.02	0.04	0.07	0.11	0.13	0.16	0.18	0.21	0.23	0.25	0.27	0.29	0.31	0.32
Process	0.00	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04
Refrigeration	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03

Table F- 2: Cumulative Savings by End-Use: LAB System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**0.56**	**0.63**	**0.71**	**0.81**	**0.92**	**0.98**	**1.05**	**1.11**	**1.18**	**1.24**	**1.30**	**1.36**	**1.41**	**1.47**	**1.53**
Appliance	0.00	0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.05	0.05	0.06	0.06	0.07	0.08
Behavioral	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51	0.51
Envelope	0.01	0.03	0.07	0.11	0.16	0.19	0.22	0.25	0.28	0.31	0.34	0.37	0.40	0.43	0.47
Hot Water	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.02	0.02	0.02	0.02
HVAC	0.04	0.08	0.12	0.16	0.21	0.24	0.26	0.29	0.32	0.34	0.37	0.39	0.41	0.44	0.46
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.25**	**0.59**	**1.03**	**1.21**	**1.43**	**1.45**	**1.47**	**1.49**	**1.51**	**1.53**	**1.58**	**1.64**	**1.69**	**1.74**	**1.79**
Envelope	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.07	0.07
Hot Water	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.02
HVAC	0.03	0.06	0.11	0.17	0.24	0.30	0.35	0.40	0.45	0.50	0.55	0.61	0.66	0.71	0.55
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.01
Lighting	0.21	0.47	0.80	0.82	0.85	0.75	0.65	0.55	0.45	0.35	0.25	0.15	0.05	-0.05	0.23
Motor/Compressor	0.01	0.04	0.10	0.18	0.29	0.35	0.41	0.47	0.53	0.59	0.65	0.72	0.78	0.84	0.90
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial	**0.01**	**0.02**	**0.05**	**0.09**	**0.13**	**0.15**	**0.17**	**0.20**	**0.22**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**	**0.25**
Envelope	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hot Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.01	0.02	0.05	0.09	0.12	0.15	0.17	0.19	0.22	0.24	0.26	0.29	0.31	0.34	0.24
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor/Compressor	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table F- 3: Cumulative Savings by End-Use: ISO System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**0.417**	**0.859**	**1.317**	**1.623**	**1.938**	**2.077**	**2.216**	**2.355**	**2.494**	**2.632**	**2.567**	**2.501**	**2.435**	**2.369**	**2.303**
Appliance	0.025	0.078	0.161	0.264	0.401	0.457	0.512	0.568	0.624	0.679	0.706	0.733	0.760	0.787	0.814
Behavioral	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Envelope	0.042	0.087	0.136	0.190	0.247	0.288	0.329	0.369	0.410	0.451	0.492	0.533	0.573	0.614	0.655
Hot Water	0.067	0.132	0.193	0.244	0.281	0.306	0.331	0.357	0.382	0.408	0.377	0.347	0.316	0.286	0.255
HVAC	0.033	0.067	0.099	0.131	0.161	0.179	0.198	0.216	0.235	0.253	0.253	0.252	0.251	0.251	0.250
Lighting	0.198	0.395	0.588	0.626	0.655	0.657	0.659	0.661	0.663	0.665	0.565	0.464	0.364	0.264	0.163
Other	0.052	0.100	0.140	0.168	0.194	0.190	0.186	0.183	0.179	0.175	0.173	0.172	0.170	0.168	0.166
Commercial	**0.560**	**1.143**	**1.745**	**1.867**	**2.183**	**2.159**	**2.135**	**2.110**	**2.086**	**2.062**	**2.055**	**2.048**	**2.041**	**2.034**	**2.027**
Envelope	0.001	0.002	0.004	0.008	0.012	0.015	0.017	0.020	0.022	0.025	0.028	0.030	0.033	0.035	0.038
Hot Water	0.001	0.002	0.004	0.006	0.008	0.010	0.012	0.015	0.017	0.019	0.019	0.020	0.020	0.021	0.021
HVAC	0.001	0.002	0.004	0.006	0.009	0.010	0.012	0.014	0.016	0.017	0.018	0.018	0.019	0.019	0.020
Kitchen	0.000	0.001	0.002	0.003	0.006	0.008	0.010	0.012	0.014	0.017	0.018	0.020	0.022	0.024	0.026
Lighting	0.553	1.123	1.703	1.791	2.062	1.997	1.932	1.867	1.803	1.738	1.699	1.661	1.622	1.583	1.544
Motor/Compressor	0.002	0.007	0.016	0.030	0.049	0.067	0.086	0.105	0.123	0.142	0.160	0.179	0.197	0.216	0.234
Office Equipment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other	0.001	0.004	0.008	0.014	0.023	0.030	0.038	0.045	0.053	0.061	0.067	0.074	0.080	0.087	0.094
Process	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Refrigeration	0.001	0.002	0.005	0.009	0.015	0.021	0.026	0.032	0.038	0.043	0.045	0.046	0.047	0.048	0.050

MID PROGRAM SCENARIO – MID-RATES CASE

Table F- 4: Cumulative Savings by End-Use: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**30.13**	**48.65**	**69.56**	**87.87**	**107.25**	**118.27**	**129.28**	**140.29**	**151.31**	**162.32**	**165.16**	**167.99**	**170.83**	**173.66**	**176.50**
Appliance	0.74	2.27	4.65	7.58	11.44	13.17	14.90	16.63	18.37	20.10	20.82	21.54	22.27	22.99	23.71
Behavioral	14.03	14.02	14.02	14.01	14.01	14.01	14.01	14.01	14.00	14.00	14.00	13.99	13.99	13.99	13.98
Envelope	4.17	8.96	14.47	20.78	27.82	32.56	37.30	42.04	46.77	51.51	56.27	61.04	65.80	70.56	75.32
Hot Water	3.29	6.53	9.57	12.14	14.00	15.26	16.52	17.78	19.04	20.30	18.77	17.24	15.71	14.18	12.65
HVAC	4.72	9.64	14.72	20.71	26.90	30.28	33.66	37.03	40.41	43.79	44.77	45.76	46.75	47.74	48.73
Lighting	3.17	7.19	12.06	12.53	12.94	12.84	12.75	12.66	12.56	12.47	10.35	8.24	6.13	4.01	1.90
Other	0.01	0.04	0.07	0.10	0.14	0.15	0.15	0.15	0.16	0.16	0.17	0.18	0.19	0.19	0.20
Commercial	**14.80**	**31.14**	**49.14**	**58.27**	**70.16**	**73.35**	**76.54**	**79.73**	**82.91**	**86.10**	**87.19**	**88.28**	**89.37**	**90.46**	**91.55**
Envelope	0.12	0.44	0.99	1.84	3.00	3.90	4.79	5.69	6.59	7.48	8.38	9.28	10.18	11.08	11.98
Hot Water	0.37	0.78	1.25	1.76	2.30	2.65	3.00	3.35	3.69	4.04	4.11	4.19	4.26	4.33	4.41
HVAC	0.58	1.58	3.06	4.92	7.11	8.93	10.76	12.59	14.41	16.24	17.52	18.80	20.07	21.35	22.63
Kitchen	0.04	0.13	0.29	0.54	0.91	1.27	1.64	2.00	2.36	2.73	2.98	3.23	3.49	3.74	3.99
Lighting	13.48	27.51	41.97	46.44	52.49	51.29	50.09	48.89	47.69	46.48	44.32	42.15	39.98	37.81	35.65
Motor/Compressor	0.11	0.39	0.89	1.63	2.60	3.19	3.77	4.35	4.93	5.51	6.10	6.68	7.27	7.85	8.43
Office Equipment	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other	0.07	0.24	0.50	0.82	1.23	1.46	1.70	1.93	2.16	2.39	2.51	2.63	2.74	2.86	2.97
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.02	0.08	0.18	0.32	0.51	0.65	0.79	0.93	1.07	1.21	1.26	1.32	1.37	1.42	1.48
Industrial	**0.60**	**1.56**	**2.97**	**4.85**	**7.21**	**8.57**	**9.93**	**11.29**	**12.65**	**14.01**	**15.02**	**16.04**	**17.05**	**18.07**	**19.08**
Envelope	0.12	0.44	0.99	1.84	3.00	3.90	4.79	5.69	6.59	7.48	8.38	9.28	10.18	11.08	11.98
Hot Water	0.37	0.78	1.25	1.76	2.30	2.65	3.00	3.35	3.69	4.04	4.11	4.19	4.26	4.33	4.41
HVAC	0.58	1.58	3.06	4.92	7.11	8.93	10.76	12.59	14.41	16.24	17.52	18.80	20.07	21.35	22.63
Kitchen	0.04	0.13	0.29	0.54	0.91	1.27	1.64	2.00	2.36	2.73	2.98	3.23	3.49	3.74	3.99
Lighting	13.48	27.51	41.97	46.44	52.49	51.29	50.09	48.89	47.69	46.48	44.32	42.15	39.98	37.81	35.65
Motor/Compressor	0.11	0.39	0.89	1.63	2.60	3.19	3.77	4.35	4.93	5.51	6.10	6.68	7.27	7.85	8.43
Office Equipment	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Other	0.07	0.24	0.50	0.82	1.23	1.46	1.70	1.93	2.16	2.39	2.51	2.63	2.74	2.86	2.97
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.02	0.08	0.18	0.32	0.51	0.65	0.79	0.93	1.07	1.21	1.26	1.32	1.37	1.42	1.48

Table F- 5: Cumulative Achievable Potential by End-Use: LAB System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**0.74**	**0.86**	**1.01**	**1.19**	**1.39**	**1.50**	**1.61**	**1.73**	**1.84**	**1.95**	**2.03**	**2.11**	**2.19**	**2.27**	**2.34**
Appliance	0.00	0.00	0.01	0.02	0.03	0.04	0.05	0.05	0.06	0.07	0.08	0.08	0.09	0.10	0.10
Behavioral	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Envelope	0.02	0.04	0.08	0.13	0.20	0.24	0.27	0.31	0.35	0.39	0.42	0.46	0.50	0.54	0.58
Hot Water	0.02	0.04	0.06	0.08	0.09	0.10	0.10	0.11	0.12	0.13	0.12	0.11	0.10	0.09	0.08
HVAC	0.06	0.13	0.21	0.31	0.43	0.49	0.55	0.61	0.67	0.73	0.77	0.82	0.86	0.91	0.95
Lighting	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.52**	**1.17**	**1.99**	**2.31**	**2.73**	**2.77**	**2.81**	**2.86**	**2.90**	**2.94**	**3.08**	**3.22**	**3.36**	**3.49**	**3.63**
Envelope	0.00	0.01	0.03	0.05	0.09	0.11	0.13	0.16	0.18	0.20	0.23	0.25	0.27	0.29	0.32
Hot Water	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.05	0.05	0.05	0.06	0.05
HVAC	0.03	0.08	0.16	0.25	0.35	0.42	0.50	0.58	0.65	0.73	0.80	0.88	0.95	1.03	0.82
Kitchen	0.00	0.00	0.00	0.01	0.01	0.01	0.02	0.02	0.02	0.03	0.03	0.03	0.04	0.04	0.04
Lighting	0.45	0.97	1.58	1.60	1.66	1.47	1.28	1.10	0.91	0.72	0.54	0.35	0.16	-0.03	0.58
Motor/Compressor	0.03	0.09	0.20	0.37	0.59	0.71	0.84	0.96	1.08	1.21	1.33	1.45	1.58	1.70	1.82
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Industrial	**0.01**	**0.04**	**0.08**	**0.13**	**0.18**	**0.21**	**0.25**	**0.28**	**0.32**	**0.35**	**0.35**	**0.35**	**0.35**	**0.36**	**0.36**
Envelope	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Hot Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.01	0.03	0.07	0.12	0.17	0.20	0.23	0.27	0.30	0.33	0.36	0.40	0.43	0.46	0.33
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor/Compressor	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table F- 6: Cumulative Savings by End-Use (ISO)(GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	0.417	0.859	1.317	1.623	1.938	2.077	2.216	2.355	2.494	2.632	2.567	2.501	2.435	2.369	2.303
Appliance	0.025	0.078	0.161	0.264	0.401	0.457	0.512	0.568	0.624	0.679	0.706	0.733	0.760	0.787	0.814
Behavioral	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Envelope	0.042	0.087	0.136	0.190	0.247	0.288	0.329	0.369	0.410	0.451	0.492	0.533	0.573	0.614	0.655
Hot Water	0.067	0.132	0.193	0.244	0.281	0.306	0.331	0.357	0.382	0.408	0.377	0.347	0.316	0.286	0.255
HVAC	0.033	0.067	0.099	0.131	0.161	0.179	0.198	0.216	0.235	0.253	0.253	0.252	0.251	0.251	0.250
Lighting	0.198	0.395	0.588	0.626	0.655	0.657	0.659	0.661	0.663	0.665	0.565	0.464	0.364	0.264	0.163
Other	0.052	0.100	0.140	0.168	0.194	0.190	0.186	0.183	0.179	0.175	0.173	0.172	0.170	0.168	0.166
Commercial	0.603	1.234	1.893	2.053	2.432	2.424	2.416	2.409	2.401	2.393	2.383	2.373	2.364	2.354	2.344
Envelope	0.001	0.002	0.005	0.010	0.016	0.019	0.023	0.026	0.030	0.033	0.037	0.040	0.043	0.047	0.050
Hot Water	0.001	0.002	0.004	0.007	0.010	0.013	0.016	0.018	0.021	0.024	0.025	0.025	0.026	0.027	0.028
HVAC	0.001	0.002	0.004	0.007	0.010	0.012	0.014	0.016	0.018	0.020	0.021	0.022	0.022	0.023	0.024
Kitchen	0.000	0.001	0.002	0.004	0.007	0.010	0.013	0.016	0.019	0.021	0.024	0.026	0.029	0.031	0.033
Lighting	0.596	1.210	1.840	1.959	2.282	2.224	2.167	2.109	2.051	1.993	1.944	1.895	1.846	1.797	1.748
Motor/Compressor	0.003	0.009	0.020	0.037	0.061	0.084	0.108	0.131	0.154	0.177	0.201	0.224	0.247	0.270	0.293
Office Equipment	0.000	0.000	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Other	0.001	0.004	0.009	0.017	0.026	0.035	0.044	0.052	0.061	0.069	0.076	0.083	0.091	0.098	0.105
Process	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Refrigeration	0.001	0.003	0.006	0.011	0.019	0.026	0.033	0.040	0.047	0.053	0.055	0.057	0.058	0.060	0.061

UPPER PROGRAM SCENARIO – MID-RATES CASE

Table F- 7: Cumulative Savings by End-Use: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**44.42**	**73.63**	**106.11**	**134.45**	**164.50**	**180.81**	**197.12**	**213.43**	**229.74**	**246.05**	**249.57**	**253.08**	**256.60**	**260.11**	**263.62**
Appliance	1.33	4.19	8.54	13.71	20.45	22.57	24.69	26.81	28.94	31.06	31.26	31.46	31.67	31.87	32.07
Behavioral	18.70	18.70	18.69	18.69	18.68	18.68	18.68	18.67	18.67	18.67	18.66	18.66	18.65	18.65	18.65
Envelope	7.34	15.60	24.98	35.57	47.28	55.28	63.27	71.26	79.25	87.24	95.25	103.26	111.27	119.28	127.30
Hot Water	4.83	9.59	14.05	17.86	20.65	22.57	24.48	26.40	28.31	30.23	28.03	25.84	23.64	21.44	19.24
HVAC	6.34	12.89	19.60	27.42	35.43	39.82	44.22	48.61	53.00	57.39	58.42	59.44	60.46	61.49	62.51
Lighting	5.85	12.60	20.11	21.00	21.73	21.61	21.50	21.39	21.27	21.16	17.62	14.09	10.55	7.02	3.48
Other	0.03	0.08	0.14	0.20	0.27	0.28	0.29	0.29	0.30	0.31	0.32	0.33	0.34	0.36	0.37
Commercial	**18.21**	**38.59**	**61.42**	**74.60**	**92.01**	**97.27**	**102.53**	**107.79**	**113.05**	**118.31**	**120.42**	**122.54**	**124.66**	**126.78**	**128.89**
Envelope	0.20	0.68	1.55	2.87	4.68	6.05	7.42	8.79	10.17	11.54	12.92	14.29	15.67	17.04	18.42
Hot Water	0.45	0.97	1.60	2.32	3.14	3.72	4.30	4.88	5.46	6.04	6.21	6.38	6.54	6.71	6.88
HVAC	0.83	2.28	4.48	7.26	10.56	13.34	16.12	18.90	21.68	24.46	26.50	28.53	30.56	32.59	34.63
Kitchen	0.05	0.16	0.38	0.70	1.18	1.65	2.12	2.59	3.06	3.53	3.85	4.18	4.51	4.83	5.16
Lighting	16.38	33.41	51.05	57.34	66.10	64.75	63.41	62.07	60.72	59.38	56.56	53.74	50.92	48.11	45.29
Motor/Compressor	0.14	0.48	1.09	1.99	3.19	3.95	4.70	5.45	6.20	6.95	7.71	8.46	9.21	9.97	10.72
Office Equipment	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Other	0.14	0.47	0.98	1.58	2.36	2.78	3.20	3.61	4.03	4.45	4.63	4.81	5.00	5.18	5.36
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.04	0.13	0.28	0.50	0.79	1.02	1.25	1.48	1.70	1.93	2.03	2.12	2.22	2.31	2.41
Industrial	**0.84**	**2.19**	**4.20**	**6.86**	**10.24**	**12.22**	**14.20**	**16.18**	**18.15**	**20.13**	**21.63**	**23.13**	**24.64**	**26.14**	**27.64**
Envelope	0.02	0.06	0.14	0.25	0.40	0.49	0.57	0.66	0.74	0.83	0.92	1.00	1.09	1.17	1.26
Hot Water	0.08	0.16	0.24	0.33	0.43	0.47	0.50	0.54	0.57	0.61	0.62	0.63	0.64	0.65	0.66
HVAC	0.08	0.25	0.53	0.90	1.36	1.73	2.09	2.45	2.81	3.17	3.47	3.77	4.07	4.37	4.66
Kitchen	0.00	0.00	0.01	0.02	0.03	0.05	0.06	0.08	0.09	0.10	0.11	0.12	0.12	0.13	0.14
Lighting	0.41	0.84	1.30	1.76	2.27	2.44	2.60	2.77	2.94	3.10	2.96	2.81	2.66	2.52	2.37
Motor/Compressor	0.23	0.79	1.78	3.27	5.25	6.45	7.66	8.87	10.08	11.28	12.47	13.65	14.83	16.02	17.20
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.02	0.08	0.17	0.27	0.42	0.51	0.60	0.69	0.78	0.87	0.92	0.98	1.03	1.09	1.14
Process	0.01	0.02	0.03	0.04	0.05	0.05	0.06	0.06	0.06	0.07	0.07	0.08	0.08	0.09	0.09
Refrigeration	0.00	0.00	0.01	0.02	0.03	0.04	0.05	0.07	0.08	0.09	0.09	0.10	0.10	0.10	0.11

Table F- 8: Cumulative Savings by End-Use: LAB System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	**1.07**	**1.34**	**1.65**	**2.03**	**2.47**	**2.70**	**2.94**	**3.17**	**3.40**	**3.64**	**3.77**	**3.91**	**4.05**	**4.18**	**4.32**
Appliance	0.01	0.03	0.05	0.08	0.12	0.14	0.15	0.16	0.17	0.18	0.19	0.19	0.19	0.19	0.19
Behavioral	0.85	0.85	0.85	0.85	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84	0.84
Envelope	0.03	0.09	0.17	0.28	0.41	0.50	0.58	0.66	0.74	0.83	0.91	0.99	1.07	1.16	1.24
Hot Water	0.05	0.10	0.14	0.18	0.20	0.22	0.24	0.25	0.27	0.29	0.26	0.24	0.22	0.19	0.17
HVAC	0.13	0.27	0.42	0.63	0.86	0.98	1.11	1.23	1.35	1.47	1.55	1.63	1.71	1.79	1.87
Lighting	0.00	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.01	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial	**0.86**	**1.89**	**3.11**	**3.61**	**4.30**	**4.41**	**4.53**	**4.64**	**4.75**	**4.86**	**5.11**	**5.36**	**5.60**	**5.85**	**6.10**
Envelope	0.01	0.03	0.07	0.12	0.20	0.25	0.30	0.35	0.40	0.45	0.50	0.55	0.60	0.65	0.70
Hot Water	0.01	0.02	0.03	0.04	0.05	0.05	0.05	0.06	0.06	0.07	0.07	0.07	0.07	0.07	0.07
HVAC	0.05	0.12	0.23	0.36	0.50	0.61	0.72	0.83	0.94	1.05	1.08	1.11	1.14	1.17	1.20
Kitchen	0.00	0.00	0.01	0.01	0.02	0.03	0.03	0.04	0.05	0.06	0.06	0.07	0.07	0.08	0.08
Lighting	0.75	1.59	2.48	2.51	2.64	2.39	2.14	1.90	1.65	1.40	1.38	1.35	1.33	1.30	1.28
Motor/Compressor	0.04	0.13	0.30	0.55	0.88	1.07	1.25	1.44	1.62	1.81	1.99	2.18	2.36	2.55	2.73
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Process	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Industrial	**0.02**	**0.05**	**0.10**	**0.16**	**0.23**	**0.27**	**0.32**	**0.36**	**0.40**	**0.45**	**0.45**	**0.45**	**0.46**	**0.46**	**0.46**
Envelope	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
Hot Water	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.01	0.04	0.08	0.14	0.20	0.24	0.28	0.32	0.36	0.40	0.40	0.39	0.39	0.39	0.39
Kitchen	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Motor/Compressor	0.00	0.00	0.00	0.01	0.01	0.02	0.02	0.02	0.02	0.03	0.03	0.03	0.03	0.04	0.04
Office Equipment	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Other	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Process	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.02	0.02	0.02	0.02	0.02
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table F- 9: Cumulative Savings by End-Use: ISO System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Residential	0.458	0.942	1.445	1.779	2.123	2.274	2.424	2.575	2.726	2.877	2.803	2.730	2.656	2.583	2.509
Appliance	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027	0.027
Behavioral	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Envelope	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046	0.046
Hot Water	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074	0.074
HVAC	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036	0.036
Lighting	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218	0.218
Other	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057	0.057
Commercial	0.709	1.457	2.247	2.480	2.985	2.994	3.003	3.012	3.022	3.031	3.025	3.020	3.014	3.009	3.003
Envelope	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Hot Water	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
HVAC	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Kitchen	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Lighting	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699	0.699
Motor/Compressor	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004	0.004
Office Equipment	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Other	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002	0.002
Process	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Refrigeration	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001

DETAILED RATE SENSITIVITY RESULTS CUMULATIVE SAVINGS

The tables below present the cumulative savings for CDM programs - not including savings from program years prior to 2020.

LOWER PROGRAM SCENARIO

Table F- 10: Cumulative Savings by Sector: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
High Rates																
Residential	22	35	48	60	72	80	87	95	103	111	114	118	121	125	128	1,319
Commercial	13	27	43	49	58	59	61	62	64	65	66	66	66	67	67	833
Industrial	0	1	2	4	6	7	8	9	10	11	12	12	13	14	15	124
Total	**35**	**63**	**93**	**113**	**136**	**146**	**156**	**166**	**177**	**187**	**192**	**196**	**200**	**206**	**210**	2,276
Low Rates																
Residential	18	26	34	42	50	55	60	65	71	76	79	81	84	87	90	918
Commercial	11	22	35	40	45	46	47	47	48	48	49	49	50	50	50	637
Industrial	0	1	2	3	4	5	5	6	7	8	8	9	9	10	11	88
Total	**29**	**49**	**71**	**85**	**99**	**106**	**112**	**118**	**126**	**132**	**136**	**139**	**143**	**147**	**151**	1,643

MID PROGRAM SCENARIO

Table F- 11: Cumulative Savings by Sector: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
High Rates																
Residential	33	55	80	101	123	136	148	161	174	186	189	192	195	198	201	2,172
Commercial	16	33	53	63	76	80	84	87	91	95	96	98	99	100	101	1,172
Industrial	1	2	3	5	8	10	11	13	14	16	17	18	19	20	21	178
Total	**50**	**90**	**136**	**169**	**207**	**226**	**243**	**261**	**279**	**297**	**302**	**308**	**313**	**318**	**323**	3,522
Low Rates																
Residential	27	43	60	75	91	100	110	119	128	137	140	142	145	147	150	1,614
Commercial	14	29	46	53	63	66	68	71	74	76	77	78	79	80	80	954
Industrial	1	1	3	4	6	7	9	10	11	12	13	14	15	16	17	139
Total	**42**	**73**	**109**	**132**	**160**	**173**	**187**	**200**	**213**	**225**	**230**	**234**	**239**	**243**	**247**	2,707

UPPER PROGRAM SCENARIO

Table F- 12: Cumulative Savings by Sector: IIC System (GWh)

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	Total
High Rates																
Residential	48	80	116	147	180	198	216	234	252	270	274	277	281	285	289	3,147
Commercial	19	40	64	79	98	103	109	115	121	127	129	132	134	137	139	1,546
Industrial	1	2	5	7	11	13	15	18	20	22	24	25	27	29	30	249
Total	**68**	**122**	**185**	**233**	**289**	**314**	**340**	**367**	**393**	**419**	**427**	**434**	**442**	**451**	**458**	4,942
Low Rates																
Residential	41	67	95	120	147	161	176	190	205	219	222	225	228	231	234	2,561
Commercial	17	37	58	70	86	90	94	99	103	108	109	111	113	114	116	1,325
Industrial	1	2	4	6	9	11	13	15	16	18	19	21	22	23	25	205
Total	**59**	**106**	**157**	**196**	**242**	**262**	**283**	**304**	**324**	**345**	**350**	**357**	**363**	**368**	**375**	4,091

DETAILED DEMAND RESPONSE RESULTS

The following section provides detailed results tables for the demand response analysis.

Table F- 13 and **Table F-14** present the measure-level potential results for cost-effective measures at each assessment year in the study period for the IIC system. Technical and economical potential was not assessed for the LAB system as Dunsky extended IIC programs to LAB, in agreement with NL Utilities.

Table F- 13: Residential Technical and Economic Potential (MW)

System	Measure	Tech Potential 2020	Tech Potential 2024	Tech Potential 2029	Tech Potential 2034	Economic Potential 2020	Economic Potential 2024	Economic Potential 2029	Economic Potential 2034
IIC	**Setpoint Control**	428	440	464	478	28	30	31	32
IIC	**Domestic Hot Water**	230	236	249	256	24	25	26	27
IIC	**Clothes Dryer**	207	212	222	228	21	22	23	24
IIC	**Hot Tubs / Spas**	1.5	1.6	1.7	1.8	0.4	0.4	0.4	0.4
IIC	**Dual-Fuel**	21	21	22	22	21	21	22	22
IIC	**TOU**	8.0	8.6	9.0	9.8	8.0	8.6	9.0	9.8

Table F- 14: C&I Technical and Economic Potential (MW)

System	Measure	Tech Potential 2020	Tech Potential 2024	Tech Potential 2029	Tech Potential 2034	Economic Potential 2020	Economic Potential 2024	Economic Potential 2029	Economic Potential 2034
IIC	Anti-Sweat Heater Control	3.2	3.3	3.4	3.5	0.4	0.4	0.5	0.5
IIC	Commercial Refrigeration	12	13	13	13	1.6	1.6	1.7	1.7
IIC	Interruption of Humidification (Manual or BAS)	11	11	12	12	1.4	1.4	1.5	1.5
IIC	Interruption of Winter Cooling/Free Cooling Systems	1.2	1.3	1.3	1.4	0.2	0.2	0.2	0.2
IIC	Lighting Control (Manual) for Fuel Heated Buildings	9.3	10	10	10	1.1	1.2	1.2	1.3
IIC	Reduction of fresh air flow (Manual or BAS)	24	24	26	26	3.6	3.7	3.9	3.9
IIC	Reduction of Ventilation Flow (with VAVs)	39	40	42	43	5.5	5.7	6.0	6.2
IIC	Setpoint Control for Electric Heated Building (Manual)	78	80	84	87	10	10	11	11
IIC	Dual-Fuel	46	48	49	50	46	48	49	50
IIC	Small & Medium Industrials	33	33	32	32	33	33	32	32
IIC	Large Industrial Curtailment	125	125	125	125	125	125	125	125
IIC	TOU Rates	3.0	3.4	3.5	3.8	3.0	3.4	3.5	3.8

Table F- 15, Table F- 16, Table F- 17, and **Table F- 18** present the program costs, potential peak reduction and PACT for each study period. Because of their small size, LAB DR programs were integrated with IIC programs.

Table F- 15: DR Program Results – 2020 Implementation

DR Program	Scenario	Peak Reduction (MW)[58]	Total Benefits [59] ($M 2020)	Total Costs [60] ($M 2020)	PACT[61]
Residential DLC	**Equipment Control Expansion**	25	$152	$21	6.3
Commercial curtailment	**Equipment Control Expansion**	4.3	$4.0	$3.7	0.9
TOU – IIC Only62	**Rate-based Expansion**	11	$55	$97	0.6
Backup Generation	**All**	27	$215	$114	1.9
Industrial curtailment	**Equipment Control Expansion**	112	$405	$13	31.7
Industrial curtailment	**Rate-based Expansion**	104	$376	$14	27.0
Industrial curtailment	**Optimize Existing Curtailment**	152	$550	$17	32.8

Table F- 16:DR Program Results – 2024 Implementation

DR Program	Scenario	Peak Reduction (MW)	Total Benefits ($M 2020)	Total Costs ($M 2020)	PACT
Residential DLC	**Equipment Control Expansion**	26	$174	$22	6.8
Commercial curtailment	**Equipment Control Expansion**	4.7	$4.7	$6.7	0.6
TOU – IIC Only	**Rate-based Expansion**	12	$66	$97	0.7
Backup Generation	**All**	27	$239	$118	2.0
Industrial curtailment	**Equipment Control Expansion**	114	$453	$13	34.8
Industrial curtailment	**Rate-based Expansion**	105	$414	$14	28.8
Industrial curtailment	**Optimize Existing Curtailment**	153	$603	$17	35

[58] At full deployment (For new programs: after a 5-year ramp-up).

[59] At full deployment (For new programs: after a 5-year ramp-up).

[60] At full deployment (For new programs: after a 5-year ramp-up).

[61] Including a 5-year ramp-up for new programs.

[62] First year cost and PACT. Does not include negative impact from lost industrial curtailment potential.

Table F- 17: DR Program Results – 2029 Implementation

DR Program	Scenario	Peak Reduction (MW)	Total Benefits ($M 2020)	Total Costs ($M 2020)	PACT
Residential DLC	Equipment Control Expansion	27	$198	$23	7.5
Commercial curtailment	Equipment Control Expansion	5.2	$5.8	$7.4	0.6
TOU – IIC Only	Rate-based Expansion	13	$76	$97	0.8
Backup Generation	All	29	$269	$127	2.1
Industrial curtailment	Equipment Control Expansion	117	$515	$13	38.9
Industrial curtailment	Rate-based Expansion	108	$470	$15	31.1
Industrial curtailment	Optimize Existing Curtailment	154	$674	$18	37.6

Table F- 18: DR Program Results – 2034 Implementation

DR Program	Scenario	Peak Reduction (MW)	Total Benefits ($M 2020)	Total Costs ($M 2020)	PACT
Residential DLC	Equipment Control Expansion	28	$225	$24	8.3
Commercial curtailment	Equipment Control Expansion	5.5	$6.9	$7.8	0.7
TOU – IIC Only	Rate-based Expansion	13	$87	$97	0.9
Backup Generation	All	30	$303	$132	2.3
Industrial curtailment	Equipment Control Expansion	120	$583	$13	43.4
Industrial curtailment	Rate-based Expansion	109	$527	$15	34.3
Industrial curtailment	Optimize Existing Curtailment	154	$745	$18	40.7

DEMAND RESPONSE PROGRAM COST-EFFECTIVENESS

Based on the DR scenarios, the peak reduction potential and cost-effectiveness for each program stream was assessed considering program costs (including customer incentives, set up costs, program ramp-up, and marketing costs) and benefits (including peak capacity avoided costs and ancillary benefits such as peak hour generation reduction benefits and voltage regulation where applicable).

Key findings from the program analysis reveal that:

- **Industrial curtailment presents the best cost-effectiveness:** Maximizing industrial curtailment and other measures with no bounce-back, like BUGs (for LAB system) and dual-fuel achieve the highest cost-effectiveness.
- **Industrial sector DR programs may suffer from being combined with other programs:** In all scenarios, industrial customer enrollment in the DR programs is expanded to reach small and medium industrials. The model savings per customer are higher in the Scenario 1, which improves cost-effectiveness as compared to the TOU and Equipment scenarios where the large industrials must exert their peak demand reductions against a utility load curve already flattened by DR programs in the other sectors.

High avoided costs

Though not presented here, a high number of manual or DLC measures pass cost-effectiveness. Due to high avoided costs and a relatively flat load shape, DLC potential is mainly constrained by the load shape. In all cases, adoption must be limited in order to limit consumption displacement. Depending on measures and their effect on peak, potential varies widely. As mentioned before, among measures with a large potential to sustain a program and positive PACT are the residential setpoint controls and domestic water heater DLC, respectively, due to the heating demand during

DYNAMIC RATE DESIGN

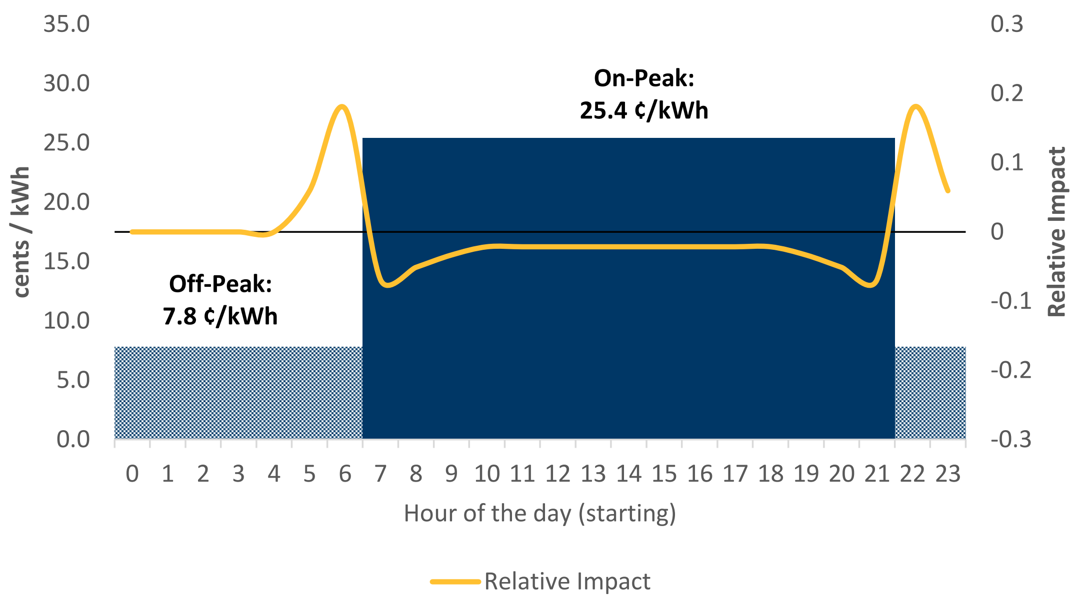
Various rate designs were tested on the IIC system standard peak day and load curves. This includes four TOU designs and one CPP design.

The analysis tested a range of TOU rate designs in the IIC systems, starting with the two-tier and three-tier models presented in the recent NL Hydro marginal cost study.[63] In the figure below, the line presents

[63] Source: "Marginal Cost Study Update – 2018", Nov. 15, 2018, NL Hydro

the relative impact of dynamic rates on demand while the filled areas define pricing (on-peak hour: 7:00 to 21:59 inclusively).

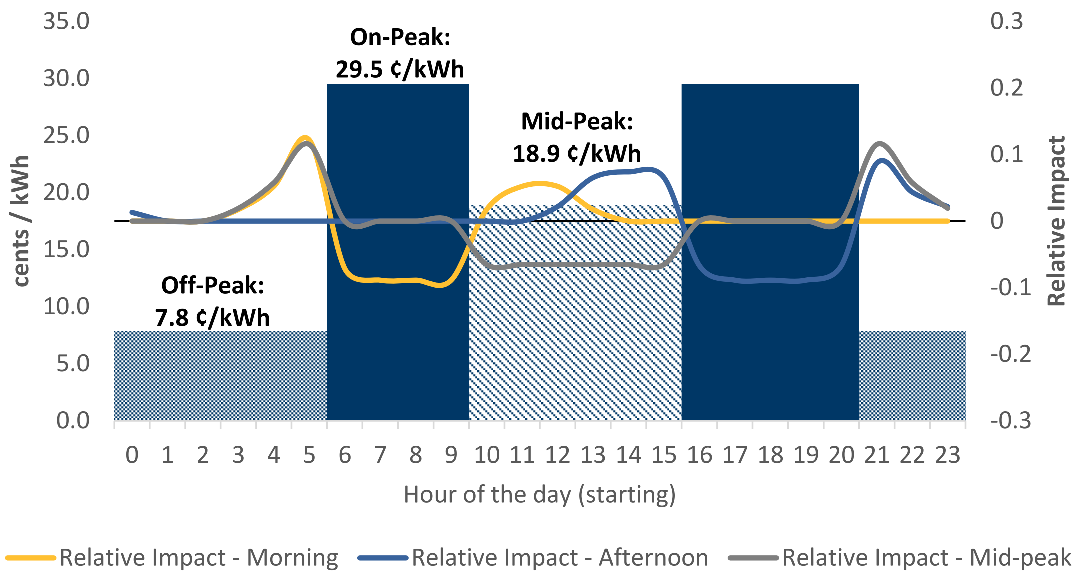
Figure F- 4: TOU Rate Design #1 (2 Tier – NL Hydro Marginal Cost Study)



The above TOU design increased the standard peak day demand by 54 MW and increased the demand in all five historical years.

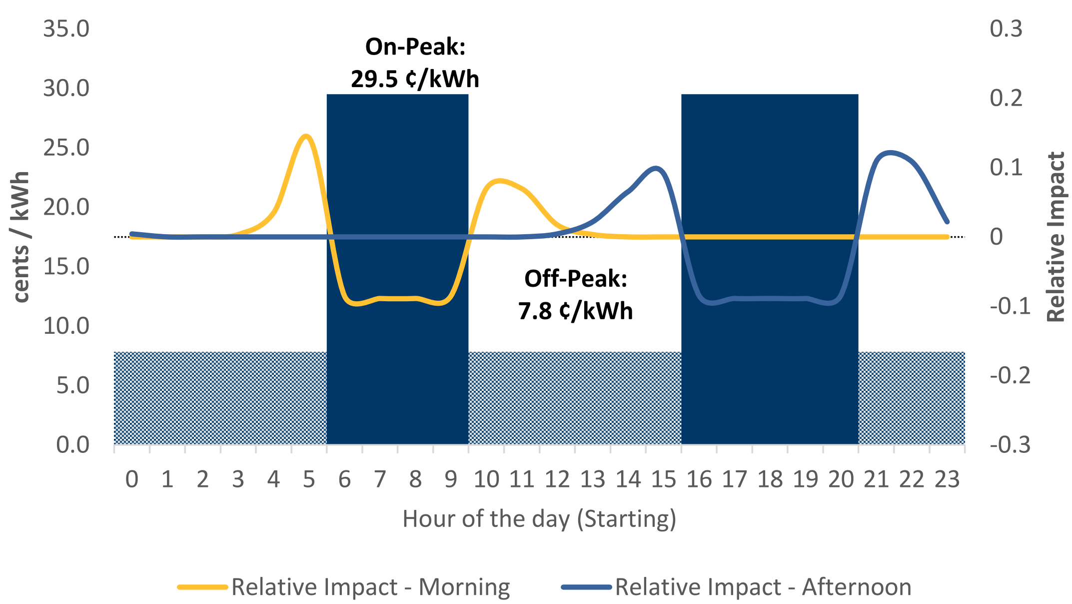
The rate design below has two on-peak segments and a single mid-peak segment in the middle of the day. The three lines show the relative impact on demand for each of these segments. For example, in the morning peak hours (6:00 to 9:59 – yellow line) the dynamic pricing impact will be to reduce demand during peak hours and increase it earlier in the morning and over mid-peak hours (demand shifting). In comparison, mid-peak (10:00 to 20:59 – grey line) will not shift demand to peak hours because of higher energy costs and will instead shift demand to the early morning or late evening.

Figure F- 5: TOU Rate Design #2 (3 Tier – NL Hydro Marginal Cost Study)



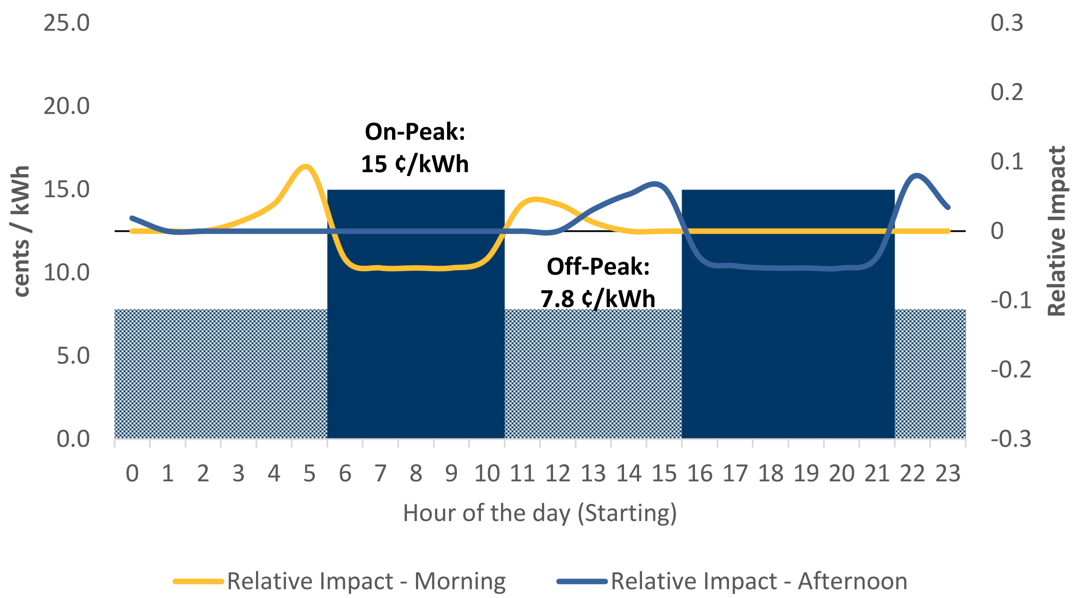
The above TOU design increased the standard peak day demand by 66 MW and increased the demand in all five historical years.

Figure F- 6: TOU Rate Design #3 (2 Tier – ≈4:1 Ratio)



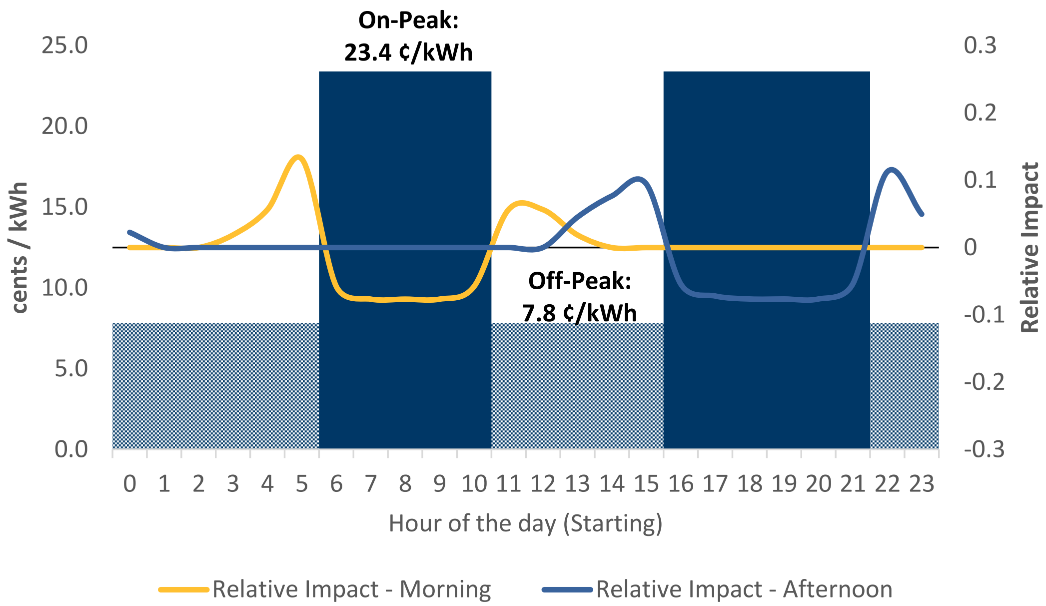
The above TOU design increased the standard peak day demand by 11 MW and increased the demand in all five historical years.

Figure F- 7: TOU Rate Design #4 (2 Tier – ≈2:1 Ratio)



The above TOU design decreased the standard peak day demand by 11 MW and decreased the demand in four years out of five historical years.

Figure F- 8: CPP Rate Design #1 (2 Tier – 3:1 Ratio)



The above CPP design increased the standard peak day demand by 16 MW and increased the demand in all five historical years. Overall, dynamic rate implementation reduces the demand saving potential from existing time constrained industrial curtailment contracts. The industrial curtailment is not as well suited to address the new peaks generated by dynamic rates. **Figure F- 9** and

Figure F- 10 respectively present the impact of large industrial curtailment on its own and combined with TOU. We see that demand savings from large industrial alone is 125 MW, while the TOU and large industrial combined is 92 MW.

Figure F- 9: Industrial curtailment impact on demand

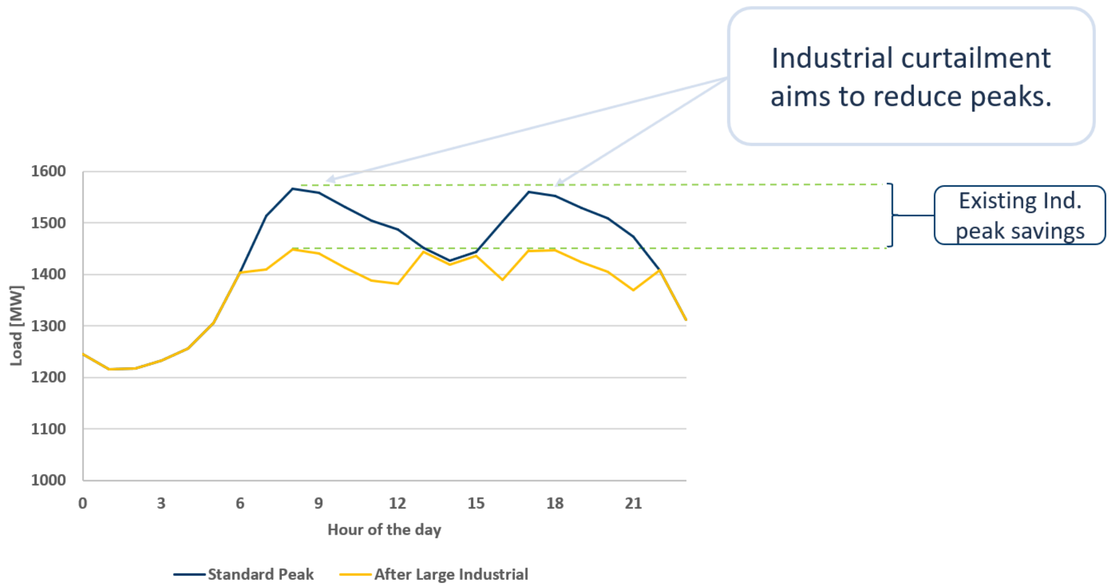
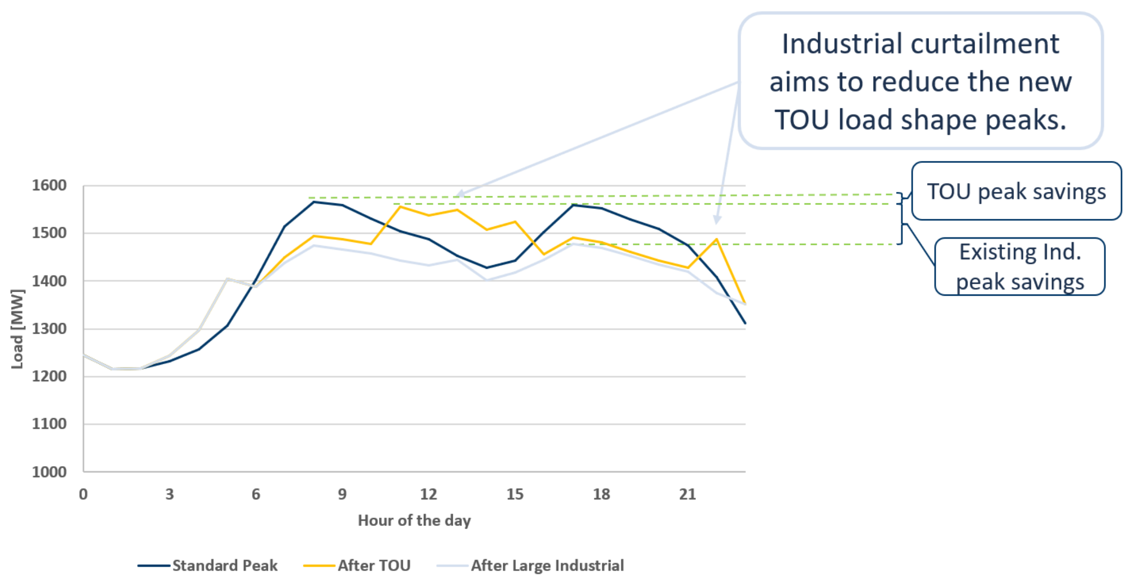


Figure F- 10: Combined TOU and industrial curtailment impact on demand



FUEL SWITCHING DETAILED RESULTS TABLES

The following section provides detailed results tables for the fuel switching analysis. It first provides detailed results for the primary analysis for each incentive scenario. Following these tables are detailed results tables for the sensitivity analyses.

PRIMARY ANALYSIS

The primary analysis tested fuel switching under the MID electricity rate scenario and no carbon pricing applied to oil rates.

Table F- 19: Percent of all customers adopting heat pump technologies (MID electricity rates, no carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.005%	0.005%	0.004%	0.004%	0.004%	0.014%	0.013%	**0.049%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.011%**
% Commercial square footage adopting heat pumps for space heating	0.008%	0.006%	0.006%	0.005%	0.005%	0.013%	0.012%	**0.054%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.000%	0.000%	0.002%	0.002%	**0.008%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.04%	0.03%	0.03%	0.03%	0.03%	0.09%	0.08%	**0.33%**
% Residential customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.06%**
% Commercial square footage adopting heat pumps for space heating	0.06%	0.05%	0.05%	0.04%	0.04%	0.11%	0.10%	**0.44%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	**0.04%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.53%	0.49%	0.47%	0.45%	0.42%	1.32%	1.30%	**4.96%**
% Residential customers adopting heat pumps for domestic hot water heating	0.06%	0.06%	0.06%	0.06%	0.06%	0.28%	0.28%	**0.85%**
% Commercial square footage adopting heat pumps for space heating	0.42%	0.39%	0.36%	0.34%	0.31%	0.86%	0.83%	**3.52%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.04%	0.04%	0.04%	0.04%	0.04%	0.20%	0.20%	**0.59%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 20: Fuel switching cumulative energy impacts (MID electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	0	1	1	1
Net energy impact	-14	-28	-42	-55	-68	-102	-137
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	1	2	2	3	4	6	7
Net energy impact	-13	-27	-40	-53	-65	-97	-131
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	9	17	24	31	38	60	80
Net energy impact	-5	-12	-18	-24	-30	-43	-58

Table F- 21: Fuel switching cumulative demand impacts (MID electricity rates, no carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	1	1
Net demand impact	-7	-13	-20	-27	-32	-49	-66
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	1	1	2	2	3	4	6
Net demand impact	-6	-12	-19	-25	-30	-45	-61
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	8	15	22	28	34	54	73
Net demand impact	1	1	1	1	1	4	6

Table F- 22: Fuel switching cumulative energy impacts by sector and technology (MID electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Residential customers adopting DMSHP	0.02	0.04	0.06	0.08	0.09	0.14	0.18
Residential customers adopting ASHP	0.04	0.07	0.10	0.12	0.15	0.28	0.39
Residential customers adopting domestic HW HP	0.00	0.00	0.00	0.01	0.01	0.02	0.02
Residential (TOTAL)	**0.06**	**0.12**	**0.16**	**0.21**	**0.25**	**0.43**	**0.58**
Commercial customers adopting DMSHP	0.07	0.12	0.17	0.22	0.26	0.37	0.47
Commercial customers adopting ASHP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial customers adopting domestic HW HP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial (TOTAL)	**0.07**	**0.12**	**0.17**	**0.22**	**0.26**	**0.37**	**0.47**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Residential customers adopting DMSHP	0.20	0.39	0.55	0.71	0.85	1.24	1.61
Residential customers adopting ASHP	0.17	0.32	0.44	0.56	0.68	1.24	1.75
Residential customers adopting domestic HW HP	0.01	0.02	0.03	0.04	0.05	0.09	0.09
Residential (TOTAL)	**0.38**	**0.72**	**1.02**	**1.30**	**1.57**	**2.57**	**3.45**
Commercial customers adopting DMSHP	0.52	0.97	1.37	1.74	2.07	2.99	3.85
Commercial customers adopting ASHP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial customers adopting domestic HW HP	0.00	0.00	0.00	0.01	0.01	0.01	0.01
Commercial (TOTAL)	**0.52**	**0.97**	**1.37**	**1.74**	**2.08**	**3.01**	**3.86**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Residential customers adopting DMSHP	3.35	6.46	9.42	12.24	14.83	22.07	29.24
Residential customers adopting ASHP	1.57	2.94	4.20	5.43	6.66	12.69	18.46
Residential customers adopting domestic HW HP	0.13	0.25	0.38	0.50	0.63	1.25	1.25
Residential (TOTAL)	**5.04**	**9.65**	**14.00**	**18.18**	**22.12**	**36.01**	**48.94**
Commercial customers adopting DMSHP	3.62	7.00	10.17	13.13	15.85	23.35	30.59
Commercial customers adopting ASHP	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial customers adopting domestic HW HP	0.02	0.03	0.05	0.07	0.09	0.17	0.17
Commercial (TOTAL)	**3.64**	**7.04**	**10.22**	**13.20**	**15.93**	**23.52**	**30.76**

Note: All results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 23: Annual utility incentive costs (MID electricity rates, no carbon pricing)

MID	2020	2021	2022	2023	2024	2025-2029 Average	2030-2034 Average	Average per year
Residential	$180,000	$163,000	$150,000	$140,000	$130,000	$82,000	$78,000	$104,000
Commercial	$145,000	$127,000	$113,000	$104,000	$95,000	$52,000	$49,000	$73,000
Total	**$325,000**	**$290,000**	**$264,000**	**$244,000**	**$225,000**	**$134,000**	**$127,000**	**$177,000**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025-2029 Average**	**2030-2034 Average**	**Average per year**
Residential	$5,659,000	$5,283,000	$5,037,000	$4,808,000	$4,469,000	$2,727,000	$2,698,000	$3,492,000
Commercial	$2,053,000	$1,916,000	$1,796,000	$1,681,000	$1,545,000	$867,000	$837,000	$1,167,000
Total	**$7,712,000**	**$7,200,000**	**$6,832,000**	**$6,489,000**	**$6,014,000**	**$3,594,000**	**$3,535,000**	**$4,660,000**

SENSITIVITY ANALYSIS: HIGH ELECTRICITY RATES

This analysis assumed electricity rates at the HIGH rate scenario and no carbon pricing applied to oil rates.

Table F- 24: Percent of all customers adopting heat pump technologies (HIGH electricity rates, no carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	2.0%	2.1%	2.0%	1.9%	1.8%	4.9%	5.0%	**19.7%**
% Residential customers adopting heat pumps for space heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.014%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.003%	0.003%	**0.009%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.001%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.002%	0.002%	**0.006%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	2.0%	2.1%	2.0%	1.9%	1.8%	4.9%	5.0%	**19.7%**
% Residential customers adopting heat pumps for space heating	0.01%	0.01%	0.01%	0.01%	0.01%	0.03%	0.03%	**0.12%**
% Residential customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.05%**
% Commercial square footage adopting heat pumps for space heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	**0.01%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.01%	0.01%	**0.03%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	2.0%	2.1%	2.0%	1.9%	1.8%	4.9%	5.0%	**19.7%**
% Residential customers adopting heat pumps for space heating	0.29%	0.25%	0.25%	0.24%	0.23%	0.69%	0.66%	**2.62%**
% Residential customers adopting heat pumps for domestic hot water heating	0.05%	0.05%	0.05%	0.05%	0.05%	0.25%	0.25%	**0.76%**
% Commercial square footage adopting heat pumps for space heating	0.05%	0.03%	0.03%	0.03%	0.02%	0.07%	0.06%	**0.27%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.03%	0.03%	0.03%	0.03%	0.03%	0.16%	0.16%	**0.48%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 25: Fuel switching cumulative energy impacts (HIGH electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-17	-35	-52	-68	-83	-125	-168
Energy increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net energy impact	-17	-35	-52	-68	-83	-125	-168
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-17	-35	-52	-68	-83	-125	-168
Energy increases from fuel switching (all sectors)	0	0	0	0	1	1	1
Net energy impact	-17	-35	-52	-68	-83	-125	-167
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-17	-35	-52	-68	-83	-125	-168
Energy increases from fuel switching (all sectors)	3	5	7	10	12	18	24
Net energy impact	-15	-30	-45	-59	-72	-107	-144

Table F- 26: Fuel switching cumulative demand impacts (HIGH electricity rates, no carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-8	-17	-25	-33	-40	-60	-81
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-8	-17	-25	-33	-40	-60	-81
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-8	-17	-25	-33	-40	-60	-81
Demand increases from fuel switching (all sectors)	0	0	0	0	1	1	1
Net demand impact	-8	-17	-25	-32	-40	-59	-79
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-8	-17	-25	-33	-40	-60	-81
Demand increases from fuel switching (all sectors)	3	6	8	11	13	21	27
Net demand impact	-5	-11	-17	-22	-27	-40	-53

SENSITIVITY ANALYSIS: LOW ELECTRICITY RATES

This analysis assumed electricity rates at the LOW rate scenario and no carbon pricing applied to oil rates.

Table F- 27: Percent of all customers adopting heat pump technologies (LOW electricity rates, no carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.3%	1.3%	1.3%	1.2%	1.1%	3.2%	3.2%	**12.8%**
% Residential customers adopting heat pumps for space heating	0.016%	0.015%	0.015%	0.015%	0.014%	0.057%	0.055%	**0.187%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.013%**
% Commercial square footage adopting heat pumps for space heating	0.026%	0.025%	0.024%	0.023%	0.021%	0.056%	0.054%	**0.229%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.003%	0.003%	**0.010%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.3%	1.3%	1.3%	1.2%	1.1%	3.2%	3.2%	**12.8%**
% Residential customers adopting heat pumps for space heating	0.09%	0.09%	0.09%	0.09%	0.08%	0.31%	0.30%	**1.05%**
% Residential customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.07%**
% Commercial square footage adopting heat pumps for space heating	0.15%	0.15%	0.15%	0.14%	0.13%	0.35%	0.34%	**1.40%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.05%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.3%	1.3%	1.3%	1.2%	1.1%	3.2%	3.2%	**12.8%**
% Residential customers adopting heat pumps for space heating	0.87%	0.86%	0.84%	0.81%	0.76%	2.48%	2.45%	**9.07%**
% Residential customers adopting heat pumps for domestic hot water heating	0.06%	0.06%	0.06%	0.06%	0.06%	0.31%	0.31%	**0.93%**
% Commercial square footage adopting heat pumps for space heating	0.60%	0.59%	0.58%	0.55%	0.51%	1.41%	1.39%	**5.64%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.05%	0.05%	0.05%	0.05%	0.05%	0.23%	0.23%	**0.70%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 28: Fuel switching cumulative energy impacts (LOW electricity rates, no carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-11	-23	-33	-44	-54	-81	-109
Energy increases from fuel switching (all sectors)	0	1	1	2	2	4	5
Net energy impact	-11	-22	-32	-42	-51	-77	-104
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-11	-23	-33	-44	-54	-81	-109
Energy increases from fuel switching (all sectors)	3	5	8	10	12	20	27
Net energy impact	-9	-17	-26	-34	-42	-61	-81
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-11	-23	-33	-44	-54	-81	-109
Energy increases from fuel switching (all sectors)	14	28	42	56	68	111	153
Net energy impact	3	6	9	12	15	30	45

Table F- 29: Fuel switching cumulative demand impacts (LOW electricity rates, no carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-5	-11	-16	-21	-26	-39	-52
Demand increases from fuel switching (all sectors)	0	1	1	1	2	3	4
Net demand impact	-5	-10	-15	-20	-24	-36	-48
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-5	-11	-16	-21	-26	-39	-52
Demand increases from fuel switching (all sectors)	2	4	6	8	10	16	23
Net demand impact	-3	-7	-10	-13	-16	-23	-29
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-5	-11	-16	-21	-26	-39	-52
Demand increases from fuel switching (all sectors)	13	26	39	51	63	104	145
Net demand impact	8	15	23	30	37	65	93

SENSITIVITY ANALYSIS: CARBON PRICING, FEDERAL BACKSTOP

This analysis applied the federal backstop carbon pricing plan carbon levy to oil rates. Electricity rates are assumed at the MID rate scenario.

Table F- 30: Percent of all customers adopting heat pump technologies (MID electricity rates, federal backstop carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.013%	0.012%	0.012%	0.011%	0.011%	0.043%	0.041%	**0.144%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.005%	0.005%	**0.016%**
% Commercial square footage adopting heat pumps for space heating	0.018%	0.017%	0.015%	0.014%	0.013%	0.036%	0.034%	**0.146%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.011%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.08%	0.08%	0.08%	0.07%	0.07%	0.24%	0.24%	**0.86%**
% Residential customers adopting heat pumps for domestic hot water heating	0.01%	0.01%	0.01%	0.01%	0.01%	0.03%	0.03%	**0.09%**
% Commercial square footage adopting heat pumps for space heating	0.12%	0.11%	0.10%	0.10%	0.09%	0.24%	0.23%	**1.00%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.00%	0.00%	0.00%	0.00%	0.00%	0.02%	0.02%	**0.06%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.83%	0.81%	0.78%	0.74%	0.70%	2.26%	2.22%	**8.35%**
% Residential customers adopting heat pumps for domestic hot water heating	0.07%	0.07%	0.07%	0.07%	0.07%	0.36%	0.35%	**1.07%**
% Commercial square footage adopting heat pumps for space heating	0.55%	0.53%	0.51%	0.48%	0.44%	1.24%	1.22%	**4.98%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.05%	0.05%	0.05%	0.05%	0.05%	0.26%	0.26%	**0.78%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 31: Fuel switching cumulative energy impacts (MID electricity rates, federal backstop carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	1	1	1	2	3	3
Net energy impact	-14	-28	-41	-55	-67	-100	-135
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	2	4	6	7	9	15	20
Net energy impact	-12	-24	-37	-48	-59	-88	-118
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	13	26	38	50	61	99	135
Net energy impact	-1	-2	-4	-5	-7	-4	-3

Table F- 32: Fuel switching cumulative demand impacts (MID electricity rates, federal backstop carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	1	1	1	1	2	3
Net demand impact	-7	-13	-20	-26	-32	-47	-63
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	2	3	5	6	7	12	17
Net demand impact	-5	-10	-16	-21	-25	-37	-50
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	12	24	36	47	57	93	129
Net demand impact	5	11	15	20	24	44	62

SENSITIVITY ANALYSIS: CARBON PRICING, SOCIAL COST OF CARBON

This analysis applied a social cost of carbon levy to oil rates. Electricity rates are assumed at the MID rate scenario.

Table F- 33: Percent of all customers adopting heat pump technologies (MID electricity rates, SCC carbon pricing)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.086%	0.086%	0.086%	0.086%	0.086%	0.391%	0.436%	**1.256%**
% Residential customers adopting heat pumps for domestic hot water heating	0.003%	0.003%	0.003%	0.003%	0.003%	0.017%	0.018%	**0.050%**
% Commercial square footage adopting heat pumps for space heating	0.102%	0.100%	0.098%	0.095%	0.090%	0.269%	0.298%	**1.052%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.002%	0.002%	0.002%	0.002%	0.003%	0.013%	0.015%	**0.041%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.37%	0.37%	0.37%	0.37%	0.35%	1.39%	1.49%	**4.72%**
% Residential customers adopting heat pumps for domestic hot water heating	0.01%	0.01%	0.01%	0.02%	0.02%	0.08%	0.09%	**0.25%**
% Commercial square footage adopting heat pumps for space heating	0.36%	0.36%	0.35%	0.34%	0.31%	0.91%	0.96%	**3.58%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.01%	0.01%	0.01%	0.01%	0.01%	0.07%	0.07%	**0.20%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	1.55%	1.53%	1.51%	1.46%	1.38%	4.50%	4.62%	**16.54%**
% Residential customers adopting heat pumps for domestic hot water heating	0.12%	0.12%	0.12%	0.12%	0.12%	0.64%	0.67%	**1.92%**
% Commercial square footage adopting heat pumps for space heating	0.79%	0.77%	0.76%	0.72%	0.67%	1.89%	1.92%	**7.52%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.10%	0.10%	0.10%	0.10%	0.10%	0.53%	0.55%	**1.58%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood)space heating / domestic water heating customers.

Table F- 34: Fuel switching cumulative energy impacts (MID electricity rates, SCC carbon pricing), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	2	5	7	9	11	21	32
Net energy impact	-12	-24	-35	-47	-57	-82	-106
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	8	16	24	31	39	68	99
Net energy impact	-6	-12	-19	-24	-29	-35	-39
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	22	44	66	87	107	177	246
Net energy impact	8	16	24	31	39	74	108

Table F- 35: Fuel switching demand impacts (MID electricity rates, SCC carbon pricing), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	2	4	6	8	10	19	30
Net demand impact	-5	-10	-14	-19	-23	-30	-37
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	7	14	21	28	35	63	93
Net demand impact	0	0	1	1	2	13	26
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	22	43	64	84	104	172	242
Net demand impact	15	29	43	57	71	123	176

SENSITIVITY ANALYSIS: TRC SCREENING

This analysis screened out measures that did not pass TRC screening. Electricity rates are assumed at the MID rate scenario and no carbon pricing is applied to oil rates.

Table F- 36: Percent of all customers adopting heat pump technologies (MID electricity rates, no carbon pricing, TRC screening)

LOWER	2020	2021	2022	2023	2024	2025 to 2029	2030 to 2034	Total
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.000%**
% Residential customers adopting heat pumps for domestic hot water heating	0.001%	0.001%	0.001%	0.001%	0.001%	0.004%	0.004%	**0.011%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.000%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.002%	0.002%	**0.006%**
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Residential customers adopting heat pumps for domestic hot water heating	0.004%	0.004%	0.004%	0.004%	0.004%	0.020%	0.020%	**0.06%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.002%	0.002%	0.002%	0.002%	0.002%	0.011%	0.011%	**0.03%**
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2025 to 2029**	**2030 to 2034**	**Total**
% Residential customers adopting DMSHP in electric baseboard households	1.7%	1.7%	1.6%	1.6%	1.5%	4.1%	4.1%	**16.2%**
% Residential customers adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Residential customers adopting heat pumps for domestic hot water heating	0.058%	0.057%	0.057%	0.056%	0.057%	0.283%	0.281%	**0.85%**
% Commercial square footage adopting heat pumps for space heating	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	0.000%	**0.00%**
% Commercial customers adopting heat pumps for domestic hot water heating	0.029%	0.028%	0.028%	0.028%	0.028%	0.139%	0.138%	**0.42%**

Note: Unless otherwise noted, all results represent adoption by non-electric (e.g. oil and wood) space heating / domestic water heating customers.

Table F- 37: Fuel switching cumulative energy impacts (MID electricity rates, no carbon pricing, TRC screening), GWh

LOWER	2020	2021	2022	2023	2024	2029	2034
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net energy impact	-14	-28	-42	-56	-68	-103	-138
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net energy impact	-14	-28	-42	-56	-68	-103	-138
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Energy reductions from electric resistance household adoption of DMSHP	-14	-28	-42	-56	-68	-103	-138
Energy increases from fuel switching (all sectors)	0	0	0	1	1	1	1
Net energy impact	-14	-28	-42	-55	-67	-102	-137

Table F- 38: Fuel switching cumulative demand impacts (MID electricity rates, no carbon pricing, TRC screening), MW

LOWER	2020	2021	2022	2023	2024	2029	2034
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-7	-14	-20	-27	-33	-50	-67
MID	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-7	-14	-20	-27	-33	-50	-66
UPPER	**2020**	**2021**	**2022**	**2023**	**2024**	**2029**	**2034**
Demand reductions from electric resistance household adoption of DMSHP	-7	-14	-20	-27	-33	-50	-67
Demand increases from fuel switching (all sectors)	0	0	0	0	0	0	0
Net demand impact	-7	-14	-20	-27	-33	-49	-66

ELECTRIC VEHICLE ADOPTION DETAILED RESULTS TABLES

Table F- 39: Adoption Under Baseline Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Vehicle Sales	LDV Personal	PHEVs	76	178	200	278	347	542	806	993	1,210	1,415	1,615	1,810	1,994	2,157	2,328	2,438
		BEVs	80	123	210	358	505	559	606	682	738	774	803	829	844	858	869	861
		EVs	156	301	410	636	853	1,100	1,412	1,675	1,948	2,189	2,418	2,638	2,838	3,015	3,197	3,299
	LDV Commercial	PHEVs	20	34	49	66	108	149	195	244	329	412	499	603	702	789	891	953
		BEVs	3	9	17	27	45	68	103	142	195	249	302	355	402	446	489	510
		EVs	23	43	66	94	153	217	299	386	524	661	801	958	1,104	1,235	1,381	1,463
	MDV	BEVs	0	1	2	9	21	44	77	117	161	212	268	331	396	457	550	617
	HDV	BEVs	-	-	-	0	0	1	3	6	10	14	19	28	37	46	55	64
	Bus	BEVs	0	1	1	3	4	6	9	12	15	18	22	25	29	33	37	40
	Total	EVs	180	345	479	741	1,031	1,369	1,800	2,196	2,658	3,094	3,528	3,981	4,405	4,786	5,220	5,484
Cumulative Vehicle Sales	LDV Personal	PHEVs	122	300	501	778	1,126	1,667	2,473	3,466	4,676	6,091	7,706	9,515	11,509	13,666	15,995	18,432
		BEVs	121	244	454	811	1,317	1,875	2,481	3,163	3,902	4,676	5,479	6,308	7,152	8,010	8,879	9,740
		EVs	243	544	954	1,590	2,442	3,542	4,954	6,629	8,577	10,767	13,185	15,823	18,662	21,676	24,874	28,173
	LDV Commercial	PHEVs	20	54	103	169	277	426	621	865	1,194	1,606	2,106	2,709	3,410	4,199	5,091	6,044
		BEVs	3	12	28	56	101	169	272	414	609	858	1,159	1,515	1,917	2,363	2,852	3,362
		EVs	23	66	131	225	378	595	894	1,279	1,803	2,464	3,265	4,223	5,327	6,562	7,943	9,406
	MDV	BEVs	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
	HDV	BEVs	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
	Bus	BEVs	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
	Total	EVs	267	612	1,091	1,832	2,863	4,233	6,033	8,228	10,886	13,981	17,508	21,489	25,894	30,680	35,901	41,385
% Annual Sales	LDV Personal	PHEVs	0%	1%	1%	1%	1%	2%	3%	3%	4%	5%	5%	6%	6%	7%	7%	7%
		BEVs	0%	0%	1%	1%	2%	2%	2%	2%	3%	3%	3%	3%	3%	3%	3%	3%
		EVs	1%	1%	2%	2%	3%	4%	5%	6%	7%	7%	8%	8%	9%	9%	10%	10%
	LDV Commercial	PHEVs	0%	0%	0%	1%	1%	1%	2%	2%	3%	3%	4%	5%	5%	6%	6%	7%
		BEVs	0%	0%	0%	0%	0%	1%	1%	1%	2%	2%	2%	3%	3%	3%	3%	4%
		EVs	0%	0%	1%	1%	1%	2%	3%	3%	4%	5%	6%	7%	8%	9%	10%	11%
	MDV	BEVs	0%	0%	0%	0%	1%	2%	3%	5%	7%	9%	11%	13%	15%	17%	20%	22%
	HDV	BEVs	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	7%	10%	12%	14%	16%
	Bus	BEVs	0%	1%	1%	2%	4%	6%	8%	10%	12%	15%	17%	20%	23%	25%	27%	29%
Energy Consumption (GWh)	LDV Personal	PHEVs	0.23	0.57	0.96	1.51	2.22	3.32	4.97	7.04	9.59	12.60	16.05	19.96	24.29	28.99	34.10	39.45
		BEVs	0.46	0.94	1.75	3.17	5.21	7.49	10.01	12.85	15.94	19.22	22.65	26.21	29.86	33.58	37.38	41.15
		EVs	0.69	1.51	2.71	4.68	7.43	10.81	14.98	19.88	25.53	31.82	38.70	46.17	54.14	62.58	71.48	80.60
	LDV Commercial	PHEVs	0.06	0.15	0.30	0.50	0.84	1.32	1.97	2.78	3.91	5.34	7.08	9.21	11.69	14.50	17.68	21.10
		BEVs	0.02	0.06	0.16	0.32	0.61	1.05	1.73	2.68	4.01	5.74	7.85	10.36	13.21	16.38	19.87	23.51
		EVs	0.07	0.22	0.46	0.82	1.44	2.37	3.70	5.46	7.92	11.08	14.93	19.56	24.90	30.88	37.55	44.61
	MDV	BEVs	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
	HDV	BEVs	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
	Bus	BEVs	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
	Total	EVs	1	2	3	6	10	16	25	36	51	69	90	116	147	182	222	266

Table F- 40: Adoption Under the sample $5M Investment Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Vehicle Sales	LDV Personal	PHEVs	76	210	270	432	557	829	1,121	1,202	1,345	1,743	2,075	4,415	5,470	6,262	7,013	7,536
		BEVs	79	157	320	655	1,140	1,685	2,536	3,540	4,410	5,983	7,301	5,606	5,249	5,097	5,015	4,862
		EVs	**156**	**367**	**589**	**1,087**	**1,697**	**2,514**	**3,657**	**4,742**	**5,755**	**7,726**	**9,377**	**10,020**	**10,719**	**11,359**	**12,029**	**12,398**
	LDV Commercial	PHEVs	20	41	70	114	215	340	502	687	973	1,467	1,971	2,410	2,839	3,223	3,674	3,956
		BEVs	3	11	24	47	90	155	265	398	574	879	1,177	1,395	1,585	1,765	1,927	2,000
		EVs	**23**	**52**	**94**	**161**	**305**	**495**	**768**	**1,085**	**1,547**	**2,346**	**3,149**	**3,804**	**4,424**	**4,988**	**5,602**	**5,955**
	MDV	BEVs	0	1	2	9	22	45	80	122	169	224	286	356	430	500	607	685
	HDV	BEVs	-	-	-	0	0	1	3	6	10	15	20	30	40	51	61	71
	Bus	BEVs	0	1	1	3	4	7	9	12	15	19	23	27	32	36	41	45
	Total	EVs	**179**	**421**	**687**	**1,259**	**2,028**	**3,063**	**4,517**	**5,967**	**7,497**	**10,330**	**12,855**	**14,238**	**15,645**	**16,934**	**18,339**	**19,155**
Cumulative Vehicle Sales	LDV Personal	PHEVs	122	332	602	1,034	1,591	2,419	3,541	4,742	6,087	7,831	9,906	14,321	19,791	26,052	33,066	40,602
		BEVs	120	277	597	1,252	2,392	4,077	6,613	10,153	14,564	20,546	27,848	33,453	38,703	43,800	48,815	53,677
		EVs	**243**	**610**	**1,199**	**2,286**	**3,983**	**6,497**	**10,154**	**14,896**	**20,651**	**28,377**	**37,754**	**47,775**	**58,493**	**69,852**	**81,881**	**94,279**
	LDV Commercial	PHEVs	20	61	131	245	460	800	1,302	1,989	2,962	4,429	6,400	8,810	11,649	14,872	18,547	22,502
		BEVs	3	14	38	85	174	329	595	993	1,567	2,446	3,623	5,018	6,603	8,368	10,295	12,295
		EVs	**23**	**75**	**169**	**330**	**634**	**1,129**	**1,897**	**2,982**	**4,529**	**6,875**	**10,024**	**13,828**	**18,252**	**23,240**	**28,842**	**34,797**
	MDV	BEVs	0	1	4	13	34	80	160	281	450	674	960	1,315	1,746	2,246	2,853	3,539
	HDV	BEVs	-	-	-	0	0	1	5	11	22	37	57	87	128	178	239	310
	Bus	BEVs	0	1	2	5	9	16	25	37	52	71	94	122	153	190	230	275
	Total	EVs	**266**	**687**	**1,374**	**2,634**	**4,661**	**7,724**	**12,240**	**18,207**	**25,704**	**36,034**	**48,889**	**63,127**	**78,772**	**95,706**	**114,045**	**133,200**
% Annual Sales	LDV Personal	PHEVs	0%	1%	1%	2%	2%	3%	4%	4%	5%	6%	7%	14%	17%	19%	21%	23%
		BEVs	0%	1%	1%	3%	4%	6%	9%	12%	15%	20%	24%	18%	17%	16%	15%	15%
		EVs	**1%**	**1%**	**2%**	**4%**	**6%**	**9%**	**13%**	**17%**	**20%**	**26%**	**31%**	**32%**	**34%**	**35%**	**36%**	**37%**
	LDV Commercial	PHEVs	0%	0%	1%	1%	2%	3%	4%	6%	8%	12%	15%	18%	21%	23%	26%	29%
		BEVs	0%	0%	0%	0%	1%	1%	2%	3%	5%	7%	9%	11%	12%	13%	14%	15%
		EVs	**0%**	**0%**	**1%**	**1%**	**3%**	**4%**	**6%**	**9%**	**12%**	**19%**	**24%**	**29%**	**33%**	**36%**	**40%**	**43%**
	MDV	BEVs	0%	0%	0%	0%	1%	2%	3%	5%	7%	9%	11%	14%	17%	19%	23%	25%
	HDV	BEVs	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	8%	10%	13%	15%	17%
	Bus	BEVs	0%	1%	1%	2%	4%	6%	8%	10%	13%	16%	19%	22%	25%	27%	30%	33%
Energy Consumption (GWh)	LDV Personal	PHEVs	0.23	0.63	1.15	2.01	3.14	4.82	7.09	9.57	12.40	16.12	20.59	30.13	42.01	55.68	71.06	87.61
		BEVs	0.45	1.07	2.31	4.91	9.51	16.41	26.95	41.73	60.28	85.64	116.82	140.92	163.63	185.80	207.72	229.01
		EVs	**0.69**	**1.70**	**3.46**	**6.92**	**12.65**	**21.22**	**34.03**	**51.30**	**72.68**	**101.77**	**137.41**	**171.05**	**205.63**	**241.47**	**278.78**	**316.62**
	LDV Commercial	PHEVs	0.06	0.17	0.38	0.73	1.41	2.50	4.16	6.47	9.81	14.90	21.79	30.29	40.34	51.82	64.95	79.13
		BEVs	0.02	0.08	0.21	0.49	1.05	2.06	3.81	6.48	10.42	16.52	24.77	34.61	45.86	58.43	72.21	86.51
		EVs	**0.07**	**0.25**	**0.59**	**1.22**	**2.46**	**4.56**	**7.98**	**12.96**	**20.22**	**31.42**	**46.56**	**64.90**	**86.21**	**110.25**	**137.16**	**165.64**
	MDV	BEVs	0.01	0.03	0.09	0.29	0.78	1.80	3.59	6.33	10.13	15.17	21.59	29.60	39.28	50.53	64.19	79.62
	HDV	BEVs	-	-	-	0.00	0.03	0.22	0.79	1.84	3.51	5.94	9.25	14.18	20.77	29.00	38.88	50.44
	Bus	BEVs	0.02	0.07	0.19	0.40	0.76	1.29	2.03	3.00	4.23	5.77	7.63	9.85	12.42	15.35	18.64	22.25
	Total	EVs	**0.78**	**2.06**	**4.33**	**8.83**	**16.67**	**29.11**	**48.42**	**75.42**	**110.78**	**160.06**	**222.45**	**289.58**	**364.30**	**446.61**	**537.64**	**634.57**

Table F- 41: Adoption Under the sample $20M Investment Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Annual Vehicle Sales	LDV Personal	PHEVs	122	219	290	474	622	910	1,267	1,362	1,703	2,006	2,203	2,392	2,596	2,714	2,844	4,733
		BEVs	121	166	346	723	1,275	1,939	2,920	4,044	5,551	6,820	7,661	8,495	9,244	9,980	10,553	8,802
		EVs	**243**	**385**	**637**	**1,197**	**1,897**	**2,849**	**4,187**	**5,406**	**7,255**	**8,826**	**9,863**	**10,888**	**11,840**	**12,694**	**13,397**	**13,536**
	LDV Commercial	PHEVs	20	43	75	125	238	381	567	769	1,196	1,633	2,001	2,447	2,882	3,273	3,731	4,016
		BEVs	3	11	26	52	100	174	300	445	706	978	1,196	1,416	1,609	1,792	1,957	2,030
		EVs	**23**	**54**	**101**	**176**	**338**	**555**	**867**	**1,214**	**1,902**	**2,611**	**3,197**	**3,863**	**4,492**	**5,064**	**5,688**	**6,046**
	MDV	BEVs	0	1	2	9	22	45	80	122	169	224	286	356	430	500	607	685
	HDV	BEVs	-	-	-	0	0	1	3	6	10	15	20	30	40	51	61	71
	Bus	BEVs	0	1	1	3	4	7	9	12	15	19	23	27	32	36	41	45
	Total	EVs	**267**	**441**	**742**	**1,385**	**2,261**	**3,457**	**5,147**	**6,760**	**9,351**	**11,695**	**13,389**	**15,164**	**16,834**	**18,345**	**19,793**	**20,383**
Cumulative Vehicle Sales	LDV Personal	PHEVs	122	341	632	1,106	1,728	2,638	3,905	5,267	6,970	8,976	11,179	13,571	16,167	18,881	21,725	26,458
		BEVs	121	287	633	1,356	2,631	4,570	7,490	11,534	17,085	23,905	31,566	40,061	49,305	59,285	69,838	78,640
		EVs	**243**	**628**	**1,265**	**2,462**	**4,359**	**7,208**	**11,395**	**16,801**	**24,055**	**32,881**	**42,745**	**53,633**	**65,473**	**78,166**	**91,563**	**105,099**
	LDV Commercial	PHEVs	20	63	139	263	502	883	1,450	2,219	3,414	5,047	7,049	9,495	12,378	15,650	19,381	23,397
		BEVs	3	14	40	91	191	365	665	1,110	1,815	2,794	3,989	5,405	7,014	8,806	10,763	12,794
		EVs	**23**	**77**	**178**	**355**	**693**	**1,247**	**2,115**	**3,328**	**5,230**	**7,841**	**11,038**	**14,900**	**19,392**	**24,456**	**30,144**	**36,190**
	MDV	BEVs	0	1	4	13	34	80	160	281	450	674	960	1,315	1,746	2,246	2,853	3,539
	HDV	BEVs	-	-	-	0	0	1	5	11	22	37	57	87	128	178	239	310
	Bus	BEVs	0	1	2	5	9	16	25	37	52	71	94	122	153	190	230	275
	Total	EVs	**267**	**708**	**1,449**	**2,835**	**5,096**	**8,552**	**13,699**	**20,459**	**29,809**	**41,504**	**54,893**	**70,057**	**86,891**	**105,237**	**125,029**	**145,413**
% Annual Sales	LDV Personal	PHEVs	0%	1%	1%	2%	2%	3%	4%	5%	6%	7%	7%	8%	8%	8%	9%	14%
		BEVs	0%	1%	1%	3%	5%	7%	10%	14%	19%	23%	25%	27%	29%	31%	32%	27%
		EVs	**1%**	**2%**	**2%**	**4%**	**7%**	**10%**	**15%**	**19%**	**25%**	**29%**	**32%**	**35%**	**37%**	**39%**	**40%**	**41%**
	LDV Commercial	PHEVs	0%	0%	1%	1%	2%	3%	5%	6%	10%	13%	15%	19%	21%	24%	27%	29%
		BEVs	0%	0%	0%	0%	1%	1%	3%	4%	6%	8%	9%	11%	12%	13%	14%	15%
		EVs	**0%**	**1%**	**1%**	**2%**	**3%**	**5%**	**7%**	**10%**	**15%**	**21%**	**25%**	**29%**	**33%**	**37%**	**41%**	**44%**
	MDV	BEVs	0%	0%	0%	0%	1%	2%	3%	5%	7%	9%	11%	14%	17%	19%	23%	25%
	HDV	BEVs	0%	0%	0%	0%	0%	0%	1%	2%	3%	4%	5%	8%	10%	13%	15%	17%
	Bus	BEVs	0%	1%	1%	2%	4%	6%	8%	10%	13%	16%	19%	22%	25%	27%	30%	33%
Energy Consumption (GWh)	LDV Personal	PHEVs	0.23	0.65	1.21	2.15	3.42	5.25	7.82	10.63	14.22	18.51	23.25	28.45	34.12	40.09	46.37	56.81
		BEVs	0.46	1.11	2.45	5.32	10.46	18.41	30.55	47.44	70.80	99.73	132.46	169.00	209.02	252.45	298.62	337.20
		EVs	**0.69**	**1.76**	**3.66**	**7.47**	**13.88**	**23.66**	**38.37**	**58.07**	**85.02**	**118.23**	**155.71**	**197.45**	**243.14**	**292.53**	**344.99**	**394.01**
	LDV Commercial	PHEVs	0.06	0.18	0.40	0.78	1.53	2.77	4.64	7.22	11.32	16.99	23.99	32.61	42.82	54.47	67.81	82.20
		BEVs	0.02	0.08	0.23	0.53	1.16	2.28	4.26	7.25	12.09	18.88	27.26	37.25	48.67	61.43	75.42	89.94
		EVs	**0.07**	**0.26**	**0.63**	**1.31**	**2.69**	**5.05**	**8.90**	**14.47**	**23.41**	**35.87**	**51.24**	**69.86**	**91.49**	**115.90**	**143.22**	**172.14**
	MDV	BEVs	0.01	0.03	0.09	0.29	0.78	1.80	3.59	6.33	10.13	15.17	21.59	29.60	39.28	50.53	64.19	79.62
	HDV	BEVs	-	-	-	0.00	0.03	0.22	0.79	1.84	3.51	5.94	9.25	14.18	20.77	29.00	38.88	50.44
	Bus	BEVs	0.02	0.07	0.19	0.40	0.76	1.29	2.03	3.00	4.23	5.77	7.63	9.85	12.42	15.35	18.64	22.25
	Total	EVs	**0.79**	**2.12**	**4.56**	**9.48**	**18.13**	**32.03**	**53.68**	**83.71**	**126.30**	**180.97**	**245.43**	**320.95**	**407.09**	**503.32**	**609.92**	**718.46**

Table F- 42: Cumulative EV Sales by Lever Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	243	544	954	1,590	2,442	3,542	4,954	6,629	8,577	10,767	13,185	15,823	18,662	21,676	24,874	28,173
		LDV Commercial	23	66	131	225	378	595	894	1,279	1,803	2,464	3,265	4,223	5,327	6,562	7,943	9,406
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**612**	**1,091**	**1,832**	**2,863**	**4,233**	**6,033**	**8,228**	**10,886**	**13,981**	**17,508**	**21,489**	**25,894**	**30,680**	**35,901**	**41,385**
DCFC	Low	LDV Personal	243	560	1,015	1,754	2,795	4,215	6,135	8,487	11,434	14,978	19,295	24,895	31,696	38,900	46,527	54,387
		LDV Commercial	23	68	141	250	436	712	1,108	1,641	2,421	3,476	4,887	6,886	9,490	12,403	15,659	19,111
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**266**	**630**	**1,162**	**2,022**	**3,274**	**5,022**	**7,428**	**10,447**	**14,361**	**19,204**	**25,240**	**33,224**	**43,092**	**53,745**	**65,271**	**77,304**
	High	LDV Personal	243	610	1,199	2,251	3,854	6,187	9,529	13,893	19,867	27,590	37,040	47,371	58,504	70,355	82,728	95,418
		LDV Commercial	23	75	169	324	610	1,063	1,752	2,724	4,273	6,514	9,536	13,153	17,319	21,980	27,191	32,714
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**266**	**687**	**1,374**	**2,592**	**4,507**	**7,346**	**11,465**	**16,937**	**24,645**	**34,854**	**47,635**	**61,967**	**77,729**	**94,777**	**113,003**	**131,939**
L2	Low	LDV Personal	244	554	988	1,679	2,630	3,921	5,665	7,821	10,434	13,491	17,068	21,190	26,017	31,136	36,559	42,151
		LDV Commercial	23	67	136	237	407	660	1,023	1,514	2,208	3,120	4,291	5,770	7,624	9,698	12,016	14,474
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**623**	**1,130**	**1,934**	**3,081**	**4,676**	**6,873**	**9,654**	**13,148**	**17,361**	**22,418**	**28,403**	**35,547**	**43,276**	**51,660**	**60,431**
	High	LDV Personal	244	580	1,083	1,933	3,167	5,001	7,679	11,236	15,811	21,445	28,478	37,040	47,847	59,315	71,409	83,859
		LDV Commercial	23	70	150	274	494	853	1,411	2,216	3,423	5,089	7,370	10,411	14,515	19,106	24,238	29,678
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**652**	**1,239**	**2,225**	**3,704**	**5,949**	**9,275**	**13,772**	**19,740**	**27,284**	**36,907**	**48,894**	**64,268**	**80,863**	**98,731**	**117,343**
Incentives	Low	LDV Personal	267	604	1,053	1,737	2,642	3,797	5,222	6,923	8,915	11,171	13,684	16,448	19,443	22,644	26,026	29,486
		LDV Commercial	41	109	202	325	511	765	1,111	1,548	2,133	2,825	3,672	4,695	5,886	7,227	8,734	10,336
		MDV	1	3	8	24	55	114	210	347	527	750	1,035	1,388	1,814	2,307	2,901	3,566
		HDV	-	-	0	0	1	2	7	14	25	40	60	90	130	180	240	309
		Bus	0	1	3	6	10	17	27	39	54	73	96	123	155	191	230	274
		Total	**309**	**717**	**1,266**	**2,091**	**3,219**	**4,695**	**6,576**	**8,871**	**11,654**	**14,859**	**18,547**	**22,745**	**27,428**	**32,549**	**38,131**	**43,970**
	High	LDV Personal	279	648	1,150	1,897	2,900	4,149	5,760	7,458	9,449	11,706	14,221	16,990	19,995	23,210	26,598	30,064
		LDV Commercial	50	137	263	424	672	995	1,427	1,954	2,634	3,326	4,173	5,196	6,386	7,728	9,235	10,837
		MDV	2	6	13	32	70	137	243	389	575	799	1,083	1,437	1,863	2,355	2,949	3,615
		HDV	-	0	0	0	1	3	8	16	27	42	62	92	132	182	242	311
		Bus	0	1	3	6	11	18	28	40	56	75	98	125	156	192	232	275
		Total	**332**	**793**	**1,428**	**2,360**	**3,653**	**5,302**	**7,465**	**9,858**	**12,741**	**15,947**	**19,637**	**23,840**	**28,532**	**33,668**	**39,255**	**45,101**

Table F- 43: Annual EV Energy Consumption (GWh) by Lever Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	0.69	1.51	2.71	4.68	7.43	10.81	14.98	19.88	25.53	31.82	38.70	46.17	54.14	62.58	71.48	80.60
		LDV Commercial	0.07	0.22	0.46	0.82	1.44	2.37	3.70	5.46	7.92	11.08	14.93	19.56	24.90	30.88	37.55	44.61
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.83**	**3.44**	**6.19**	**10.41**	**16.43**	**24.92**	**36.18**	**50.70**	**68.66**	**90.29**	**116.47**	**147.13**	**182.04**	**221.93**	**265.67**
DCFC	Low	LDV Personal	0.69	1.56	2.90	5.21	8.65	13.44	20.06	27.86	37.52	48.87	62.68	80.85	102.71	125.29	148.75	172.53
		LDV Commercial	0.07	0.22	0.49	0.92	1.67	2.85	4.61	7.05	10.71	15.75	22.54	32.20	44.78	58.89	74.64	91.28
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.78**	**1.89**	**3.66**	**6.82**	**11.86**	**19.54**	**30.92**	**45.74**	**65.48**	**90.38**	**121.87**	**163.80**	**215.59**	**272.76**	**336.29**	**404.26**
	High	LDV Personal	0.69	1.70	3.46	6.80	12.21	20.21	31.93	47.81	70.01	99.09	135.02	174.66	217.67	263.84	307.59	350.48
		LDV Commercial	0.07	0.25	0.59	1.20	2.36	4.29	7.34	11.81	19.08	29.77	44.33	61.79	81.93	104.51	129.70	156.33
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.78**	**2.06**	**4.32**	**8.68**	**16.11**	**27.75**	**45.52**	**70.45**	**106.33**	**154.63**	**216.00**	**287.20**	**367.70**	**456.93**	**550.19**	**647.27**
L2	Low	LDV Personal	0.69	1.54	2.81	4.96	8.03	12.06	17.43	23.92	31.66	40.60	51.00	62.92	76.84	91.45	106.89	122.76
		LDV Commercial	0.07	0.22	0.47	0.87	1.56	2.63	4.25	6.50	9.76	14.11	19.75	26.89	35.85	45.90	57.11	68.96
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.87**	**3.56**	**6.52**	**11.13**	**17.94**	**27.93**	**41.25**	**58.66**	**80.49**	**107.41**	**140.56**	**180.79**	**225.93**	**276.90**	**332.18**
	High	LDV Personal	0.69	1.61	3.09	5.73	9.73	15.35	23.50	34.38	48.36	65.55	86.96	113.02	146.12	181.19	217.00	253.43
		LDV Commercial	0.07	0.23	0.53	1.01	1.90	3.43	5.91	9.60	15.27	23.22	34.20	48.89	68.73	90.96	115.78	142.01
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.95**	**3.88**	**7.43**	**13.17**	**22.03**	**35.66**	**54.81**	**80.87**	**114.54**	**157.82**	**212.66**	**282.95**	**360.74**	**445.67**	**535.89**
Incentives	Low	LDV Personal	0.79	1.76	3.11	5.30	8.27	11.81	15.99	20.95	26.71	33.17	40.31	48.11	56.51	65.44	74.84	84.38
		LDV Commercial	0.14	0.39	0.75	1.25	2.02	3.11	4.66	6.68	9.43	12.73	16.80	21.74	27.47	33.94	41.17	48.83
		MDV	0.02	0.07	0.19	0.53	1.24	2.56	4.72	7.81	11.85	16.87	23.28	31.23	40.81	51.90	65.26	80.24
		HDV	-	-	0.00	0.01	0.09	0.37	1.07	2.27	4.04	6.46	9.77	14.67	21.18	29.29	38.95	50.18
		Bus	0.02	0.09	0.21	0.45	0.84	1.40	2.16	3.16	4.41	5.94	7.80	10.00	12.55	15.44	18.65	22.16
		Total	**0.98**	**2.30**	**4.27**	**7.53**	**12.46**	**19.26**	**28.61**	**40.86**	**56.43**	**75.18**	**97.96**	**125.75**	**158.52**	**196.00**	**238.88**	**285.80**
	High	LDV Personal	0.85	1.92	3.47	5.90	9.25	13.04	17.77	22.68	28.40	34.83	41.96	49.75	58.16	67.12	76.51	86.06
		LDV Commercial	0.17	0.50	1.01	1.67	2.71	4.11	6.06	8.48	11.67	14.98	19.05	23.98	29.71	36.18	43.42	51.08
		MDV	0.04	0.13	0.29	0.72	1.57	3.09	5.47	8.76	12.94	17.97	24.37	32.33	41.91	52.99	66.36	81.33
		HDV	-	0.00	0.00	0.02	0.14	0.48	1.26	2.55	4.37	6.80	10.10	15.00	21.51	29.62	39.29	50.52
		Bus	0.03	0.10	0.23	0.49	0.88	1.47	2.25	3.26	4.52	6.05	7.91	10.11	12.66	15.54	18.76	22.27
		Total	**1.08**	**2.65**	**5.00**	**8.79**	**14.57**	**22.18**	**32.81**	**45.73**	**61.91**	**80.63**	**103.39**	**131.17**	**163.95**	**201.46**	**244.33**	**291.26**

Table F- 44: Cumulative EV Sales by Sensitivity Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	243	544	954	1,590	2,442	3,542	4,954	6,629	8,577	10,767	13,185	15,823	18,662	21,676	24,874	28,173
		LDV Commercial	23	66	131	225	378	595	894	1,279	1,803	2,464	3,265	4,223	5,327	6,562	7,943	9,406
		MDV	0	1	4	13	34	78	155	273	434	646	914	1,245	1,641	2,098	2,649	3,266
		HDV	-	-	-	0	0	1	5	11	21	35	54	82	120	166	221	285
		Bus	0	1	2	5	9	16	25	36	51	69	90	116	145	178	215	255
		Total	**267**	**612**	**1,091**	**1,832**	**2,863**	**4,233**	**6,033**	**8,228**	**10,886**	**13,981**	**17,508**	**21,489**	**25,894**	**30,680**	**35,901**	**41,385**
Battery Costs	Low	LDV Personal	244	550	968	1,616	2,491	3,625	5,080	6,810	8,824	11,090	13,593	16,331	19,265	22,384	25,691	29,102
		LDV Commercial	24	69	141	242	410	650	979	1,406	1,980	2,705	3,591	4,660	5,863	7,193	8,638	10,131
		MDV	0	2	5	18	48	109	217	380	609	915	1,306	1,794	2,385	3,084	3,896	4,822
		HDV	-	-	0	0	1	3	9	20	36	58	87	128	181	245	319	404
		Bus	0	1	2	5	10	16	26	38	53	72	95	122	153	188	226	269
		Total	**269**	**622**	**1,116**	**1,882**	**2,959**	**4,403**	**6,310**	**8,654**	**11,502**	**14,840**	**18,672**	**23,036**	**27,847**	**33,093**	**38,771**	**44,729**
	High	LDV Personal	242	541	947	1,573	2,408	3,487	4,868	6,504	8,403	10,529	12,876	15,436	18,179	21,093	24,185	27,372
		LDV Commercial	22	63	125	213	354	557	833	1,192	1,676	2,282	3,022	3,902	4,911	6,040	7,300	8,620
		MDV	0	1	3	10	26	60	118	206	322	471	651	862	1,097	1,340	1,654	1,956
		HDV	-	-	-	-	0	1	2	5	10	18	29	45	68	98	134	178
		Bus	0	1	2	5	9	15	24	35	49	66	87	111	139	171	205	244
		Total	**265**	**607**	**1,077**	**1,801**	**2,797**	**4,119**	**5,845**	**7,942**	**10,461**	**13,365**	**16,665**	**20,357**	**24,394**	**28,742**	**33,479**	**38,369**
Vehicle Availability	Low	LDV Personal	243	468	744	1,170	1,714	2,540	3,603	4,858	6,290	7,948	9,866	12,179	14,779	17,595	20,684	23,928
		LDV Commercial	15	37	65	119	193	299	466	691	982	1,423	2,016	2,785	3,703	4,746	6,018	7,423
		MDV	0	1	4	9	20	40	70	141	253	410	644	953	1,337	1,786	2,332	2,947
		HDV	-	-	-	0	0	1	3	6	11	17	26	36	50	66	85	106
		Bus	0	1	2	5	8	14	23	34	48	66	88	113	142	175	212	252
		Total	**258**	**507**	**815**	**1,302**	**1,935**	**2,895**	**4,165**	**5,730**	**7,585**	**9,865**	**12,639**	**16,066**	**20,010**	**24,368**	**29,331**	**34,657**
	High	LDV Personal	346	833	1,498	2,406	3,536	4,876	6,441	8,224	10,233	12,457	14,894	17,541	20,383	23,399	26,597	29,895
		LDV Commercial	34	94	178	307	488	732	1,066	1,499	2,055	2,736	3,549	4,514	5,623	6,860	8,242	9,706
		MDV	1	3	9	23	53	112	200	325	492	707	977	1,309	1,706	2,164	2,714	3,332
		HDV	-	-	-	0	0	3	7	16	28	46	71	103	142	190	245	310
		Bus	0	1	3	6	11	17	26	38	52	70	92	117	147	180	217	257
		Total	**382**	**932**	**1,688**	**2,742**	**4,088**	**5,740**	**7,741**	**10,101**	**12,861**	**16,017**	**19,582**	**23,585**	**28,001**	**32,793**	**38,015**	**43,499**
Fuel Prices	Low	LDV Personal	235	520	909	1,511	2,319	3,363	4,701	6,287	8,131	10,202	12,487	14,979	17,657	20,522	23,582	26,762
		LDV Commercial	14	44	93	167	294	482	747	1,096	1,583	2,207	2,971	3,897	4,971	6,176	7,532	8,976
		MDV	0	0	1	3	11	33	75	143	239	366	528	728	966	1,229	1,584	1,970
		HDV	-	-	-	-	-	0	0	0	2	5	10	21	38	62	92	132
		Bus	0	1	2	4	9	15	23	34	48	65	86	110	138	170	206	245
		Total	**249**	**565**	**1,004**	**1,686**	**2,633**	**3,893**	**5,545**	**7,560**	**10,002**	**12,844**	**16,082**	**19,736**	**23,771**	**28,159**	**32,996**	**38,085**
	High	LDV Personal	251	569	1,001	1,673	2,573	3,733	5,222	6,989	9,044	11,355	13,907	16,693	19,689	22,853	26,185	29,600
		LDV Commercial	28	79	155	262	433	670	990	1,399	1,947	2,633	3,459	4,439	5,564	6,819	8,216	9,692
		MDV	1	3	7	22	54	115	218	369	575	843	1,179	1,590	2,079	2,644	3,301	4,039
		HDV	-	0	0	0	1	4	10	21	37	57	84	122	170	228	295	371
		Bus	0	1	2	5	10	17	26	38	53	71	93	120	150	183	221	262
		Total	**280**	**651**	**1,167**	**1,963**	**3,071**	**4,538**	**6,466**	**8,816**	**11,656**	**14,960**	**18,723**	**22,963**	**27,651**	**32,727**	**38,219**	**43,964**

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Electricity Rates	Low	LDV Personal	245	550	966	1,613	2,480	3,598	5,035	6,739	8,720	10,948	13,408	16,093	18,982	22,044	25,285	28,621
		LDV Commercial	24	68	137	235	393	616	922	1,315	1,846	2,515	3,323	4,288	5,399	6,640	8,025	9,492
		MDV	0	2	5	16	41	92	178	308	487	720	1,014	1,375	1,807	2,306	2,898	3,563
		HDV	-	-	-	0	0	2	7	15	27	44	66	98	140	191	251	320
		Bus	0	1	2	5	9	16	25	36	51	69	91	116	146	179	216	256
		Total	**269**	**621**	**1,110**	**1,868**	**2,924**	**4,325**	**6,167**	**8,413**	**11,131**	**14,295**	**17,902**	**21,971**	**26,474**	**31,360**	**36,676**	**42,254**
	High	LDV Personal	240	536	938	1,562	2,399	3,480	4,867	6,512	8,424	10,574	12,948	15,538	18,323	21,288	24,440	27,700
		LDV Commercial	21	60	121	210	356	566	857	1,234	1,749	2,400	3,192	4,142	5,239	6,466	7,841	9,300
		MDV	0	1	3	10	27	65	134	238	384	575	818	1,119	1,479	1,894	2,403	2,972
		HDV	-	-	-	-	0	1	3	7	15	26	42	66	99	140	190	249
		Bus	0	1	2	5	9	16	24	36	50	68	90	115	144	177	214	254
		Total	**262**	**597**	**1,064**	**1,786**	**2,791**	**4,128**	**5,884**	**8,027**	**10,622**	**13,644**	**17,090**	**20,980**	**25,284**	**29,966**	**35,088**	**40,475**
Vehicle Sales	Low	LDV Personal	240	529	916	1,503	2,275	3,256	4,487	5,919	7,552	9,351	11,298	13,382	15,580	17,869	20,249	22,655
		LDV Commercial	23	63	125	212	350	543	803	1,132	1,571	2,113	2,757	3,512	4,366	5,302	6,328	7,415
		MDV	0	1	4	12	31	70	138	238	373	547	762	1,023	1,329	1,676	2,085	2,534
		HDV	-	-	-	0	0	1	4	9	18	29	45	67	96	131	172	218
		Bus	0	1	2	5	9	14	22	32	44	59	76	96	119	144	171	200
		Total	263	595	1,047	1,731	2,665	3,885	5,455	7,331	9,557	12,098	14,938	18,081	21,489	25,121	29,004	33,024
	High	LDV Personal	246	559	994	1,681	2,620	3,853	5,467	7,421	9,738	12,393	15,383	18,708	22,355	26,305	30,576	35,075
		LDV Commercial	23	68	137	239	407	651	993	1,444	2,068	2,870	3,862	5,071	6,492	8,113	9,960	11,999
		MDV	0	1	4	14	37	87	175	312	504	762	1,094	1,511	2,021	2,621	3,358	4,200
		HDV	-	-	-	0	0	2	5	13	24	42	65	101	149	210	283	371
		Bus	0	1	2	5	10	17	27	41	58	80	107	139	177	220	269	324
		Total	270	629	1,137	1,938	3,074	4,609	6,669	9,231	12,393	16,147	20,510	25,530	31,194	37,469	44,447	51,968

Table F- 45: Annual EV Energy Consumption (GWh) by Sensitivity Scenario

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		LDV Personal	0.69	1.51	2.71	4.68	7.43	10.81	14.98	19.88	25.53	31.82	38.70	46.17	54.14	62.58	71.48	80.60
		LDV Commercial	0.07	0.22	0.46	0.82	1.44	2.37	3.70	5.46	7.92	11.08	14.93	19.56	24.90	30.88	37.55	44.61
		MDV	0.01	0.03	0.09	0.28	0.76	1.76	3.50	6.13	9.76	14.54	20.57	28.01	36.93	47.21	59.59	73.48
		HDV	-	-	-	0.00	0.02	0.22	0.76	1.78	3.37	5.67	8.78	13.37	19.43	26.95	35.91	46.32
		Bus	0.02	0.07	0.18	0.40	0.75	1.28	1.99	2.92	4.10	5.56	7.31	9.37	11.74	14.42	17.39	20.65
		Total	**0.79**	**1.83**	**3.44**	**6.19**	**10.41**	**16.43**	**24.92**	**36.18**	**50.70**	**68.66**	**90.29**	**116.47**	**147.13**	**182.04**	**221.93**	**265.67**
Battery Costs	Low	LDV Personal	0.70	1.55	2.80	4.89	7.81	11.40	15.79	20.93	26.85	33.45	40.67	48.51	56.85	65.68	74.99	84.52
		LDV Commercial	0.08	0.24	0.52	0.94	1.66	2.73	4.26	6.31	9.14	12.76	17.22	22.51	28.43	34.94	41.98	49.21
		MDV	0.01	0.04	0.12	0.40	1.08	2.45	4.88	8.56	13.70	20.58	29.39	40.37	53.67	69.38	87.66	108.50
		HDV	-	-	0.00	0.01	0.14	0.52	1.51	3.25	5.86	9.47	14.16	20.86	29.44	39.83	51.92	65.64
		Bus	0.02	0.08	0.19	0.42	0.79	1.33	2.08	3.06	4.30	5.84	7.69	9.86	12.37	15.19	18.34	21.78
		Total	**0.80**	**1.90**	**3.63**	**6.65**	**11.48**	**18.43**	**28.52**	**42.12**	**59.86**	**82.10**	**109.13**	**142.11**	**180.76**	**225.03**	**274.89**	**329.65**
	High	LDV Personal	0.68	1.49	2.65	4.54	7.16	10.39	14.37	19.03	24.43	30.44	37.04	44.20	51.83	59.89	68.41	77.13
		LDV Commercial	0.07	0.20	0.42	0.74	1.29	2.11	3.27	4.83	7.00	9.76	13.17	17.26	21.96	27.24	33.12	39.28
		MDV	0.01	0.03	0.07	0.22	0.58	1.34	2.66	4.63	7.26	10.59	14.65	19.40	24.68	30.15	37.23	44.02
		HDV	-	-	-	-	0.00	0.08	0.33	0.83	1.65	2.90	4.66	7.38	11.12	15.91	21.78	28.86
		Bus	0.02	0.07	0.18	0.39	0.73	1.24	1.93	2.82	3.96	5.36	7.03	9.00	11.26	13.81	16.64	19.74
		Total	**0.78**	**1.79**	**3.32**	**5.90**	**9.76**	**15.16**	**22.56**	**32.15**	**44.29**	**59.04**	**76.56**	**97.24**	**120.85**	**147.01**	**177.18**	**209.02**
Vehicle Availability	Low	LDV Personal	0.69	1.37	2.23	3.44	5.09	7.50	10.67	14.38	18.58	23.35	28.74	35.16	42.45	50.35	59.02	68.08
		LDV Commercial	0.05	0.13	0.23	0.41	0.69	1.09	1.75	2.71	4.01	5.95	8.52	12.02	16.31	21.26	27.35	34.10
		MDV	0.01	0.03	0.09	0.21	0.45	0.91	1.58	3.17	5.70	9.23	14.48	21.44	30.08	40.20	52.48	66.31
		HDV	-	-	-	0.00	0.02	0.22	0.55	1.06	1.79	2.82	4.18	5.93	8.10	10.71	13.77	17.30
		Bus	0.02	0.07	0.18	0.37	0.66	1.14	1.83	2.74	3.91	5.36	7.11	9.16	11.53	14.21	17.18	20.44
		Total	**0.76**	**1.60**	**2.73**	**4.44**	**6.91**	**10.86**	**16.38**	**24.06**	**33.99**	**46.71**	**63.03**	**83.71**	**108.46**	**136.72**	**169.81**	**206.24**
	High	LDV Personal	0.94	2.34	4.29	7.04	10.46	14.39	18.93	24.08	29.83	36.14	43.01	50.44	58.37	66.76	75.61	84.69
		LDV Commercial	0.11	0.32	0.62	1.12	1.87	2.92	4.42	6.43	9.05	12.31	16.23	20.89	26.25	32.24	38.93	45.99
		MDV	0.02	0.07	0.20	0.52	1.19	2.52	4.50	7.31	11.06	15.91	21.99	29.46	38.39	48.68	61.07	74.97
		HDV	-	-	-	0.00	0.05	0.47	1.20	2.53	4.59	7.54	11.52	16.66	23.07	30.80	39.88	50.37
		Bus	0.03	0.10	0.24	0.49	0.86	1.40	2.12	3.06	4.25	5.70	7.46	9.52	11.89	14.57	17.54	20.80
		Total	**1.10**	**2.83**	**5.36**	**9.17**	**14.42**	**21.70**	**31.19**	**43.42**	**58.78**	**77.60**	**100.20**	**126.97**	**157.97**	**193.06**	**233.04**	**276.81**
Fuel Prices	Low	LDV Personal	0.65	1.41	2.52	4.34	6.88	10.07	13.97	18.57	23.90	29.86	36.42	43.56	51.20	59.34	67.97	76.86
		LDV Commercial	0.04	0.13	0.29	0.56	1.04	1.80	2.94	4.51	6.76	9.70	13.35	17.79	22.96	28.78	35.33	42.29
		MDV	0.00	0.00	0.01	0.07	0.25	0.74	1.68	3.21	5.37	8.24	11.88	16.38	21.74	27.65	35.65	44.34
		HDV	-	-	-	-	-	0.00	0.01	0.06	0.27	0.76	1.69	3.43	6.16	9.99	15.00	21.47
		Bus	0.02	0.06	0.16	0.36	0.69	1.19	1.86	2.75	3.88	5.27	6.95	8.93	11.22	13.80	16.68	19.83
		Total	**0.71**	**1.61**	**2.98**	**5.33**	**8.86**	**13.80**	**20.46**	**29.11**	**40.17**	**53.83**	**70.29**	**90.10**	**113.27**	**139.57**	**170.62**	**204.79**
	High	LDV Personal	0.73	1.61	2.91	5.03	7.96	11.48	15.82	20.90	26.75	33.27	40.41	48.17	56.46	65.19	74.35	83.70
		LDV Commercial	0.09	0.28	0.57	1.01	1.72	2.75	4.19	6.09	8.68	11.98	15.97	20.73	26.18	32.26	39.03	46.15
		MDV	0.02	0.06	0.16	0.49	1.22	2.59	4.90	8.31	12.95	18.97	26.53	35.77	46.77	59.48	74.28	90.87
		HDV	-	0.00	0.00	0.05	0.24	0.66	1.70	3.43	5.93	9.32	13.67	19.81	27.62	37.03	47.95	60.34
		Bus	0.02	0.08	0.20	0.43	0.80	1.34	2.08	3.05	4.27	5.77	7.57	9.69	12.12	14.86	17.91	21.23
		Total	**0.85**	**2.03**	**3.85**	**7.01**	**11.93**	**18.82**	**28.69**	**41.77**	**58.58**	**79.31**	**104.15**	**134.15**	**169.15**	**208.82**	**253.51**	**302.28**

			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Electricity Rates	Low	LDV Personal	0.70	1.54	2.76	4.78	7.59	11.04	15.28	20.25	25.96	32.32	39.28	46.84	54.92	63.45	72.43	81.63
		LDV Commercial	0.07	0.23	0.49	0.87	1.52	2.48	3.84	5.65	8.15	11.35	15.25	19.92	25.29	31.30	38.00	45.08
		MDV	0.01	0.04	0.11	0.36	0.93	2.06	4.01	6.94	10.95	16.20	22.81	30.94	40.66	51.89	65.21	80.17
		HDV	-	-	-	0.00	0.08	0.37	1.11	2.42	4.39	7.14	10.76	15.99	22.77	31.06	40.83	52.06
		Bus	0.02	0.07	0.19	0.41	0.76	1.29	2.01	2.95	4.13	5.60	7.36	9.43	11.81	14.50	17.49	20.76
		Total	**0.80**	**1.88**	**3.54**	**6.42**	**10.88**	**17.24**	**26.26**	**38.20**	**53.59**	**72.61**	**95.46**	**123.12**	**155.45**	**192.20**	**233.97**	**279.70**
	High	LDV Personal	0.68	1.48	2.64	4.56	7.23	10.55	14.63	19.44	24.99	31.20	38.00	45.37	53.24	61.57	70.39	79.43
		LDV Commercial	0.06	0.19	0.41	0.75	1.34	2.22	3.50	5.22	7.63	10.74	14.54	19.12	24.42	30.36	37.00	44.04
		MDV	0.01	0.02	0.06	0.22	0.61	1.47	3.01	5.37	8.63	12.95	18.41	25.17	33.29	42.63	54.06	66.86
		HDV	-	-	-	-	0.00	0.11	0.46	1.18	2.39	4.23	6.81	10.73	16.05	22.77	30.88	40.45
		Bus	0.02	0.07	0.18	0.39	0.74	1.26	1.97	2.90	4.07	5.52	7.26	9.31	11.67	14.34	17.31	20.55
		Total	**0.76**	**1.76**	**3.29**	**5.92**	**9.92**	**15.61**	**23.57**	**34.11**	**47.73**	**64.63**	**85.02**	**109.70**	**138.66**	**171.67**	**209.64**	**251.34**
Vehicle Sales	Low	LDV Personal	0.68	1.47	2.60	4.42	6.91	9.99	13.67	17.90	22.68	27.90	33.51	39.47	45.72	52.20	58.92	65.67
		LDV Commercial	0.07	0.21	0.44	0.77	1.34	2.16	3.31	4.82	6.88	9.47	12.57	16.22	20.34	24.88	29.84	35.08
		MDV	0.01	0.03	0.08	0.27	0.70	1.58	3.09	5.34	8.38	12.30	17.15	23.02	29.91	37.70	46.91	57.02
		HDV	-	-	-	0.00	0.02	0.19	0.67	1.54	2.87	4.75	7.26	10.87	15.56	21.26	27.91	35.50
		Bus	0.02	0.07	0.18	0.37	0.69	1.16	1.78	2.58	3.56	4.76	6.17	7.79	9.62	11.65	13.86	16.24
		Total	**0.77**	**1.78**	**3.29**	**5.83**	**9.66**	**15.09**	**22.52**	**32.18**	**44.38**	**59.18**	**76.65**	**97.37**	**121.15**	**147.70**	**177.44**	**209.51**
	High	LDV Personal	0.70	1.55	2.82	4.95	7.98	11.70	16.43	22.10	28.75	36.30	44.73	54.03	64.16	75.08	86.81	99.18
		LDV Commercial	0.07	0.22	0.48	0.87	1.56	2.60	4.12	6.18	9.11	12.94	17.72	23.56	30.43	38.28	47.21	57.04
		MDV	0.01	0.03	0.09	0.30	0.83	1.95	3.94	7.02	11.35	17.14	24.61	34.00	45.48	58.98	75.55	94.50
		HDV	-	-	-	0.00	0.03	0.24	0.87	2.05	3.95	6.74	10.60	16.39	24.19	34.06	46.04	60.25
		Bus	0.02	0.08	0.19	0.43	0.81	1.40	2.22	3.31	4.72	6.48	8.65	11.25	14.30	17.82	21.80	26.24
		Total	**0.80**	**1.89**	**3.59**	**6.56**	**11.21**	**17.90**	**27.57**	**40.66**	**57.88**	**79.61**	**106.30**	**139.23**	**178.56**	**224.21**	**277.41**	**337.21**

Table F- 46: EV Charging Hourly Load Profile (MW) in 2034 under Unmanaged Charging by Scenario

		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23
Baseline		106	88	63	39	21	11	9	10	14	20	29	39	46	50	51	53	58	71	87	102	111	114	115	113
DCFC	Low	160	133	95	59	33	18	15	17	24	32	44	58	67	74	77	79	89	108	135	160	175	177	179	174
	High	242	202	144	90	50	28	24	26	38	50	68	87	100	110	114	119	134	165	207	248	272	274	276	266
Incentives	Low	134	111	80	49	27	15	12	13	19	27	37	49	57	63	64	67	74	90	112	133	145	147	148	145
	High	221	184	132	82	46	25	21	24	34	45	62	80	92	101	105	109	122	151	188	225	246	249	251	242
Level 2	Low	113	94	68	41	22	12	10	11	15	22	31	42	49	54	55	57	63	76	93	109	119	121	123	120
	High	116	96	69	42	23	12	10	11	16	22	32	43	50	55	56	58	64	77	95	112	121	124	126	123
$5M Investment		209	149	93	52	29	24	27	38	51	70	91	104	115	119	124	139	171	213	255	279	282	284	275	251
$20M Investment		267	222	158	99	55	31	26	29	41	55	74	96	110	121	126	131	147	182	228	273	299	302	303	293

Table F- 47: EV Peak Load Impact (MW) in 2034 under Unmanaged Charging by Scenario

		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
Baseline		0.39	0.93	1.68	2.90	4.68	7.30	10.94	15.66	21.66	29.10	37.90	48.38	60.52	74.16	89.51	106.08
DCFC	Low	0.39	0.96	1.80	3.19	5.31	8.43	12.93	18.85	26.77	36.85	49.62	66.62	87.80	111.30	137.46	165.45
	High	0.39	1.04	2.12	4.05	7.18	11.99	19.16	28.92	42.88	61.62	85.41	112.90	143.90	178.11	215.63	255.40
Incentives	Low	0.48	1.14	2.05	3.45	5.49	8.33	12.23	17.25	23.58	31.14	40.25	51.24	64.10	78.71	95.29	113.33
	High	0.52	1.29	2.37	3.99	6.37	9.61	14.08	19.42	26.06	33.62	42.72	53.72	66.59	81.22	97.82	115.86
Level 2	Low	0.39	0.95	1.75	3.06	5.01	7.90	12.08	17.63	24.88	33.94	45.10	58.78	75.39	93.95	114.75	137.16
	High	0.40	0.99	1.92	3.49	5.96	9.85	15.79	24.03	35.24	49.69	68.34	91.98	122.38	155.89	192.83	232.06
Proposed $5M Investment		0.39	1.04	2.11	4.11	7.41	12.63	20.47	31.03	44.64	63.57	87.30	114.35	144.74	178.16	214.95	253.88
Proposed $20M Investment		0.39	1.07	2.23	4.42	8.09	13.86	22.65	34.49	51.17	72.48	97.49	126.69	159.93	196.90	237.79	280.98

Table F- 48: Cost Effectiveness of Modeled Scenarios Under Unmanaged and Managed Charging Load by 2034

		Unmanaged EV Load				EV Load Management			
		Benefits	Costs	BCR	NPV	Benefits	Costs	BCR	NPV
Baseline		$119,480,561	$(163,207,702)	**0.73**	**$(43,727,141)**	$119,480,561	$ (51,535,943)	**2.32**	**$ 67,944,618**
DCFC	**Low**	$51,428,913	$(71,873,727)	**0.72**	**$(20,444,813)**	$ 51,428,913	$(25,052,041)	**2.05**	**$ 26,376,872**
	High	$162,812,613	$(221,649,090)	**0.73**	**$(58,836,477)**	$ 162,812,613	$ (80,486,027)	**2.02**	**$ 82,326,586**
Level 2	**Low**	$25,468,957	$(40,093,007)	**0.64**	**$(14,624,050)**	$ 25,468,957	$ (14,470,629)	**1.76**	**$ 10,998,328**
	High	$102,085,295	$(164,390,738)	**0.62**	**$(62,305,443)**	$ 102,085,295	$(58,551,075)	**1.74**	**$ 43,534,220**
Incentives	**Low**	$10,634,373	$(16,158,335)	**0.66**	**$(5,523,962)**	$ 10,634,373	$(8,029,117)	**1.32**	**$ 2,605,256**
	High	$16,937,965	$(36,481,899)	**0.46**	**$(19,543,933)**	$16,937,965	$ (21,922,482)	**0.77**	**$ (4,984,516)**
		$157,093,300.56	$(214,506,952.87)	**0.73**	**$(57,413,652.30)**	$157,093,301	$(70,738,954.38)	**2.22**	**$86,354,346.18**
$20M Investment		$197,333,549	$(267,591,522)	**0.74**	**$ (70,257,973)**	$197,333,549	$(95,635,637.66)	**2.06**	**$ 101,697,911.59**

Schedule D
Electric Vehicle Overview

Electric Vehicle Overview

Introduction

Customers consider many factors when purchasing a vehicle including price, operating costs and lifestyle. Since 2010, electric vehicles ("EVs") have become an increasingly competitive option in the vehicle marketplace.

EV growth is commonly driven by: (i) investments in charging infrastructure, (ii) financial incentives, and, (iii) public education and awareness initiatives.

The Muskrat Falls project will connect the province to the North American electricity grid. As a result, surplus electricity will be available in Newfoundland and Labrador to fuel an EV market. The net revenue gained from domestic sales could be used to provide rate mitigating benefits to customers.

Electric Vehicles Technologies

An EV is an alternative fuel vehicle that uses an electric motor for propulsion instead of more common propulsion systems based on gas powered internal combustion engines. EVs contain batteries that store electricity which powers the vehicle's wheels via an electric motor. An EV that travels 20,000 km/year would use approximately the same amount of electricity every year as a typical electric water heater. This equates to a cost of approximately $0.03/km for an EV compared to a cost of approximately $0.12/km for a conventional vehicle. [1]

There are two major types of EVs:

Battery Electric Vehicle

("BEV") – this type of vehicle has an engine and is propelled by electricity that comes from one or several high capacity batteries. BEVs are powered by electricity by plugging in to an electrical outlet or specialty Electric Vehicle Charging Equipment ("EVCE").

Plug-in Hybrid Electric Vehicle

("PHEV") – this type of vehicle combines a gasoline or diesel engine with an electric motor and a rechargeable battery. Modern PHEVs can be driven in electric mode over varying distances before the combustion engine is required. Unlike earlier hybrids that use gasoline as their main power source, PHEVs can be plugged-in and recharged from an outlet, allowing them to drive extended distances using only electricity.

Refuel or Recharge

Vehicle Type	Gasoline	Electricity
Gas Only	X	
PHEV	X	X
BEV		X

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1 This is based on the efficiency of an internal combustion engine vehicle of 0.1 L/km, and the price of self-serve gasoline of $1.163 per/L on the Avalon Peninsula, as approved by the Board on December 10, 2020. Electric vehicle costs are based on the efficiency of a battery electric vehicle of 0.18 kWh/km and a residential customer price of electricity of $0.12203/kWh plus HST ($0.14/kWh).

The primary difference between a BEV and a PHEV is the driving range. A BEV's driving range is limited by the storage capacity of its battery and availability of charging infrastructure. A PHEV is equipped with a fuel tank and an internal combustion engine which allows for an increased driving range.[2]

EV efficiency is measured in kWh/km. EVs convert about 59%–62% of the electrical energy to power that allows the vehicle to operate. Conventional gasoline vehicles only convert about 16%–25% of the energy in gasoline to power the wheels.[3]

The battery system in an EV is the key technology as it defines its range and performance characteristics. EV batteries are designed to last approximately 12 to 15 years in moderate climates and 8 to 12 years in severe climates.[4] Battery prices fell 87% from 2010 to 2019, with the introduction of new chemistries, new manufacturing techniques and simplified design.[5]

Electric Vehicle Charging Equipment
Charging stations can be found in a variety of places, including shopping malls, restaurants, office buildings, etc. The development and proliferation of EVs must be accompanied by EV charging infrastructure.

Figure 1 shows the types of EV charging infrastructure.

	Level 1	Level 2	Level 3
Connection:	• Standard 120 volt household outlet	• 240 volt plug	• 480 volt plug
Installation:	• Does not require the installation of charging equipment	• Requires installation of charging equipment by a qualified electrician	• Requires specialized, high-powered charging equipment installation by a qualified electrician
Rate of Charge:	• Up to 8 km of range per hour of charging	• Up to 30 km of range per hour of charging	• Up to 140 km of range per hour of charging

Primarily, there are 3 types of chargers. Level 1 chargers use a regular socket that you would find in a home. This type of charging takes the longest, anywhere from 9-50 hours.

2 See Environmental Protection Agency, *Explaining electric & plug-in hybrids electric vehicles.*
3 See Environmental Protection Agency, *Where the Energy Goes: Gasoline Vehicles.*
4 See U.S. Department of Energy, *Electric vehicle benefits and considerations.*
5 Bloomberg New Energy Finance, *Global EV outlook*, 2020.

Second, there are level 2 chargers. These type of chargers are often installed at home or at workplaces. It can take 2 to 9 hours to fully charge.

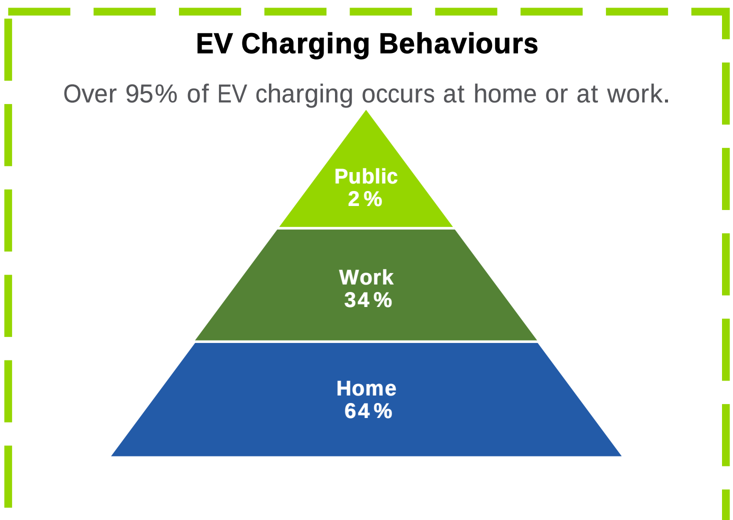
Lastly, there are Level 3 chargers, also referred to as Direct Current Fast Chargers ("DCFC"). These chargers provide the fastest rate of charge reaching 80% of a vehicle range in 30 minutes. This is the type of charging that is required to ease customers concerns about their ability to reach their destinations. These are typically installed along the highway for long distance travel or in high population areas.

Barriers to EV Adoption

In order to advance EV adoption, a number of barriers must be removed.

EV market barriers are the access to charging infrastructure, the upfront capital cost, and public perceptions about EVs. A lack of charging infrastructure creates the consumer perception that EVs will run out of battery power and be left 'stranded' or unable to reach their destination.

Overall, 89% of respondents said that the range of their EV is sufficient for their daily needs.[6] Further, even though access to public charging is improving, 86% of respondents said they primarily charge at home.



EVs typically have a higher up front purchase cost than conventional vehicles but lower ongoing operating costs. The average incremental capital cost difference between a conventional family sedan and a similar model EV is approximately $19,000.[7] The main cost driver for EVs is the large battery that represents approximately 75% of the vehicle's power train cost.[8]

Fuel costs, on the other hand, are up to 80% lower for an EV compared to a conventional vehicle.[9]

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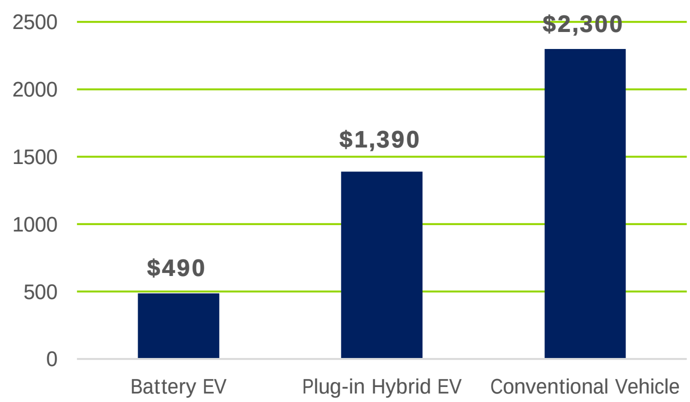
6 Fleetcarma, *2020 EV driver insights survey*, November 2020.
7 The purchase price of eight EVs were compared to similar internal combustion engine vehicles. The average difference in price between EVs and the internal combustion engine vehicles was $18,820.
8 Power train typically consists of the main components of a vehicle that generate power. This typically includes the engine, transmission, drive shafts, etc.
9 Based on electricity rates of $0.135/kWh.

Annual Fuel Cost of an

EV vs. Conventional Vehicle



Range anxiety continues to be a barrier to adoption, though in most cases, the distance that EV drivers travel each day is well within the range capacity of an EV. For example, the average passenger vehicle in Newfoundland and Labrador travels approximately 50 km each day.[10] The range that EVs can travel in a single charge has been increasing in recent years. The average range has grown from 219 km in 2013, to 386 km in 2019.[11] Based on this range capacity, the 50 km traveled each day by drivers in Newfoundland and Labrador can be accommodated.

Consumer knowledge and public perceptions about EVs are another barrier to EV adoption. A consumer survey conducted by McKinsey & Company in 2019 shows that about 50% of all consumers today are not yet familiar with EVs and related technology.[12]

There are also difficulties with EV availability at dealerships and limited local service and maintenance options.

EV Markets

Global EV stock is expanding rapidly. At the end of 2019, there were more than 7 million vehicles worldwide.[13] Over 2.1 million of these were sold in 2019, alone. EVs accounted for 2.6% of global car sales and about 1% of global car stock in 2019, which represents a 40% year-on-year increase.[14]

The COVID-19 pandemic will affect global EV markets, although to a lesser extent than it will the overall passenger car market. Based on car sales data during January to April 2020, current estimates provide that the

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[10] Natural Resources Canada, *2008 Canadian vehicle survey update report*, 2008.

[11] Canada Energy Regulator, *Market Snapshot: Average electric vehicle range almost doubled in the last six years*, June 2019.

[12] McKinsey & Company, *The road ahead for e-mobility,* 2019.

[13] See International Energy Agency, *Global EV outlook*, 2020.

[14] See International Energy Agency, *Global EV outlook*, 2020.

passenger car market will contract by 15% over the year relative to 2019, while electric sales for passenger and commercial light-duty vehicles will remain broadly at 2019 levels. Bloomberg estimates that EV sales will account for about 3% of global car sales in 2020. This outlook is underpinned by supporting policies, particularly in China and Europe. China recently extended its subsidy scheme until 2022. China and Europe also recently strengthened and extended their New Energy Vehicle mandate and CO_2 emissions standards.

The global EV stock remains concentrated in China, Europe and the United States, but is increasing across the globe. China and Europe achieved new records in EV market share at 4.9% and 3.5% respectively. By 2019, nine countries had more than 100,000 EVs on the road, and more than 20 countries reached market shares above 1%.[15] The greatest market penetration is in Norway, where in 2020, EV market share exceeded 75%.[16] Norway has a wide array of EV incentives and has a goal of 100% zero-emission vehicles by 2025.

While EV adoption has accelerated across Canada, EV sales vary significantly across the provinces. Uptake has been strongest in British Columbia and Quebec, the two provinces with purchase incentives as well as policy mandates requiring that EVs represent an increasing proportion of passenger vehicle sales. Since the introduction of federal incentives in 2019, EV market share has exceeded 10% in British Columbia and 7% in Quebec.[17] In the first and second quarters of 2020, 3.5% of new vehicle sales registered in Canada were EVs. This corresponds to over 21,000 new EV registrations. Of new EV registrations in this period, over 94% were in Quebec, Ontario and British Columbia.[18] However, EV sales continue to rise across the country. The share of EV sales occurring outside of British Columbia, Quebec and Ontario has risen from approximately 2.2% in 2017 to 4.5% in 2019.[19]

[15] See International Energy Agency, *Global EV outlook*, 2020.
[16] See Clean Technica, *Norway EV Market Share Breaks All Records*, April 2020.
[17] See Electric Mobility Canada, *Electric Vehicle Sales in Canada – Q3 2019*.
[18] Statistics Canada, *New Motor Vehicle Registrations, first half of 2020.*
[19] See Electric Mobility Canada, *Electric Vehicle Sales in Canada – Q3 2019*.

Schedule E
Potential Study Addendum: Demand Response Assessment

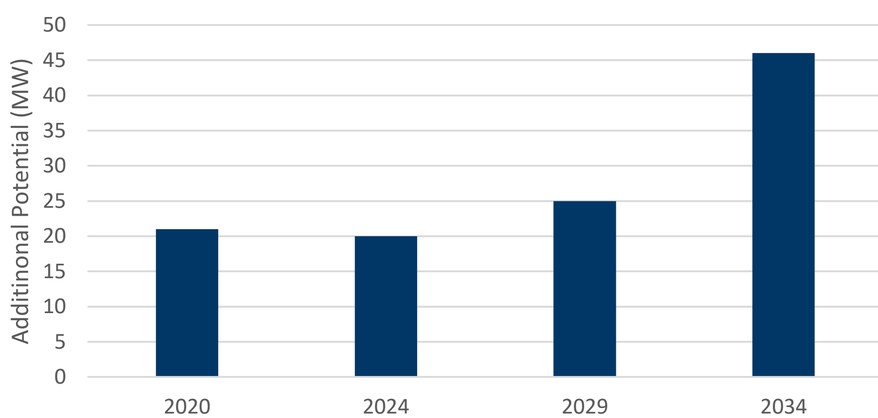
ADDENDUM: DEMAND RESPONSE POTENTIAL ASSESSMENT – FURTHER ANALYSIS

KEY FINDINGS

Based on the analysis presented above, and the comparison of the results among the scenarios presented in Figure 1, Figure 2 and Table 1 below, the following key observations are drawn:

1) **Consider updating the Corner Brook Curtailment contract to allow for longer duration events:** A simple change in the Corner Brook contract to allow a maximum 16-hour event duration in a single day would greatly improve the potential for ODR (46 MW) for dynamic rates programs on the IIC system, but only toward the end of the study period (after 2030, as per Figure 1 below). This is largely because the extended Corner Brook curtailment duration would allow for shifting residential loads to the early morning and late evening without creating a new peak at these times. Despite the observation that this would yield benefits later in the study, the contract adjustment should be made sooner if possible, as it would provide more flexibility to all current and possible DR strategies.

Figure 1: Additional Peak Load Reduction Potential resulting from expanding the Corner Brook Event duration to 16h as compared to the No TOU/CPP Scenario



2) **Using a combined residential customer CPP and commercial TOU rate design offers significant additional peak load reduction potential, however, this does not fully emerge until after 2030.** Optimizing dynamic rates approaches offers the highest peak load reduction (230 MW in 2034) when combined with a 16-hour curtailment constraint for Corner Brook. However, the ODR, TOU and CPP programs do not provide sufficient benefits to carry the full cost of the AMI investments needed to enable these programs before 2034. A full business case assessment for AMI may

reveal other benefits streams that could be combined with TOU/CPP programs to render the investment cost-effective.

3) **Take a stepwise approach to considering new DR programs:** Currently there is little additional benefit from new DR programs, including the TOU/CPP programs which do not appear to be cost-effective in the near term. In the initial years, focus should remain on expanding the current commercial and industrial curtailment programs (as per the initial report recommendations) along with expanding the duration of the Corner Brook curtailment event duration. However, as EVs become more prevalent in the province, they may eventually contribute to a new evening peak. As this trend takes hold, the Utilities should pilot EV load management strategies (i.e. dynamic rates for customers with EV chargers or direct EV load management). This will help determine which option is most effective at mitigating the impact of EV charging on the utility annual peak, and help ensure that investments in EV adoption return benefit to the system.

Figure 2: Net Achievable DR Impact by Program – Initial Potential Study (Scenario 1) and Updated Scenarios (2034)

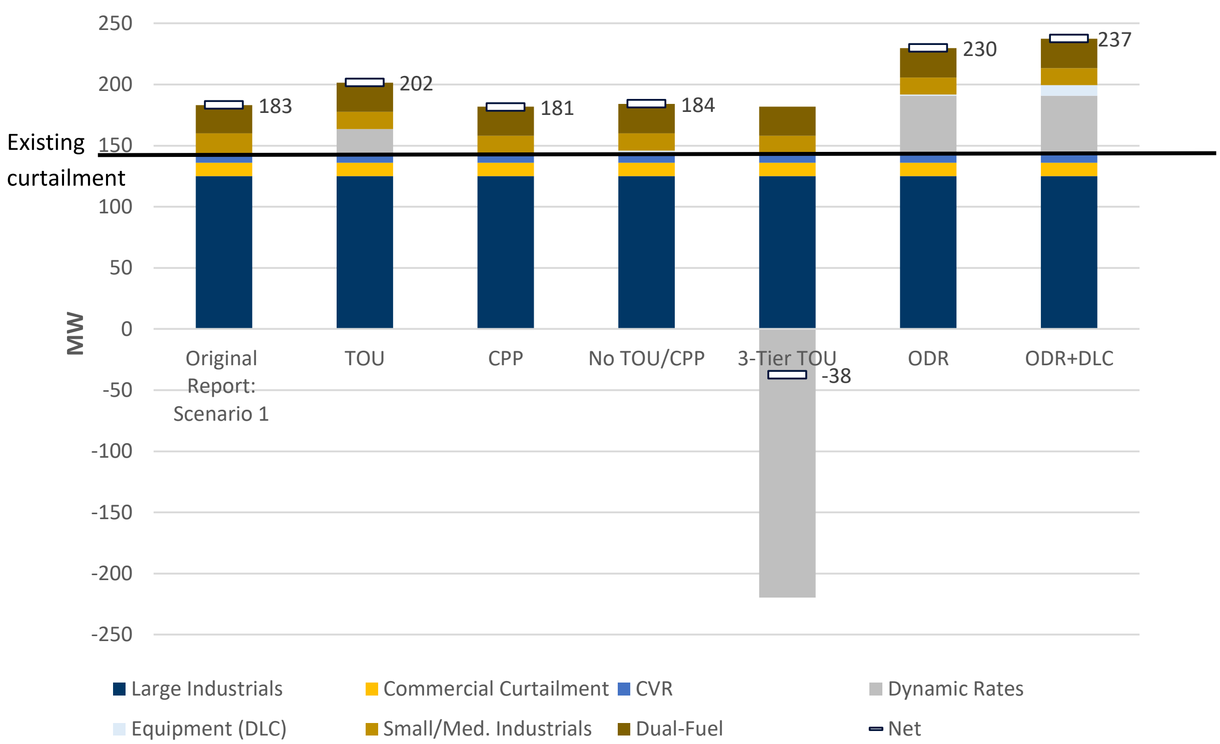


Table 1: Total Achievable DR Potential (MW) for all Scenarios with optimized Corner Brook contract

Scenario	2020	2024	2029	2034
Baseline (Report Scenario 1)	182	182	183	183
TOU Scenario	190	190	194	202

CPP Scenario	162	160	161	181
No TOU/CPP Scenario	179	180	182	185
3-Tier TOU Scenario	14	6	-13	-38
ODR Scenario	200	200	208	230
ODR with DLC Scenario	201	202	209	237

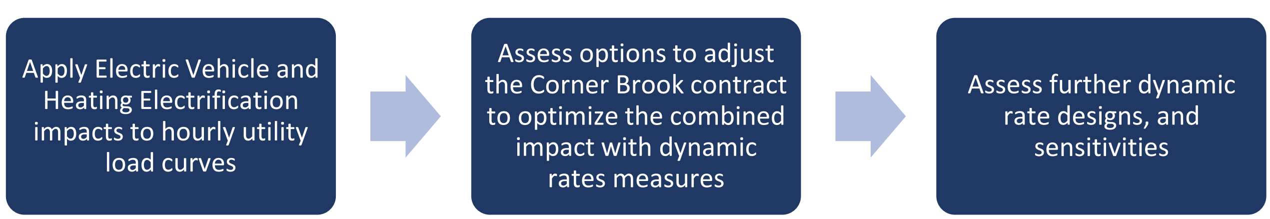
INTRODUCTION

In the recently completed *Newfoundland and Labrador Conservation Potential Study (2020-2034)*, Dunsky performed an assessment of demand response (DR) (Chapter 4), space and water heating fuel switching (Chapter 5), and electric vehicle adoption potentials (Chapter 6). In the demand response assessment, it was observed that the Corner Brook curtailment contract (the largest single DR resource available on the Island Interconnected system) contained conditions that significantly constrained the ability of other DR programs to generate net peak reductions. Most notably, the study found that Time of Use (TOU) and Critical Peak Pricing (CPP) rate designs would reduce the effectiveness of the Corner Brook curtailment by shifting peak loads to times that cannot be addressed under the constraints of the current Corner Brook contract, and thus they were not able to provide cost-effective net peak demand reductions under the current constraints. In the original study, the combined impact of EV adoption and electrification of heating loads (fuel switching via electric heat pumps) on the DR potential was not assessed.

Given that each of fuel switching, EV adoption, and DR programs all impact the shape and magnitude of the utility load curve, the NL Utilities requested that Dunsky revisit the DR analysis to account for three further factors.

1) Reassess the DR potential after the combined impact of energy efficiency, fuel switching, and EV adoption have been applied to the standard peak day load curve;
2) Apply adjusted Corner Brook curtailment contract conditions, designed such that it would be more compatible with other DR programs, in particular for dynamic rates programs, and;
3) Assess new dynamic rate scenarios and sensitivities to determine if there is an optimized rate design that could yield cost-effective peak demand reduction over the study period (2020-2034).

Figure 3: DR Potential Update Steps covered in this Addendum



Dunsky completed this further assessment of the DR potential, and the results are presented in this Addendum to the original report. All assessment was limited to the **Island Interconnected System (IIC),** starting with the same baseline load curve and growth projections as applied in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

UPDATED SCENARIOS AND SENSITIVITIES

To assess the potential of an optimized Corner Brook curtailment contract, six scenarios were assessed. In each case these were tested against the updated load curve that included the baseline EV and heating electrification adoption projections as presented in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

Table 2: New DR Scenarios Assessed (IIC)

Scenario	DR Programs
1	TOU rate design as per Potential Study **(TOU)**
2	CPP Program from Potential Study **(CPP)**
3	Only applies the new Corner Brook contract **(no TOU/CPP)**
4	3-tier TOU rate design from the Marginal Cost Study Updated **(3-Tier TOU)**
5	Optimized Dynamic Rate Design **(ODR)**
6	ODR with Direct Load Control (DLC) **(ODR + DLC)**

In addition to the scenario-specific DR programs listed above, the same set of Type 2 DR measures (measures with no same day rebound or pre-charge load curve impacts) were applied for each scenario as per those outlined in Chapter 4 of the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

Sensitivities: In addition to the six scenarios assessed as listed above, two further sensitivities were applied.

1. First the impact of extending the maximum total Corner Brook curtailment duration from 250 hours per year to 350 hours per year was assessed to determine the portion of the Maritime Link that could be committed to off-island sales.
2. Second, the most promising DR scenario was assessed with, and without the impact of natural adoption of heat pumps for customers with electric baseboard heat on the peak day load curve. This was included to account for uncertainty over the peak coincident load from heat pumps in the NL climate.

KEY ASSUMPTIONS

Table 3 below presents the key inputs and assumptions applied under the DR Potential update assessment and scenarios.

Table 3: Assumptions and Inputs Applied in the DR Potential Update

Name	Scenarios	Input & Assumptions
Corner Brook Curtailment Optimization	All	Our initial analysis shows that extending the maximum daily period of curtailment from 12 hours to 16 hours (for the full 105 MW) would prove sufficient to allow optimization of other DR programs. See Table 14 in the appendix for further details.
Fuel Switching Projections	All	The **Low Scenario** was applied for the projected heating fuel switching adoption, as described in Chapter 5 of the *Newfoundland and Labrador Conservation Potential Study (2020-2034).* This projection covers the expected natural adoption of ductless and central heat pumps, as well as heat pump water heaters, and the associated load impacts, as described therein. It is important to note that the Fuel Switching analysis included conversion from electric baseboard space heating to heat pumps, which is projected to be significantly larger than conversion from oil-fired or wood-fired heating to heat pumps.
Electric Vehicle Projections	All	The **Baseline Scenario** was applied for the projected EV adoption rates, as described on p. 112-114 in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).* This covers the expected adoption of Light Personal Vehicles, Light Commercial Vehicles, Medium-Duty Vehicles, Heavy-Duty Vehicles, considering current market conditions and federal government incentives.
Dynamic Rates	1, 2, 4, 5, 6	All scenarios apply an opt-out assumption, with 85% participation in dynamic rates programs. 1. **Scenarios 1 & 2** apply the optimal two-tier TOU (2:1) and CPP (3:1) rate designs as described in p. 68-70 in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).* 2. **Scenario 4** applies the three-tier TOU rate design from the recent NL Hydro marginal cost study.[1] 3. **Scenario 5** applies an optimal TOU/CPP combination that was designed to maximize the total DR potential when coupled with the 16-hour duration Corner Brook contract conditions (see Figure 9 presented later in this update for details).
EV Load Management [2]	1, 2, 3, 4, 5, 6	1. **Active** load management via remote utility control of the charger (95% peak hour load impact reduction). 2. **Passive** load management under the dynamic rates programs (75% peak hour load impact reduction).

1 Source: "Marginal Cost Study Update – 2018," Nov. 15, 2018, NL Hydro.
2 Active and passive load management impacts are based on Dunsky's overview of multiple pilots and projects assessing impact of EV load management (Charge the North, BC Hydro, Green Mountain Power, PG&E, NSPI, etc.).

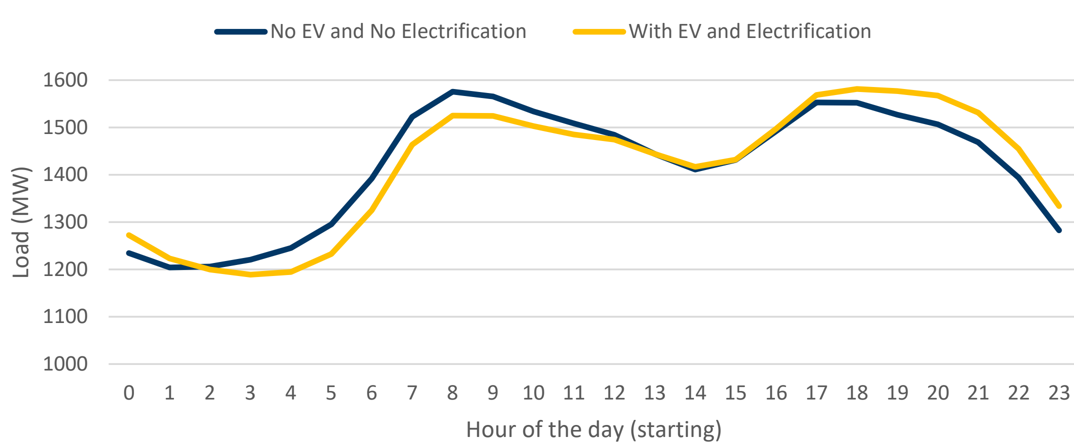
		Scenario 6: Combines active and passive EV load management. For all customers who opt out of the dynamic rates, they become eligible to participate in the Active EV load management measure.

RESULTS

IMPACT ON LOAD CURVE

The first step of the DR Potential Update entailed applying the projected heat pump and EV adoption, without any load management, to the utility peak load and to assess the impact on the shape of the standard peak day load curve. Figure 4 below illustrates the expected impact by 2034. While the adoption of EVs is expected to somewhat raise the annual peak load due to EV charging coincident with the evening peak, the adoption of heat pumps, particularly in conversions from electric resistance heating will help to somewhat reduce the peak load.[3] Overall, the combined effect slightly increases the daily peak by 2034, and shifts the daily maximum from a morning peak to an early evening peak. While the combined effect of EV adoption and heat pump adoption may change the shape of the load curve, and the timing of the daily peak, these changes are not sufficient to alter the overall economic conclusions related to investing to support EV adoption as described in the initial study.

Figure 4: Combined impact of EV and Electrification on the 2034 Standard Peak day load curve (2034)



SCENARIOS 1-3: OPTIMIZATION OF THE CORNER BROOK CONTRACT

Applying the updated peak day load curves, the DR Model was then used to assess the annual peak load reduction potential for each assessment. Figure 5 below presents the results for the full set of DR

[3] Further charts showing the individual impacts of EV adoption and Fuel Switching are provided in the appendix to this Addendum.

programs at the start year of each 5-year interval, as was assessed in the *Newfoundland and Labrador Conservation Potential Study (2020-2034).*

Figure 5: Achievable DR Potential for Scenarios 1-3 under with optimized Corner Brook contract[4]

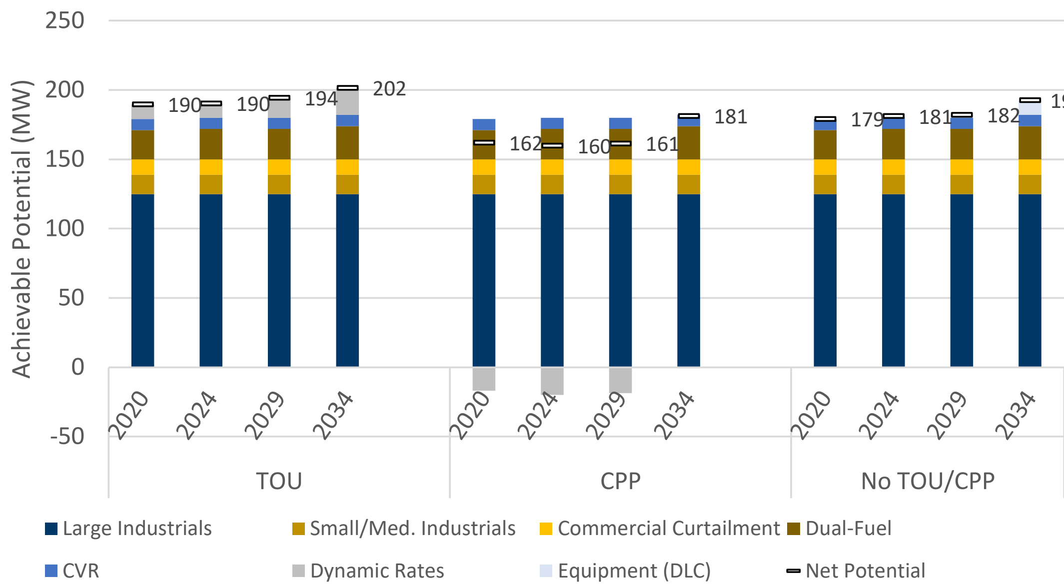
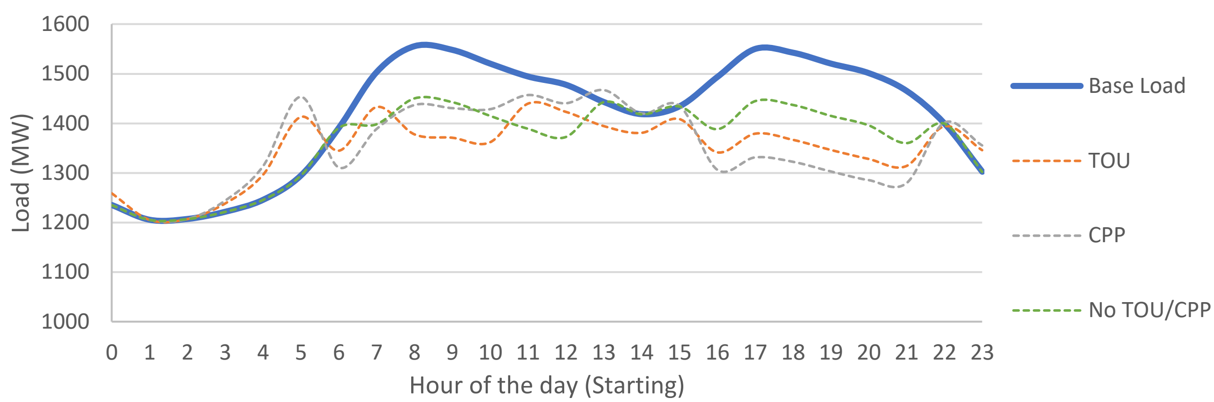


Figure 6 below provides further details on how each scenario-specific DR program interacts with the standard peak day load curve. In each case the impact of the scenario specific program was assessed against the standard peak day to determine the potential, and in conjunction with the 16-hour maximum daily duration Corner Brook contract constraints over 5-years of historical IIC load curves to ensure that no new peak days arise.

[4] As shown in the *Newfoundland and Labrador Conservation Potential Study (2020-2034)* - Vol.2 table F-19, under the mid scenario, heat pumps are mainly applied to replace electric resistance heating. Since all other replacements combined (combustible fuel conversions to heat pump) account for less than 1% of total customers, it was assumed that the potential of the dual fuel program would not be impacted.

Figure 6: Standard Peak Day impacts Scenario 1-3 (2020)



Overall it can be seen that the 2:1 TOU scenario provides the highest potential of the initial options assessed using the dynamic rate programs as defined in the initial report. Further examination of Figure 6 indicates the CPP scenario suffers from a higher mid-day peak than the TOU scenario, as it more aggressively displaces peak load from the morning and evening heating peaks. On the other hand, the no TOU/CPP scenario is less successful than the TOU scenario at mitigating the morning and evening residential heating peaks.

SCENARIOS 4-6: OPTIMIZATION OF DYNAMIC RATES

Figure 7 below provides the results of the scenarios that tested alternative dynamic rate structures, and direct load control (DLC) of equipment and EV chargers. As noted in key assumptions, the ODR scenario does include passive EV management, while the ODR+DLC scenario includes EV DLC for the share of market that opt-out of dynamic rates. Under these assessments the ODR scenario and ODR+DLC scenario provide similar potential savings. This result favours the ODR scenario without the addition of DLC programs. Overall, DLC offers little additional peak load reduction under the ODR+DLC scenario, but carries incentive, administration and controls infrastructure costs (detailed tables are available in the Appendix).

Figure 7: Achievable DR Potential for Scenarios 4-6 with optimized Corner Brook contract

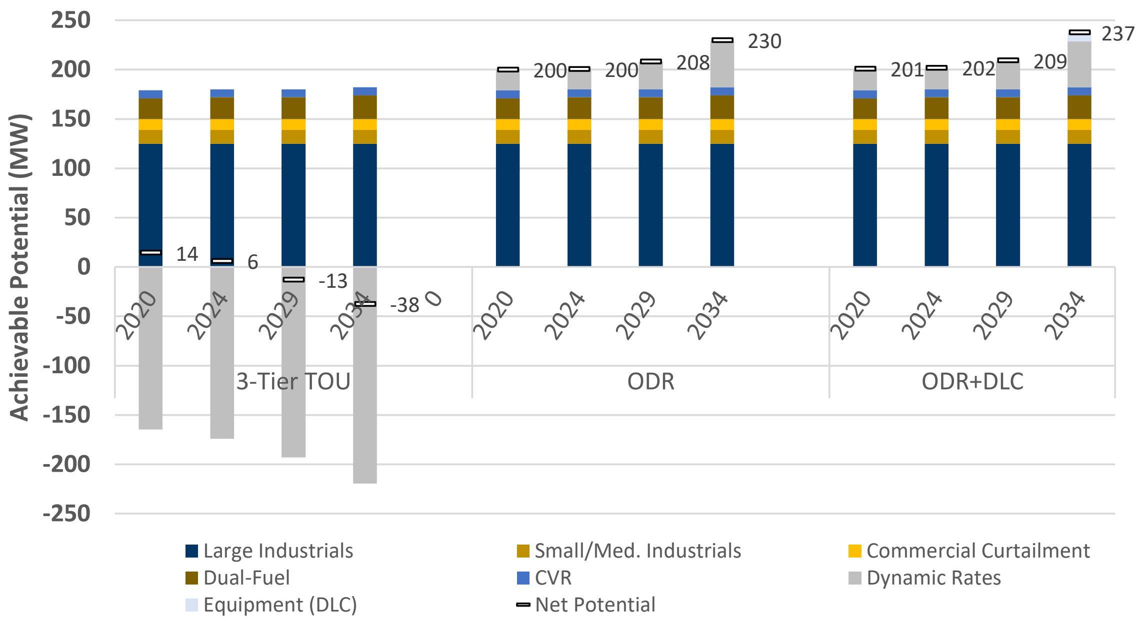


Figure 8 below shows the impact of each scenario-specific DR program on the peak day load curve. This analysis illustrates the impact of the 3-tier TOU scenario that creates new and higher peaks in the early morning and late evening, thereby offering a negative overall net DR potential. The ODR and ODR +DLC scenarios are largely super imposed, helping to flatten the load throughout the day.

Figure 8: Standard Peak Day impacts Scenario 4-6 (2020)

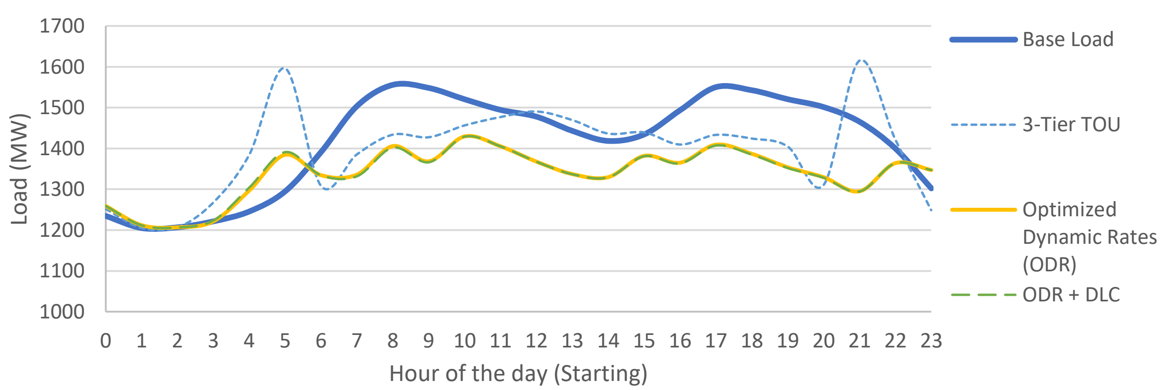
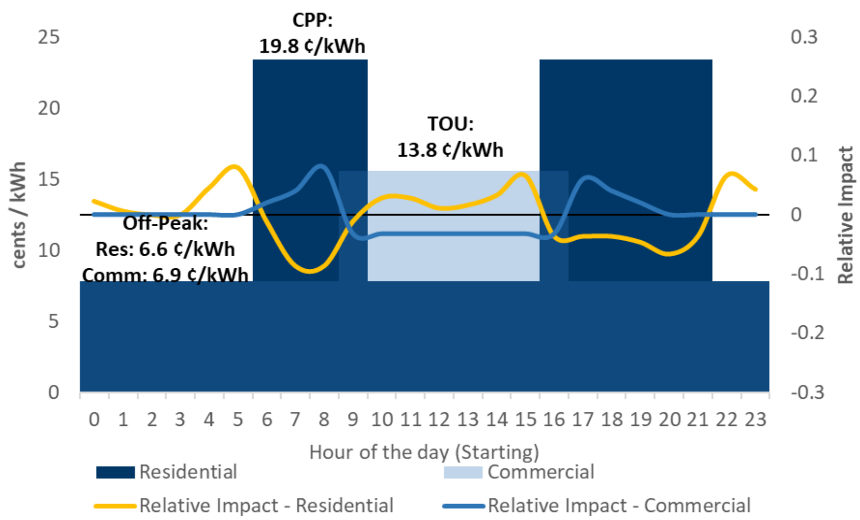


Figure 9 below provides the ODR program design that was arrived at through iterative application of the DR Model under varied rate designs. After testing various ODR designs, it was found that a 3:1 CPP program for residential customers effectively reduced the evening and morning peaks, while the TOU rates for commercial customers helped to avoid a new peak forming during the day time. In combination, these two programs were found to offer the largest overall peak reduction in an opt-out ODR program. Moreover, although the evening CPP event is six hours long, this is not an unrealistic duration as similar

CPP durations are or were implemented in other jurisdictions.[5] To account for the long duration, heating load driven peaks in NL, the assumed CPP reduction impact was reduced by 23% for the evening event.

Figure 9: ODR Design - Hourly Load Impacts (Residential CPP and Commercial TOU)[6]



DR PROGRAM COST-EFFECTIVENESS

Table 4 below shows cost effectiveness and net impact of each DR program under the most advantageous scenario (ODR and DLC), for each starting year (2020, 2024, 2029 and 2034) and assuming each program would run for a 10-year duration.

The results show that all programs can achieve cost effectiveness (based on a Program Administrator Cost Test (PAC) threshold of 1.0) by 2034. Note that residential DLC (the program including EV DLC) is only implemented in 2034. By then, there is limited room to expand the more cost-effective commercial DR program and the peak has shifted in the evening, making residential DLC a good program to target this new peak. The Dynamic Rates program cost-effectiveness assessment includes the full cost AMI deployment, and as such the benefits provided via the peak load reduction impacts do not appear to be sufficient to fully account for these costs in the earlier portion of the study period. AMI may offer some benefits that currently employed Advanced Meter Reading practices do not (such as reduced meter reading costs, two-way communications, and increased benefits from home energy feedback devices), which could help contribute to the business case for installing AMI across the IIC system.

5 Extended duration CPP program examples from Vermont and California are provided in the Appendix.

6 The optimized dynamic rates were designed to maintain a constant average bill in each sector, for existing residential and general service #2.1 rates.

Table 4: Best case DR Program (ODR+DLC Scenario) Peak Reduction Impacts (MW) and PAC results

Program Name	2020		2024		2029		2034	
	MW	PAC	MW	PAC	MW	PAC	MW	PAC
Equipment[7]	1.1	3.2	1.1	3.2	1.2	3.3	8.6	3.5
Dual Fuel[8]	21	1.7	22	1.8	22	1.9	24	2.1
TOU (Dynamic Rates including TOU & CPP)	21	0.5	21	0.5	28	0.7	47	1.2
Industrial Curtailment[9]	147	11.7	147	12.7	147	14.1	147	15.6

[7] The Equipment program includes Residential DLC and Commercial DLC (including EV DLC).
[8] Dual-Fuel program includes backup generators (BUGs) and dual fuel systems, as per the program description in Table F-16.
[9] Includes both Large Industrial Curtailment (125 MW) and Small/Med Industrial Curtailment (22 MW).

SENSITIVITY 1: CORNER BROOK TOTAL CURTAILMENT HOURS PER YEAR

For each scenario we applied three possible constraints for the maximum total hours of Corner Brook curtailment in a given year, and assessed the impact of varying this on the distribution of IIC system peak hours (using historical hourly load data from 2015-2019 calendar years). From this we determined the number of hours that would exceed 1,590 MW, after accounting for the required capacity contingency requirements.[10] The 1,590 MW threshold was established as the estimated required capacity threshold below which the entire unallocated Maritime Link capacity could be dedicated to off-island sales (see Table 5 below).

Table 5: On-island capacity used to determine threshold for Maritime Link capacity requirements (Current capacity, with planned retirements removed)[11]

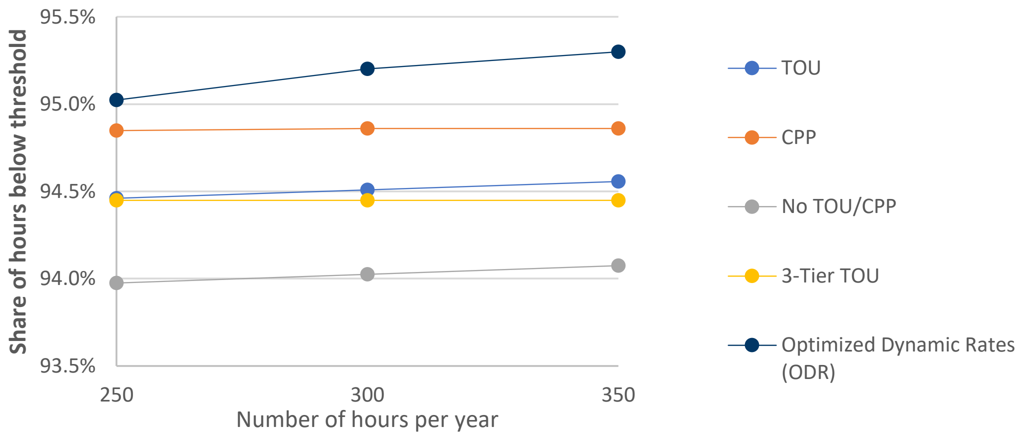
Resource	Capacity (MW)
On-Island Hydro Generation	1,132
Diesel Fueled Gas-fired Generation	124
Grid Connected Diesel-fired Generation	15
Grid Connected Oil-fired Generation	0
Labrador-Island Link[12]	820
Maritime Link Off-island Sales[13]	(500)
Net Total Capacity for IIC	***1,590 MW***

Our analysis then determined the number of hours per year that the total required IIC capacity exceeds 1,590 MW. This provides an indicator of further potential value that could be derived from DR programs on the IIC system such that lowering the number of hours that exceed the 1,590 MW threshold could increase the ability to sell the Maritime Link capacity.

Figure 10 below presents the portion of hours in a year where the system load would be expected to exceed the 1,590 MW threshold in 2020 under each DR program scenario, and under varied maximum hours of Corner Brook curtailment. Overall, the results indicate that regardless of the DR programs employed, approximately 6% of the hours per year would exceed the 1,590 MW threshold. Overall, it was found that the ODR scenario has the fewest hours that exceed the 1,590 MW threshold, but that the difference among the scenarios was not substantial.

10 Estimated based on the maximum between 10-min and 30-min reserve (296 MW) or 16% of the peak load.
11 Retirements include Holyrood (oil), Harwoods and Stephenville (gas) generating facilities.
12 80 MW of forecasted losses, as per NL Hydro's 2018 Marginal Cost Study Update, on the Labrador-Island Link, yielding a net 820 MW of power for usage on the island.
13 The Maritime Link is presented as a capacity draw (negative value) to account for off-island sales.

Figure 10: Portion below 1,590 MW threshold per year (2020)



Further details on the ODR scenario, are presented in Table 6 and Table 7 below. Table 6 below presents the number of hours where load is below threshold, 0-5% above (1,590 – 1,670 MW), 5-10% above (1,670 – 1,750 MW) and above 10% threshold (> 1,750 MW). From this it can be observed that increasing the number of Corner Brook curtailment hours per year has practically no impact to lower the number of hours that exceed 1,750 MW in total IIC system required capacity (including buffers).

Table 6: IIC hourly load buckets (ODR Scenario – using 2015-2019 historical load curves)[14]

Corner Brook curtailment hours per year	< 1,590 MW	1,590 – 1,670 MW	1,670 – 1,750 MW	> 1,750 MW
350	8,348	312	88	11
300	8,340	318	91	12
250	8,324	327	97	12

Table 7: Portion of Corner Brook curtailment (ODR Scenario) that falls into sequential day events

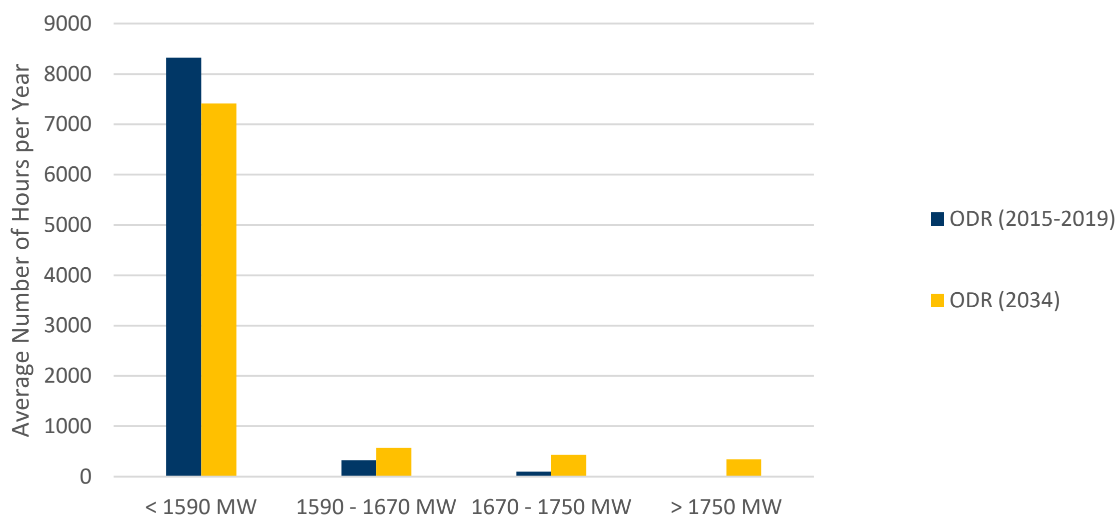
Number of days in a row	1	2	3	4+
Share of Corner Brook calls	59.5%	40.5%	0%	0%

We then applied the same assessment to the same historical load curves, but adjusted to account for customer growth, EV adoption and heat pump adoption in 2034. The results on the threshold analysis

14 Number of hours in a year might not add up to 8760 hours due to rounding.

are presented in Figure 11 below, which shows that the number of hours that will exceed the 1,590 MW will grow with time due to overall load growth on the IIC system.

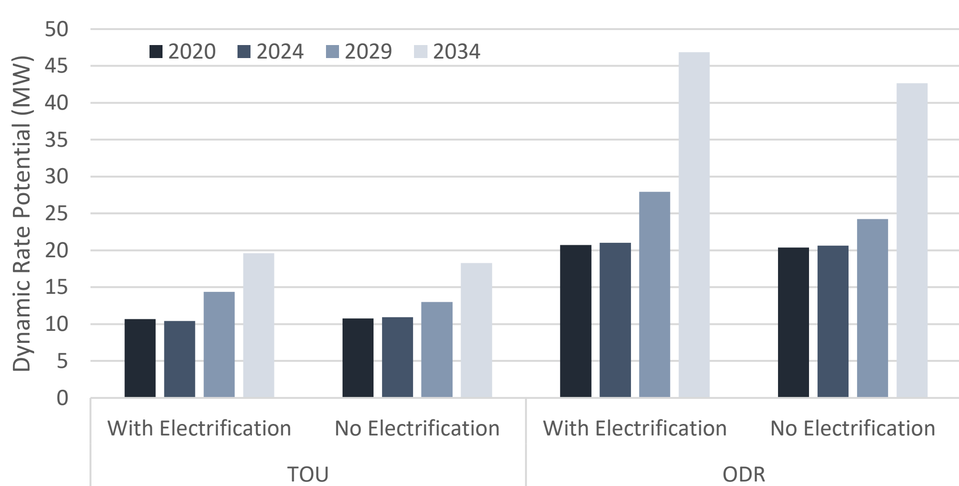
Figure 11: Number of hours by total IIC demand bin (250 hour maximum for Corner Brook curtailment)



SENSITIVITY 2: HEAT PUMP ADOPTION LOAD IMPACTS

In order to assess sensitivity to heat pump loads on peak days, potential demand reduction under the TOU and ODR scenarios was re-assessed without applying the fuel switching impact to the IIC utility load curve. The results in Figure 12 below present a comparison of the net demand reduction impact of the TOU and ODR programs, with and without the heat pump electrification peak load reduction being applied to the standard day load curve.

Figure 12: Electrification Load Curve Impact on Dynamic Rates



The results suggest that conversion to heat pumps will have little impact on the DR potential for the TOU and ODR programs. This is primarily because while HPs may somewhat change the amplitude of the annual peak, we assumed that they do not significantly change the peak day load curve shape (i.e. our study assumed that heat pumps would have a similar hourly load curve shape as electric baseboards). However, if it is found through Newfoundland Power's heat pump study that heat pumps exhibit a significantly different peak day shape from electric resistance, then it could change this result.

SENSITIVITY 3: $20M INVESTMENT SCENARIO FOR EV ADOPTION

To assess the viability of the ODR measures under a higher level of EV adoption, the ODR and ODR+DLC scenarios were tested using the $20M investment scenario from the initial report EV adoption analysis, coupled with the baseline heating electrification load curve impacts. Figure 13 below shows the cumulative EV sales to 2034 under the two EV adoption scenarios, which projects an additional 100,000 EVs under the $20M investment scenario, as compared to the baseline adoption. As a result, under the $20M investment scenario peak demand would increase by 231 MW (2034) over today's peak, as compared to 63 MW in the baseline EV adoption scenario. Moreover, the timing of the daily peak would be expected to move from the morning to the evening by 2024 in the $20M Investment scenario, compared to 2029 in the baseline scenario.

Figure 13: Forecasted EV Adoption – Baseline and $20M Investment Scenarios[15]

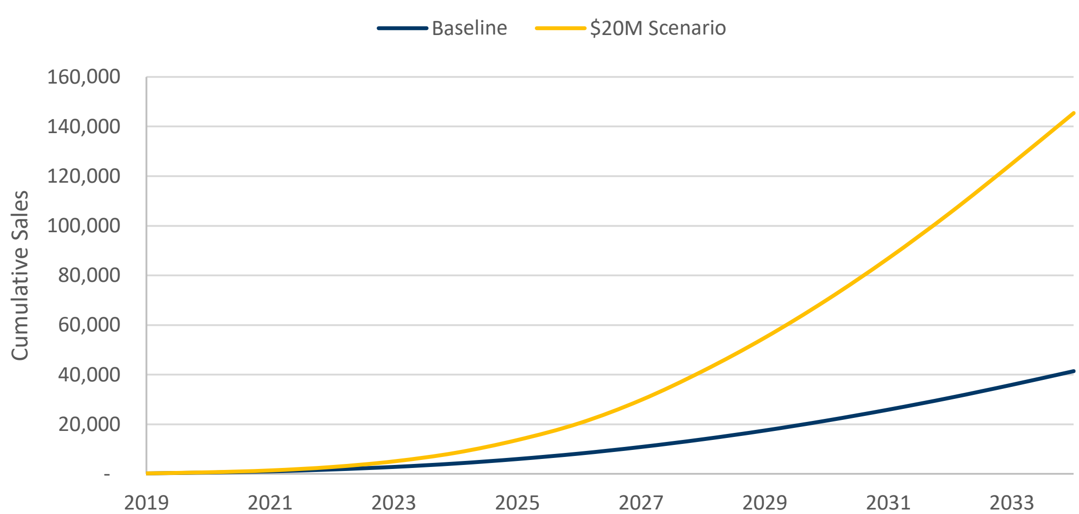


Figure 14 and Figure 15 below show the ODR scenario under the elevated EV adoption rates. Overall, the results show that the ODR scenario potential reached 45 MW by 2029 under more aggressive EV adoption, but then falls off as EV adoption increased further by 2034. This is because further EV adoption leads to a new peak appearing in the late evening thereby reducing the potential from the evening residential CPP program. It is possible that the residential CPP times could be adjusted to target this new peak, or that all

[15] Data from 2020-2034 Conservation Potential Study – Vol.2, Table F – 40, and Vol.1, Figure 6 – 3.

customers with EV chargers could be subject to time of use rates with steep evening price increases to mitigate this impact.

Figure 14: ODR Potential Under EV Adoption Scenarios

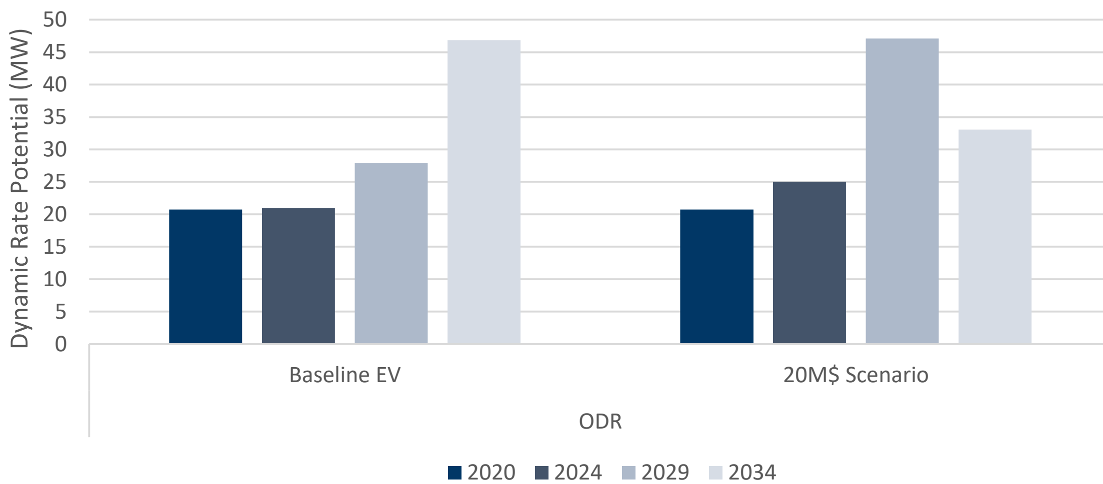
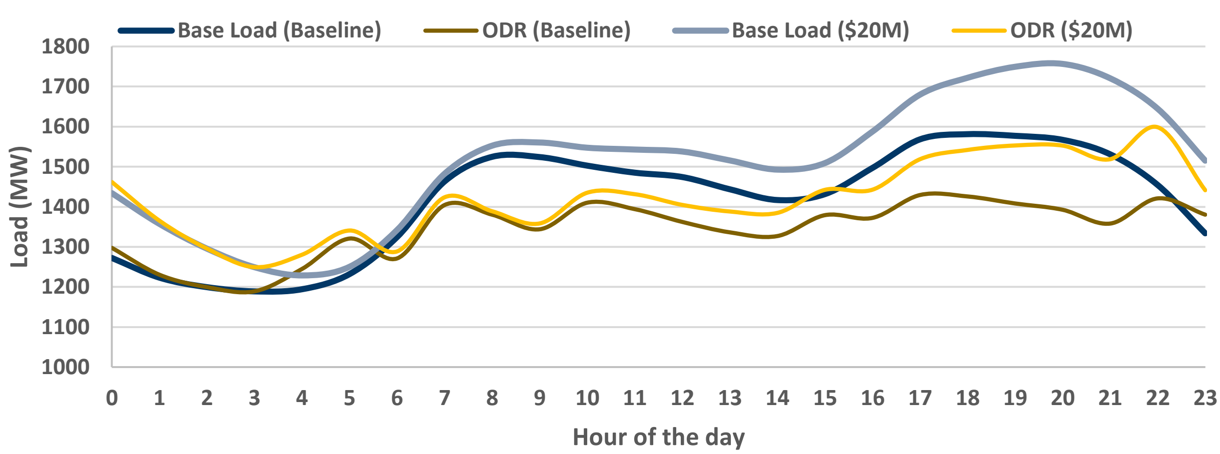


Figure 15: Peak Day Hourly Load Curve – ODR Scenario (2034)



Not shown in the figures above, we also assessed the additional peak demand potential from adding DLC measures to the ODR scenario. Similar to the baseline EV adoption, adding DLC alongside ODR has little impact over and above the ODR measures under the $20M investment scenario for EV adoption. This is because there is little DLC potential for appliances during the late evening peak event, and DLC program participation among EV owners who opted out of the ODR program is expected to be low. Of the 1.9 MW of DLC potential assessed in 2034, direct EV load management contributes the majority of 1.3 MW.[16]

These results suggest that a general dynamic rates approach to tackling the shifting peak load associated with EV adoption may not be the ideal option. Instead, targeting homes and businesses with EV chargers to engage in load management either through targeted EV rates (variable rates) or requiring new EV chargers to have enabled direct load control or smart charging capabilities may be the most effective way to mitigate the evening peak load associated with EV charging.

SENSITIVITY 4: EV CHARGING CONTROL STRATEGIES

Finally, we compared the potential for various EV load management strategies, and the results are presented in Table 8 below. Overall, while the direct control of EVs (as demonstrated in the No TOU/CPP scenario) provides the most peak reduction per enrolled vehicle, the dynamic rates approaches offer much broader participation via the assumed opt-out program requirement and as a result, the CPP and TOU approaches offer the highest EV peak reduction potential.[17] [18]

Table 8: Peak Reduction Potential (MW) for EV load management options (2034)

Scenario	TOU	CPP	EV DLC only	3-Tier TOU	ODR (Baseline Scenario)	ODR + DLC	ODR ($20M Scenario)
EV Load Management	21	30	8.7	29	18	19	66

While EV adoption under the current scenario is steadily increasing, as shown in Figure 13 above, the potential for EV load management does not follow this growth. This is because it is not until late in the study period (around 2029) that the EV adoption is sufficient to shift the current morning peak exhibited on the system to an evening peak. Because there is little EV charging demand in the morning, the potential peak load reduction attributable to EV load management is minimal up until 2029.

16 It should be noted that direct EV load management, without any dynamic rates, may offer significant potential 239 MW) as it is shown in Figure 6 – 18 of the 2020-2034 Conservation Potential Study – Vol.1. However, this analysis was conducted outside of the DR modelling assessment, and may over state the actual direct load control potential.

17 Under the dynamic rates program, we assumed all homes and businesses would be enrolled in an opt-out program model, with an 85% retention.

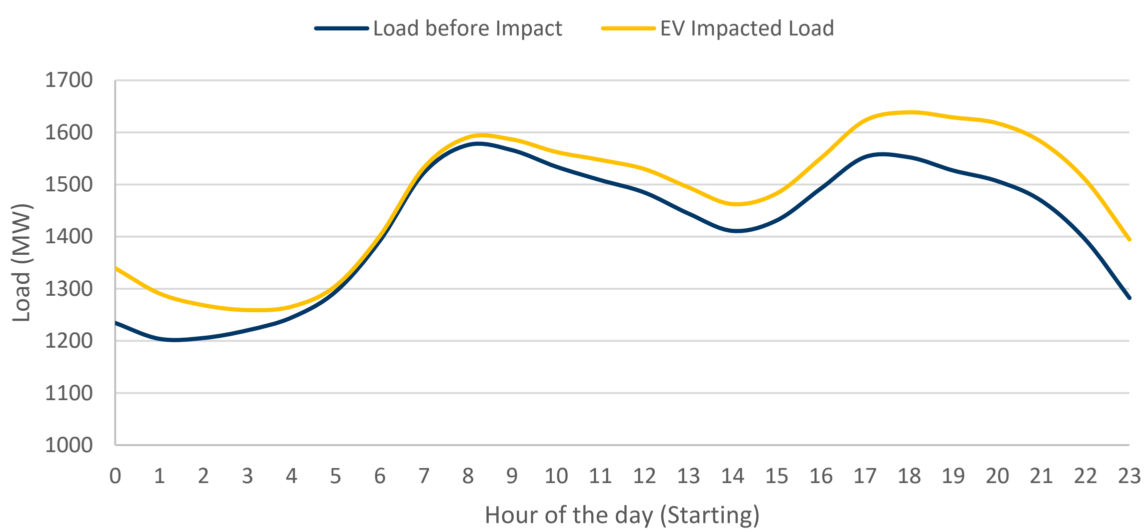
18 Table 11 to 14, in appendix, present the cost-effectiveness of various programs.

APPENDIX

2034 PEAK DAY LOAD CURVE IMPACTS FROM FUEL SWITCHING AND EV ADOPTION

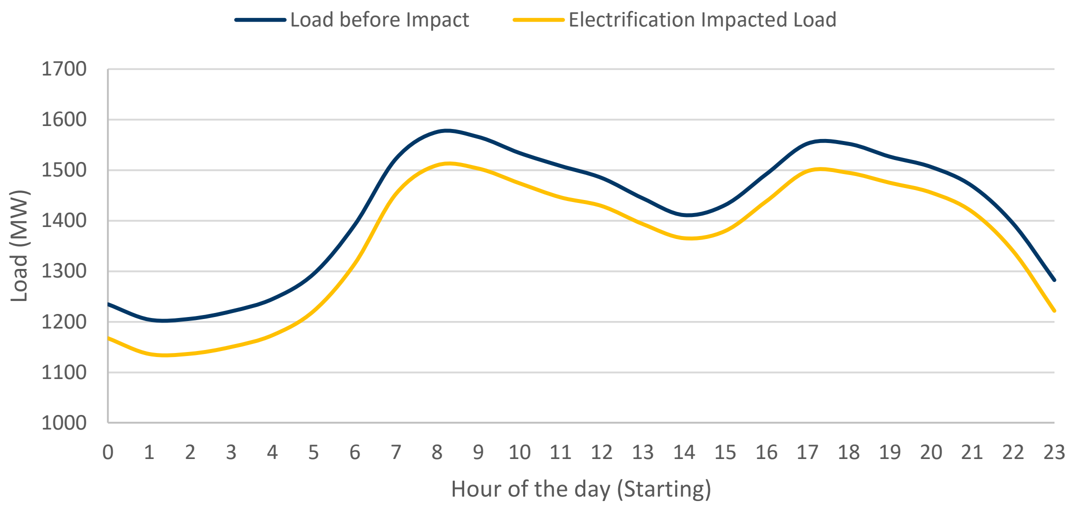
Electric vehicle impact in 2034 is presented in Figure 16. EVs increase, under the Baseline Scenario, the utility load by about 100 MW between 7:00 PM and 0:00 AM, while having a more limited impact (around 50 MW) during the day.

Figure 16: Impact of EV adoption on 2034 Standard Peak Day Load Curve (IIC)



Electrification, under the low scenario, reduces the overall electric demand in a relatively constant way with a reduction ranging from 50 to 75 MW over the standard peak day.

Figure 17: Impact of heating electrification on 2034 Standard Peak Day Load Curve (IIC)[19]



DETAILED PROGRAM RESULTS TABLES

Table 9 shows the demand savings achieved by programs, for each scenario studied. This data is also available graphically in Figure 2.

Table 9: DR Program Impacts (MW) under each scenario (2034)

Programs	TOU	CPP	No TOU/CPP	3-Tier TOU	ODR	ODR+DLC
Large Industrials	125	125	125	125	125	125
Small/Med. Industrials	14	14	14	14	14	14
Commercial Curtailment	11	11	11	11	11	11
Dual-Fuel	24	24	24	24	24	24
CVR	8	8	8	8	8	8
Optimized Dynamic Rates	20	- 1	0	-220	47	47
Equipment (DLC)	0.0	0.0	2.0	0.0	0.8	8.6

[19] The heating electrification component of the study included converting electric resistance heating to heat pumps. Due to the cost-effectiveness of this solution relative to the electrification of oil-fired heating, replacement of electric resistance heating represents the majority of heat pump adoption, thereby leading to an overall net reduction in the peak electric demand with time.

Tables below present the costs and benefits for each program by implementation years. They are presented for the ODR + DLC scenario, but the ODR scenario is also contained within these tables by simply not taking the Residential DLC and the DR Commercial programs into account. All costs and benefits are discounted using the 2020-2034 Conservation Potential Study discount rate of 3.92%. The program costing methodology is available in Appendix B (see DR Programs and Scenarios) of the potential study.

Table 10: Program costs/benefits – 2020

Program Name	Development Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$660,000	$0	0.0
DR Backup Power	$150,000	$75,000	$164,000,000	$281,000,000	1.7
DR Commercial	$150,000	$75,000	$1,070,000	$3,390,000	3.2
Dynamic Rates (TOU/CPP)	$88,600,000 [20]	$150,000	$139,000,000	$75,800,000	0.5
Industrial Curtailment	$150,000	$75,000	$33,500,000	$391,000,000	11.7

Table 11: Program costs/benefits – 2024

Program Name	Development Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$660,000	$0	0.0
DR Backup Power	$150,000	$75,000	$170,000,000	$312,000,000	1.8
DR Commercial	$150,000	$75,000	$1,090,000	$3,530,000	3.2
Dynamic Rates (TOU/CPP)	$88,600,000	$150,000	$139,000,000	$75,600,000	0.5
Industrial Curtailment	$150,000	$75,000	$34,400,000	$439,000,000	12.7

Table 12: Program costs/benefits – 2029

Program Name	Development Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$660,000	$0	0.0
DR Backup Power	$150,000	$75,000	$182,000,000	$353,000,000	1.9

[20] Including the full deployment of AMIs estimated in Appendix E of the 2020-2034 Conservation Potential Study.

DR Commercial	$150,000	$75,000	$1,120,000	$3,740,000	3.3
Dynamic Rates (TOU/CPP)	$88,600,000	$150,000	$139,000,000	$103,400,000	0.7
Industrial Curtailment	$150,000	$75,000	$35,700,000	$503,000,000	14.1

Table 13: Program costs/benefits – 2034

Program Name	Development Costs	Fixed Annual Costs	Total Costs (Full Deployment)	Total Benefits (Full Deployment)	PAC Ratio
Residential DLC	$100,000	$75,000	$1,070,000	$1,570,000	1.5
DR Backup Power	$150,000	$75,000	$189,000,000	$397,000,000	2.1
DR Commercial	$150,000	$75,000	$3,070,000	$11,010,000	3.6
Dynamic Rates (TOU/CPP)	$88,600,000	$150,000	$139,000,000	$173,600,000	1.2
Industrial Curtailment	$150,000	$75,000	$36,600,000	$570,000,000	15.6

LIMITING CONSTRAINTS FOR CORNER BROOK CONTRACT

In order to optimize the Corner Brook contract, current constraints were evaluated against the set of scenarios proposed in this study. The 12-hour limit of curtailment per day proved to be the most limiting factor in the integration with dynamic rates. Furthermore, both the CPP and No TOU/CPP scenario were within a few MW of exceeding the 12 hours, meaning that this extension could become beneficial for these scenarios with only small changes to the demand pattern.

Table 14: Resulting Peak based on Consecutive Hours of Curtailment in 2020 (MW)

Scenario	TOU	CPP	NO TOU/CPP	3-Tier TOU	ODR	ODR + DLC
12-hour curtailment	1,483	1,467	1,451	1,615	1,469	1,468
16-hour curtailment	**1,440**	1,467	1,451	1,615	**1,430**	**1,429**

LIST OF CPP WITH 6 HOURS OR MORE

Although there are many considerations to implementing a CPP program (ratepayer bill, low-income household impact, etc.), the table below shows a few CPP programs that were or are 6 hours or longer to confirm the possibility of an extended CPP event.

Table 15: List of CPP with a six-hour or longer duration

Utility	Duration	Source
Green Mountain Power	8h	https://greenmountainpower.com/wp-content/uploads/2018/03/Rate-14-TOU-and-Critical-Peak-Pricing-4.1.18.pdf
SDG&E	7h	https://pubs.naruc.org/pub.cfm?id=5378C352-2354-D714-518C-BD97831D7C0E
PG&E	6h	https://www.pge.com/includes/docs/pdfs/mybusiness/energysavingsrebates/demandresponse/cpp/dr_cpp_1858.pdf

CONSERVATION POTENTIAL STUDY VOL.1 – FIGURE UPDATE

This section provides updated figures from the initial potential study report, based on the findings from the further analysis presented in this addendum.

Figure 1-6 (Updated)

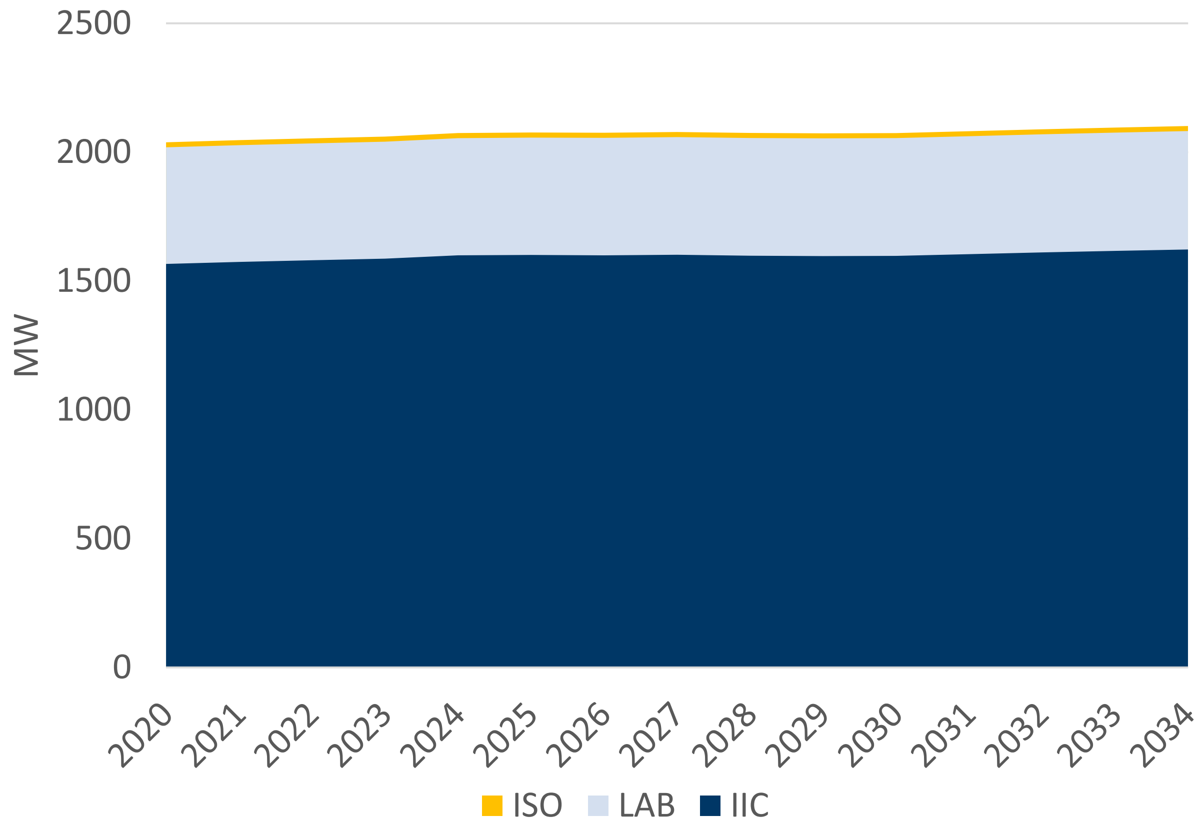
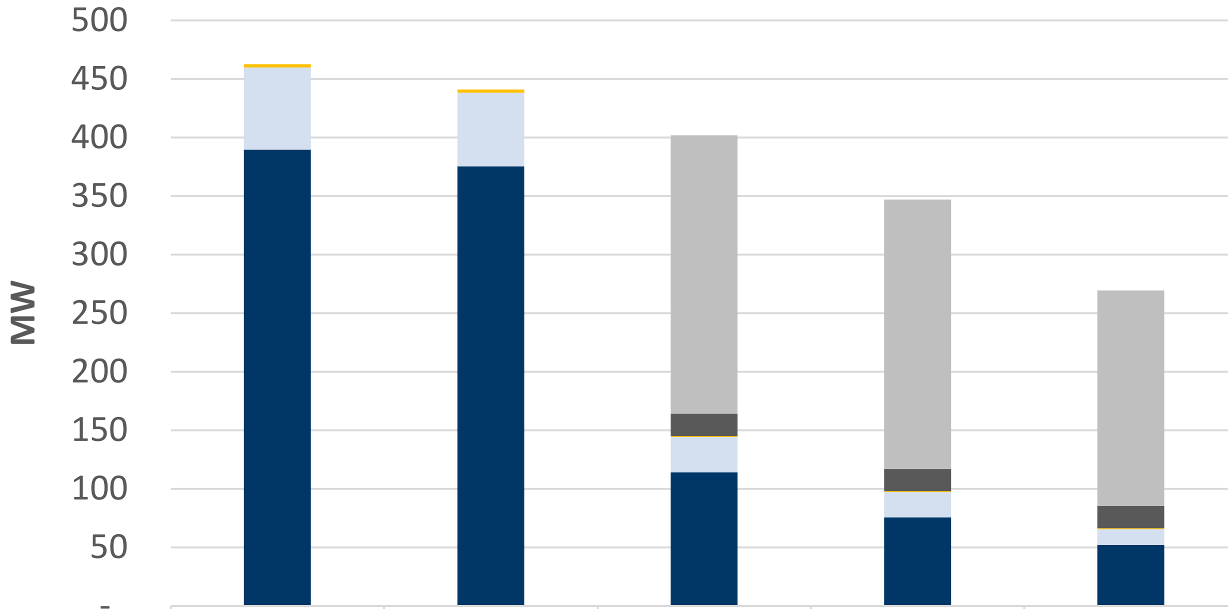
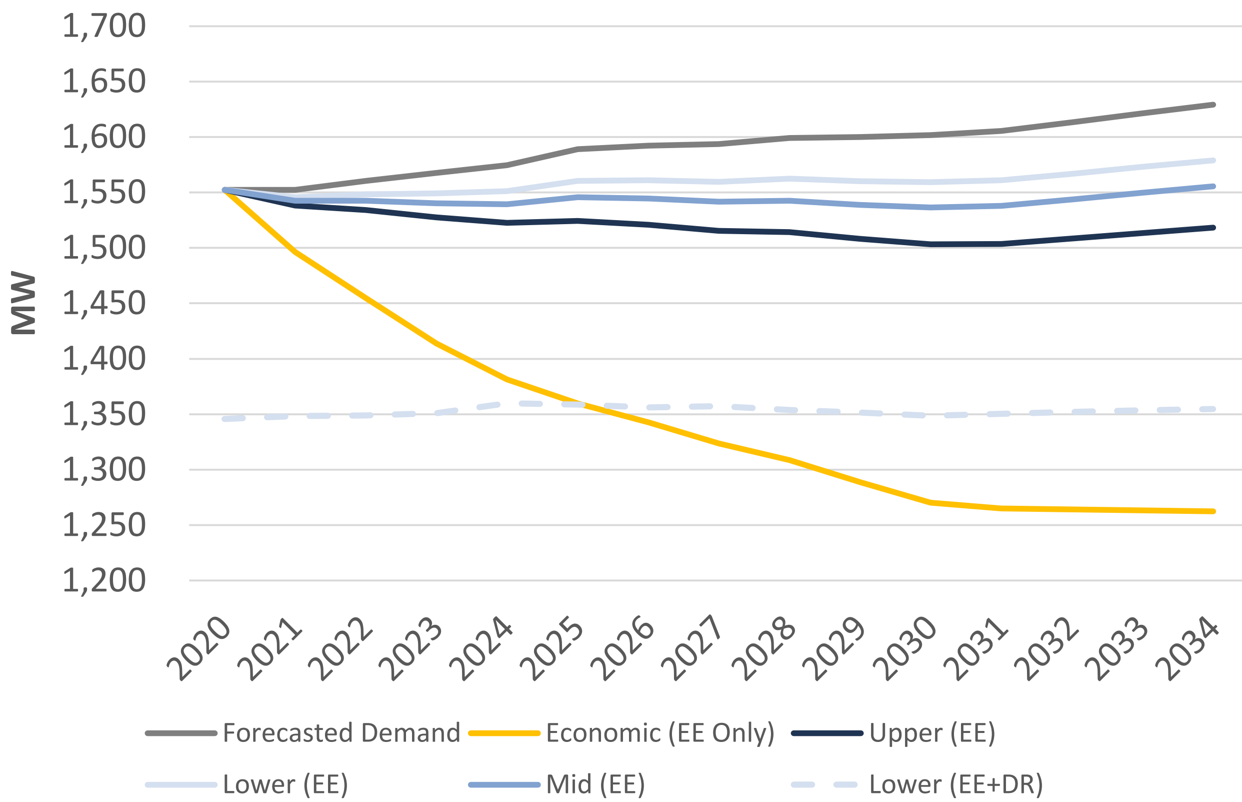


Figure 2-9 (Updated)



	Technical	Economic	Upper	Mid	Lower
IIC (DR)			238	230	184
LAB (DR)			19	19	19
ISO (EE)	3	3	1	1	1
LAB (EE)	70	63	30	22	14
IIC (EE)	390	375	114	76	52

Figure 2-10 (Updated)



Schedule F
2021 Plan Program Descriptions

Residential EV & Charging Infrastructure Program

Program Description

The objective of this program is to reduce the upfront capital cost of EVs and EV charging infrastructure. EVs typically have a higher up-front purchase cost than gasoline powered vehicles but lower ongoing operating and maintenance costs. The upfront cost of an all-electric vehicle is approximately $19,000 more than a standard gas-powered vehicle. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV. The program components consist of at the cash rebates and a variety of education and marketing tools.

Once an EV is purchased, typically more costs are required to install Level 2 EV charging equipment at home. There may also be installation costs, including the cost of upgrades to wiring and electrical capacity. This program provides a rebate for qualifying Level 2 EV chargers to reduce this barrier to EV adoption. This program will also require customers to deploy connected Level 2 EV charging infrastructure at their homes to allow for future utility demand response programs.

Target Market: Residential

The program targets potential EV buyers and will reduce the overall cost of ownership, making the vehicle more economically attractive. Research shows that incentives will increase EVs load by as much as 16-32% in the short-term.

Eligible Measures

Both all electric and plug-in hybrid electric vehicles would be eligible. Qualifying network capable 240 V AC residential Level 2 chargers for EVs would also be eligible for rebate under this program.

Delivery Strategy

The program will be promoted through outreach, key partners and advertising delivered in conjunction with other residential EV marketing. Partnerships with dealerships will be central to delivery of this program. Dealers carry program marketing materials in-store to promote the rebates to customers and undertake training to educate staff about the program to further drive customer reach. The EV purchase incentive would be applied to the pre-tax purchase price.

Tools and tactics include website presence, tradeshows, retail point-of-sale materials, trade ally activities and advertising.

Residential EV & Charging Infrastructure Program

Market Considerations

Based on publicly available data, annual vehicle sales in Newfoundland and Labrador are estimated at approximately 37,000 vehicles. As of 2019, approximately 410,000 on-road vehicles were registered in the province, with 94% estimated to be LDVs. 66% of vehicles are estimated to be primarily for personal use.

Consumers are accustomed to having many options with respect to models, colors, and features when purchasing a new vehicle. The limited variety of EV models currently being manufactured and available at dealerships constrain adoption of EVs.

EV adoption faces a number of barriers such as the initial cost, access to charging and lack of customer understanding of the technology and awareness of the benefits.

Incentive Strategy

Incentives for this program include at the cash rebates. The Utilities will provide a rebate of $2,500 for an all-electric vehicle and $1,000 towards a plug-in EV. This reflects consideration of the incremental cost and the total cost of ownership with an EV. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV.[1]

For residential EV charging infrastructure, an incentive will be provided toward the charger with a rebate of up to $500 of the pre-tax purchase price. Customers can apply online or by mail for this on-bill credit.

Program Monitoring & Evaluation

The program will be monitored for participation levels, program influence and cost effectiveness. Third party evaluations will be conducted after the first year of implementation and biannually during operation.

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[1] This assumes the current federal incentive of $5,000 on a BEV and $2,500 on a PHEV covers a portion of this incremental cost (26% for an all-electric vehicle) and remains in place for the duration of the 2021 Plan.

Residential EV & Charging Infrastructure Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	515	1,067	1,896	2,061	2,964	8,503
Estimated Cumulative Energy Usage (GWh)	0.3	1.5	4.3	9.3	17.1	32.5
Modified Total Resource Cost						**1.9**

Commercial EV & Charging Infrastructure Program

Program Description

The objective of this program is to reduce the upfront capital cost of EVs for commercial customers adding EVs to their fleet of vehicles. EVs typically have a higher up-front purchase cost than gasoline powered vehicles but lower ongoing operating and maintenance costs. The upfront cost of an all-electric vehicle is approximately $19,000 more than a standard gas-powered vehicle. Currently, businesses that purchase EVs receive either a point of sale rebate or a tax credit from the Federal Government. The Utilities' program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV. The program components consist of at the cash rebates and a variety of education and marketing tools.

Once an EV is purchased, typically more costs are required to install Level 2 charging equipment. There may also be installation costs, including the cost of upgrades to wiring and electrical capacity. This joint program provides a rebate for qualifying Level 2 EV chargers to reduce this barrier. This program will also require customers to deploy connected Level 2 EV charging infrastructure at their facilities to allow for future utility demand response programs.

Target Market: Commercial

The program targets potential EV buyers. This incentive would reduce the overall cost of ownership, making the vehicle more attractive from an economic standpoint. Research shows that incentives will increase EVs load by as much as 16-32% in the short-term.

Large companies or municipalities are likely to have fleet and transportation managers who will approach vehicle purchases by considering total cost of ownership which includes considering the vehicle purchase costs and ongoing operating costs. Buying decisions in larger companies are often heavily influenced by financial factors, budgets, company standards, etc. The purchase process generally involves defining the specifications of the vehicles wanted, then seeking out bids from vehicle manufacturers that meet these specifications.

Eligible Measures

Both all electric and plug-in hybrid electric vehicles would be eligible. Qualifying commercial network capable 240 V AC Level 2 chargers for EVs would also be eligible for rebate under this program.

Commercial EV & Charging Infrastructure Program

Delivery Strategy

The program will be promoted through outreach, key partners and advertising delivered in conjunction with other EV marketing. Partnerships with dealerships will be central to delivery of this program. Dealers carry program marketing materials in-store to promote the rebates to customers and undertake training to educate staff about the program. Outreach to commercial customers who have employee and fleet charging opportunities will be essential to this program.

Marketing initiatives include partnering with trade allies in the automobile industry, particularly dealerships. Tools and tactics include website presence, tradeshows, retail point of sale signage, trade ally activities and advertising.

Market Considerations

Based on publicly available data, annual vehicle sales in Newfoundland and Labrador were estimated at approximately 37,000 vehicles. As of 2019, approximately 410,000 on-road vehicles were registered in the province, with 94% estimated to be LDVs. 34% of vehicles are estimated to be primarily for commercial use.

Commercial EV adoption faces a number of barriers such as the initial cost, model availability, access to charging and lack of customer understanding of charging technology. This program will help to address all of these barriers.

Incentive Strategy

Incentives for this program include at the cash rebates. The Utilities will provide a rebate of $2,500 for an all-electric vehicle and $1,000 towards a plug-in EV. This reflects consideration of the incremental cost and the total cost of ownership with an EV. This program will work in conjunction with the Federal rebate to further reduce the capital cost of an EV.[2]

For the charging infrastructure, the incentive will be provided toward the installation of a charger with a rebate of up to $3,000 off the pre-tax purchase price. Customers can apply online or by mail for this on-bill credit.

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2 This assumes the current federal incentive of $5,000 on a BEV and $2,500 on a PHEV covers a portion of this incremental cost (26% for an all-electric vehicle) remains in place for the duration of the 2021 Plan.

Commercial EV & Charging Infrastructure Program

Program Monitoring & Evaluation

The program will be monitored for participation levels, program influence and cost effectiveness. Formal evaluations will be conducted after the first year of implementation and biannually during operation.

Estimated Costs & Energy Savings

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	263	391	486	591	830	2,561
Estimated Cumulative Energy Usage (GWh)	0.1	0.4	1.0	2.4	4.8	8.7
Modified Total Resource Cost						**2.2**

Custom Electrification Program

Program Description

This program will be offered to help customers replace “standard” fossil fueled technologies with electric equivalent technologies that are more efficient. The Custom Electrification program would operate in a similar fashion as the Business Efficiency Program. Incentives are provided on an individualized basis for projects that are cost-effective from both the customer and utility perspectives.

Target Market: Commercial

This program targets business owners who have an interest in reducing their operating costs and their GHG emissions. The program includes a custom approach that evaluates projects on a case by case basis.

Eligible Measures

Eligible measures include any technology or process that could be electrified cost effectively from a customer and utility perspective. Projects could include the installation of mini-split heat pumps for water or space heating, electrification of business processes, dockside electrification or the purchase of electric fork lifts.

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. A complimentary walk-through audit helps customers identify electrification opportunities.

Delivery of this program includes partnering with manufacturers, distributors, electrical contractors and service providers. The program creates business opportunities for trade allies to sell more efficient products.

The program also targets commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics include trade ally and business association activities, such as workshops for distributors, contractors and building operators, website and advertising, such as in trade publications.

Custom Electrification Program

Market Considerations

Barriers to increased market penetration of these technologies include initial cost, awareness of the benefits of electrification and building ownership, budget and planning cycles, technical know-how and customer time constraints.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention, provide technical and financial support and feasibility studies for electrification projects. The custom stream provides incentives based on project energy consumption of 15 cents/kWh. Rebates are paid on the energy use the customer is forecast to achieve in the first year of the project. Incentives of up to $50,000 per site help garner interest and lower customer project costs.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality and cost effectiveness. Each incented custom project will have a measurement and verification plan to confirm energy use achieved is consistent with incentives paid. Third party evaluations will be conducted after the first year of implementation and biannually during operation.

Estimated Costs & Energy Consumption

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	174	304	249	360	351	1,438
Estimated Cumulative Energy Usage (GWh)	0.1	0.5	1.0	1.7	2.6	5.9
Modified Total Resource Cost						**2.1**

Insulation and Air Sealing Program

Program Description

The objective of this program is to improve the insulation levels and air tightness of residential homes. The program focuses on insulation levels in residential basements, crawl spaces and attics. It will also include measures to improve air sealing and duct insulation. Increasing the insulation R-value in a home, improving air sealing, and insulating heating ducts will result in space heating energy savings. The program components include rebates, financing, customer education and trade-ally engagement. Residential basement, crawl space and attic insulation rebates have been offered through takeCHARGE since 2009. Rebates for air sealing and duct insulation are new elements of this program and will be available beginning in 2022.

Target Market: Residential

This program targets residential customers completing retrofit projects at a primary residence. Due to the National Building Code of Canada new homes must be well-insulated, therefore this program is only offered to existing homes. Eligibility will be limited to electrically-heated homes.

Eligible Measures

Eligible measures in this program include insulation upgrades to basements, crawl spaces, attics, and heating ducts. It will also include measures which result in better air sealing as demonstrated through a pre and post air sealing blower door test.

Delivery Strategy

Program promotion will include partnering with retailers and trade allies in the renovation industry. Initiatives will target both do-it-yourself and professional installers. Tools and tactics will include retail point-of-sale materials, advertising, website, tradeshows and community outreach.

Rebates will be processed through online and mailed customer applications.

Insulation and Air Sealing Program

Market Considerations

Barriers to increased market penetration of insulation include initial cost, awareness of benefits, difficulties of renovating an existing living space, and a decreasing number of eligible participants. Additional barriers for the air sealing program are the availability of qualified blower door test inspectors and qualified air sealing contractors. Experience with the existing insulation program has shown participation to be responsive to awareness-building marketing activities.

Incentive Strategy

Incentives for this program include rebates and financing. For the insulation portion of the program, customers can receive a rebate of 75% of the cost of insulation installed in the basement and crawl space and 50% of the cost of insulation installed in the attic. Rebate amounts are capped at $1,000 for each attic and basement project.

Incentives for air sealing will be based upon the level of improvement in a blower-door test completed before and after air sealing measures have been implemented. Customers achieving a 10% improvement will receive a $100 rebate, customers achieving a 20% improvement will receive a $250 rebate and customers achieving improvement of 30% or higher will receive a $350 rebate. Upon completion of their project, and showing at least a 10% improvement, customers will also receive 50% of the cost of their blower-door test, up to $250. The maximum rebate a customer can receive is $600.

Duct insulation incentives will cover 50% of the cost to insulate ducts in unconditioned spaces of electrically heated residential homes. To qualify, a minimum insulation value of R-6 and a maximum insulation value of R-8 must be installed. Eligible homes are those heated primarily through a central electric furnace or central heat pump. The rebate amount will be capped at $500 per home.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality, market saturation, and cost effectiveness. A representative sample of installations will be inspected. A third-party evaluation of the new program components will be conducted after the first year of implementation, with the full program being reviewed by an external consultant every three years during operation.

Insulation and Air Sealing Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,745	1,796	2,097	2,013	2,131	9,782
Estimated Cumulative Energy Savings (GWh)	54.4	60.6	67.0	73.8	80.8	336.6
Total Resource Cost						**6.6**

Thermostat Program

Program Description
The objective of this program is to encourage installation of programmable and high-performance electronic thermostats. Programmable and high-performance electronic thermostats allow customers to better control the temperature of their homes and to set it back during the night or while away. The program components include rebates, financing, and customer education. This program has been offered through takeCHARGE since 2009.
Target Market: Residential
This program targets residential customers. This includes existing and new homes that are a primary residence. Eligibility is limited to electrically-heated homes.
Eligible Measures
Eligible measures in this program include both programmable and high-performance electronic thermostats. Smart thermostats that can be controlled by a smart phone, tablet or computer are also eligible. All thermostats must have a setting precision of at least +/- 0.5 degrees Celsius.
Delivery Strategy
Program promotion will include partnering with retailers, electrical contractors, homebuilders and real estate professionals. The goal is to educate customers regarding the energy savings and comfort benefits of programmable and high-performance electronic thermostats. Tools and tactics include retail point-of-sale materials, website, tradeshows and community outreach. Rebates will be processed through online and mailed customer applications.

Thermostat Program

Market Considerations

Barriers to installation of programmable and high-performance electronic thermostats include lack of awareness of benefits, difficulty understanding how to program thermostats, reluctance to pay for an electrician to install the thermostats, and a decreasing number of eligible participants due to previous success of the program.

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $5 per high performance electronic thermostat and $10 per programmable thermostat. These reflect the incremental cost of these measures above the baseline dial thermostat.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality, market saturation and cost effectiveness. A representative sample of installations will be inspected. A third party program evaluation will be completed every three years.

Estimated Costs & Energy Savings

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	567	453	507	528	475	2,530
Estimated Cumulative Energy Savings (GWh)	27.1	29.8	32.3	34.7	37.0	160.9
Total Resource Cost						**1.6**

Instant Rebates Program

Program Description

The objective of the Instant Rebates program is to increase home energy efficiency by increasing access to a variety of energy efficient technologies. The program, offers at-the-cash rebates at participating retailers during specific campaign periods during the year. This program has been in place since 2014.[3]

Products under the Instant Rebate program help customers save on many end-uses including space heating, water heating, lighting and electronics. Many of these items are low-cost and easy to install.

Target Market: Residential

The target market is residential customers looking to make changes to decrease their overall energy usage. All customers can take advantage of this program, as long as they are purchasing an approved product.

A variety of media such as TV, print, radio, online, website, as well as social media channels are used to engage customers and create program awareness.

Eligible Measures

Eligible measures include dimmer switches, ENERGY STAR® ceiling fans with lights, ENERGY STAR light fixtures, ENERGY STAR Dehumidifiers, ENERGY STAR LED light bulbs, faucet aerators, high performance showerheads, lighting timers, smart plugs, motion sensors, outlet and switch insulators, smart power strips, weather stripping, window insulation film and air purifiers.

[3] The Instant Rebates program is the ongoing component of the Small Technologies Program launched in 2014. The Small Technologies Program also included rebates on appliance and electronics. These rebates were available through online and mail-in application from 2014 to 2017. This component of the program was concluded in response to wide availability of high efficient models and forecasted decline of marginal costs. The program originally provided rebates on refrigerators, chest freezers, washing machines and televisions.

Instant Rebates Program

Delivery Strategy
This program is offered as an upstream rebate program with incentives applied when purchased at the cash. The program uses a combination of mass marketing, as well as retail partnerships and in-store promotion through the hiring of Retail Coordinators. Events at participating retailers help to keep customers informed of the rebates and associated energy savings benefits. Educational resources are also used to help customers understand how to select and install these energy efficient items.
Market Considerations
The technologies included in the program do not involve a major renovation and are typically easy to install. Barriers to the use of eligible products include lack of awareness of the products themselves and the benefits offered, such as smart power bars, and lack of understanding of how to install certain products, such as draft-proofing items.
Incentive Strategy
Product incentives are derived based upon the purchase price of the product and the associated energy savings benefits of the product, and as a result, vary depending on product type. Rebate amounts range from $1.00 to $30.00 per item. Incentives will continue to be offered at the cash, so customers will not have to apply for reimbursement.
Program Monitoring & Evaluation
The program will be monitored for participation levels, service quality, market saturation, and cost effectiveness, particularly as it relates to LED bulbs, which represent a majority of the products rebated. Socket saturation surveys and third-party evaluation will be conducted to inform the conclusion of the program. This will include determining LED saturation in homes and how influential the program is on customers' decisions to purchase these bulbs.

Instant Rebates Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,507	1,424	-	-	-	2,931
Estimated Cumulative Energy Savings (GWh)	76.6	81.3	78.7	77.3	77.1	391.0
Total Resource Cost						**1.7**

HRV Program

Program Description
The objective of this program is to increase the installation rate of higher efficiency heat recovery ventilators ("HRV"). HRVs provide ventilation while minimizing heat loss. The program components include rebates, financing, customer education and trade-ally engagement. This program has been in place since 2013.
Target Market: Residential
This program targets all residential customers regardless of heat source or age of home.
Eligible Measures
Eligible measures in this program include HRV models that have a sensible recovery efficiency of 70% or greater and meet the minimum fan efficacy requirements. HRVs must be installed by a certified Heating, Refrigeration and Air Conditioning (HRAI) installer.
Delivery Strategy
Program promotion will include partnering with trade allies in the home building and renovation industry, particularly HRAI certified installers. Tools and tactics include website presence, online advertising and tradeshows. Rebates will be processed through online and mailed customer applications.
Market Considerations
The market includes new installations and existing HRV replacements. This program faces a number of barriers such as customer understanding of what an HRV is and its purpose in the home. Other barriers are the initial cost, the cost associated with using a certified installer, and awareness of the benefits of selecting a more efficient HRV.

HRV Program

Incentive Strategy

Incentives for this program include rebates and financing. The rebate value is $175 for qualifying HRV units. This reflects the incremental cost of a more efficient unit. A $25 incentive is also provided to installers for each approved application. This upstream incentive helps to ensure that installers stock and promote eligible models.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality, and cost effectiveness. A representative sample of installations will be inspected. A third-party program evaluation will be completed every three years.

Estimated Costs & Energy Savings

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	199	202	254	241	245	1,141
Estimated Cumulative Energy Savings (GWh)	1.7	2.0	2.3	2.6	3.0	11.6
Total Resource Cost						**1.6**

Benchmarking Program

Program Description

Energy social benchmarking is the analysis of a household's energy consumption and comparing its performance with that of similar households. A report is delivered to participating customers via mail and/or email. These reports include a comparison of the customer's electricity usage to similar homes and their own consumption from the previous year. The Home Energy Reports and an online web portal provide tips and resources to facilitate energy use reduction. This program has been in place since 2016.

The Benchmarking program will be offered to Newfoundland Power customers only.

Target Market: Residential

The Benchmarking program participants are randomly selected across Newfoundland Power's service territory. Customers can choose to opt-out of the program at any time, but cannot opt-in due to the requirement to select similar treatment and control groups to analyze savings.

Eligible Measures

A home's energy use is compared anonymously to the usage patterns of other homes that are of similar size, age, heating type, etc. The Home Energy Report is designed to provide information to help home owners understand their energy use and find ways to make the home more efficient.

Delivery Strategy

The program is delivered largely by a third-party service provider that develops and issues the Home Energy Reports and maintains the online web portal. takeCHARGE oversees all aspects of the program to ensure greater customer engagement with their home energy use. The program is available year-round and is supported with takeCHARGE marketing efforts, such as contests, to increase participant engagement levels.

Benchmarking Program

Market Considerations

This program allows Newfoundland Power to actively engage with customers using direct home energy consumption information. Cross promotion of existing takeCHARGE rebate programs through Home Energy Reports helps drive participation in the other residential programs.

Incentive Strategy

No monetary incentive is offered. It has been demonstrated for this type of program that using social norm comparisons drives the greatest changes to household energy consumption.

Program Monitoring & Evaluation

The program will be monitored for participation levels, engagement levels, service quality and cost effectiveness. Each year a third-party evaluator, independent of the program delivery agent will validate the claimed energy savings.

Estimated Costs & Energy Savings

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,023	957	976	997	1,017	4,970
Estimated Cumulative Energy Savings (GWh)	14.0	14.0	14.0	14.0	14.0	70.0
Total Resource Cost						**1.3**

Low Income Kit Program

Program Description

The objective of this program is to allow access to energy efficient items for customers whose financial circumstances are a barrier to program participation. The program will require customers who qualify under the Utilities' threshold for low income to apply for an energy efficiency kit. The kit will contain measures to save energy on space heating, water heating and lighting. This program also helps the Utilities reach low income customers with energy efficiency education through information included in the kits and online resources. The full cost of the kit, including delivery, will be incurred by the Utilities. This is a new program, starting in 2022.

Target Market: Low income residential

This program targets residential customers who meet the Utilities' low-income threshold. Renters and home owners will be eligible for this program regardless of heating source. Customers are limited to one kit per household.

Eligible Measures

The kits will include items such as LED light bulbs, high performance shower heads, faucet aerators and weatherstripping. The exact contents of each kit will be determined in conjunction with the selected program partner.

Delivery Strategy

This program will be delivered through a third-party vendor who will supply energy efficiency kits, coordinate customer delivery and provide installation support. The Utilities will approve applications and provide marketing, education and other supports as required.

Low Income Kit Program

Market Considerations

Barriers to installation of these measures for low income customers include the upfront cost, lack of awareness of benefits, and difficulty understanding how to install certain items, such as weatherstripping.

Incentive Strategy

The Utilities will cover the full cost of the kit and delivery.

Program Monitoring & Evaluation

The program will be monitored for installation levels, service quality, and cost effectiveness. A third-party evaluation will be conducted after the first year of implementation and biannually during operation.

Estimated Costs & Energy Savings

	2021	2022	2023	2024	2025	Total
Estimated Costs ($000s)	60	470	569	494	574	2,167
Estimated Cumulative Energy Savings (GWh)	-	3.7	7.3	10.2	13.1	34.3
Total Resource Cost						**3.3**

Business Efficiency Program

Program Description

The objective of the Business Efficiency Program ("BEP") is to help commercial customers become more energy efficient and reduce peak demand. Incentives are provided for upgrades for existing facilities. The program allows customers to implement projects customized to their own facilities. takeCHARGE has been offering rebates to commercial customers since 2009.

Target Market: Commercial

This program targets business owners who have an interest in making their business more energy efficient. The program includes a custom approach, but also includes prescriptive rebates for specific energy savings measures such as LED lighting, air source heat pumps, thermostats, occupancy sensors, and more. The program also targets commercial customers with opportunities to reduce peak demand, with a focus on businesses who are replacing fossil fueled technologies with electric equivalent technologies.

Eligible Measures

There are three components of the BEP: (i) prescriptive rebates; (ii) custom energy rebates; and (iii) custom demand rebates.

Prescriptive rebates provide money back when customers purchase and install eligible products. The specific measures eligible for per unit rebates include LED screw-in lamps, High Bay LED fixtures, T8 LED tubes, T5 LED tubes, LED luminaires, LED parking lot lighting, LED exit signs, high performance showerheads, programmable thermostats, occupancy sensors, rooftop air source heat pump systems and pre-rinse spray valves.

Custom energy rebates involve takeCHARGE consulting with the customer on an energy saving project that is customized to individual customer circumstances. Incentives are provided on an individualized basis for projects that are cost effective from the customer and utility perspectives. Rebates are paid on the energy savings the customer achieves in the first year of the project.

The custom demand rebate operates similarly to the custom energy rebates component, except the rebate is determined based on the peak demand reduction the customer achieves after completing the project. This component will evolve to support customers who are electrifying their facilities implementing demand management mechanisms, helping ensure that all customers benefit from the electrification of commercial buildings.

Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. A complimentary on-site energy assessment helps customers identify efficiency and demand management opportunities.

Marketing for this program includes partnering with trade-allies such as lighting distributors and electrical contractors. The program creates business opportunities for trade allies to sell more efficient products.

The program also targets commercial property owners through direct marketing and through industry associations such as the Building Owners and Managers Association. Tools and tactics include outreach such as presentations to associations, retail point-of-sale materials, website and advertising.

Market Considerations

Barriers to increased market penetration include initial cost, awareness of the program and available incentives, building ownership, budget and planning cycles, technical know-how and customer time constraints.

Incentive Strategy

Incentives for this program help with the costs for upgrades, energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at 10 cents/kWh for first year savings or project demand savings at $100 per kW per month over the December to March period for the first year of participation and $50 per kW each year for the life of the demand management system installed. Demand savings projects require a minimum of 50 kW savings to be sustainable over at least 5 years. The demand incentive may be updated to better support customers pursuing beneficial electrification. Incentives of up to $50,000 per site help lower customer project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online submissions.

Program Monitoring & Evaluation

The program will be monitored for participation levels, service quality and cost effectiveness. Custom projects will have a measurement and verification plan to confirm savings achieved are consistent with incentives paid. A third-party program evaluation will be completed every three years.

Business Efficiency Program

Estimated Costs & Energy Savings						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	1,816	2,092	2,183	2,267	2,591	10,949
Estimated Cumulative Energy Savings (GWh)	51.6	58.7	66.2	73.7	82.1	332.3
Total Resource Cost						**2.9**

Isolated Systems Community Program

Program Description

The objective of this program is to provide outreach, education and energy efficient products to home and business owners in Hydro's 40 remote diesel-system communities throughout Newfoundland and Labrador, free of charge.

Target Market

This program targets both residential and commercial customers in Hydro's isolated systems. This includes Isolated Diesel systems on the Island, in Labrador, and the L'Anse au Loup system.

Eligible Measures

Measures will range from efficient lighting products, water heating products, pipe insulation, hot water tank insulation, commercial LED exit signs, and others that may be applicable.

The Isolated systems lighting replacement program offers free of charge to commercial customers, the supply and install of new high-performance lighting technologies.

Delivery Strategy

Hydro has engaged a contractor to deliver this program. They use a number of delivery strategies, including hiring and training local representatives, to engage residential and commercial customers. Direct installation will be completed, whereby the customer receives the technology installed in their home or business at no cost. During the direct install visit, customers also receive information on energy usage and efficiency options.

Isolated Systems Community Program

Market Considerations

Availability and awareness of energy efficient technologies continues to be an issue in rural communities and often technologies available are at a higher price than in urban markets. This program will address the barriers of availability. Opportunities exist in electric hot water heating, plug load and behavior-based areas.

Hydro's commercial customers tend to be smaller businesses and as such find it challenging to find the time and resources to address energy consumption issues; this program will provide the one on one interaction needed to assist these customers. The technologies included in the program do not involve a major renovation. This program will allow the utility to reach customers that may not have been able to participate in the other incentive programs.

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost effectiveness. A representative sample of direct installs will be surveyed for confirmation of continued installation and use. An evaluator will be involved to develop quality assurance guidelines and procedures and ensure they are aligned with evaluation standards and best practices.

Estimated Costs & Energy Savings

	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	999	999	999	999	999	4,995
Estimated Cumulative Energy Savings (GWh)	11.2	11.8	12.2	12.5	12.8	60.5
Total Resource Cost						**1.4**

Isolated Business Efficiency Program

Program Description

The objective of the Isolated Business Efficiency Program is to help commercial customers increase their electrical energy efficiency by providing incentives on energy efficient options for existing facilities. The program provides supports to encourage customers to implement projects customized to their own facilities.

This program is offered to business customers in Hydro's isolated diesel and L'Anse au Loup system areas.

Target Market: Commercial

This program targets business owners and property managers in Hydro's isolated diesel and L'Anse au Loup systems who have an interest in making their businesses more energy efficient. The program includes a custom project approach and also rebates for specific measures, such as high-performance lighting and Air Source Heat Pumps.

Eligible Measures

The custom stream allows customers to obtain rebates for almost any energy efficiency measures that result in economical electrical energy savings. The program excludes alternative energy and fuel switching. The specific measures eligible for per unit rebates have included programmable thermostats, occupancy sensors, high performance showerheads, and LED wall packs. In 2016, LED screw-in lamps, High Bay LED fixtures, Electrically Commutated Motors for Evaporator fans, Cold climate air source heat pump systems and Low Flow Pre-rinse spray valves were added to the prescriptive list of incentives.

Isolated Business Efficiency Program

Delivery Strategy

The delivery strategy for this program is mainly through individual customer interactions. The custom track involves a walkthrough audit and feasibility analysis to determine savings and eligible incentives. This allows for a wide range of eligible technologies and projects.

Marketing for this program includes partnering with lighting manufacturers, distributors, electrical contractors and lighting service providers as key market influencers and allies. The program will create business opportunities for trade allies to sell more efficient products.

The program will also target commercial property owners through direct marketing. Tools and tactics will include trade ally and business association activities, such as workshops for distributors, contractors and building operators, and a website. Demonstration projects will be selected from program participants.

Market Considerations

Barriers to efficiency in the commercial market include financial and human resource concerns. Incentives will assist in making energy efficiency upgrades more accessible. Human resource concerns are around awareness and knowledge of the technology options as well as time to develop the business case for retrofit projects.

The isolated systems have additional challenges with access to products and access to specific technical skill sets in the evaluation of projects and technology. Hydro’s program staff will assist in addressing these gaps.

Incentive Strategy

Incentives for this program are designed to reduce the cost barrier, attract customer attention and provide technical and financial support for energy audits and feasibility studies. The custom stream provides incentives based on project energy savings at the lesser of $0.4/kWh for first year savings or 80% of eligible project costs.

Incentives vary for the prescriptive measures. Rebates will be processed through mail-in and online customer applications.

Isolated Business Efficiency Program

Program Monitoring & Evaluation

The program will be monitored for participation level, service quality, and cost. Each incented project will have a measurement and verification plan to confirm energy savings achieved are consistent with incentives paid.

Estimated Costs & Energy Savings

	2021	2022	2023	2024	2025	Total
Estimated Costs ($000s)	1.0	1.0	1.0	1.0	1.0	5.0
Estimated Cumulative Energy Savings (GWh)	0.9	1.0	1.1	1.2	1.3	5.5
Total Resource Cost						**1.5**

Industrial Energy Efficiency Program

Program Description

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation projects. This program is a custom program to respond to the unique needs of Hydro's industrial customers, rather than a prescriptive technology approach.

Target Market: Industrial

This program targets existing, transmission level, industrial customers served by Newfoundland and Labrador Hydro.

Eligible Measures

Eligibility of projects is based on engineering review and confirmation of estimated energy savings impact. Technologies include, but are not limited to, compressed air, pump systems, process equipment and process controls.

Delivery Strategy

The program is managed internally, with external engineering services used as required. The utility takes the role of facilitator and consultant in providing methods for industrial customers to complete project proposals and implement approved projects.

This program was initially launched as a three-year pilot program in 2009, with the first project applications being submitted in 2011, and closed to new projects in 2013. The industrial pilot was reviewed in 2014 by an external party for performance; the review indicated the program matched or exceeded performance of comparable industrial CDM programs relative to the size of the industrial sector in the Newfoundland and Labrador market. The program was officially re-launched as an ongoing program in 2015, with the same structure as the pilot program.

Industrial Energy Efficiency Program

Market Considerations
This market requires a one-on-one approach to project design and delivery. The program builds on the work already completed by the industrial customers, and addresses their unique barriers to improved efficiency, which include, but are not limited to, access to capital and human resources. The lifecycle for each program transaction will be measured in months rather than weeks because of the need for review, contract development, budgeting and implementation timelines, and post-installation evaluation. This type of program requires that facilities have financial and business stability to continue operations for a time period appropriate to achieve cost effective savings.
Incentive Strategy
Incentives for this program include an initial comprehensive energy audit for the site, funding assistance for feasibility studies, and financial assistance for project implementation based on energy savings.
Program Monitoring & Evaluation
The program will be regularly monitored for participation level, service quality, and cost effectiveness, including engineering review and inspection of all projects and assessment of long-term impact on customer processes.

Industrial Energy Efficiency Program

Estimated Costs & Energy Savings[4]						
	2021	**2022**	**2023**	**2024**	**2025**	**Total**
Estimated Costs ($000s)	224	224	224	224	224	1,120
Estimated Cumulative Energy Savings (GWh)	31.0	31.0	31.0	31.0	31.0	155.0
Total Resource Cost						-

4 Hydro reminds its five transmission-level industrial customers annually of the availability of this program, but applications are not received every year. As a result of such a small market and budget considerations, participation is extremely variable from year to year and difficult to forecast. Therefore, the TRC cannot be forecast but all proposed projects must result in a positive TRC.

Schedule G
Stakeholder Consultation Summary

Stakeholder Consultation Summary

The planning cycle for customer programming is a continuous process involving stakeholder consultation at each phase.

The Utilities conducted a number of customer surveys and stakeholder interviews and workshops to inform the development of the Electrification, Conservation and Demand Management Plan 2021-2025 ("the 2021 Plan").

An overview of these customer and stakeholder consultations is provided in Table G-1.

Table G-1
2021 Plan Customer and Stakeholder Consultations

Residential End Use Survey	600 customers were surveyed.[1] The information gathered was used to assess potential electricity savings and electrification opportunities.
Commercial End Use Survey	403 facilities were surveyed.[2] This research provided information on commercial energy use in the province.
Customer Barrier Survey	666 residential customers and 150 commercial customers were surveyed to determine the largest barriers to technology adoption.[3]
Stakeholder Interviews and Workshops	Industry experts were interviewed to help quantify the potential and possible barriers, for electrification and CDM in the province.[4]
Government and Key Stakeholder Consultation	The Utilities currently participate in the Electrification Working Group formed by the Department of Energy, Innovation and Technology to inform the development of the Province's rate mitigation plan. Prior to this, Utilities worked with the Provincial Government and other stakeholders to assess opportunities and address challenges associated with increasing EV adoption through the Provincial Office of Climate Change's Electric Vehicle Working Group.

Initiatives in the 2021 Plan were developed to be flexible to address government policies and funding as well as economic and market conditions. The Utilities will consult with stakeholders and customers throughout program design and the implementation of the 2021 Plan. This collaborative process enables the Utilities to continuously evaluate market trends, advances in technology, customer barriers and program effectiveness.

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1 The Residential End Use Survey was completed by MQO Research in 2017.
2 The Commercial End Use Survey was completed by ICF Consulting Canada using mail out surveys to commercial customers. Surveys were completed over 2017 and 2018.
3 The Customer Barrier Survey was completed by Dusky Energy Consulting in 2019.
4 Workshops were held to consult with stakeholders such as commercial customers, trade allies, customer group representatives and retail partners.

Schedule H
Marginal Cost Projection of the Island Interconnected System
2021-2040

Table H-1
Marginal Cost Projection
For the Island Interconnected System
2021-2040

	Energy			Capacity
	Winter On-Peak ($/MWh)	Winter Off-Peak ($/MWh)	Non-Winter ($/MWh)	($/kW-Yr.)
2021	78	64	27	326
2022	79	64	29	333
2023	70	56	26	341
2024	68	56	27	350
2025	67	56	29	358
2026	74	63	29	364
2027	77	66	30	372
2028	79	69	34	380
2029	83	72	39	390
2030	85	73	40	398
2031	87	75	41	406
2032	88	76	42	414
2033	90	78	43	422
2034	92	79	44	431
2035	94	81	44	439
2036	96	83	45	448
2037	98	84	46	457
2038	100	86	47	466
2039	102	88	48	475
2040	104	89	49	485

Table H-1 shows the most recent marginal cost forecast based on projections by Newfoundland and Labrador Hydro in April 2020. December through March is considered the winter season and April through November is considered the non-winter season. From 7:00 a.m. to 11:00 p.m. on weekdays is considered on-peak hours. Off-peak hours occur after 11:00 p.m. until 7:00 a.m. and include weekends.

Schedule I
Electrification and CDM Program Economic Evaluation Practices

Table I-1 shows the primary economic tests used by utilities to evaluate CDM programs in Canadian jurisdictions.

Table I-1
Current Canadian Utility Practice
CDM Economic Evaluation Practices

Province	**Primary Economic Test**				
	TRC[1]	PAC[2]	RIM[3]	PCT[4]	SCT[5]
British Columbia[6]	X[7]				
Ontario	X[7]				
Nova Scotia[8]	X				
Manitoba[9]		X			
Quebec[10]	X				
Prince Edward Island[11]		X			
New Brunswick[10]		X			
Total	**4**	**3**			

1 Total Resource Cost Test ("TRC"). The TRC evaluates programs from the perspective of the customer and the utility. It includes the costs and benefits experienced by the utility system, plus costs and benefits to program participants.

2 Program Administrator Cost Test ("PAC"). The PAC evaluates programs from the perspective of the utility. It includes the costs and benefits experienced by the utility system.

3 Ratepayer Impact Measure ("RIM"). The RIM evaluates programs to provide an indication of their impact on rates. This test includes all of the costs and benefits included in the PAC, plus estimates of the utility lost revenues created by programs.

4 Participant Cost Test ("PCT"). The PCT evaluates programs from the perspective of the participant. This test includes all impacts on the program participants, but no other impacts.

5 Societal Cost Test ("SCT"). The SCT evaluates programs from the perspective of society as a whole. This test includes the costs and benefits experienced by society such as health benefits and GHG emission reductions.

6 British Columbia considers PAC and RIM as secondary tests.

7 British Columbia and Ontario use a modified TRC that includes non-energy benefits that are not traditionally included in the TRC.

8 Nova Scotia considers PAC as an informative test.

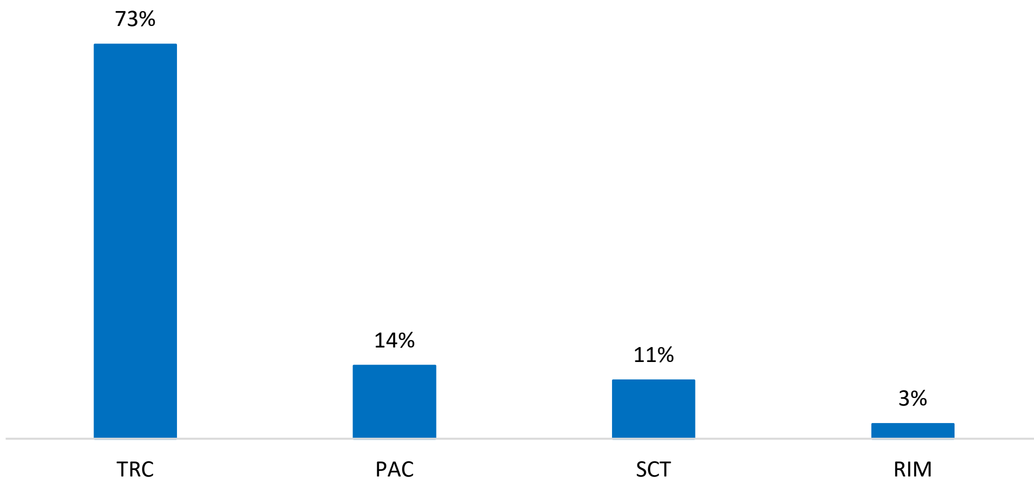
9 Manitoba also considers the utility net present value and levelized utility cost.

10 Quebec and New Brunswick consider the PCT a secondary test.

11 Prince Edward Island uses the PAC at the portfolio and program level as the primary test. The TRC is used as a secondary test at the program level.

Chart I-1 shows the percent of U.S. states which use some of the economic tests in Table I-1. [12]

Chart I-1
Current American Utility Practice
CDM Economic Evaluation Practices
(% of States)



n=37

[12] Research conducted by the American Council for an Energy Efficient Economy (January 2020) "*Evaluation, Measurement, & Verification Database*". *The Societal Cost Test ("SCT")* includes benefits such as environmental benefits and improved health and comfort.

Table I-2 shows the primary economic tests used to evaluate electrification programs in North American jurisdictions.

Table I-2
Current North American Utility Practice
Electrification Economic Evaluation Practices

Jurisdiction	**Rate Impacts Assessment**[13]	**Overall Cost Assessment**[14]	**Not assessing cost effectiveness**
Arizona			X
British Columbia			X
California		X[15]	
Kansas			X
Maryland			X
Massachusetts			X
Missouri		X	
New York		X	
Ohio	X	X	
Oregon	X	X[15]	
Rhode Island	X	X	
Utah			X
Vermont		X	
Washington			X
Total	**3**	**7**	**7**

13 Rate Impacts Assessment includes utilities that are using the RIM test for electrification programs.
14 Overall Cost Assessment includes utilities that are using the TRC, SCT or a test created by the utility specifically for electrification that evaluates programs from the perspective of the customer, the utility and the ability to meet policy objectives.
15 California and Oregon are using multiple tests in the Overall Cost Assessment category to evaluate cost effectiveness.

Schedule J
Utility Investment Models for Electric Vehicle Charging Infrastructure

Utility Investment Models for EV Charging Infrastructure

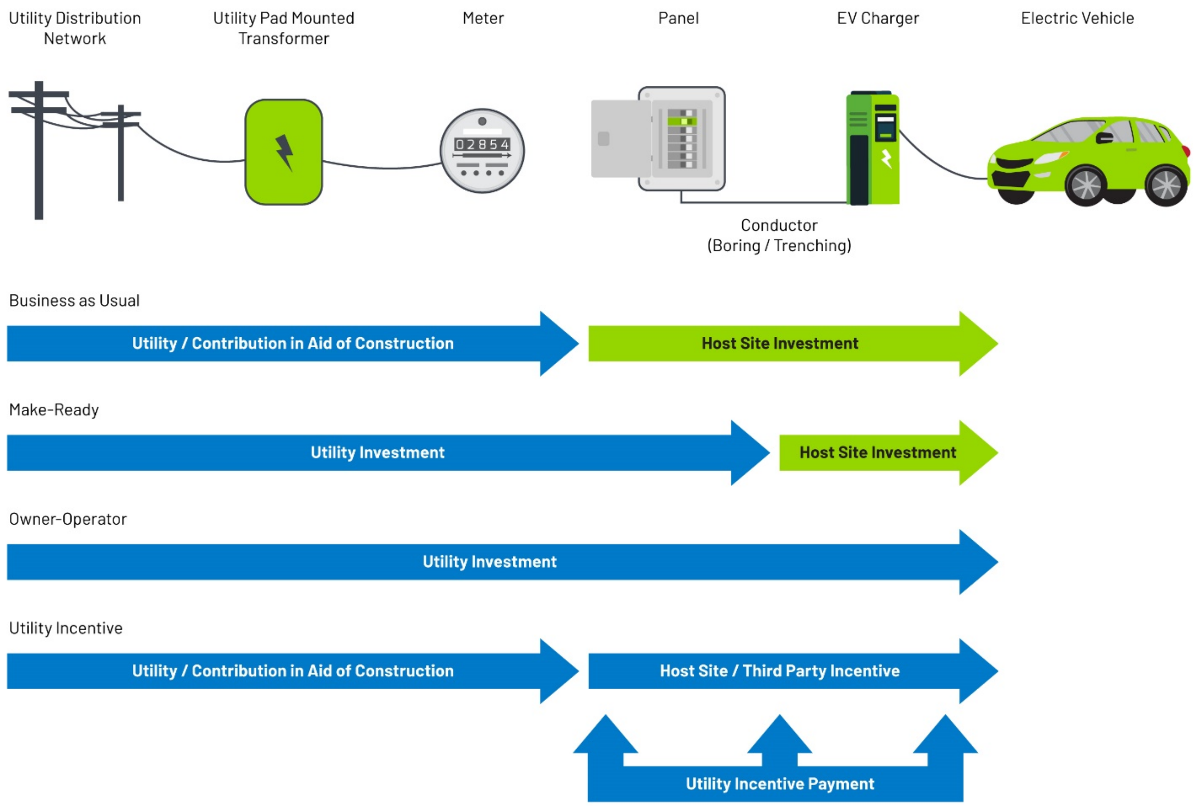
A lack of sufficient EV charging infrastructure is a barrier to widespread EV adoption. A comprehensive charging network is needed to eliminate customer concerns about reaching their destination and to enable long-distance travel.

Variables to consider when determining the most effective utility investment model for a jurisdiction include siting, the capacity of the distribution system, the local EV charging infrastructure market and EV adoption rate. The appropriate investment model may vary across a utility's service area and over time.

Utility investment in EV charging infrastructure can have numerous benefits including: (i) increasing the pace and scale of charging infrastructure development, (ii) maintaining reliability and minimizing grid impacts, and (iii) providing more equitable access to charging infrastructure for all EV drivers.

There are three primary models for utility investment in EV charging infrastructure: (i) make-ready, (ii) utility charging network; and, (iii) utility incentive. Figure J-1 below shows the three common models for utility investment in EV charging infrastructure, compared to a business as usual investment.[1]

Figure J-1



1 MJ Bradley and Associates, *Utility Investment in Electric Vehicle Charging Infrastructure: Key Regulatory Considerations*, 2017.

Utility Investment Models for EV Charging Infrastructure

Business as Usual: When a customer requests a new service connection, the Utilities follow a Board approved methodology to determine the required utility and customer contributions. The customer investment is referred to as a contribution in aid of construction ("CIAC"). The utility typically funds and owns the infrastructure up to the customer meter and the customer owns all assets behind the meter.

Make-Ready Model: The make-ready model includes the installation of electrical infrastructure to enable customers to purchase and install DCFC. This may include upgrades to transformers and service capacity, installing meters or running new service drops to specific areas of a host site, such as in a parking lot at a workplace.

Investment in make-ready infrastructure helps reduce the costs associated with customer DCFC infrastructure. Make-ready costs are typically a large portion of the capital costs of an installation, at about 30%–40%.[2]

Utility Owner-Operator Model: The utility owns and operates all components of the EV charging infrastructure, also referred to as a Utility Charging Network. A utility owner-operator would also oversee other program components, including marketing and host site recruitment, pricing and ongoing operations and maintenance.

Utility Incentive Model: The utility administers and provides rebates for EV charging infrastructure.

The 2021 Plan: Utility Investment in EV Charging Infrastructure

The Utilities are proposing investment in the make-ready and utility owner-operator models.

Table J-1 shows the number of DCFC's forecast to be installed from 2021 through 2025 as a result of utility investment in the 2021 Plan.

Table J-1
DCFC's Installed
2021 through 2025

	2021	2022	2023	2024	2025	Total
Make-ready	-	1	3	5	6	15
Utility Charging Network	18	11	3	5	4	41
Total	**18**	**12**	**6**	**10**	**10**	**56**

Through utility investment in DCFCs in the 2021 Plan, a total of 56 fast chargers are expected to be in place in the province by 2025.[3]

[2] Chris Nelder and Emily Rogers, *Reducing EV Charging Infrastructure Costs*, Rocky Mountain Institute, 2019, p. 23.

[3] To maximize impacts of investments, existing federal programs will be leveraged to reduce utility costs associated with DCFC infrastructure deployment.

Schedule K
2021 Plan Pilot Descriptions

Custom Fleet Pilot Program

A significant portion of the forecast electricity demand associated with EVs in the province is expected to come from commercial vehicles. However, in the early years, medium-duty vehicles ("MDVs") and heavy-duty vehicles ("HDVs") uptake is expected to lag due to low model availability and higher upfront capital costs for EVs compared to conventional vehicles. Barriers to increased market penetration of MDVs, HDVs and buses include initial cost, awareness of benefits, market gaps for service and maintenance of EVs, the investment required for charging infrastructure and EV model availability.

The Custom Fleet Pilot Program targets commercial customers interested in the electrification of MDVs, HDVs and buses. The objective of this pilot is to reduce the costs associated with electrification of vehicles which are not eligible under the prescriptive electrification programs. It will also allow the Utilities to understand the unique barriers associated with electric MDVs, HDVs and bus adoption. This program will also enable the Utilities to work with participants to pilot initiatives that encourage off-peak charging.

Due to the custom nature of the Custom Fleet Pilot Program, eligible measures vary and depend on the needs of the interested participants. The pilot program components may include support through feasibility and fleet optimization studies, financial support for EVs and charging infrastructure, and technical advice. Incentives for each customer will vary depending on the potential load electrified.

Table K-1 shows the estimated costs, the number of vehicles and the additional electrified load added to the system associated with the Custom Fleet Pilot Program.

Table K-1
Custom Fleet Pilot Program
Costs, Vehicles and Electrified Load

	2021	**2022**	**2023**	**2024**
Costs ($000s)	295	605	857	1,038
# of Vehicles	2	3	5	7
Electrified Load (MWh)	104	126	230	275

EV Demand Response Pilot Program

By 2034, EV adoption is forecast to increase load and potentially change the Utilities' load shape. The 2020–2034 Potential Study suggests that in the near term, research and evaluation be used to understand these potential impacts and explore mitigation strategies. Managed or controlled EV charging will be key to limiting utility demand impacts thereby reducing customer costs. Managed charging allows EVs to be charged at times and at power levels that benefit both customers and the Utilities.

The EV Demand Response Pilot Program targets customers who are existing or potential EV owners and will be charging at home with a level 2 charger. The objective of this pilot program is to assess demand response measures to determine their ability to shift peak loads, customer acceptance and cost effectiveness. The pilot program will collect EV charging information showing the load profile of charging operation and the impact on the distribution system.

The EV Demand Response Pilot Program will consider various technologies that help reduce charging at times of system peak such as smart chargers and direct load controllers. Vehicle analytics will be used to understand charging behaviour and the impact of EV charging demand on the electrical system. Incentives may be a combination of equipment purchase and a monthly participation credit, based on allowing the utility to manage EV charging. The pilot program will provide EV charging information showing the load profile of charging operations.

Table K-2 shows the estimated costs, the number of vehicles and the demand reduction associated with the EV Demand Response Pilot Program.

Table K-2
EV Demand Response Pilot Program
Costs, Vehicles and Demand Reduction

	2022	**2023**	**2024**
Costs ($000s)	573	316	258
# of Vehicles (Cumulative)	75	125	125
Demand Reduction (kW)	96	159	159

Small Business Direct Install Pilot Program

Small business owners face a number of barriers to making energy efficient upgrades including competing monetary demands and lack of time. They may also be unsure of where to start and of the benefits of these upgrades. To help overcome these participation barriers, this pilot program facilitates the direct installation of energy efficient measures at no cost to the customer.

The Small Business Direct Install Pilot Program targets Rate 2.1 commercial customers interested in making their business more energy efficient. The objective of this pilot program is to assess the cost effectiveness of a provincial direct install program. The pilot will also help businesses identify larger energy efficient upgrades which could be eligible for incentives through the Business Efficiency Program and no-cost ways to save on their energy costs.

The pilot program will be delivered through a third-party vendor who will supply eligible energy saving measures, coordinate customer visits, and install eligible measures. Eligible measures will include both water saving and lighting technologies.

Table K-3 shows the estimated costs, the number of participants and the energy savings associated with the Small Business Direct Install Pilot Program.

Table K-3
Small Business Direct Install Pilot Program
Costs, Participants and Energy Savings

	2021	**2022**	**2023**
Costs ($000s)	24	434	468
# of Participants	0	270	270
Cumulative Energy Savings (GWh)	0.0	1.0	2.0

Heat Pump Load Research Pilot Program

The Heat Pump Load Research Pilot Program began in the fall of 2019, with the objective of determining the impacts of the growing popularity of residential mini-split heat pumps ("MSHP") on Newfoundland Power's electricity system. The results will be used to determine the potential impact of MSHPs on system load shapes with an emphasis on system peak. The results will also serve to inform future conservation and demand management program design and customer education initiatives.

To accomplish these objectives, metering equipment was installed in 264 homes throughout Newfoundland to monitor electricity consumption. Approximately half of participating homes have a MSHP (the treatment group) while the other half are heated with an electrical resistance heating system (the control group). A meter was installed to monitor the MSHP in all treatment group homes, so that the electricity consumption of the MSHP could be recorded in addition to that of the whole house. The pilot program is expected to conclude in the spring of 2021.

Table K-4 shows the estimated costs and the number of participants associated with the Heat Pump Load Research Pilot Program.

Table K-4
Heat Pump Load Research Pilot Program
Cost and Participants

	2019	2020	2021
Costs ($000s)	462	202	129
# of Participants	264	264	264

Schedule L
Electrification, Conservation and Demand Management Program Forecasts

Table L-1
Electrification Programs
Energy Usage Estimates: 2021 – 2025
by Sector
(GWh)

	2021	2022	2023	2024	2025	Total
Residential						
EV & Charging Infrastructure Incentives	0.3	1.5	4.3	9.3	17.1	32.5
Total Residential Portfolio	**0.3**	**1.5**	**4.3**	**9.3**	**17.1**	**32.5**
Commercial						
EV & Charging Infrastructure Incentives	0.1	0.4	1.0	2.4	4.8	8.7
Custom Commercial	0.1	0.5	1.0	1.7	2.6	5.9
Total Commercial Portfolio	**0.2**	**0.9**	**2.0**	**4.1**	**7.4**	**14.6**
Total Portfolio	**0.5**	**2.4**	**6.3**	**13.4**	**24.5**	**47.1**

Table L-2
Electrification Programs
Program Cost Estimates: 2021 – 2025
by Sector
($000s)

	2021	2022	2023	2024	2025	Total
Residential						
EV & Charging Infrastructure Incentives	515	1,067	1,899	2,061	2,964	8,506
Total Residential Portfolio	**515**	**1,067**	**1,899**	**2,061**	**2,964**	**8,506**
Commercial						
EV & Charging Infrastructure Incentives	263	391	486	591	830	2,561
Custom Commercial	174	304	249	360	351	1,438
Total Commercial Portfolio	**437**	**695**	**735**	**951**	**1,181**	**3,999**
Total Portfolio	**952**	**1,762**	**2,634**	**3,012**	**4,145**	**12,505**

Table L-3
Conservation Programs
Energy Reduction Estimates: 2021 – 2025 (Includes Prior Years' Savings)
by Sector
(GWh)

	2021	2022	2023	2024	2025	Total
Residential						
Insulation and Air Sealing Program	54.4	60.6	67.0	73.8	80.8	336.6
Thermostat Program	27.1	29.8	32.3	34.7	37.0	160.9
ENERGY STAR Window Program	9.9	9.9	9.9	9.9	9.9	49.5
Coupon Program	0.2	0.2	0.2	0.2	0.2	1.0
Isolated Systems Community Program	10.0	10.5	10.9	11.2	11.5	54.1
Small Technology Program	76.6	81.3	78.7	77.3	77.1	391.0
HRV Program	1.7	2.0	2.3	2.6	3.0	11.6
Benchmarking	14.0	14.0	14.0	14.0	14.0	70.0
Low Income	0.0	3.7	7.3	10.2	13.1	34.3
Block Heater Timer Program	0.3	0.3	0.3	0.3	0.3	1.5
Total Residential Portfolio	**194.2**	**212.3**	**222.9**	**234.2**	**246.9**	**1,110.5**
Commercial						
Isolated Systems Community Program	1.2	1.3	1.3	1.3	1.3	6.4
Isolated Systems Business Efficiency Program	0.9	1.0	1.1	1.2	1.3	5.5
Business Efficiency Program	51.6	58.7	66.2	73.7	82.1	332.3
Total Commercial Portfolio	**53.7**	**61.0**	**68.6**	**76.2**	**84.7**	**344.2**
Industrial						
Industrial Energy Efficiency Program	**31.0**	**31.0**	**31.0**	**31.0**	**31.0**	**155.0**
Total Portfolio	**278.9**	**304.3**	**322.5**	**341.4**	**362.6**	**1,609.7**

Table L-4
Conservation Programs
Demand Reduction Estimates: 2021 – 2025 (Includes Prior Years' Savings)
by Sector
(MW)

	2021	2022	2023	2024	2025	Total
Residential						
Insulation and Air Sealing Program	18.2	20.7	23.4	26.2	29.1	29.1
Thermostat Program	4.1	4.2	4.3	4.4	4.4	4.4
ENERGY STAR Window Program	3.1	3.1	3.1	3.1	3.1	3.1
Coupon Program	0.0	0.0	0.0	0.0	0.0	0.0
Isolated Systems Community Program	3.3	3.5	3.6	3.7	3.8	3.8
Small Technology Program	18.2	19.1	18.6	18.2	18.2	18.2
HRV Program	0.5	0.6	0.7	0.8	0.9	0.9
Benchmarking	1.7	1.7	1.7	1.7	1.7	1.7
Low Income	0.0	1.0	2.1	2.9	3.8	3.8
Block Heater Timer Program	0.0	0.0	0.0	0.0	0.0	0.0
Total Residential Portfolio	**49.1**	**53.9**	**57.5**	**61.0**	**65.0**	**65.0**
Commercial						
Isolated Systems Community Program	0.1	0.1	0.1	0.1	0.1	0.1
Isolated Systems Business Efficiency Program	0.4	0.4	0.5	0.5	0.5	0.5
Business Efficiency Program	9.3	10.7	12.2	13.9	15.7	15.7
Total Commercial Portfolio	**9.8**	**11.2**	**12.8**	**14.5**	**16.3**	**16.3**
Industrial						
Industrial Energy Efficiency Program	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**
Total Portfolio	**59.6**	**65.8**	**71.0**	**76.2**	**82.0**	**82.0**

**Table L-5
Conservation Programs
Program Cost Estimates: 2021 – 2025
by Sector
($000s)**

	2021	2022	2023	2024	2025	Total
Residential						
Insulation and Air Sealing Program	1,745	1,796	2,097	2,013	2,131	9,782
Thermostat Program	567	453	507	528	475	2,530
Isolated Systems Community Program	999	999	999	999	999	4,995
Small Technology Program	1,507	1,424	-	-	-	2,931
HRV Program	199	202	254	241	245	1,141
Benchmarking Program	1,023	957	976	997	1,017	4,970
Low Income	60	470	569	494	574	2,167
Total Residential Portfolio	**6,100**	**6,301**	**5,402**	**5,272**	**5,441**	**28,516**
Commercial						
Isolated Systems Business Efficiency Program	71	71	71	71	71	355
Business Efficiency Program	1,816	2,092	2,183	2,267	2,591	10,949
Total Commercial Portfolio	**1,887**	**2,163**	**2,254**	**2,338**	**2,662**	**11,304**
Industrial						
Industrial Energy Efficiency Program	**224**	**224**	**224**	**224**	**224**	**1,120**
Total Programs Portfolio	**8,211**	**8,688**	**7,880**	**7,834**	**8,327**	**40,940**

Table L-6
Electrification Programs
Modified Total Resource Cost Test Results
by Sector

	mTRC Results
Residential	
EV & Charging Infrastructure Incentives	1.9
Commercial	
EV & Charging Infrastructure Incentives	2.2
Custom Commercial	2.1

Table L-7
Conservation Programs
Total Resource Cost Test Results
by Sector

	TRC Results
Residential	
Insulation and Air Sealing Program	6.6
Thermostat Program	1.6
Isolated Systems Community Program	1.4
Instant Rebates Program	1.7
HRV Program	1.6
Benchmarking	1.3
Low Income	3.3
Commercial	
Isolated Systems Business Efficiency Program	1.5
Business Efficiency Program	2.9
Industrial	
Industrial Energy Efficiency Program	- [1]

[1] Hydro reminds its five transmission-level customers annually of the availability of this program, but the applications are not received every year. As a result of such a small market and budget considerations, participation is extremely variable from year to year and difficult to forecast. Therefore, the TRC cannot be forecast but all proposed projects must result in a positive TRC.

Schedule M
Letters of Support

Newfoundland Labrador

Government of Newfoundland and Labrador
Department of Industry, Energy and Technology
Office of the Minister

DEC 16 2020

Mr. Kevin Fagan
Vice President
Newfoundland and Labrador Hydro

Mr. Byron Chubbs
Vice President
Newfoundland Power

Dear Mr. Fagan and Mr. Chubbs:

RE: Electrification, Conservation and Demand Management Plan: 2021-2025

Thank you for sharing your companies' Electrification, Conservation and Demand Management Plan for 2021-2025, along with the accompanying presentation. The plan indicates the province's utilities are taking actions to begin addressing the electrification, and conservation and demand management (CDM) recommendations in the Board of Commissioners of Public Utilities Rate Mitigation Options and Impacts Report. The Board's report demonstrated clearly that these action areas have excellent potential to assist with our rate mitigation efforts.

The evidence in the report suggests progress to date and a path forward for these areas. Given the external market conditions for non-firm energy sales in recent years, domestic load growth is a promising market for our energy sector, provided that load growth can occur in a cost-effective manner that can limit or reduce peak demand growth that would trigger costly new power supply infrastructure. We were pleased to see a role for CDM to help avoid these higher demand peaks.

We also note the plan concludes that dynamic rates for managing load growth does not appear to be a favourable tool at this time. Rate design, time of use rates, and critical peak pricing continue to interest our Government and hold promise for the future and we hope to see additional research and further progress in these areas over time.

We also note there are other areas of interest over the longer term that we look forward to advancing as economic feasibility allows. While the plan demonstrates that light duty vehicles are promising markets for our renewable electricity in the short and medium terms, our Government believes heavy duty and marine transportation are longer-term markets worthy of further examination. We look forward to working with you in these areas in the future.

P.O. Box 8700, St. John's, NL, Canada A1B 4J6 709 729 2920 709 729 0059 www.gov.nl.ca

Newfoundland Labrador

I sincerely appreciate your efforts to share your work to date to advance electrification and CDM and look forward to working together to make our province a leader in these areas.

Sincerely,

ANDREW PARSONS, QC
Minister of Industry, Energy and Technology
Attorney General

November 30, 2020

Krista Langthorne, Manager
Business Development
Newfoundland Power
55 Kenmount Road
St. John's, NL A1B 3P6
Canada

Re: Support of the 2021-25 Electrification, Conservation and Demand Management Plan

Dear Ms. Langthorne:

I have had a chance to review your draft plan for the above-mentioned five year period which you shared with the Alliance describing an expansion of the previous CDM (Conservation and Demand Management) plans and programs to transportation electrification end use cases. Overall, I believe you and your team at NL Power have done a great job in developing a comprehensive analysis at the electric vehicle (EV) and its projections, the important role of the utility as well as other EV market actors, and trying to meet the public policy goals of both the federal and provincial governments. More specifically, I think you have been responsive to the request from the Board (PUB) in February 2020 that requested you to develop such a study. Based upon our experience in reviewing similar transportation electrification and decarbonization plans in other North American jurisdictions, I believe that you have both met this requirement for a holistic, well-founded Plan that is similar to best practices in these jurisdictions. This should provide a solid basis for constructive dialogue with EV stakeholders.

Background and Introduction

The Alliance for Transportation Electrification, a 501(c)(6) non-profit corporation, is led by utilities, electric vehicle (EV) infrastructure firms and service providers, automobile manufacturers, and EV charging industry stakeholders and affiliated trade associations. We started with 20 organizations at the launch in early 2018. By taking a "big tent" approach to advance the industry, we have grown rapidly to include about 50 national dues-paying members and affiliated organizations. We are actively involved in over twenty regulatory and other state and Provincial proceedings in North America today.

General comments

Increasing the adoption of EVs and building out the transportation electrification (TE) infrastructure has become both a goal of the federal government as well as the Province, as the Plan states in the Background section. This is an important public policy imperative today in many (if not most) jurisdictions across North America today, not only from the environmental perspective of reducing GHGs as well the harmful tailpipe emissions that especially during this period of Covid-19 have shown deleterious and disproportional impacts on certain neighborhoods and communities. But an increasing number of observers realize that this fundamental transformation of the vehicle and transportation industries is happening, both for light-duty and medium and heavy-duty vehicles, and there are important economic and international competitiveness issues related to the automobile industry in the NAFTA countries of Canada, the United States, and Mexico. Yet, Newfoundland and Labrador are not unique in that transportation emissions constitutes about 32 percent of overall GHG emissions; this percentage ranges from 30 to 45 percent in general across North American jurisdictions depending on specific generation and fuel mix for electricity. Accordingly, the Plan does a fine job in taking on this broad public policy imperatives while suggesting broad outlines of programs/tariffs and accompanying budgets to carry these out.

Secondly, it makes sense to the Alliance to build on the successes of the existing programs in energy efficiency (the CDM programs) and integrating them in to a more coherent whole. While the Alliance is not familiar with the previous CDM programs over the past decade, many of our utility members are also approaching demand-side management (DSM) programs in a more integrated and holistic way. Obviously, traditional DSM programs are developed to reduce system peak in a cost-effective method and therefore reduce energy consumption, while electrification programs, and EVs in particular will increase electricity use over time. But the critical nature of controlling loads on the demand side, and especially make them more responsive and flexible, has become quite apparent in the evolving grid of the future.

Third, as stated earlier, the Plan you have developed is consistent with several of the other “best practice” TE plans by other utilities, as well as policy guidance by certain Public Utility Commissions, in North America jurisdictions. This is a very dynamic field recently as more EVs are publicly announced, and as more utilities, vendors, and host sites are moving forward with plans in the TE field. You have attached a good summary of the various initiatives in North America on electrification, and mostly on light-duty vehicle electrification. But even this static description does not do justice to the number and breadth of utility initiatives. Recently, for example, Portland General Electric (PGE) in Oregon, Avista Utilities in Washington, and Xcel Energy in both Colorado and Minnesota have developed similar TE plans and received approval from their Commissions, and are moving ahead now with specific programs and tariffs which flow from those Plans. Your Plan of NL Power can be considered to be in a similar best practice category that includes comprehensive and solid analysis on not only transportation electrification potential, but also the long-term conservation potential study (CPS).

Finally, since the Board and the Province have insisted you assess the rate migration options in the context of the Muskrat Falls Project in its final report in February 2020, I believe you have made your best efforts to examine the potential and likely impacts of greater TE on revenues and rates over this period of time. In fact, I believe your estimates in the study are appropriately cautious, since the Alliance believes that the Upper Case (more robust) projections of EV adoption are more likely in the five to ten-year time horizon. But our members firmly believe that greater EV adoption will result in greater revenue requirements, and if we can collectively achieve managed charging to move these loads off-peak, such benefits can be shared with all customers.

Specific comments

Regarding the market projections for EV sales in the Plan, we think it is always appropriate to develop a range of forecasts for the adoption of these vehicles and consumers over the time horizon, and longer out to 2035. You appear to have utilized a range of market projections and forecasts that have been developed globally and for North America, and then brought them down to the Provincial and your service territory level. The Alliance tends to put more in the bullish range of forecasted EV adoption (Upper Scenario in your Plan), and therefore we would think that adoption by 2025 approaching the 145,000 vehicles, and increased electricity sales of 720 GwH, will be more likely.

Secondly, your Plan rightfully points out the critical importance of “managed charging” in various parts of the plan, including the striking table on p. 12. If there is one table that you and the EV stakeholders should focus on as specific programs and tariffs are developed in the months ahead, it would be this table showing a $283 million differential in costs between unmanaged and managed charging (namely, the difference in costs out to 2034 between $431 million in unmanaged charging and $147 million for managed charging). Of course, managed charging is a broad term that is really flexible load management (that apply to other DSM measures and DERs as well) means that can include: dynamic or time-varying rates of the utility; demand response techniques to reduce system peak; and technology based solutions either in the EVSE or in the OEM telematics that can move the charging load off-peak. I realize that you have ruled out either TOU or CPP rates in the near term as not being cost-effective and feasible, but agree with you that you should continue to monitor the impacts of EV loads on the system regarding rate design techniques. Therefore, you and all the stakeholders should remain focused on these critical costs of unmanaged charging, and controlling the system peak, as you develop specific programs during this period.

Thirdly, you propose an ongoing stakeholder process that can assist you in monitoring and assessing this plan, market development, and the achievements of the specific programs over this five-year period. You have built up a good foundation with various stakeholders during the CDM plan in the recent past, but the TE space includes a number of new and varied stakeholders such as EV service providers (EVSPs, or the charging station providers who all have different business models), vendors, automobile and bus and truck OEMs (Original Equipment Manufacturers), and down the road commercial fleet operators who wish to convert from diesel fuel to electric vehicles. You are in the most appropriate position to facilitate these discussions, under the guidance and supervision of the Board, as these programs develop.

Fourth, it is important to point out that both in Newfoundland and Labrador and many other North American jurisdictions, that the EV infrastructure market development is still in a nascent stage. Multiple business models are being developed by the third party EVSPs, as well as by utilities in all jurisdictions, and it is too early to conclude which model will be the most successful. The Alliance believes that only a strong utility role can help accelerate the transformation of these infrastructure investments and serve as a catalyst or enabler to allow the overall market to succeed. In this context, both a "make-ready investment approach" and a utility "own and operate" approach can be developed and help to transform this market in parallel fashion, as you rightly point out on p. 15. We agree with your conclusions here and urge you to develop multiple approaches and programs in dealing with market gaps and the EV infrastructure industry and vendors.

Regarding the residential charging portfolio, we like your holistic approach to supplement the federal incentive on vehicle purchase incentives, as well as incentives for the installation of Level 2 charging infrastructure at the residence. Consumer surveys and evidence from other jurisdictions (utilities and EVSPs) indicate that over 80 percent of charging is done at home. In order for both consumers and the electric grid (lower system peak) to benefit from these increased loads, it will be important for you to be engaged strongly with the residential use cases, and understand the changes on consumer behavior over time. We also applaud your requirement that Level 2 chargers eligible for your incentives must be capable of demand response, or flexible load management. We would submit that most all manufacturers of EVSE in North America today have such capabilities built in to both the equipment and the software, and are compliant with an open protocol called Open ADR which minimizes the potential impact of vendor lock-in.

Regarding the commercial EV charging portfolio, we appreciate your focus on customized services to potential business and fleet customers, as well as building upon your successes with the current Business Efficiency Program for demand-side conservation. Utilities in other jurisdictions have learned that these end use cases are sensitive to costs, margins, and TCO (total cost of operation) over the life of the vehicles including the associated charging infrastructure. Accordingly, it makes sense to us that you will approach these applications from customers on an individualized basis with projects that must demonstrate benefits both to the customer and the utility.

Finally, we appreciate that you have included a role for enhanced customer education and research (some jurisdictions called this "education and outreach" or E&O) over the next five years, with a budgeted amount of $12 million overall. It makes sense to us to build upon the successes in the takeCHARGE program focused on conservation programs and savings and expand this program to the TE stakeholder space as well. You rightly point out the importance of engaging with new stakeholders and businesses in accelerating the pace of TE in your service territory, such as automobile dealers, EV owners, EVSP providers. It will also be important to engage in ride-and-drive events (when the end of the Covid-19 pandemic allows such physical events to take place again), trade shows in the Province, and leading by example by engaging with NL Power employees on EV adoption and engagement. Moreover, especially in this era of Covid-19, the role of web portals and educating consumers about the basic of EV adoption and charging infrastructure has become even more important. Accordingly, we think that you have set forth a reasonable and necessary budget and range of activities to carry this out.

In summary, we believe that you have developed a comprehensive and sound Plan for transportation electrification and demand side management on which a solid foundation can be based in the future. We appreciate the opportunity to comment on the Plan, and look forward to continuing to engage with you and others in Newfoundland and Labrador in the months and years ahead to achieve these goals.

Sincerely,

Philip B. Jones

Philip B. Jones, Executive Director
1402 Third Avenue, Suite 1315
Seattle, WA 98101

DRIVE ELECTRIC NL

December 7, 2020

In respect to the Newfoundland Power submission
to the Board of Commissioners of Public Utilities, Newfoundland and Labrador

RE: takeCHARGE Conservation Demand Management and Electrification Plan

To whom it may concern,

Drive Electric NL has reviewed the initiatives to encourage the adoption of electric vehicles as outlined in the proposed takeCHARGE Conservation Demand Management and Electrification Plan.

The initiatives for vehicle purchase rebates, charger installation rebates and EV driver education will greatly aid the adoption of electric vehicles in the province. Similar initiatives in place in other provinces such as Quebec and BC demonstrated tangible improvement in EV ownership, year over year.

The adoption of electric vehicles in Newfoundland and Labrador will enable the province to meet climate change commitments, provide significant cost savings to EV owners, and create new opportunities for eco-tourism.

EV use in the province will also provide a new, permanent domestic market for significant surplus power from Muskrat Falls. The adoption of electric vehicles is by far the best long-term solution for rate mitigation. Drive Electric NL advocates for the aggressive adoption of EVs in Newfoundland and Labrador to achieve this goal as quickly as possible.

We applaud Newfoundland Power and Newfoundland and Labrador Hydro's efforts to encourage the adoption of EVs in the province.

Jon Seary
Joe Butler
Drive Electric NL

Drive Electric NL is a not-for profit organization, created to educate individuals and businesses in Newfoundland and Labrador on the benefits of EV ownership and related opportunities. As long term electric vehicle owners and business owners, we draw on a wealth of EV knowledge and experience.

P.O. Box 13851, St. John's, NL, Canada A1B 4G7 - 709.895.3560 - jon@driveelectricnl.ca

Annual Report on the Rural Deficit – 2020

Summary of Specific Initiatives

March 31, 2021

A report to the Board of Commissioners of Public Utilities

newfoundland labrador hydro
a nalcor energy company

Contents

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") provides electrical service to approximately 27,500 customers on the Hydro Rural Interconnected System and Hydro Rural Diesel Systems. As a result of policy set out by the Government of Newfoundland and Labrador, these customers are served at an operating loss ("Rural Deficit") as the electricity rates in these areas do not recover Hydro's full cost of providing service. Additionally, Hydro serves approximately 11,300 rural customers on the Labrador Interconnected System, whose rates recovers the cost to serve as well as a contribution to funding a portion of the Rural Deficit. More than 95% of the Rural Deficit funding is provided through the Utility Rate charged to Newfoundland Power.

This report provides an overview of Hydro's Rural Deficit, as well as the direct operating and capital initiatives undertaken by Hydro to manage costs associated with serving customers in rural areas, thereby mitigating the Rural Deficit.

2.0 Rural Deficit Overview

Table 1 provides the estimated annual Rural Deficit for 2016 to 2020, as well as year-over-year variances. The Rural Deficit for 2020 was calculated using actual revenues and expenses allocated to Hydro's Rural Deficit areas based on the 2019 Test Year Cost of Service Study allocations.

Table 1: Hydro Rural Deficit Estimates ($ millions)

	Annual Amounts					Year-over-Year			
	2016	**2017**	**2018[1]**	**2019**	**2020**	**2017/16**	**2018/17**	**2019/18**	**2020/19**
Revenues (A)	59.8	58.6	63.6	67.2	68.3	(1.2)	5.0	3.6	1.1
Costs[2]									
Operating Expenses	43.8	43.6	44.0	44.8	44.0	(0.2)	0.4	0.8	(0.8)
Fuel	26.8	27.8	28.1	29.3	21.8	1.0	0.3	1.2	(7.5)
Purchased Power	7.3	7.2	8.5	9.1	7.8	(0.1)	1.3	0.6	(1.3)
Depreciation	14.2	17.3	19.3	19.3	18.7	3.1	2.0	0.0	(0.6)
Return	25.1	23.1	22.9	23.4	25.1	(2.0)	(0.2)	0.5	1.7
Total Costs (B)	**117.2**	**119.0**	**122.8**	**125.9**	**117.4**	**1.8**	**3.8**	**3.1**	**(8.5)**
Rural Deficit (B-A)	57.4	60.4	59.2	58.7	49.1	3.0	(1.2)	(0.5)	(9.6)

[1] 2018 figures were restated in 2019 to reflect the outcome of Hydro's 2017 GRA Compliance Application [Board Order No. P.U. 30(2019)], consistent with the 2019 Annual Financial Returns.

[2] Table 1 does not include the costs incurred for Conservation Demand Management ("CDM") programs offered in rural communities as they are captured in Hydro's CDM Cost Deferral Account, approved in Board Order No. P.U. 49(2016).

The $49.1 million Rural Deficit in 2020 represents a decrease of approximately $9.6 million, or 16.4%, from 2019. The primary drivers of the change are as follows:

- Revenues increased in 2020 primarily due to the approximately 6.4% increase in customer rates that was implemented on October 1, 2019;
- Fuel costs and purchased power costs decreased mainly as a result of an average decrease of 5.3 cents per kWh in diesel fuel used to serve isolated customers in 2020 relative to 2019[3] and a 0.9 cent per kWh decrease in No. 6 fuel[4] price in 2020 relative to 2019; and
- Return was higher primarily as a result of an increased actual rate of return on rate base for Hydro in 2020 relative to 2019.

Chart 1 shows the annual Rural Deficit including and excluding fuel costs, demonstrating that fuel costs are consistently one of the primary cost drivers in Rural Deficit areas.

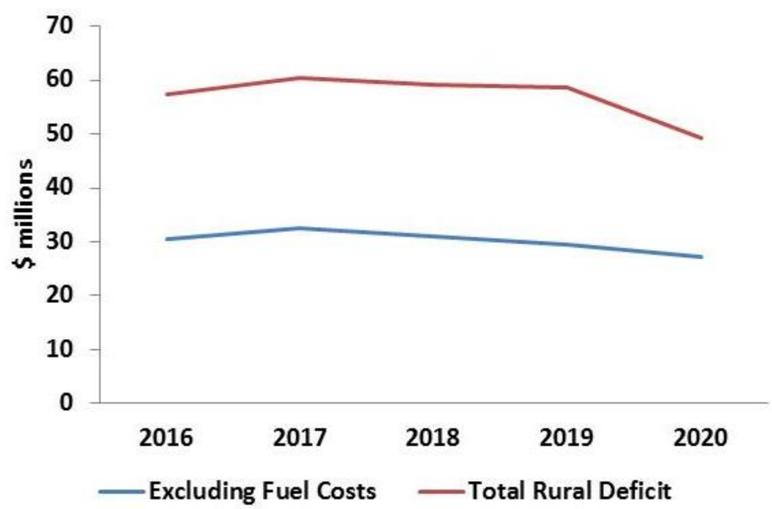


Chart 1: Five-Year Rural Deficit ($ millions)

Chart 1 also demonstrates that, excluding the cost of fuel, Hydro's costs over the period have been stable.

[3] Changes in the price of diesel directly impact the purchase price that Hydro pays to serve customers on the L'Anse au Loup System, and for wind generation purchases supplying Ramea.
[4] A portion of Holyrood No. 6 fuel costs are allocated to rural customers on the Island Interconnected System.

In 2019, Hydro established a working group comprised of professionals from across Hydro with the goal of identifying and implementing opportunities to reduce the Rural Deficit. While the working group's ability to advance certain initiatives was delayed in 2020 due to the COVID-19 pandemic, this group plans to continue its work by engaging external partners in 2021 to explore the potential for new initiatives subject to further restrictions or other limitations that may arise due to the ongoing COVID-19 pandemic.

3.0 Operating Initiatives

3.1 Internal Energy Efficiency Initiatives

Hydro continued its focus on improving internal energy efficiency in 2020. Hydro's internal energy efficiency programs aim to achieve reductions in energy usage in all facilities within the areas contributing to the Rural Deficit, including diesel plants, offices, and line depots. Since it began in 2008, the program has provided cumulative energy savings of 17,787 MWh, resulting in savings of approximately $5.3 million.[5]

Throughout 2020, Hydro completed or launched operating initiatives through its internal energy efficiency program; however, the primary focus for internal energy efficiency in 2020 was to identify future capital and operating projects that could reduce energy consumption at Hydro's facilities. Initiatives completed in 2020 achieved savings of 197 MWh and approximately $59,000, as follows:

- Retrofit of lighting fixtures to more energy efficient versions at various generation sites resulting in savings of approximately 77 MWh and approximately $23,000; and
- Replacement of HPS[6] streetlights with more efficient LED streetlights in diesel communities resulting in savings of approximately 120 MWh and approximately $36,000.

In addition, Hydro continued the following initiatives to support its management of the Rural Deficit:[7]

- Capturing waste heat in several of Hydro's diesel plants to heat Hydro premises;
- Planning the sizes of replacement units at Hydro's diesel generating stations to optimize fuel efficiency;

[5] Savings calculated throughout this report are based on an estimated average avoided cost of fuel of 30 cents per kWh.
[6] High-Pressure Sodium ("HPS").
[7] Savings achieved through this initiative are primarily through avoided costs or productivity improvements; therefore, Hydro is not able to quantify the exact impact on the rural deficit.

- Monitoring diesel system fuel efficiency to identify poor performers so that corrective action may be taken;
- Utilizing cost-effective commercial air flights during regular work hours, where practical, rather than helicopter use;
- Choosing the most fuel-efficient combination of engines, where possible,[8] to supply community loads;
- Having running maintenance (e.g., oil changes) completed by diesel system representatives rather than deploying maintenance crews to diesel communities; and
- Participating in the Off-Grid Utility Association to work with other utilities with diesel plants for comparison of operating procedures and new technology to enhance efficiency in operations and maintenance.

Hydro has also placed an increased focus on identifying planning and scheduling efficiencies, including a significant coordination effort to ensure that delays and duplicate asset outages are minimized.

Hydro continues to perform life cycle cost analysis when analyzing tenders for the purchase of new diesel engines to help ensure the overall least-cost option is chosen. The life cycle cost analysis includes items such as capital, overhaul, fuel (based upon fuel efficiency data), and routine operation and maintenance costs. Besides diesel engine replacement, life cycle cost analysis is performed on all capital projects when appropriate.

3.2 Conservation and Demand Management Program Initiatives

The high cost of generation in isolated diesel communities and the increased system load in the L'Anse au Loup area continues to support the need for effective delivery of energy-efficiency programs in these areas. In 2012, two programs were launched to offer energy-efficiency incentives for residential and commercial customers located in Hydro's isolated diesel communities. These programs continued through 2020 and are further detailed below.

3.2.1 Isolated Systems Community Energy Efficiency Program

The Isolated Systems Community Energy Efficiency Program is a program specifically targeted to residential and commercial customers in Hydro's Isolated Diesel Systems. The objective of the program

[8] Completed automatically in some plants.

is to provide outreach, education, and energy-efficient products and installation free of charge to residential and business customers in the diesel system communities within Newfoundland and Labrador. From 2012 to 2020, the program installed 135,047 energy-efficient products, saving a total of approximately 9,938 MWh of electricity (469 MWh in 2020), and also provided employment for over 55 residents of these communities.

The Isolated Systems Community Energy Efficiency Program includes residential and commercial direct installations and focuses on building knowledge and capacity in the communities by hiring and training local representatives. These representatives work within their own communities to promote the program, provide useful information on energy use, and provide direct installation of energy-efficient products, including low flow showerheads, faucet aerators, LED lamps, specialty size light bulbs, smart power strips, and hot water tank and pipe insulation.

In 2020, 633 residential and 78 business customers received direct installation or kit drop-off totalling 8,852 products consisting of water saving technologies and LED specialty bulbs for lighting needs. While this work was ongoing, information was collected about the type of lighting, heating, and appliances in the homes and businesses, which will be used for future program planning.

3.2.2 Isolated Systems Business Efficiency Program

The Isolated Systems Business Efficiency Program was launched in 2012. The program provides rebates and technical assistance for commercial customers in isolated diesel communities on coastal Newfoundland and Labrador. Hydro’s energy efficiency team works one-on-one with customers to create a plan to address their energy efficiency needs and provides ongoing technical support for projects undertaken. This custom approach has encouraged customers to undertake projects to improve the energy efficiency of lighting, refrigeration, motor controls, and other building systems. In 2020, two customers completed projects under this program involving upgrades to insulation and refrigeration systems in Hydro’s isolated areas. This program deals primarily with small business customers and has achieved 767 MWh of annual energy savings since 2012, 49 MWh of which were achieved in 2020.

3.3 Hydro-Québec Power Purchase Contract Renewal

Hydro is presently in negotiations with Hydro-Québec to renew the Power Purchase Agreement for the provision of energy to Hydro’s customers in the L’Anse au Loup area. The existing contract, which resulted in savings of approximately $4.3 million in 2020,[9] was set to expire in 2020; however, the contract has been extended to May 31, 2021 to allow for completion of negotiations. If the contract is not extended, Hydro will be required to use diesel generators to meet all supply needs for the area.

3.4 Net Metering

Net metering initiatives are undertaken by customers, not by Hydro directly; however, there is an impact on Hydro's system as a result of net metering activity. Hydro currently has one net metering customer in an isolated diesel community[10] under Hydro's Net Metering service option. Net metering for this customer began in November 2019 and resulted in the displacement of 44,480 kWh of diesel generation in 2020. This equates to savings of approximately $5,300 when compared to supplying those kWh from a diesel generator.

3.5 Mary's Harbour Mini Hydro Facility

The Mary's Harbour mini hydro facility began operations in September 2019 and generated approximately 603 MWh in 2020, displacing diesel fuel generation. The purchase of energy from this facility resulted in net savings of approximately $14,000 in 2020.

4.0 Capital Initiatives

4.1 Diesel Asset Management Strategy

Hydro has continued to evolve its asset management strategy, resulting in isolated system cost savings. Hydro has changed its approach to its diesel unit overhauls for 1,200 RPM units.[11] The 1,200 RPM units were previously overhauled at 20,000 hours of operation, the same as 1,800 RPM units. Hydro worked with both manufacturers of their 1,200 RPM units and it was determined that since these units are slower turning and more robust than 1,800 RPM units, they could be run for 30,000 hours between overhauls. Hydro's 1,200 RPM units will now be replaced at 120,000 hours instead of 100,000 hours, extending the useful life of the units.

Hydro has also begun replacing engines rather than overhaul them when it is cost effective to do so and when engines are available. This approach is evaluated on a case-by-case basis. With some newer units, it has proven to be more cost effective to purchase a complete engine rather than purchase the parts

[9] Compared to supplying the service area with diesel generators.
[10] The customer is located in Makkovik, Labrador and has a 48 kW solar energy generator.
[11] Hydro has seven 1,200 RPM units.

and overhaul the engine in the diesel plant with internal labour. Purchasing a complete engine has several benefits, such as shorter time to complete the work, enhanced reliability of the engine, and potential warranty benefits. However, some of Hydro's units do not have engines available for purchase due to the age of the units and therefore must be overhauled. Historically, purchasing complete engines was more expensive when compared to overhaul; however, in recent years, that has not been the case. As prices fluctuate from year to year, this approach will continue to be evaluated on a case-by-case basis to ensure that Hydro is availing of the least-cost alternative in the provision of reliable service.

4.2 Diesel Unit Sizes

In response to increasing loads in certain isolated diesel communities, Hydro has been replacing some of its 1,800 RPM diesel units with larger, slower turning 1,200 RPM units. This has resulted in material reductions in labour costs and travel associated with corrective maintenance,[12] as well as increased reliability. Experience has shown that the 1,200 RPM units have less corrective maintenance requirements than the 1,800 RPM units, resulting in less unplanned downtime for the units, as well as a reduction in labour and travel costs associated with the corrective maintenance. This approach has resulted in lower operating costs in rural deficit areas.

4.3 LED Street Lights in Isolated Systems

The Nain LED street light pilot project,[13] implemented in 2015, provided direct cost savings as a result of the displacement of fuel costs. As a result, Hydro converted the street lights in the community of Ramea to LED street lights in 2018 and submitted a two-year capital proposal in its 2019 Capital Budget Application to convert streetlights to LED in the remaining diesel systems. The proposal was approved and execution began in 2019 with the conversion of streetlights in the community of Cartwright. In 2020, all remaining isolated Labrador communities' streetlights were converted to LED. This project produces annual energy savings of approximately 120 MWh and reduces diesel fuel costs by approximately $36,000. LED street lights may also contribute to lower operating and maintenance costs than HPS street lights due to the elimination of re-lamping requirements and longer life.

[12] Savings achieved through this initiative are primarily through avoided costs or productivity improvements; therefore, Hydro is not able to quantify the exact impact on the rural deficit.
[13] Hydro initiated a pilot LED street light replacement project for the Town of Nain with a total of 125 high-pressure sodium street light fixtures replaced with LED street light fixtures. The street light retrofit yields savings of approximately 45 MWh annually, which offsets approximately 12,000 litres of fuel consumption.

Hydro submitted a capital proposal in its 2021 Capital Budget Application to replace all HPS streetlights by 2026 for both the Island and Labrador. This will result in approximately 1,300 streetlights replaced per year until completion in 2026 and, once complete, estimated annual savings of 273 MWh.

4.4 Diesel Plant Communication Upgrades

In 2020, Hydro completed an upgrade in the communications technology at three diesel plants (Mary's Harbour, Makkovik, and L'Anse Au Loup) through a conversion from service provided from copper cables to fibre optic technology. The copper cables were prone to frequent communications outages. Fibre optic services are less prone to electrical interference and are more reliable which will result in reduced maintenance costs. Additional conversions to fibre optic technology are planned for three more diesel plants in 2021. The improved communications with diesel plants will improve the ability to monitor plants loads and may provide opportunities to implement demand management initiatives in diesel areas that can contribute to deferral of capacity additions on isolated diesel systems.

Additional upgrades completed at L'Anse Au Loup diesel plant will result in improved communications in managing secondary energy purchases from Hydro Quebec. This, in turn, permits Hydro to operate the diesel plant more efficiently and provide savings through reduced diesel fuel consumption. This upgrade will also result in annual network cost savings of $44,000.

5.0 Conclusion

Hydro continues to pursue initiatives and activities to manage the Rural Deficit, including cost reduction and energy conservation initiatives. The management of the Rural Deficit is challenging as it is impacted by social policy initiatives resulting in energy pricing in diesel areas that can be lower than the energy pricing on the Island Interconnected System (i.e., as a result of the Northern Strategic Plan billing credit provided in Labrador diesel communities), as directed by Government. These pricing signals can promote load growth and result in higher fuel usage and capacity requirements that can lead to additional capital investments and higher cost to provide service.

Variability in the Rural Deficit over recent years has primarily been the result of diesel fuel price variability. Hydro's other costs have been stable over the period 2016 to 2020, demonstrating Hydro's ongoing effort to limit growth in the Rural Deficit.

IN THE MATTER OF the *Public Utilities Act*, ("*Act*"); and

IN THE MATTER OF Newfoundland and Labrador Hydro's Annual Return for 2020 filed pursuant to Section 59(2) of the *Act*.

AFFIDAVIT

I, Carol Anne Lutz, Certified Professional Account, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am the Controller, Newfoundland and Labrador Hydro, and as such I either have personal knowledge of, or I have been so informed and verily believe, the matters and things contained within the Newfoundland and Labrador Hydro 2020 Annual Return.
2. I have read the contents of the within 2020 Annual Return and they are true to the best of my knowledge, information, and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador)
this 1st day of April, 2021)
before me:)

SWalsh

Barrister – Newfoundland and Labrador

Carol Anne Lutz, CPA

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April 1, 2022

Board of Commissioners of Public Utilities
Prince Charles Building
120 Torbay Road, P.O. Box 21040
St. John's, NL A1A 5B2

Attention: Ms. Cheryl Blundon
Director of Corporate Services & Board Secretary

Dear Ms. Blundon:

Re: Newfoundland and Labrador Hydro's 2021 Annual Return

Please find enclosed Newfoundland and Labrador Hydro's ("Hydro") 2021 Annual Return filed pursuant to Section 59(2) of the *Public Utilities Act*.

Hydro's 2021 Annual Return is confidential pending its presentation in the House of Assembly of Newfoundland and Labrador. Once that presentation has occurred, Hydro will provide the documents to the required parties.

Should you have any questions, please contact the undersigned.

Yours truly,

NEWFOUNDLAND AND LABRADOR HYDRO

SWalsh

Shirley A. Walsh
Senior Legal Counsel, Regulatory
SAW/kd

Encl.

ecc:

Board of Commissioners of Public Utilities
Jacqui H. Glynn
PUB Official Email

2021 Annual Return

(Return 20 pursuant to Section 59(2) of the *Public Utilities Act)*

April 1, 2022

newfoundland labrador hydro

A report to the Board of Commissioners of Public Utilities

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NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2021

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Independent Auditor's Report

To the Directors of Newfoundland and Labrador Hydro

Opinion
We have audited the non-consolidated financial statements of Newfoundland and Labrador Hydro (the "Company"), which comprise the non-consolidated statement of financial position as at December 31, 2021, and the non-consolidated statements of profit and comprehensive income, changes in equity and cash flows for the year then ended, and notes to the financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying non-consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2021, and the results of its financial performance and its cash flows for the year then ended in accordance with the financial reporting provisions of Section 59 of the Public Utilities Act.

Basis for Opinion
We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Emphasis of Matter - Basis of Accounting
We draw attention to Note 2 to the non-consolidated financial statements, which describes the basis of accounting. The non-consolidated financial statements are prepared to assist the Company in complying with the financial reporting provisions of Section 59 of the Public Utilities Act. As a result, the non-consolidated financial statements may not be suitable for another purpose.

Other Matter
Newfoundland and Labrador Hydro has prepared separate consolidated financial statements for the year ended December 31, 2021 in accordance with International Financial Reporting Standards on which we issued an unmodified auditor's report to the Lieutenant-Governor in Council, Province of Newfoundland and Labrador dated March 17, 2022.

Responsibilities of Management and Those Charged with Governance for the Financial Statements
Management is responsible for the preparation and fair presentation of the financial statements in accordance with the financial reporting provisions of Section 59 of the Public Utilities Act, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements
Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

Deloitte LLP

Chartered Professional Accountants
March 21, 2022

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF FINANCIAL POSITION

As at December 31 (millions of Canadian dollars)	Notes	**2021**	2020
ASSETS			
Current assets			
Cash		**42**	28
Trade and other receivables	5	**123**	97
Inventories	6	**84**	92
Prepayments		**7**	8
Deferred asset	7	**56**	23
Related party loan receivable	24	**53**	-
Total current assets		**365**	248
Non-current assets			
Property, plant and equipment	8	**2,230**	2,206
Intangible assets	9	**6**	7
Right-of-use assets		**2**	2
Sinking fund investments	10	**192**	183
Investments in joint arrangements	11	**654**	610
Total assets		**3,449**	3,256
Regulatory deferrals	12	**184**	172
Total assets and regulatory deferrals		**3,633**	3,428
LIABILITIES AND EQUITY			
Current liabilities			
Short-term borrowings	14	**55**	262
Trade and other payables	13	**106**	119
Contract payable	24	**18**	-
Current portion of long-term debt	14	**7**	7
Derivative liability	23	**56**	23
Other current liabilities		**6**	2
Total current liabilities		**248**	413
Non-current liabilities			
Long-term debt	14	**2,041**	1,765
Deferred contributions	15	**25**	21
Decommissioning liabilities	16	**13**	15
Employee future benefits	18	**98**	107
Other long-term liabilities		**4**	4
Total liabilities		**2,429**	2,325
Shareholder's equity			
Share capital	19	**23**	23
Contributed capital	19	**145**	146
Reserves		**(6)**	(22)
Retained earnings		**1,015**	939
Total equity		**1,177**	1,086
Total liabilities and equity		**3,606**	3,411
Regulatory deferrals	12	**27**	17
Total liabilities, equity and regulatory deferrals		**3,633**	3,428

Commitments and contingencies (Note 25)

See accompanying notes

On behalf of the Board

DIRECTOR

DIRECTOR

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF PROFIT AND COMPREHENSIVE INCOME

For the year ended December 31 (millions of Canadian dollars)	Notes	**2021**	2020
Energy sales		**589**	611
Other revenue		**37**	26
Revenue		**626**	637
Fuels		**122**	158
Power purchased		**170**	122
Operating costs	20	**130**	136
Transmission rental		**21**	21
Depreciation and amortization		**84**	79
Net finance expense	21	**91**	90
Other expense	22	**2**	4
Expenses		**620**	610
Profit for the year from operations		**6**	27
Share of profit of joint arrangement	11	**41**	25
Preferred dividends		**11**	8
Profit before regulatory adjustments		**58**	60
Regulatory adjustments	12	**(33)**	(15)
Profit for the year		**91**	75
Other comprehensive income			
Items that may or have been reclassified to profit or loss			
Items related to employee future benefits		**13**	(1)
Total items that may be reclassified subsequently to profit or loss		**13**	(1)
Items that will not be reclassified subsequently to profit or loss			
Share of other comprehensive income of joint arrangement		**3**	1
Total items that will not be reclassified subsequently to profit or loss		**3**	1
Other comprehensive income for the year		**16**	-
Total comprehensive income for the year		**107**	75

See accompanying notes

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF CHANGES IN EQUITY

(millions of Canadian dollars)	Note	Share Capital	Contributed Capital	Reserves	Retained Earnings	Total
Balance at January 1, 2021		**23**	**146**	**(22)**	**939**	**1,086**
Profit for the year		**-**	**-**	**-**	**91**	**91**
Other comprehensive income for the year		**-**	**-**	**16**	**-**	**16**
Total comprehensive income for the year		**-**	**-**	**16**	**91**	**107**
Regulatory adjustment	**19**	**-**	**(1)**	**-**	**-**	**(1)**
Dividends	**19**	**-**	**-**	**-**	**(15)**	**(15)**
Balance at December 31, 2021		**23**	**145**	**(6)**	**1,015**	**1,177**
Balance at January 1, 2020		23	147	(22)	877	1,025
Profit for the year		-	-	-	75	75
Total comprehensive income for the year		-	-	-	75	75
Regulatory adjustment	19	-	(1)	-	-	(1)
Dividends	19	-	-	-	(13)	(13)
Balance at December 31, 2020		23	146	(22)	939	1,086

See accompanying notes

NEWFOUNDLAND AND LABRADOR HYDRO
NON-CONSOLIDATED STATEMENT OF CASH FLOWS

For the year ended December 31 (millions of Canadian dollars)	Notes	**2021**	2020
Operating activities			
Profit for the year		**91**	75
Adjustments to reconcile profit to cash provided from operating activities:			
Depreciation and amortization		**84**	79
Regulatory adjustments	12	**(33)**	(15)
Amortization of rate stabilization plan fuel credit		**33**	24
Share of profit of joint arrangement	11	**(41)**	(25)
Finance income	21	**(14)**	(13)
Finance expense	21	**105**	103
Other		**10**	6
		235	234
Changes in non-cash working capital balances	28	**(12)**	21
Interest received		**2**	1
Interest paid		**(107)**	(103)
Net cash provided from operating activities		**118**	153
Investing activities			
Additions to property, plant and equipment	8	**(112)**	(88)
Additions to intangible assets		**(1)**	-
Contributions to sinking funds	10	**(7)**	(7)
Increase in related party loan receivable	24	**(53)**	-
Changes in non-cash working capital balances	28	**2**	(2)
Net cash used in investing activities		**(171)**	(97)
Financing activities			
Proceeds from long-term debt	14	**287**	-
Dividends paid	19	**(15)**	(13)
(Decrease) increase in short-term borrowings		**(207)**	29
Rate stabilization plan fuel credit		**(3)**	(55)
Other		**5**	3
Net cash provided from (used in) financing activities		**67**	(36)
Net increase in cash		**14**	20
Cash, beginning of the year		**28**	8
Cash, end of the year		**42**	28

See accompanying notes

1. DESCRIPTION OF BUSINESS

Newfoundland and Labrador Hydro (Hydro or the Company) is incorporated under a special act of the Legislature of the Province of Newfoundland and Labrador (the Province). The principal activity of Hydro is the generation, transmission and sale of electricity. Hydro's operations include both regulated and non-regulated activities. Hydro is a 100% owned subsidiary of Nalcor Energy (Nalcor). Hydro's head office is located at 500 Columbus Drive in St. John's, Newfoundland and Labrador, A1B 0C9, Canada.

Hydro holds interests in the following entities:

A 65.8% interest in Churchill Falls (Labrador) Corporation Limited (Churchill Falls). Churchill Falls is incorporated under the laws of Canada and owns and operates a hydroelectric generating plant and related transmission facilities situated in Labrador which has a rated capacity of 5,428 megawatts (MW).

A 51.0% interest in Lower Churchill Development Corporation (LCDC), an inactive subsidiary. LCDC is incorporated under the laws of Newfoundland and Labrador and was established with the objective of developing all or part of the hydroelectric potential of the Lower Churchill River.

2. SIGNIFICANT ACCOUNTING POLICIES

2.1 Statement of Compliance and Basis of Measurement

These annual audited non-consolidated financial statements (financial statements) have been prepared in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB) with the exception of Hydro's investments in joint arrangements and related disclosures. These statements are non-consolidated as the investments in joint arrangements have been accounted for using the equity method of accounting, as described in Note 2.8. Consolidated statements for the same period have been prepared for presentation to the Lieutenant Governor in Council of the Province.

These financial statements have been prepared on a historical cost basis, except for financial instruments at fair value through profit or loss (FVTPL) which have been measured at fair value. The financial statements are presented in Canadian Dollars (CAD) and all values rounded to the nearest million, except when otherwise noted. The financial statements were approved by Hydro's Board of Directors (the Board) on March 4, 2022.

2.2 Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents consist of amounts on deposit with Schedule 1 Canadian Chartered banks, as well as highly liquid investments with maturities of three months or less. Investments with maturities greater than three months and less than twelve months are classified as short-term investments.

2.3 Inventories

Inventories are carried at the lower of cost and net realizable value. Cost is determined on a weighted average basis and includes expenditures incurred in acquiring inventories and bringing them to their existing condition and location. Net realizable value represents the estimated selling price for inventories less all estimated costs of completion and costs necessary to make the sale.

2.4 Property, Plant and Equipment

Items of property, plant and equipment are recognized at cost less accumulated depreciation and accumulated impairment losses. Cost includes materials, labour, contracted services, professional fees and, for qualifying assets, borrowing costs capitalized in accordance with Hydro's accounting policy outlined in Note 2.6. Costs capitalized with the related asset include all those costs directly attributable to bringing the asset into operation.

When significant parts of property, plant and equipment are required to be replaced at intervals, Hydro recognizes such parts as individual assets with specific useful lives and depreciation rates. Likewise, when a major inspection is performed, its cost is recognized in the carrying amount of the asset as a replacement if the recognition criteria are satisfied. All other repairs and maintenance costs are recognized in profit or loss as incurred.

Depreciation commences when the assets are ready for their intended use. Residual values and useful lives are reviewed at the end of each year and adjusted prospectively, if appropriate. As per Board Order P.U. 30 (2019), Hydro was approved to recover gains and losses through accumulated amortization and to record removal costs through depreciation. To comply with International Accounting Standard (IAS) - 16, the adjustments related to the recovery of gains and losses through accumulated amortization and removal depreciation are presented as a regulatory adjustment in Note 12. The depreciation rates used are as follows:

Generation plant	
Hydroelectric	25 to 110 years
Thermal	20 to 70 years
Diesel	3 to 70 years
Transmission	
Lines	26 to 65 years
Terminal stations	20 to 60 years
Distribution system	20 to 60 years
Other assets	3 to 70 years

Hydroelectric generation plant includes the powerhouse, turbines, governors and generators, as well as water conveying and control structures, including dams, dikes, tailraces, penstocks and intake structures. Thermal generation plant is comprised of the powerhouse, turbines and generators, boilers, oil storage tanks, stacks, and auxiliary systems. Diesel generation plant includes the buildings, engines, generators, switchgear, fuel storage and transfer systems, dikes and liners and cooling systems.

Transmission lines include the support structures, foundations and insulators associated with lines at voltages of 230, 138 and 69 kilovolt (kV). Terminal station assets are used to step up voltages of electricity for transmission and to step down voltages for distribution. Distribution system assets include poles, transformers, insulators, and conductors.

Other assets include telecontrol, buildings, vehicles, furniture, tools and equipment.

The carrying amount of a replaced asset is derecognized when replaced. Gains and losses on disposal of an item of property, plant and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant and equipment and are recorded in other expense. Pursuant to Board Order No. P.U. 30 (2019), the gains and losses are deferred on retirement of property, plant and equipment. The deferral will be recovered through future depreciation expense.

2.5 Intangible Assets

Intangible assets that are expected to generate future economic benefit and are measurable, including computer software costs and feasibility studies, are capitalized as intangible assets in accordance with IAS 38.

Intangible assets with finite useful lives are carried at cost less accumulated amortization and accumulated impairment losses. The estimated useful life and amortization method are reviewed at the end of each year with the effect of any changes in estimate being accounted for on a prospective basis. Intangible assets with indefinite useful lives are carried at cost less accumulated impairment losses.

Amortization is calculated on a straight-line basis over the estimated useful lives of the assets as follows:

Feasibility studies	22 years
Computer software	7 years

2.6 Borrowing Costs

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale. Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization. All other borrowing costs are recognized in the Non-Consolidated Statement of Profit and Comprehensive Income in the period in which they are incurred.

2.7 Impairment of Non-Financial Assets

Property, plant and equipment and other non-financial assets are reviewed for impairment losses whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. Where it is not possible to estimate the recoverable amount of an individual asset, Hydro estimates the recoverable amount of the cash generating unit (CGU) to which the asset belongs. The recoverable amount is the higher of fair value less costs of disposal and value in use. Value in use is generally computed by reference to the present value of future cash flows expected to be derived from non-financial assets. In assessing value in use, the estimated future cash flows are discounted to their present value using a discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset or CGU is estimated to be less than its carrying amount, the carrying amount of the asset or CGU is reduced to its recoverable amount and an impairment loss is recognized immediately in the Non-Consolidated Statement of Profit and Comprehensive Income.

2.8 Investments in Joint Arrangements

A joint arrangement is an arrangement in which two or more parties involved have joint control. Control exists when Hydro has the power, directly or indirectly, to govern the financial and operating policies of another entity, so as to obtain benefits from its activities. A joint arrangement is either classified as a joint operation or a joint venture based on the rights of the parties involved. Hydro's investment in Churchill Falls is classified as a joint operation.

Hydro's investment in Churchill Falls is recorded using the equity method of accounting. Under the equity method, the interest in the investment is carried in the Non-Consolidated Statement of Financial Position at cost plus post acquisition changes in Hydro's share of net assets of the investment. The Non-Consolidated Statement of Profit and Comprehensive Income reflects the share of the profit or loss of the joint operation.

2.9 Employee Future Benefits

(i) <u>Pension Plan</u>

Employees participate in the Province's Public Service Pension Plan (Plan), a multi-employer defined benefit plan. Contributions by Hydro to this Plan are recognized as an expense when employees have rendered service entitling them to the contributions. Liabilities associated with this Plan are held with the Province.

(ii) <u>Other Benefits</u>

Hydro provides group life insurance and health care benefits on a cost-shared basis to retired employees, in addition to a retirement allowance.

The cost of providing these benefits is determined using the projected unit credit method, with actuarial valuations being completed on an annual basis, based on service and Management's best estimate of salary escalation, retirement ages of employees and expected health care costs.

Actuarial gains and losses on Hydro's defined benefit obligation are recognized in reserves in the period in which they occur. Past service costs are recognized in operating costs as incurred. Pursuant to Board Order No. P.U. 36 (2015), Hydro recognizes the amortization of employee future benefit actuarial gains and losses in the Non-Consolidated Statement of Profit and Comprehensive Income as a regulatory adjustment.

The retirement benefit obligation recognized in the Non-Consolidated Statement of Financial Position represents the present value of the defined benefit obligation.

2.10 Provisions
A provision is a liability of uncertain timing or amount. A provision is recognized if Hydro has a present legal obligation or constructive obligation as a result of past events, it is probable that an outflow of resources will be required to settle the obligation and the amount can be reliably estimated. Provisions are not recognized for future operating losses. The provision is measured at the present value of the best estimate of the expenditures expected to be required to settle the obligation using a discount rate that reflects the current market assessments of the time value of money and the risks specific to the obligation. Provisions are re-measured at each Non-Consolidated Statement of Financial Position date using the current discount rate.

2.11 Decommissioning, Restoration and Environmental Liabilities
Legal and constructive obligations associated with the retirement of property, plant and equipment are recorded as liabilities when those obligations are incurred and are measured as the present value of the expected costs to settle the liability, discounted at a rate specific to the liability. The liability is accreted up to the date the liability will be incurred with a corresponding charge to net finance expense. The carrying amount of decommissioning, restoration and environmental liabilities is reviewed annually with changes in the estimates of timing or amount of cash flows added to or deducted from the cost of the related asset or expensed in the Non-Consolidated Statement of Profit and Comprehensive Income if the liability is short-term in nature.

2.12 Revenue from Contracts with Customers
Hydro recognizes revenue from contracts with customers related to the sale of electricity to regulated Provincial industrial, utility and direct customers in rural Newfoundland and Labrador and to non-regulated industrial, utility and external market customers.

Revenue is measured based on the consideration specified in a contract with a customer and excludes amounts collected on behalf of third parties. Hydro recognizes revenue when it transfers control of a product or service to a customer.

Revenue from the sale of energy is recognized when Hydro satisfies its performance obligation by transferring energy to the customer. Sales within the Province are primarily at rates approved by the Newfoundland and Labrador Board of Commissioners of Public Utilities (PUB), whereas export sales and sales to other certain major industrial customers are either at rates under the terms of the applicable contracts, or at market rates. Hydro recognizes revenue at the amount to which it has the right to invoice, which corresponds directly to the value of Hydro's performance to date.

2.13 Leasing

Lessee Accounting
Hydro assesses whether a contract is or contains a lease, at inception of a contract. Hydro recognizes a right-of-use asset and a corresponding lease liability with respect to all lease agreements in which it is the lessee, except for short-term leases (defined as leases with a lease term of 12 months or less) and leases of low-value assets. For these leases, Hydro recognizes the lease payments as an operating expense on a straight-line basis over the term of the lease unless another systematic basis is more representative of the time pattern in which economic benefits from the leased asset are consumed.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted by using the rate implicit in the lease. If this rate cannot be readily determined, Hydro uses its incremental borrowing rate.

Lease payments included in the measurement of the lease liability comprise:

- Fixed (and in-substance) lease payments less any lease incentives;
- variable lease payments that depend on an index or rate; and
- payments expected under residual value guarantees and payments relating to purchase options and renewal option periods that are reasonably certain to be exercised (or periods subject to termination options that are not reasonably certain to be exercised).

The lease liability is subsequently measured at amortized cost using the effective interest rate method. Lease liabilities are remeasured, with a corresponding adjustment to the related right-of-use assets, when there is a change in variable lease payments arising from a change in an index or rate, or when Hydro changes its assessment of whether purchase, renewal or termination options will be exercised. Hydro did not make any such adjustments during the periods presented.

The right-of-use assets comprise the initial measurement of the corresponding lease liability, lease payments made at or before the commencement day and any initial direct costs. They are subsequently measured at cost less accumulated depreciation and accumulated impairment losses.

Whenever Hydro incurs an obligation for costs to dismantle and remove a leased asset, restore the site on which it is located or restore the underlying asset to the condition required by the terms and conditions of the lease, a provision is recognized and measured under *IAS 37 – Provisions, Contingent Liabilities and Contingent Assets*. The costs are included in the related right-of-use asset.

Right-of-use assets are depreciated over the shorter period of the lease term and useful life of the underlying asset. If a lease transfers ownership of the underlying asset or the cost of the right-of-use asset reflects that Hydro expects to exercise a purchase option, the related right-of-use asset is depreciated over the useful life of the underlying asset. Depreciation starts at the commencement date of the lease.

Variable rents that do not depend on an index or rate are not included in the measurement of the lease liability and the right-of-use asset. The related payments are recognized as an expense in operating costs in the period in which the event or condition that triggers those payments occurs.

As a practical expedient, IFRS 16 permits a lessee not to separate non-lease components, and instead account for any lease and associated non-lease components as a single arrangement. Hydro has elected to apply this practical expedient.

2.14 Foreign Currencies

Transactions in currencies other than Hydro's functional currency (foreign currencies) are recognized using the exchange rate in effect at the date of transaction, approximated by the prior month end close rate. At the end of each reporting period, monetary items denominated in foreign currencies are translated at the rates of exchange in effect at the period end date. Foreign exchange gains and losses not included in regulatory deferrals are recorded in the Non-Consolidated Statement of Profit and Comprehensive Income as other expense.

2.15 Income Taxes

Hydro is exempt from paying income taxes under Section 149(1) (d.2) of the Income Tax Act.

2.16 Financial Instruments

Classification and Initial Measurement
Financial assets and financial liabilities are recognized in the Non-Consolidated Statement of Financial Position when Hydro becomes a party to the contractual provisions of the instrument and are initially measured at fair value.

Financial assets are classified at amortized cost, fair value through other comprehensive income (FVTOCI), FVTPL or as derivatives designated as hedging instruments in an effective hedge. Financial liabilities are classified at FVTPL, amortized cost or as derivatives designated as hedging instruments in an effective hedge. Transaction costs that are directly attributable to the acquisition or issue of financial assets and financial liabilities (other than financial assets and financial liabilities at FVTPL) are added to or deducted from the fair value of the financial assets or financial liabilities, as appropriate, on initial recognition. Transaction costs directly attributable to the acquisition of financial assets or financial liabilities at FVTPL are recognized immediately in profit or loss.

Financial Assets at Amortized Cost
Financial assets with contractual cash flows arising on specified dates, consisting solely of principal and interest, and that are held within a business model whose objective is to collect the contractual cash flows are subsequently measured at amortized cost using the effective interest rate method and are subject to impairment. Gains and losses are recognized in profit or loss when the asset is derecognized, modified or impaired.

Hydro's financial assets at amortized cost include cash, trade and other receivables, related party loan receivable and sinking fund investments.

Financial Assets at FVTPL
Financial assets that do not meet the criteria for being measured at amortized cost or FVTOCI are measured at FVTPL. Financial assets at FVTPL are measured at fair value at the end of each reporting period, with any fair value gains or losses recognized in profit or loss to the extent they are not a part of a designated hedging relationship. Currently, Hydro has no financial assets measured at FVTPL.

Financial Liabilities at Amortized Cost
Hydro subsequently measures all financial liabilities at amortized cost using the effective interest method. Gains and losses are recognized in profit or loss when the liability is derecognized.

Hydro's financial liabilities at amortized cost include trade and other payables, short-term borrowings, contract payable and long-term debt.

Financial Liabilities at FVTPL
Financial liabilities that do not meet the criteria for being measured at amortized cost or FVTOCI are measured at FVTPL. Financial liabilities at FVTPL are measured at fair value at the end of each reporting period, with any fair value gains or losses recognized in profit or loss to the extent they are not part of a designated hedging relationship.

Hydro's financial liabilities measured at FVTPL include derivative instruments not part of a designated hedging relationship.

Derecognition of Financial Instruments
Hydro derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or when it transfers the financial asset and substantially all the risks and rewards of ownership of the asset to another party.

Hydro derecognizes financial liabilities when, and only when, its obligations are discharged, cancelled or have expired. The difference between the carrying amount of the financial liability derecognized and the consideration paid and payable is recognized in profit or loss.

Impairment of Financial Assets

Hydro recognizes a loss allowance for expected credit losses (ECL) on investments in debt instruments that are measured at amortized cost or at FVTOCI. The amount of ECL is updated at each reporting date to reflect changes in credit risk since initial recognition of the respective financial instrument.

Hydro always recognizes lifetime ECL for trade and other receivables. The ECL on these financial assets are estimated based on Hydro's historical credit loss experience, adjusted for factors that are specific to the debtors, general economic conditions and an assessment of both the current as well as the forecast direction of conditions at the reporting date, including time value of money where appropriate. Hydro also records 12-month ECL for those financial assets which have low credit risk and where the low credit risk exemption has been applied. The classes of financial assets that have been identified to have low credit risk are cash and sinking funds.

For all other financial instruments, Hydro recognizes lifetime ECL when there has been a significant increase in credit risk since initial recognition. If, on the other hand, the credit risk on the financial instrument has not increased significantly since initial recognition, Hydro measures the loss allowance for that financial instrument at an amount equal to 12-month ECL. The assessment of whether lifetime ECL should be recognized is based on significant increases in the likelihood or risk of a default occurring since initial recognition instead of on evidence of a financial asset being credit-impaired at the reporting date or an actual default occurring.

Lifetime ECL represents the ECL that will result from all possible default events over the expected life of a financial instrument. In contrast, 12-month ECL represents the portion of lifetime ECL that is expected to result from default events on a financial instrument that are possible within 12 months after the reporting date.

2.17 Government Grants

Government grants are recognized when there is reasonable assurance that Hydro will comply with the associated conditions and that the grants will be received.

Government grants are recognized in profit or loss on a systematic basis over the periods in which Hydro recognizes as expenses the related costs for which the grants are intended to compensate. Specifically, government grants whose primary condition is that Hydro should purchase, construct or otherwise acquire non-current assets are recognized as deferred revenue in the Non-Consolidated Statement of Financial Position and transferred to the Non-Consolidated Statement of Profit and Comprehensive Income on a systematic and rational basis over the useful lives of the related assets.

Government grants that are receivable as compensation for expenses or losses already incurred or for the purpose of giving immediate financial support to Hydro with no future related costs are recognized in the Non-Consolidated Statement of Profit and Comprehensive Income in the period in which they become receivable.

2.18 Regulatory Deferrals

Hydro's revenues from its electrical sales to most customers within the Province are subject to rate regulation by the PUB. Hydro's borrowing and capital expenditure programs are also subject to review and approval by the PUB. Rates are set through periodic general rate applications utilizing a cost of service methodology. Hydro's allowed rate of return on rate base based upon Board Order No. P.U. 30 (2019) is 5.4% in 2021 and 5.4% in 2020. Hydro applies various regulator approved accounting policies that differ from enterprises that do not operate in a rate regulated environment. Generally, these policies result in the deferral and amortization of costs or credits which are expected to be recovered or refunded in future rates. In the absence of rate regulation, these amounts would be included in the determination of profit or loss in the year the amounts are incurred. The effects of rate regulation on the financial statements are disclosed in Note 12.

3. SIGNIFICANT ACCOUNTING JUDGMENTS AND ESTIMATES

The preparation of the financial statements in conformity with IFRS requires Management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, revenues and expenses. Actual results may differ materially from these estimates, including changes as a result of future decisions made by the PUB. The estimates and underlying assumptions are reviewed on an on-going basis. Revisions to accounting estimates are recognized in the period in which the estimate is reviewed if the revision affects only that period or future periods.

In 2020, the outbreak of the Coronavirus disease (COVID-19) has resulted in governments worldwide enacting emergency measures to combat the spread of the virus. For the year ended December 31, 2021, COVID-19 did not have a significant financial impact on the Company's results of operations, financial position or cash flow. There continues to be uncertainty around the duration and magnitude of the pandemic and therefore the extent of any future effect on the Company is unknown at this time. Management will continue to assess the impact of COVID-19 on the Company's operations and financial results.

3.1 Use of Judgments

(i) Property, Plant and Equipment
Hydro's accounting policy relating to property, plant and equipment is described in Note 2.4. In applying this policy, judgment is used in determining whether certain costs are additions to the carrying amount of the property, plant and equipment as opposed to repairs and maintenance. If an asset has been developed, judgment is required to identify the point at which the asset is capable of being used as intended and to identify the directly attributable borrowing costs to be included in the carrying value of the development asset. Judgment is also used in determining the appropriate componentization structure for Hydro's property, plant and equipment.

(ii) Revenue
Management exercises judgment in estimating the value of electricity consumed by retail customers in the period, but billed subsequent to the end of the reporting period. Specifically, this involves an estimate of consumption for each retail customer, based on the customer's past consumption history.

When recognizing deferrals and related amortization of costs or credits, Management assumes that such costs or credits will be recovered or refunded through customer rates in future years. Recovery of some of these deferrals is subject to a future PUB order. As such, there is a risk that some or all of the regulatory deferrals will not be approved by the PUB which could have a material impact on Hydro's profit or loss in the year the order is received.

(iii) Determination of CGUs
Hydro's accounting policy relating to impairment of non-financial assets is described in Note 2.7. In applying this policy, Hydro groups assets into the smallest identifiable group for which cash flows are largely independent of the cash flows from other assets or groups of assets. Judgment is used in determining the level at which cash flows are largely independent of other assets or groups of assets.

(iv) Discount Rates
Certain of Hydro's financial liabilities are discounted using discount rates that are subject to Management's judgment.

(v) Leases

Definition of a lease
At inception of a contract, Hydro assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, Hydro assesses whether the contract involves the use of an identified asset, Hydro has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use and Hydro has the right to direct the use of the asset.

Lease extension and termination options
In determining the lease term, Hydro considers all facts and circumstances that create an economic incentive to exercise an extension option, or not to exercise a termination option. The assessment is reviewed if a significant event or a significant change in circumstances occurs within its control. The assessment requires the consideration of facts and circumstances such as contractual terms and conditions for option periods, significant leasehold improvements undertaken, costs to terminate the lease, the importance of the asset to the lessee's operations and past practice.

(vi) Regulatory adjustments
Regulatory assets and liabilities recorded in Hydro arise due to the rate setting process for regulated utilities governed by the PUB. The amounts relate to costs or credits which Management believes will be recovered or settled through customer rates in future periods, pursuant to the proceedings and outcomes of future PUB orders. Certain estimates are necessary since the regulatory environment often requires amounts to be recognized at estimated values until these amounts are finalized pursuant to regulatory decisions or other regulatory proceedings. The final amounts approved by the PUB for deferral as regulatory assets and liabilities and the approved recovery or settlement periods may differ from those originally expected. Any resulting adjustments to original estimates could have a material impact and are recognized in profit or loss in the period in which they become known.

3.2 Use of Estimates

(i) Property, Plant and Equipment
Amounts recorded for depreciation are based on the useful lives of Hydro's assets. The useful lives of property, plant and equipment are determined by independent specialists and reviewed annually by Hydro. These useful lives are Management's best estimate of the service lives of these assets. Changes to these lives could materially affect the amount of depreciation recorded.

(ii) Decommissioning Liabilities
Hydro recognizes a liability for the fair value of the future expenditures required to settle obligations associated with the retirement of property, plant and equipment. Decommissioning liabilities are recorded as a liability at fair value, with a corresponding increase to property, plant and equipment. Accretion of decommissioning liabilities is included in the Non-Consolidated Statement of Profit and Comprehensive Income through net finance expense. Differences between the recorded decommissioning liabilities and the actual decommissioning costs incurred are recorded as a gain or loss in the settlement period.

(iii) Employee Future Benefits
Hydro provides group life insurance and health care benefits on a cost-shared basis to retired employees, in addition to a severance payment upon retirement. The expected cost of providing these other employee benefits is accounted for on an accrual basis, and has been actuarially determined using the projected unit credit method prorated on service, and Management's best estimate of salary escalation, retirement ages of employees and expected health care costs.

(iv) Leases incremental borrowing rate

Hydro uses its incremental borrowing rates in measuring its lease liabilities. The incremental borrowing rate is the rate of interest that a lessee would have to pay to borrow over a similar term, and with a similar security, the funds necessary to obtain an asset of a similar value to the right-of-use asset in a similar economic environment. The determination of the incremental borrowing rate requires the consideration of different components, all of which are to incorporate a number of important lease characteristics.

(v) Deferred Assets and Derivative Liabilities

Effective October 1, 2015, Hydro entered into a power purchase agreement (PPA) with Nalcor Energy Marketing Corporation (Energy Marketing) which allows for the purchase of available Recapture energy from Hydro for resale by Energy Marketing in export markets or through agreements with counterparties. Additionally, the PPA allows for the use of Hydro's transmission service rights by Energy Marketing to deliver electricity, through rights which are provided to Hydro pursuant to a Transmission Service Agreement with Hydro-Québec dated April 1, 2009. The current terms of the PPA require a 60 day termination notice by either party. Management's assumption is that the term of the PPA at December 31, 2021, will continue for at least the next 12 months.

Fair values relating to Hydro's financial instruments and derivatives that have been classified as Level 3 have been determined using inputs for the assets or liabilities that are not readily observable. Certain of these fair values are classified as Level 3 as the transactions do not occur in an active market, or the terms extend beyond the period for which a quoted price is available.

Hydro's PPA with Energy Marketing is accounted for as a derivative instrument, where Hydro determines that the fair value at initial recognition differs from the transaction price and the fair value is evidenced neither by a quoted price in an active market for an identical asset or liability nor based on a valuation technique that uses only data from observable markets. These derivative transactions are initially measured at fair value and the expected difference is deferred. Subsequently, the deferred difference is recognized in other comprehensive income (loss) on an appropriate basis over the life of the related derivative instrument but not later than when the valuation is wholly supported by observable market data or the transaction has occurred.

Hydro has elected to defer the difference between the fair value of the power purchase derivative liability upon initial recognition and the transaction price of the power purchase derivative liability and to amortize the deferred asset on a straight-line basis over its effective term (Note 7). These methods, when compared with alternatives, were determined by Management to most accurately reflect the nature and substance of the transactions.

4. CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

The following is a list of standards/interpretations that have been issued and are effective for accounting periods commencing on or after January 1, 2021, as specified.

- *IFRS 16 – Leases – COVID-19 Related Rent Concessions beyond June 30, 2021 (Amendment to IFRS 16)*[1]
- *IAS 37 – Provisions, Contingent Liabilities and Contingent Assets – Onerous Contracts – Costs of Fulfilling a Contract (Amendments to IAS 37)*[2]
- *IAS 1 – Presentation of Financial Statements – Classification of Liabilities as Current or Non-Current (Amendments to IAS 1)*[3]
- *IAS 1 – Presentation of Financial Statements– Disclosure of Accounting Policies (Amendments to IAS 1)*[3]
- *IAS 8 – Accounting Policies, Changes in Accounting Estimates and Errors – Definition of Accounting Estimates (Amendments to IAS 8)*[3]

[1] Effective for annual periods beginning on or after April 1, 2021
[2] Effective for annual periods beginning on or after January 1, 2022, with earlier application permitted.
[3] Effective for annual periods beginning on or after January 1, 2023, with earlier application permitted.

4.1 IFRS 16 – Leases – COVID-19-Related Rent Concessions beyond June 30, 2021 (Amendment to IFRS 16)
The IASB issued an extension to the practical expedient available to lessees that permits a lessee to elect not to assess whether a COVID-19 related rent concession is a lease modification. The extension allows the application of the practical expedient to reductions in lease payments originally due on or before June 30, 2022. Since Hydro does not have any COVID-19 related rent concessions, the application of this amendment does not have an impact on Hydro's financial statements.

4.2 IAS 37 – Provisions, Contingent Liabilities and Contingent Assets – Onerous Contracts – Costs of Fulfilling a Contract (Amendments to IAS 37)
The amendments to IAS 37 specify that the cost of fulfilling a contract comprises the costs that relate directly to the contract. Costs that relate directly to a contract can either be incremental costs of fulfilling that contract, such as direct labour and materials, or an allocation of other costs that relate directly to fulfilling contracts, such as the allocation of the depreciation charge for an item of property, plant and equipment used in fulfilling the contract. These amendments apply to contracts for which the entity has not yet fulfilled all its obligations at the beginning of the annual reporting period in which the entity first applies the amendments and are currently not applicable to Hydro, however, may apply to future transactions.

4.3 IAS 1 – Presentation of Financial Statements – Classification of Liabilities as Current or Non-Current (Amendments to IAS 1)
The IASB issued amendments to IAS 1 to promote consistency in applying the requirements by helping companies determine whether, in the Statement of Financial Position, debt and other liabilities with an uncertain settlement date should be classified as current (due or potentially due to be settled within one year) or non-current. The classification is based on rights that are in existence at the end of the reporting period and specify that classification is unaffected by expectations about whether an entity will exercise its right to defer settlement of a liability. The amendments are applied retrospectively upon adoption. Management is currently assessing the amendments and any potential impact on Hydro's financial statements.

4.4 IAS 1 – Presentation of Financial Statements– Disclosure of Accounting Policies (Amendments to IAS 1)
The IASB issued amendments to IAS 1, which change the requirements with regard to the disclosure of accounting policies. The amendments replace all instances of the term 'significant accounting policies' with 'material accounting policy information'. Accounting policy information is material if, when considered together with other information included in an entity's financial statements, it can reasonably be expected to influence decisions that the primary users of general purpose financial statements make on the basis of those financial statements. The application of these amendments is not expected to have an impact on Hydro's financial statements.

4.5 IAS 8 – Accounting Policies, Changes in Accounting Estimates and Errors – Definition of Accounting Estimates (Amendments to IAS 8)
The IASB issued amendments to IAS 8 to clarify the distinction between changes in accounting estimates and changes in accounting policies and the correction of errors. The amendments are intended to improve the understanding of the existing requirements and therefore are not expected to have an impact on Hydro's financial statements.

5. TRADE AND OTHER RECEIVABLES

As at December 31 (millions of Canadian dollars)	**2021**	2020
Trade receivables	**121**	97
Other receivables	**13**	10
Due from related parties	**6**	7
Loss allowance	**(17)**	(17)
	123	97

As at December 31 (millions of Canadian dollars)	**2021**	2020
0-60 days	**120**	95
60+ days	**3**	2
	123	97

As at December 31 (millions of Canadian dollars)	**2021**	2020
Loss allowance, beginning of the year	**(17)**	(14)
Change in balance during the year	**-**	(3)
Loss allowance, end of the year	**(17)**	(17)

6. INVENTORIES

As at December 31 (millions of Canadian dollars)	**2021**	2020
Fuel	**46**	54
Materials and other	**38**	38
	84	92

Fuel inventory includes No. 6 fuel in the amount of $34.8 million (2020 - $43.6 million). The cost of inventories recognized as an expense during the year is $124.8 million (2020 - $160.8 million) and is included in operating costs and fuels.

7. DEFERRED ASSET

The deferred asset related to Hydro's PPA with Nalcor Energy Marketing (Energy Marketing) is amortized into income on a straight-line basis over the assumed nine month term of the contract, which commenced on January 1, 2021. Subsequently in March, August and December 2021, Management reassessed the anticipated contract term and determined that a new deferred asset and derivative liability was required resulting in a deferred asset addition of $3.9 million, $3.2 million, and $55.7 million, respectively. The balances at March and August 2021 were fully amortized at December 31, 2021. The remaining $55.7 million balance is to be amortized into income on a straight-line basis over the assumed twelve month term commencing on January 1, 2022 and expiring December 31, 2022. The components of change are as follows:

As at December 31 (millions of Canadian dollars)	**2021**	2020
Deferred asset, beginning of the year	**23**	9
Additions	**63**	38
Amortization	**(30)**	(24)
Deferred asset, end of the year	**56**	23

In February 2022, an amendment was made to suspend the existing terms of the PPA with Energy Marketing until April 30, 2022.

8. PROPERTY, PLANT AND EQUIPMENT

(millions of Canadian dollars)	Generation Plant	Transmission and Distribution	Other	Assets Under Development	Total
Cost					
Balance at January 1, 2020	1,329	1,141	131	43	2,644
Additions	-	-	-	90	90
Disposals	(6)	(1)	(3)	-	(10)
Transfers	39	56	8	(103)	-
Decommissioning liabilities and revisions	1	-	-	-	1
Other adjustments	-	-	-	(3)	(3)
Balance at December 31, 2020	1,363	1,196	136	27	2,722
Additions	**1**	**-**	**-**	**113**	**114**
Disposals	**(10)**	**(1)**	**(2)**	**-**	**(13)**
Transfers	**68**	**46**	**9**	**(122)**	**1**
Other adjustments	**(1)**	**(2)**	**-**	**-**	**(3)**
Balance at December 31, 2021	**1,421**	**1,239**	**143**	**18**	**2,821**
Depreciation					
Balance at January 1, 2020	256	145	44	-	445
Depreciation	44	27	6	-	77
Disposals	(4)	-	(2)	-	(6)
Balance at December 31, 2020	296	172	48	-	516
Depreciation	**47**	**28**	**7**	**-**	**82**
Disposals	**(5)**	**-**	**(2)**	**-**	**(7)**
Balance at December 31, 2021	**338**	**200**	**53**	**-**	**591**
Carrying value					
Balance at January 1, 2020	1,073	996	87	43	2,199
Balance at December 31, 2020	1,067	1,024	88	27	2,206
Balance at December 31, 2021	**1,083**	**1,039**	**90**	**18**	**2,230**

Capitalized interest for the year ended December 31, 2021 was $1.6 million (2020 - $1.5 million) related to assets under development.

9. INTANGIBLE ASSETS

(millions of Canadian dollars)	Computer Software	Feasibility Studies	Assets Under Development	Total
Cost				
Balance at January 1, 2020	14	2	-	16
Disposals	-	(1)	-	(1)
Transfers	4	-	(4)	-
Other adjustments	-	-	4	4
Balance at December 31, 2020	18	1	-	19
Additions	**-**	**-**	**1**	**1**
Transfers	**1**	**-**	**(1)**	**-**
Balance at December 31, 2021	**19**	**1**	**-**	**20**
Amortization				
Balance at January 1, 2020	10	1	-	11
Amortization	1	1	-	2
Disposals	-	(1)	-	(1)
Balance at December 31, 2020	11	1	-	12
Amortization	**2**	**-**	**-**	**2**
Balance at December 31, 2021	**13**	**1**	**-**	**14**
Carrying value				
Balance at January 1, 2020	4	1	-	5
Balance at December 31, 2020	7	-	-	7
Balance at December 31, 2021	**6**	**-**	**-**	**6**

10. SINKING FUND INVESTMENTS

As at December 31, 2021, sinking funds include $191.7 million (2020 - $182.6 million) related to repayment of Hydro's long-term debt. Sinking fund investments consist of bonds, debentures, short-term borrowings and coupons issued by, or guaranteed by, the Government of Canada, provincial governments or Schedule 1 banks, and have maturity dates ranging from 2022 to 2033.

Hydro debentures, which are intended to be held to maturity, are deducted from debt while all other sinking fund investments are shown separately on the Non-Consolidated Statement of Financial Position as assets. Annual contributions to the various sinking funds are in accordance with bond indenture terms, and are structured to ensure the availability of adequate funds at the time of expected bond redemption. Effective yields range from 1.42% to 6.82% (2020 - 1.52% to 6.82%).

The movement in sinking funds for the year is as follows:

As at December 31 (millions of Canadian dollars)	**2021**	2020
Sinking funds, beginning of the year	**183**	174
Contributions	**7**	7
Change in sinking fund investments in own debentures	**(11)**	(10)
Earnings	**13**	12
Sinking funds, end of the year	**192**	183

Sinking fund instalments due over the next five years are as follows:

(millions of Canadian dollars)	2022	2023	2024	2025	2026
Sinking fund instalments	7	7	7	7	4

11. INVESTMENTS IN JOINT ARRANGEMENTS

As at December 31 (millions of Canadian dollars)	**Ownership Interest**	**2021**	2020
Churchill Falls	65.8%		
Shares, at cost		**167**	167
Equity in retained earnings, beginning of the year		**446**	421
Accumulated other comprehensive loss, beginning of the year		**(3)**	(4)
Other comprehensive gain		**3**	1
Equity in profit for the year		**41**	25
		654	610

12. REGULATORY DEFERRALS

(millions of Canadian dollars)		January 1 2021	Reclass & Disposition	Regulatory Activity	**December 31 2021**	Remaining Recovery Settlement Period (years)
Regulatory asset deferrals						
Rate stabilization plan (RSP)	(a)	40	24	(8)	**56**	n/a
Foreign exchange losses	(b)	46	-	(2)	**44**	20.0
Retirement asset pool	(c)	13	-	6	**19**	n/a
Supply cost variance deferral account	(d)	-	-	18	**18**	n/a
Power purchase expense recognition	(e)	-	-	18	**18**	n/a
Supply deferrals	(f)	59	(55)	8	**12**	n/a
Deferred energy conservation costs	(g)	8	-	-	**8**	n/a
Business system transformation program	(h)	4	-	1	**5**	n/a
Other	(k-t)	2	-	2	**4**	n/a
		172	(31)	43	**184**	
Regulatory liability deferrals						
Removal provision	(i)	(12)	-	(5)	**(17)**	n/a
Insurance amortization and proceeds	(j)	(3)	-	(4)	**(7)**	n/a
Other	(k-t)	(2)	-	(1)	**(3)**	n/a
		(17)	-	(10)	**(27)**	

12.1 Regulatory Adjustments Recorded in the Non-Consolidated Statement of Profit and Comprehensive Income

For the year ended December 31 (millions of Canadian dollars)		**2021**	2020
RSP amortization		**(24)**	(32)
RSP fuel deferral		**33**	57
RSP interest		**(3)**	(2)
Rural rate adjustment		**2**	2
Total RSP activity	(a)	**8**	25
Supply deferral recovery		**4**	11
Supply deferrals		**(12)**	(55)
Total supply deferral activity	(f)	**(8)**	(44)
Supply cost variance deferrals	(d)	**(18)**	-
Power purchase expense recognition	(e)	**(18)**	-
Removal provision	(i)	**5**	4
Other	(b,c,g,h,j-t)	**(2)**	-
		(33)	(15)

The following section describes Hydro's regulatory assets and liabilities which will be, or are expected to be, reflected in customer rates in future periods and have been established through the rate setting process. In the absence of rate regulation, these amounts would be reflected in operating results in the year and profit for 2021 would have decreased by $32.7 million (2020 – $15.1 million).

12.(a) RSP

In 1986, the PUB ordered Hydro to implement the RSP which primarily provides for the deferral of fuel expense variances resulting from changes in fuel prices, hydrology, load and associated interest. Adjustments required in utility rates to cover the amortization of the balance are implemented on July 1 of each year. Similar adjustments required in industrial rates are implemented on January 1 of each year.

During 2021, Hydro recorded a net increase in the RSP balance of $16.6 million (2020 - $23.7 million) resulting in a balance from customers of $56.5 million (2020 - $39.9 million). The increase in the RSP asset is primarily due to the recovery of the 2020 energy supply deferrals as per Board Order No. P.U. 15 (2021) resulting in a net increase to the RSP of $54.9 million (2020 - $19.8 million); and Board Order No. P.U. 6 (2021) which approved a transfer of the remaining balance in the 2017 GRA Cost Recovery Rider to the Island Industrial Customer RSP Current Plan resulting in a net increase to the RSP of $0.3 million; partially offset by adjustments related to the one-time fuel price bill credits for utility, rural and industrial customers as per Board Order No.'s P.U. 16 (2020) and P.U. 6 (2021) resulting in a net decrease of $30.9 million (2020 - net increase of $30.8 million) and normal operation of the RSP resulting in a net decrease of $7.7 million (2020 – $25.4 million).

Per Board Order No. P.U. 33 (2021) and Hydro's compliance filing, the RSP was discontinued for purposes of deferring variations in hydraulic production, No. 6 fuel, and load as at October 31, 2021. The Board ordered that the RSP will be maintained to provide timely recovery of the remaining balance resulting in the continuation of amortization and interest charges.

12.(b) Foreign Exchange Losses

In 2002, the PUB ordered Hydro to defer realized foreign exchange losses related to the issuance of Swiss Franc and Japanese Yen denominated debt and amortize the balance over a 40 year period. Accordingly, these costs were recognized as a regulatory asset. During 2021, amortization expense of $2.2 million (2020 - $2.2 million) was recorded.

12.(c) Retirement Asset Pool

As per Board Order No. P.U. 30 (2019), the Board approved Hydro's proposed depreciation methodology which includes the deferral of gains and losses on retirement of assets. The deferral will be recovered through future depreciation expense. In 2021, Hydro deferred $6.1 million (2020 - $2.1 million) of retirement asset activity resulting in a total balance of $19.3 million.

12.(d) Supply Cost Variance Deferral Account

In Board Order No. P.U. 33 (2021), the PUB approved Hydro's proposal to establish an account to defer payments under the Muskrat Falls Project agreements, rate mitigation funding, project cost recovery from customers and supply cost variances. The deferral commenced activity on November 1, 2021. As at December 31, 2021, $18.3 million was deferred for future recovery from customers.

12.(e) Power Purchase Expense Recognition

In Board Order No. P.U. 9 (2021) and Board Order No. P.U. 33 (2021), the PUB approved Hydro's proposal to deviate from IFRS to allow recognition of expenses related to the purchase of energy in accordance with the commercial terms of the Muskrat Falls Power Purchase Agreement. As at December 31, 2021, IFRS power purchase expenses were $14.8 million higher during Muskrat Falls pre-commissioning and $2.8 million higher during post-commissioning than commercial payments which resulted in the deferral of a regulatory asset of $17.6 million.

12.(f) Supply Deferrals

Pursuant to Board Order No. P.U. 22 (2017), the Board approved Supply deferral costs using three specific deferral accounts: the Energy Supply, Holyrood Conversion and Isolated Systems Supply cost deferrals. During 2021, Hydro recorded a net decrease to the supply deferrals of $47.4 million (2020 – net increase $24.3 million) resulting in a balance from customers of $12.3 million (2020 - $59.7 million). The decrease in the supply deferral asset is primarily due to the recovery of the 2020 supply cost deferral of $54.9 million from the RSP as per Board Order No. P.U. 15 (2021); Board Order No. P.U. 21 (2019) approved the recovery from customers of $18.4 million over a 20 month period; of which, in 2021 Hydro recovered $4.5 million (2020 - $10.9 million); Board Order No. P.U. 6 (2021) which approved a transfer of the remaining balance in the 2017 GRA cost recovery Rider to the Island Industrial Customer, which resulted in a net decrease to the supply deferral of $0.3 million (2020 - $nil); and normal operation of the supply deferral, resulting in a net increase of $12.3 million (2020 - $54.9 million), with recovery of the period's activity to be determined through an annual application process.

Per Board Order No. P.U. 33 (2021) and Hydro's compliance application, the Energy Supply and Holyrood Conversion Deferrals were discontinued as at October 31, 2021 with the account maintained to provide for a timely recovery of the remaining balance.

12.(g) Deferred Energy Conservation Costs

In 2021, Hydro deferred $1.1 million (2020 - $0.6 million) in Energy Conservation Costs associated with an electrical conservation demand management program for residential, industrial, and commercial sectors. As per Board Order No. P.U. 22 (2017), Hydro recovered $1.5 million (2020 – $1.5 million) of the balance through a rate rider.

12.(h) Business System Transformation Program

As per Board Order No.'s P.U. 23 (2019) and P.U. 30 (2019), the Board approved the deferral of business system transformation program costs. The recovery of the deferral is subject to a future Board order. During the year, Hydro deferred $1.0 million (2020 – $1.1 million).

12.(i) Removal Provision

As per Board Order No. P.U. 30 (2019), the Board approved Hydro's proposed depreciation methodology which includes the provision for removal costs. Hydro recorded a net increase to the provision relating to 2021 activity of $4.9 million (2020 - $4.1 million) resulting in a total balance of $16.9 million (2020 - $12.0 million). The increase was driven by removal depreciation of $5.2 million (2020 - $5.1 million) which was partially offset by removal costs of $0.3 million (2020 - $1.0 million).

12.(j) Insurance Amortization and Proceeds

Pursuant to Board Order No. P.U. 13 (2012), Hydro records net insurance proceeds against the capital costs and amortizes the balance over the life of the asset. Under IFRS, Hydro is required to recognize the insurance proceeds and corresponding amortization in regulatory liabilities. During 2021, Hydro recorded a net increase of $4.2 million (2020 - $nil) to the regulatory liability. The increase was driven by insurance proceeds of $4.5 million (2020 - $nil) which was partially offset by insurance amortization of $0.3 million (2020 - $nil).

12.(k) Deferred Lease Costs

In Board Order No's. P.U. 17 (2016), P.U. 23 (2016) and No. P.U. 49 (2016) the Board approved amortization of lease costs associated with mobile diesel units at Holyrood Thermal Generating Station (HTGS) over a period of five years. In 2021, Hydro recorded amortization of $0.1 million (2020 - $0.3 million) of the deferred lease costs.

12.(l) Deferred Foreign Exchange on Fuel

Hydro purchases fuel for HTGS in USD. There are regulatory mechanisms that allow Hydro to defer variances in fuel prices (including foreign exchange fluctuations). During 2021, Hydro recognized an increase to regulatory assets due to foreign exchange losses on fuel purchases of $0.6 million (2020 - $0.2 million gains).

12.(m) Phase Two Hearing Costs

Pursuant to Board Order No. P.U. 13 (2016), Hydro received approval to defer consulting fees and salary related costs relating to Phase Two of the investigation into the reliability and adequacy of power on the Island Interconnected system after the interconnection with the Muskrat Falls generating station. In 2019, Phase Two of the Board's investigation was concluded with recovery to be addressed in a future Board Order. There were no additions in 2021 or 2020. The total deferred balance is $1.4 million (2020 - $1.4 million).

12.(n) Asset Disposal

As per Board Order No. P.U. 49 (2016), the Board ordered that Hydro recognize a regulatory asset of $0.4 million related to the Sunnyside transformer that was disposed of in 2014. Hydro is required to recover the deferred asset in rate base and amortize the asset for 22.4 years commencing in 2015. Hydro is required to exclude the new Sunnyside transformer from rate base until the Sunnyside transformer original asset deferral has been fully amortized.

12.(o) Hydraulic Resources Optimization Deferral Account

In Board Order No. P.U. 49 (2018), a deferral account to capture the revenues and costs associated with the hydraulic optimization activities was approved. For the year ended December 31, 2021, the balance of hydraulic optimization activities is a net gain of $1.3 million (2020 - $1.0 million) recorded as a deferred liability.

12.(p) Deferred Purchased Power Savings

In 1997, the PUB ordered Hydro to defer $1.1 million related to reduced purchased power rates resulting from the interconnection of communities in the area of L'Anse au Clair to Red Bay to the Hydro-Québec system and amortize the balance over a 30 year period. The remaining unamortized savings in the amount of $0.2 million (2020 - $0.2 million) are deferred as a regulatory liability.

12.(q) Non-Customer Contributions in Aid of Construction

Pursuant to Board Order No. P.U. 1 (2017), Hydro recognized amortization of deferred contributions in aid of construction (CIAC) from entities which are non-customer related parties in profit or loss. During 2021, Hydro recorded $1.2 million (2020 - $0.9 million) in non-customer related party CIAC amortization as a regulatory adjustment. In the absence of rate regulation, IFRS requires these non-customer related party CIACs to be recorded as contributed capital with no corresponding amortization. As a result, during 2021 Hydro also recorded an increase of $1.2 million (2020 - $0.9 million) to contributed capital to recognize the amount that was reclassified to profit or loss.

12.(r) Employee Future Benefits Actuarial Loss

Pursuant to Board Order No. P.U. 36 (2015), Hydro has recognized the amortization of employee future benefit actuarial gains and losses in net income. During 2021 Hydro recorded $0.2 million (2020 - $0.1 million) employee future benefits losses as a regulatory adjustment. In the absence of rate regulation, IFRS would require Hydro to include employee future benefits actuarial gains and losses in other comprehensive income. As a result, during 2021 Hydro also recorded a decrease of $0.2 million (2020 - $0.1 million) to other comprehensive income to recognize the amount that was reclassified to profit or loss.

12.(s) Reliability and Resource Adequacy Study

Pursuant to Board Order No. P.U. 29 (2019), the Board approved the deferral of costs associated with the Reliability and Resource Adequacy proceeding. Hydro deferred $1.3 million in 2021 (2020 - $0.6 million) resulting in a regulatory asset of $2.1 million (2020 - $0.8 million). The recovery of the balance is to be determined in a future Board Order.

12.(t) Frequency Converter Revenue Deferral Account

In Board Order No. P.U. 35 (2020), the Board approved the deferral of the cumulative revenue requirement impact associated with the loss on the sale of a frequency converter, commencing December, 2019. The disposition of the cumulative revenue requirement impact included in the deferral account balance will be addressed as part of Hydro's next general rate application. During 2021, Hydro deferred $0.2 million as a regulatory liability (2020 - $0.2 million).

13. TRADE AND OTHER PAYABLES

As at December 31 (millions of Canadian dollars)	**2021**	2020
Trade payables	**51**	72
Accrued interest payable	**25**	25
Due to related parties	**7**	7
Other payables	**23**	15
	106	119

14. DEBT

14.1 Short-term Borrowings

Hydro utilized its $300.0 million government guaranteed promissory note program to fulfil its short-term funding requirements. As at December 31, 2021, there were two promissory notes outstanding for a total of $55.0 million with a maturity date of January 10, 2022 bearing an average interest rate of 0.20% (2020 - $262.0 million bearing an average interest rate of 0.17%). Upon maturity, the promissory notes were reissued.

Hydro's $200.0 million CAD or USD equivalent committed revolving term facility with a maturity date of July 27, 2021 was increased to $500.0 million on April 16, 2021, and extended to reflect a new maturity date of July 31, 2022. As at December 31, 2021, there were no amounts drawn on the facility (2020 - $nil). Borrowings in CAD may take the form of Prime Rate Advances, Bankers' Acceptances (BAs), and letters of credit, with interest calculated at the Prime Rate or BA fee. Borrowings in USD may take the form of Base Rate Advances and letters of credit. The facility also provides coverage for overdrafts on Hydro's bank accounts, with interest calculated at the Prime Rate. Hydro's committed credit facility with its banker of $300.0 million matured during the year and was not renewed.

14.2 Long-term Debt

The following table represents the value of long-term debt measured at amortized cost:

As at December 31 (millions of Canadian dollars)	Face Value	Coupon Rate %	Year of Issue	Year of Maturity	**2021**	2020
Hydro						
Y *	300	8.40	1996	2026	**297**	297
AB *	300	6.65	2001	2031	**304**	304
AD *	125	5.70	2003	2033	**124**	124
AF	500	3.60	2014/2017	2045	**482**	481
1A	600	3.70	2017/2018	2048	**638**	639
2A	300	1.75	2021	2030	**287**	-
Total	2,125				**2,132**	1,845
Less: Sinking fund investments in own debentures					**84**	73
					2,048	1,772
Less: Sinking fund payments due within one year					**7**	7
Total					**2,041**	1,765

*Sinking funds have been established for these issues.

Hydro's promissory notes and debentures are unsecured and unconditionally guaranteed as to principal and interest and, where applicable, sinking fund payments, by the Province, with exception of Series 1A and Series 2A which are borrowed directly from the Province. The Province charges Hydro a guarantee fee of 25 basis points annually on the total debt (net of sinking funds) with a remaining term to maturity of less than or equal to 10 years and 50 basis points annually on total debt (net of sinking funds) with a remaining term to maturity greater than 10 years for debt outstanding as of December 31, 2010. For debt issued subsequent to December 31, 2010, the guarantee rate is 25 basis points annually on the total debt (net of sinking funds) with an original term to maturity of less than or equal to 10 years and 50 basis points annually on total debt (net of sinking funds) with an original term to maturity greater than 10 years. The guarantee fee recorded for the year ended December 31, 2021 was $8.6 million (2020 - $8.6 million).

On April 13, 2021 the Province of Newfoundland and Labrador issued long-term debt with a face value of $300.0 million, specifically on Hydro's behalf. The debt matures on June 2, 2030 with a coupon rate of 1.75% paid semi-annually.

15. DEFERRED CONTRIBUTIONS

Hydro has received contributions in aid of construction of property, plant and equipment. These contributions are deferred and amortized to other revenue over the life of the related property, plant and equipment asset.

As at December 31 (millions of Canadian dollars)	**2021**	2020
Deferred contributions, beginning of the year	**22**	20
Additions	**5**	3
Amortization	**(1)**	(1)
Deferred contributions, end of the year	**26**	22
Less: current portion	**(1)**	(1)
	25	21

16. DECOMMISSIONING LIABILITIES

Hydro has recognized liabilities associated with the retirement of portions of the HTGS and the disposal of Polychlorinated Biphenyls (PCB).

The reconciliation of the beginning and ending carrying amounts of decommissioning liabilities for December 31, 2021 are as follows:

As at December 31 (millions of Canadian dollars)	**2021**	2020
Decommissioning liabilities, beginning of the year	**15**	14
Revisions	**-**	1
Decommissioning liabilities, end of the year	**15**	15
Less: current portion	**(2)**	-
	13	15

The total estimated undiscounted cash flows required to settle the HTGS obligations at December 31, 2021 are $15.2 million (2020 - $15.2 million). Payments to settle the liability are expected to occur between 2022 and 2025. The fair value of the decommissioning liabilities was determined using the present value of future cash flows discounted at Hydro's credit adjusted risk free rate of 1.3% (2020 - 0.5%). Hydro has recorded $14.6 million (2020 - $14.8 million) related to HTGS obligations.

The total estimated undiscounted cash flows required to settle the PCB obligations at December 31, 2021 are $0.2 million (2020 - $0.3 million). Payments to settle the liability are expected to occur between 2022 and 2025. The fair value of the decommissioning liabilities was determined using the present value of future cash flows discounted at Hydro's credit adjusted risk free rate of 1.3% (2020 - 0.5%). Hydro has recorded $0.2 million (2020 - $0.3 million) related to PCB obligations.

Hydro's assets include generation plants, transmission assets and distribution systems. These assets can continue to run indefinitely with ongoing maintenance activities. As it is expected that Hydro's assets will be used for an indefinite period, no removal date can be determined and consequently, a reasonable estimate of the fair value of any related decommissioning liability cannot be determined at this time. If it becomes possible to estimate the fair value of the cost of removing assets that Hydro is required to remove, a decommissioning liability for those assets will be recognized at that time.

17. LEASES

Amounts Recognized in the Non-Consolidated Statement of Profit and Comprehensive Income

For the year ended December 31 (millions of Canadian dollars)		**2021**	2020
Variable lease payments not included in the measurement of leases	(a)	**29**	28

(a) Variable lease payments not included in the measurement of leases include payments made to Nalcor for power generated from assets which are owned by the Province. These variable lease payments are included in power purchased in the Non-Consolidated Statement of Profit and Comprehensive Income.

The total cash outflow for leases for the year ended December 31, 2021 amount to $28.7 million (2020 - $28.3 million).

18. EMPLOYEE FUTURE BENEFITS

18.1 Pension Plan

Employees participate in the Province's Public Service Pension Plan, a multi-employer defined benefit plan. The employer's contributions for the year ended December 31, 2021 of $8.0 million (2020 - $7.8 million) are expensed as incurred.

18.2 Other Benefits

Hydro provides group life insurance and health care benefits on a cost shared basis to retired employees, and in certain cases their surviving spouses, in addition to a retirement allowance. In 2021, cash payments to beneficiaries for its unfunded other employee future benefits were $3.2 million (2020 - $3.1 million). An actuarial valuation was performed as at December 31, 2021.

As at December 31 (millions of Canadian dollars)	**2021**	2020
Accrued benefit obligation, beginning of the year	**107**	101
Current service cost	**4**	4
Interest cost	**3**	3
Benefits paid	**(3)**	(3)
Actuarial (gain) loss	**(13)**	2
Accrued benefit obligation, end of the year	**98**	107

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Component of benefit cost		
Current service cost	**4**	4
Interest cost	**3**	3
Total benefit expense for the year	**7**	7

The significant actuarial assumptions used in measuring the accrued benefit obligations and benefit expenses are as follows:

	2021	2020
Discount rate - benefit cost	**2.70%**	3.20%
Discount rate - accrued benefit obligation	**3.35%**	2.70%
Rate of compensation increase	**3.50%**	3.50%

Assumed healthcare trend rates:

	2021	2020
Initial health care expense trend rate	**5.53%**	5.64%
Cost trend decline to	**3.60%**	3.60%

Current rate 5.53%, reducing linearly to 3.6% in 2040 and thereafter.

A 1% change in assumed health care trend rates would have had the following effects:

Increase (millions of Canadian dollars)	**2021**	2020
Current service and interest cost	**2**	2
Accrued benefit obligation	**15**	18

Decrease (millions of Canadian dollars)	**2021**	2020
Current service and interest cost	**(1)**	(1)
Accrued benefit obligation	**(12)**	(13)

19. SHAREHOLDER'S EQUITY

19.1 Share Capital

As at December 31 (millions of Canadian dollars)	**2021**	2020
Common shares of par value of $1 each		
Authorized: 25,000,000		
Issued, paid and outstanding: 22,503,942	**23**	23

19.2 Contributed Capital

As at December 31 (millions of Canadian dollars)	**2021**	2020
Contributed capital, beginning of the year	**146**	147
Amortization	**(1)**	(1)
Contributed capital, end of the year	**145**	146

During 2021, Lower Churchill Management Corporation contributed $0.2 million (2020 - $0.2 million) in additions to property, plant and equipment. Pursuant to Board Order No. P.U. 1 (2017), Hydro recognized $1.2 million (2020 - $0.9 million) in amortization as a regulatory adjustment.

19.3 Dividends

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Declared during the year		
Final dividend for prior year: $0.03 per share (2020 - $0.03)	**1**	1
Interim dividend for current year: $0.64 per share (2020 - $0.54)	**14**	12
	15	13

20. OPERATING COSTS

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Salaries and benefits	**83**	87
Maintenance and materials	**24**	21
Professional services	**8**	8
Insurance	**4**	4
Travel and transportation	**4**	3
Other operating costs	**7**	13
	130	136

21. NET FINANCE EXPENSE

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Finance income		
Interest on sinking fund	**13**	12
Other interest income	**1**	1
	14	13
Finance expense		
Long-term debt	**96**	92
Debt guarantee fee	**9**	9
Other	**2**	4
	107	105
Interest capitalized during construction	**(2)**	(2)
	105	103
Net finance expense	**91**	90

22. OTHER EXPENSE

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Loss on disposal of property, plant and equipment	**6**	2
Insurance proceeds	**(5)**	-
Other	**1**	2
Other expense	**2**	4

23. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

23.1 Fair Value

The estimated fair values of financial instruments as at December 31, 2021 and 2020 are based on relevant market prices and information available at the time. Fair value estimates are based on valuation techniques which are significantly affected by the assumptions used including the amount and timing of future cash flows and discount rates reflecting various degrees of risk. As such, the fair value estimates below are not necessarily indicative of the amounts that Hydro might receive or incur in actual market transactions.

As a significant number of Hydro's assets and liabilities do not meet the definition of a financial instrument, the fair value estimates below do not reflect the fair value of Hydro as a whole.

Establishing Fair Value

Financial instruments recorded at fair value are classified using a fair value hierarchy that reflects the nature of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities.

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices).

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value. For assets and liabilities that are recognized at fair value on a recurring basis, Hydro determines whether transfers have occurred between levels in the hierarchy by reassessing categorization (based on the lowest level input that is significant to the fair value measurement as a whole) at the end of each reporting period. There were no transfers between Level 1, 2 and 3 fair value measurement for the years ended December 31, 2021 and 2020.

	Level	**Carrying Value**	**Fair Value**	Carrying Value	Fair Value
As at (millions of Canadian dollars)		**December 31, 2021**		December 31, 2020	
Financial assets					
Sinking funds - investments in Hydro debt issue	**2**	**84**	**94**	73	88
Sinking funds - other investments	**2**	**192**	**230**	183	234
Financial liabilities					
Derivative liability	**3**	**56**	**56**	23	23
Long-term debt (including amount due within one year before sinking funds)	**2**	**2,132**	**2,508**	1,845	2,394

The fair value of cash, trade and other receivables, related party loan receivable, short-term borrowings and trade and other payables approximates their carrying values due to their short-term maturity.

The fair values of Level 2 financial instruments are determined using quoted prices in active markets, which in some cases are adjusted for factors specific to the asset or liability. Level 2 derivative instruments are valued based on observable commodity future curves, broker quotes or other publicly available data. Level 2 fair values of other risk management assets and liabilities and long-term debt are determined using observable inputs other than unadjusted quoted prices, such as interest rate yield curves and currency rates.

Level 3 financial instruments include the derivative liability relating to the PPA with Energy Marketing and represents the future value provided to Energy Marketing through the contract.

The following table summarizes quantitative information about the valuation techniques and unobservable inputs used in the fair value measurement of Level 3 financial instruments as at December 31, 2021:

(millions of Canadian dollars)	Carrying Value	Valuation Techniques	Significant Unobservable Input(s)	Range
Derivative liability (PPA)	56	Modelled pricing	Volumes (MWh)	27-34% of available generation

The derivative liability arising under the PPA is designated as a Level 3 instrument as certain forward market prices and related volumes are not readily determinable to estimate a portion of the fair value of the derivative liability. Hence, fair value measurement of this instrument is based upon a combination of internal and external pricing and volume estimates. As at December 31, 2021, the effect of using reasonably possible alternative assumptions for volume inputs to valuation techniques may have resulted in a -$0.1 million to +$0.9 million change in the carrying value of the derivative liability.

The components of the change impacting the carrying value of the derivative liability for the years ended December 31, 2021 and 2020 are as follows:

(millions of Canadian dollars)	**(Level 3)**
Balance at January 1, 2021	**(23)**
Purchases	**(63)**
Changes in profit or loss	
Mark-to-market	**(21)**
Settlements	**51**
Total	**30**
Balance at December 31, 2021	**(56)**

(millions of Canadian dollars)	(Level 3)
Balance at January 1, 2020	(9)
Purchases	(38)
Changes in profit or loss	
Mark-to-market	1
Settlements	23
Total	24
Balance at December 31, 2020	(23)

23.2 Risk Management

Hydro is exposed to certain credit, liquidity and market risks through its operating, investing and financing activities. Financial risk is managed in accordance with Hydro's Board approved Financial Risk Management Policy, which outlines the objectives and strategies for the management of financial risk, including the use of derivative contracts. Permitted financial risk management strategies are aimed at minimizing the volatility of Hydro's expected future cash flows.

Credit Risk

Hydro's expected future cash flow is exposed to credit risk through its operating activities, primarily due to the potential for non-performance by its customers, and through its financing and investing activities, based on the risk of non-performance by counterparties to its financial instruments. The degree of exposure to credit risk on cash and derivative assets as well as from the sale of electricity to customers, including the associated accounts receivable, is determined by the financial capacity and stability of those customers and counterparties. The maximum exposure to credit risk on these financial instruments is represented by their carrying values on the Non-Consolidated Statement of Financial Position at the reporting date.

The COVID-19 pandemic has increased the credit risk of the Company, as the potential risk for non-performance of the Company's customers has increased with the current economic slowdown. Hydro had established flexible collection practices during the COVID-19 pandemic for its customers and has since returned to its normal customer collections practices. Hydro is continuing to monitor the risk of non-performance by its customers and as at December 31, 2021 the impact on the Company's expected credit loss allowance is not considered material. As well, Hydro is continuing to monitor the implications of COVID-19, including the risk of credit losses, pronouncements from governments and regulators and, if required, will make adjustments to the expected credit loss allowance in future periods.

Credit risk on cash is minimal, as Hydro's cash deposits are held by a Schedule 1 Canadian Chartered Bank with a rating of A+ (Standard and Poor's).

Credit exposure on Hydro's sinking funds is limited by restricting the holdings to long-term debt instruments issued by the Government of Canada or any province of Canada, Crown corporations and Schedule 1 Canadian Chartered Banks. The following credit risk table provides information on credit exposures according to issuer type and credit rating for the remainder of the sinking funds portfolio:

	Issuer Credit Rating	**Fair Value of Portfolio (%)**	Issuer Credit Rating	Fair Value of Portfolio (%)
	2021		2020	
Provincial Governments	**AA- to AAA**	**16.62%**	AA- to AAA	17.10%
Provincial Governments	**A- to A+**	**26.02%**	A- to A+	26.53%
Provincially owned utilities	**AA- to AAA**	**23.31%**	AA- to AAA	24.03%
Provincially owned utilities	**A- to A+**	**34.05%**	A- to A+	32.34%
		100.00%		100.00%

Hydro's exposure to credit risk on its energy sales and associated accounts receivable is determined by the credit quality of its customers. Hydro's three largest customers account for 82.8% (2020 - 81.3%) of total energy sales and 62.2% (2020 - 64.3%) of accounts receivable. Energy sales for the three largest customers include $448.6 million (2020 - $455.0 million) for Regulated Hydro, as well as $39.3 million (2020 - $41.4 million) for Non-Regulated Hydro.

Liquidity Risk

Hydro is exposed to liquidity risk with respect to its contractual obligations and financial liabilities. Liquidity risk management is aimed at ensuring cash is available to meet those obligations as they become due.

Short-term liquidity is mainly provided through cash on hand, funds from operations and a $300.0 million promissory note program. In addition, Hydro maintains a $500.0 million (2020 - $200.0 million) committed revolving term credit facility with its primary banker. These credit facilities are held with its primary banker in order to meet any requirements beyond those forecasted for a given period. Long-term liquidity risk is managed by the issuance of a portfolio of debentures with maturity dates ranging from 2026 to 2048. Sinking funds have been established for these issues, with the exception of the issues maturing in 2030, 2045 and 2048.

The following are the contractual maturities of Hydro's financial liabilities, including principal and interest, as at December 31, 2021:

(millions of Canadian dollars)	< 1 Year	1-3 Years	3-5 Years	> 5 Years	Total
Trade and other payables	106	-	-	-	106
Short-term borrowings	55	-	-	-	55
Contract payable	18	-	-	-	18
Derivative liability	56	-	-	-	56
Debt guarantee fee	9	17	17	126	169
Long-term debt including sinking funds	7	13	311	1,794	2,125
Interest	98	195	183	998	1,474
	349	225	511	2,918	4,003

Market Risk

In the course of carrying out its operating, financing and investing activities, Hydro is exposed to possible market price movements that could impact expected future cash flow and the carrying value of certain financial assets and liabilities. Market price movements to which Hydro has significant exposure include those relating to prevailing interest rates, foreign exchange rates, most notably the USD/CAD, and current commodity prices, most notably the spot prices for fuel and electricity. These exposures are addressed as part of the Financial Risk Management Policy.

Interest Rates

Changes in prevailing interest rates will impact the fair value of financial assets and liabilities, which includes Hydro's cash and sinking funds. Expected future cash flows associated with those financial instruments can also be impacted. The impact of a 0.5% change in interest rates on net income and other comprehensive income associated with cash and short-term debt was negligible throughout 2021 due to the short time period to maturity. There was no impact on profit and other comprehensive income associated with long-term debt as all of Hydro's long-term debt has fixed interest rates.

Foreign Currency and Commodity Exposure

Hydro's primary exposure to both USD foreign exchange and commodity price risk arises from its purchases of No. 6 fuel for consumption at the HTGS, and these risks are mitigated through the operation of the regulatory mechanisms.

24. RELATED PARTY TRANSACTIONS

Hydro enters into various transactions with its parent and other affiliates. These transactions occur within the normal course of operations and are measured at the exchange amount, which is the amount of consideration agreed to by the related parties. Related parties with which Hydro transacts are as follows:

Related Party	Relationship
Nalcor	100% shareholder of Hydro
The Province	100% shareholder of Nalcor
Churchill Falls	Joint arrangement of Hydro
Twin Falls	Joint venture of Churchill Falls
Energy Marketing	Wholly-owned subsidiary of Nalcor
Lower Churchill Management Corporation (LCMC)	Wholly-owned subsidiary of Nalcor
Labrador-Island Link Operating Corporation (LIL Opco)	Wholly-owned subsidiary of Nalcor
Muskrat Falls Corporation (Muskrat Falls)	Wholly-owned subsidiary of Nalcor
Nalcor Energy – Oil and Gas Inc.	Wholly-owned subsidiary of Nalcor
Board of Commissioners of Public Utilities (PUB)	Agency of the Province

Routine operating transactions with related parties are settled at prevailing market prices under normal trade terms. Outstanding balances due to or from related parties are non-interest bearing with settlement within 30 days, unless otherwise stated.

As at December 31 (millions of Canadian dollars)		**2021**	2020
Amounts owed by related parties:			
Trade and other receivables:			
LCMC		**-**	3
Energy Marketing		**4**	4
Nalcor		**2**	-
Related party loan receivable:			
Muskrat Falls	(a)	**53**	-
Amounts owed to related parties:			
Trade and other payables:			
Churchill Falls		**4**	4
Nalcor		**-**	3
Energy Marketing		**3**	-
Contract payable:			
Muskrat Falls	(b)	**18**	-
Long-term debt:			
The Province		**925**	639
Other liabilities:			
Various related parties		**1**	1

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Revenues:		
Energy and transmission sales:		
LCMC	**2**	3
Energy Marketing	**2**	-
Rebate recoveries:		
The Province	**2**	2
Nalcor	**1**	1
Operating contract revenues:		
Nalcor	**25**	26
Expenses:		
Power purchased:		
Churchill Falls	**48**	48
Muskrat Falls	**57**	-
Nalcor	**29**	28
Net operating costs:		
Various related parties	**5**	5
Net finance expense:		
The Province	**31**	31

(a) As at December 31, 2021, Hydro has a related party loan receivable from Muskrat Falls of $53.2 million (2020 - $nil) which includes interest charged on the balance outstanding at a rate of 5.43% as required under the Power Purchase Agreement. The balance is repayable by Muskrat Falls as cash is available while still meeting its debt servicing costs.

(b) Hydro entered into a Power Purchase Agreement with Muskrat Falls for the purchase of energy and capacity from the Muskrat Falls Plant. The contract payable balance represents the timing difference between the value of energy and capacity delivered to Hydro and the contractual payments made under the Power Purchase Agreement in the reporting period.

24.1 Key Management Personnel Compensation

Compensation for key management personnel, which Hydro defines as its executives who have the primary authority and responsibility in planning, directing and controlling the activities of the entity, includes compensation for senior executives. Salaries and employee benefits include base salaries, performance contract payments, vehicle allowances and contributions to employee benefit plans. Post-employment benefits include contributions to the Province's Public Service Pension Plan in the amount of $0.2 million (2020 – $0.2 million).

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Salaries and employee benefits	**2**	2

25. COMMITMENTS AND CONTINGENCIES

(a) Hydro is subject to various legal proceedings and claims in the normal course of business. Although the outcomes of such actions cannot be predicted with certainty, Management believes the Company's exposure to such claims and litigation will not materially affect its financial position or results of operations.

(b) Outstanding commitments for capital projects total approximately $24.8 million as at December 31, 2021 (2020 - $21.6 million).

(c) Hydro has entered into a number of long-term power purchase agreements as follows:

Type	**Rating**	**Effective Date**	**Term**
Hydroelectric	6.5 MW	2021	24 years
Hydroelectric	4 MW	1998	25 years
Hydroelectric	300 MW	1998	43 years
Hydroelectric	225 MW	2015	25 years
Cogeneration	15 MW	2003	20 years
Wind	390 kW	2004	Continual
Wind	27 MW	2008	20 years
Wind	27 MW	2009	20 years
Hydroelectric, Solar, Battery	240 kW Hydro 189 kW Solar 334.5 kW Battery	2019. Amended in 2020.	15 years
Biomass	450 kW	2018	1 year post in-service of Muskrat Falls

Estimated payments due in each of the next five years are as follows:

(millions of Canadian dollars)	2022	2023	2024	2025	2026
Power purchases	80.9	70.2	70.4	71.3	72.5

(d) Through a power purchase agreement signed October 1, 2015, with Energy Marketing, Hydro maintains the transmission services contract it entered into with Hydro-Québec TransÉnergie which concludes in 2024.

The transmission rental payments for the next three years are estimated to be as follows:

2022	$19.7 million
2023	$19.9 million
2024	$ 5.0 million

(e) In 2013, Hydro entered into a Power Purchase Agreement with Muskrat Falls for the purchase of energy and capacity from the Muskrat Falls Plant. The supply period under the agreement is 50 years and contractual payments commenced in November 2021 upon commissioning of the Muskrat Falls Plant. Estimated payments for the next five years have not yet been determined as they may be impacted by the Province's rate mitigation plan.

(f) In 2013, Hydro entered into the Transmission Funding Agreement (TFA) with LIL Opco, in which Hydro has committed to make payments which will be sufficient for LIL Opco to recover all costs associated with rent payments under the LIL Lease and payments to cover operating and maintenance costs incurred by LIL Opco. Hydro will be required to begin mandatory payments associated with the TFA upon commissioning of the Labrador-Island Link (LIL) assets. The term of the TFA is anticipated to continue until the service life of the LIL assets has expired.

(g) In 2014, Hydro entered into three Capacity Assistance Agreements, one with Vale Newfoundland & Labrador Limited (Vale) and two with Corner Brook Pulp and Paper Limited (CBPP) for the purchase of relief power during the winter period. In May 2021, Hydro entered into a second revised agreement with CBPP that expires on April 30, 2023. In December 2021, Hydro entered into a revised agreement with Vale that expires in March of 2022. Payment for services will be dependent on the successful provision of capacity assistance for the winter period by Vale and CBPP.

26. CAPITAL MANAGEMENT

Hydro's principal business requires ongoing access to capital in order to maintain assets to ensure the continued delivery of safe and reliable service to its customers. Therefore, Hydro's primary objective when managing capital is to ensure ready access to capital at a reasonable cost, to minimize its cost of capital within the confines of established risk parameters, and to safeguard Hydro's ability to continue as a going concern.

The capital managed by Hydro is comprised of debt (long-term debentures, short-term borrowings, bank credit facilities and bank indebtedness) and equity (share capital, shareholder contributions, reserves and retained earnings).

A summary of the capital structure is outlined below:

(millions of Canadian dollars)	**2021**		2020	
Debt				
Sinking funds	**(192)**		(183)	
Short-term borrowings	**55**		262	
Current portion of long-term debt	**7**		7	
Long-term debt	**2,041**		1,765	
	1,911	**61.9%**	1,851	63.0%
Equity				
Share capital	**23**		23	
Contributed capital	**145**		146	
Reserves	**(6)**		(22)	
Retained earnings	**1,015**		939	
	1,177	**38.1%**	1,086	37.0%
Total Debt and Equity	**3,088**	**100.0%**	2,937	100.0%

Hydro's approach to capital management encompasses various factors including monitoring the percentage of floating rate debt in the total debt portfolio, the weighted average term to maturity of its overall debt portfolio, its percentage of debt to debt plus equity, and its interest coverage.

For the regulated portion of Hydro's operations, Management targets a capital structure comprised of 75% debt and 25% equity, a ratio which Management believes to be optimal with respect to its cost of capital. This capital structure is maintained by a combination of dividend policy, shareholder contributions and debt issuance. The issuance of any new debt with a term greater than one year requires prior approval of the PUB. Hydro's committed operating facility has a covenant requiring Hydro to ensure that its consolidated debt to total capitalization ratio does not exceed 85%. As at December 31, 2021, Hydro was in compliance with this covenant.

Legislation stipulates that the total of the Government guaranteed short-term loans issued by Hydro and outstanding at any time shall not exceed a limit as fixed by the Lieutenant-Governor in Council. Short-term loans are those loans issued with a term not exceeding two years. On February 20, 2020, the Lieutenant-Governor in Council issued Order in Council OC2020-18 to increase the level of short-term borrowings permitted by Hydro from $300 million to $500 million, effective until March 31, 2022. As a result, the current limit is now $500.0 million and $55.0 million is outstanding as at December 31, 2021 (2020 - $262.0 million). The Hydro Corporation Act, 2007 (the Act) limits Hydro's total borrowings outstanding at any point in time, which includes both short-term borrowings and long-term debt. Hydro's total borrowing limit under the Act is $2.6 billion.

Historically, Hydro Regulated addressed longer-term capital funding requirements by issuing government guaranteed long-term debt in the domestic capital markets. Beginning in December 2017, the Province now issues debt in the domestic capital markets, on Hydro Regulated's behalf, and in turn loans the funds to Hydro Regulated on a cost recovery basis. Any additional funding to address long-term capital funding requirements will require approval from the Province and the PUB.

28. SUPPLEMENTARY CASH FLOW INFORMATION

For the year ended December 31 (millions of Canadian dollars)	**2021**	2020
Trade and other receivables	**(26)**	34
Inventories	**8**	11
Prepayments	**1**	(2)
Trade and other payables	**(11)**	(24)
Contract payable	**18**	-
Changes in non-cash working capital balances	**(10)**	19
Related to:		
Operating activities	**(12)**	21
Investing activities	**2**	(2)
	(10)	19

29. SEGMENT INFORMATION

Hydro operates in three business segments. The designation of segments is based on a combination of regulatory status and management accountability.

Hydro Regulated activities encompass sales of electricity to customers within the Province that are regulated by the PUB. Hydro Non-Regulated activities include the sale of energy to mining operations in Labrador West as well as costs of Hydro that are excluded from the determination of customer rates. Energy Marketing includes the sale of electricity and transmission to Energy Marketing.

(millions of Canadian dollars)	Hydro Regulated	Non-Regulated Activities	Energy Marketing	Total
	For the year ended December 31, 2021			
Energy sales	538	47	4	589
Other revenue	16	-	21	37
Revenue	554	47	25	626
Fuels	122	-	-	122
Power purchased	123	43	4	170
Operating costs	129	1	-	130
Transmission rental	-	-	21	21
Depreciation and amortization	84	-	-	84
Net finance expense	91	-	-	91
Other expense	2	-	-	2
Expenses	551	44	25	620
Profit for the year from operations	3	3	-	6
Share of profit of joint arrangement	-	41	-	41
Preferred dividends	-	11	-	11
Profit before regulatory adjustments	3	55	-	58
Regulatory adjustments	(33)	-	-	(33)
Profit for the year	36	55	-	91
Capital expenditures*	115	-	-	115
Total assets	2,910	664	59	3,633

***Capital expenditures include non-cash additions of $0.2 million contributed by Lower Churchill Management Corporation and $1.6 million of interest capitalized during construction.**

(millions of Canadian dollars)	Hydro Regulated	Non-Regulated Activities	Energy Marketing	Total
	For the year ended December 31, 2020			
Energy sales	557	50	4	611
Other revenue	6	-	20	26
Revenue	563	50	24	637
Fuels	158	-	-	158
Power purchased	75	43	4	122
Operating costs	135	1	-	136
Transmission rental	1	-	20	21
Depreciation and amortization	79	-	-	79
Net finance expense	90	-	-	90
Other expense	4	-	-	4
Expenses	542	44	24	610
Profit for the year from operations	21	6	-	27
Share of profit of joint arrangement	-	25	-	25
Preferred dividends	-	8	-	8
Profit before regulatory adjustments	21	39	-	60
Regulatory adjustments	(15)	-	-	(15)
Profit for the year	36	39	-	75
Capital expenditures*	90	-	-	90
Total assets	2,780	622	26	3,428

*Capital expenditures include non-cash additions of $0.2 million contributed by Lower Churchill Management Corporation and $1.5 million of interest capitalized during construction.

Newfoundland and Labrador Hydro

Directors[1]	Officers
John Green Chairperson, NL Hydro Retired Lawyer, McInnes Cooper	**Jennifer Williams** President and Chief Executive Officer
Donna Brewer Retired Deputy Minister of Finance	**Kevin Fagan** Vice President, Regulatory and Stakeholder Relations
Chris Loomis Retired Professor Memorial University of Newfoundland and Labrador	**Rob Collett** Vice President, Hydro Engineering and NLSO
Jennifer Williams President and Chief Executive Officer, NL Hydro President and Interim Chief Executive Officer, Nalcor Energy	**Lisa Hutchens** Vice President, Chief Financial Officer
Brendan Paddick (on leave of absence) CEO Columbus Capital Corp.	**Michael Ladha** Vice President, Chief Legal Officer and Corporate Secretary
David Oake President Invenio Consulting Inc.	**Gilbert Bennett** Vice President, Power Development
Fraser Edison President and CEO, Rutter Inc.	**Gerard Dunphy** Vice President, Churchill Falls and Muskrat Falls
John Mallam Retired NL Hydro Executive	**Gail Collins** Interim Vice President, People and Corporate Affairs
Brian Walsh Retired FortisTCI Executive	**Scott Crosbie** Vice President, Hydro Operations
Trina Troke Director of Projects, Cahill Group	**James Meaney** Vice President, Finance, Churchill Falls and Muskrat Falls
Head Office Newfoundland and Labrador Hydro PO Box 12400 Hydro Place, 500 Columbus Drive St. John's, NL Canada A1B 4K7	**Walter Parsons** Vice President, LIL and Business Development **Meredith Baker** Assistant Corporate Secretary

[1] Newfoundland and Labrador Hydro Board of Directors as at December 31, 2021.

Newfoundland and Labrador Hydro
Computation of Rate Base
Year Ended December 31, 2021
($000)

	2021	2020
Capital Assets - Return 4	2,816,362	2,708,003
Work in Progress[1]	9,164	24,988
	2,825,526	2,732,991
Deduct:		
Accumulated Depreciation - Return 6[2]	598,649	523,797
Contributions in Aid of Construction - Return 7[1]	51,605	50,680
Total Capital Assets	2,175,272	2,158,514
Deduct Items Excluded from Rate Base:		
Work in Progress[1]	(9,164)	(24,988)
Asset Retirement Obligations (net of amortization)	(352)	(768)
Net Capital Assets	2,165,756	2,132,758
Net Capital Assets, Previous Year	2,132,758	2,115,068
Unadjusted Average Capital Assets	2,149,257	2,123,913
Deduct:		
Average Net Capital Assets Excluded from Rate Base	(8,154)	(8,257)
Average Capital Assets	2,141,103	2,115,656
Cash Working Capital Allowance - Return 8	122	1,409
Fuel Inventory - Return 10	55,803	54,075
Supplies Inventory - Return 10	38,326	38,438
Average Deferred Charges - Return 11	86,402	100,981
Average Rate Base at Year-End - Return 12	**2,321,756**	**2,310,559**

[1] Contributions of $4.4 million (2020 - $1.9 million) related to capital assets not in service have been net in work in progress. In addition, insurance proceeds of $3.6 million (2020 - $ nil) related to capital assets not in service have been net in work in progress.

[2] Accumulated amortization is net of the Retirement Asset Pool and Removal Provision. Please refer to Return 6 for further details.

Newfoundland and Labrador Hydro
Capital Assets - Original Cost
Year Ended December 31, 2021
($000)

	Balance 31-Dec-2020	Adjustments During 2021	Additions During 2021	Retirements During 2021	Balance 31-Dec-2021
Power Generation					
Steam	185,153	(470)	31,022	(5,419)	210,285
Hydro	874,401	(74)	20,717	(657)	894,387
Diesel	111,699	226	11,508	(4,289)	119,144
Gas Turbine	188,079	3	3,290	(39)	191,333
	1,359,332	**(316)**	**66,537**	**(10,404)**	**1,415,149**
Substations	372,499	(5)	23,490	(756)	395,228
Transmission	561,664	5	2,965	(15)	564,619
Distribution	254,472	33	21,671	(313)	275,864
General Plant	82,528	49	4,574	(1,416)	85,735
Telecontrol	53,438	(73)	2,411	(848)	54,929
Total Depreciable Plant	**2,683,934**	**(307)**	**121,648**	**(13,752)**	**2,791,523**
Non-Depreciable Land[1]	5,073	-	-	-	5,073
Plant Investment	2,689,007	(307)	121,648	(13,752)	2,796,596
Intangible	18,996	(13)	831	(49)	19,766
Total - Return 3	**2,708,003**	**(320)**	**122,479**	**(13,801)**	**2,816,362**

[1] Prior year amounts is $5,072. Difference is immaterial.

Newfoundland and Labrador Hydro
Capital Expenditures - Overview
Year Ended December 31, 2021
($000)

	Total Board Approved Expenditures for 2021	Total Actual Expenditures for 2021	Variance from 2021 Budget
Generation	52,251	50,477	1,774
Transmission and Rural Operations	65,903	51,524	14,379
General Properties	9,045	4,630	4,415
Allowance for Unforeseen Events	2,108	4,007	(1,899)
Supplemental Projects	6,902	2,767	4,135
New Projects less than $50,000 Approved by Hydro	95	87	8
Total Capital Budget	**136,304**	**113,492**	**22,812**

2021 Capital Budget Approved by Board Order No. P.U. 2(2021)	107,453
New Project Approved by Board Order No. P.U. 25(2020)	165
New Project Approved by Board Order No. P.U. 26(2020)	216
Top-up Approved by Board Order No. P.U. 17(2021)	108
New Project Approved by Board Order No. P.U. 18(2021)	443
New Project Approved by Board Order No. P.U. 20(2021)	350
New Project Approved by Board Order No. P.U. 27(2021)	3,479
New Project Approved by Board Order No. P.U. 28(2021)	308
New Project Approved by Board Order No. P.U. 30(2021)	1,410
Top-up Approved by Board Order No. P.U. 34(2021)	1,000
2021 New Projects under $50,000 Approved by Hydro	95
Total Approved Capital Budget Before Carryovers	**115,027**
Carryover Projects 2020–2021	21,277
Total Approved Capital Budget	**136,304**

Newfoundland and Labrador Hydro
Accumulated Depreciation
Year Ended December 31, 2021
($000)

	Property, Plant and Equipment	Intangible	Total
Balance, December 31, 2020	512,880	11,966	524,846
Add:			
Depreciation	81,748	1,533	83,281
Deduct:			
Retirements, Transfers and Adjustments	(7,243)	(49)	(7,292)
Accumulated Amortization Balance, December 31, 2021	587,385	13,450	600,835
Retirement Asset Pool			
Balance, December 31, 2020	(13,117)	-	(13,117)
Add:			
Net Loss on Retirement	(6,560)	-	(6,560)
Disposal Proceeds	391	95	487
	(19,286)	95	(19,191)
Removal Provision			
Balance, December 31, 2020	12,068	-	12,068
Add:			
Removal Depreciation	5,275	-	5,275
Less:			
Removal Costs	(338)	-	(338)
	17,005	-	17,005
Total Accumulated Amortization Balance, December 31, 2021	585,103	13,546	598,649

Depreciation Rates - 2021

Depreciation is calculated on a straight-line basis over the estimated useful lives of the assets as follows:

Generation Plant	
Hydroelectric	25 to 110 years
Thermal	20 to 70 years
Diesel	3 to 70 years
Transmission	
Lines	26 to 65 years
Terminal Stations	20 to 60 years
Distribution System	20 to 60 years
Other Assets	3 to 70 years

Newfoundland and Labrador Hydro
Contributions in Aid of Construction
Year Ended December 31, 2021
($000)

	Customers	Government/ Hydro Corporate[1]	Total
Gross Contributions			
December 31, 2020	19,919	39,423	59,341
2021 Additions[2]	2,989	174	3,163
December 31, 2021	22,908	39,597	62,504
Less:			
Accumulated Amortization			(10,899)
Net Balance December 31, 2021 - Return 3			**51,605**

[1] Hydro Corporate includes Hydro's other lines of business, including but not limited to the Lower Churchill Project.
[2] Contributions of $4.4 million (2020 - $1.9 million) related to capital assets not in service have been net in work in progress. In addition, insurance proceeds of $3.6 million (2020 - $ nil) related to capital assets not in service have been net in work in progress.

Newfoundland and Labrador Hydro
Working Capital
Year Ended December 31, 2021
($000)

	2021	2020
Calculation of Cash Working Capital Allowance		
Operating Expenses for the Year - Return 9	126,062	133,514
Add: Power Purchases	105,514	74,689
Add: Transmission Expenses	386	1,429
Total	231,962	209,632
Net Lag %[1]	1.52%	2.41%
Working Capital Allowance	3,526	5,052
Deduct: HST Adjustment	3,404	3,643
Working Capital Allowance - Return 3	122	1,409

[1] Net Lag % is calculated as Net Lag Days (Revenue Lag less Expense Lag) divided by 365 days. In 2021, Hydro's Revenue Lag was 36 days (2020 - 36 days) and the Expense Lag was 30 days (2020 - 27 days) resulting in a Net Lag of 6 days (2020 - 9 days).

Newfoundland and Labrador Hydro
Statement of Operating Costs
Year Ended December 31, 2021
($000)

	2021	2020
Salaries and Benefits	79,000	84,442
System Equipment Maintenance	21,819	20,489
Office Supplies and Expenses	2,082	2,288
Professional Services	7,560	7,330
Insurance	4,412	3,785
Equipment Rentals	2,285	2,739
Travel	1,591	1,500
Miscellaneous Expenses	4,978	4,570
Building Rental and Safety	932	911
Transportation	1,863	1,215
Customer Costs	(703)	2,908
Cost (Recoveries) Charges	243	1,337
Operating Costs - Return 8	**126,062**	**133,514**

Newfoundland and Labrador Hydro
Significant Operating Expense Variance
Year Ended December 31, 2021
($000)

	2021	2020	Increase (Decrease)
Salaries and Benefits	**79,000**	**84,442**	**(5,442)**
Decrease is due to lower salary related costs and increased capital recharge, partially offset by an increase in overtime.			
System Equipment Maintenance	**21,819**	**20,489**	**1,330**
Variance is primarily due to increased contract labour associated with the Reliability and Resource Adequacy Study, which is deferred in the cost recoveries category, as well as variations in maintenance and materials.			
Insurance	**4,412**	**3,785**	**627**
Premium increase in 2021 due to market rate increases.			
Equipment Rentals	**2,285**	**2,739**	**(454)**
Decrease is due to variations in equipment rental costs.			
Miscellaneous Expenses	**4,978**	**4,570**	**408**
Increase is due to variations in adustments related to inventory.			
Transportation	**1,863**	**1,215**	**648**
Higher utilization of aircrafts and increased fuel prices in 2021.			
Customer Costs	**(703)**	**2,908**	**(3,611)**
Higher bad debt expense in 2020 is associated with an allowance for doubtful accounts related to a General Service Customer.			
Cost (recoveries) Charges	**243**	**1,337**	**(1,094)**
Decrease in cost is primarily due to the inclusion of the deferral credit associated with the Reliability and Resource Adequacy Study.			

Newfoundland and Labrador Hydro
Inventory
Year Ended December 31, 2021
($000)

	Fuel		Supplies	
	2021	**2020**	**2021**	**2020**
Opening Balance	53,721	65,834	38,622	37,414
January	54,561	55,987	38,707	38,670
February	36,841	47,661	38,685	37,751
March	35,995	51,270	38,949	38,200
April	41,073	50,019	38,793	38,894
May	52,146	43,590	38,765	38,871
June	53,627	58,565	38,202	38,662
July	73,056	57,765	37,958	38,764
August	72,313	57,109	37,879	38,632
September	71,982	56,435	37,847	38,509
October	71,194	51,932	37,858	38,248
November	62,832	53,089	37,917	38,463
December	46,103	53,721	38,051	38,622
13-Month Average - Return 3	**55,803**	**54,075**	**38,326**	**38,438**

Newfoundland and Labrador Hydro
Deferred Charges
Year Ended December 31, 2021
($000)

	Board Order No.	2021	2020
Foreign Exchange Losses	P.U. 7(2002-2003)	43,139	45,296
Foreign Exchange on Fuel	P.U. 30(2019)	(16)	(656)
Conservation Demand Program	P.U. 30(2019)	8,300	8,750
Phase II Hearing Costs	P.U. 13(2016)	1,364	1,364
Asset Disposal	P.U. 13(2016)	292	311
Deferred Lease Costs	P.U. 38(2013)	-	132
Energy Supply Deferral	P.U. 30(2019)	12,323	59,703
Deferred Power Purchases	P.U. 5(1996-1997)	(177)	(213)
2018 Revenue Deficiency	P.U. 30(2019)	(1)	(1)
2019 Revenue Deficiency	P.U. 30(2019)	77	77
Business Systems Transformation Program	P.U. 16(2019)	4,600	3,585
Reliability and Resource Adequacy	P.U. 29(2019)	2,057	765
Hydraulic Resource Optimization	P.U. 49(2018)	(2,548)	(1,268)
Frequency Converter	P.U. 35(2020)	(473)	(244)
Power Purchase Expense Recognition	P.U. 9(2021), P.U. 33(2021)	17,573	-
Deferred Charges		86,510	117,601
Deduct:			
Deferred Charges Excluded From Rate Base [1]		(25,594)	(5,714)
Deferred Charges, End Of Current Year		60,916	111,887
Deferred Charges, End Of Prior Year		111,887	90,075
Average Deferred Charges For Rate Base - Return 3		**86,402**	**100,981**

[1] The calculation of Deferred Charges for Rate Base excludes Phase II Hearing Costs of $1.4 million (2020 - $1.4 million), the Business System Transformation Deferral of $4.6 million (2020 - $3.6 million), as well as Reliability & Resource Adequacy Study of $2.1 million (2020 - $0.8 million). Recovery of these expenditures are subject to approval by the Board. As per Board Order P.U. 9(2021) and P.U. 33(2021), the Power Purchase Expense Recognition of $17.6 million (2020 - $ nil) is not eligible for recovery.

Newfoundland and Labrador Hydro
Return on Rate Base
Year Ended December 31, 2021
($000)

		2021	2020
(a)	Corporate Net Income - Return 1	91,327	74,092
	Deduct: Unregulated Earnings	55,528	38,064
	Regulated Net Income	35,799	36,028
	Add: Compliance Adjustments	-	-
	Add: Cost of Service Exclusions[1]	7,108	7,311
	Add: Regulated Interest - Return 16	83,813	83,143
(b)	Regulated Return	126,720	126,482
(c)	Average Rate Base - Return 3	2,321,756	2,310,559
(d)	Rate of Return on Average Rate Base	5.46%	5.47%
	Lower end of Approved Range - 0.20	5.23%	5.23%
	Higher end of Approved Range + 0.20	5.63%	5.63%

[1] The Cost of Service exclusions are comprised of the disallowed portion of the debt guarantee fee of $6.3 million (2020 - $6.3 million) and depreciation on assets excluded from rate base of $0.8 million (2020 - $1.0 million).

Newfoundland and Labrador Hydro
Return on Regulated Average Retained Earnings
Year Ended December 31, 2021
($000)

		2021		2020
Total Equity - Hydro as per Balance Sheet, Return 1		1,177,109		1,085,560
Add: Compliance Adjustments		-		-
		1,177,109		1,085,560
Deduct: Share Capital		22,504		22,504
Contributed Surplus		145,262		146,243
Accumulated OCI		(5,759)		(22,073)
Ending Retained Earnings as per Balance Sheet, Return 1		1,015,103		938,886
Deduct: Non-Regulated Retained Earnings				
Beginning Non-Regulated Retained Earnings	563,078		537,774	
Non-Regulated Net Income for the Year	55,528		38,064	
Non-Regulated Dividends for the Year	(15,109)		(12,760)	
Ending Non-Regulated Retained Earnings		603,497		563,078
Regulated Retained Earnings, end of year		411,606		375,807
Add:				
Regulated Contributed Surplus		100,000		100,000
Retained Earnings Cost of Service Exclusions		50,221		43,113
Total Regulated Equity, end of year		561,826		518,920
Regulated Equity, beginning of year		518,920		475,579
Regulated Average Equity		540,373		497,250
Net Income - Return 1		91,327		74,092
Add: Compliance Adjustments		-		-
Deduct: Non-Regulated Net Income		55,528		38,064
Hydro Regulated Earnings		35,799		36,028
Cost of Service Exclusions		7,108		7,311
Regulated Earnings		42,907		43,339
Rate of Return on Regulated Equity		7.94%		8.72%

Newfoundland and Labrador Hydro
Capital Structure
Year Ended December 31, 2021
($000)

	2021		2020		Average	
	Amount	**Percent**	**Amount**	**Percent**	**Amount**	**Percent**
Hydro						
Debt (Return 15)	1,911,328	61.9%	1,851,431	63.0%	1,881,380	62.4%
Equity (Return 13)	1,177,109	38.1%	1,085,560	37.0%	1,131,335	37.6%
	3,088,437	**100.0%**	**2,936,991**	**100.0%**	**3,012,715**	**100.0%**
Hydro Regulated						
Debt (Return 15)[1]	1,896,516	74.1%	1,835,855	74.8%	1,866,185	74.4%
Funded Employee Future Benefits	87,830	3.4%	83,790	3.4%	85,810	3.4%
Funded Asset Retirement Obligation	14,396	0.6%	14,276	0.6%	14,336	0.6%
Equity (Return 13)[1]	561,826	21.9%	518,920	21.2%	540,373	21.6%
	2,560,568	**100.0%**	**2,452,840**	**100.0%**	**2,506,704**	**100.0%**

[1] Non-Regulated Debt Pool for 2020 has been adjusted from prior year Annual Return to reflect late revision to 2020 PUB Quarterly Financial Statements.

Newfoundland and Labrador Hydro
Cost of Debt
Year Ended December 31, 2021
($000)

	2021	2020	Average
Long-Term Debt	2,048,049	1,772,001	1,910,025
Promissory Notes	55,000	262,000	158,500
Sinking Funds	(191,721)	(182,570)	(187,146)
Total Debt	**1,911,328**	**1,851,431**	**1,881,379**
Add back Mark to Market Value	-	-	-
Net Debt	1,911,328	1,851,431	1,881,379
Non-Regulated Debt Pool[1]	(14,812)	(15,576)	(15,194)
Total Regulated Debt - Return 14	**1,896,516**	**1,835,855**	**1,866,185**
Current Year Interest Expense - Return 16			88,560
Cost of Debt			4.75%

[1] Non-Regulated Debt Pool for 2020 has been adjusted from prior year Annual Return to reflect late revision to 2020 PUB Quarterly Financial Statements.

Newfoundland and Labrador Hydro
Interest Expense
Year Ended December 31, 2021
($000)

	2020	2020
Gross Interest		
Long-Term Debt	96,220	92,475
Promissory Notes and Short Term	1,141	2,741
	97,361	95,216
Amortization of Debt Discount and Financing Expenses	885	(156)
Provision for Foreign Exchange	2,157	2,157
Interest Earned	(14,209)	(13,029)
Debt Guarantee Fee - Hydro[1]	8,602	8,624
Other	184	179
	94,980	92,991
(Deduct):		
Cost of Service Exclusions[1]	(6,326)	(6,348)
Non-Regulated Interest	(94)	(87)
Interest for Cost of Debt - Return 15	88,560	86,556
Add:		
Interest Capitalized During Construction	(1,556)	(1,516)
Interest on Supply Cost Variance Deferral Account	9	-
Interest Charged on RSP	(3,200)	(1,897)
Regulated Net Interest - Return 12	83,813	83,143
(Deduct):		
Provision for Foreign Exchange	(2,157)	(2,157)
Add:		
Cost of Service Exclusions[1]	6,326	6,348
Accretion of ARO	77	289
Regulated Interest (PUB Quarterly)	88,059	87,623
(Deduct):		
Interest on Supply Cost Variance Deferral Account	(9)	-
Interest charged on RSP	3,200	1,897
Add:		
Non-Regulated Interest	94	87
Interest - Return 1	91,344	89,607

[1] As per Board Order No. P.U. 49(2016), Hydro has excluded the disallowed portion of the debt guarantee fee.

Newfoundland and Labrador Hydro
Rate Stabilization Plan - Activity
Year Ended December 31, 2021
($000)

	Utility							Industrial					
Month	Load Variation	Allocation Fuel Variation	Allocation Rural Rate Alteration	Financing Charges	Adjustment	Transfers	Cumulative Net Balance	Load Variation	Allocation Fuel Variation	Financing Charges	Adjustment	Transfers[1]	Cumulative Net Balance
Opening Balance							13,454						(887)
Adjustment							-					2,748	2,748
Adjusted Opening Balance							13,454						1,861
January	(3,452)	(7,007)	(401)	59	1,180	-	3,834	(263)	(534)	8	(61)	-	1,012
February	(3,151)	(7,671)	(363)	17	1,124	-	(6,210)	(227)	(555)	4	136	(15)	354
March	(2,766)	(6,645)	(365)	(27)	1,118	50,828	35,932	(198)	(477)	2	168	4,146	3,994
April	(3,522)	(3,666)	(316)	159	883	-	29,469	(265)	(282)	18	136	-	3,599
May	(2,916)	(1,248)	(298)	130	765	-	25,902	(225)	(108)	16	161	-	3,443
June	(3,272)	(47)	(269)	114	583	-	23,012	(237)	6	15	140	-	3,367
July	(3,518)	18	(369)	102	(1,886)	-	17,358	(247)	18	15	140	-	3,293
August	(3,992)	(13)	(358)	77	(1,820)	-	11,252	(279)	14	15	126	-	3,168
September	(3,442)	(25)	(342)	50	(1,773)	-	5,719	(242)	6	14	136	-	3,083
October	(4,417)	(435)	(399)	25	(2,435)	-	(1,941)	(325)	(34)	14	114	-	2,851
November	-	-	-	(9)	(2,800)	-	(4,750)	-	-	13	135	-	2,998
December	-	-	-	(21)	(3,788)	-	(8,559)	-	-	13	139	-	3,150
Year-to-Date	**(34,449)**	**(26,741)**	**(3,479)**	**676**	**(8,848)**	**50,828**	**(8,559)**	**(2,509)**	**(1,947)**	**146**	**1,468**	**4,131**	**3,150**
Hydraulic Allocation							16,062						1,170
Total							**7,503**						**4,320**
							To Return 18						To Return 18

[1] Board Order No. P.U. 6(2021) approved a transfer of $271,092 relating to the 2017 GRA Cost Recovery as at December 31, 2020 for Industrial Customers. It also approved a debit transfer of $2,476,684 to Island Industrial Customers RSP Current Plan at December 31, 2020. These transfers resulted in an opening adjustment in 2021 totalling $2,747,776. Additionally, Board Order No. P.U. 6(2021) approved a credit transfer of $15,388.10 to reflect the over collection of the GRA Recovery Rider in February (relating to amount billed in January).

Recovery of the supply deferrals was approved in Board Order No. P.U. 15(2021) which resulted in a transfer to the Island Industrial Customers RSP Current Plan of $4,145,931.

Newfoundland and Labrador Hydro
Rate Stabilization Plan - Balances
Year Ended December 31, 2021
($000)

	Hydraulic				From Return 17		
Month	**Net Hydraulic Production Variation**	**Financing Charges**	**Transfers**	**Cumulative Variance and Financing Charges**	**Utility Balance**	**Industrial Balance**	**Cumulative Net Balance**
Opening Balance	-	-	-	27,294	13,454	(887)	39,861
Adjustment[1]	-	-	-	-	-	2,748	2,748
Adjusted Opening Balance	-	-	-	27,294	13,454	1,861	42,609
January	(5,695)	121	-	21,720	3,834	1,012	26,565
February	(4,091)	96	-	17,724	(6,210)	354	11,868
March	5,740	78	-	23,542	35,932	3,994	63,468
April	18,146	104	-	41,792	29,469	3,599	74,860
May	5,445	185	-	47,422	25,902	3,443	76,767
June	5,405	209	-	53,037	23,012	3,367	79,416
July	3,482	234	-	56,753	17,358	3,293	77,404
August	4,112	251	-	61,115	11,252	3,168	75,535
September	6,434	270	-	67,820	5,719	3,083	76,622
October	(6,719)	300	-	61,400	(1,941)	2,851	62,310
November	-	271	-	61,672	(4,750)	2,998	59,920
December	-	272	-	61,944	(8,559)	3,150	56,535
Year-to-Date	32,260	2,390	-	34,650	(22,013)	1,289	13,926
Hydraulic Allocation	(14,888)	(2,390)	-	(17,279)	16,062	1,170	(48)
Total	**17,372**	**-**	**-**	**44,665**	**7,503**	**4,320**	**56,487**

[1] Board Order No. P.U. 6(2021) approved a transfer of $271,092 relating to the 2017 GRA Cost Recovery as at December 31, 2020 for Industrial Customers. It also approved a debit transfer of $2,476,684 to Island Industrial Customers RSP Current Plan at December 31, 2020. These transfers resulted in an opening adjustment in 2021 totalling $2,747,776. Additionally, Board Order No. P.U. 6(2021) approved a credit transfer of $15,388.10 to reflect the over collection of the GRA Recovery Rider in February (relating to amount billed in January).

Recovery of the supply deferrals was approved in Board Order No. P.U. 15(2021) which resulted in a transfer to the Island Industrial Customers RSP Current Plan of $4,145,931.

Newfoundland and Labrador Hydro
Assessable Revenue
Year Ended December 31, 2021
($000)

	2021		**2020**
Electricity Sales	607,195		631,064
Rate Stabilization[1]	(23,944)		(31,553)
CDM Rider	1,586		1,489
Energy Supply Deferral & Revenue Deficiency	4,464		9,536
Energy Sales (Return 1)	589,300		610,536
Other Revenue	37,165		25,937
Total Revenue (Return 1)	626,465		636,473
Deduct Regulated Hydro Revenue That Is Not Assessable:			
Input Tax Credits	183		131
Contribution in Aid of Construction	1,016		1,087
Rural Rate Alteration	2,281		2,009
CBPP Frequency Converter Deferral	229		243
Ponding Revenue Deferral	1,390		1,528
Deduct Non-Regulated Revenue:			
Recall/Export	4,266		3,624
Iron Ore Company of Canada	39,248		41,316
Tacora/Wabush Mines	7,717		8,546
Other Revenue	20,632		20,443
	76,962	-	78,927
Assessable Revenue	549,503		557,546

[1] Includes Utility adjustment $8,848 (2020 - ($10,395)) and Industrial adjustment ($1,468) (2020 - $686) from Return 17.

Newfoundland and Labrador Hydro
2021 Annual Report on the Rural Deficit

	2021[1]			
Rural Deficit Areas	**Revenues ($)**	**Cost of Service before Deficit and Revenue Allocation ($)**	**Revenue Credits ($)**	**Deficit ($)**
Island Interconnected	54,254,604	66,289,449	-	(12,034,845)
Island Isolated	1,284,650	9,493,190	-	(8,208,539)
Labrador Isolated	8,672,766	32,992,737	-	(24,319,971)
L'Anse-au-Loup	3,200,809	6,351,787	-	(3,150,977)
Total	67,412,829	115,127,162	-	(47,714,332)

	2021				
Rural Deficit Areas	**Number of Communities[2]**	**Number of Customers**	**Cost per kWh ($)**	**Deficit per Customer ($)**	**Cost Recovery Ratio**
Island Interconnected	146	22,938	0.17	(525)	0.82
Island Isolated	6	652	1.88	(12,590)	0.14
Labrador Isolated	15	2,702	0.87	(9,001)	0.26
L'Anse-au-Loup	8	1,042	0.29	(3,024)	0.50
Total	**175**	**27,334**	**0.23**	**(1,746)**	**0.59**

NOTE: Hydro has not provided forecast deficit figures for 2022–2026 due to the uncertainty regarding post-Muskrat Falls rates.

[1] The 2021 Rural Deficit calculation is based on pro forma Cost of Service studies.

[2] Hydro's definition of community corresponds to the "Town Code" in its Customer Information System. Some smaller communities may be combined if they share a single postal code.

2021 Electrification, Conservation and Demand Management Report

April 1, 2022

A report to the Board of Commissioners of Public Utilities

Contents

List of Appendices

1.0 Introduction

Electrification, Conservation and Demand Management ("ECDM") activities undertaken by Newfoundland and Labrador Hydro ("Hydro") include joint utility programs offered by Newfoundland Power Inc. ("Newfoundland Power") and Hydro (collectively, the "Utilities") through the takeCHARGE partnership, as well as programs specifically targeted to Hydro's customers. This report focuses primarily on the costs and initiatives implemented by Hydro, including Hydro's portion of costs related to the delivery of joint initiatives in 2021.

The ECDM Plan 2021–2025 ("ECDM Plan") was developed in 2020 and an application, requesting approval of the economic test for electrification programming, is currently under review by the Board of Commissioners of Public Utilities ("Board").[1] While the review is underway, the Utilities continue to execute new and existing Conservation and Demand Management ("CDM") programming that meets economic testing requirements approved in Board Order No. P.U. 18(2016).[2] If Hydro's current application is approved, the electrification portion of the programming will be required to meet the proposed economic test before implementation.[3] Similar to CDM programs, the approval of an economic test, rather than specific programs, would provide the Utilities with flexibility to adapt to changing market conditions while ensuring programs remain cost-effective for customers.

In 2021, CDM activities continued to be impacted by the COVID-19 pandemic, along with associated supply chain issues for energy efficient products and appliances. Residential programs saw an overall decrease in home improvement projects compared to 2020, when the Residential Construction Rebates Program offered by the provincial government encouraged home improvement projects. Commercial customers expressed concerns about completing energy efficiency projects during a period of uncertainty, as COVID-19 pandemic public health restrictions and lockdowns continued throughout 2021. Additionally, both residential and commercial programs were impacted by supply chain issues that limited the availability of energy efficient products.

[1] "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021).
[2] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 18(2016), Board of Commissioners of Public Utilities, June 8, 2016, p. 50, para. 9.
[3] In the ECDM Plan currently before the Board, electrification program costs are proposed to be evaluated using a modified Total Resource Cost ("mTRC") test. The mTRC test is used to ensure that electrification programs are sufficiently economic to enable customer participation. A net present value analysis is then used as a secondary assessment to ensure that electrification programs are beneficial for all ratepayers.

Throughout 2021, Hydro was required to plan and execute programs while ensuring the safety of employees, the public, and contractors. Program advertising and logistics were adjusted throughout the year to remain consistent with COVID-19 safety protocols. Despite the challenges imposed by the COVID-19 pandemic, Hydro's programs achieved an estimated 1,624 MWh (94% of target)[4] of annual incremental energy savings in 2021 and have accumulated energy savings of 53,355 MWh since 2009.

2.0 Coordination and Context

2.1 Utility Planning

Starting with the initial CDM plan in 2008, the Utilities have designed and implemented a joint utility portfolio of programs for electricity customers in Newfoundland and Labrador.[5] Currently, programs offered through the joint utility model are available for residential, commercial, and industrial customers and provide rebate options to address energy savings for electricity customers. In 2020, the Board recommended the Utilities develop a plan for beneficial electrification to manage future system peak demand and realize rate mitigation benefits. The 2020–2034 Potential Study ("Study") prepared by Dunsky Energy Consulting ("Dunsky") evaluated market potential of various electrification technologies.[6] The Study was used to help form the ECDM Plan. The ECDM Plan was submitted to the Board in 2020,[7] and the two Utilities intend to execute it jointly under takeCHARGE. While review of the current application is underway, the Utilities continue to execute new and existing CDM programming that meets economic testing requirements approved in the Five-Year Conservation Plan: 2016–2020.[8]

CDM activities for 2021 included the continuation of the residential and commercial rebate programs, the Isolated Systems Community Energy Efficiency Program, the custom industrial program, and the delivery of three government-funded programs. The Utilities also developed new CDM programming,

[4] The 2021 energy savings exclude those associated with outreach activities. These savings may be updated if further audit in 2022 indicates adjustments are required.
[5] The Five-Year Energy Conservation Plan: 2008–2012 was filed with the Board on June 27, 2008. The Five-Year Energy Conservation Plan: 2012–2016 was filed with the Board on September 14, 2012.
[6] The market potential study completed by Dunsky is designed to identify the theoretical potential for electrification in the province. The Study is not designed to identify the specific programs that should be implemented by the Utilities.
[7] The five-year ECDM Plan was filed with the Board in "2021 Electrification, Conservation and Demand Management Application," Newfoundland Power Inc., December 16, 2020, vol. 2 and "Application for Approvals Required to Execute Programming Identified in the Electrification, Conservation and Demand Management Plan 2021–2025," Newfoundland and Labrador Hydro, rev. July 8, 2021 (originally filed June 16, 2021), sch. 3. The Board has since combined the two proceedings into a joint proceeding, which is still ongoing as of the time of publishing this report.
[8] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 18(2016), Board of Commissioners of Public Utilities, June 8, 2016.

such as a low-income program and duct insulation program that are anticipated to launch in 2022. The description of the programs offered during 2021 through the joint utility partnership as well as those specific to Hydro's customers are provided in Appendix A to this report.

The Utilities continuously evaluate customer conservation programs and periodically undertake third-party program evaluations to refine program design and support future planning.

2.2 Government Engagement

Hydro continues to have a positive working relationship with both the provincial and federal governments, and remains engaged in dialogue on potential programming, policy, and partnership opportunities. In 2021, Hydro delivered three government-funded programs to customers: the Low Carbon Economy Leadership Fund Program, the Electric Vehicle Rebate Program, and the Oil to Electric Rebate Program. These programs are fully cost recovered.

Hydro continued to deliver the Low Carbon Economy Leadership Fund Program to its oil heated customers on behalf of the federal and provincial governments through insulation and thermostat rebates. 11 insulation rebates and 2 thermostat rebates were approved in areas served by Hydro in 2021.

The Electric Vehicle Rebate Program was launched on September 1, 2021. The program is intended to encourage the purchase of electric vehicles through a $2,500 rebate. The program approved 55 rebate applications in 2021.

Finally, the Oil to Electric Rebate Program was launched on August 30, 2021. This program provides rebates up to $2,500 to help homes, whose sole source of heat is oil, to transition to electricity. The program approved 40 applications in 2021.

3.0 2021 Conservation and Demand Management Program Costs and Energy Savings

3.1 Portfolio Level Program Costs and Energy Savings

Table 1 and Table 2 describe Hydro's total CDM program expenses and energy savings from 2009–2021 across all of Hydro's systems. Further detail and a breakdown of the costs that will be recovered through the CDM Deferral Account[9] and the associated energy savings are provided in Section 7, Program Energy Savings and Program Costs.

Historically, Hydro has not recovered the CDM costs incurred on the Labrador Interconnected System through customer rates as the CDM initiatives contributed to an increase in available exports of Recapture Energy for which the benefits accrued to Nalcor Energy Marketing. Following the commissioning of the Muskrat Falls Project, it is anticipated that the benefits of exports of Recapture Energy will accrue to Hydro's customers. As such, Hydro proposed modifications to the CDM Cost Deferral Account definition and CDM Cost Recovery Adjustment to permit recovery of Labrador Interconnected System costs from those customers, including their portion of the rural deficit allocation related to CDM investments for Hydro Rural customers.

Table 1: Hydro's CDM Portfolio Spending ($000)[10,11]

	2009–2016	2017	2018	2019	2020	2021
Residential						
Windows	498	-	-	-	-	-
Insulation	746	102	88	198	96	83
Thermostats	238	55	44	75	41	58
Residential Benchmarking	49	45	23	27	9	-
Coupon Program	275	-	-	-	-	-
Block Heater Timer	47	-	-	-	-	-
Heat Recovery Ventilator	40	7	10	11	3	4
Isolated Systems Community(Residential)	3,325	936	981	577	239	776
Instant Rebate	739	159	169	140	47	102
Appliance Retirement Pilot	44	-	-	-	-	-
Isolated Load Control Pilot	164	17	5	17	-	-
Commercial						
Isolated System Community(Commercial)	-	-	-	412	52	349
Commercial Lighting	166	-	-	-	-	-
ISBEP	356	41	99	24	23	43
Business Efficiency Program	503	155	155	118	60	77
Industrial	1,813	41	20	142	-	14
Total	**9,003**	**1,559**	**1,593**	**1,741**	**570**	**1,506**

[9] As per Board Order Nos. P.U. 49(2016), and P.U. 22(2017), Hydro defers costs associated with delivering CDM programs in the CDM Cost Deferral Account (excludes program costs for the Labrador Interconnected System).
[10] Program costs for 2020 were less than previous years due to lower program participation attributed to the COVID-19 pandemic and delayed implementation of the Isolated Systems Community Energy Efficiency Program.
[11] Numbers may not add due to rounding.

Table 2: Hydro's CDM Portfolio Annual Energy Savings (MWh)[12]

	2009–2016	2017	2018	2019	2020	2021	Life-to-Date
Residential							
Windows	441	-	-	-	-	-	441
Insulation	2,061	155	139	80	156	129	2,721
Thermostats	268	59	62	46	60	52	547
Residential Benchmarking	-	131	234	155	-	-	520
Coupon Program	320	-	-	-	-	-	320
Block Heater Timer	288	-	-	-	-	-	288
Heat Recovery Ventilator	16	4	12	5	1	-	38
Isolated Systems Community(Residential)	6,067	1,141	1,064	749	394	606	10,021
Instant Rebate	503	90	300	350	95	120	1,459
Commercial							
Isolated Systems Community(Commercial)	-	-	-	448	75	388	911
Commercial Lighting	637	-	-	-	-	-	637
ISBEP	448	24	205	41	49	103	870
Business Efficiency Program	1,639	908	429	234	120	61	3,391
Industrial	25,772	-	162	5,092	-	165	31,191
Total	**38,461**	**2,513**	**2,608**	**7,200**	**950**	**1,624**	**53,355**

3.2 Residential Programs

Hydro's residential portfolio included four programs offered jointly by the Utilities (insulation, high-performance thermostats, heat recovery ventilators ("HRV"), and instant rebates) and one offered solely by Hydro (the Isolated Systems Community Energy Efficiency Program). Throughout 2021, Hydro continued to promote the takeCHARGE programs and technologies. Local advertising and building partnerships with retailers remains a priority and is an integral factor in the promotion of customer rebate programs.

3.3 Commercial Programs

Hydro's commercial portfolio includes the Business Efficiency Program offered jointly by the Utilities to provide prescriptive and custom rebates for commercial energy efficiency projects. Hydro also offers the Isolated Systems Business Efficiency Program ("ISBEP") to commercial customers in their isolated regions to provide technical support to identify economical energy efficiency opportunities and financial support for capital upgrades. Additionally, Hydro provides direct installs to several commercial customers in isolated communities through the Isolated Systems Community Energy Efficiency Program. Cumulatively, these programs yielded 552 MWh (75% of target) of energy savings in 2021.

[12] Numbers may not add due to rounding.

The COVID-19 pandemic impacted the number of projects completed in 2021 by commercial customers. Customers expressed hesitancy in completing energy efficiency projects during a period of uncertainty where their businesses continued to be impacted by public health restrictions. Additionally, supply chain issues limited the availability of energy efficient products. In 2021, Hydro approved 14 prescriptive business rebates for energy saving upgrades such as Light Emitting Diode (“LED”) high bay lighting and LED luminaires. Five custom projects were also completed between the Business Efficiency Program and ISBEP for lighting upgrade projects in Hydro’s isolated and interconnected service areas.

3.4 Isolated System Community Energy Efficiency Program

The Isolated Systems Community Energy Efficiency Program targets residential and commercial customers in Hydro’s isolated diesel systems. The objective of the program is to provide outreach, education, and energy efficient products free of charge to residential and business customers in the diesel system communities within Newfoundland and Labrador. From 2012–2021, the program installed 144,338 energy efficient products, resulted in total energy savings of almost 11 GWh, and provided employment for over 55 residents of these communities.

The Isolated Systems Community Energy Efficiency Program includes residential and commercial direct installations and focuses on building knowledge and capacity in the communities by hiring and training local representatives. These representatives work within their own communities to promote the program, offer useful information on energy use, and provide direct installation of energy efficient products. In 2021, 329 residential and 59 business customers received direct installations totalling 9,291 products consisting of water saving technologies, LED specialty bulbs, smart power-strips, and weather stripping products. A program evaluation strategy was performed to ensure product savings and validation processes are consistent with best practices and future portfolio evaluations.

In addition to direct installations, three pilots were executed through the Isolated Systems Community Energy Efficiency Program in 2021. These pilots include the installation of smart and programmable thermostats, the installation of shifted energy units, and the installation of ductless mini-split heat pumps. The pilot to install smart and programmable thermostats replaced standard dial and inefficient thermostats with Mysa smart thermostats in select isolated regions. Through this pilot project, 131 thermostats were replaced which yielded energy savings and the potential for demand response programs. The shifted energy pilot involved installing 26 shifted energy units on hot water tanks which provided consumption savings through timed-use and learning algorithms, as well as demand savings by providing demand response options. Finally, the heat pump pilot involved installing single zone, cold-climate ductless mini-split heat pumps with energy monitors in nine residences in the Labrador Straits area. Collectively, these pilots yielded 112 MWh of annual energy savings in Hydro's isolated communities.

In 2021, the Isolated Systems Community Efficiency Program began to utilize Simp Tek's energy advisor platform, which links existing customer data with utility data. The platform will perform an energy analysis on customers to identify the top 10% energy consumers, who will then be provided with a customized plan to reduce their energy usage. This is a significant change from the previous program delivery, transitioning from a broader approach consisting of lower-cost energy efficient upgrades to a more targeted, data-driven strategy with deeper energy retrofits across the isolated communities.

3.5 Industrial Energy Efficiency Program

Since 2010, Hydro has delivered the Industrial Energy Efficiency Program, which offers support and financial incentives for Hydro's industrial customers based on projects for lighting retrofits, process improvements, equipment changes, loss prevention (e. g., heat, steam energy), and funding for energy audit consultant reports. Promotion of the Industrial Energy Efficiency Program is facilitated through Hydro's Key Account Management framework to support improved project planning, scheduling, and execution. Within this framework, industrial customers are directly engaged with their Key Accounts Specialist to assist with the Industrial Energy Efficiency Program. This also permits Hydro to better understand customer facilities, processes, plans and schedules for potential efficiency improvement projects. In 2021, one industrial energy efficiency project was completed that resulted in annual electrical savings of 165 MWh. Hydro's Key Accounts Specialist remains engaged with industrial customers to assist with future projects.

4.0 Electrification

The ECDM Plan addresses the top customer adoption barriers to electrification identified by Hydro's customers, shown in Table 3. The Study undertaken by Dunsky identified high potential in the electric vehicle ("EV") sector, provided customer adoption barriers were addressed, such as the need for public

EV fast-charging stations and the higher vehicle purchase prices. Hydro received similar feedback from its customer surveys conducted through the Electricity Feedback Panel ("Panel").[13]

Table 3: Most Indicated Reason a Customer Has Not Purchased an EV (2018–2021)

Year	Reason
2018	Vehicle Price[14]
2019	Vehicle Price[15]
2020	Vehicle Price[16]
2021	Availability of Charging Stations[17]

Hydro finished construction on the province's first EV fast-charging network in 2021, which is an important first step to making EVs more accessible in the province. Funding for the charging network was provided by Hydro, the provincial government, and the federal government through Natural Resources Canada's EV and Alternative Fuel Infrastructure Deployment Initiative.

The ECDM Plan proposes new programs to support electrification of the transportation sector along with new programs and strategies to help manage system peak demand. Among the initiatives identified in the ECDM Plan is further investment in expanding the provincial EV fast-charging network. The proposed expansion of the EV charging network will see an additional 19 stations installed in the province, 3 of which will be located in Labrador.[18] Since milestone deadlines for federal funding programs were set to pass before a final decision from the Board was expected, the Board evaluated

[13] Two online surveys conducted by Narrative Research. The first one from November 6–18, 2019. 510 panelists participated out of 638 members of the Panel, resulting in a response rate of 80%. The second survey from May 10–17, 2021. 633 panelists participated out of 933 members of the Panel, resulting in a response rate of 68%. The purpose of the surveys were to understand opinions and perceptions regarding EVs, including: the likelihood of purchasing an EV; motivators/deterrents to purchasing an EV; and, information sources on EVs.
[14] In 2018, availability of charging stations ranked second behind vehicle price.
[15] In 2019, availability of charging stations ranked second behind vehicle price.
[16] In 2020, availability of charging stations ranked second behind vehicle price.
[17] In 2021, vehicle price ranked second behind availability of charging stations.
[18] In the May 2021 Narrative Research survey, more than half of respondents (54%) indicated they would be somewhat or much more likely to purchase or lease an all-EV as a result of increased access to chargers along the Trans-Canada Highway.

and approved the proposal to expand the EV charging network separately from the remainder of the ECDM Plan, in Board Order No. P.U. 30(2021).[19]

In 2021, Hydro was successful in its application to administer, on behalf of the federal government, a province-wide funding program that will assist commercial sites in installing public Level 2 EV chargers. Level 2 chargers are often referred to as 'destination' chargers, because they're designed to charge an EV over a longer period of time, but are also significantly less expensive to install than fast-chargers. The program will help to further support electrification of the transportation sector in the province. The program is expected to launch in the second quarter of 2022.

5.0 Planning and Evaluation

During 2021, the following external evaluations and surveys were completed to measure customer awareness, interest, and uptake in current programs:

- Socket saturation survey - to determine the prevalence of LEDs used for lighting in customers' homes, as a means of informing future program planning;
- Annual marketing survey - to assess home energy use and energy saving practices, as well as awareness of, and participation in, the takeCHARGE programs; and
- Residential thermostat program evaluation – an external review was initiated in 2021 to assess program effectiveness, participation, satisfaction, energy and demand savings.

6.0 Outreach and Support

During 2021, Hydro continued to partner with Newfoundland Power to deliver the takeCHARGE program, which offers customer education and conservation awareness activities, primarily through promotion of its takeCHARGE rebate programs and outreach activities. Residential and business programs were promoted through activities including mass media marketing, targeted promotions, community outreach, school contests, trade ally development and partnerships.

Advertising campaigns included radio, online and social media advertisements. Campaigns run throughout the year for insulation, thermostats, HRVs, instant rebates, heat pump education and the

[19] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 30(2021), Board of Commissioners of Public Utilities, September 29, 2021.

Business Efficiency Program. The media used is chosen based on the time of year that programs are in market and consumer purchasing behaviours. In 2021, new creative ads and promotions were created for the overall brand, insulation, thermostat, HRV, instant rebates, Business Efficiency Program and the oil heat rebates for insulation and thermostats.

The takeCHARGE team is also active on social media through a joint utility Facebook page that has over 15,300 likes, as well as a YouTube channel, Twitter account, and website. The takeCHARGE website continues to be a leading source of information for customers seeking energy efficiency information. In 2021, there were 520,536 page views, of which 82% were new visitors. The top three pages visited were the home page, insulation rebates and thermostat rebates.

The takeCHARGE Town Challenge initiative invites municipalities to submit proposals that will support their efforts to develop or improve energy conservation or energy efficiency projects. In 2021, Hydro awarded the Town of Miles Cove $10,000 for upgrades at their community centre and town office, the main hub for public gatherings, weddings and community groups.

The "Make the Switch" Bulb Giveaway by takeCHARGE provides LED bulbs to selected non-profit organizations and other groups to help reduce operational lighting costs in their facilities or to help their members/residents be more energy efficient. In 2021, Hydro distributed 2,000 bulbs to five groups within Hydro territories.

takeCHARGE offered school contests for students in kindergarten to grade 6 classes and grade 7 to grade 12 classes. These contests aim to support student understanding of why saving energy is important and to demonstrate what they can do to conserve energy. Five groups were awarded prizes, including three grand prizes and two second prizes.

The 12th annual takeCHARGE Energy Efficiency Week was held from October 1–8, 2021 and Business Efficiency Week was held from November 29–December 5, 2021. Both promotional weeks were dedicated to providing customers with information to assist them in saving energy and money through reducing their energy consumption. During each week, a full social media campaign was launched and online webinars were held to engage customers.

In 2021, Hydro, in partnership with Newfoundland Power, held the takeCHARGE Luminary Awards. The awards program provides an opportunity to recognize companies, individuals and communities contributing to energy efficiency in Newfoundland and Labrador. Due to COVID-19 restrictions, the event was held virtually on October 28, 2021.

For the second year in a row, takeCHARGE received two ENERGY STAR® Canada Awards. In 2021, the awards received were for utility program of the year and promotional campaign of the year. The awards recognize excellence in offering Canadian consumers the most energy-efficient products and technology available on the market.

Table 4 shows Hydro's costs to provide education and outreach, support, and planning for its CDM programs from 2009–2021.

Table 4: Hydro's Support Costs ($000)[20]

	2009–2015	2016	2017	2018	2019	2020	2021
Education	1,227	138	111	63	124	68	67
Support	344	42	40	47	41	46	47
Planning	1,605	250	251	128	178	142	135
Total	**3,176**	**429**	**401**	**238**	**343**	**257**	**249**

[20] Numbers may not add due to rounding.

7.0 Program Energy Savings and Program Costs

Table 5 provides the estimated annual energy savings from programs for which costs are deferred by Hydro in the CDM Cost Deferral Account for future recovery from customers pending approval of the Board.

Table 5: Energy Savings from Island Interconnected and Isolated Systems CDM Program Activities (MWh)[21,22]

	2009–2016	2017	2018	2019	2020	2021	Life-to-Date
Residential							
Windows	197	-	-	-	-	-	197
Insulation	762	111	76	54	117	96	1,216
Thermostats	148	43	46	34	44	38	355
Residential Benchmarking	-	131	234	155	-	-	520
Coupon Program	213	-	-	-	-	-	213
Block Heater Timer	-	-	-	-	-	-	-
Heat Recovery Ventilator	3	-	1	1	-	-	4
Isolated Systems Community(Residential)	6,067	1,141	1,064	749	394	606	10,021
Instant Rebate	172	9	86	153	18	43	482
Commercial							
Isolated Sytem Community(Commercial)	-	-	-	448	75	388	911
Commercial Lighting	207	-	-	-	-	-	207
ISBEP	448	24	205	41	49	103	870
Business Efficiency Program	1,586	601	295	99	97	42	2,719
Industrial	25,772	-	162	-	-	-	25,934
Total	**35,575**	**2,060**	**2,170**	**1,735**	**794**	**1,316**	**43,650**

Table 6 provides a breakdown of annual CDM program costs included in the CDM Cost Deferral Account. Deferred costs associated with the delivery of programs include direct costs for advertising, salaries, rebates and other expenses directly associated with a specific program. The deferred costs are recovered from customers through the CDM Cost Recovery Adjustment and vary depending on the uptake of the program and the number of programs offered.

[21] Hydro's CDM Cost Deferral Account does not capture spending associated with CDM programs offered to customers on the Labrador Interconnected System, therefore Table 5 does not reflect energy savings associated with these programs.
[22] Numbers may not add due to rounding.

Table 6: CDM Program Costs Included in the CDM Cost Deferral Account[23,24,25]($000s)

	2009–2016	2017	2018	2019	2020	2021
Residential						
Windows	438	-	-	-	-	-
Insulation	635	93	80	193	88	76
Thermostats	219	53	43	75	40	57
Residential Benchmarking	49	45	23	27	9	-
Coupon Program	236	-	-	-	-	-
Block Heater Timer	-	-	-	-	-	-
Heat Recovery Ventilator	19	5	5	10	3	4
Isolated Systems Community(Residential)	3,325	936	981	577	239	775
Instant Rebate	549	104	130	108	41	95
Appliance Retirement Pilot	44	-	-	-	-	-
Isolated Load Control Pilot	164	17	5	17	-	-
Commercial						
Isolated Systems Community(Commercial)	-	-	-	412	52	349
Commercial Lighting	104	-	-	-	-	-
ISBEP	357	41	99	24	23	43
Business Efficiency Program	473	138	141	100	60	75
Industrial	1,759	41	20	(30)	-	6
Total	**8,371**	**1,474**	**1,528**	**1,512**	**555**	**1,480**

8.0 Program Participation and Savings

Table 7 provides statistics on participation in each of Hydro's programs. The transaction units are specific to each program. The Residential Energy Star Window, Insulation, Thermostat, and HRV Programs reflect approved rebates. The Coupon Program reflects numbers of coupons redeemed on energy efficient products. The Commercial Lighting and Instant Rebate Programs reflect the number of products rebated through the programs. The Block Heater Timer Program reflects the number of timers determined to be installed through post-giveaway surveys or coupon redemption. The ISBEP, Business Efficiency Program, and Industrial Efficiency Programs reflect the number of completed retrofit projects. The Isolated Systems Community Energy Efficiency Program denotes the number of residential and commercial customer premises that received direct installations. Finally, the Residential Benchmarking Program indicates the number of customers included in the treatment group.

[23] Credits are due to an overstated accrual in a prior year.
[24] Program costs for 2020 were less than previous years due to lower program participation attributed to the COVID-19 pandemic and delayed implementation of the Isolated Systems Community Energy Efficiency Program.
[25] Numbers may not add due to rounding.

Table 7: Life-to-Date Program Participation

	2009–2016	2017	2018	2019	2020	2021	Total
Residential							
Windows	211	-	-	-	-	-	**211**
Insulation	333	39	42	32	57	45	**548**
Thermostats	230	56	66	46	56	47	**501**
Residential Benchmarking	1,000	1,000	1,000	1,000	-	-	**4,000**
Coupon Program	9,010	-	-	-	-	-	**9,010**
Block Heater Timer	629	-	-	-	-	-	**629**
Heat Recovery Ventilator	29	7	21	8	1	-	**66**
Isolated Systems Community(Residential)	4,999	1,007	727	940	633	329	**8,635**
Instant Rebate	38,072	9,764	19,285	23,293	2,863	3,648	**96,925**
Commercial							
Isolated Systems Community(Commercial)	-	-	-	220	87	59	**366**
Commercial Lighting	1,930	-	-	-	-	-	**1,930**
ISBEP	12	3	10	4	2	4	**35**
Business Efficiency Program	39	46	34	13	22	15	**169**
Industrial	6	-	1	2	-	1	**10**
Total	**56,500**	**11,922**	**21,186**	**25,558**	**3,721**	**4,148**	**123,035**

1 # 9.0 Levelized Utility Costs

2 Levelized Utility Cost ("LUC") is a method used to compare costs associated with conservation programs
3 to the value of energy saved. The LUC represents the economic cost to the utility (cents per kWh) to
4 achieve those energy savings. LUC is an industry metric that is calculated by discounting future energy
5 savings resulting from conservation programs to a present value. Table 8 provides the LUC for Hydro's
6 2021 programs. The energy savings represent the annual savings resulting from individual program
7 participation during 2021.

Table 8: Hydro Program Participation, Savings, and LUC 2021

Program	Participation	Energy Savings (MWh)	Demand Savings (kW)	LUC (¢/kWh)	Life-to-Date LUC (¢/kWh)
Windows	-	-	-	-	-
Insulation	45	129	56	6.4	4.5
Thermostats	47	52	4	12.4	10.4
Residential Benchmarking	-	-	-	-	-
Coupon Program	-	-	-	-	-
Industrial	1	165	19	1.9	1.6
Block Heater Timer	-	-	-	-	-
Isolated Systems Community	590	994	307	25.8	15.3
ISBEP	4	103	25	5.3	9.6
Heat Recovery Ventilator	-	-	-	-	21.0
Business Efficiency Program(Custom and Prescriptive)	15	61	8	19.5	4.7
Instant Rebate	3,648	120	23	14.6	16.9
Total	**4,350**	**1,624**	**306**	**17.2**	**5.7**

10.0 Conclusion

In 2021, Hydro continued to promote energy CDM while also planning for the future of electricity in Newfoundland and Labrador by completing the province's first EV fast charging network across the Island. CDM was encouraged through joint utility programs offered by Hydro and Newfoundland Power through takeCHARGE and through programming specifically targeted to Hydro's isolated and industrial customers. CDM programs have been successful in providing education and fostering the development of a culture of energy conservation in the province. In addition, Hydro continued to work with its customers to understand needs and drivers of electrical consumption to support the achievement of sustainable energy savings through its programming. Additionally, Hydro has worked in partnership with the provincial government on various programs and initiatives to support energy efficiency and a lower carbon economy. Overall, Hydro's efforts supported annual incremental energy savings of 1,624 MWh in 2021 and cumulative energy savings of 53,355 MWh since 2009.

Appendix A

Conservation and Demand Management Program Descriptions

newfoundland labrador hydro

Residential takeCHARGE Rebate Programs

Program incentives are processed primarily through customer applications. The programs are promoted in partnership with trade allies in the retail, home building and renovation industries.

Insulation Rebate Program

The objective of this program is to provide incentives to increase the insulation R-value in residential basements, crawl spaces and attics, thereby increasing the efficiency of the home's building envelope. Eligibility for the programs is limited to electrically heated homes, determined on the basis of annual energy usage. Home retrofit projects are eligible. Customers can receive an incentive of 75% of basement wall and ceiling insulation materials up to $1,000 and 50% of attic insulation material costs up to $1,000.

Thermostat Rebate Program

This program encourages installation of programmable and electronic thermostats to allow customers better control of the temperature in their home and to save energy. These high-performance thermostats provide accurate temperature control while the programmable option allows customers to set back the temperature automatically during the night or when they are away. Eligibility for the program is limited to electrically heated homes, determined on the basis of annual energy usage. Home retrofit projects and new home developments are eligible. Incentives of $10 for each programmable thermostat and $5 for each electronic high-performance thermostat are offered.

HRV Rebate Program

This program encourages customers to purchase a high-efficiency HRV to improve the efficiency of their home. Eligible measures in this program include HRV models that have a Sensible Recovery Efficiency of 70% or more. Customers who purchase a high efficiency HRV can receive a rebate of $175. All customers are eligible for this program regards of the age of the home or its heat source.

Isolated System Community Energy Efficiency Program – Hydro Program

This program includes both residential and commercial components targeting customers in Isolated Diesel communities and L'Anse-au-Loup. The focus is on residential customers through the direct installation of a kit of technologies, at-cash register coupons on small technologies and mail-in rebates on energy efficient appliances. Commercial customers also receive a direct installation of a kit of technologies. The kit includes items for water savings, draft proofing, lighting and other measures.

Homeowners receive education on energy efficiency and information on the existing takeCHARGE rebate programs. Community events, social media promotions and exchanges are held to promote the program and energy efficiency awareness.

Block Heater Timer Program – Hydro Program

This program targeted customers in the Labrador Interconnected System to encourage the purchase of energy saving Block Heater Timers through in-store discounts offered at partnering retailers. The program launched with a giveaway of the technology to create awareness of the product as there was little or no use of the technology before the program. The incentive was offered over two winter seasons (2012–2013 and 2013–2014) and ended in spring 2014.

Small Technologies Program

Instant Rebates

This program promotes a variety of smaller technologies, such as LED lighting, and smart power bars, through instant rebates available at the cash register of participating retailers. All customers are eligible for this program regardless of the age of the home or its heat source.

Appliances and Electronics

This program encouraged customers to purchase high-efficiency appliances. Participants received incentives of $100 for select energy efficient washers, freezers, and $20 for eligible TVs. All customers were eligible for this program regardless of the age of the home or its heat source. This program ended December 31, 2017.

Residential Benchmarking Program

This program encouraged customers to adopt energy efficient behavioural changes. Participants received Home Energy Reports that provided insight into their homes’ electricity use. The reports helped customers understand changes in their usage over time, as well as how they compared to similar homes. They also included practical tips on how to save energy moving forward. The program also included an online component that allowed customers to engage even further through weekly challenges and personalized saving plans. Hydro ended this program in December 2019.

Energy Efficient Loan Program

This program was offered by the Government of Newfoundland and Labrador and takeCHARGE, making it easier to save energy and money. On-bill financing with a 2.5 % interest rate reduction from standard utility financing rates was available for insulation, heat pumps and home energy assessments. Through the Energy Efficient Loan Program, eligible applicants could receive low-interest financing for up to $10,000 over a maximum of five years. This program ended March 31, 2020.

Commercial takeCHARGE Rebate Programs

Business Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of commercial facilities and equipment types. The program components include financial incentives based on energy savings and other financial and educational supports to enable commercial facility owners to identify and implement energy efficiency and demand reduction projects.

This program is available for existing commercial facilities that can save energy or reduce demand by installing more efficient equipment and systems. The program includes custom project incentives and prescriptive rebates for specific measures on a per unit basis.

Isolated Systems Business Efficiency Program – Hydro Program

The ISBEP was launched in 2012 and targets commercial customers in the Isolated Diesel communities and L'Anse-au-Loup. The program provides a custom approach to finding energy efficiency solutions and financial assistance for feasibility studies and for retrofit projects. It has the same program design and offerings as the joint utility Business Efficiency Program, but has higher incentive levels for retrofit work because of the higher avoided cost of generation in these systems.

Industrial Energy Efficiency Program

The objective of this program is to improve electrical energy efficiency in a variety of industrial processes. The program components include financial incentives based on energy savings and other supports to enable industrial facilities to identify and implement efficiency and conservation opportunities. This program is a custom program designed to respond to the unique needs of the industrial market rather than a prescriptive technology approach.

2021 Report on the Rural Deficit

Summary of Specific Initiatives

March 31, 2022

A report to the Board of Commissioners of Public Utilities

Contents

1.0 Introduction

Newfoundland and Labrador Hydro ("Hydro") provides electrical service to approximately 27,300 customers on the Hydro Rural Interconnected System and Hydro Rural Diesel Systems. As a result of policy set out by the Government of Newfoundland and Labrador, these customers are served at an operating loss ("Rural Deficit") as the electricity rates in these areas do not recover Hydro's full cost of providing service. Additionally, Hydro serves approximately 11,400 rural customers on the Labrador Interconnected System, whose rates recover the cost to serve as well as a contribution to funding a portion of the Rural Deficit. Over 96%[1] of the Rural Deficit funding is provided through the Utility Rate charged to Newfoundland Power Inc. ("Newfoundland Power").

This report provides an overview of Hydro's Rural Deficit, as well as the direct operating and capital initiatives undertaken by Hydro to manage costs associated with serving customers in rural areas, thereby mitigating the Rural Deficit.

2.0 Rural Deficit Overview

Table 1 provides the estimated annual Rural Deficit for 2017–2021, as well as year-over-year variances. The Rural Deficit for 2021 was calculated using actual revenues and expenses allocated to Hydro's Rural Deficit areas based on the 2019 Test Year Cost of Service Study allocations.

Table 1: Hydro Rural Deficit Estimates ($ millions)

	Annual Amounts					Year-over-Year			
	2017	**2018[2]**	**2019**	**2020**	**2021**	**2018/17**	**2019/18**	**2020/19**	**2021/20**
Revenues (A)	58.6	63.6	67.2	68.3	67.4	5.0	3.6	1.1	(0.9)
Costs[3]									
Operating Expenses	43.6	44.0	44.8	44.0	40.8	0.4	0.8	(0.8)	(3.2)
Fuel	27.8	28.1	29.3	21.8	19.5	0.3	1.2	(7.5)	(2.3)
Purchased Power	7.2	8.5	9.1	7.8	10.1	1.3	0.6	(1.3)	2.3
Depreciation	17.3	19.3	19.3	18.7	19.6	2.0	0.0	(0.6)	0.9
Return	23.1	22.9	23.4	25.1	25.1	(0.2)	0.5	1.7	-
Total Costs (B)	**119.0**	**122.8**	**125.9**	**117.4**	**115.1**	**3.8**	**3.1**	**(8.5)**	**(2.3)**
Rural Deficit (B-A)	60.4	59.2	58.7	49.1	47.7	(1.2)	(0.5)	(9.6)	(1.4)

[1] In accordance with the 2019 Test Year Cost of Service Study, allocation is 96.1% for Newfoundland Power and 3.9% for customers on the Hydro Rural Labrador Interconnected System.
[2] 2018 figures were restated in 2019 to reflect the outcome of Hydro's 2017 General Rate Application, Compliance Application (Board Order No. P.U. 30(2019)), consistent with the 2019 Annual Financial Returns.
[3] Table 1 does not include the costs incurred for Conservation Demand Management ("CDM") programs offered in rural communities as they are captured in Hydro's CDM Cost Deferral Account, approved in Board Order Nos. P.U. 49(2016) and P.U. 22(2017).

The $47.7 million Rural Deficit in 2021 represents a decrease of approximately $1.4 million, or 2.9%, from 2020. The primary drivers of the change are as follows:

- Operating expenses decreased as a result of lower salary related costs in 2021 and increased capital recharge, offset by an increase in overtime;
- Fuel costs decreased mainly as a result of an average 0.7 cents per kWh decrease in No. 6 fuel[4] price, a decrease in rural sales, offset by an increase of 1.9 cents per kWh in diesel fuel used to serve isolated customers in 2021 relative to 2020;[5] and
- Purchased power costs increased primarily as a result of the implementation of the Muskrat Falls Purchase Power Agreement effective November 1, 2021.

Chart 1 shows the annual Rural Deficit including and excluding fuel costs, demonstrating that fuel costs are consistently one of the primary cost drivers in Rural Deficit areas.

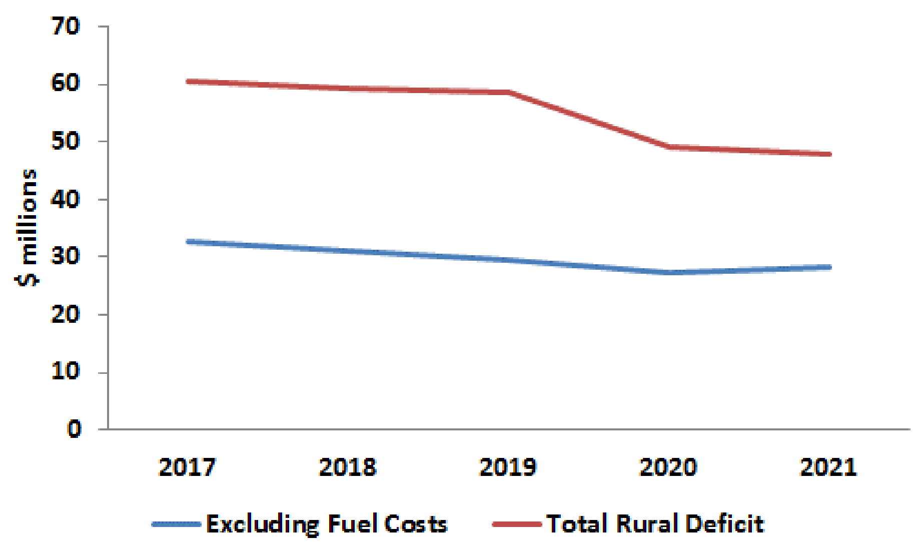

Chart 1: Five-Year Rural Deficit ($ millions)

Chart 1 also demonstrates that, excluding the cost of fuel, Hydro's costs over the period have been stable.

[4] A portion of Holyrood No. 6 fuel costs are allocated to rural customers on the Island Interconnected System.
[5] Changes in the price of diesel directly impact the purchase price that Hydro pays to serve customers on the L'Anse-au-Loup System, and for wind generation purchases supplying Ramea.

Hydro's efforts to identify and implement opportunities to reduce the Rural Deficit continued to be impacted by the COVID-19 pandemic through 2021. Factors such as supply chain impacts, reduced uptake on CDM initiatives,[6] and limitations on travel to remote areas due to changing public health restrictions all affected Hydro's ability to further reduce the Rural Deficit. Despite the challenges imposed by the pandemic, Hydro was able to execute certain initiatives throughout 2021 which contributed to reducing the Rural Deficit, as highlighted in Sections 3.0 and 4.0.

3.0 Operating Initiatives

3.1 Internal Energy Efficiency Initiatives

Hydro continued its internal energy efficiency efforts in 2021 with programs that aim to achieve reductions in energy usage in all facilities within the areas contributing to the Rural Deficit, including diesel plants, offices, and line depots. Since it began in 2008, the program has provided cumulative energy savings of 17,943 MWh.

The primary focus for internal energy efficiency in 2021 was to identify future capital and operating projects that could reduce energy consumption at Hydro's facilities. Initiatives completed in 2021 achieved savings as follows:

- Retrofit of lighting fixtures to more energy efficient versions at various generation sites resulting in annual savings of approximately 68 MWh; and
- Replacement of existing Holyrood Terminal Station lighting with light-emitting diode ("LED") luminaires and wallpacks yielding approximately 60 MWh.

In addition, Hydro continued the following initiatives to support its management of the Rural Deficit:[7]

- Capturing waste heat in several of Hydro's diesel plants to heat Hydro premises;
- Planning the sizes of replacement units at Hydro's diesel generating stations to optimize fuel efficiency;
- Monitoring diesel system fuel efficiency to identify poor performers so that corrective action may be taken; and

[6] Please refer to the 2021 Conservation and Demand Management Report.
[7] Savings achieved through this initiative are primarily through avoided costs or productivity improvements; therefore, Hydro is not able to quantify the exact impact on the Rural Deficit.

- Choosing the most fuel-efficient combination of engines, where possible,[8] to supply community loads.

3.2 Conservation and Demand Management Program Initiatives

The high cost of generation in isolated diesel communities and the increased system load in the L'Anse-au-Loup area continues to support the need for effective delivery of energy-efficiency programs in these areas. In 2012, two programs were launched to offer energy-efficiency incentives for residential and commercial customers located in Hydro's isolated diesel communities. These programs continued through 2021 and are further detailed in the sections that follow.

3.2.1 Isolated Systems Community Energy Efficiency Program

The Isolated Systems Community Energy Efficiency Program is a program specifically targeted to residential and commercial customers in Hydro's Isolated Diesel Systems. The objective of the program is to provide outreach, education, and energy-efficient products and installation free of charge to residential and business customers in the diesel system communities within Newfoundland and Labrador. From 2012–2021, the program installed 144,338 energy-efficient products, saving a total of approximately 11 GWh of electricity (994 MWh[9] in 2021), and also provided employment for over 55 residents of these communities.

The Isolated Systems Community Energy Efficiency Program includes residential and commercial direct installations and focuses on building knowledge and capacity in the communities by hiring and training local representatives. These representatives work within their own communities to promote the program, provide useful information on energy use, and provide direct installation of energy-efficient products, including low-flow showerheads, faucet aerators, LED lamps, specialty size light bulbs, smart power strips, and hot water tank and pipe insulation.

In 2021, 329 residential and 59 business customers received direct installation or kit drop off totalling 9,291 products consisting of water saving technologies and LED specialty bulbs for lighting needs. While this work was ongoing, information was collected about the type of lighting, heating, and appliances in the homes and businesses, which will be used for future program planning.

[8] Completed automatically in some plants.
[9] These savings may be updated if further audit in 2022 indicates adjustments are required.

In addition to direct installations, three pilots projects were executed through the Isolated Systems Community Energy Efficiency Program in 2021 that achieved savings of 112 MWh;

- Installation of Mysa Smart Thermostats replacing standard dial and inefficient thermostats in select areas. Through this program, 131 thermostats were replaced which yielded energy savings and the potential for demand response programs;
- Installation of 26 shifted energy units on hot water tanks that provide both consumption savings through timed-use and learning algorithms, and demand savings by providing demand response options; and
- Installation of ductless mini-split heat pumps, for customers with electric baseboard heating, involved installing single-zone, cold-climate ductless mini-split heat pumps with energy monitors in nine residences in the Labrador Straits area.

Additionally, in 2021, the Isolated Systems Program began to utilize Simptek's Energy Advisor platform, which links existing customer data with utility data. The Energy Advisor platform will perform an energy analysis on customers to identify the top 10% energy consumers, who will then be provided with a customized plan to reduce their energy usage. This is an improvement from the previous program delivery, transitioning from a broader approach consisting of lower-cost energy efficient upgrades to a more targeted, data-driven strategy with deeper energy retrofits across the isolated communities.

3.2.2 Isolated Systems Business Efficiency Program

The Isolated Systems Business Efficiency Program was launched in 2012. The program provides rebates and technical assistance for commercial customers in isolated diesel communities on coastal Newfoundland and Labrador. Hydro's energy efficiency team works one-on-one with customers to create a plan to address their energy efficiency needs and provides ongoing technical support for projects undertaken. This custom approach has encouraged customers to undertake projects to improve the energy efficiency of lighting, refrigeration, motor controls, and other building systems. In 2021, four customers completed projects under this program involving upgrades to insulation and refrigeration systems in Hydro's isolated areas. This program deals primarily with small business customers and has achieved 870 MWh of annual energy savings since 2012, 103 MWh of which were achieved in 2021.[10]

[10] Hydro experienced lower than anticipated uptake for this program in 2021 due to the impact of COVID-19 pandemic on businesses' ability to invest in energy efficiency.

3.3 Hydro-Québec Power Purchase Contract Renewal

Hydro executed a new Power Purchase Agreement with Hydro-Quebec for the L'Anse-au-Loup System effective September 1, 2021.[11] This agreement enables Hydro to continue to purchase surplus hydroelectric energy from Hydro-Quebec's Lac Robertson Plant to supply Hydro's customers in the L'Anse-au-Loup area. The terms and conditions of the new agreement are similar to the original and will continue to enable Hydro to supply the majority of customer load in L'Anse-au-Loup with deliveries from Hydro-Quebec at a much lower cost than diesel generation. The approximate savings in 2021[12] were $4.1 million.

3.4 Net Metering

Net metering initiatives are undertaken by customers, not by Hydro directly; however, there is an impact on Hydro's system as a result of net metering activity.[13] Hydro currently has one net metering customer in an isolated diesel community under Hydro's net metering service option. In 2021, this customer's net metering resulted in the displacement of approximately 29 MWh of diesel generation.

3.5 Mary's Harbour Mini Hydro Facility

The Mary's Harbour mini hydro facility began operations in September 2019. The photovoltaic and battery energy storage facility began operations in November 2021. Together they generated approximately 725 MWh in 2021, displacing diesel fuel generation. The purchase of energy from this facility resulted in net savings of approximately $17,000 in 2021.

3.6 Cost Effective Renewables

Hydro is actively engaged with Indigenous groups and stakeholders, with a particular focus on communities served primarily by diesel powered generation, to foster development of cost-effective renewables. The standard model for such developments involve a third party developing and operating the renewables, with Hydro purchasing the output at a cost below that which would be incurred to generate equivalent energy in Hydro's diesel generating stations. To date, there are three communities where such developments have been completed (Makkovik, Mary's Harbour and Ramea), but discussions are ongoing in other areas in relation to specific projects.

[11] The previous agreement expired August 31, 2021.
[12] Compared to supplying the service area with diesel generators.
[13] The customer is located in Makkovik, Labrador and has a 48 kW solar energy generator.

3.7 Long-Term Supply for Southern Labrador

Currently, southern Labrador communities are served by four separate, isolated diesel systems (13 engines total) serving each community individually (Charlottetown and Pinsent's Arm, Mary's Harbour, Port Hope Simpson, and St. Lewis ("Southern Labrador Communities").

The communities of Charlottetown and Pinsent's Arm were previously served by the Charlottetown Diesel Generating Station until a fire occurred in 2019. Since the fire a temporary configuration was completed to serve as an interim solution.

Hydro has been exploring a long-term solution to address reliability, safety, and environmental concerns associated with the long-term use of mobile generation as a primary source of power. In Hydro's Long-Term Supply for Southern Labrador Application,[14] Hydro proposed the construction of a regional diesel generating station in Port Hope Simpson with four diesel gensets and the construction of 50 kilometres of 25 kV distribution line to connect the existing Charlottetown distribution system. The proposed centralized plant will provide a stable, reliable source of supply for the region.

Hydro is also exploring the potential role of renewable energy resources in its isolated systems. The proposed interconnection of southern Labrador communities will result in eight fewer diesel units (i.e., a reduction from 13 units to 5) and three fewer diesel plants (i.e., individual plants in each of the four communities vs. one regional plant). This reduction in diesel units and plants will result in more efficient operations and is anticipated to reduce fuel consumption by approximately 600,000 litres annually and contribute to a projected reduction of approximately $152.7 million in the Rural Deficit over the 50-year planning horizon of Hydro's analysis. It would also increase the potential for renewable integration by 15% when compared to the current opportunity for the four isolated systems (i.e., 9.7 GWh to 11.2 GWh).

3.8 Other Cost Management Initiatives

During 2021, Hydro continued to manage its operating costs in an effort to minimize its impact on the Rural Deficit. Examples of such initiatives are as follows:

- Utilizing cost-effective commercial air flights during regular work hours, where practical, rather than helicopter use;

[14] "Long-Term Supply for Southern Labrador – Phase 1," Newfoundland and Labrador Hydro, July 16, 2021.

- Having running maintenance (e.g., oil changes) completed by diesel system representatives rather than deploying maintenance crews to diesel communities;
- Participating in the Off-Grid Utility Association to work with other utilities with diesel plants for comparison of operating procedures and new technology to enhance efficiency in operations and maintenance; and
- Focusing on identifying planning and scheduling efficiencies, including a significant coordination effort to ensure that delays and duplicate asset outages are minimized.

4.0 Capital Initiatives

4.1 Replace Metering System

Through its 2022 Capital Budget Application, Hydro received Board approval[15] for replacement of approximately 31,000[16] manually-read meters and TS1 AMI[17] meters by the end of 2024. Completion of this project is projected to result in average annual Rural Deficit savings of approximately $765,000 when compared to continuing with manually-read meters.

4.2 Diesel Asset Management Strategy

Hydro has continued to evolve its asset management strategy, resulting in isolated system cost savings. Hydro has changed its approach to its diesel unit overhauls for 1,200 RPM units,[18] running for the units for 30,000 hours between overhauls and replacing them at 120,000 hours instead of 100,000 hours, thereby extending the useful life of the units.

Hydro has also continued to replace engines rather than overhaul them when it is cost effective to do so and when engines are available. As prices fluctuate from year-to-year, this approach will continue to be evaluated on a case-by-case basis to ensure that Hydro is availing of the least-cost alternative in the provision of reliable service.

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[15] *Public Utilities Act,* RSNL 1990, c P-47, Board Order No. P.U. 37(2021), Board of Commissioners of Public Utilities, December 20, 2021.
[16] 28,056 energy-only meters and 3,131 demand and energy meters.
[17] Automated Metering Infrastructure ("AMI").
[18] Hydro has seven 1,200 RPM units.

4.3 Diesel Unit Sizes

In response to increasing loads in certain isolated diesel communities, Hydro has been replacing some of its 1,800 RPM diesel units with larger, slower turning 1,200 RPM units. This has resulted in lower operating costs in Rural Deficit areas as a result of material reductions in labour costs and travel associated with corrective maintenance,[19] as well as increased reliability.

4.4 LED Street Lights

The Nain LED street light pilot project,[20] implemented in 2015, provided direct cost savings as a result of the displacement of fuel costs. As a result, Hydro converted the street lights in the community of Ramea to LED street lights in 2018 and submitted a two-year capital proposal in its 2019 Capital Budget Application to convert street lights to LED in the remaining diesel systems. The proposal was approved and execution began in 2019 with the conversion of street lights in the community of Cartwright. In 2020, all remaining isolated Labrador communities' street lights were converted to LED. This project produces annual energy savings of approximately 120 MWh. LED street lights may also contribute to lower operating and maintenance costs than high-pressure sodium ("HPS") street lights due to the elimination of relamping requirements and longer life.

Hydro submitted a capital proposal in its 2021 Capital Budget Application to replace all HPS street lights by 2026 for both the Island and Labrador. In 2021, an estimated 689 HPS street lights were replaced resulting in approximate annual savings of 179 MWh.

4.5 Diesel Plant Communication Upgrades

In 2021, Hydro completed an upgrade in the communications technology at three additional diesel plants (Nain, Cartwright, and Rigolet) through a conversion from service provided from copper cables to fibre optic technology. The copper cables were prone to frequent communications outages. Fibre optic services are less prone to electrical interference and are more reliable which will result in reduced maintenance costs. Additional conversions to fibre optic technology are planned for the St. Lewis Diesel Plant in 2022. The upgraded communications with diesel plants will improve the ability to monitor

[19] Savings achieved through this initiative are primarily through avoided costs or productivity improvements; therefore, Hydro is not able to quantify the exact impact on the Rural Deficit.

[20] Hydro initiated a pilot LED street light replacement project for the Town of Nain with a total of 125 HPS street light fixtures replaced with LED street light fixtures. The street light retrofit yields savings of approximately 45 MWh annually, which offsets approximately 12,000 litres of fuel consumption.

plants loads and may provide opportunities to implement demand management initiatives in diesel areas that can contribute to deferral of capacity additions on isolated diesel systems.

Additional upgrades completed at L'Anse-au-Loup Diesel Plant will result in improved communications in managing secondary energy purchases from Hydro-Quebec. This, in turn, permits Hydro to operate the diesel plant more efficiently and provide savings through reduced diesel fuel consumption. This upgrade will also result in annual network cost savings of $44,000.

5.0 Conclusion

Hydro continues to pursue initiatives and activities to manage the Rural Deficit, including cost reduction and energy conservation initiatives. Management of the Rural Deficit is challenging as it is impacted by social policy initiatives resulting in energy pricing in diesel areas that can be lower than the energy pricing on the Island Interconnected System (i.e., as a result of the Northern Strategic Plan Billing Credit provided in Labrador diesel communities), as directed by government. These pricing signals can promote load growth and result in higher fuel usage and capacity requirements that can lead to additional capital investments and higher cost to provide service.

Variability in the Rural Deficit over recent years has primarily been the result of diesel fuel price variability. Hydro's other costs have been stable over the period 2016–2021, demonstrating Hydro's ongoing effort to limit growth in the Rural Deficit.

Affidavit

IN THE MATTER OF the *Public Utilities Act*, ("*Act*"); and

IN THE MATTER OF Newfoundland and Labrador Hydro's Annual Return for 2021 filed in pursuant to Section 59(2) of the *Act*.

AFFIDAVIT

I, Carol Ann Lutz, Certified Professional Accountant, of St. John's in the Province of Newfoundland and Labrador, make oath and say as follows:

1. I am the Controller for Newfoundland and Labrador Hydro, and as such I either have personal knowledge of, or I have been so informed and verily believe, the matters and things contained within the Newfoundland and Labrador Hydro 2021 Annual Return.
2. I have read the contents of the within 2021 Annual Return and they are true to the best of my knowledge, information, and belief.

SWORN at St. John's in the)
Province of Newfoundland and)
Labrador this 1st day of)
April 2022 before me:)

S Walsh

Barrister – Newfoundland and Labrador

C Lutz

Carol Anne Lutz, CMA, CPA, MBA