Appendix 7.2

Modelling & Analysis Results

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1 | Introduction

This appendix provides a summary of modelling and analysis results and observations for the 2025 Integrated Resource Plan. The modelling and analysis process was comprised of many steps, including analyzing eight scenarios, 11 sensitivities, and performing a Least Regrets Analysis (LRA) to identify resource plans robust to uncertainty. Scenarios and sensitivity results informed the LRA by identifying feasible resource options that could be included in a potential development plan, and by providing guidance on how those resources should be combined into meaningfully different plans for further investigation. While baseline customer side solutions including the Efficiency Plan Projection, demand response, and curtailable rates programs are assumed in the model, sensitivities were used to explore the potential for additional energy efficiency and the impact of eliminating demand response. The LRA then assessed the regrets observed when different resource commitments were simulated against the range of IRP load projections. Each potential development plan also has trade-offs and risks that include considerations that go beyond the modelling and analysis outputs, and the modelling results presented in this appendix served as a foundation for subsequent evaluations and risk and financial analyses.

The observations on results presented throughout this appendix contributed to the learnings of the 2025 IRP. In particular, it is repeatedly observed that there are limited resources that can be brought into service in a timely manner to continue to serve energy and capacity needs safely and reliably; meeting an accelerated pace of decarbonization and electrification will be a challenge in the early years and it is important that we get ahead of the energy transition and stay ahead. The modelling and analysis steps presented here demonstrate how the LRA was used to understand underbuild and overbuild regrets, and to support evaluation for the identification of five shortlisted plans for further risk and financial analysis. Furthermore, the results contained within this appendix confirm that natural gas fuelled combustion turbines can be strategically used to support an affordable pathway to net-zero in Manitoba while preserving reliability.

Other appendices that may help in a fulsome understanding of the results, include:

- Appendix 2 – 2025 IRP Development Process – summarizes the entire IRP development process, in particular how scenarios were developed.
- Appendix 3 – Existing System - details the existing system, which is an input into the modelling and analysis.
- Appendix 4 – Policy Update - documents relevant policy for the IRP analysis.
- Appendix 5 – Load Projections - documents the assumptions and results for the 2025 IRP load projections, including net-zero economy GHG emissions analysis.

- Appendix 6 – Resource Options – documents resource characteristics used in the modelling and analysis.
- Appendix 7.1 – Modelling & Analysis Approach – documents the methodology and modelling software, and outputs of the 2025 IRP modelling and analysis.

Greenhouse gas results presented in this Appendix, and other Appendices, are based on Manitoba Hydro's modelling & analysis approach – any changes to the underlying modelling assumptions could change GHG emissions impact data and corresponding conclusions.

1.1. Foreword on Modelling and Analyses Results

1.1.1. Reporting Study Year and Output Types

Wherever possible, consistency was maintained in the modelling and analysis conducted for the 2025 IRP and efforts have been made to present results in a consistent manner as well. However, the modelling and analysis work presented here includes four different categories of study: scenarios, sensitivities, least regrets analysis, and shortlisted development plan analysis. Each of these categories of study address specific analytical needs, including informing downstream metric evaluations, financial analysis, and risk analysis, and as such have specific requirements. As a result, the reported study years and outputs presented in this appendix reflect what is most appropriate for each study type.

1.1.2. Cautions for Interpreting 2050 Study Results

Uncertainty in the 2025 IRP analysis increases further into the study timeframe (out to 2050). This is both due to increased uncertainty in the assumptions in the long term used in the modelling and analysis, as well as from how the model optimized to find a solution.

As discussed in Appendix 7.1 – Modelling & Analysis Approach, the final portfolio of resources identified by the model may not be the lowest possible cost solution, as such there is the potential for alternative long-term capacity expansion strategies to emerge without a clear signal as to the dominant strategy. This effect is strongest for decisions later in the study horizon and caution must be exercised when interpreting study results in 2050. Results in the 2049/50 timeframe provide indicative outcomes, and are most useful for identifying trends, sources of risk, and insights into technologies that may be of particular interest in the future.

2 | Scenario Results

This section discusses the modelling and analysis results for the eight 2025 IRP scenarios, as shown in Table A7.2.1 Manitoba Hydro used scenarios to explore a reasonable range of what the energy future might look like in Manitoba, combining different load projections and resource option strategies to define each one. The implications of the underlying assumptions of each scenario are presented and analyzed in the following sections.

Table A7.2.1 – IRP Scenarios

Resource Options Strategies	Load Projection 1 - Baseline	Load Projection 2 - Medium	Load Projection 3 - High
A - Technology Neutral	S1A	-	-
B - Net-Zero Grid 2035	S1B	S2B	S3B
C - Near Term Wind Generation Projects	S1C	S2C	S3C
D – No Fossil Fuel-Based Resources	-	-	S3D

2.1. Installed Capacity Additions

The installed capacity distributions for the scenarios are provided in Figure A7.2.1, Figure A7.2.2, and Figure A7.2.3, and Table A7.2.2, Table A7.2.3, and Table A7.2.4 for the 2032[1], 2035, and 2050 study years. These figures show that as load increases moving from the 1-Baseline load projection to the 3-High load projection, reflecting the assumptions of decarbonization in Manitoba through electrification, the installed capacity additions required also increase. The 2-Medium and 3-High load projections assume a net-zero economy by 2050 and significant amounts of capacity are needed after 2045 to meet future negative GHG emission loads assumed in both projections.

[1] 2032 data is provided for installed capacity additions only, to support discussions in Section 4 – Least Regrets Analysis.

Recall that the Efficiency Manitoba Efficiency Plan Projection, Demand Response, and the Curtailable Rates programs are base assumptions included in the scenarios. Additional Energy Efficiency is not eligible for selection in the scenarios as per the resource options strategy assumptions (further details are provided in Appendix 7.1). For the scenarios, the Customer Side Solutions category shown in the following figures include the Efficiency Manitoba Efficiency Plan Projection and Demand Response. Unlike energy efficiency programs and Demand Response, the Curtailable Rates program is represented as a load modifier rather than a selectable resource option in the model, and so is not included in the Customer Side Solution category shown in the following figures.

Furthermore, the Market Purchases category shown in the figures below includes only the market purchases resource options representing contacted capacity import purchase agreement, and does not reflect opportunity import market activity.

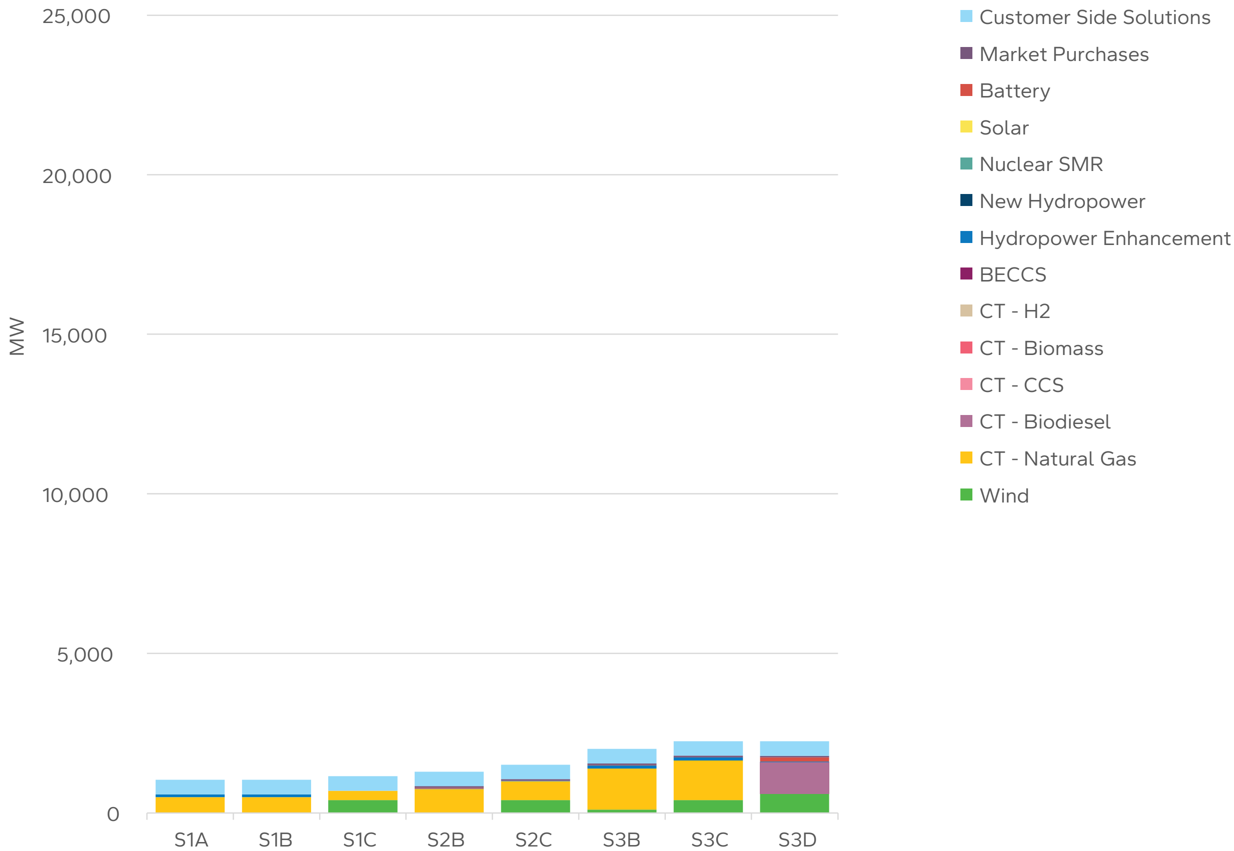


Figure A7.2.1 - Scenario Results: Cumulative Installed Capacity Additions (MW) to 2032

Table A7.2.2 – Scenario Results: Cumulative Installed Capacity Additions (MW) to 2032

	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Wind	0	0	400	0	400	100	400	600
CT - Natural Gas	496	496	296	744	592	1,288	1,240	0
CT - Biodiesel	0	0	0	0	0	0	0	992
CT - CCS	0	0	0	0	0	0	0	0
CT - Biomass	0	0	0	0	0	0	0	0
CT - H2	0	0	0	0	0	0	0	0
BECCS	0	0	0	0	0	0	0	0
Hydropower Enhancement	86	86	0	15	15	101	101	15
New Hydropower	0	0	0	0	0	0	0	0
Nuclear SMR	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0
Battery	0	0	0	29	0	13	1	133
Market Purchases	0	0	0	50	50	50	50	50
Customer Side Solutions	455	455	455	455	455	455	455	455
Total MW	1,037	1,037	1,151	1,293	1,511	2,006	2,246	2,244

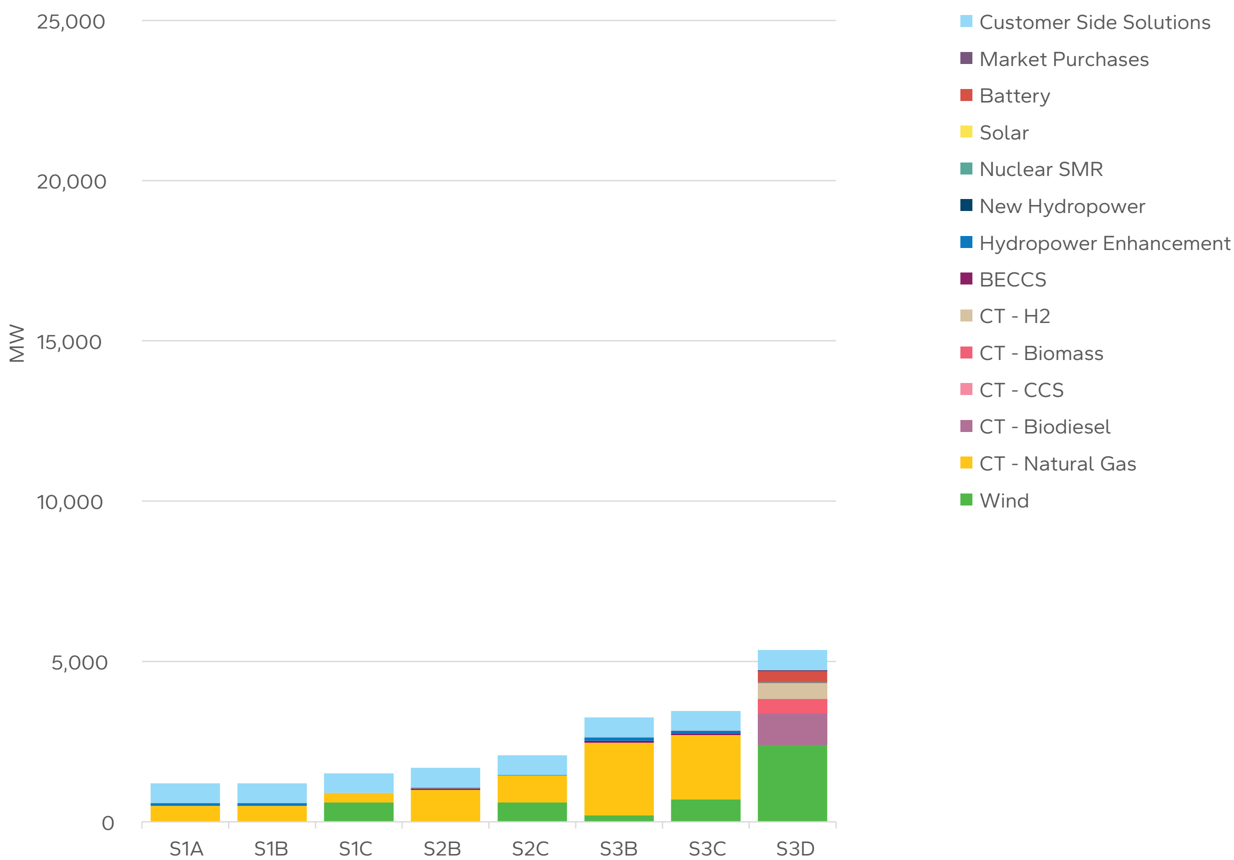


Figure A7.2.2 - Scenario Results: Cumulative Installed Capacity Additions (MW) to 2035

Table A7.2.3 – Scenario Results: Cumulative Installed Capacity Additions (MW) to 2035

	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Wind	0	0	600	0	600	200	700	2,400
CT - Natural Gas	496	496	296	992	840	2,262	2,004	0
CT - Biodiesel	0	0	0	0	0	0	0	992
CT - CCS	0	0	0	0	0	0	0	0
CT - Biomass	0	0	0	0	0	0	0	444
CT - H2	0	0	0	0	0	0	0	496
BECCS	0	0	0	32	0	63	32	0
Hydropower Enhancement	86	86	0	15	15	101	101	15
New Hydropower	0	0	0	0	0	0	0	0
Nuclear SMR	0	0	0	0	0	0	0	0
Solar	0	0	0	0	0	0	0	0
Battery	0	0	0	29	0	13	3	344
Market Purchases	0	0	0	0	0	0	0	50
Customer Side Solutions	617	617	617	617	617	617	617	617
Total MW	1,199	1,199	1,513	1,685	2,071	3,256	3,456	5,357

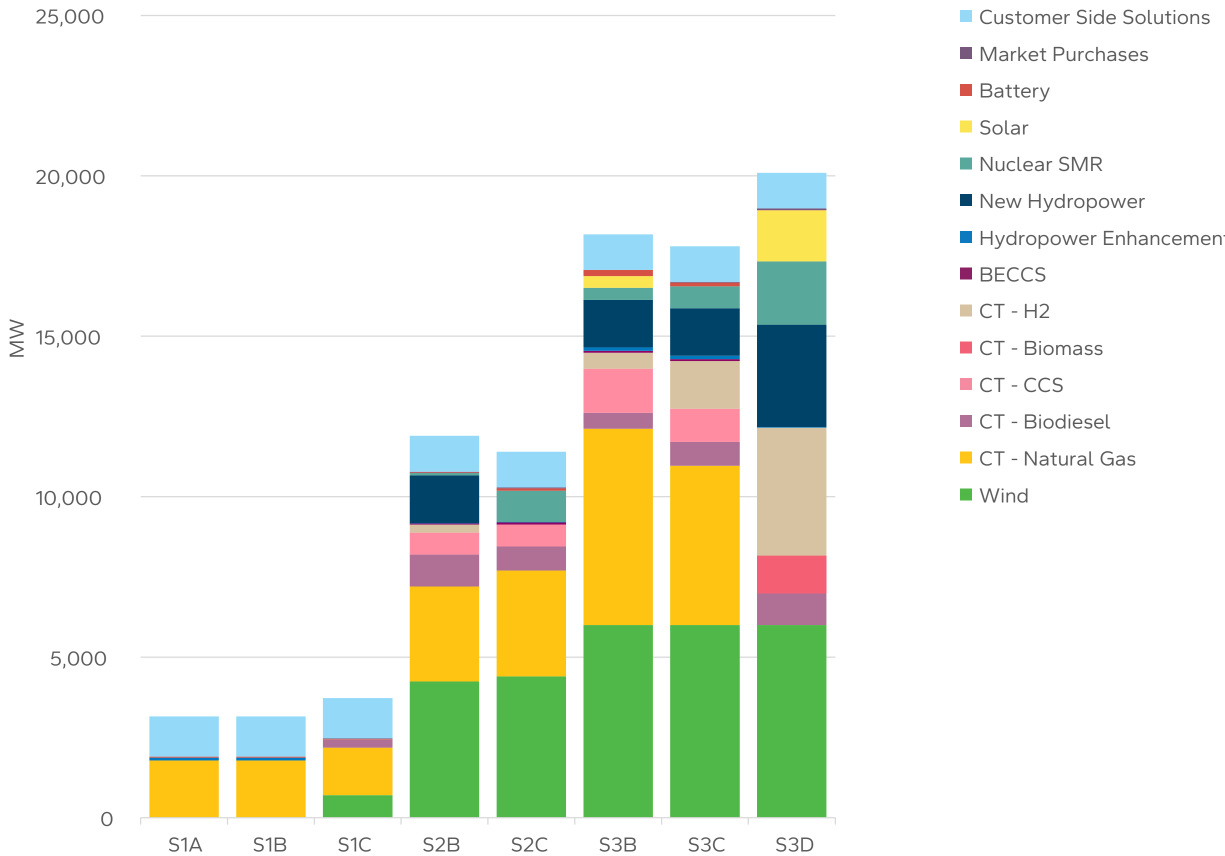


Figure A7.2.3 - Scenario Results: Cumulative Installed Capacity Additions (MW) to 2050

Table A7.2.4 – Scenario Results: Cumulative Installed Capacity Additions (MW) to 2050

	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Wind	0	0	700	4,244	4,400	6,000	6,000	6,000
CT - Natural Gas	1,784	1,784	1,480	2,958	3,302	6,116	4,962	0
CT - Biodiesel	0	0	248	992	744	496	744	992
CT - CCS	0	0	0	688	688	1,376	1,032	0
CT - Biomass	0	0	0	0	0	0	0	1,173
CT - H2	0	0	0	248	0	4,96	1,488	3,988
BECCS	0	0	0	32	63	63	63	0
Hydropower Enhancement	86	86	0	15	15	101	101	15
New Hydropower	0	0	0	1,485	0	1,485	1,485	3,195
Nuclear SMR	0	0	0	77	977	377	677	1,970
Solar	0	0	0	0	0	361	0	1,594
Battery	30	30	18	16	70	194	116	6
Market Purchases	0	0	25	25	25	0	25	50
Customer Side Solutions	1,255	1,255	1,255	1,118	1,118	1,108	1,108	1,108
Total MW	3,154	3,154	3,725	11,898	11,403	18,174	17,801	20,091

Generally, in 2032 a large portion of the new installed capacity additions is Customer Side Solutions. Given that the quantity of Customer Side Solutions (in MW) is the same in all scenarios, the percentage contribution from Customer Side Solutions, relative to total, is reduced as the load increases and more resources are required.

Across all scenarios, except S3D, a significant proportion of the installed capacity additions in 2035 are provided by natural gas fuelled combustion turbines (including natural gas turbines (CT-NG), combined-cycle (CCCT-NG), and aeroderivative units). In the 3D scenario, the resource option strategy does not allow CT-NG to be included in the portfolio of resources. As a result, biodiesel combustion turbines (CT-BD), biomass combustion turbines (CT-biomass), hydrogen fuelled combustion turbines (CT-H2), batteries, and wind, in combination with customer side solutions and the existing system, are relied on to provide the required capacity. For S3D, the installed capacity has to more than double from 2,200 MW to 5,200 MW from 2032 to 2035. This includes adding almost 1,000 MW of CT-BD and CT-H2 plus an additional 1,800 MW of wind. Given that wind has an accredited capacity between 0-20% (depending on the total quantity of installed wind on the grid), more wind must be added to provide the same level of accredited capacity as other resources with higher accreditation factors, such as combustion turbines.

The quantity of wind installed in each scenario by 2035 varies from 0 to over 2,000 MW. Apart from 200 MW of wind to meet the higher load of S3B, wind was not part of the portfolio of resources selected to meet the least cost optimization objective for these scenarios by 2035. Of Scenarios S1C, S2C, and S3C, all of which included 600 MW of near-term wind generation projects, only S3C included further additional wind – 100 MW of additional wind (700 MW of installed wind capacity total) is added by 2035.

By 2050, with the lower load growth associated with S1A and S1B, wind was not selected to be included in the portfolio of resources. Under the larger loads associated with the 2-Medium and 3-High load projection scenarios, a significant quantity of wind is added with little variation due to the resource selection strategy. S2B and S2C add over 4,200 MW of wind while all 3-High load projection scenarios include the maximum available wind at 6,000 MW.

In 2035, the resources are generally a mix of customer side solutions, wind, and natural gas turbines (CT-NG). But by 2050 as the load grows, particularly for the 2-Medium and 3-High load projection scenarios, the diversity of resources increases. Except for S3D, the mix of resources are still dominated by wind and CT-NGs, but other resources start to comprise a significant portion of the portfolio of resources. With CT-NGs restricted in S3D, the portfolio of resources relies on an even greater diversity of resources including batteries, small modular nuclear reactors (SMRs), new hydropower, and combustion turbines powered by hydrogen and biomass.

2.2. Accredited Capacity and Dependable Energy

Accredited capacity and dependable energy describe how resources contribute to meeting the capacity and energy requirement constraints in the capacity expansion planning model, where these constraints are based on Manitoba Hydro's capacity and energy planning criteria. Additional detail on the generation planning criteria and how they are implemented in the model can be found in Appendix 7.1 – Modelling & Analysis Approach.

2.2.1. Accredited Capacity

The accredited capacity breakdowns for the scenarios are provided in Figure A7.2.4 through Figure A7.2.7, with winter and summer accredited capacity shown separately for the 2035 and 2050 study years. These figures confirm that accredited capacity additions increase moving from the 1-Baseline load projection to the 3-High load projection, as well as with a later study year.

Across all scenarios except S3D, the winter and summer accredited capacity additions in 2035 are dominated by natural gas fuelled combustion turbines (including CT-NG, CCCT-NG), and aeroderivative units), followed by customer side solutions (includes the Efficiency Plan Projection and demand response). In the 3D scenario, the resource option strategy does not allow CT-NG to be included in the portfolio of resources. As a result, biodiesel combustion turbines (CT-Biodiesel), biomass combustion turbines (CT-biomass), hydrogen fuelled combustion turbines (CT-H2), batteries, and wind, in combination with customer side solutions and the existing system, are relied upon to provide the required accredited capacity.

By 2050, greater diversity in accredited capacity resources is seen in the 2-Medium and 3-High load projection scenarios, while the 1-Baseline load projection scenarios continue to rely on CT-NG and customer side solutions. This is consistent with installed capacity results, where the proportion of accredited capacity provided by each resource type is in large part dictated by installed capacities. However, some resources have special considerations worth highlighting:

- Accredited capacity from wind resources declines as more wind is added to the system, starting with initial wind additions being accredited at 20%. This is evident in Figure A7.2.4 through Figure A7.2.7, which confirm that the proportion of the system's total accredited capacity attributed to wind is smaller than the proportion of total installed capacity of wind in the system.
- Solar resources are accredited at 35% in the summer, but provide no accredited capacity in the winter due to their generation profile being poorly matched to the Manitoba load profile. In scenarios 3B and 3D, solar additions in 2050 result in small summer accredited capacity amounts (Figure A7.2.5), with no associated winter accredited capacity additions (Figure A7.2.7).

- CT-H2 units provide accredited capacity in the winter, but the associated electrolyzer units reduce the accredited capacity of the system in the summer. This is evident by the negative accredited capacity shown in Figure A7.2.7 for the 3-High load projection scenarios, which include the largest amounts of CT-H2 units in their portfolios of resources.
- Energy markets are assumed to provide no accredited capacity to Manitoba Hydro outside of contractual agreements.

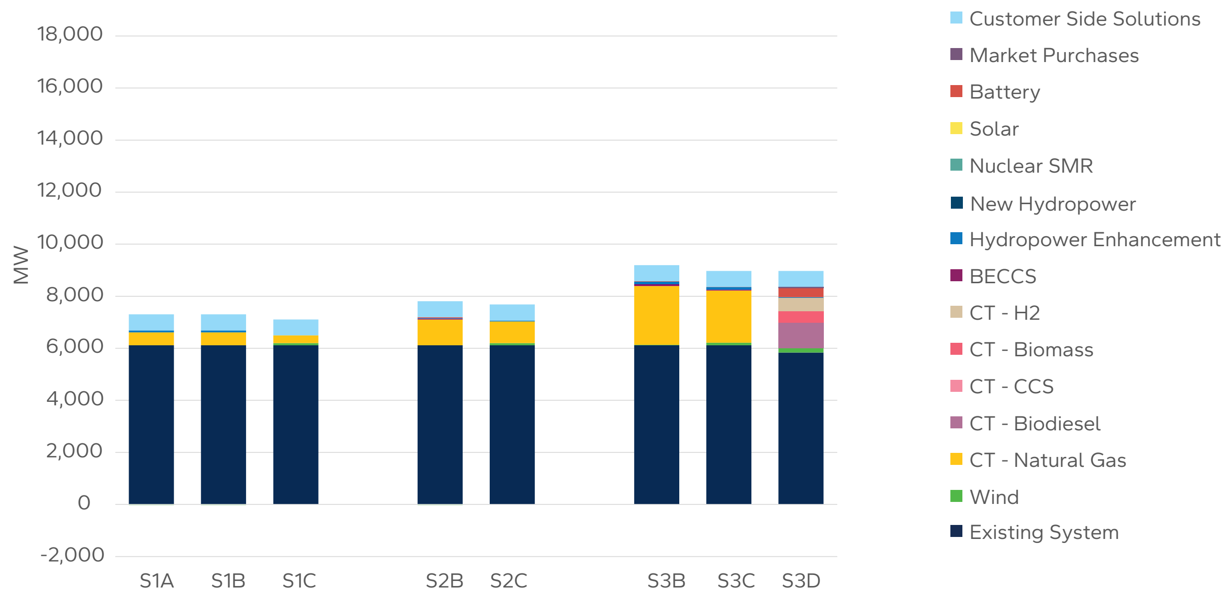


Figure A7.2.4 - Scenarios: Winter Accredited Capacity in 2035

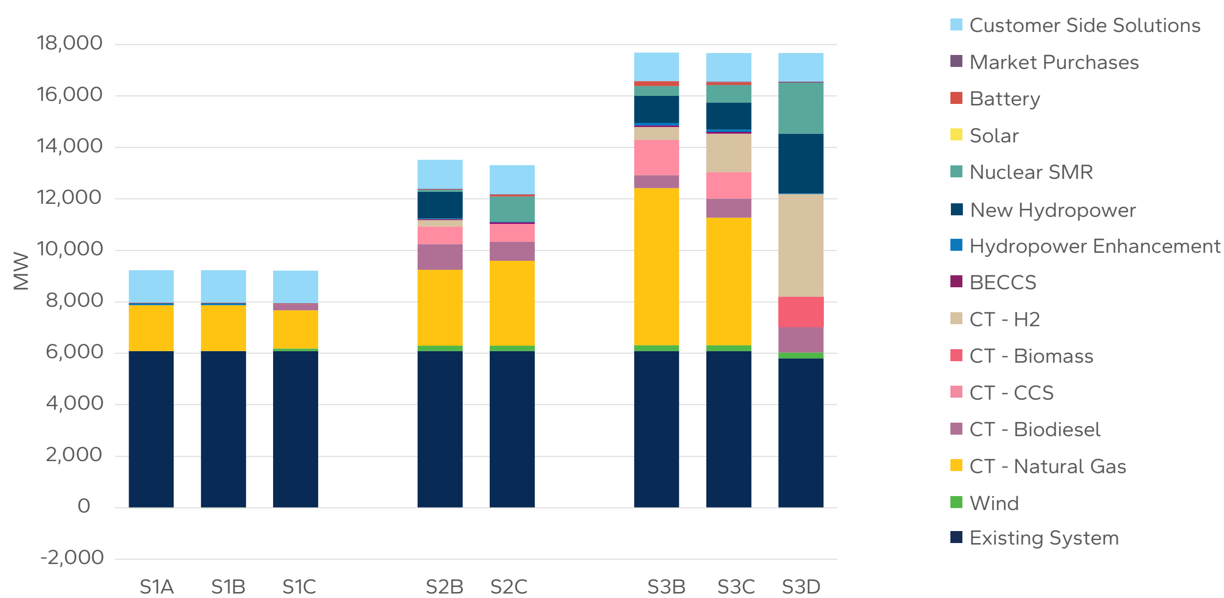


Figure A7.2.5 - Scenarios: Winter Accredited Capacity in 2050

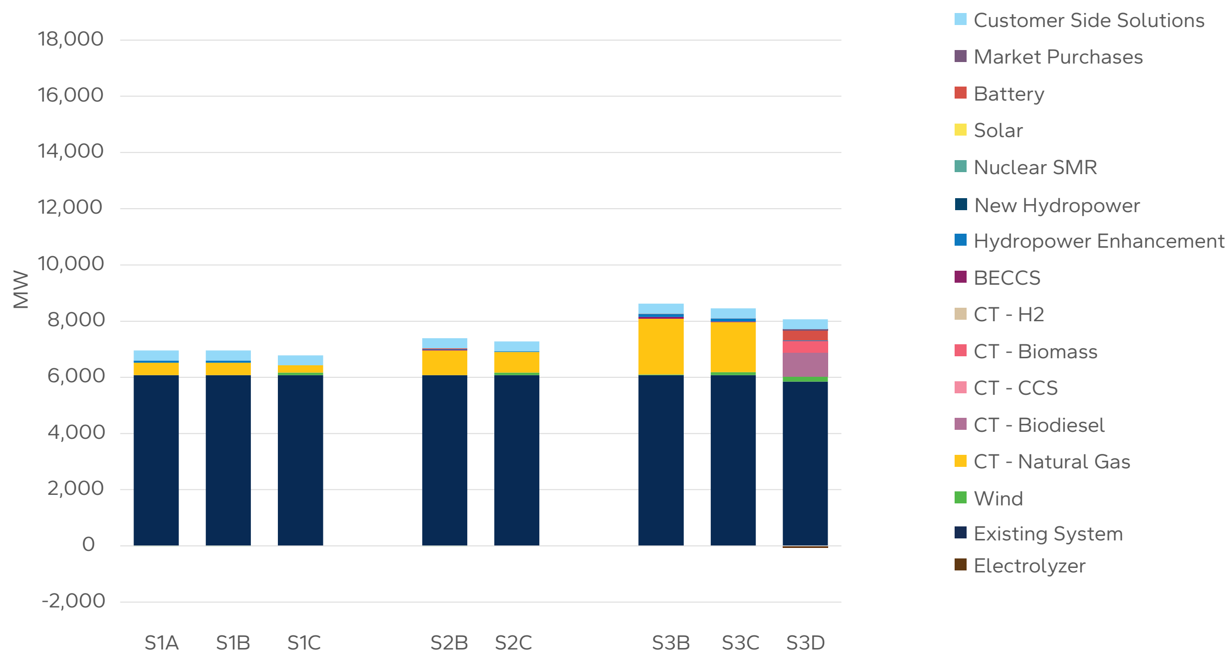


Figure A7.2.6 - Scenarios: Summer Accredited Capacity in 2035

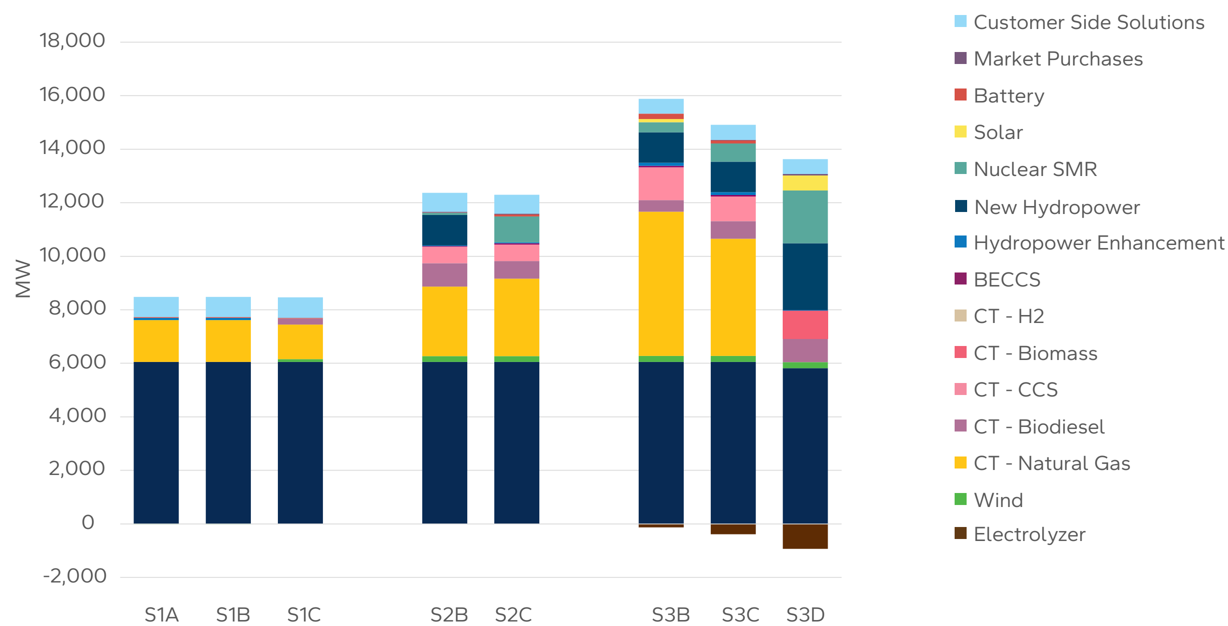


Figure A7.2.7 - Scenarios: Summer Accredited Capacity in 2050

While the resources noted previously have some of the largest accredited capacity variations between winter and summer, other resources can have seasonally changing capacity accreditations as well, as discussed in Appendix 6 – Resource Options and Appendix 7.1 – Modelling & Analysis Approach. The cumulative effect of the seasonality in resource option capacity accreditation is also apparent in Table A7.2.5. This table compares the average increase in accredited capacity (relative to the existing system) for each load projection, by season and study year. By 2035, average cumulative accredited capacity additions range from 19% to 51% of the existing system's accredited capacity in the winter, and from 14% to 40% in the summer. By 2050, winter accredited capacity is increased on average by 52% to 196% compared to the existing system across the load projections, while summer increases range from 40% to 140%.

Winter increases in cumulative accredited capacity additions, on average, are greater than in the summer for all load projections and both study years. For example, winter accredited capacity on average across the 3-High load projection scenarios is almost three times the existing system's by 2050, while the increase is closer to 2.5 times in the summer. This is largely due to the increased inclusion of CT-H2 units in the 3-High load projection scenario results by 2050, where the associated electrolyzers reduce summer accredited capacity.

Table A7.2.5 – Senarios: Average Cumulative Accredited Capacity Additions per Load Projection Expressed as a percentage change from the existing system accredited capacity

		1-Baseline	2-Medium	3-High
2035	**Winter**	19%	27%	51%
2035	**Summer**	14%	21%	40%
2050	**Winter**	52%	121%	196%
2050	**Summer**	40%	104%	140%

2.2.2. Dependable Energy

Dependable energy for each scenario is provided in Figure A7.2.8 through Figure A7.2.11, with results shown separately for the winter and summer seasons and for the 2035 and 2050 study years. Like accredited capacity, dependable energy added to the system generally increases with the load projection and study year.

By 2035, CT-NG units and customer side solutions are prominent contributors to the system's dependable energy, as they are for accredited capacity. However, imports also play a more significant role, as does wind in scenarios employing the near-term wind generation projects resource options strategy (Strategy C). By 2050, there is similarly a diversification of the resource types supplying dependable energy to the system under the 2-Medium and 3-High load projections, with wind contributions growing from 2035 levels.

Some resources not only have energy accreditation factors that vary seasonally, but also that differ notably from their capacity accreditation factors. Understanding energy accreditation by resource type is important for understanding the results shown in Figure A7.2.8 through Figure A7.2.11, and how they relate to the accredited capacity results in Figure A7.2.4 through Figure A7.2.7. Key resource-specific accreditation details are summarized as follows:

- Wind accreditation factors are higher for energy than capacity, and do not decrease as more wind is added. Whereas first wind additions to the system had capacity accredited at 20%, energy is accredited at 48% in the winter and 39% in the summer. As a result, wind's contribution to the system's total dependable energy is larger than its contribution to the system's total accredited capacity.
- Unlike its capacity accreditation, the energy accreditation for solar resources does not vary seasonally and remains consistent throughout the year at 17%. Capping solar generation's summer dependable energy at its winter value allows dependable energy to be captured appropriately on an annual basis, as the system's ability to make use of summer dependable energy is limited by its ability to shift energy seasonally via hydraulic storage.
- This dependable energy assumption is applicable only in relation to the generation planning criteria, and solar energy generation in the system remains greater in the summer than the winter.

- Excess behind-the-meter solar generation sold back to the grid is assumed for each load projection and is reflected in the dependable energy values shown in the figure (note that excess behind-the-meter solar has no associated accredited capacity). Only the 3B and 3D cases include additional utility-scale solar in the portfolios of resources. Behind-the-meter solar generation that offsets customer demand is accounted for separately, as part of the overall demand of a load projection.
- There is an assumed level of dependable energy provided by the energy markets that Manitoba Hydro participates in. Dependable energy associated with opportunity imports is included in the existing system category. Conversely, dependable energy implications from diversity contracts, which includes imports during the winter months, are accounted for through a direct modification of the system's dependable energy requirements, like all other firm contracts.
- CT-H2 provide limited winter dependable energy, which can vary from 3.6% to 36%, depending on the type selected. No dependable energy is provided in the summer. Electrolyzers are required to support CT-H2, and they in turn consume energy and reduce the system's summer dependable energy
- In scenario 3D, it is assumed that there is no backup fuel available for the CT-BD units. As a result, the dependable energy provided by CT-BD units is limited based on their ability to dispatch using only BD fuel supplies, which is subject to annual limits. This results in a 4% winter energy accreditation and 0% summer energy accreditation for CT-BD units in 3D. In all other scenarios, CT-BD units are assumed to have biomethane as a backup fuel, and their accredited winter and summer energy is equivalent to a CT-NG units.
- Batteries provide accredited capacity to the system but result in a net reduction in the system's dependable energy, because they consume energy due to losses during charging and discharging

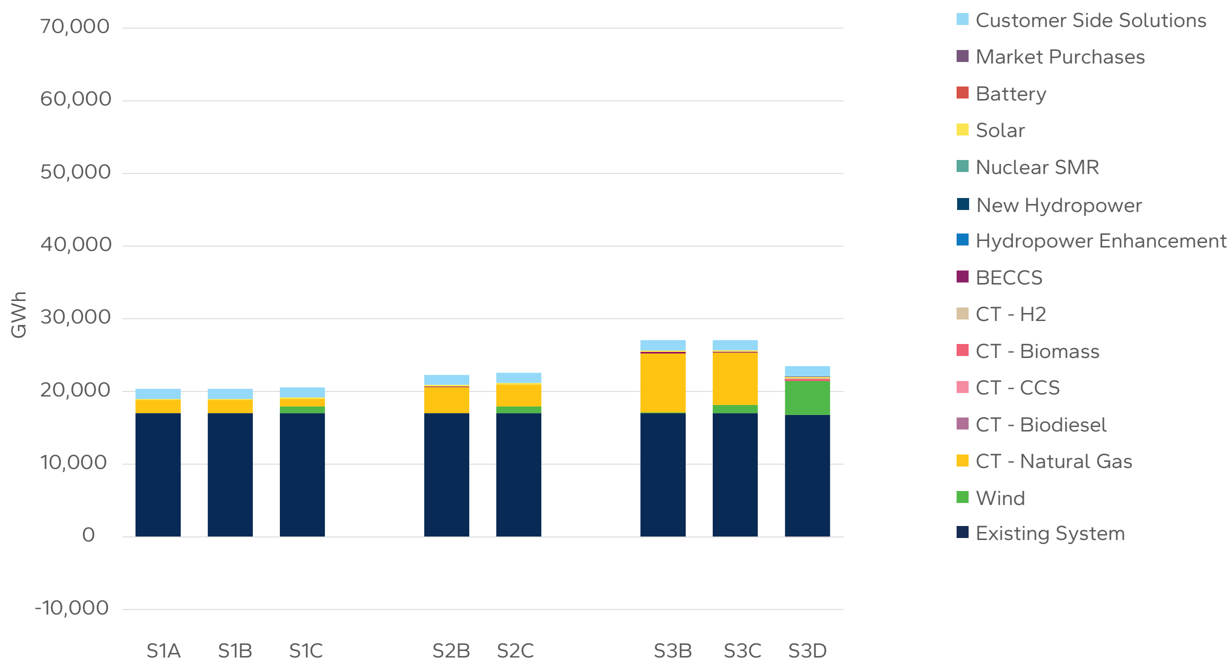


Figure A7.2.8 - Scenarios: Winter Dependable Energy in 2035

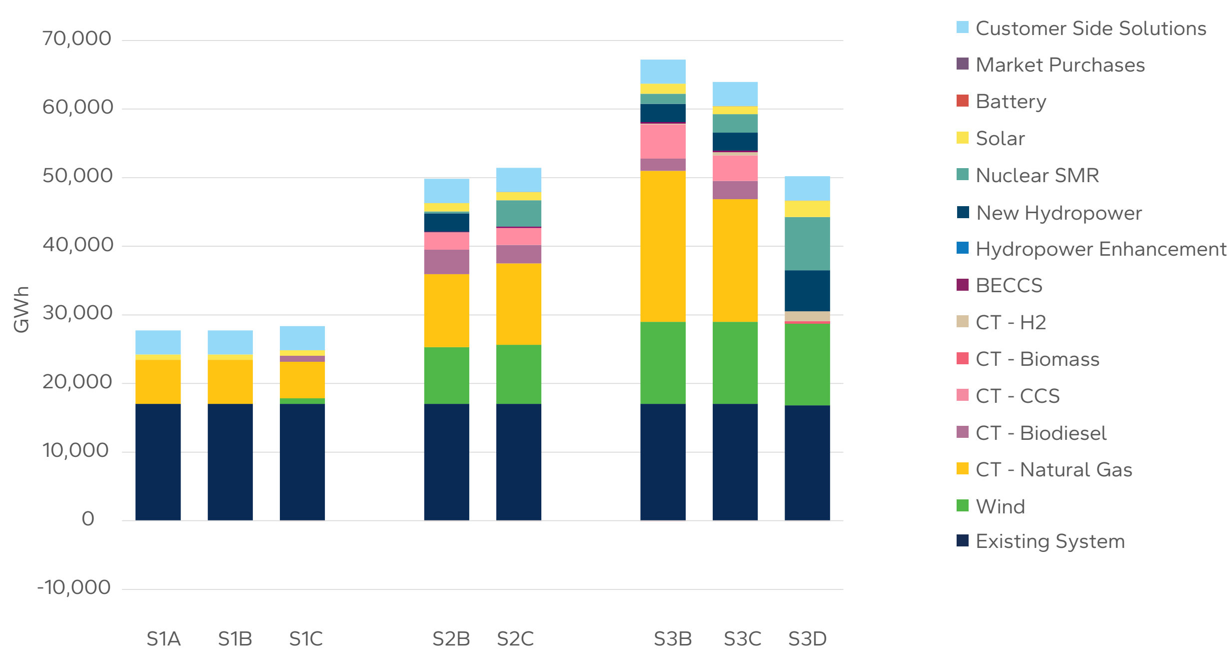


Figure A7.2.9 - Scenarios: Winter Dependable Energy in 2050

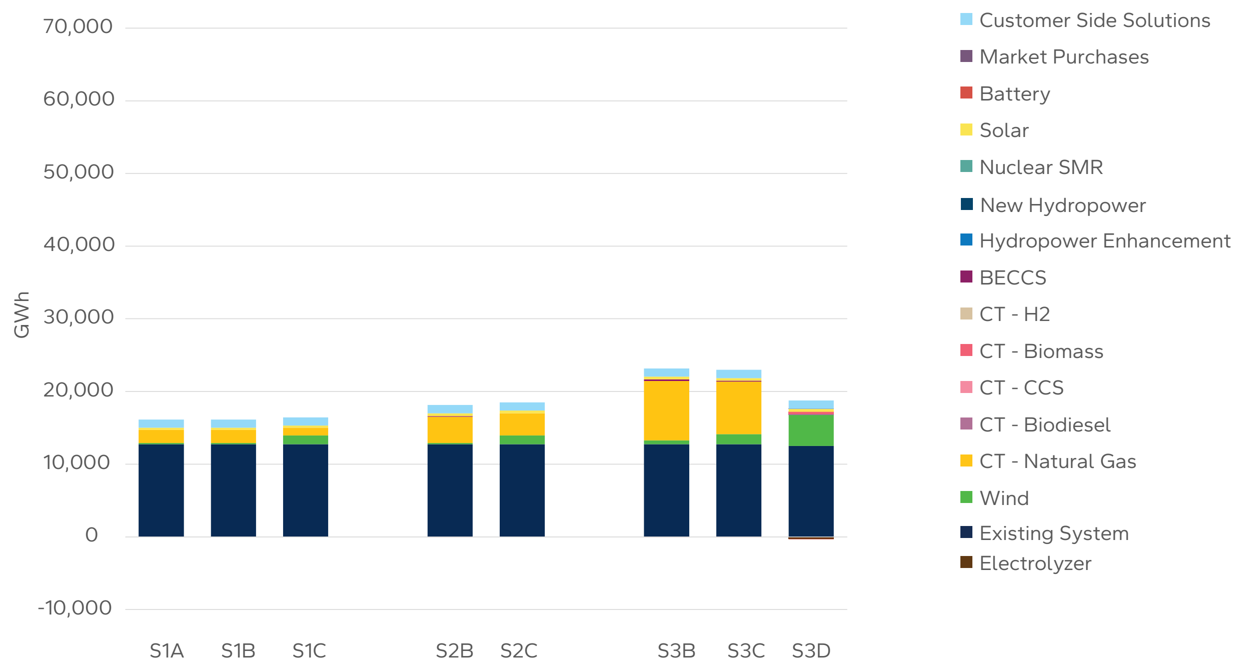


Figure A7.2.10 - Scenarios: Summer Dependable Energy in 2035

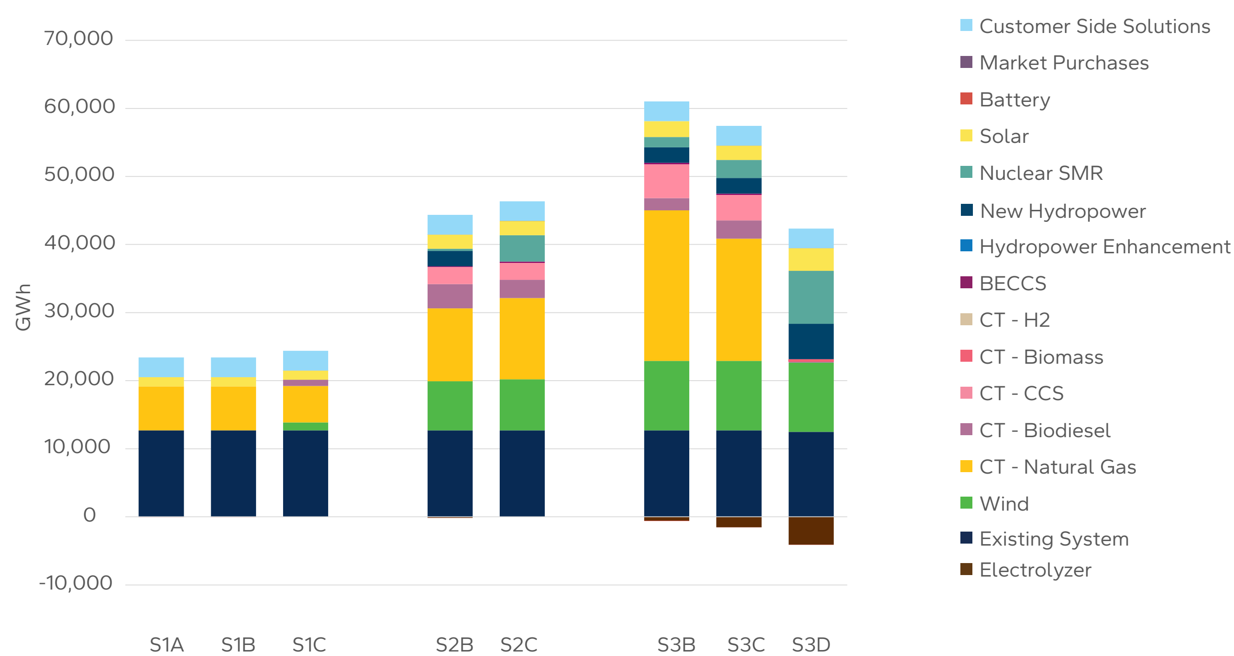


Figure A7.2.11 - Scenarios: Summer Dependable Energy in 2050

The implications of imports and wind resources contributing more to dependable energy than they do to accredited capacity is highlighted in Table A7.2.6; comparing to Table A7.2.5, which summarizes accredited capacity additions, shows that the system's dependable energy increases more than its accredited capacity across the load projections. This frequently results in accredited capacity being the governing constraint for the addition of new resources. By 2035 and across the load projections, the average increase in dependable energy ranges from 41% to 75% in the winter and from 44% to 85% in the summer. By 2050, the increase in the system's dependable energy ranges from 88% to 287% in the winter, and from 105% to 322% in summer.

Table A7.2.6 – Scenarios: Average Cumulative Dependable Energy Additions per Load Projection

		1-Baseline	2-Medium	3-High
2035	**Winter**	41%	53%	75%
2035	**Summer**	44%	60%	85%
2050	**Winter**	88%	227%	287%
2050	**Summer**	105%	272%	322%

The overall dependable energy profiles of the scenarios, shown in Figure A7.2.8 through Figure A7.2.11, are dictated first by the installed capacity of each resource type, then influenced by the technology-specific considerations noted above. Figure A7.2.12 helps illustrate how the same set of resources contribute differently to the system's accredited capacity and dependable energy. How these resources are operated within the system, and their resulting average energy generation, is discussed in the following section; it is important to note that dispatchable resources, such as CT-NG units, provide dependable energy for planning purposes, but simulation of system operations shows that these resources, on average, have very low utilization factors.

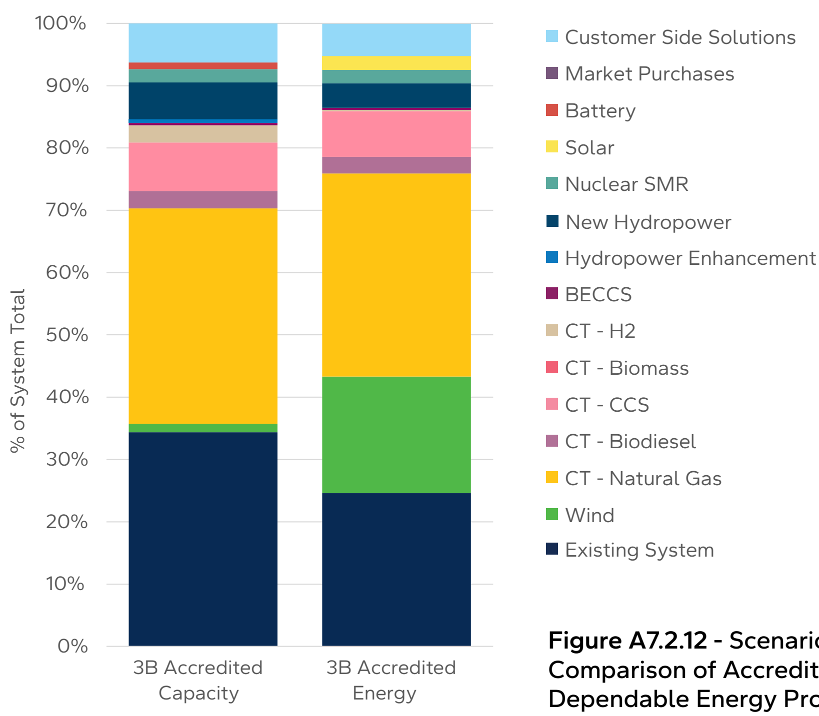


Figure A7.2.12 - Scenarios: Illustrative Comparison of Accredited Capacity and Dependable Energy Profiles for 3B, in 2050

2.2.3. Available vs. Required Accredited Capacity and Dependable Energy

Figure A7.2.13 and Figure A7.2.14 show how the portfolios of resources across the scenarios meet the accredited capacity and dependable energy requirements of the system in 2035 and 2050, respectively. These ratios presented in the figures reflect the accredited capacity and energy contributions of the resource additions in each portfolio, as well as the growing and changing requirements of the system over time. In 2035, available winter accredited capacity is the most closely matched to the system requirements, with no buffer in 3C or 3D. Available winter dependable energy is also just matched to system requirements in 3D. Accredited capacity and energy may be added beyond system requirements due to any of the following:

- When a resource is added based on a need to meet one of the planning criteria requirements, resulting in excess in the other (for example, when adding a resource is required to meet the accredited capacity requirement, that resource also provides dependable energy and may create or increase a surplus of dependable energy);
- When a single unit cannot provide enough incremental accredited capacity or dependable energy to meet the planning requirement, requiring a second unit to be selected even if the resulting total accredited capacity or dependable energy then exceeds the requirement. For example, if the system is short 100 MW of winter accredited capacity, adding a resource option that provides 150 MW of winter accredited capacity would create an excess of 50 MW; or
- If the model sees an economic advantage to adding resources in advance of need.

By 2050, winter accredited capacity meets system requirements, with no surplus, in all scenarios except 2B. Summer dependable energy requirements are only just met, with no surplus, in 3D. This is in part due to the larger number of CT-H2 projects added by 2050 in 3D, which reduce summer dependable energy.

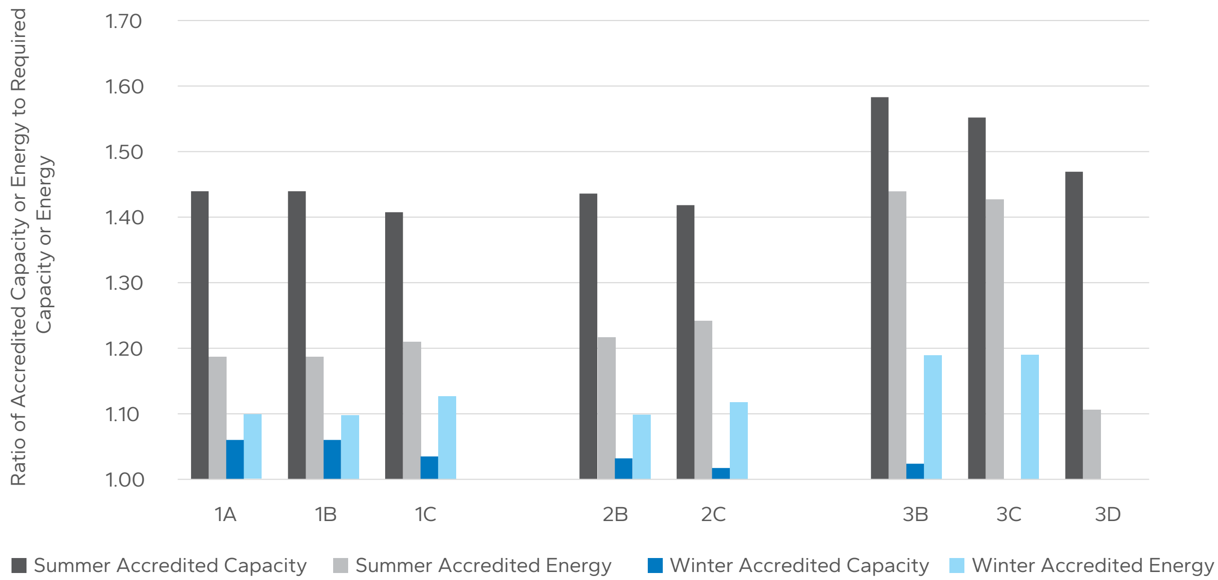


Figure A7.2.13 - Scenarios: Ratio of Available Accredited Capacity or Dependable Energy to System Requirements by Season, for 2035

(Ratio = 1.00 indicates that accredited capacity or dependable energy exactly equals the minimum system requirement)

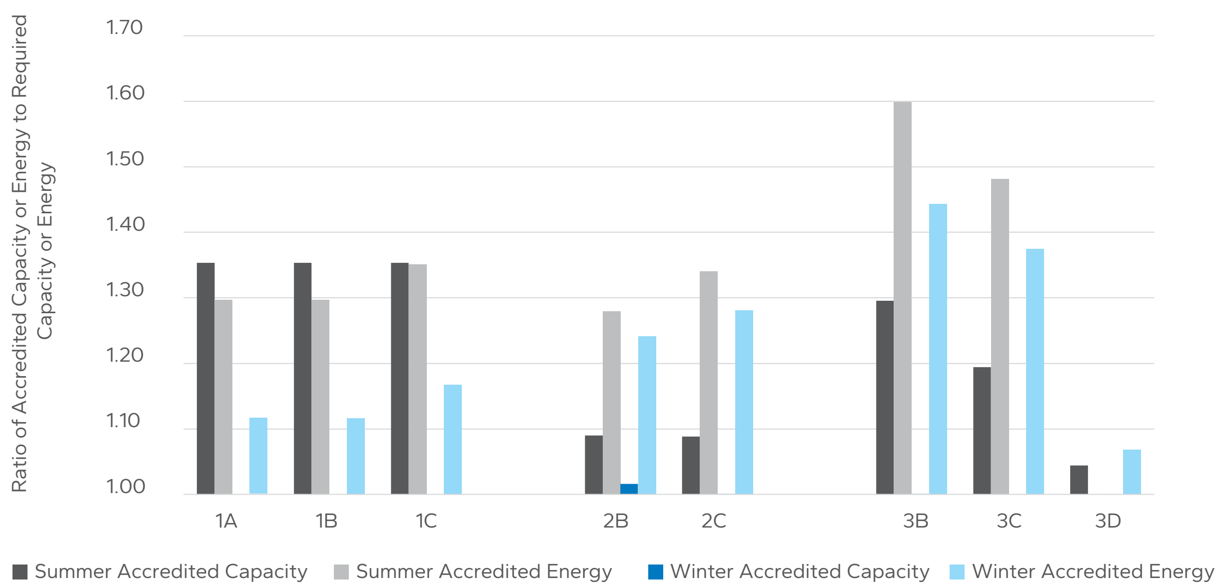


Figure A7.2.14 - Scenarios: Ratio of Available Accredited Capacity or Dependable Energy to System Requirements by Season, for 2050

(Ratio = 1.00 indicates that accredited capacity or dependable energy exactly equals the minimum system requirement)

2.3. Average Energy

Energy generation in the model supplies Manitoba's electricity demand, firm export commitments, opportunity exports, and system losses. The Manitoba load and firm contracts represent fixed energy requirements that must be consistently supplied throughout the study period. In contrast, opportunity exports and system losses vary depending on generation levels determined by the production costing model, reflecting influences such as economic signals and hydrological conditions.

The generation mix across the scenarios includes dispatchable resources, wind, solar, customer-side solutions, physical energy imports, and financial settlements of firm contracts. From a modelling perspective, wind, solar, and customer-side solutions are treated as fixed energy generation sources with pre-determined generation profiles. Generation from other resources is based on production costing optimization of the system and reflects that the electrical system in Manitoba is predominantly hydropower-based, with output largely dependent on hydrological conditions.

When there is a deficiency between the total energy demand of the system—which includes Manitoba load, firm exports, and system losses—and the combined supply from wind, solar, customer-side solutions, and hydropower, it is met through dispatchable generation, physical imports, or financial settlements. Under favorable hydrological conditions, reliance on these supplementary sources can be minimized, and any surplus energy may be exported as opportunity energy.

The term "average energy" refers to annual energy generation averaged across all simulated hydrological conditions (flow years) and does not represent a specific hydrological condition. Figure A7.2.15 and Figure A7.2.16 show average energy generation for each scenario and categorized by resource type for 2035 and 2050, respectively. Please note that the scales differ between the two load year figures.

In 2035, the Manitoba electrical system remains hydropower-dominated across all load scenarios. However, by 2050, this is only the case in 1-Baseline load projection scenarios. In the 2-Medium and 3-High load projection scenarios, the energy mix shifts toward a more balanced distribution—approximately half hydropower and half from other resources. The figures show that combustion turbines (CT) (including natural gas combustion turbines (CT-NG), biodiesel combustion turbines (CT-BD), natural gas combined-cycle combustion turbines (CCCT-NG), CCCT with carbon capture and sequestration (CCCT-CCS), and aeroderivative units) are infrequently relied on for energy on average. By 2050 and under the 2-Medium and 3-High load projections, high levels of energy demand result in combustion turbines generating somewhat more often, but they remain minor energy sources for the system.

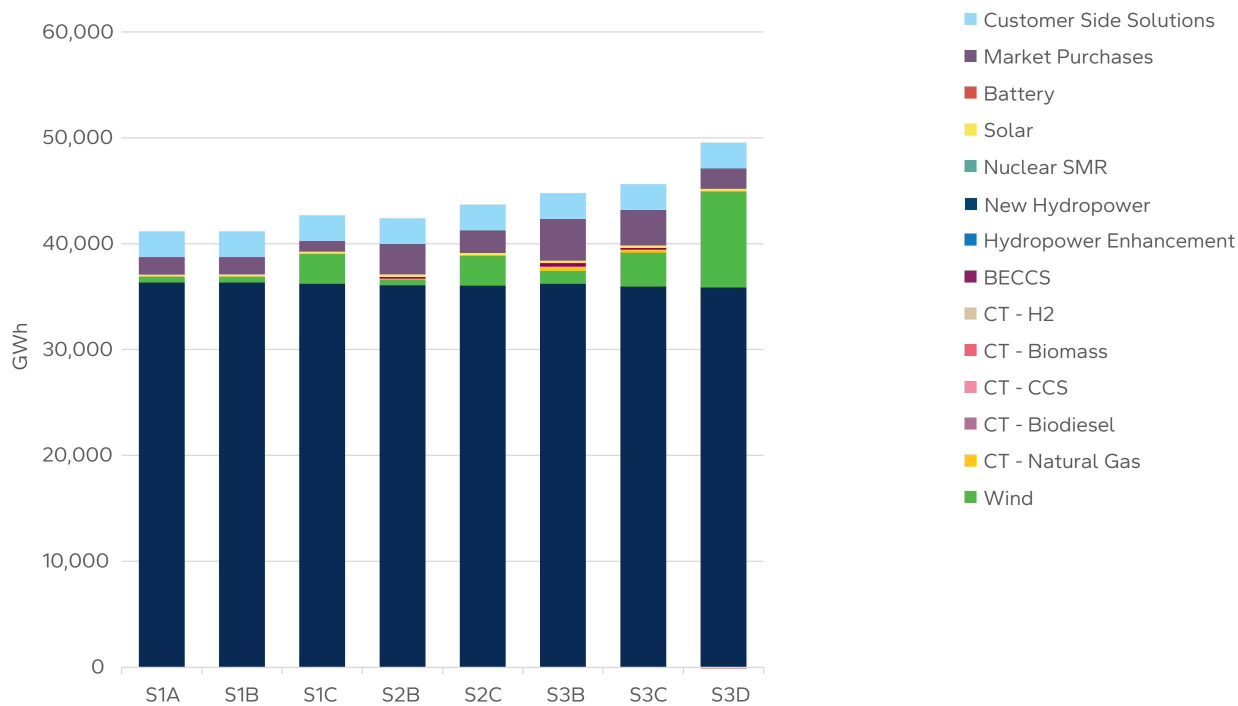


Figure A7.2.15 - Average Energy Generation for load year 2035

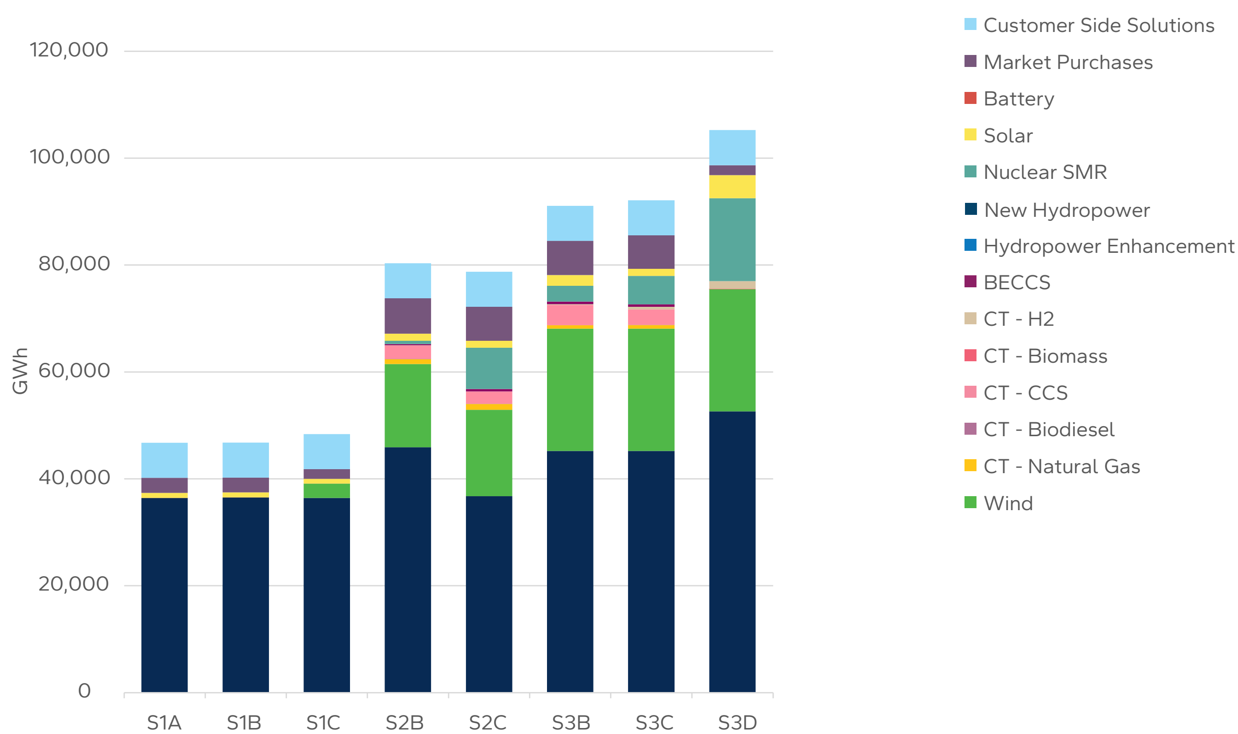


Figure A7.2.16 - Average Energy Generation for load year 2050

2.4. System Operations under Different Flow Conditions

Changes in the overall operation of the system under varying flow conditions are also important to consider across all scenarios. Figure A7.2.17 and Figure A7.2.18 illustrate system operations under high-flow (flood) conditions, years 2035 and 2050 respectively. Figure A7.2.19 and Figure A7.2.20 show system operations under average flow conditions for those same years. Figure A7.2.21 and Figure A7.2.22 present system operations under dependable low-flow (drought) conditions for 2035 and 2050.

Hydroelectric production currently ranges from 23 TWh to 45 TWh, depending on flow conditions. In the near future (load year 2035), under dependable low-flow conditions, hydropower generation serves approximately 70% and 60% of total load for the 1-Baseline load projection and 3-High load projection scenarios, respectively. By 2050, this declines to 60% for 1-Baseline load projection scenarios and 35% for the 3-High load projection scenarios.

Energy generation from dispatchable combustion turbines shows a negative correlation with hydropower generation. Dispatchable sources, such as CT-NG, CCCT-CCS, and CT-BD, have increased generation under low flow conditions. The extent of this effect increasing with the projected load but is also dependent on the portfolio of resources. Similarly, opportunity import purchases also increase when inflows, and correlated hydropower, decrease.

Given the variability in energy imports and exports under different flow conditions, cross-border electricity trade will remain a key strategy for economically meeting customer demand.

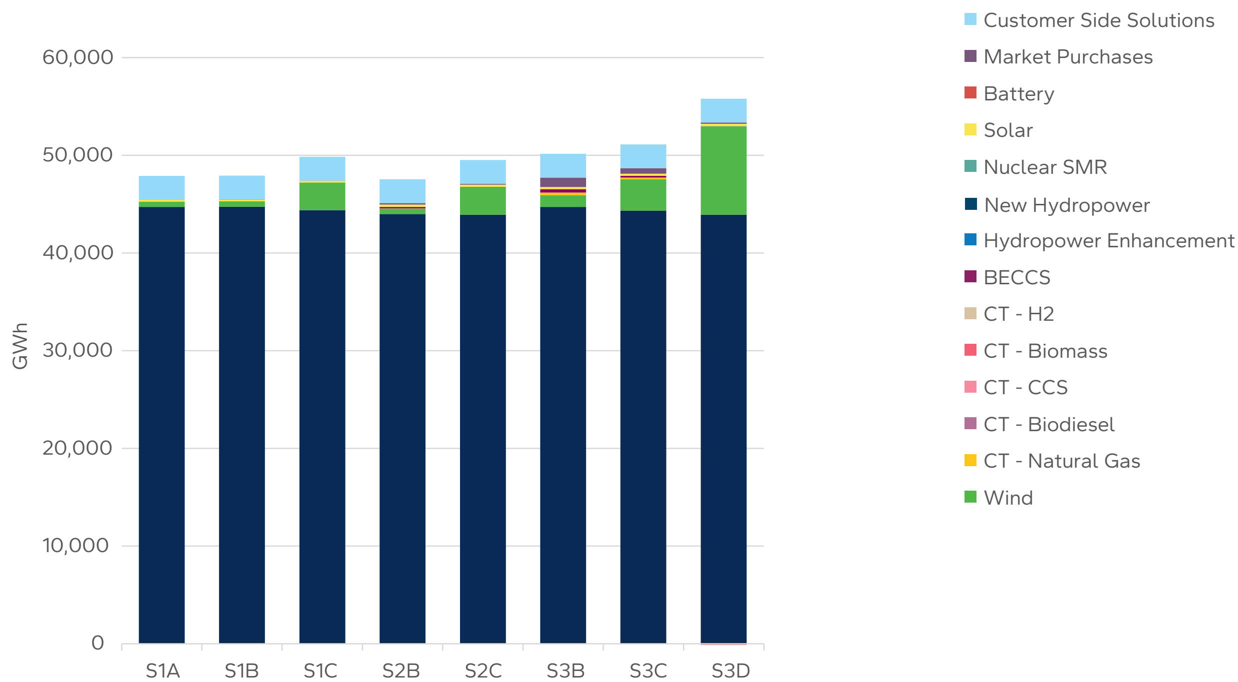


Figure A7.2.17 - Energy Generation for Load Year 2035 for Flood Condition

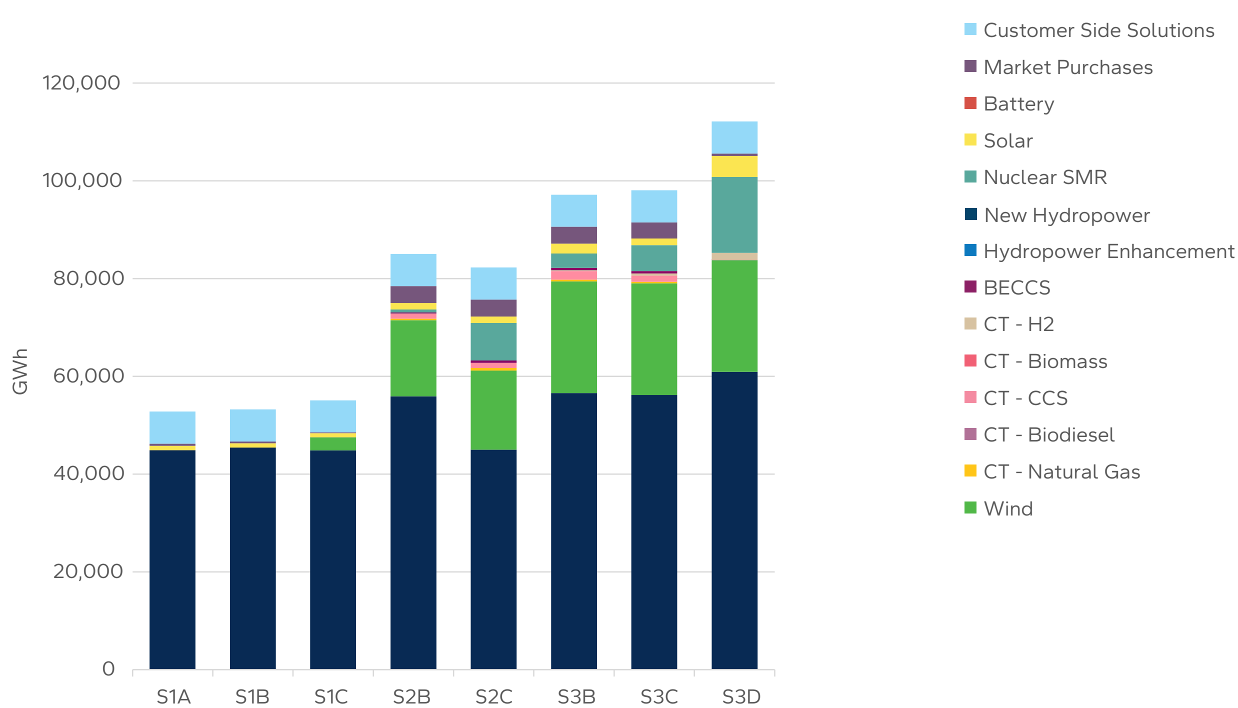


Figure A7.2.18 - Energy Generation for Load Year 2050 for Flood Condition

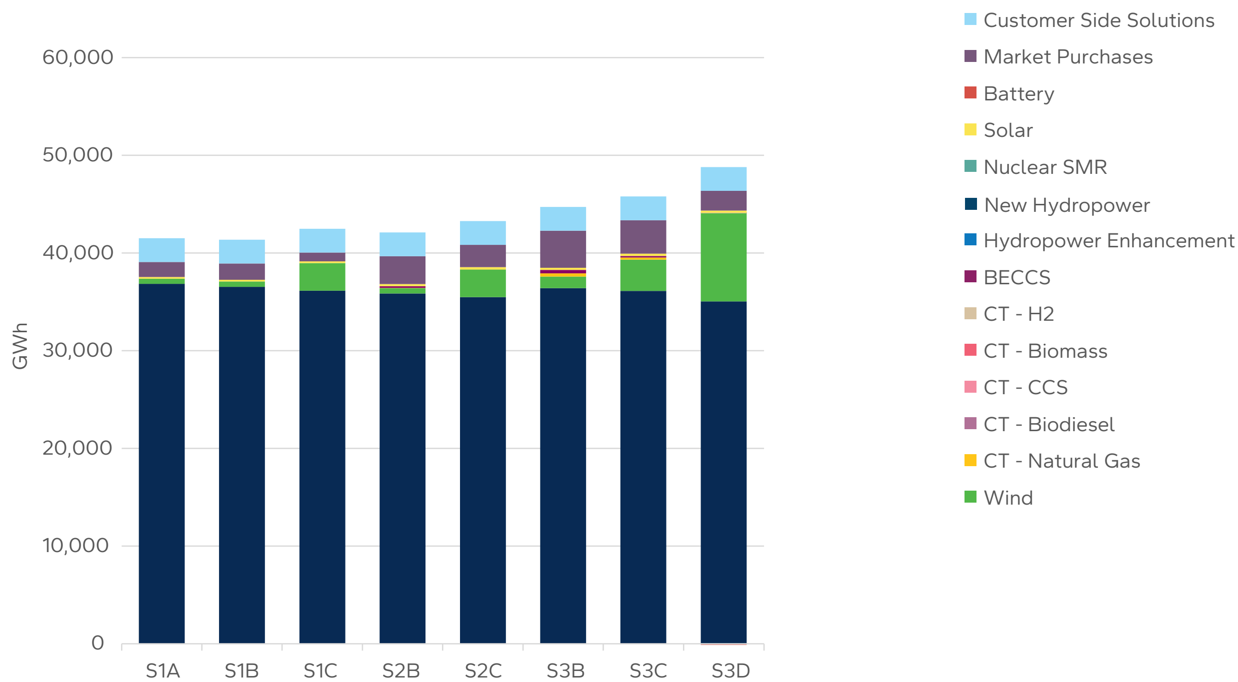


Figure A7.2.19 - Energy Generation for Load Year 2035 for Average Flow Condition

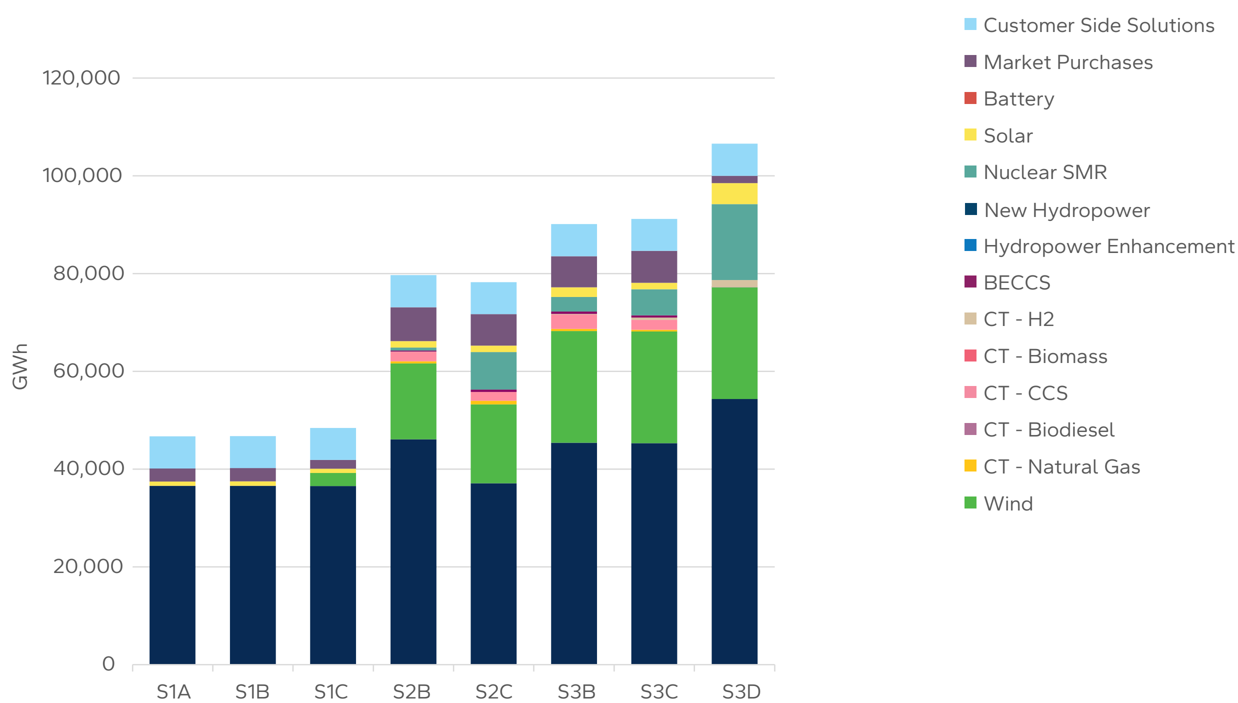


Figure A7.2.20 - Energy Generation for Load Year 2050 for Average Flow Condition

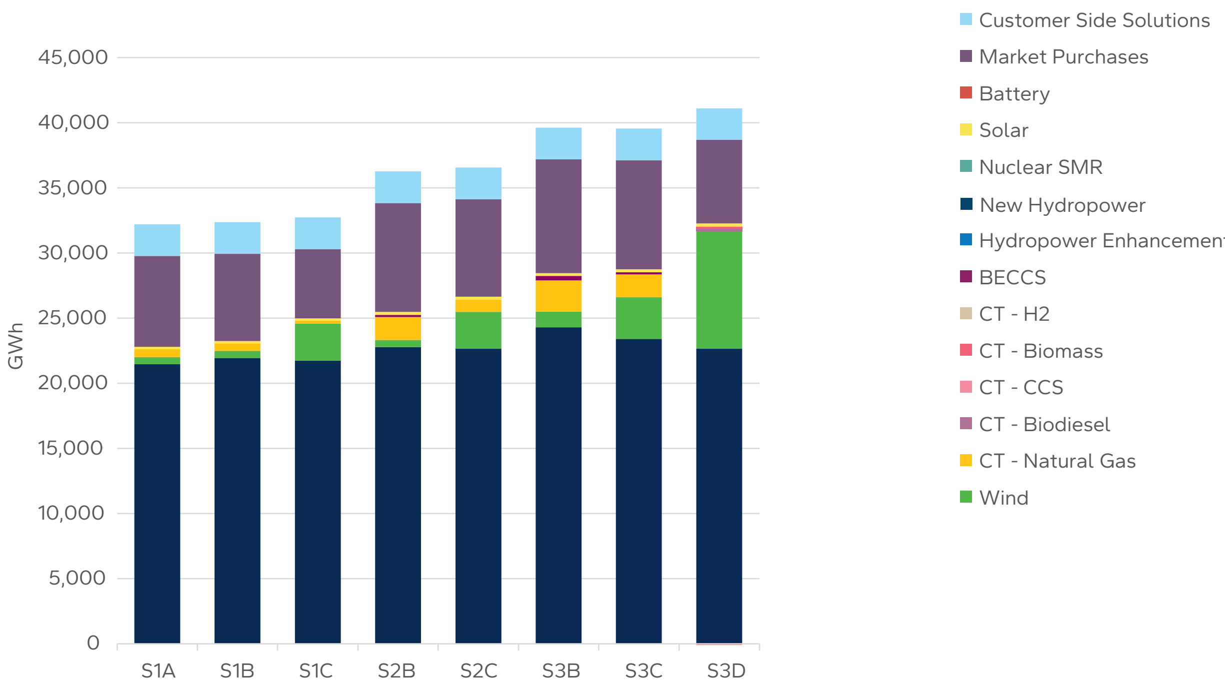


Figure A7.2.21 - Energy Generation for Load Year 2035 for Drought Condition

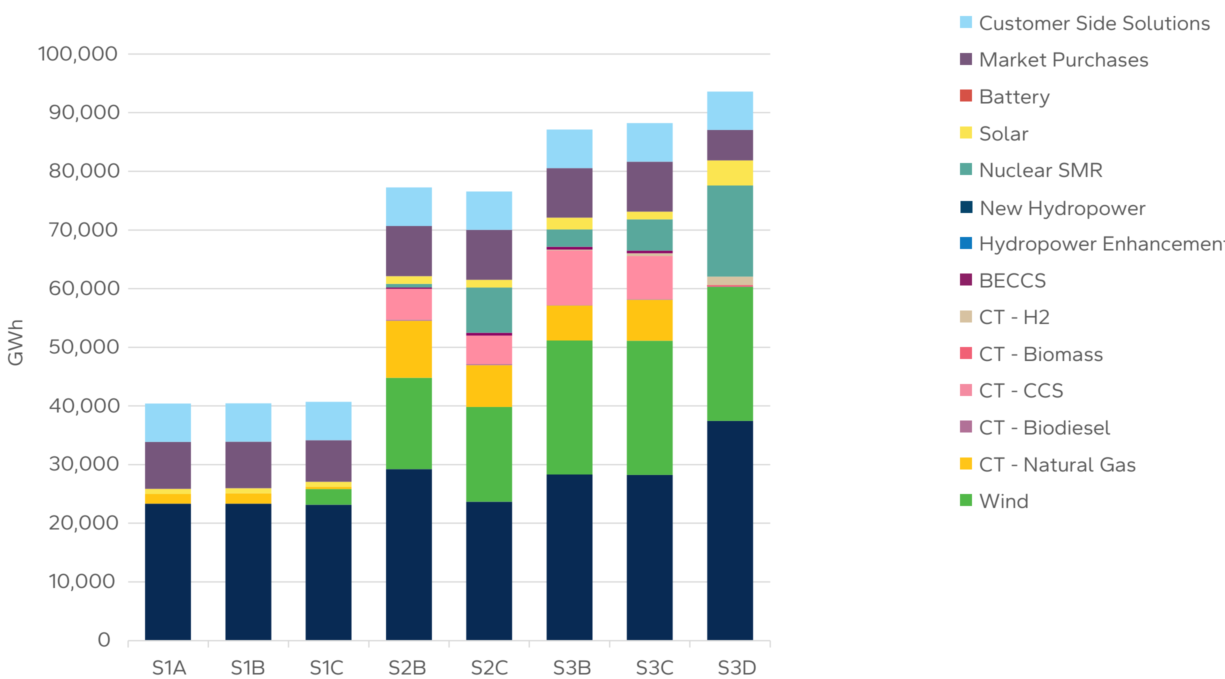


Figure A7.2.22 - Generation for Load Year 2050 for Drought Condition

2.5. U.S. Interconnections & Market Activities

The interconnection of neighbouring electricity markets with Manitoba Hydro's predominantly hydropower generation system is mutually beneficial. These cross-border links allow both the import and export of electricity, offering important advantages in terms of reliability, economic efficiency, and environmental impact:

- **Reliability:** Imports help ensure system stability during drought conditions or unplanned supply disruptions, such as equipment outages.
- **Economic Efficiency:** Surplus hydropower can be exported when available, while imports during periods of lower market prices can offset the need for more expensive local thermal generation, improving overall system economics.
- **Regional Electricity Generation GHG Emission Reductions:** By net exporting electricity (on average), Manitoba Hydro supports reductions in fossil fuel use and related GHG emissions from electrical generators in neighbouring regions.[2]

2.5.1. Import Limitations and Operational Constraints

While imports enhance reliability, they are not unlimited. The maximum import capacity is constrained by existing transmission limits and further constraints are added to the model, as described in Appendix 7.1 – Modelling & Analysis Approach. Within these restrictions, import decisions in the model are made on an opportunity basis to support the economic operation of the system. Market capacity imports are represented separately as a resource option.

Figure A7.2.23 and Figure A7.2.24 illustrate import patterns under average and drought conditions, respectively. These figures show that:

- Under average flow conditions, required imports tend to increase with system load.
- However, when more intermittent resources, such as wind and solar, are integrated into the resource mix, required imports decrease compared to scenarios with the same load projection but fewer intermittent resources. This can be seen in Figure A7.2.23 and Figure A7.2.24 by comparing S1C to S1A and S1B, S2C to S2B, and S3C to S3B, where S1C, S2C, and S3C all have more wind installed by 2035 than the other scenarios for the same load projections. This highlights that intermittent resource generation is not dependent on inflows.
- Similar trends are observed during drought conditions, though the import volumes are significantly higher.

[2] Manitoba Hydro cannot claim these GHG emission reductions, they are attributed to non-Manitoba utilities.

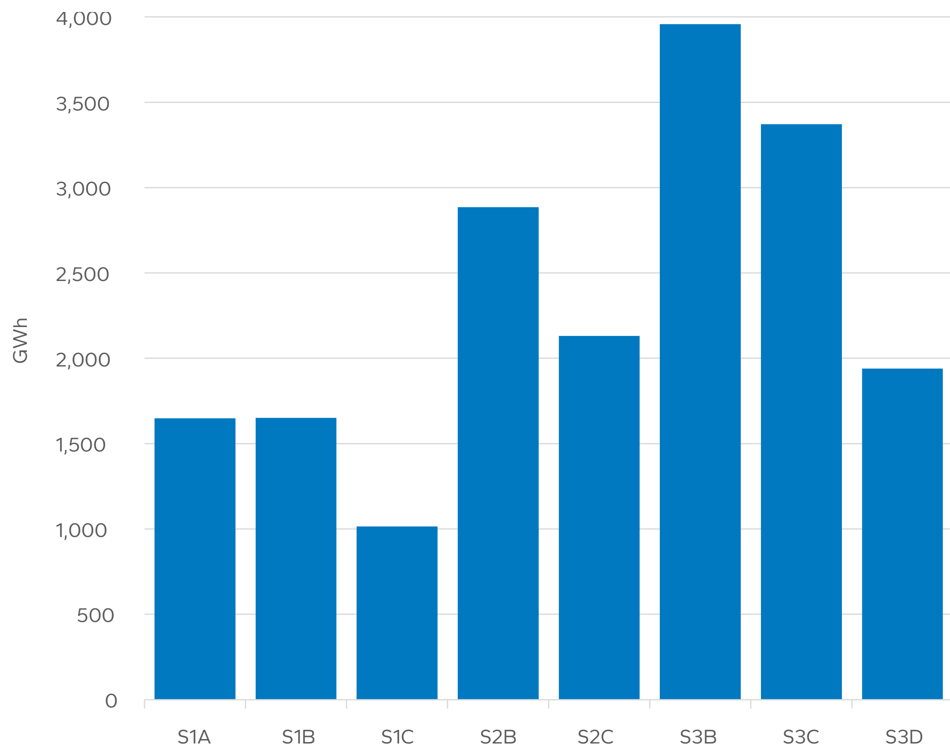


Figure A7.2.23 - Scenarios - Energy Imports in 2035 Averaged across All Flow Conditions

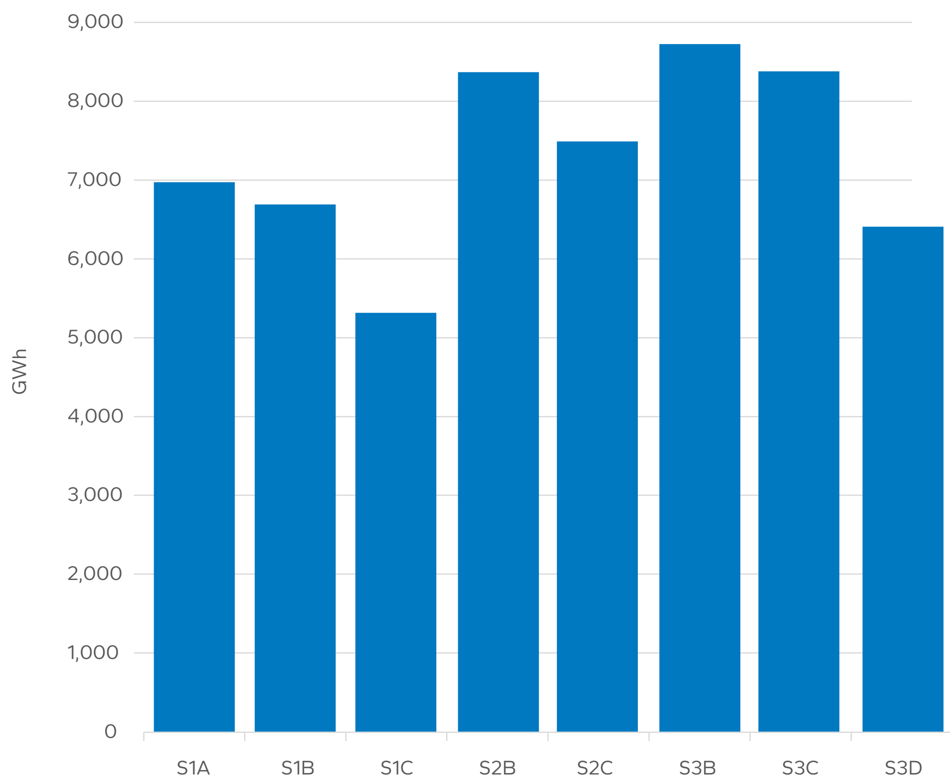


Figure A7.2.24 - Scenarios - Energy imports in 2035 for Drought Condition

2.5.2. Opportunity Exports and Market Participation

Economic energy trades with neighboring markets are a key component of Manitoba Hydro's operations. All surplus electric energy—beyond what is needed for Manitoba's load and firm export contracts—is either:

- Exported to opportunity markets,
- Stored in reservoirs for future use, or
- Spilled if operational constraints prevent it from being exported or stored.

Opportunity exports are limited by the capacity of interconnections, including commitments under firm contracts. Figure A7.2.25 and Figure A7.2.26 present opportunity export volumes under average and drought conditions, respectively. These show that:

- Opportunity exports generally decrease as Manitoba load increases.
- However, a higher share of intermittent resources in the resource mix leads to increased surplus energy, enabling greater opportunity exports to neighboring markets.

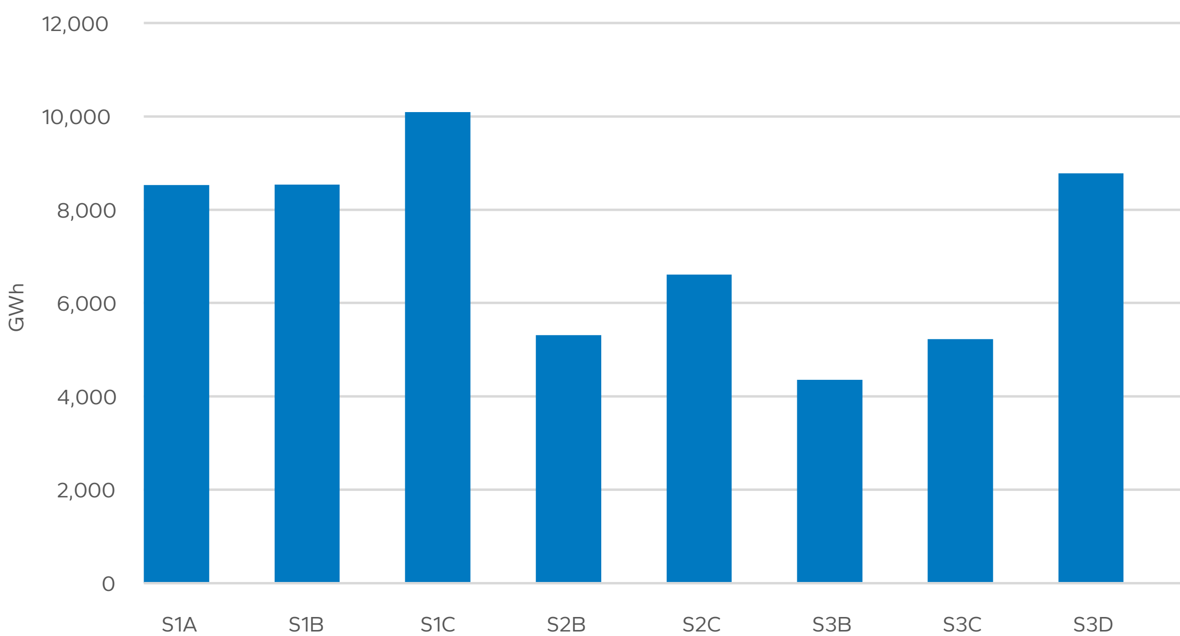


Figure A7.2.25 - Opportunity Export in 2035 Averaged Across All Flow Conditions

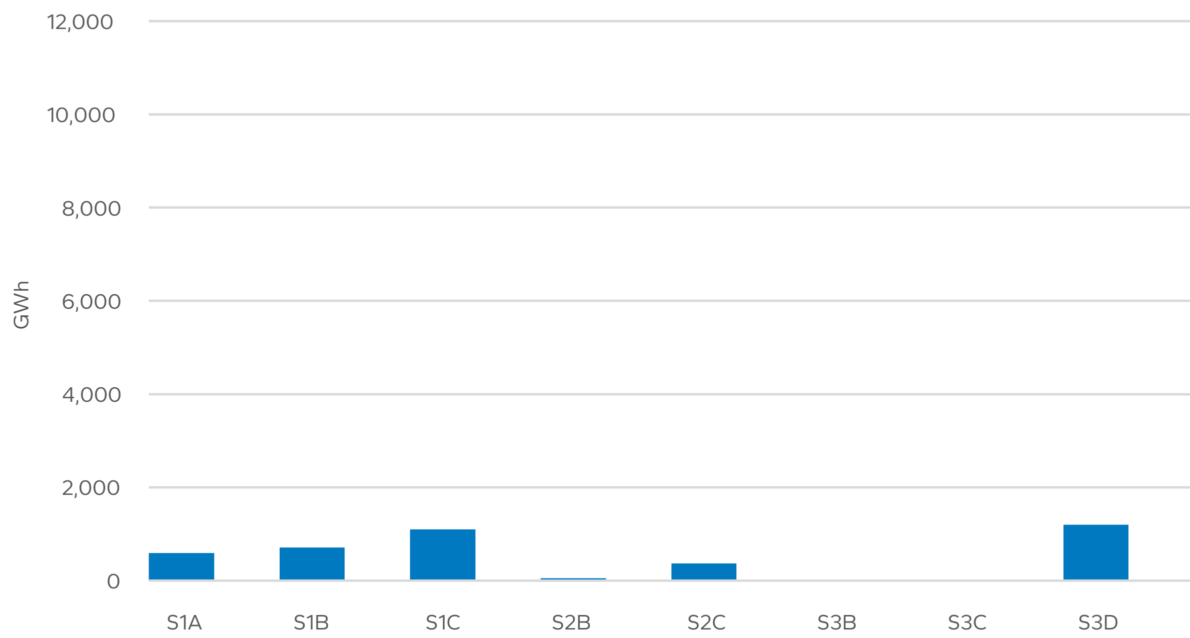


Figure A7.2.26 - Opportunity Export in 2035 for Drought Condition

2.6. Resource Capital Costs

The observations in this section are on the capital investment costs only. The GSPRO model searches for the lowest cost plan which includes both operating and capital investment costs.

Figure A7.2.27 and Figure A7.2.28 illustrate the range in capital costs observed across the scenarios studied. Capital costs include the generator capital cost, generator and transmission fixed operating and maintenance costs, savings from the Investment Tax Credit (ITC) (if applicable), generator interconnection costs, system transmission line upgrades (if applicable), and capital tax for the generator and associated transmission. Capital costs are shown for new resource additions and resources otherwise not included as a base assumption only; the Efficiency Manitoba efficiency plan projection, Demand Response, and Curtailable Rates programs and base assumptions and so no costs are included for these items. Additional EE is not available for selection in the scenarios and so there are also no costs are reported for these programs. In all cases, capital expenditures will be required to develop new resources to meet Manitoba's capacity and energy requirements. Table A7.2.7 and Table A7.2.8 summarize the cumulative capital expenditures to 2035 and 2050.

Note: Wind capital costs included in the total cumulative resource capital costs shown in the figures are for the associated transmission and capital tax. The impact of wind power purchase agreement (PPA) costs are calculated based on the full 25 years of the power purchase agreement.

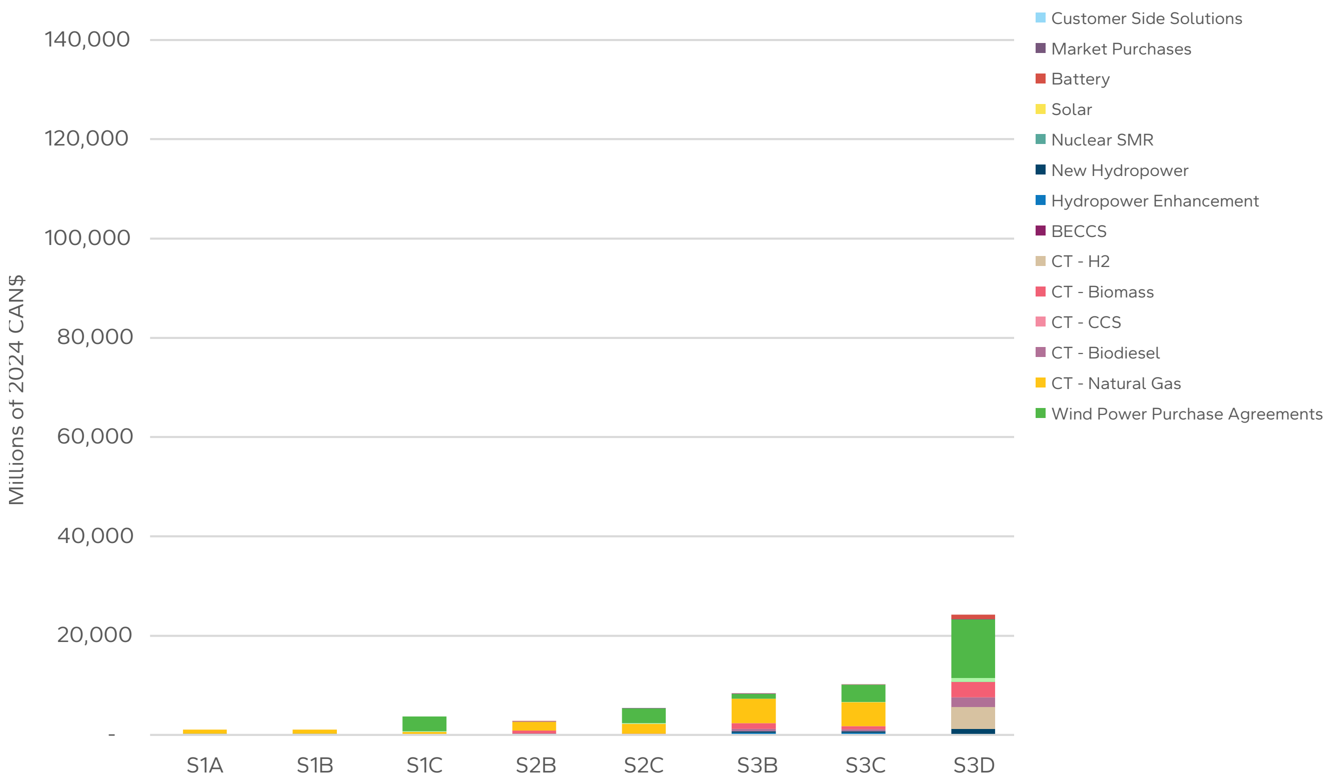


Figure A7.2.27 - Scenarios – Cumulative Resource Capital Costs to 2035

Table A7.2.7 – Scenarios – Cumulative Resource Capital Costs to 2035 (Millions of 2024 CAN$)

	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Additional EE	-	-	-	-	-	-	-	-
SSE	244	244	-	161	161	405	405	161
New Hydropower	-	-	-	71	-	318	318	1,036
CT-H2	-	-	-	-	-	-	-	4,424
CT-BD	-	-	-	25	40	472	432	1,954
CT-Biomass	-	-	-	598	11	1,195	609	3,076
CT/CCCT-NG	851	851	628	1,799	2,032	4,892	4,804	-
Nuclear SMR	-	-	-	-	-	-	-	2
Wind Power Purchase Agreements and Capital Costs	-	-	3,098	-	3,098	960	3,542	12,565
Market Purchases	-	-	-	69	69	69	69	110
Solar	-	-	-	-	-	-	-	1
Battery	-	-	-	73	-	31	8	843
Total	1,095	1,095	3,726	2,727	5,343	8,273	10,118	24,064

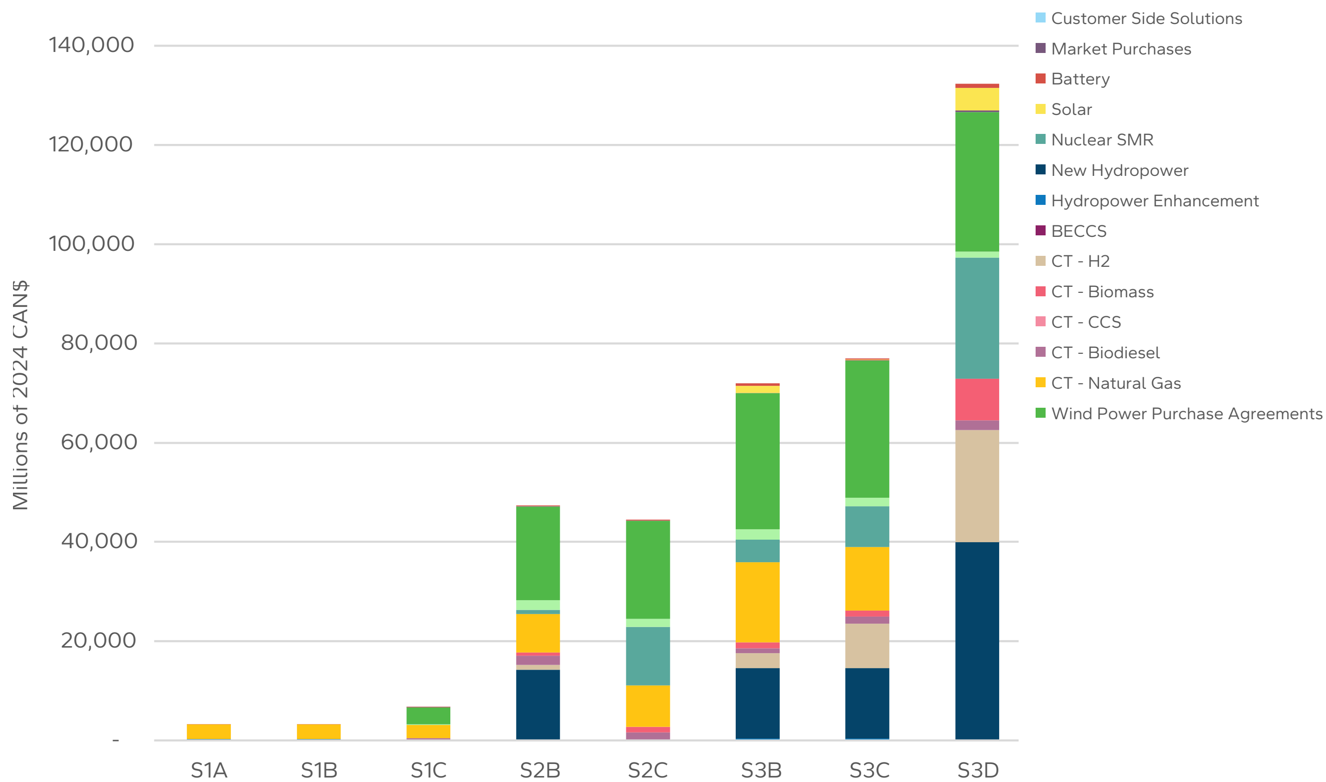


Figure A7.2.28 - Scenarios – Cumulative Resource Capital Costs to 2050

Table A7.2.8 – Scenarios – Cumulative Resource Capital Costs to 2050 (Millions of 2024 CAN$)

	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Additional EE	-	-	-	-	-	-	-	-
SSE	230	230	-	161	161	391	391	161
New Hydropower	-	-	-	14,049	-	14,191	14,191	39,816
CT-H2	-	-	-	973	-	3,038	8,939	22,591
CT-BD	-	-	442	1,919	1,435	958	1,448	1,954
CT-Biomass	-	-	-	600	1,126	1,200	1,183	8,406
CT/CCCT-NG	2,999	2,999	2,676	7,735	8,409	16,158	12,852	-
Nuclear SMR	-	-	-	905	11,753	4,521	8,137	24,371
Wind Power Purchase Agreements and Capital Costs	-	-	3,570	20,762	21,346	29,502	29,394	29,365
Market Purchases	-	-	21	83	83	69	90	262
Solar	-	-	-	73	-	1,459	88	4,581
Battery	76	76	46	112	180	529	307	858
Total	3,305	3,305	6,734	47,291	44,411	71,948	76,928	132,102

2.6.1. Annual Cumulative Capital Cost Observations

Generally, as load grows or restrictions are added, more resources are needed, and capital costs increase. In some scenarios, significantly more resources are needed to account for this. Figure A7.2.29 shows the yearly cumulative growth in capital for each of the load projections and it also shows the majority of the capital for 2-Medium and 3-High load projections will be spent after 2040.

The 2-Medium load projection and 3-High load projection assume a net-zero economy by 2050 and large investments are needed after 2045 to meet negative GHG emissions load. This is especially evident in Scenarios 2B and 2C which have fairly constant load growth until 2045.

Note: wind capital costs included in the total cumulative resource capital costs shown in the figure are for the associated transmission and capital tax. The impact of wind PPA costs are calculated based on the full 25 years of the power purchase agreement

Scenarios 1A and 1B

The portfolio of resources for Scenarios 1A and 1B is the same. The only difference is in the fuel source used post-2034. 1B assumes a net-zero grid by 2035 and this is achieved by switching the fuel type for the natural gas combustions turbines (CT-NG) which causes the operating costs to be higher for 1B, which isn't reflected in Figure A7.2.29.

Scenario 1C

Scenario 1C shows the overall increase in cumulative capital costs due to the additional 600 MW of near-term wind generation projects as compared to 1A and 1B. All three scenarios still need to build almost the same amount of thermal generation to meet capacity needs.

Scenarios 2B and 2C

Figure A7.2.29 shows that the capital investment costs are similar between the 2B and 2C scenarios. Through 2035, Scenario 2C has higher capital investment costs since it includes the 600 MW of near-term wind generation projects. The difference between Scenario 2B and 2C in 2050 is that 2B builds new hydropower generation in 2048 while 2C builds small modular nuclear reactors (SMRs) in 2049 to keep up with the negative GHG emissions load. Building hydropower generation or large amounts of nuclear SMRs near the end of the horizon causes increases in the present value of net system costs. Both scenarios are essentially the same prior to the negative GHG emissions load coming online. These scenarios show how the model can come up with different solutions to meet future load growth.

Scenarios 3B and 3C

The capital investment between Scenario 3B and 3C is also very similar. There are differences in the early years as 3C includes the 600 MW of near-term wind generation projects. Differences post 2035 are related to the model optimizing with and without the near-term wind generation projects. Due to higher load growth, both scenarios need to build hydropower generation. Scenario 3C costs approximately $5B (2024 CAN$) more since nuclear SMRs and hydrogen fuelled combustion turbines (CT-H2) were built instead of CT-NGs.

Scenario 3D

Figure A7.2.29 shows the impact of assuming no fossil fuel-based resources would be allowed post 2034 (Scenario 3D). Large investments in capital are needed to meet the expected load growth without using fossil fuels. These investments would be in hydro supply-side enhancements, new hydropower generation, CT-H2, biomass combustion turbines (CT-biomass), nuclear SMR, wind, solar, and battery.

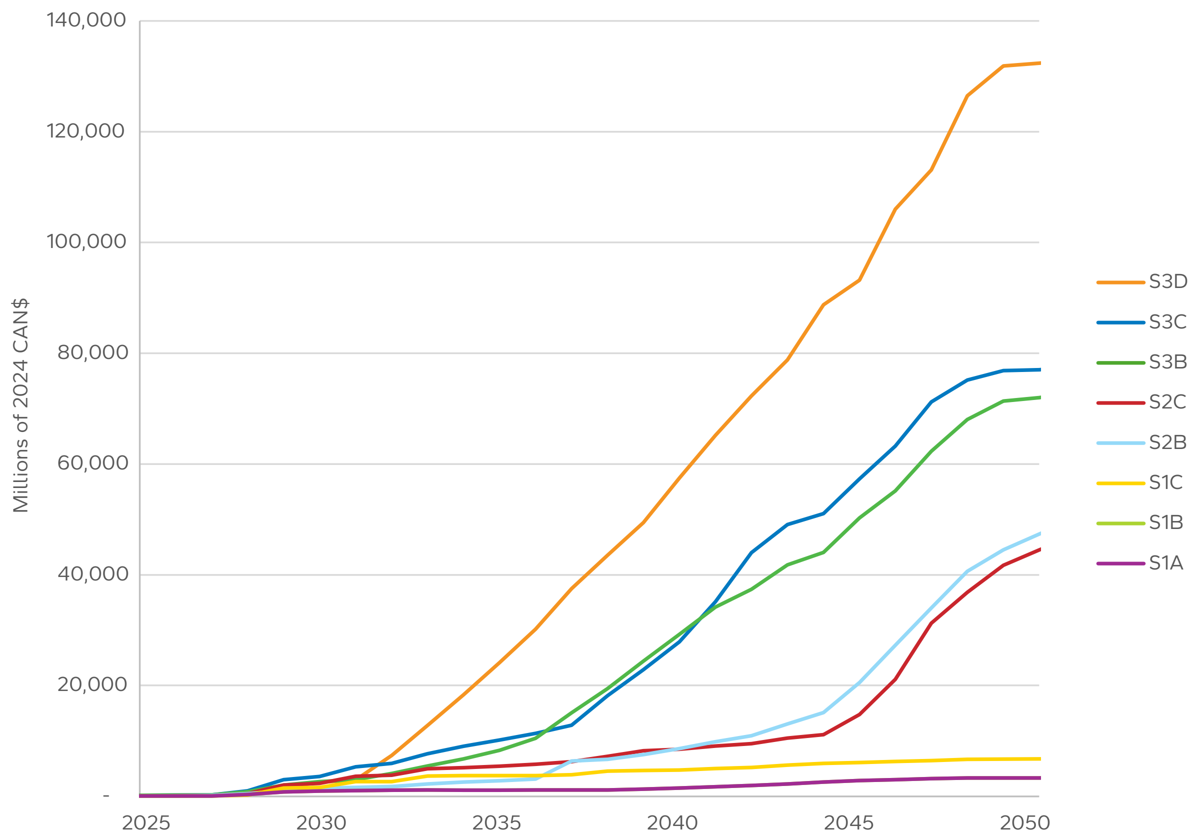


Figure A7.2.29 - Scenarios – Cumulative Resource Capital Costs to 2050 for each Scenario

2.7. Transmission and Distribution Systems Costs

Figure A7.2.30 and Figure A7.2.31 illustrate the costs for the distribution, transmission network upgrades, and generation interconnection infrastructure for each of the IRP scenarios in 2035 and 2050. By 2035, the net present value (NPV) of the costs ranges from $5B to $12B. By 2050, the NPV of the costs ranges from $17B to $66B. In 2035 and 2050, load projections 3B, 3C, and 3D have a step change to meet high load growth and decarbonization through electrification.

Generation interconnection infrastructure costs were included in the model while transmission growth and distribution growth costs were included in post processing.

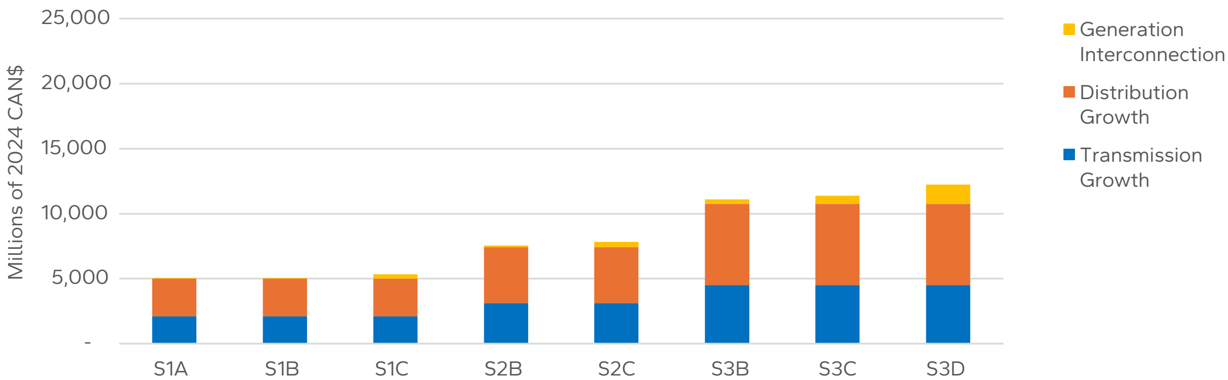


Figure A7.2.30 - Net Present Value of Transmission and Distribution Capital Costs to 2035

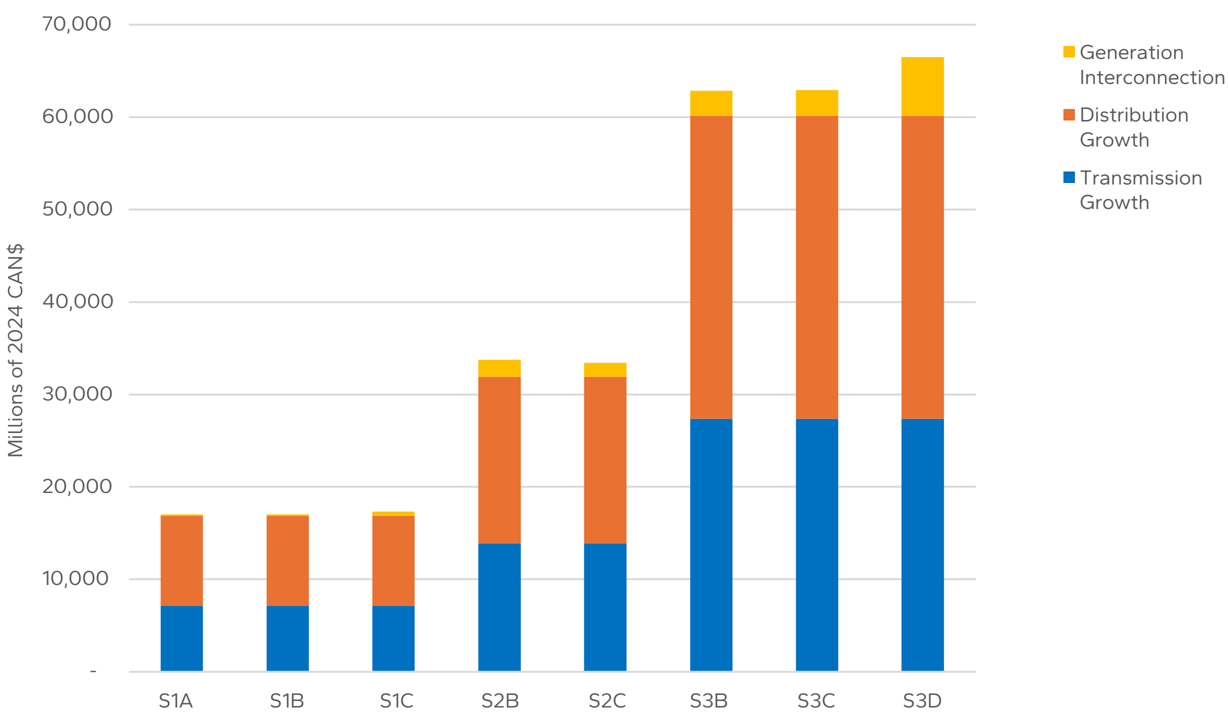


Figure A7.2.31 - Net Present Value of Transmission and Distribution Capital Costs to 2050

2.8. Natural Gas Supply Costs

The 2025 IRP considers natural gas supply costs for Manitoba Hydro's entire natural gas system. These supply costs include those for both utility scale natural gas combustion turbine (CT-NG) generation as well as all other natural gas customers. Considering these costs enables understanding of the various impacts and trade-offs between Manitoba Hydro's two energy delivery systems (natural gas and electricity). Natural gas supply costs are derived based on the natural gas price forecast and include additional costs related to natural gas transportation and storage, as well as estimated GHG emissions pricing.

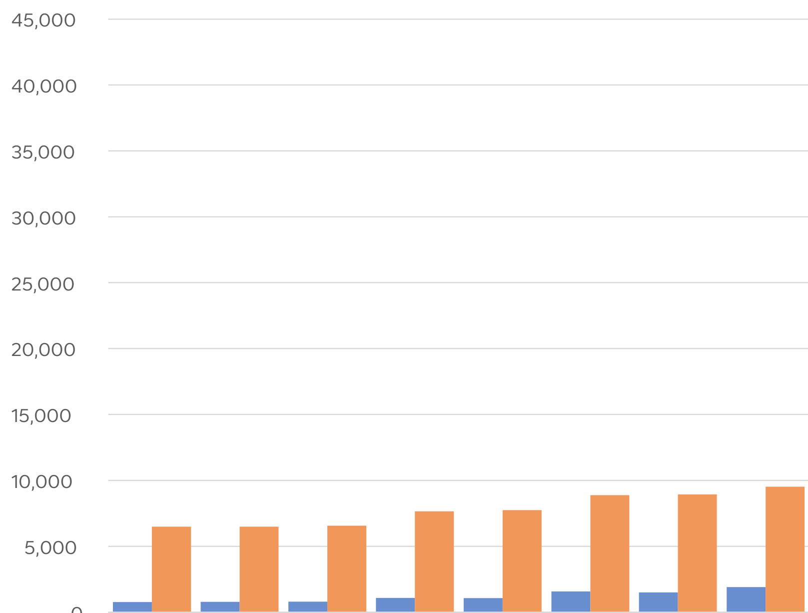
Natural gas supply costs for non-generation customers are accounted for in the financial indicators calculated during post-processing, such as annual and net system costs, and reflect the assumed natural gas consumption of customers in Manitoba specific to each load projection. Note that natural gas supply costs for non-generation customers are ultimately recouped through natural gas rates.

Unlike other customers, natural gas demand related to generation by any new CT-NG added to the system is not included in the load projections. CT-NG fuel demand varies by scenario and is based on the scenario's optimized portfolio of resources and the production costing simulation of the system given that portfolio. Natural gas supply costs are also included in the net system cost financial indicators.

2.9. Annual and Net System Cost

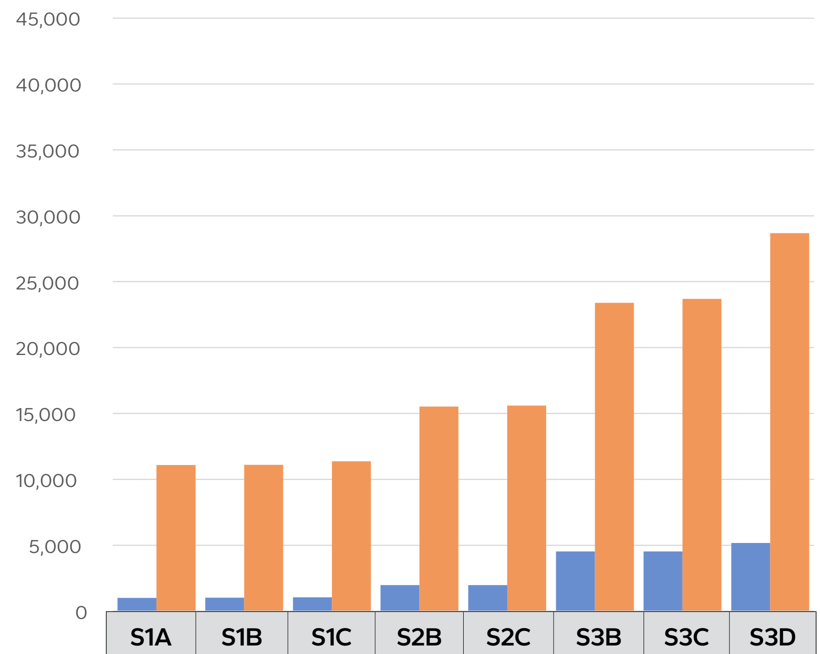
Figure A7.2.32, Figure A7.2.33, and Figure A7.2.34 provide the incremental net system costs for each of the scenarios in the forecast years of 2035, 2045, and 2050 respectively. Each scenario result is stated in terms of both the cumulative present value of net system costs up to that point, as well as the corresponding annual costs in the given year.

Similar to the capital costs, the incremental net system costs tend to be driven upwards mainly by load growth, and to a lesser extent by restrictions on the resource strategy. The incremental cumulative present values of net system costs are roughly $13.5B, $22B, and $34.5B to serve the 1-Baseline, 2-Medium, and 3-High load projections, respectfully, to 2050. The restriction on natural gas combustion turbines (CT-NG) (strategy D) further increases the cost to serve the 3-High load projection to roughly $44B.



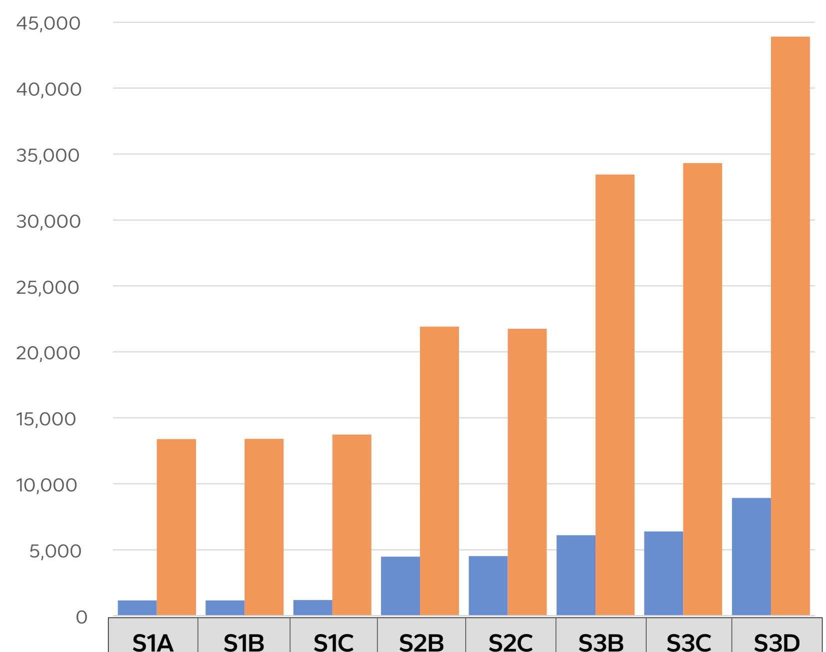
	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Incremental Annual Net System Cost [M$/year]	776	779	802	1,082	1,067	1,579	1,495	1,910
Incremental Cumulative Present Value of Net System Costs [M$]	6,494	6,491	6,562	7,659	7,741	8,884	8,932	9,513

Figure A7.2.32 - Scenarios – Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2035



	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Incremental Annual Net System Cost [M$/year]	1,009	1,017	1,058	1,978	1,973	4,532	4,531	5,178
Incremental Cumulative Present Value of Net System Costs [M$]	11,086	11,099	11,375	15,519	15,598	23,386	23,696	28,676

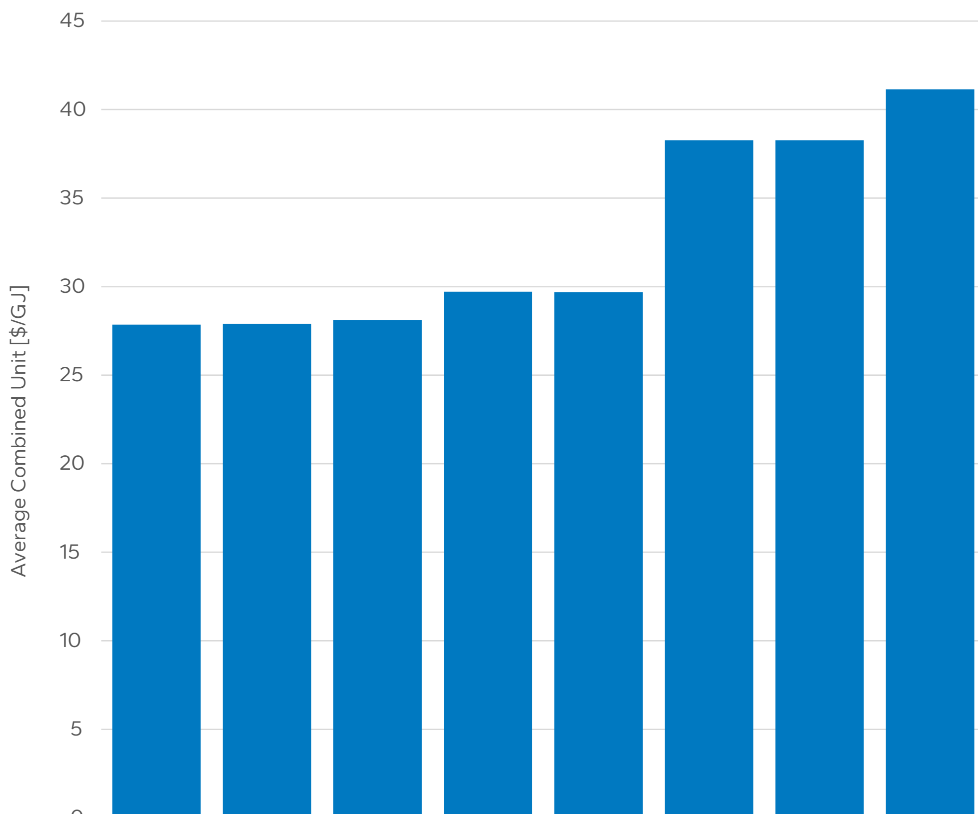
Figure A7.2.33 - Scenarios – Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (in 2045)



	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Incremental Annual Net System Cost [M$/year]	1,162	1,158	1,187	4,477	4,516	6,096	6,389	8,916
Incremental Cumulative Present Value of Net System Costs [M$]	13,382	13,407	13,730	21,909	21,755	33,450	34,307	43,895

Figure A7.2.34 - Scenarios – Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (in 2050)

Figure A7.2.35 illustrates the cost of supplying an average unit of energy (both electric and gas) and shows less of an increase between the 1-Baseline and 2-Medium load projections, while showing a more pronounced increase moving to 3-High load projection. Compared to the 1-Baseline and 2-Medium load projections, the growth in annual peak electrical demand in the 3-High load projection more strongly outpaces the growth in annual electric energy demand. This means that the costs associated with meeting all system planning requirements under the 3-High load projection, including the larger accredited capacity requirements, get spread over a relatively smaller energy base when calculating this economic indicator, resulting in larger costs per unit of energy for the 3-High load projection, as shown in Figure A7.2.35.



S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
27.9	27.9	28.1	29.7	29.7	38.3	38.3	41.1

Figure A7.2.35 - Scenarios – Average Base Combined Energy Unit Requirement (in 2045)

2.10. Greenhouse Gas Emissions Data

As the 2025 IRP studies both a net-zero grid by 2035 and a net-zero economy by 2050 in Manitoba, greenhouse gas (GHG) emissions data presented within this subsection cover both province-wide GHG emissions (economy) and electric generation specific GHG emissions (grid).

2.10.1. Manitoba Provincial GHG Emissions

Figure A7.2.36 presents an estimate of total provincial GHG emissions in Manitoba from 2024 to 2050 under each of the eight scenarios.

Figure A7.2.36 shows similar trend lines for scenarios based on the same load projection. For example, Scenarios S3B, S3C, and S3D all have almost identical provincial GHG emission profiles, even though they represent different resource options strategies. This indicates that regardless of the resource options strategy provincial GHG emissions are primarily influenced by activities in the economy outside of the electricity generation sector. Although the electricity generation sector is essential for supporting GHG emission reductions in other economic sectors (e.g., decarbonization via electrification), the sector itself has a minimal direct contribution to total provincial GHG emissions.

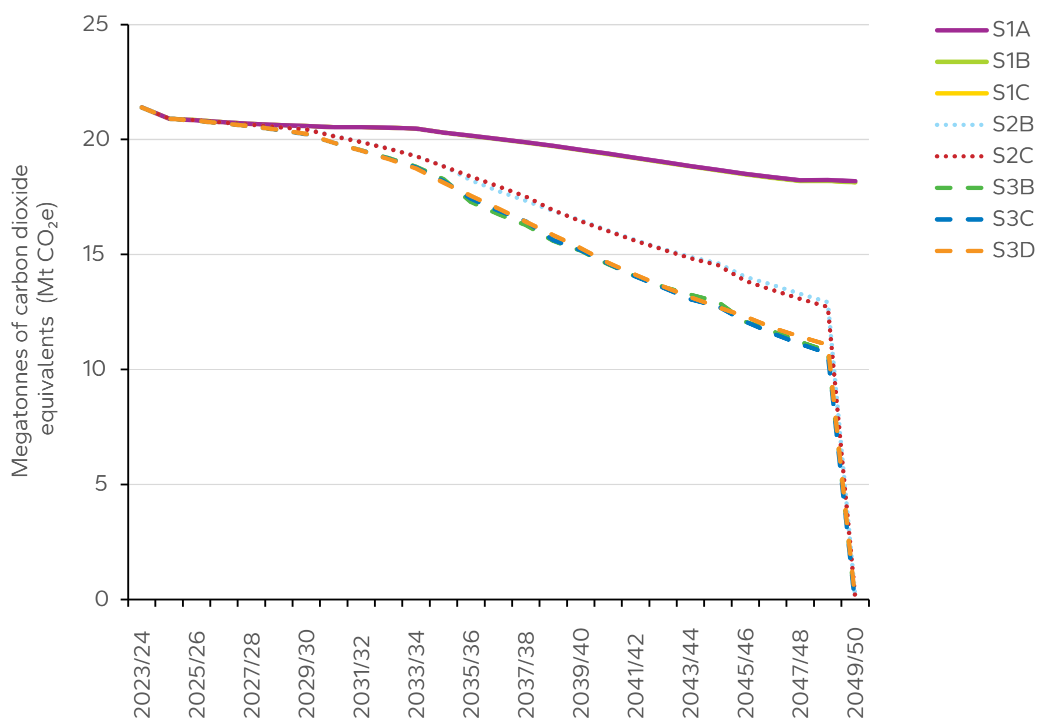


Figure A7.2.36 - Manitoba GHG Emissions by Scenario 2024-2050

For the 2025 IRP, GHG emission results are presented as an average of all flow conditions. Projected GHG emissions could vary in a given year based on weather and other factors. Figure A7.2.37 and Figure A7.2.38 present a detailed Manitoba GHG emissions breakdown in 2035 and 2050 under the average of all flow conditions. For the 2-Medium load projection, compared to current levels of GHG emissions, assumptions in the load projections reduced gross transportation emissions by around 56% and other stationary combustion GHG emissions by around 49% by 2050. For the 3-High load projection, compared to current levels of GHG emissions, assumptions in the load projections reduced gross transportation emission by around 74% and other stationary combustion GHG emissions reduced by around 67% by 2050. With the transportation sector currently contributing to over eight million tonnes CO_2 of provincial GHG emissions, the electrification of transportation is the largest contributor to assumed provincial GHG emissions reductions over the 2024-2050 period. These GHG emissions reductions can be achieved with a relatively modest impact to annual system peak.

Even though assumptions in the load projections resulted in substantial GHG emission reductions across Manitoba's economy, the 2050 chart includes substantial negative GHG emission in order to meet a net-zero economy in 2050 in the 2-Medium and 3-High load projection. Figure A7.2.37 and Figure A7.2.38 also show that while Scenario 3D is the only scenario that precludes the use of natural gas combustion turbines (CT-NG) as a resource option in 2035 and beyond, there are minimal differences in GHG emissions profiles as compared to scenarios that do allow natural gas combustion turbines (CT-NG) (i.e. scenarios S3B, S3C, and S3D).

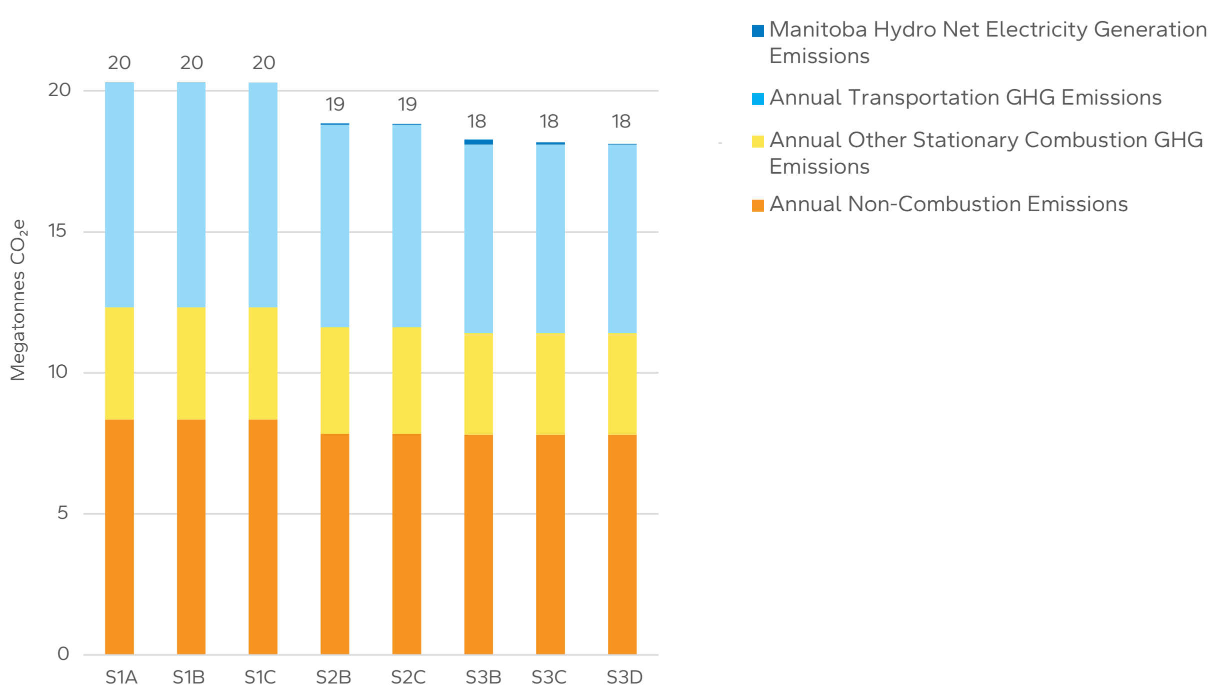


Figure A7.2.37 - Manitoba GHG Emissions by Scenario in 2035

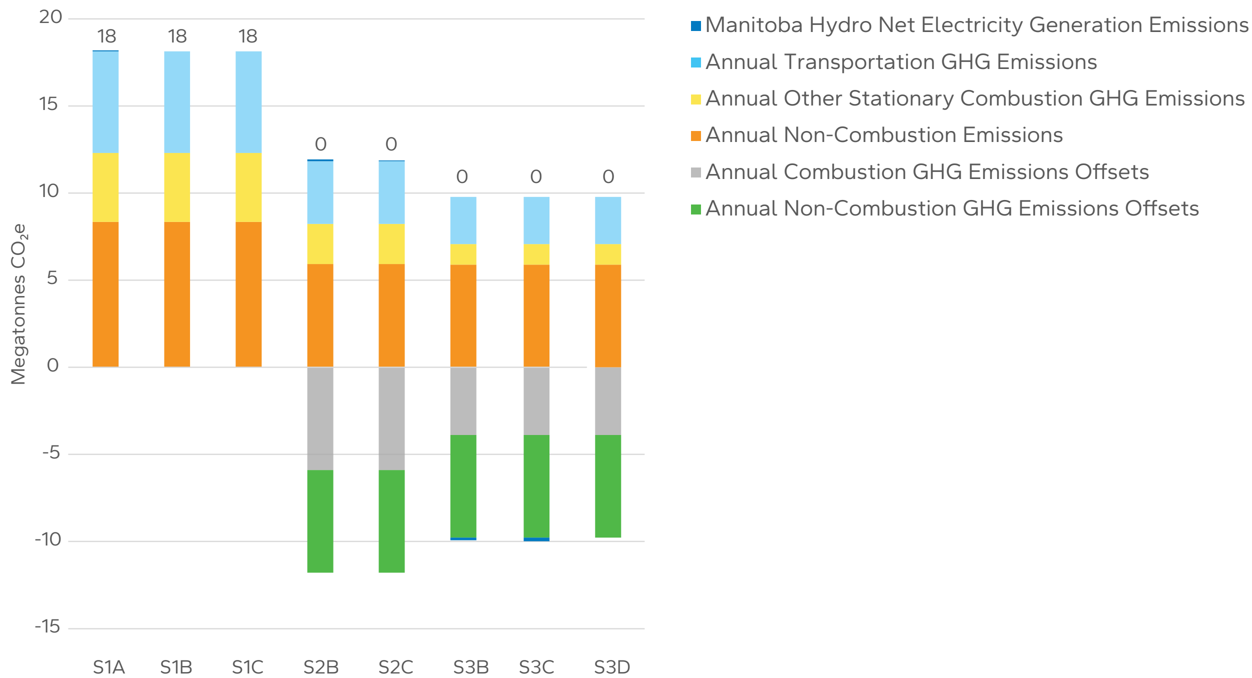


Figure A7.2.38 - Manitoba GHG Emissions by Scenario in 2050

2.10.2. Manitoba Electricity Generation GHG Emissions

All scenarios based on resource options strategies B, C, and D are assumed to achieve a net-zero grid from 2035 onwards and therefore have similar net GHG emission profiles. Figure A7.2.39, Figure A7.2.40, and Figure A7.2.41 detail average net electricity generation GHG emissions for scenarios and are grouped by load projections.

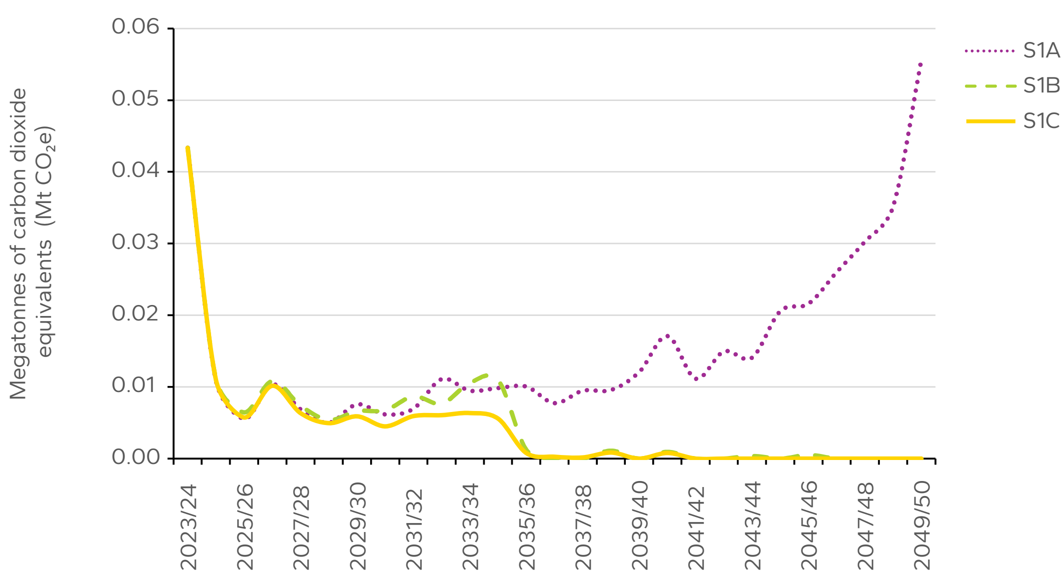


Figure A7.2.39 - S1A, S1B, and S1C Average Net Manitoba Electricity Generation GHG Emissions

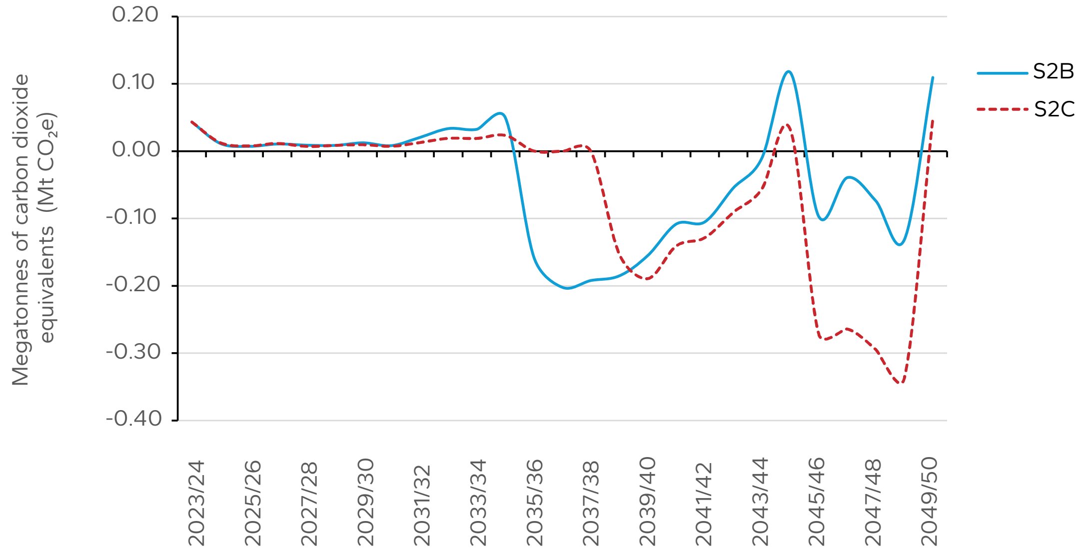


Figure A7.2.40 - S2B, and S2C Average Net Manitoba Electricity Generation GHG Emissions

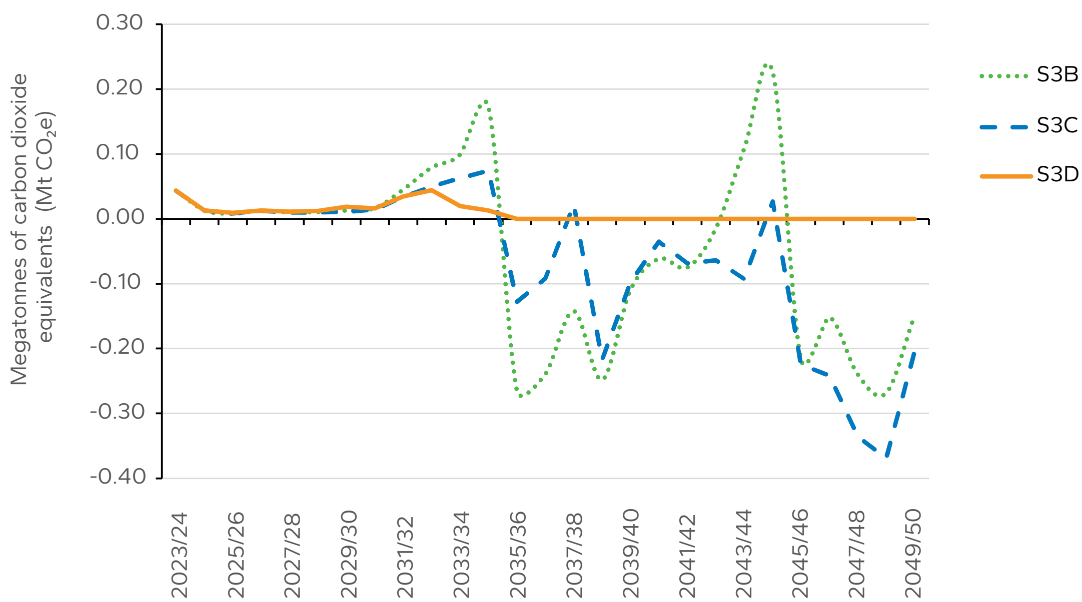


Figure A7.2.41 - S3B, S3C, and S3D Average Net Manitoba Electricity Generation GHG Emissions

The model applied the net-zero grid constraint on an ongoing cumulative basis, not an annual basis. As demonstrated by Figure A7.2.39, Figure A7.2.40, and Figure A7.2.41, certain years may have net Manitoba electricity generation GHG emissions above zero and certain years may have GHG emissions below zero; however, on an ongoing cumulative basis, a net-zero grid was achieved in all scenarios with net-zero grid constraints in 2035. S1A, the only scenario that did not include a net-zero grid requirement, was projected to result in about 15 kilotonnes CO_2e from grid-connected Manitoba electricity generation GHG emissions per year.

Table A7.2.9 further demonstrates how a net-zero grid requirement was achieved on an ongoing cumulative basis. In scenarios with resource options strategies B, C, or D, cumulative net Manitoba electricity generation GHG emissions from 2035-2050 are either negative or, as in the case of S3D, are near-zero.

Table A7.2.9 – Cumulative Net Grid-Connected Manitoba Electricity Generation GHG Emissions Between Select Years by Scenario (Million tonnes CO_2e)

Scenario	Cumulative from 2024-2035	Cumulative from 2035-2050	Cumulative from 2024-2050
S1A	0.09	0.30	0.39
S1B	0.09	0.00	0.10
S1C	0.07	0.00	0.08
S2B	0.20	-1.26	-1.05
S2C	0.14	-1.82	-1.68
S3B	0.48	-1.91	-1.43
S3C	0.30	-2.22	-1.92
S3D	0.23	0.03	0.27

Since S3D assumes no fossil-fuel-based generation from 2035 onwards, no negative GHG emission generation (e.g., bioenergy with carbon capture and sequestration (BECCS)) was required by the model. Similarly, the fuel required for electricity generation in all 1-Baseline load projection scenarios was low enough that the model did not include negative GHG emission generation in its optimized selection – instead, a reliance on the use of and biomethane credit framework was the model's selected pathway to manage GHG emissions from natural gas combustion turbines (CT-NG).

The model selected negative GHG emission generation in the build-out portfolios for S2B, S2C, S3B, and S3C. Once built, these resources are assumed to operate at high (i.e., 83%) baseload utilization factors due to the strong carbon pricing signal resulting from a net-zero grid constraint. The result was cumulative negative Manitoba electricity generation GHG emissions, as the generation portfolio was typically, on average, producing more negative GHG emissions than required to offset the gross electrical generation GHG emissions resulting from the low (utilization factor) operation of the CT-NG.

2.10.3. Net Incremental Regional Electricity Generation GHG Emissions

The net-zero grid requirement only affects Manitoba electricity generation resources; however, future Manitoba Hydro resource build-outs can influence regional (non-Manitoba) electricity generation GHG emissions throughout the entire interconnected region. Table A7.2.10 presents cumulative net incremental regional electricity generation GHG emissions – the values are all negative as they represent avoided[3] GHG emissions.

In all scenarios, cumulatively over the study horizon, Manitoba continues to support GHG emission reductions outside of the province through the net export of electricity but Manitoba Hydro cannot claim these GHG emission reductions as they are attributed to non-Manitoba utilities. However, to serve the negative GHG emissions load requirement in 2050 for both the 2-Medium and 3-High load projections, Manitoba becomes a net importer of electricity (under the modelling constraints and set-up used for the 2025 IRP). Therefore, in scenarios using the 2-Medium and 3-High load projections, the cumulative net incremental regional electricity generation GHG emissions increase (i.e., avoided GHG emissions decrease) relative to the 1-Baseline load projection.

In addition to the load projections considered, the resource options strategies also influence cumulative net incremental regional electricity generation GHG emissions. In instances of common load projections, resource options strategy C resulted in more cumulative net regional avoided electricity generation GHG emissions. This is consistent with Manitoba Hydro's understanding that the GHG benefits of advancing non-emitting generation projects are largely realized outside of the province, especially in the near-term.

[3] Note: Cumulative net incremental regional electricity generation GHG emissions are not negative GHG emissions in that way the bioenergy carbon capture and sequestration (BECCS) generates negative GHG emissions. It is expressed as a negative in the Table to demonstrate reductions from a baseline where the extra-provincial electricity demand was served by fossil-fuel generation resources and not from exported electricity from Manitoba.

A similar conclusion can be drawn when comparing resource options strategy D with both B and C under the 3-High load projection. As more baseload and variable energy generation resources are added (e.g., small modular nuclear reactors (SMRs) and new hydropower), there is more surplus electricity available for net-export (on average). This is directly reflected by the significant increase in cumulative net regional avoided electricity generation GHG emissions between resource options strategies D and C, under the 3-High load projection.

While resource option strategies are projected to have only a modest impact on Manitoba electricity generation GHG emissions, they may have meaningful impacts on regional (non-Manitoba) electricity generation GHG emissions.

Table A7.2.10 – Cumulative (2024-2050) net incremental regional electricity generation GHG emissions

Scenario	Load Projection	Cumulative net incremental regional electricity generation GHG emissions from 2024 to 2050 (Million tonnes CO_2e)
S1A	1-Baseline load projection	-138
S1B	1-Baseline load projection	-137
S1C	1-Baseline load projection	-168
S2B	2-Medium load projection	-77
S2C	2-Medium load projection	-89
S3B	3-High load projection	-83
S3C	3-High load projection	-89
S3D	3-High load projection	-177

3 | Sensitivity Results

Sensitivities are used to test the potential impact of an isolated assumption change on scenario results. This section provides results for each of the sensitivities studied as part of the 2025 IRP, including a review of the sensitivity's objective, methodology, and key findings.

3.1. Energy Market Prices

3.1.1. Objective

Low and high energy market prices were explored to test the impact on the portfolio of resources selected under the 1-Baseline and 3-High load projections, both with and without the 600 MW of near-term wind generation projects.

3.1.2. Key Takeaways

- The amount of combustion turbines (CT) (natural gas (CT-NG) and biodiesel (CT-BD)) added in all cases by 2050 is consistent between sensitivities for the same load projection, indicating combustion turbines are being built to meet capacity needs and are not influenced by the energy market price.
- The economics of wind is sensitive to the energy market prices.
- The profitability of wind is speculative based on the ability to sell the energy outside the province and the price that is expected to be achieved.
- For the 1-Baseline load projection with low energy market prices, wind is not built unless near-term wind additions are assumed. With high market prices, some additional wind beyond the near-term additions is built in the 2030s and 2040s.
- Generally, low market prices result in reduced net exports, while high market prices result in increased net exports.
- Manitoba electricity generation GHG emissions are not meaningfully impacted by energy market prices under the 1-Baseline load projection.
- Changes in Manitoba electricity generation GHG emissions under the 3-High load projection were generally small, ranging from -64 to 6 thousand tonnes of CO_2e for most sensitivities. The potential for more significant changes in Manitoba electricity generation GHG emissions was observed in 2035 when the amount of bioenergy carbon capture and sequestration (BECCS) in the system was affected, and in 2050 when the system includes significantly different amounts of non-emitting, higher-utilization factor resources, such as wind.

- The largest reductions in net incremental regional (non-Manitoba) electrical generation GHG emissions are seen in the high energy market price sensitivities when compared to their base cases.
- High market prices generally reduce annual net system costs and PVs of net system costs by 2035 and 2050. This result is driven by increased net revenue from opportunity export sales under higher market prices. Low market prices have comparatively little implications for financial indicators.

3.1.3. Methodology

Spring 2024 Energy Price Forecast low and high price sensitivities were applied to the 1-Baseline (1B and 1C) and 3-High (3B, and 3C) load projections. Results were compared to the base scenarios, which assumed reference pricing.

Exploring high and low energy price sensitivities provides an indication of the range of future export revenue that can be expected due to energy price uncertainty. The high and low energy price sensitivities are developed using sensitivity cases from the US Department of Energy's Energy Information Administration's (EIA) 2023 Annual Energy Outlook.[4] The difference between EIA's reference case and the High/Low "oil and gas supply" case are taken and that differential is applied to Manitoba Hydro's consensus natural gas price. Those high and low gas cases are then multiplied by the consensus forecast's Implied Heat Rate (IHR)[5] fundamentals-based high and low energy price case for on- and off-peak energy.

For this sensitivity, it was assumed additional energy efficiency was not available.

3.1.4. Results

Figure A7.2.42 and Figure A7.2.43 show the cumulative capacity additions in 2035 and 2050 for each of the sensitivities compared to the scenarios. Across each load projection, approximately the same amount of thermal capacity is built in the low, reference, and high cases. This indicates a need for dispatchable capacity in the Manitoba Hydro system that is uninfluenced by energy market prices.

Low Energy Market Prices

1-Baseline Load Projection

Wind is sensitive to energy market prices, as excess energy can be sold in the export market; the economics of new wind additions under the 1-Baseline load projection is influenced by the opportunity export revenues that can be achieved. By 2035 and 2050, sensitivity 1B Low Energy Prices does not add any additional wind and sensitivity 1C Low Energy Prices does not add additional wind beyond the assumed 600 MW of near-term wind additions.

[4] EIA Annual Energy Outlook 2023: https://www.eia.gov/outlooks/archive/aeo23/

[5] Implied Heat Rate: https://www.eia.gov/tools/glossary/index.php?id=I

For sensitivity 1C Low Energy Prices compared to Scenario 1C, by 2050 there is a difference in the proportions of combustion turbine types built but no meaningful difference in the total quantity. Scenario 1C, which included 100 MW more installed wind capacity and a market purchase, added one CT-BD for a combined total of 1,720 MW of added CT-NG and CT-BD. The 1C Low Energy Prices sensitivity included two CT-BD units, for a combined total of 1,780 MW of CT-NG and CT-BD. These results show that dispatchable capacity from combustion turbines, regardless of fuel supply type, is needed in the Manitoba Hydro system no matter what the energy market price is.

3-High Load Projection

Comparing Scenario 3C to its low-market-price sensitivity in 2035 shows that the model builds approximately 2,000 MW of combustion turbines and only 100 more MW of wind generation, regardless of market prices. A similar result is seen when looking at Scenario 3B. This again shows the value the model places on dispatchable capacity.

As the load continues to grow to 2050, the model adds significant amounts of combustion turbines, hydropower and/or small modular nuclear reactors (SMRs), and wind and/or solar. By 2050, the model has built approximately the same amount of combustion turbines as wind or solar in each of the 3-High load projection cases. By 2050, there is no consistent impact from low market prices across the S3B and S3C sensitivities. The need to meet increasing demand dampens market signals during capacity expansion optimization, and alternative long-term capacity expansion planning strategies that satisfy optimization requirements in 2050 are also evident. However, the 3C Low Energy Price sensitivity confirms wind can become less competitive under low energy prices.

High Energy Market Prices

With high energy market prices, the model tends to select more wind in 2035 as there is an increased benefit from selling excess energy on the export market. This is the case under both the 1-Baseline and 3-High load projection. Even with additional wind selected, the model still needs to build thermal dispatchable capacity resources. By 2050, the influence of high energy market prices on wind selection is overshadowed in the 3-High load projection cases by the need to meet increased demand, although a preference for more high-capacity-factor nuclear SMRs and less combined-cycle combustion turbine with carbon capture and sequestration (CCCT-CCS) and hydrogen fuelled combustion turbine (CT-H2) is observed. This suggests that when the model needs to add a lot of new capacity to the system to meet demand, it will include more base-loaded generating resource options if there is an economic signal to do so. Under the 1-Baseline load projection, increased market prices lead to increased wind additions by 2050 under resource option strategy B, but not under resource options strategy C, indicating that wind may become a more competitive option for serving mild long-term growth in demand, but this finding is not conclusive. Combustion turbines remain a dominant source of capacity.

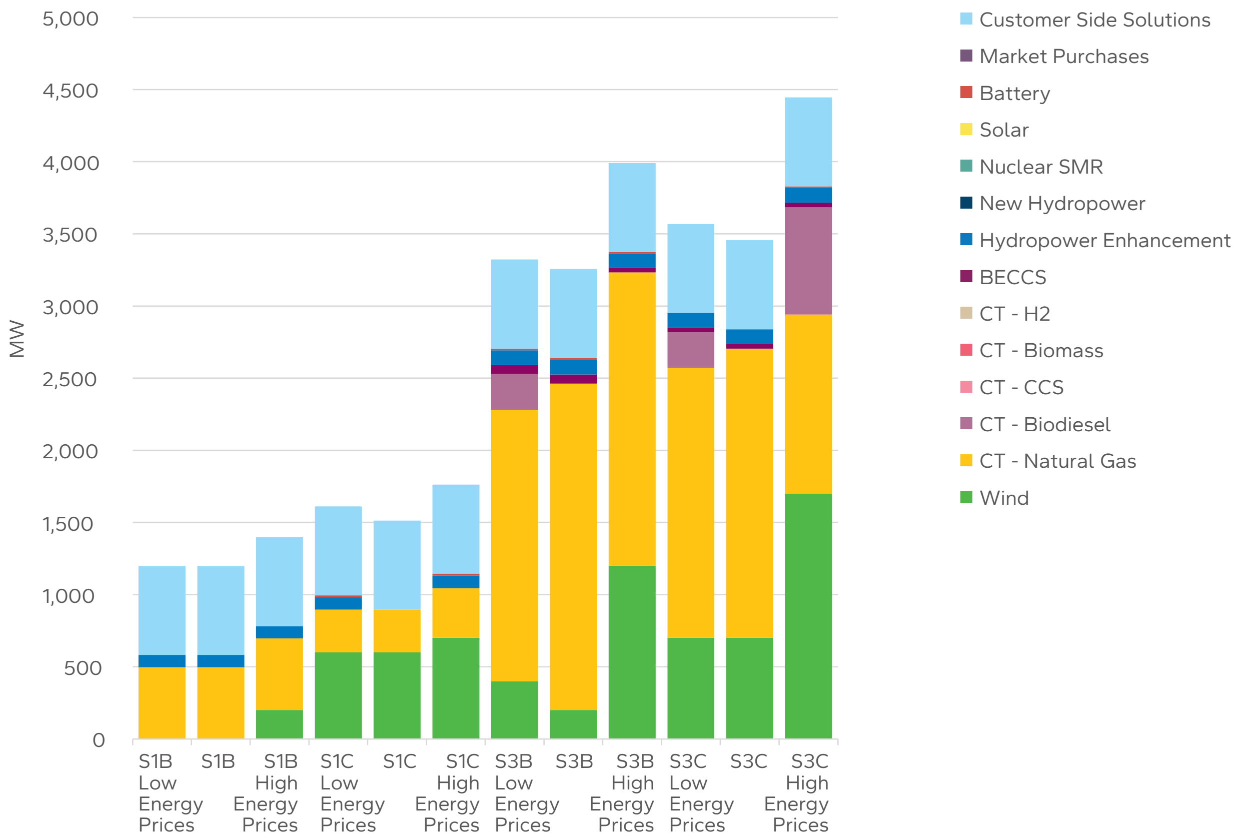


Figure A7.2.42 - Sensitivities - Energy Market Prices: Cumulative Installed Capacity [MW] Additions by Resource Type by 2035

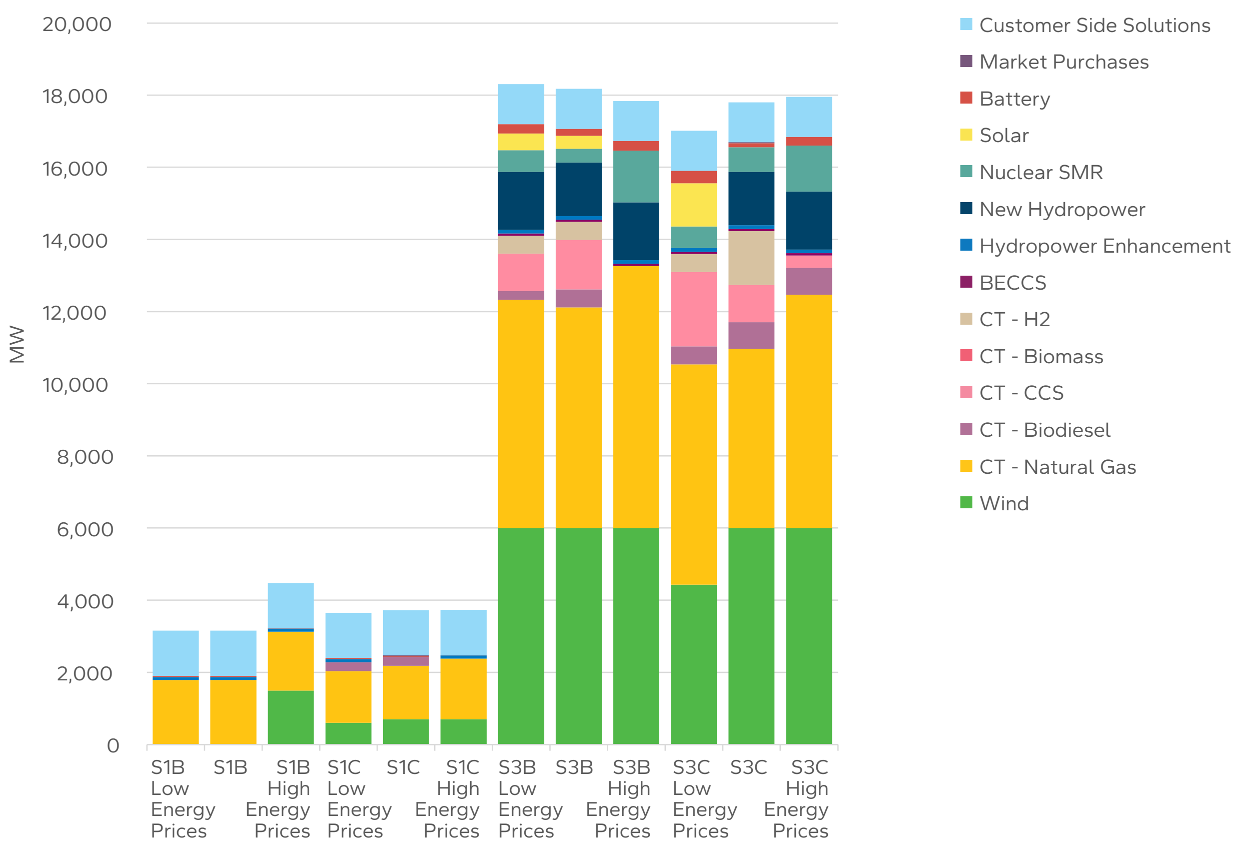


Figure A7.2.43 - Sensitivities - Energy Market Prices: Cumulative Installed Capacity [MW] Additions by Resource Type by 2050

Market Activity

Energy market prices have a direct effect on net market activity, as demonstrated in Figure A7.2.44 Net market activity is captured in the figures by net exports, which is calculated as average opportunity exports less imports (both physical and financial settlements). As shown, the 1-Baseline load projection cases have less demand to meet and higher amounts of net exports overall, than under the 3-High load projection. Generally, low market prices result in reduced net exports, while high market prices result in increased net exports. The 3B Low Energy Prices sensitivity is an exception. Compared to Scenario 3B, this sensitivity has more added wind in 2035 and more base-loaded nuclear SMRs and solar (which assumes a set generation profile) in 2050, resulting in increased net exports even under low energy market prices as these resources generate with indifference to energy market price signals. Figure A7.2.44 also shows that by 2050, the bolstering effect of high energy prices on net exports shifts Manitoba Hydro from being a net importer to being a net exporter under a 3-High load projection.

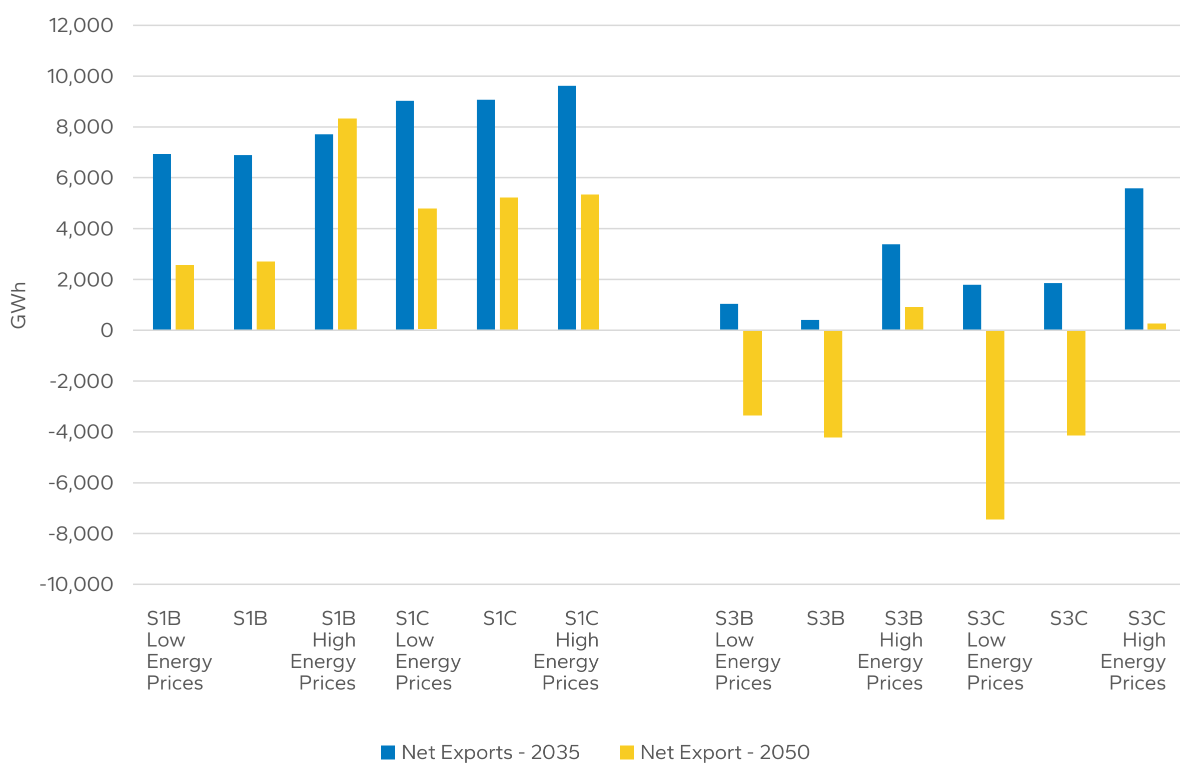


Figure A7.2.44 - Energy Market Prices – Effect of Energy Price on Net Exports

GHG Emissions

Figure A7.2.45 and Figure A7.2.46 show the impact of energy prices on annual MH electricity generation GHG emissions, transportation generation GHG emissions, and stationary combustion GHG emissions.

In 2035, market prices do not meaningfully impact Manitoba electricity generation GHG emissions under the 1-Baseline load projection scenarios, with all changes being less than 1 thousand tonnes CO_2e.

Under all the 3-High load projection scenarios, bioenergy with carbon capture and sequestration (BECCS) is added to the system in 2035, resulting in Manitoba electricity generation GHG emission becoming net-negative. Energy price implications generally remain small under the 3-High load projections, with sensitivity results differing from the scenarios by -13 to 6 thousand tonnes of CO_2e, except for the 3B High Energy Price sensitivity. In this case, less BECCS is added to the system in 2035, resulting in net Manitoba electricity generation GHG emissions being 137 thousand tonnes of CO_2e higher than 3B (but, still net-negative).

By 2050, Manitoba electricity generation GHG emissions are net-zero for the 1-Baseline cases. For the 3-High load projection cases, low energy market prices reduce Manitoba electricity generation GHG emissions by 64 thousand tonnes of CO_2e under strategy B, but increase them by 236 thousand tonnes of CO_2e under strategy C. These results directly reflect changes to the portfolios of resources resulting from the different energy market price assumptions, and the corresponding operation of those systems; the average utilization factor for all fossil-fuel burning combustion turbines in 2050 in the 3B Low Energy Price sensitivity is reduced by 0.08% compared to Scenario 3B, whereas the 3C Low Energy Price sensitivity, which includes less wind additions than the 3C scenario, shows an increase of 0.06%. While these changes in average utilization factor are small, they are sufficient to influence the GHG emissions outcomes. High energy market prices applied to the 3-High load projection result in consistent reductions in Manitoba electricity generation GHG emissions, ranging from 28 to 17 thousand tonnes of CO_2e.

Note that Figure A7.2.46 shows positive Manitoba electricity generation GHG emissions for the 3C Low Energy Price sensitivity in 2050. The model does constrain to achieve a net-zero grid from 2035 onwards; however, it is achieved over a multi-year window, which is the case for 3C Low Energy Price sensitivity (over the 2045-2050 timeframe, the result would be -165 thousand tonnes of CO_2e).

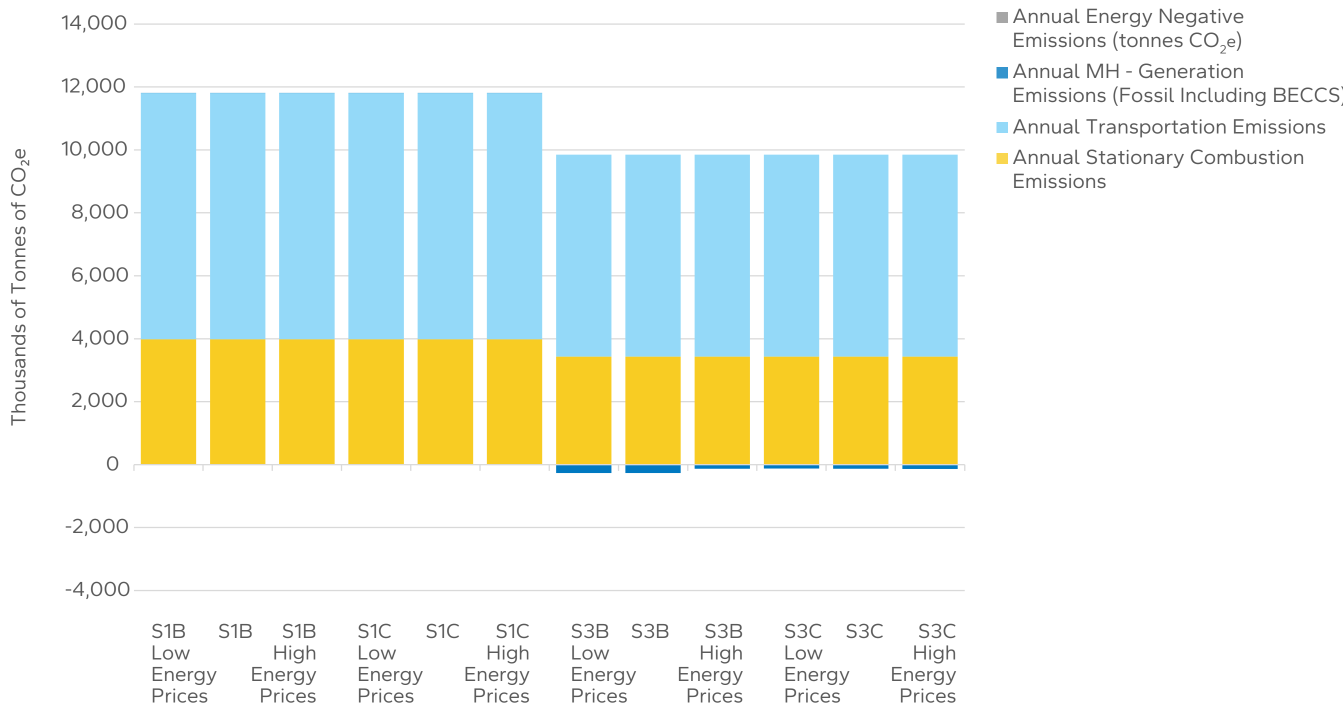


Figure A7.2.45 - Sensitivites - Energy Market Prices: Annual MH Electricity Generation GHG Emissions, Transportation GHG Emissions, and Stationary Combustion GHG Emissions by 2035

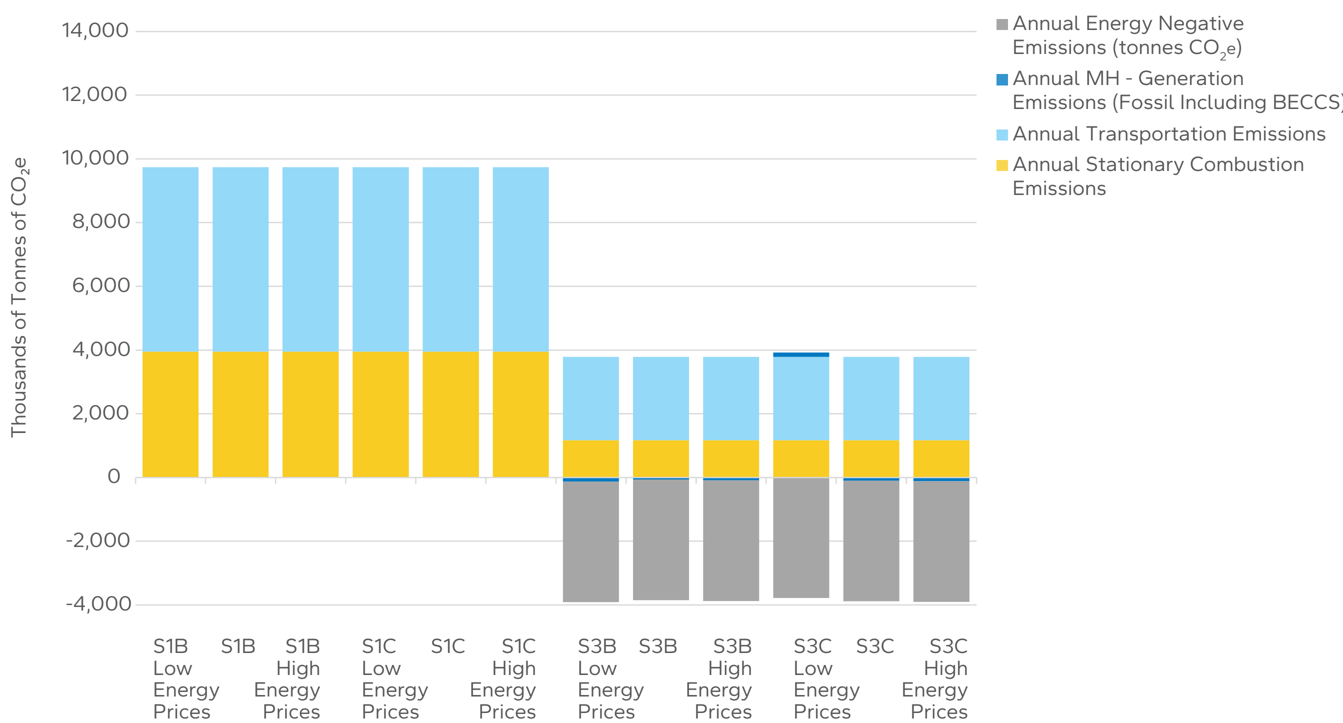


Figure A7.2.46 - Sensitivites - Energy Market Prices: Annual MH Electricity Generation GHG Emissions, Transportation GHG Emissions, and Stationary Combustion GHG Emissions by 2050

Net incremental regional (non-Manitoba) electricity generation GHG emissions are shown in Figure A7.2.47. These results are closely linked to the net export results presented in in Figure A7.2.44. Increased net exports under the 1-Baseline load projection led to greater reductions in net incremental regional (non-Manitoba) electricity generation GHG emissions compared to 3-High load projection results. Generally, energy market prices have a much more significant impact on non-Manitoba electricity generation GHG emissions than Manitoba electricity generation GHG emissions.

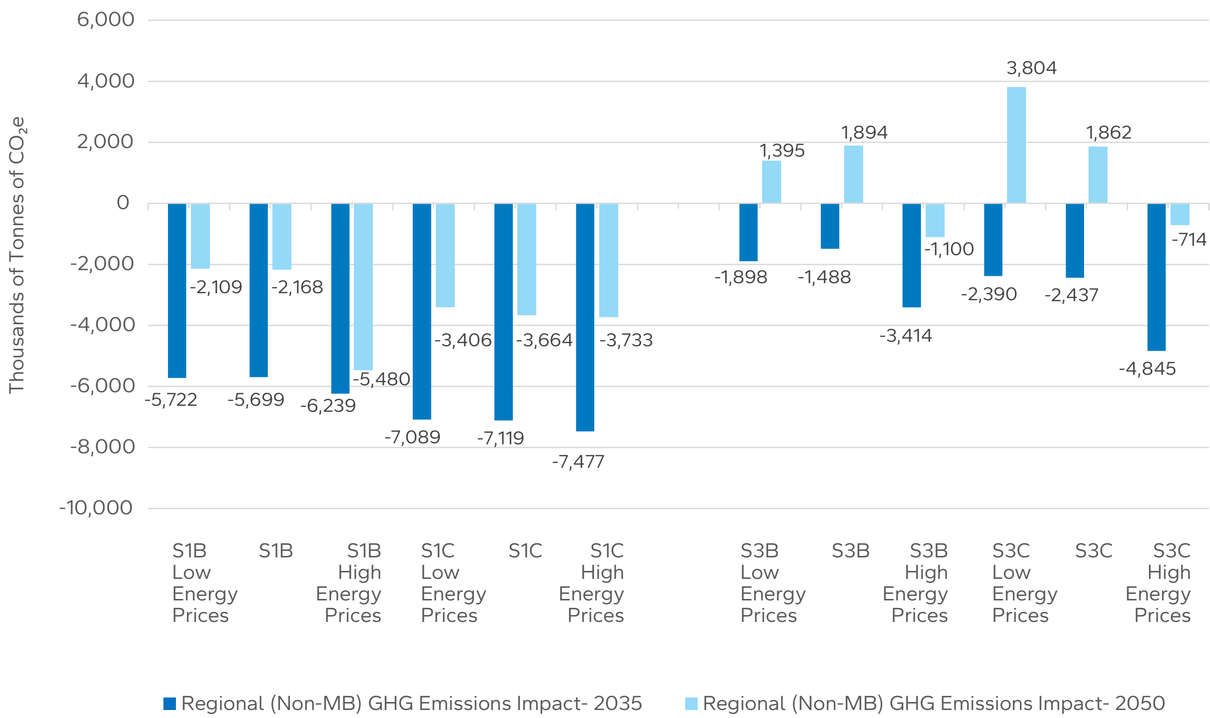


Figure A7.2.47 - Energy Market Prices – Net Regional Electricity Generation GHG Emissions

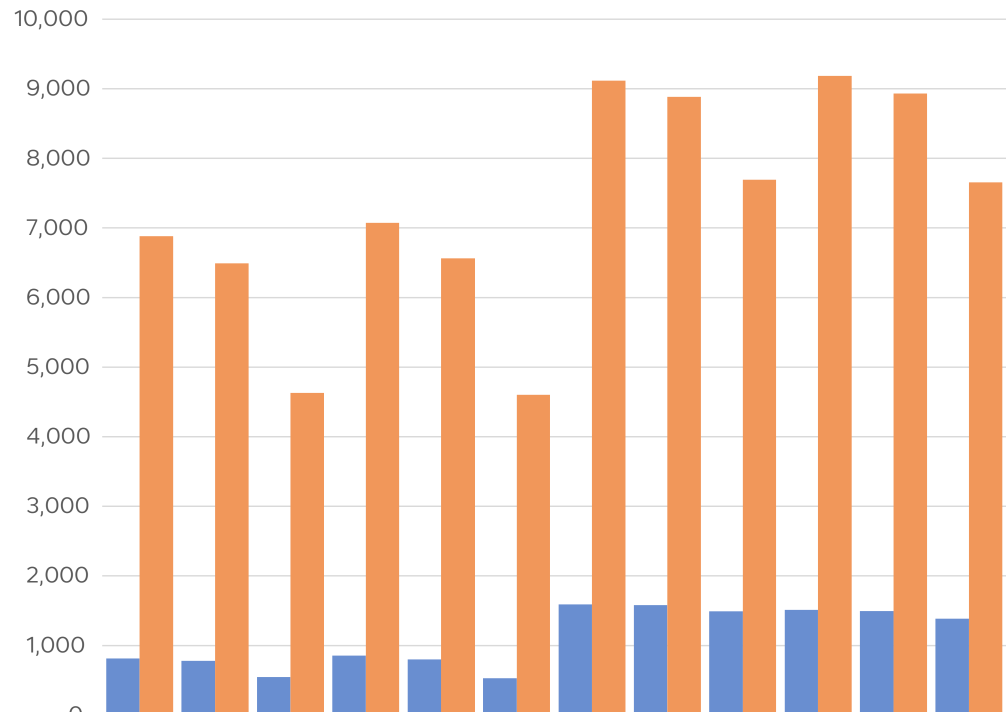
Annual Net System Cost and Present Value of Net System Costs

Figure A7.2.48 and Figure A7.2.49 show the impact on incremental annual net system costs in 2035 and 2050.

For the 1-Baseline and 3-High load projections in 2035 and 2050, low energy market prices do not significantly change the annual system costs. High energy market prices tend to lower the incremental annual system costs as more energy is sold on the export market. An exception is the 3B High Energy Prices sensitivity in 2050, which results in incremental annual net system cost that are slightly higher than the 3B scenario's costs, primarily because the model adds significant amounts of nuclear SMRs in 2049 causing the increase in incremental annual net system costs seen in 2050.

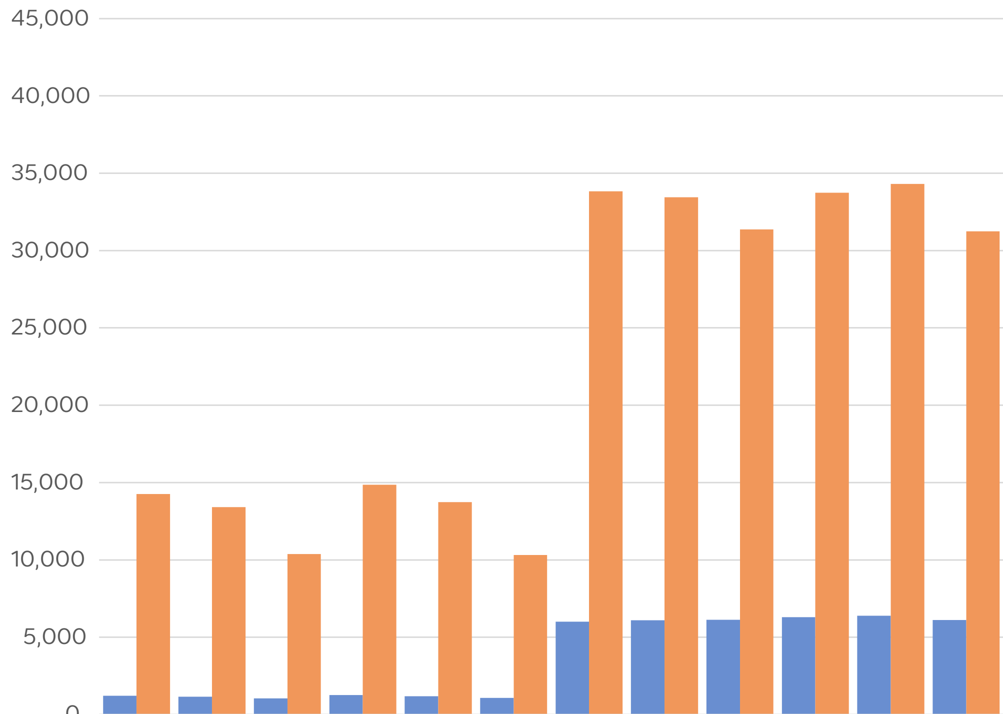
Figure A7.2.48 and Figure A7.2.49 also show the incremental present value of net system costs. For the 3-High load projection, most capital will be spent after 2040.

Similar to incremental annual net system costs in 2035 and 2050, sensitivities with high energy prices have a lower net system cost as excess wind energy is available to sell on the export market.



	S1B Low Energy Prices	S1B	S1B High Energy Prices	S1C Low Energy Prices	S1C	S1C High Energy Prices	S3B Low Energy Prices	S3B	S3B High Energy Prices	S3C Low Energy Prices	S3C	S3C High Energy Prices
Incremental Annual Net System Cost [M$/year]	813	779	546	855	802	532	1,590	1,579	1,492	1,511	1,495	1,385
Incremental Cumulative Present Value of Net System Costs [M$]	6,880	6,491	4,631	7,073	6,562	4,601	9,117	8,884	7,691	9,184	8,932	7,654

Figure A7.2.48 - Sensitivities - Energy Market Prices: Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2035



	S1B Low Energy Prices	S1B	S1B High Energy Prices	S1C Low Energy Prices	S1C	S1C High Energy Prices	S3B Low Energy Prices	S3B	S3B High Energy Prices	S3C Low Energy Prices	S3C	S3C High Energy Prices
Incremental Annual Net System Cost [M$/year]	1,218	1,158	1,050	1,267	1,187	1,071	6,006	6,096	6,132	6,302	6,389	6,117
Incremental Cumulative Present Value of Net System Costs [M$]	14,253	13,407	10,372	14,855	13,730	10,317	33,829	33,450	31,363	33,740	34,307	31,246

Figure A7.2.49 - Sensitivities - Energy Market Prices: Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2050

3.2. High Capital Costs

3.2.1. Objective

This section evaluates the impact of high capital costs on generation buildouts under three load projections:

- 1-Baseline load projections,
- 2-Medium load projections, and
- 3-High load projections.

The high capital cost assumptions applied in these sensitivities capture technology-driven cost impacts and are not intended to include project execution or market uncertainty cost implications. Each projection is analyzed with and without the inclusion of 600 MW of near-term wind generation projects.

3.2.2. Key Takeaways

- The amount of wind generation selected is sensitive to capital cost assumptions.
- In sensitivities with higher capital costs, natural gas fueled combustion turbines (CT-NG) remain the most cost-effective modular firm capacity resource.
- Elevated capital costs influence both the timing and type of generation selected.
- Under 2-Medium and 3-High load projections, most capital expenditures occur post-2040.
- With increased capital costs, the model will tend to avoid overbuilding and selects smaller dispatchable capacity units which results in a portfolio of resources that simultaneously meets the load forecast and planning requirements, defers larger and more capital-intensive units, and results in a lower cost plan.

3.2.3 Methodology

- High capital cost assumptions were applied to all generation types simultaneously in scenarios 1B, 1C, 2B, 2C, 3B, and 3C. High capital cost values are compared against reference values for 2035 and 2050 in Table A7.2.11.
- High capital costs were defined by assuming generator capital costs remain constant over time, rather than following a decreasing projection. New hydropower and nuclear small modular reactors (SMR) were the exceptions,

where new hydropower costs follow an increased trajectory and nuclear SMR costs were increased approximately 40% above the 2024 reference cost then remained constant for the duration of the study. Nuclear SMR costs were treated in this manner due to their greater uncertainty.

- Transmission station and line costs were held constant across all scenarios and sensitivities.
- Hydropower enhancements were excluded from high capital cost adjustments.
- Additional energy efficiency was assumed to be unavailable for this sensitivity.

Table A7.2.11 – Percentage Change from 2024 Reference Cost in Resource Capital Costs by 2035 and 2050 (in brackets)

Resource Type	Reference Capital Cost	High Capital Cost
Battery Storage	-18% (-27%)	0% (0%)
Biomass Turbine	-11% (-20%)	0% (0%)
Biomass Turbine with Carbon Capture and Sequestration	-11% (-25%)	0% (0%)
Combined Cycle Natural Gas Turbine with Carbon Capture and Sequestration	-11% (-25%)	0% (0%)
Combined Cycle Natural Gas Turbine	-7% (-18%)	0% (0%)
Simple Cycle Natural Gas Turbine (including Biodiesel)	-9% (-21%)	0% (0%)
Aeroderivative Natural Gas Turbine	-7% (-21%)	0% (0%)
Simple Cycle Hydrogen Turbine	-9% (-21%)	0% (0%)
Combine Cycle Hydrogen Turbine	-10% (-21%)	0% (0%)
New Hydrogeneration (Conawapa)	Not Applicable (+5.5%)	Capital cost increased by 19% over 2024 reference capital cost Future cost curve: Not Applicable (+5.5%)
New Hydrogeneration (Notigi)	+1.2% (+10.7%)	Capital cost increased by 31.7% over 2024 reference capital cost Future cost curve: +1.2% (+10.7%)
Nuclear Small Modular Reactor	0% (0%)	Capital cost increased by 39% over 2024 reference capital cost Future Cost Curve: 0% (0%)
Solar	-23% (-46%)	0% (0%)
Wind	-11% (-21%)	0% (0%)

3.2.4. Results

Cumulative Capacity Additions

Figure A7.2.50 and Figure A7.2.51 illustrate cumulative capacity additions by 2035 and 2050.

1-Baseline load projection:

- By 2035, differences between high capital cost sensitivities and base scenarios are minimal.
- In sensitivity S1B High Capital Costs (without forced in near-term wind generation projects), the model delays some resource additions, opting for smaller-scale CT-NG (344 MW), batteries, and market purchases instead of larger CT-NG (496 MW) and supply side enhancements.
- The model prioritizes dispatchable capacity regardless of cost, favoring smaller generators (e.g., aeroderivative (LM6000s) over SCGTs) with higher operating costs.
- In sensitivity S1C High Capital Costs (with forced in near-term wind generation projects), no additional wind is selected; only 296 MW of CT-NG is built.
- By 2050, thermal capacity additions converge across scenarios, with no additional wind selected under high capital assumptions.

2-Medium load projection:

- Similar to the 1-Baseline load projection case, the model selects smaller, less efficient CT-NG units and avoids additional wind.
- Batteries and market purchases are used to meet incremental load growth.
- By 2050, thermal generation is favored over more expensive small modular nuclear reactors (SMRs).
- Despite higher capital costs, the model results show that similar amounts of new generation are added to meet load growth.

3-High load projection:

- Due to significant load growth, the model builds nearly all available capacity regardless of capital cost.
- By 2035, all cases show similar capacity additions, with 3B High Capital selecting slightly less wind.
- By 2050, lower-cost thermal resources are preferred over nuclear SMRs.

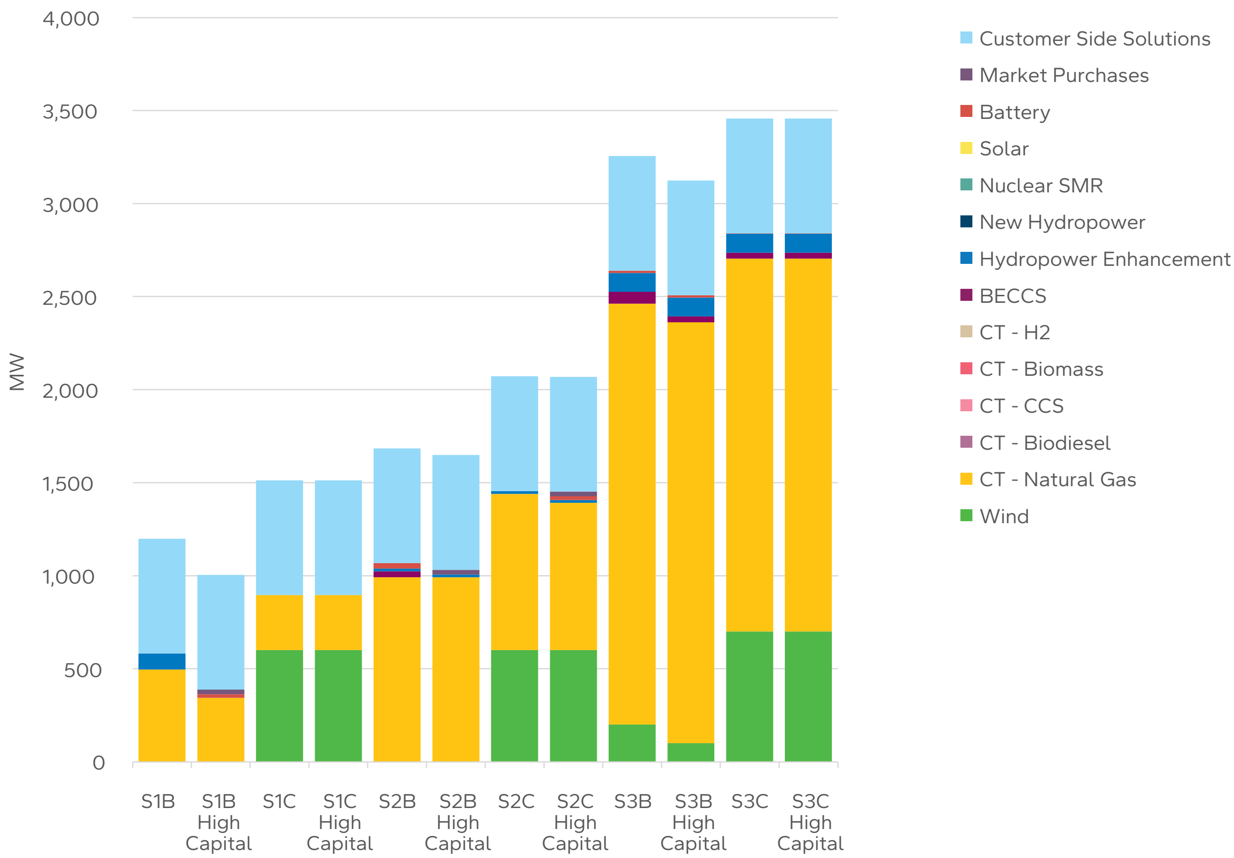


Figure A7.2.50 - Sensitivities - High Capital Costs: Cumulative Installed Capacity [MW] Additions by Resource Type by 2035

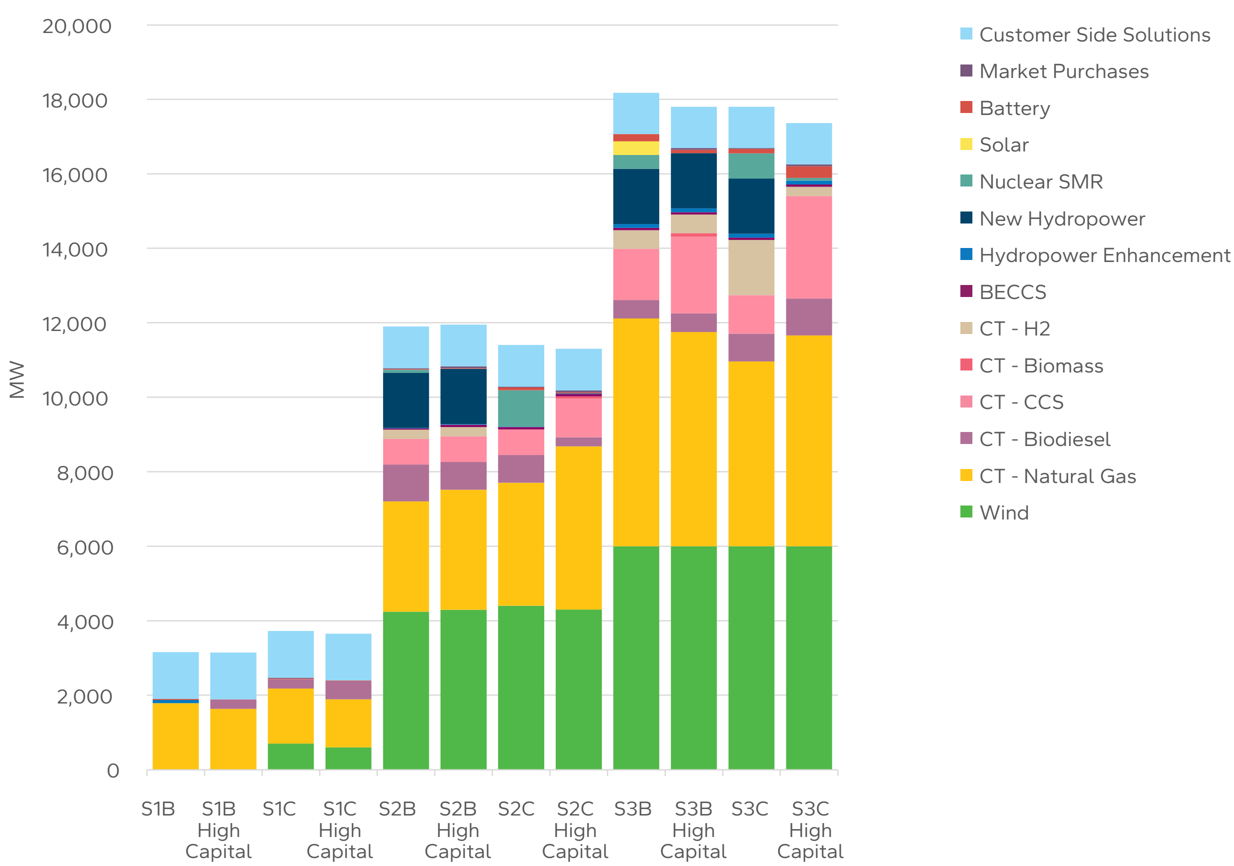
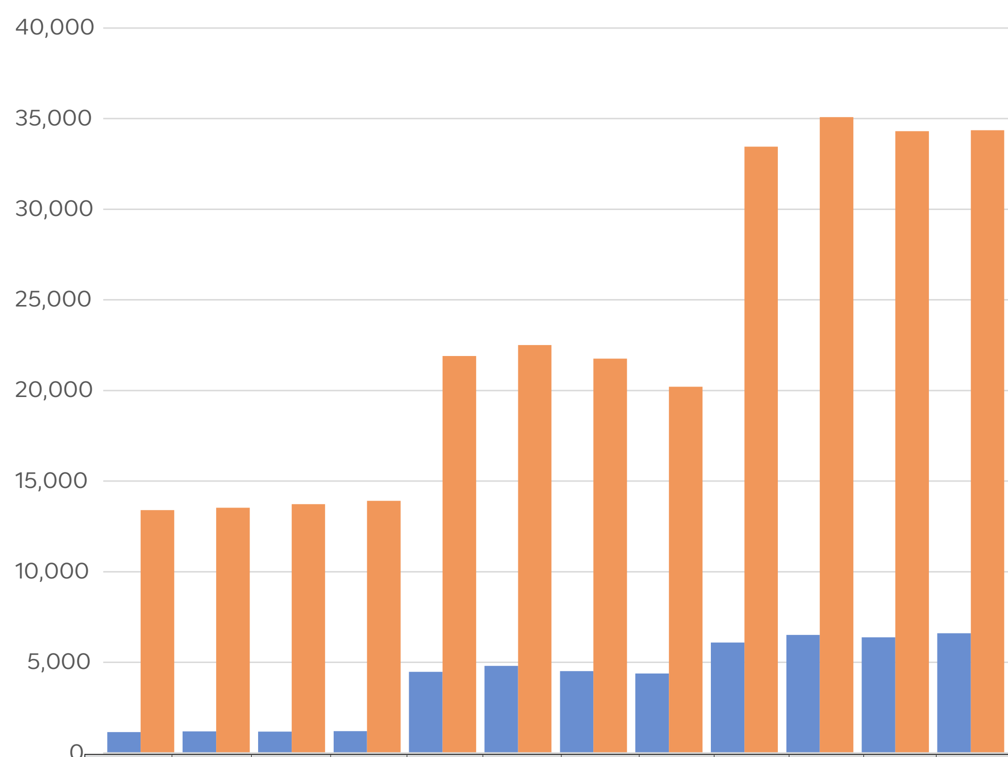


Figure A7.2.51 - Sensitivities - High Capital Costs: Cumulative Installed Capacity [MW] Additions by Resource Type by 2050

Incremental Present Value of Net System Costs and Incremental Annual Net System Costs

Figure A7.2.52 presents the incremental present value of net system costs and the incremental annual net system costs through 2050.

- As expected, higher capital costs increase both the incremental present value and incremental annual system costs.
- An exception is scenario S2C High Capital, where costs decrease due to the model selecting lower-cost CT-NG over more expensive nuclear SMRs. Nuclear SMR capital costs are assumed to increase by ~40% over the 2024 reference cost then remain constant for the study horizon, while CT-NG costs remained constant for the study horizon.



	S1B	S1B High Capital	S1C	S1C High Capital	S2B	S2B High Capital	S2C	S2C High Capital	S3B	S3B High Capital	S3C	S3C High Capital
Incremental Annual Net System Cost [M$/year]	1,158	1,194	1,187	1,203	4,477	4,804	4,516	4,392	6,096	6,514	6,389	6,610
Incremental Cumulative Present Value of Net System Costs [M$]	13,407	13,539	13,730	13,917	21,909	22,512	21,755	20,212	33,450	35,078	34,307	34,358

Figure A7.2.52 - Sensitivities - High Capital costs: Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2050

3.3. Additional Energy Efficiency

3.3.1. Objective

Scenarios did not include additional energy efficiency as a resource option. This sensitivity analysis was undertaken to analyze various additional energy efficiency categories in 1-Baseline, 2-Medium and 3-High load projection scenarios.

3.3.2. Key Takeaways

- Residential home insulation and residential ground source heat pump (GSHP) categories are generally selected to the maximum potential when available to be selected.
- The assumptions for cost and performance of GSHPs systems were sourced from Efficiency Manitoba's market potential study (drafted by a consultant) which assumes performance that may be higher than the actual performance of GSHP systems in Manitoba as described in Appendix 6 – Resource Options. Further study is required to confirm their performance and costs and how that may impact their cost effectiveness as a resource option for meeting demand.
- In the near-term timeframe (pre-2030), commercial ground source heat pumps and thermal electric storage categories are sometimes selected when large dispatchable capacity rich resources such as CT-NG, CT-BD, and batteries are not yet available. They are frequently selected to their maximum market potential at a faster pace when load growth projections are steeper.
- By 2050, additional energy efficiency defers and/or reduces new resources such as combustion turbines (CT) (natural gas (CT-NG), natural gas with carbon capture and sequestration (CT-CCS), biodiesel (CT-BD), hydrogen (CT-H2)), nuclear small modular reactors (SMRs), battery storage, and new large hydropower generation.
- The custom energy solution category is not selected in the 1-Baseline load projection but is selected in the 2-Medium, and 3-High load projections to its maximum market potential.
- The air source heat pump (ASHP) categories are not selected as ASHPs do not provide any incremental savings during coincident system peak events. During the critical time of system peak when the winter air temperature is very low, ASHPs are typically not able to operate and auxiliary heating system (e.g., electric base board or electric furnace) are required to serve the customer's heating demand.

3.3.3. Methodology

For additional energy efficiency and heat pumps, the capital cost includes the cost to administer the program, incentive cost, ITC (if applicable), and transmission and distribution savings. In this sensitivity analysis, the eleven different additional energy efficiency groups as shown in Table A7.2.12, were available to be selected by the capacity expansion optimization model to meet the load for different load projections under various strategies.

Table A7.2.12 – Sensitivities: Additional Energy Efficiency Groups

Number	Energy Efficiency Groups	Category
1	Residential - Home Insulation	EE-1
2	Residential - Electric furnace with Electric Thermal Storage	EE-1
3	Industrial - Custom Energy Solutions	EE-1
4	Residential - Energy Efficiency Assistance Program Cold Climate Air Source Heat Pump	EE-2
5	Residential - Community Heat Pump Cold Climate Air Source Heat Pump	EE-2
6	Residential – Standard Air Source Heat Pumps	EE-2
7	Residential - Electric furnace with Electric Thermal Storage & Cold Climate Air Source Heat Pump	EE-2
8	Residential - Community Heat Pump - Ground Source Heat Pumps	EE-3
9	Residential - Ground Source Heat Pumps	EE-3
10	Residential - Energy Efficiency Assistance Program - Ground Source Heat Pumps	EE-3
11	Commercial - Ground Source Heat Pumps	EE-3

3.3.4. Results

Figure A7.2.53 and Figure A7.2.54 illustrate cumulative capacity additions by 2035 and 2050, and include a breakout of the Customer Side Solutions category to provide visibility around additional energy efficiency selections (which would otherwise be aggregated into this category). Figure A7.2.55 and Figure A7.2.56 illustrate the net system costs.

1-Baseline Load Projection Sensitivity Analysis

- The residential home insulation category and the ground source heat pumps categories are generally selected before 2035. Commercial ground source heat pumps and electric thermal storage categories are frequently selected only after 2042.
- Custom energy solutions and air source heat pump categories are not selected in this load projection.
- In this sensitivity analysis, about 70 MW of additional energy efficiency is selected which results in the reduction of the selection of combustion turbines by 2035 with no change in the selection of wind resources. Minor changes in the selection of hydropower enhancements and battery were also observed.
- By 2050, about 600 MW of additional energy efficiency is selected which increases selection of wind resources in resource options strategy B and C scenarios (up to 300 MW) and reduces the selection of CT-NG & CT-BD, hydropower enhancement projects, battery, and capacity market purchases.
- By 2050, annual and net present value (NPV) of net system costs are lower in the additional energy efficiency sensitivities than the scenarios.

2-Medium Load Projection Sensitivity Analysis

- The residential home insulation and residential ground source heat pumps are generally selected to their maximum limits throughout the study horizon. Commercial GSHP, electric thermal storage, and custom energy solutions categories are selected as load grows to the maximum potential by 2049. The air source heat pumps categories are not selected.
- In this sensitivity analysis, about 150 MW of additional energy efficiency is selected by 2035 which reduces the CT-NG up to 250 MW. Small reductions in the bioenergy carbon capture and sequestration (BECCS) and battery were also noted in the timeframe for strategy B and C.

- With 900 MW of additional energy efficiency by 2050, there is a shift in resources selected, reducing CT-NG, CT-H2, small modular nuclear reactors (SMR), and battery resources while the selection of CCCT-CCS is doubled. In resource options strategy B, the addition of additional energy efficiency eliminates new large hydropower. There were no changes to the selection of wind resources.
- By 2050, annual and NPV of net system costs for additional energy efficiency sensitivities are lower than the scenarios.

3-High Load Projection Sensitivity Analysis

- Residential home insulation and residential as well as commercial ground source heat pumps are selected early and to the annual maximum limits throughout the study horizon. Electric thermal storage and custom energy solutions categories are selected as load grows and are selected frequently to the maximum potential by 2040. Air source heat pumps categories are not selected.
- In the high load projection, about 230 MW of additional energy efficiency is selected by 2035 resulting in the reduction in combined CT-NG and CT-BD. Some minor changes in wind, BECCS, and battery was also noted.
- About 900 MW of additional energy efficiency is selected by 2050 which reduces natural gas and CT-H2, nuclear SMR, battery, utility scale solar, and capacity market purchases.
- Selection of wind, CT-CCS, hydropower enhancements and larger hydropower remained unchanged.
- By 2050, annual and NPV of net system costs of additional energy efficiency sensitivities are lower than the scenarios.

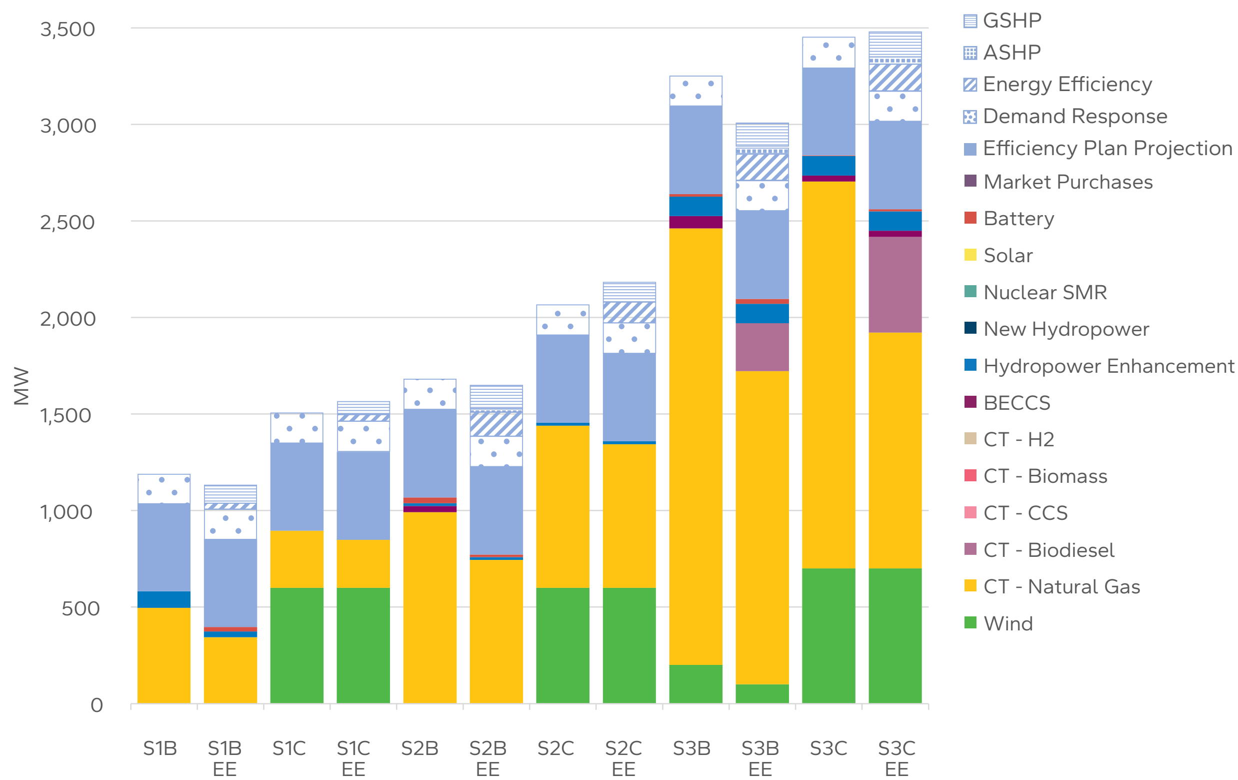


Figure A7.2.53 - Sensitivities - Additional Energy Efficiency: Cumulative Installed Capacity [MW] Additions by Resource Type by 2035

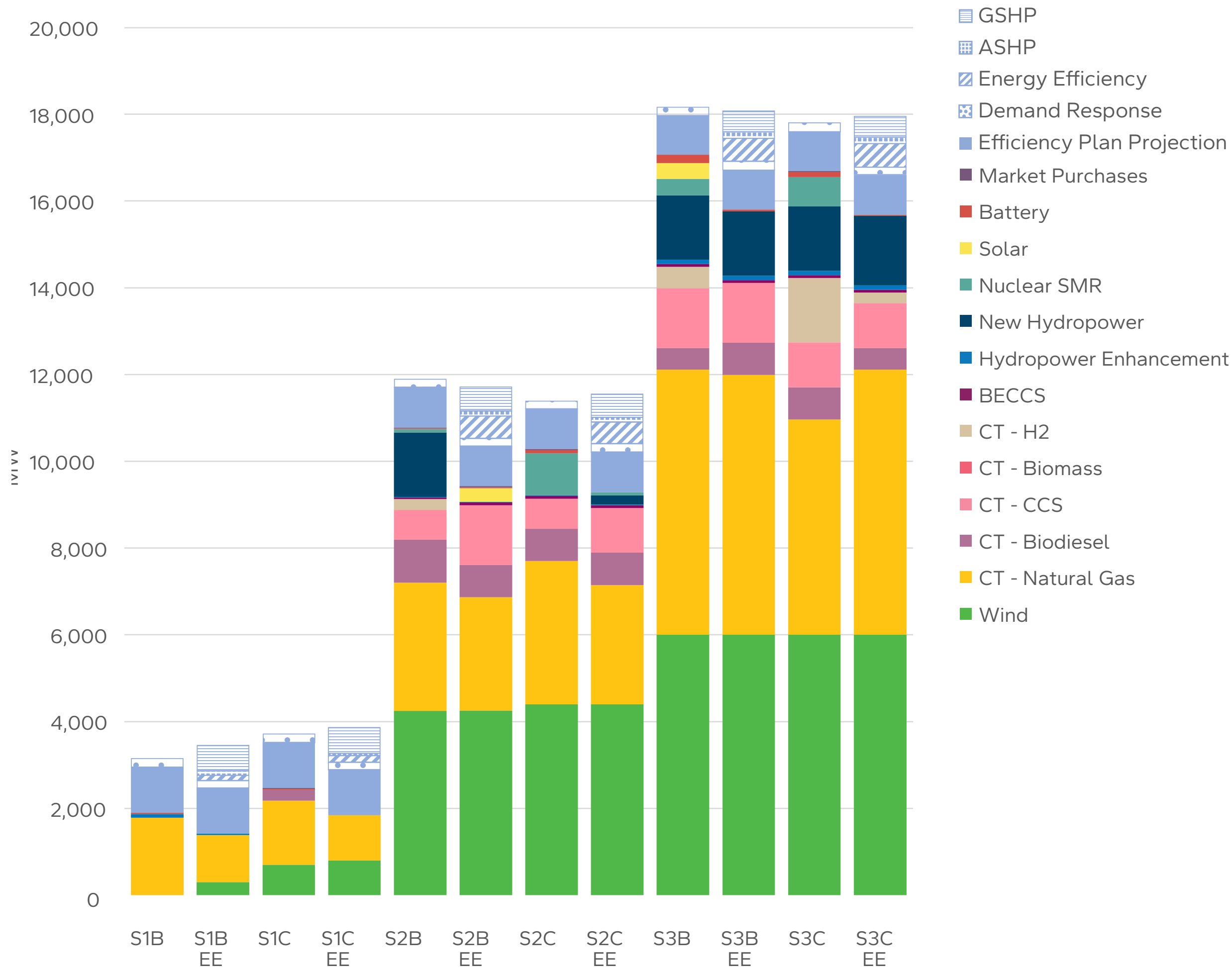
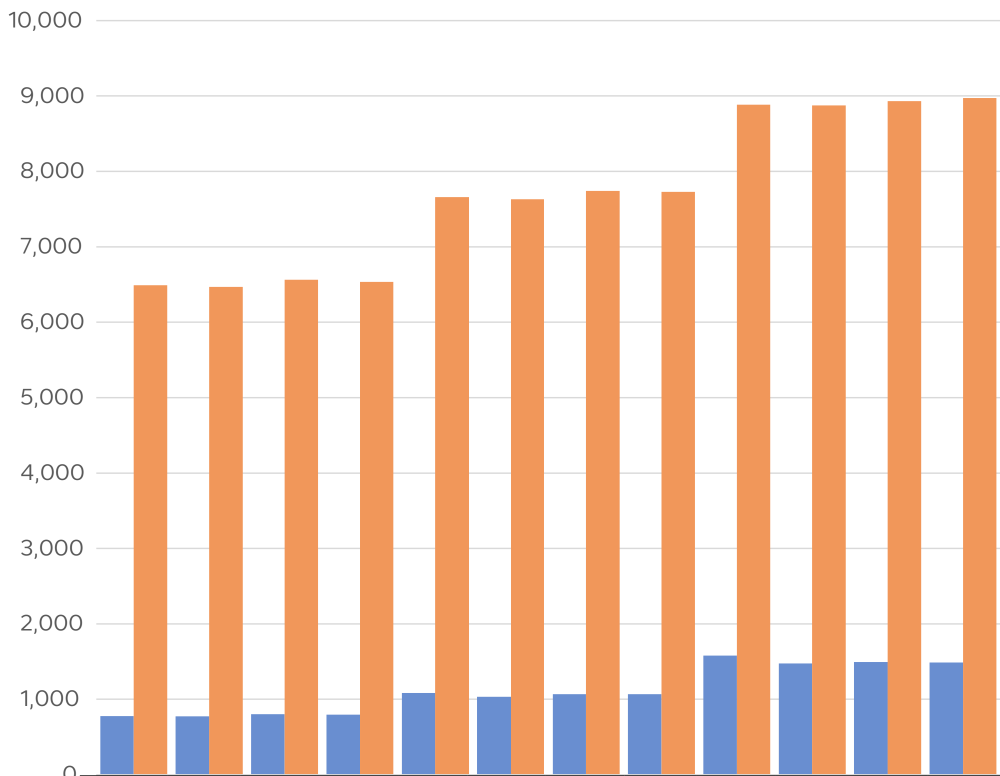
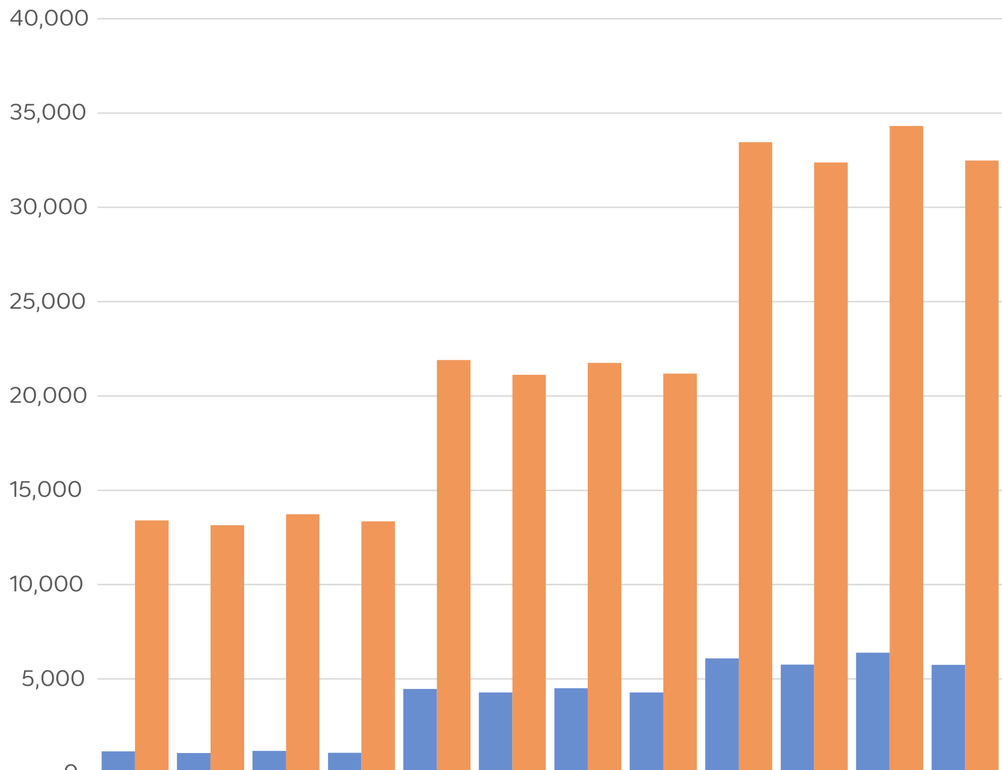


Figure A7.2.54 - Sensitivities - Additional Energy Efficiency: Cumulative Installed Capacity [MW] Additions by Resource Type by 2050



	S1B	S1B EE	S1C	S1C EE	S2B	S2B EE	S2C	S2C EE	S3B	S3B EE	S3C	S3C EE
Incremental Annual Net System Cost [M$/year]	779	773	802	797	1,082	1,034	1,067	1,069	1,579	1,474	1,495	1,488
Incremental Cumulative Present Value of Net System Costs [M$]	6,491	6,467	6,562	6,535	7,659	7,630	7,741	7,730	8,884	8,874	8,932	8,972

Figure A7.2.55 - Sensitivities - Additional Energy Efficiency: Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2050



	S1B	S1B EE	S1C	S1C EE	S2B	S2B EE	S2C	S2C EE	S3B	S3B EE	S3C	S3C EE
Incremental Annual Net System Cost [M$/year]	1,158	1,078	1,187	1,093	4,477	4,278	4,516	4,287	6,096	5,759	6,389	5,753
Incremental Cumulative Present Value of Net System Costs [M$]	13,407	13,156	13,730	13,357	21,909	21,124	21,755	21,191	33,450	32,382	34,307	32,486

Figure A7.2.56 - Sensitivities - Additional Energy Efficiency: Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2050

3.4. Demand Response and Curtailable Rates Program Availability

3.4.1. Objective

This sensitivity explores the value of demand response (DR) and curtailable rates program (CRP) winter capacity savings, by investigating the implications if no DR or CRP is assumed to be available throughout the study period.

3.4.2. Key Takeaways

- By 2035, DR and CRP accredited capacity is primarily replaced by batteries. DR and CRP function similar to batteries, as peak-shaving resources with no dependable energy benefits, confirming that this type of resource provides near-term value to the Manitoba Hydro system.
- Pursuing DR and/or extending the CRP can reduce the benefits of adding batteries to Manitoba's generation portfolio. This helps to explain why relatively small amounts of batteries were selected in most of the scenarios, all of which included both DR and the CRP as committed resources.
- Under the 3-High load projection, and prior to 2030, DR and CRP are valuable mitigation tools for avoiding or lessening near-term accredited winter capacity shortfalls. If the future unfolds with less near-term demand, the need to mitigate potential near-term capacity shortfalls will also be lessened.
- Making DR and CRP unavailable has only a small impact on annual Manitoba electricity generation GHG emissions, increasing net Manitoba electricity generation GHG emissions by less than 10 thousand tonnes of CO_2e in 2035. In both cases, the 2035 net-zero grid was achieved and Manitoba electricity generation GHG emissions were negative.
- Without DR and CRP, annual net system costs in 2035 increase by $83M 2024 CAN/yr, while the PV of net system costs increases by $364M 2024 CAN. These cost increases indicate the potential financial value these programs can provide in a high-load future.

3.4.3. Methodology

DR programs reduced winter peak demand in the months of December, January, and February by flattening the demand profile. Figure A7.2.57 provides an illustrative example of how DR programs affect peak demand during a winter day, which can include a reduction in the daily peak as well as shifting the timing of the peak. To simplify modelling, it was assumed that the total annual energy requirements remain unchanged by DR, recognizing that some larger, higher capacity factor loads would likely experience a reduction in energy consumed when the load is curtailed.

Examples of demand response programs include:

- Residential Direct Load Control (e.g., EV Smart Charger Control, WiFi thermostat)
- Commercial/Industrial Interruptible Rates & Manual Curtailment
- Dynamic Rates

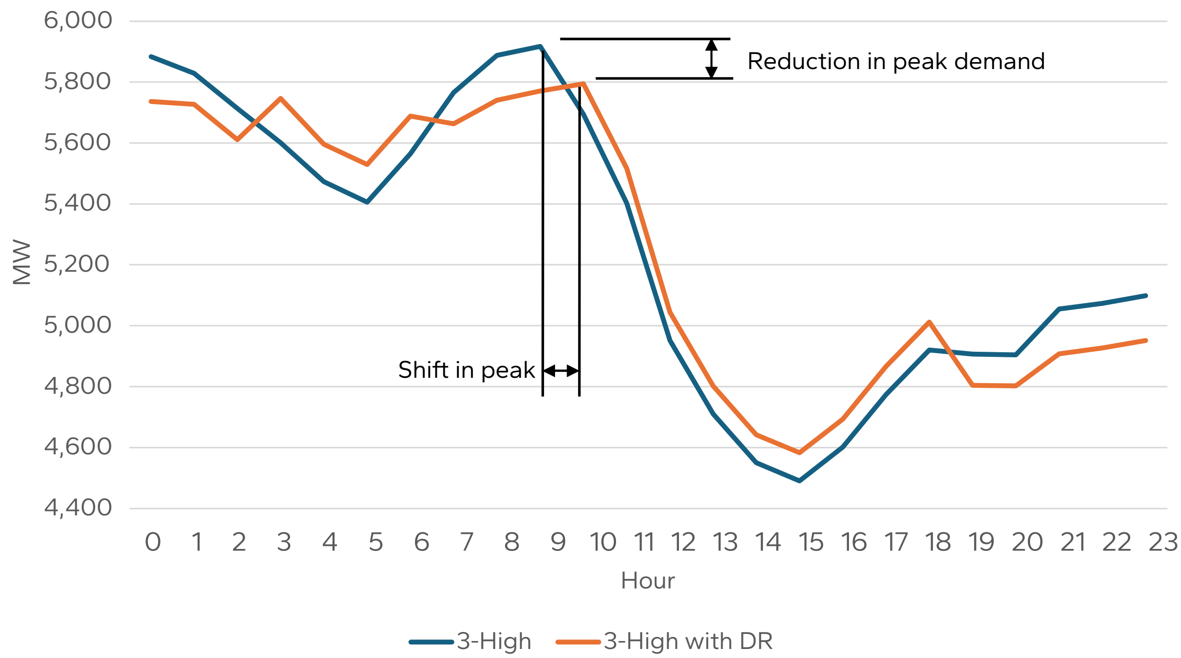


Figure A7.2.57 - Demand Response and Curtailable Rates Program Availability – Illustrative Example of Demand Response Effect on a Winter-Day Peak in February 2035

Due to the relatively small scale of individual potential demand response programs and the interactive effects of these DR programs, DR has been modelled on an aggregated basis as a single resource option with annual accredited winter capacity savings as shown in Figure A7.2.58. In all other sensitivities, and scenarios, DR is included in the buildout as a committed resource. For the purposes of this sensitivity, a No DR and CRP case was developed with zero accredited winter capacity savings attributed to DR for the entire study horizon. DR has no summer accredited capacity savings, or dependable energy savings in any season.

CRP assumptions were also modified accordingly for this sensitivity. In all other cases CRP winter capacity savings are assumed to persist throughout the study horizon at a constant annual accredited winter peak savings of 151 MW, whereas for the No DR and CRP sensitivity, CRP is assumed not to extend past current contract end dates and drops to 0 MW starting in 2029.

The modelling approach for this sensitivity allows the capacity enhancement model to isolate the full value of forecasted DR and CRP to the system, providing focused results on the impacts to the optimized portfolio of resources and costs. If DR programs were represented individually, the model would fail to capture interactive effects between programs. Furthermore, modelling individual DR programs obscures evaluation of DR as a resource option – each program is relatively small compared to the scale of the supply and demand optimization problem so outcomes for such small options may not be meaningful at the model's resolution.

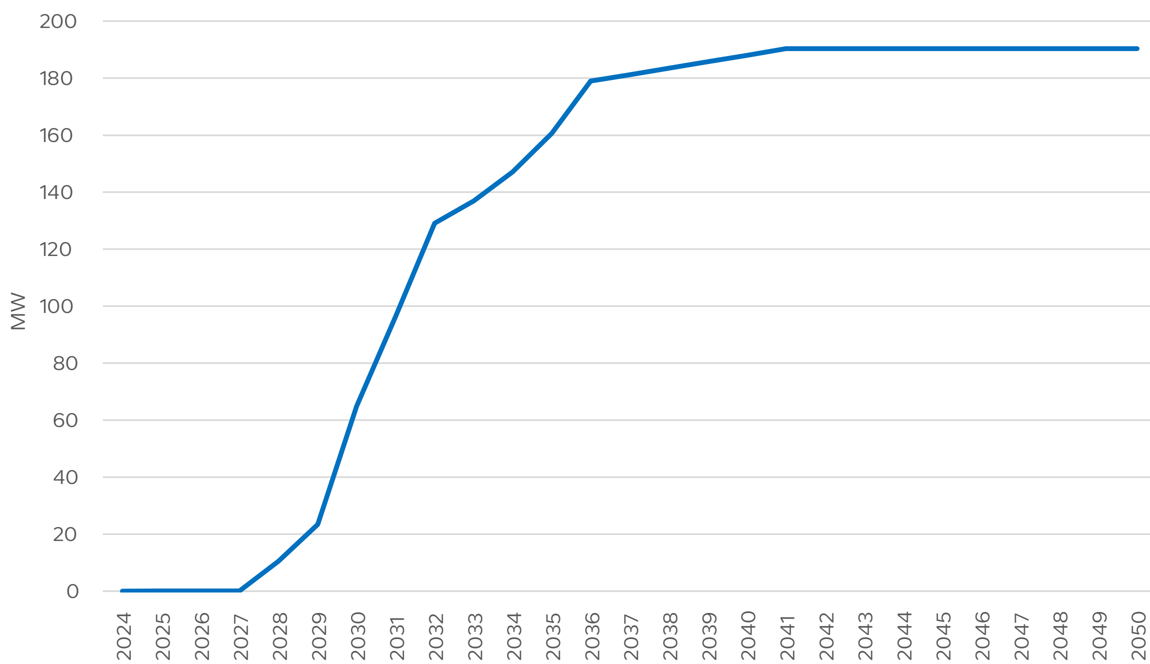


Figure A7.2.58 - Demand Response and Curtailable Rates Program Availability – Annual Accredited Winter Capacity for DR for the 3-High Load Projection

This study focuses on the 3-High load projection, which is useful for setting an upper bound on the value of DR and CRP to the Manitoba Hydro system and for parsing out how and when that value manifests. Results are presented for 2035 only, as the magnitude of DR and CRP savings being evaluated are relatively small compared to the 3-High peak demand projections by 2050, resulting in any resource selection or cost signals related to DR and CRP assumptions being indistinguishable from optimization noise.

3.4.4. Results

As shown in Figure A7.2.59, by 2035, the portfolio of resources selected to meet the 3-High load projections adapts to the absence of DR and CRP by adding an additional 318 MW of batteries as compared to the 3C case. Batteries play a similar role in meeting system requirements as DR, offering winter accredited capacity designed to target peak demand event through the shifting of energy within a day (similar to how DR shifts demand throughout the day) with no dependable energy benefits. The selection of batteries by the model to fill the vacated role of DR and CRP indicates the value of this type of resource option to the system in the near-term. Figure A7.2.59 also indicates that the total MW of installed combustion turbine (CT) capacity remains consistent, but that the No DR and CRP sensitivity includes biodiesel combustion turbine (CT-BD) additions. This may indicate that the model sees value in having some CT-BD capacity available to meet peak demand when DR and CRP are not available, given the context of a net-zero grid constraint from 2035 onwards.

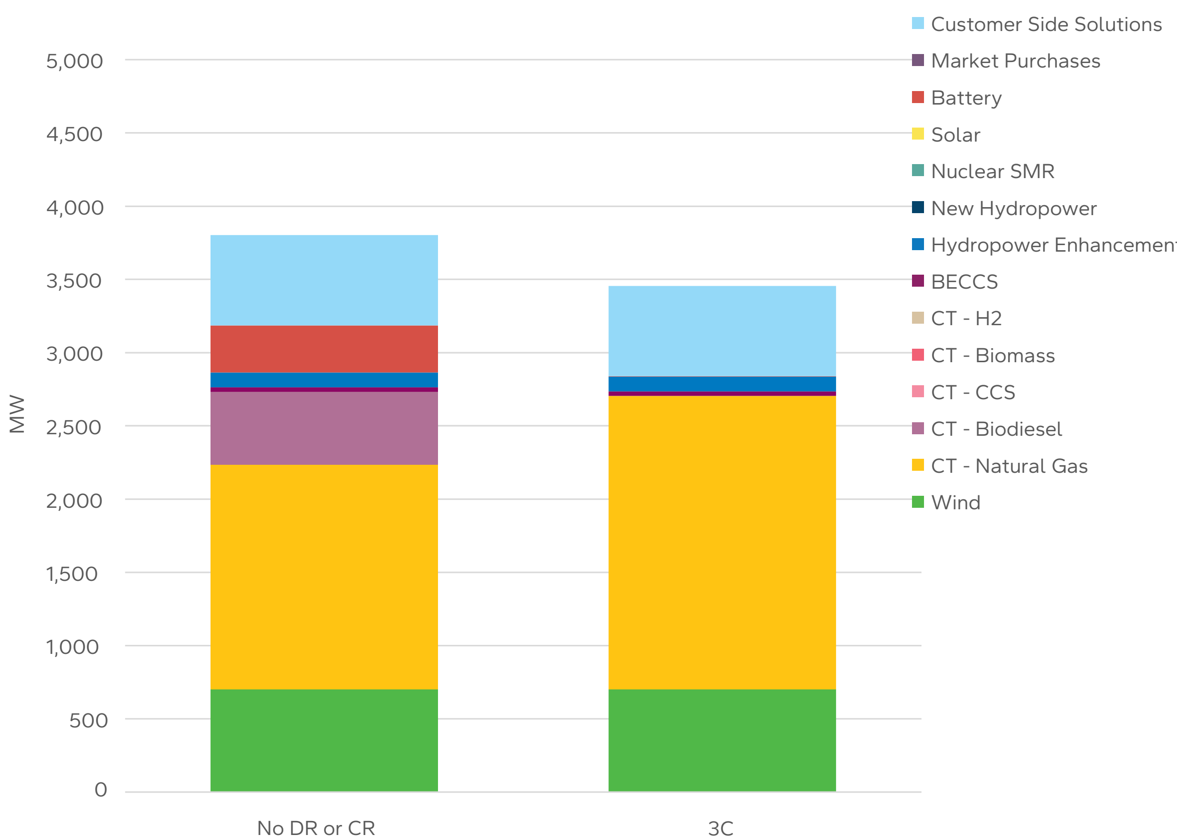


Figure A7.2.59 - Demand Response and Curtailable Rates Program Availability - Cumulative Installed Capacity by 2035

Prior to 2035, DR and CRP programs provide value by reducing near-term accredited capacity shortfalls that are projected based on the 3-High load projection, as illustrated in Table A7.2.13. These near-term shortfalls may or may not transpire in the future, and so the significance of this value is variable depending on the demand that materializes. However, in a situation with high load growth prior to 2030, DR and the CRP are valuable mitigation tools for avoiding or lessening near-term accredited capacity shortfalls. In 2030 and beyond, additional resource options become available to supply dependable energy.

Table A7.2.13 – Demand Response and Curtailable Rates Program Availability – Implications for Near-Term Accredited Capacity Shortfalls

Case	2025	2026	2027	2028	2029
3C with No DR or CRP	0	7	200	287	581
3C	0	7	200	275	388
Difference	0	0	0	12	193

Figure A7.2.60 confirms that changes to the annual Manitoba electricity generation GHG emissions are small by 2035, with the removal of DR and CRP and the resulting changes to the portfolio of resources decreasing these GHG emissions from -128 to -136 thousand tonnes of CO_2e, a change of less than 10 thousand tonnes of CO_2e. This is consistent with the replacement of DR and CRP primarily with batteries in the No DR and CRP case, as these are all peak-shaving resource options with no assumed associated direct GHG emissions and swapping between them has minimal impacts on system operations.

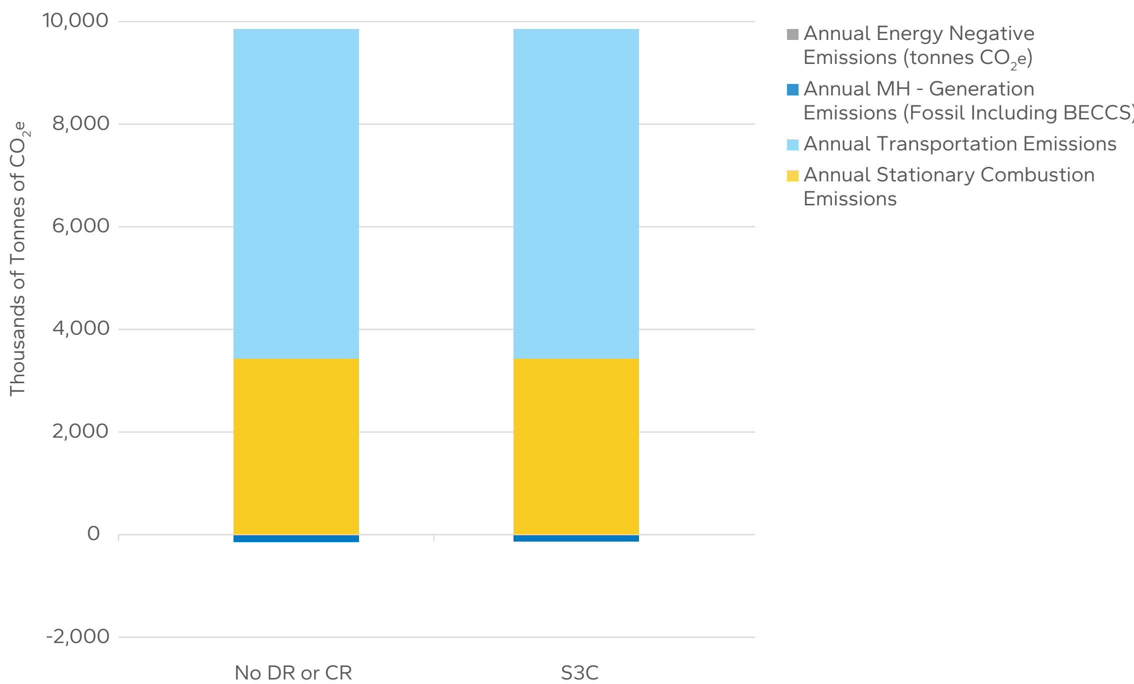
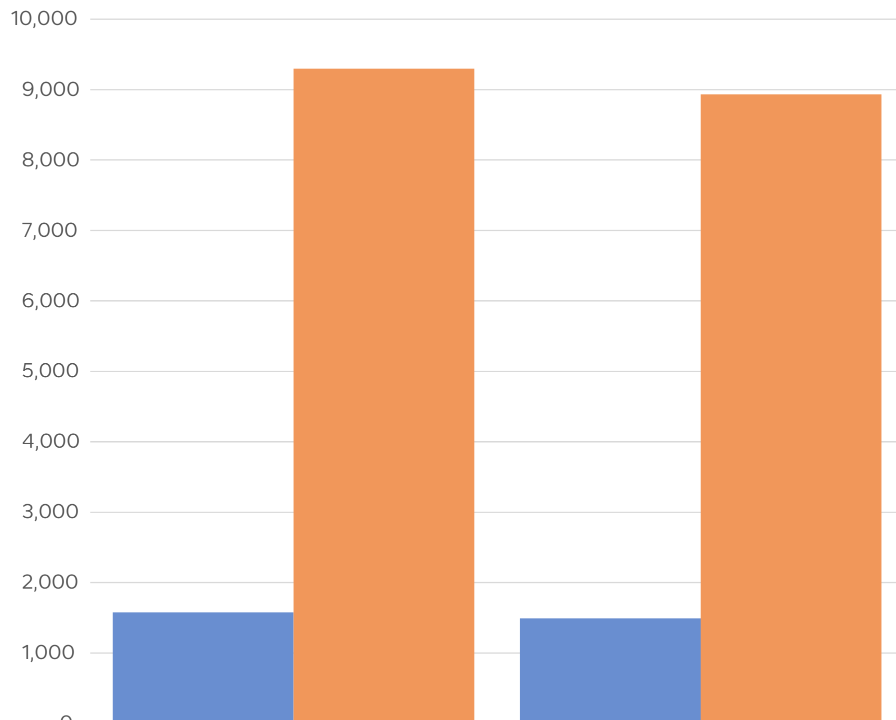


Figure A7.2.60 - Demand Response and Curtailable Rates Program Availability - Breakdown of GHG Emissions in 2035

Figure A7.2.61 shows how DR and CRP availability assumptions affect the financial indicators. Without DR and CRP, annual net system costs in 2035 increase by $83 M 2024 CAN/yr, while the PV of net system costs increases by $365 M 2024 CAN. As a base assumption, DR and CRP are assumed to be in place throughout the study horizon, and so like other existing system resources there are no investment costs for these options in the model. The increases observed in annual net system costs and the PV of net system costs without DR and CRP therefore provide an indication of the financial value these programs can provide under the 3-High load projection.



	No DR or CR	S3C
Incremental Annual Net System Cost [M$/year]	1,578	1,495
Incremental Cumulative Present Value of Net System Costs [M$]	9,297	8,932

Figure A7.2.61 - Demand Response and Curtailable Rates Program Availability - Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2050

3.5. Hydropower Enhancement Delays

3.5.1. Objective

Delays to the earliest in-service dates (ISDs) for the Lower Nelson River Hydropower Enhancement (LNR SSE) projects were explored to understand potential economic and resource adequacy implications. All hydropower enhancement projects are modelled assuming fixed ISDs with no optimization flexibility around the timing of the projects, making it necessary to analyze timing decisions related to LNR SSE projects through sensitivity analysis.

3.5.2. Key Takeaways

- The model selects the 3-unit LNR hydropower enhancement project in approximately 60% of the scenarios and sensitivities. Other LNR Hydro SSE project unit options are rarely selected but further evaluation is required.
- Under the 3-High load projection scenarios, the model chooses to include the 3-unit LNR SSE project in its portfolio of resources, regardless of the assumed ISD. Under the 1-Baseline load projection scenarios, the 3-unit LNR SSE project is selected when a delayed ISD is assumed, but not when the earliest ISD is applied.
- By 2040, the effects from delaying the 3-unit LNR SSE project are negligible in the 1-Baseline load projection case and are limited to a shift in the composition of combustion turbine (CT) types added in the 3-High load projection cases.
- In the nearer term, sensitivity analysis shows that pursuing the earliest in-service dates (ISDs) for the LNR SSE projects may require the advancement of a CT unit to cover outages. Delaying the LNR SSE projects also resulted in an adjustment to the ratio of CT-NG versus CCCT-NG units as observed in 2035 for the 3-High load projection.
- Delaying the 3-unit LNR SSE projects does not meaningfully change economic indicators by 2040.
- Delaying the 3-unit LNR SSE projects does not meaningfully change net incremental regional (non-Manitoba) electricity generation GHG emission impacts.
- The largest impact on Manitoba electricity generation GHG emissions was seen under the 3-High load projection, where delaying the 3-unit LNR SSE project resulted in 4,000 tonnes CO_2e of additional negative Manitoba electricity generation GHG emissions in 2040.
- More detailed economic analysis of LNR SSE projects and alternative in-service dates is required.

3.5.3. Methodology

The earliest ISDs for the LNR SSE projects are derived based on the goal of having upgraded LNR units available at the earliest achievable ISD while leveraging the opportunity to perform upgrades when units are already scheduled to be taken offline for stator replacements. The unit upgrade schedule applied further assumes that only one unit can be taken offline at Long Spruce and at Kettle at a time, for a maximum of two units offline at both stations each year. These earliest LNR SSE ISDs are assumed in all IRP 2025 modelling runs including the scenarios, except for in the ISD delay sensitivities.

A delayed LNR SSE ISD concept was developed assuming all unit uprates are to be completed as of 2038, when the last LNR unit stator replacement is scheduled. This concept further assumes that currently planned outages for stator replacements at the LNR stations will be completed first for all units except those included in the selected LNR SSE project option. Once stator replacements are complete, work is assumed to begin on uprating the selected LNR SSE units. As more units are included in a LNR SSE project option, the uprate work must begin earlier, and fewer units are included in the stator replacements.

The delayed LNR SSE ISD concept includes benefits that support exploring this sensitivity. These benefits include:

- Providing more time to secure funding and resources needed to complete the uprates;
- Simplifying resource and schedule management for completing the stator replacements and unit uprates, as the delay allows for completing the two different types of work packages in series rather than in parallel;
- Allowing stators to operate closer to their expected end of life for those units included in the LNR SSE option; and
- Deferral of capital expenditures related to the uprates.

For the purposes of this sensitivity, it was assumed that capital costs and fixed operating and maintenance costs do not change when the LNR SSE ISDs are delayed. However, at the delayed ISD dates, LNR SSE projects are assumed to no longer eligible for Investment Tax Credits.

The original LNR SSE project earliest ISDs are listed in Table A7.2.14. The project ISDs implemented in the model represent all units being upgraded at a hydropower station with a single ISD. This ISD precedes the first unit uprate ISD by one year, to reflect a one-year period of reduced accredited capacity as an outage is taken to facilitate the uprate.

Table A7.2.15 outlines the delayed LNR SSE ISDs. Units incorporated in the 3-unit LNR SSE option will no longer need to be taken offline for stator replacement prior to the unit uprate as previously scheduled, and so changes to the modelled maintenance schedule for these units can reach earlier in time than one year preceding the LNR SSE unit ISD as was assumed with the earliest LNR SSE ISDs. The "ISD in Model" years reflect when maintenance schedule changes take effect.

Table A7.2.14 – Hydro Hydropower Enhancement Delays – LNR SSE Earliest Unit Uprate In-Service Dates

Hydropower Station	3-Unit Uprate ISD per Unit	3-Unit Uprate ISD in Model
Long Spruce	2032	2031
Long Spruce	2033	-
Kettle	2033	2032

Table A7.2.15 – Hydro Hydropower Enhancement Delays – Delayed LNR SSE Unit Uprate In-Service Dates

Hydropower Station	3-Unit Uprate ISD per Unit	3-Unit Uprate ISD in Model
Long Spruce	2037	2036
Long Spruce	2038	-
Kettle	2036	2030

To isolate the implications of delaying LNR SSE projects, the 3-unit LNR SSE project was chosen for analysis. The 3-unit LNR SSE option was selected based on scenario and other sensitivity results, where the 3-unit option was selected in 60% of the scenario and sensitivity results. For each LNR SSE option, results were compared between cases assuming the earliest and delayed ISDs.

For the 1-Baseline load projection scenarios, the 3-unit LNR SSE project at the earliest ISDs is an obligatory project, ensuring that the implications of delaying the ISD date can be studied. This was required since in the 1C scenario, LNR SSE projects are not selected. Results without the obligatory inclusion of the 3-unit LNR SSE project are presented as 1C.1, as some model configuration adjustments were required to the initial 1C case to maintain compatibility with the other modelling cases included in this sensitivity. It was not necessary to make the delayed 3-unit LNR SSE project obligatory, as the project was selected by the model during optimization.

Under the 3-High load projection, the 3-unit LNR SSE project was selected during optimization at both the earliest and delayed ISDs. No cases were required with the LNR SSE project set as obligatory.

3.5.4. Results

Results are presented for 2040 so the selected portfolios of resources can be compared after the full accredited capacity of the LNR SSE projects are available when delayed ISDs are applied. Installed capacity in 2035 is also shown for reference.

Cumulative installed capacity additions by 2035 are shown in Figure A7.2.62, and by 2040 in Figure A7.2.63. As indicated in Figure A7.2.62, the delayed 3-unit LNR SSE projects are not fully in service by 2035. Generally, capacity expansion planning impacts by 2035 show up as changes in CT timing. Under the 1-Baseline load projection, delaying the 3-unit LNR SSE project also delays the addition of an aeroderivative CT from 2031 until 2037. When the earliest in-service dates for the LNR SSE projects are in effect, the accredited capacity provided by the aeroderivative unit in 2031 is required to cover outages needed to facilitate the LNR SSE uprates, and which come with a corresponding temporary drop in accredited capacity before the uprate is completed.

Delaying the 3-unit LNR SSE project, and the associated accredited capacity drop that precedes the uprate, also changes resource additions under the 3-High load projection. Under this load projection, delaying the 3-unit LNR SSE project delays the addition of a CT-NG in 2031 until 2032, but the total addition of CT-NG and CCCT-NG additions by 2035 increases by 114 MW. This increase reflects a shift in CT-NG and CCCT-NG ratios and a 17 MW drop in battery additions in response to the full accredited firm capacity of the delayed LNR SSE not yet being in effect by 2035.

Under the high load projection, the Pointe du Bois SSE project is selected in addition to the LNR SSE projects regardless of the LNR SSE in-service date. Pointe de Bois SSE is not selected in the baseline load projection cases.

By 2040, the full accredited capacity additions associated with the delayed LNR SSE projects are realized. Under the 1-Baseline load projection, there is no change in the portfolio of resources by 2040 due to the delayed ISDs of the LNR SSE projects. In the 1C.1 sensitivity, the LNR SSE projects are optional, and the projects are not selected. Instead, the aeroderivative unit included in the sensitivities with LNR SSE included is swapped with a larger CT-NG unit.

Under the 3-High Load projection, the selected portfolios of resource by 2040 are also consistent regardless of the LNR SSE ISD assumed. A shift to include more biodiesel combustion turbines (CT-BDs) was observed in the delayed LNR SSE case, although the total of CT-NG, CCCT-NG, and CT-BDs was the same.

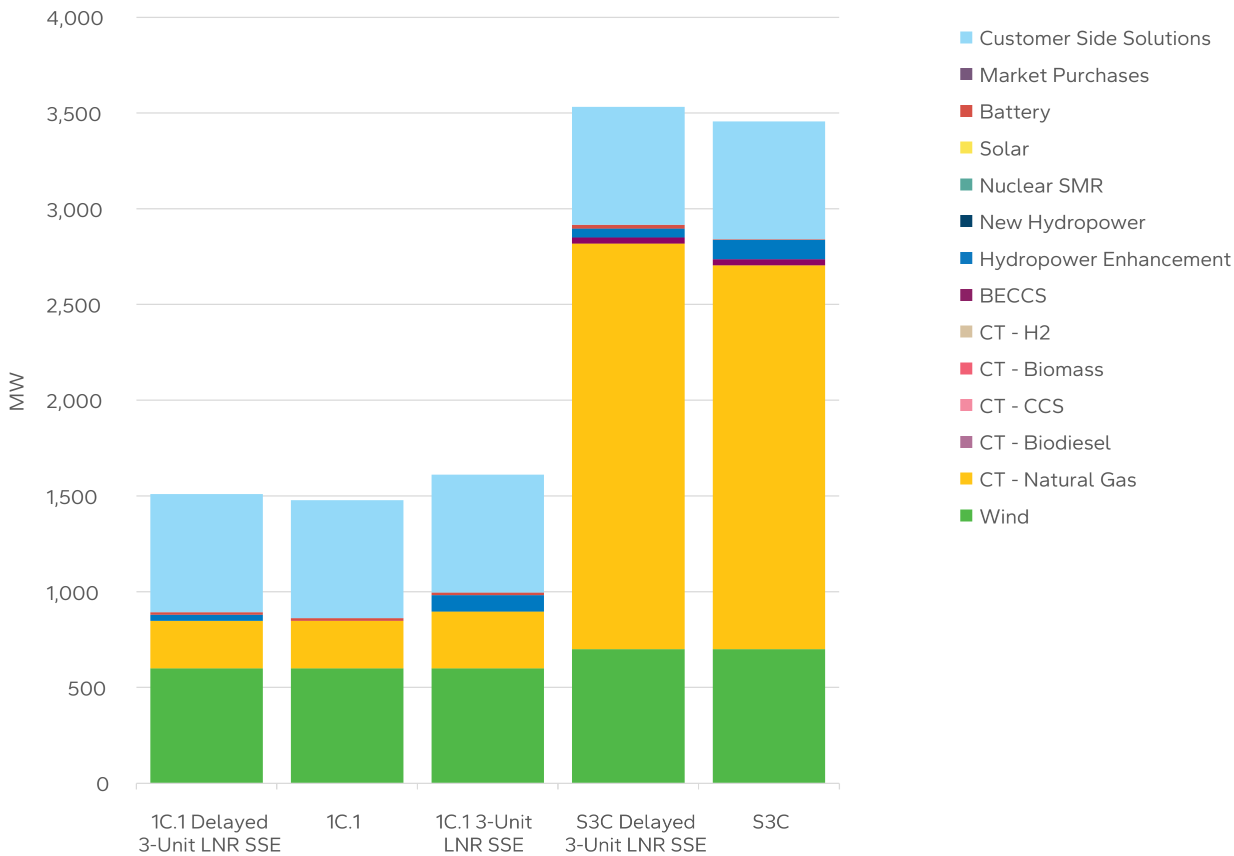


Figure A7.2.62 - Hydro Hydropower Enhancement Delays – 3-Unit LNR SSE ISD Study - Cumulative Installed Capacity by 2035

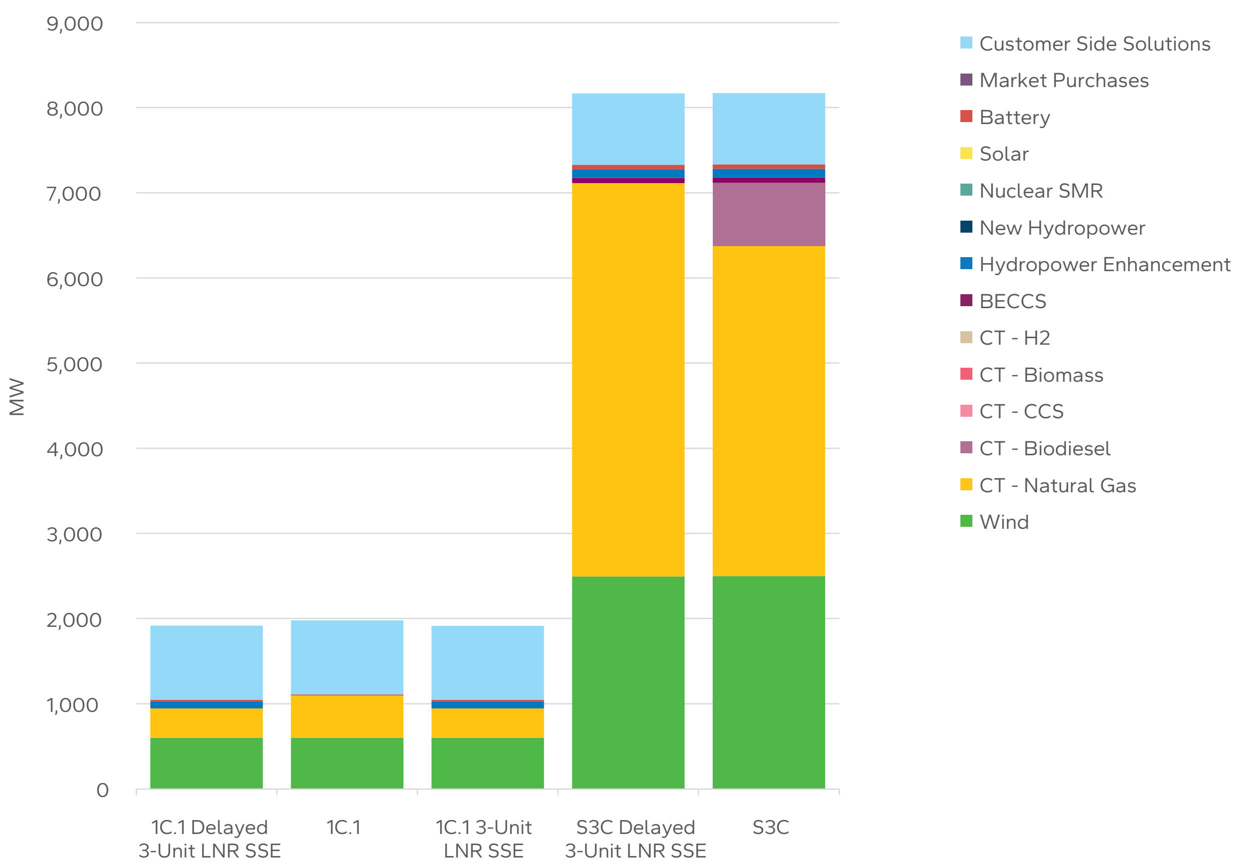


Figure A7.2.63 - Hydro Hydropower Enhancement Delays – 3-Unit LNR SSE ISD Study - Cumulative Installed Capacity by 2040

GHG emission effects in 2040 from delaying the 3-unit LNR SSE project are shown in Figure A7.2.64, with a highlight on net Manitoba electricity generation GHG emissions provided in Figure A7.2.65. Figure A7.2.64 contextualizes net Manitoba electricity generation GHG emissions effects of LNR SSE sensitivities with combustion GHG emissions in the province. As seen Figure A7.2.65, including the 3-unit LNR SSE project at any ISD has a negligible net MH generation GHG emissions effect under the 1-Baseline load projection. Under the 3-High load projection, delaying the 3-unit LNR SSE ISD results in 4,000 tonnes CO_2e of additional negative Manitoba electricity generation GHG emissions (11% more negative GHG emissions), compared to implementing LNR SSE at its earliest ISD. Increased negative GHG emissions reflects changes to the composition of the CT fleet in 2040 between the sensitivity cases. There were no significant changes to the net incremental regional (non-Manitoba) electricity generation GHG emissions.

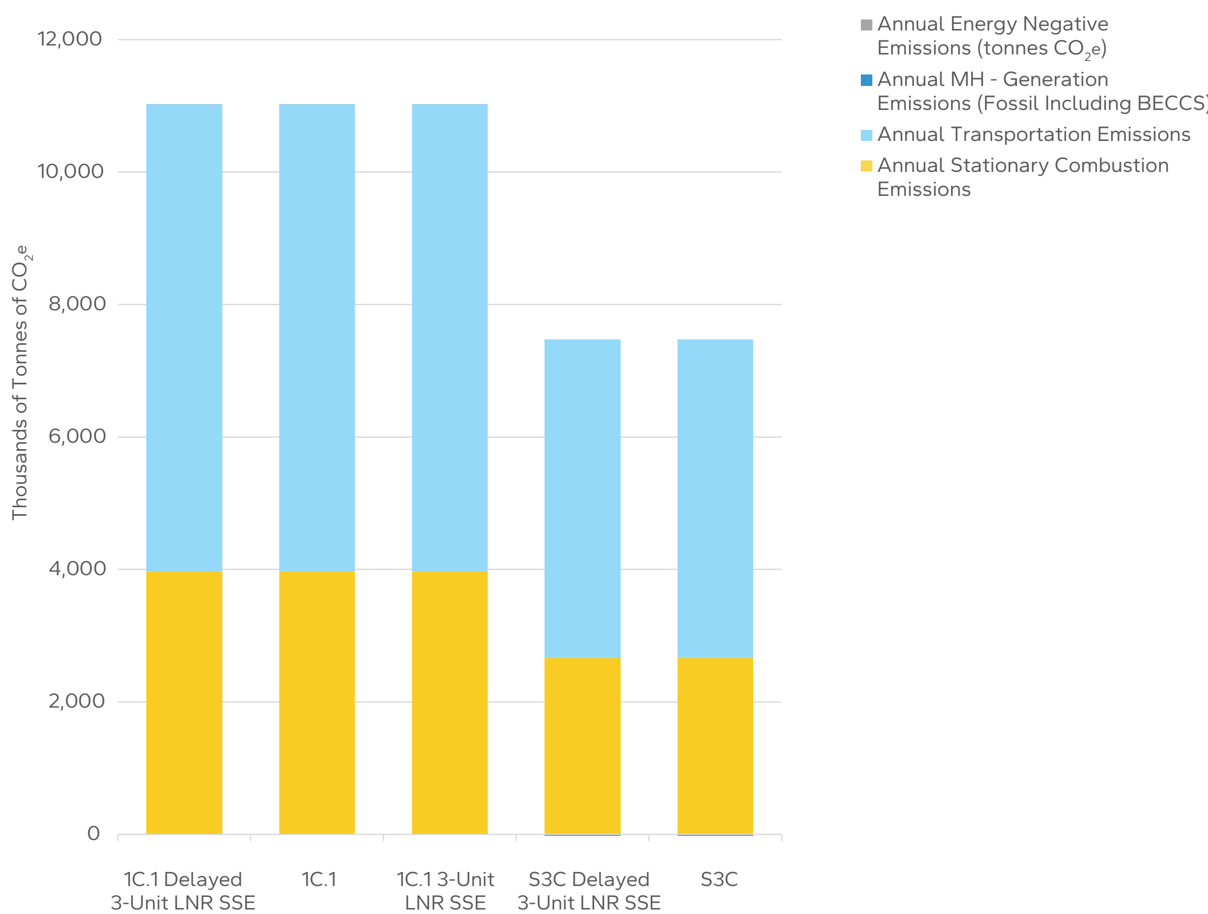


Figure A7.2.64 - Hydro Hydropower Enhancement Delays – 3-Unit LNR SSE ISD Study - Breakdown of GHG Emissions in 2040

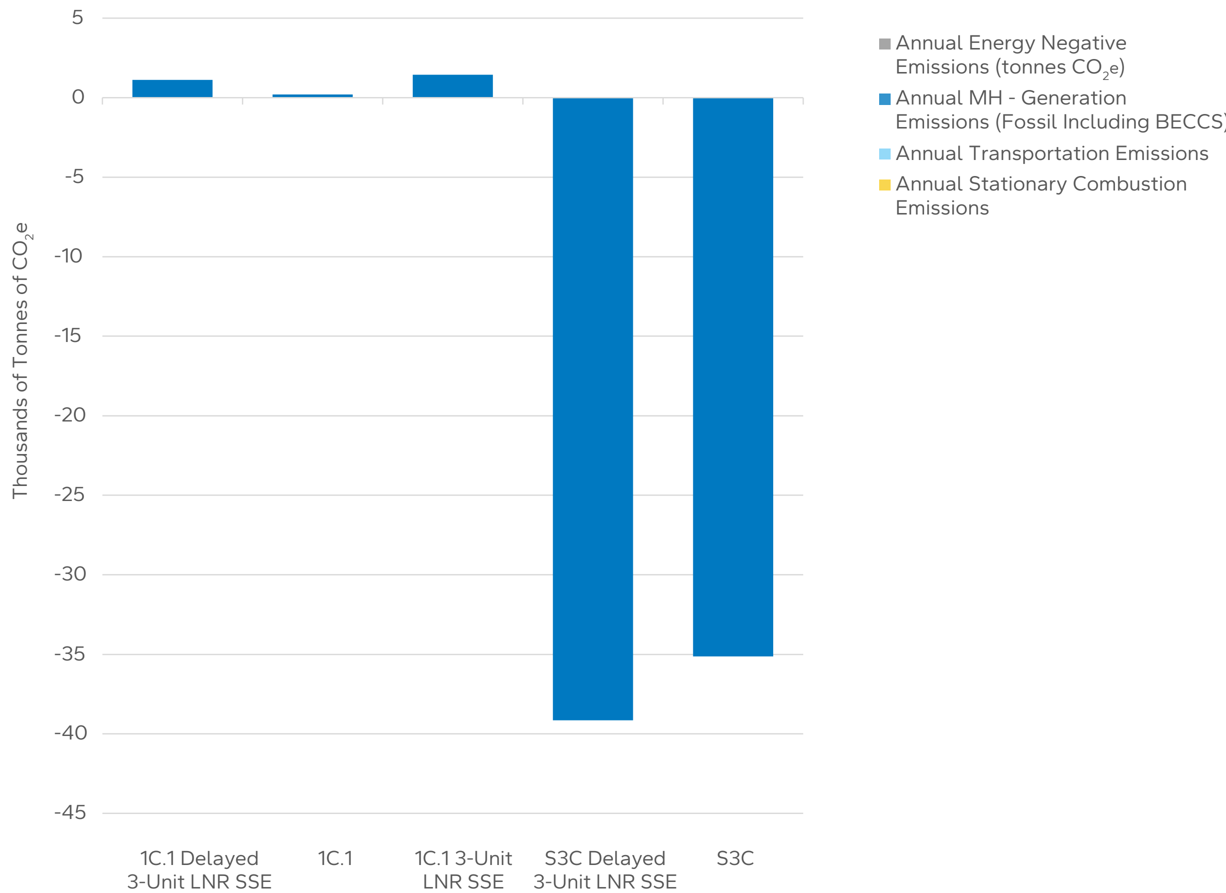
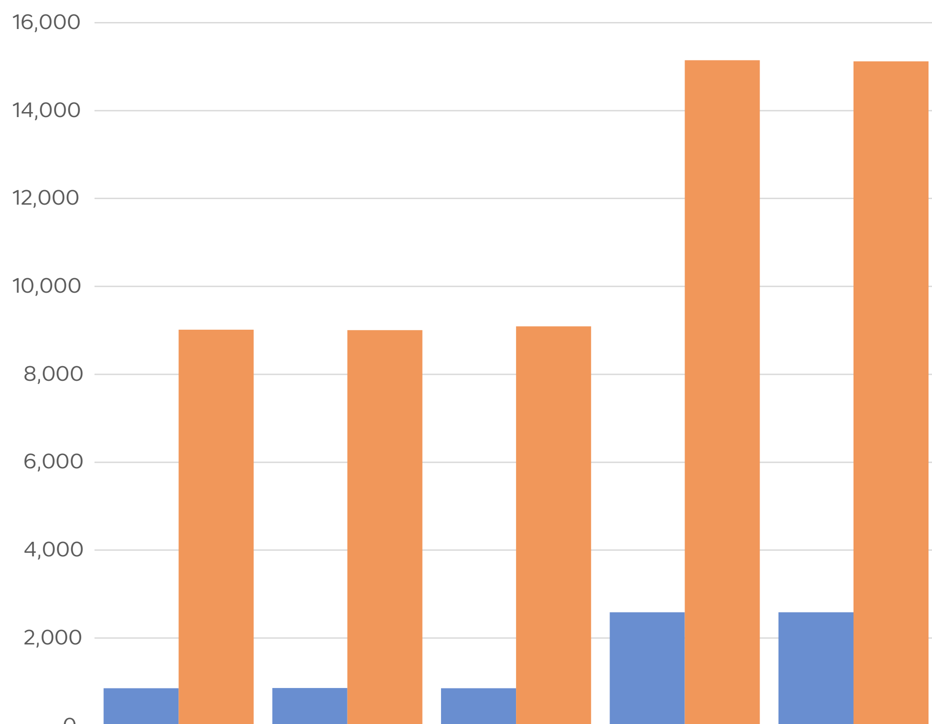


Figure A7.2.65 - Hydro Hydropower Enhancement Delays – 3-Unit LNR SSE ISD Study – Manitoba Electricity Generation GHG Emissions in 2040

Delaying the 3-unit LNR SSE project does not significantly change the economic indicator results by 2040, as shown in Figure A7.2.66. Under both the baseline and high load projections, incremental annual net system costs did not change meaningfully if the 3-unit LNR SSE projects were delayed. Under the 1-Baseline load projection, delaying the 3-unit LNR SSE project reduced the incremental PV of net system costs by $76 M 2024 CAN (1% reduction), compared to when the projects are completed by their earliest in-service dates. Delaying the 3-unit LNR SSE project has the opposite effect under the high load projection, marginally increasing the incremental PV of net system costs. Due to the variability observed in the financial indictor results, further economic analysis is required to understand the implications of delays to the LNR SSE projects.

There is no clear signal as to the financial implications of including the 3-unit LNR SSE project or not, under the 1-Baseline load projection when compared to the 1C.1 case which does not include LNR SSE. Regardless of ISD, including the LNR SSE project reduces the incremental annual net system cost. Conversely, including the LNR SSE project increases the cumulative present value of the net system costs when using the earliest ISD and when using the delayed ISD.



	1C.1 Delayed 3- Unit LNR SSE	1C.1	1C.1 3-Unit LNR SSE	S3C Delayed 3-Unit LNR SSE	S3C
Incremental Annual Net System Cost [M$/year]	859	862	857	2,589	2,587
Incremental Cumulative Present Value of Net System Costs [M$]	9,017	9,008	9,093	15,144	15,121

Figure A7.2.66 - Hydro Hydropower Enhancement Delays – 3-Unit LNR SSE ISD Study – Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs by 2040

3.6. No Fuel-Based Resources in Resource Options Strategy D

3.6.1. Objective

The No Fuel-Based Resources in Resource Options Strategy D sensitivity evaluates the impact of an even more constrained book-end than resource options strategy D by testing the implications of also removing biodiesel combustion turbines (CT-BD), hydrogen combustion turbines (CT-H2), and biomass combustion turbines (CT-biomass) as selectable resources.

3.6.2. Key Takeaways

- Under this sensitivity, instances of capacity need exceeding the accredited capacity supply potential from available resources persist throughout the planning horizon. Without access to fuel-based generation resources, insufficient resources are available to be built within the model's constraints to provide sufficient reliability to Manitobans, both in the short-term and long-term.
- Scenario 3D's reliance on CT-BD poses a risk due to the limited market for biodiesel fuel. This sensitivity increases the overall supply risk significantly by relying on small modular nuclear reactors (SMRs), a technology that is still in its demonstration stage.

3.6.3. Methodology

- Under resource options strategy D, the model cannot select any NG/RNG-CTs. Resource options strategy D was further restricted by removing CT-BD, CT-H2, and CT-biomass generation (with and without carbon capture and sequestration (CCS)) as selectable resource options.
- This sensitivity was only applied to Scenario 3D (as resource options strategy D was only applied to 3-High load projection). Results were compared to Scenario 3D.
- In alignment with resource options strategy D, the model removes the two existing combustion turbines at Brandon generating station from service in 2035; they are not removed prior to 2035 for the purpose of this sensitivity.

3.6.4. Results

Figure A7.2.67, Figure A7.2.68, and Figure A7.2.69 show the cumulative installed capacity additions in 2034, 2035, and 2050 respectively, for both the sensitivity and Scenario 3D. Unlike Scenario 3D, this sensitivity results in occurrences of capacity need exceeding the accredited capacity supply capability of the existing system and available resource options throughout the planning horizon, as shown in Figure A7.2.70. As shown in Figure A7.2.68 in 2035, capacity that was provided by fuel-based generation (CT-BDs, CT-H2, and CT-biomass) in Scenario 3D is partially replaced with the advancement of 900 MW of SMRs.

Figure A7.2.67, Figure A7.2.68, and Figure A7.2.69 outline the following implications of requiring no fuel based resources on the ability to meet accredited capacity needs:

- By 2034, 1,440 MW of capacity need cannot be met when non-fuel based resource options are limited in the pre-2035 period.
- Unmet capacity needs are reduced to 760 MW by 2035, but not eliminated as in 2035 the model selects 900 MW of Nuclear SMRs.
- By 2050, unmet capacity needs increase to 5,500 MW.

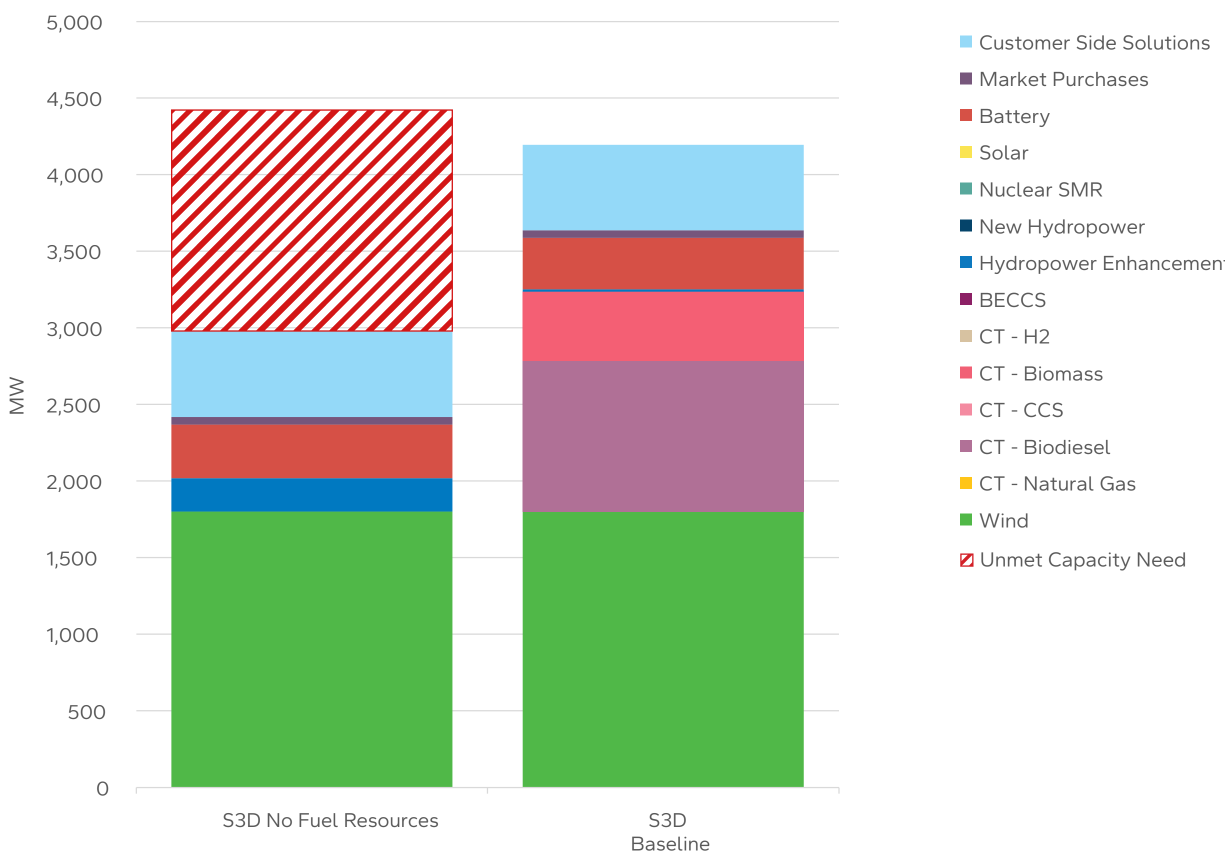


Figure A7.2.67 - Sensitivities – No Fuel Based Resource in Resource Options Strategy D: Cumulative Installed Capacity [MW] Additions by Resource Type by 2034

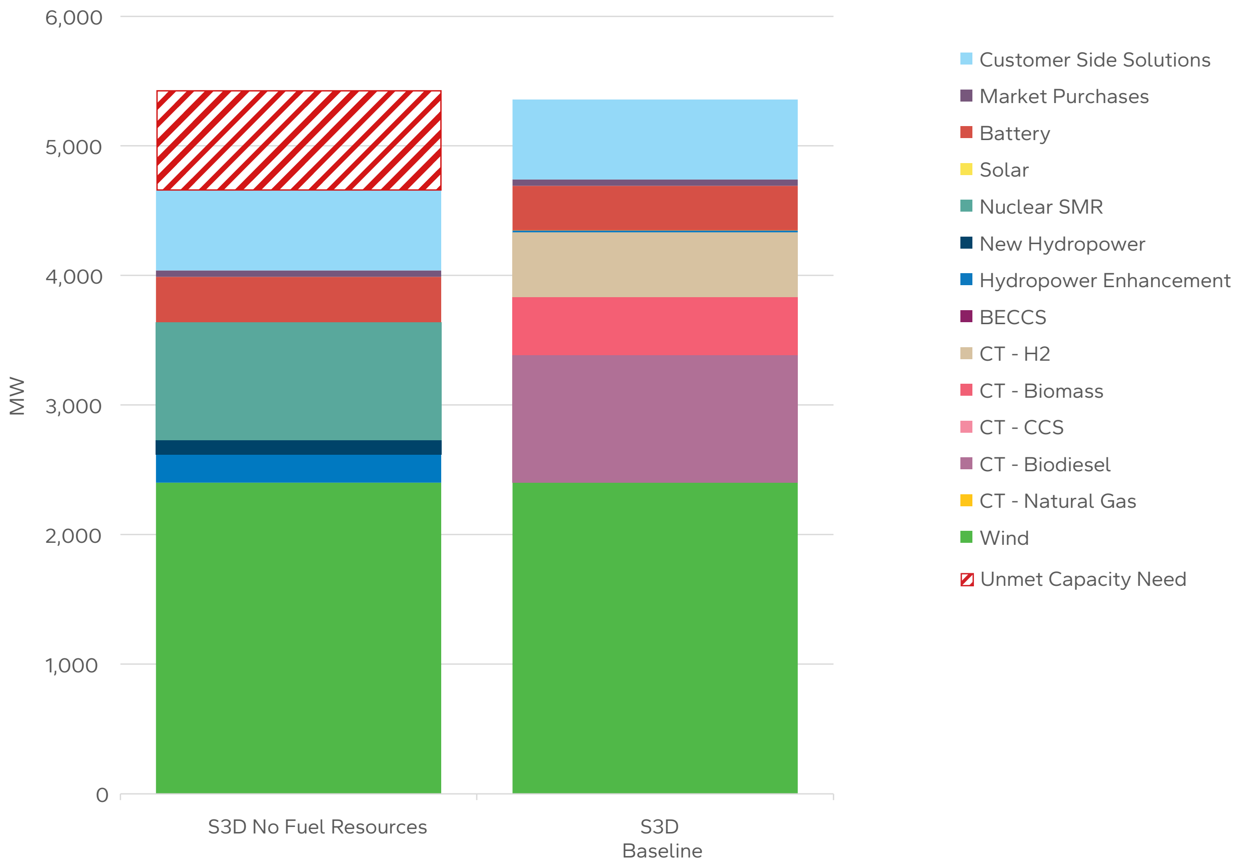


Figure A7.2.68 - Sensitivities – No Fuel Based Resource in Resource Options Strategy D: Cumulative Installed Capacity [MW] Additions by Resource Type by 2035

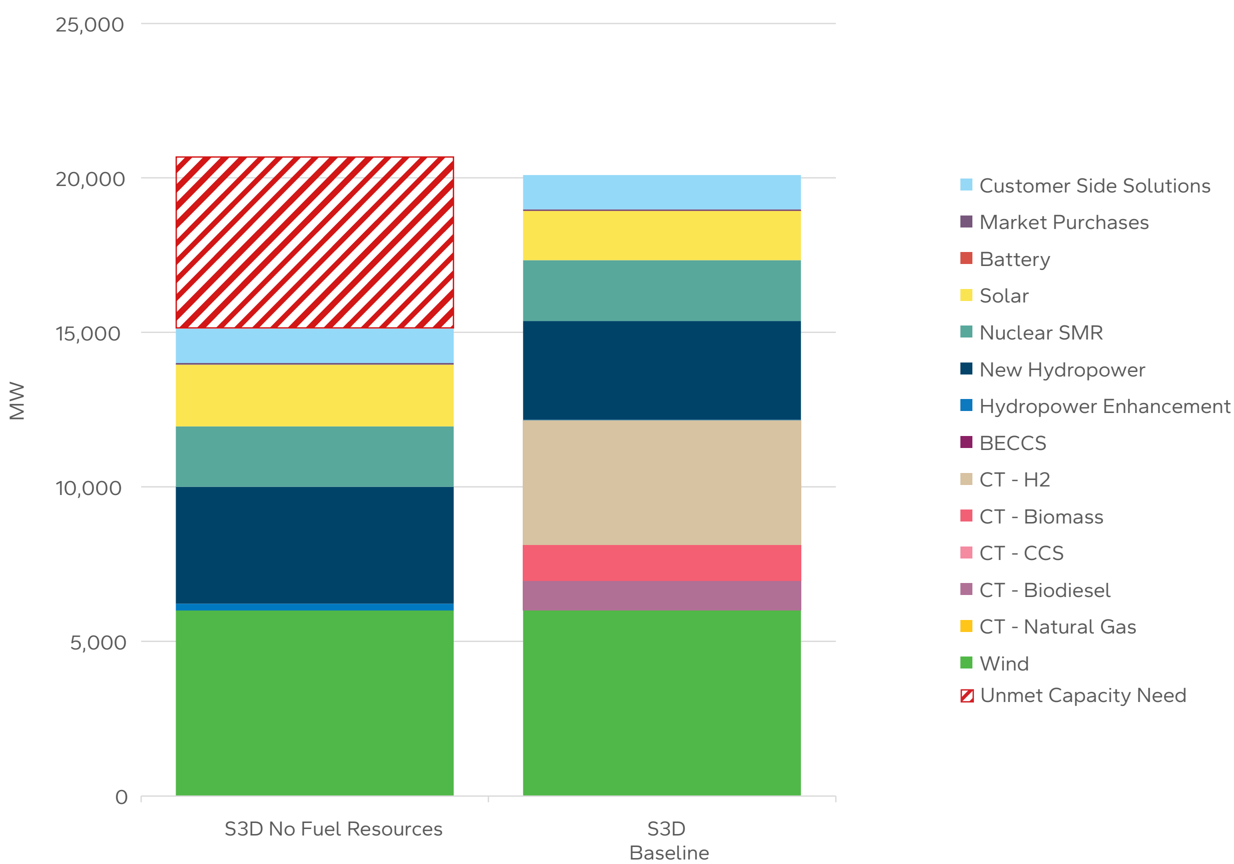


Figure A7.2.69 - Sensitivities – No Fuel Based Resource in Resource Options Strategy D: Cumulative Installed Capacity [MW] Additions by Resource Type by 2050

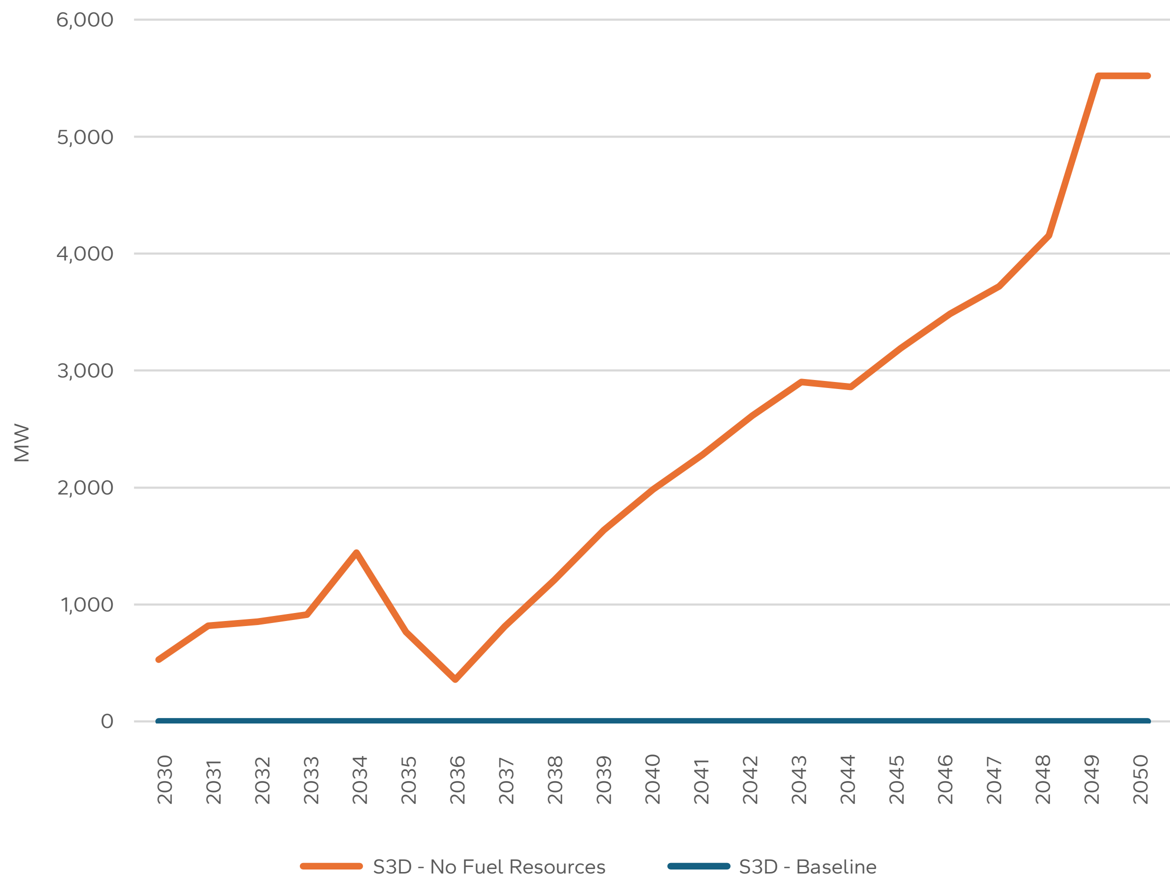


Figure A7.2.70 - Unmet Capacity Needs for S3D Baseline and the S3D No Fuel Resources sensitivity from 2030 to 2050

Due to the persistence of unmet capacity need throughout the study horizon, economic indicators for this sensitivity cannot be meaningfully compared to Scenario 3D.

3.7. Lower Negative GHG Emissions Load

3.7.1. Objective

To achieve a net-zero economy in Manitoba by 2050, the 2025 IRP load projections assumed a negative GHG emissions load would be required to remove any remaining emissions that were not reduced through other assumptions in the load projections. Feedback from Round 1 Engagement included concern for the amount of load required to net Manitoba non-combustion GHG emissions to zero. As a part of the response to this feedback, this sensitivity examines how eliminating the load increases required to offset residual non-combustion GHG emissions in 2050 could affect the portfolio of resources.

3.7.2. Key Takeaways

- Removing negative GHG emissions load from Scenario 3C to offset non-combustion GHG emissions does not produce any clear/consistent financial benefits because it only lowers annual peak electrical demand by 400 MW (a relatively small amount considering annual electrical energy is 11,400 GWh less (7,600 GWh compared to 19,000 GWh) than the 3-High load projection assumption). In the 3-High load projection, negative GHG emissions load can be potentially optimized to have a very modest impact on peak annual demand. Due to relatively low peak load impacts, negative GHG emissions load is a relatively low cost load to serve on a delivered energy (GWh) basis; even though system costs are less (for this sensitivity), the expected loss of revenue, resulting from the assumed lower load, is estimated to increase average energy costs overall, not lower them.
- Lowering the load requirements of other decarbonization loads (e.g., pursuing additional dual-fuel systems, as assumed for the 2-Medium load projection) can be a more effective method of reducing electric system costs, associated net system costs, and energy rates than lowering negative GHG emissions load.

3.7.3. Methodology

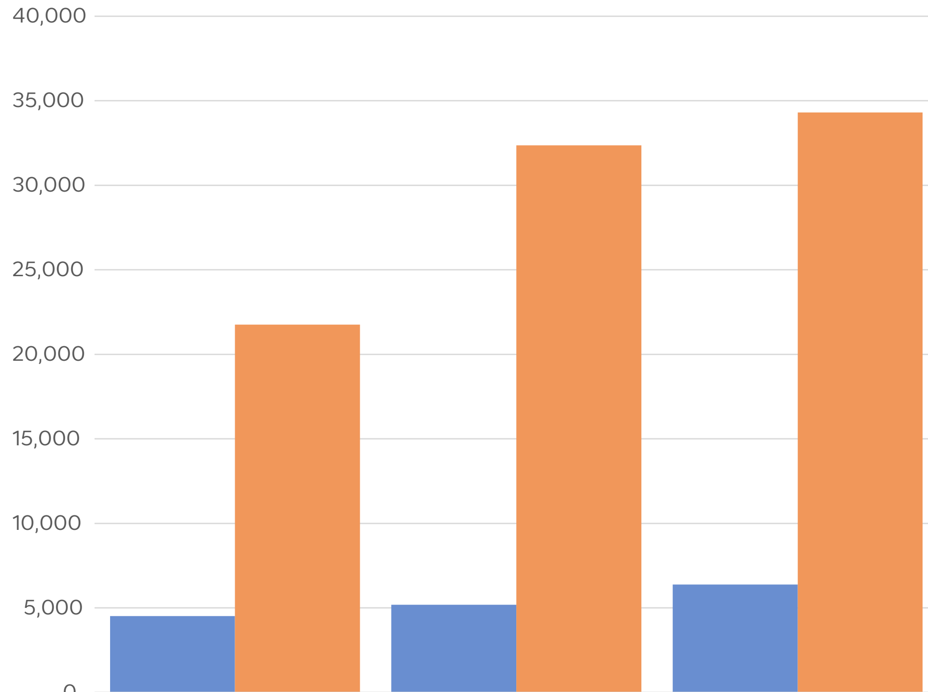
- Scenario 3C was modified so that negative GHG Emissions Load was lower, as shown in Table A7.2.16. No justification for this lower load is specifically assumed for this sensitivity, but some possibilities could include combinations of:
  - Non-combustion GHG emissions in Manitoba being reduced further than assumed for the 2025 IRP load projections.
  - Current negative GHG emissions technology becoming less energy intensive in the future.
  - Substantial negative GHG emissions becoming achievable in Manitoba via natural processes on an ongoing basis.
  - Manitoba's economy not achieving a net-zero economy by 2050.
- As the resulting annual electrical energy (GWh) in 2050 falls below both the 2-Medium load projection and 3-High load projection, this sensitivity was compared against both scenarios 2C and 3C.
- Sensitivity analysis was primarily focused on 2050, when the negative GHG emissions load is assumed to appear.
- No costs for DACCS (e.g., capital costs, operational costs) were included in any 2025 IRP analysis, including for this sensitivity, beyond the costs to serve (or avoided costs not to serve) negative GHG emissions load.

Table A7.2.16 – System-Wide and Negative GHG Emissions Load in Annual Electrical Energy (GWh) and Annual Peak Electrical Demand (MW) in 2050

	2-Medium load projection (net-zero economy)	3-High load projection (net-zero economy)	3-High load projection, lower negative GHG emissions load
Negative GHG Emissions Annual Electric Energy (GWh)	22,900	19,000	7,600
System-Wide Annual Electric Energy (GWh)	65,900	75,400	64,000
Negative GHG Emissions Annual Peak Electrical Demand (MW)	1,720	640	250
System-Wide Annual Peak Electrical Demand (MW)	10,500	14,400	14,000

3.7.4. Results

Figure A7.2.71 presents both the incremental annual net system cost (in 2050) and the cumulative net present value (NPV) of net system costs (2024-2050) for Scenarios 2C and 3C as well as this sensitivity. As expected, since end-use load is less, and all else is held equal, the net system cost metrics are lower in the sensitivity compared to Scenario 3C: the incremental NPV value is 6% less and the incremental annual value is 19% less.

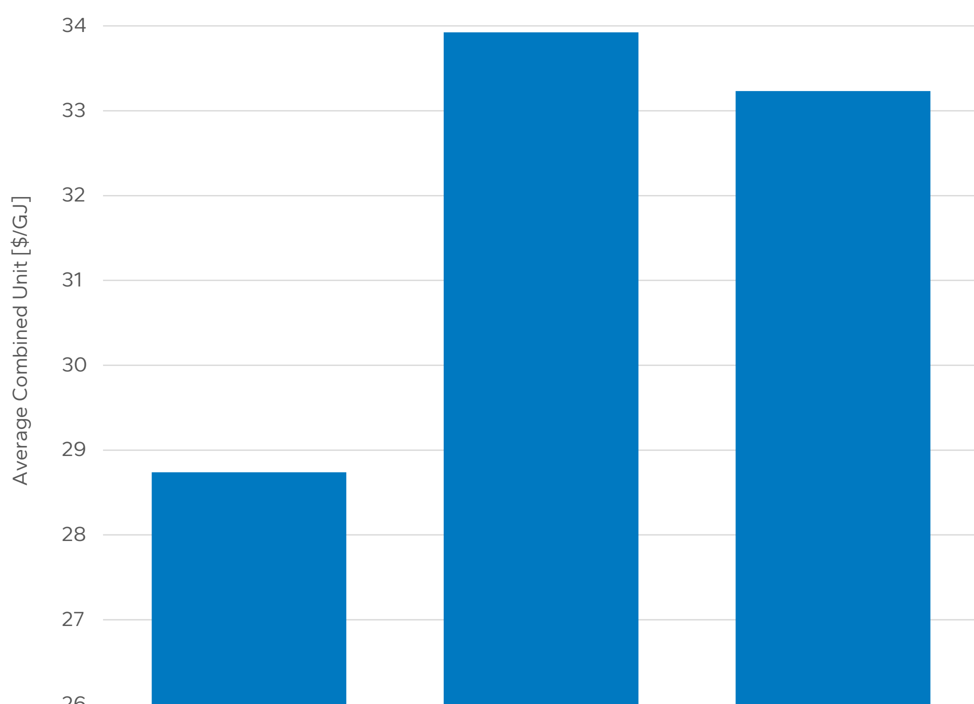


	S2C	S3C Lower Negative Emissions Load	S3C
Incremental Annual Net System Cost [M$/year]	4,516	5,188	6,389
Incremental Cumulative Present Value of Net System Costs [M$]	21,755	32,367	34,307

Figure A7.2.71 - Sensitivities – Lower Negative GHG Emissions Load: Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (in 2050)

In addition to having a lower net system cost (compared to Scenario 3C), this sensitivity also assumes over 11 TWh less domestic (within Manitoba) electricity sales per year. Figure A7.2.72 presents the base combined energy unit requirement for Scenarios 2C and 3C as well as the sensitivity. On a per unit basis (which relates to both electricity and natural gas rates), energy costs under this sensitivity are higher in 2050 (compared to Scenario 3C). Since negative GHG emissions load is assumed to have a minimal impact on peak load in Manitoba, negative GHG emissions load is a relatively low-cost load to serve on a delivered energy (GWh) basis.

The cost metrics for Scenario 2C (as shown in both Figure A7.2.71 and Figure A7.2.72) reinforce this observation: Scenario 2C, which assumes Manitoba achieves a net-zero economy in 2050 with a lower annual peak electrical demand, has a higher negative GHG emissions load in 2050 than both Scenario 3C and the sensitivity.



S2C	S3C Lower Negative Emissions Load	S3C
28.7	33.9	33.2

Figure A7.2.72 - Sensitivities – Lower Negative GHG Emissions Load: Average Base Combined Energy Unit Requirement ($/GJ) (in 2050)

Figure A7.2.73 presents the cumulative installed capacity additions in 2050 for Scenarios 2C and 3C as well as this sensitivity. If negative GHG emissions load is less than assumed in Scenario 3C then, all else being equal, less resources will be required; however, Scenario 2C, which assumes a net-zero economy is achieved in 2050 with a much lower peak electrical demand requirement, requires less resources, and less associated net system cost, than this sensitivity.

While new hydropower (1,485 nominal MW) was selected under Scenario 3C, in this sensitivity the only new hydropower resource selected was a much smaller new hydropower (120 nominal MW). This is because negative GHG emissions load is best served by baseload resources, such as new hydropower.

The model selected additional solar and combined cycle natural gas combustion turbines with carbon capture and sequestration (CCGT-CCS) for the sensitivity but also did not select any SMRs. This is consistent with the general 2025 IRP finding that multiple long-term planning strategies for energy-providing resources are available to the model to meet load growth later in the planning horizon. However, there is no clear link between this sensitivity's assumptions and the model's choice between these long-term strategies. As described in the foreword of this appendix, this reflects limitations of the model's optimization late in the study horizon. As shown in Figure A7.2.74, the model selected a nearly identical resource mix in 2040 for both Scenario 3C and the sensitivity.

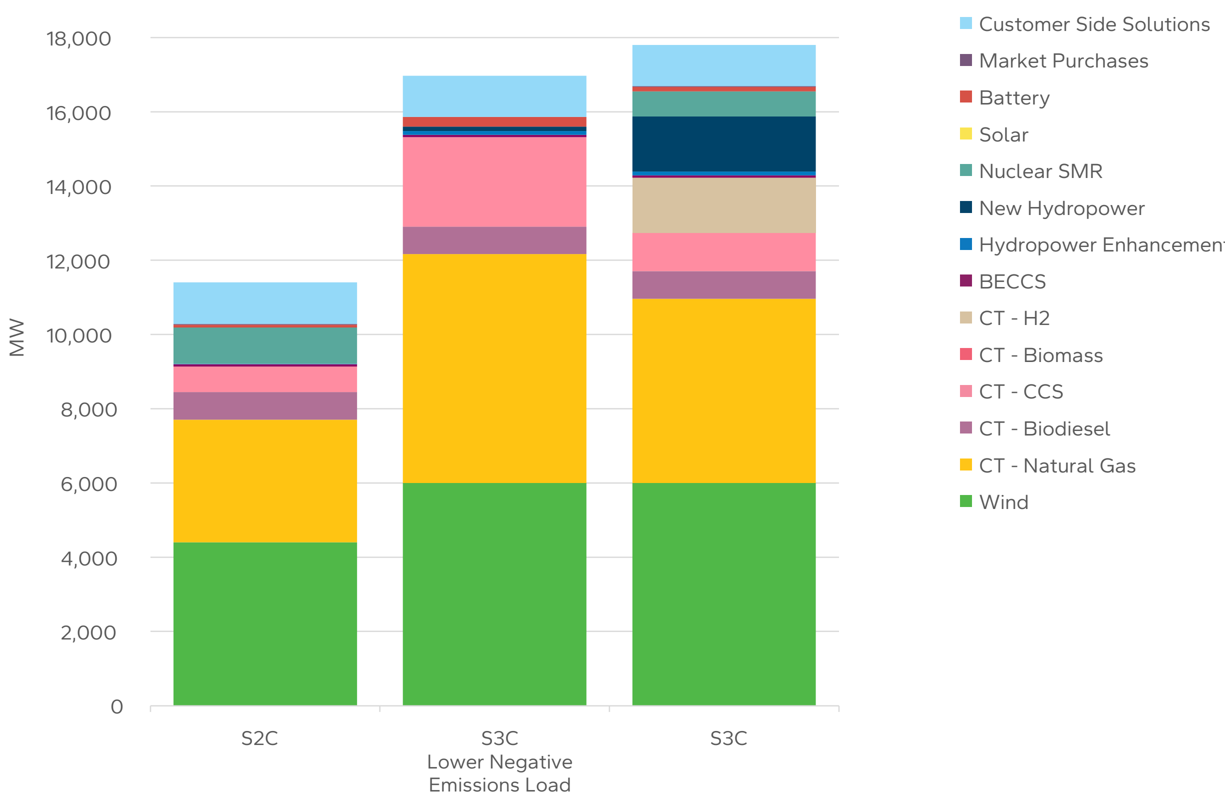


Figure A7.2.73 - Sensitivities – Lower Negative GHG Emissions Load: Cumulative Installed Capacity [MW] Additions by Resource Type by 2050

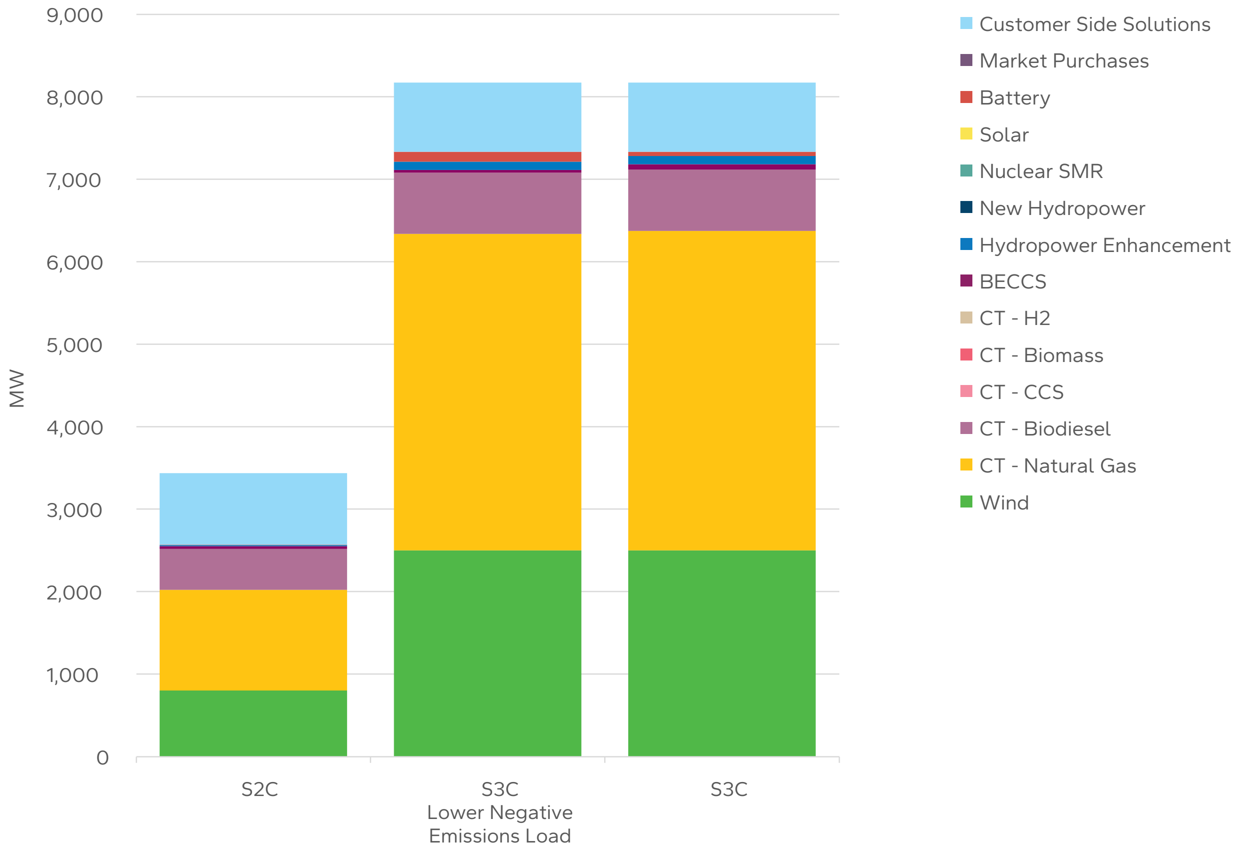


Figure A7.2.74 - Sensitivities – Lower Negative GHG Emissions Load: Cumulative Installed Capacity [MW] Additions by Resource Type by 2040

Figure A7.2.75 presents an estimate of total provincial GHG emissions from 2024 to 2050 for scenarios 1C, 2C, and 3C as well as this sensitivity. While the two comparison scenarios (S2C and S3C) are assumed to achieve a net-zero economy by 2050, it is not assumed that the sensitivity does. This sensitivity represents an energy future where Manitoba's net GHG emissions in 2050 are up to 5.9 million tonnes CO_2e. Compared to Scenario 1C, it is assumed that Manitoba's GHG emissions reductions would be limited to about 67% below those estimated for the 1-Baseline load projection without negative GHG emissions to offset remaining non-combustion GHG emissions. If negative GHG emissions could be achieved at a lower load than assumed, then Manitoba GHG emission could be lower than what is presented Figure A7.2.75.

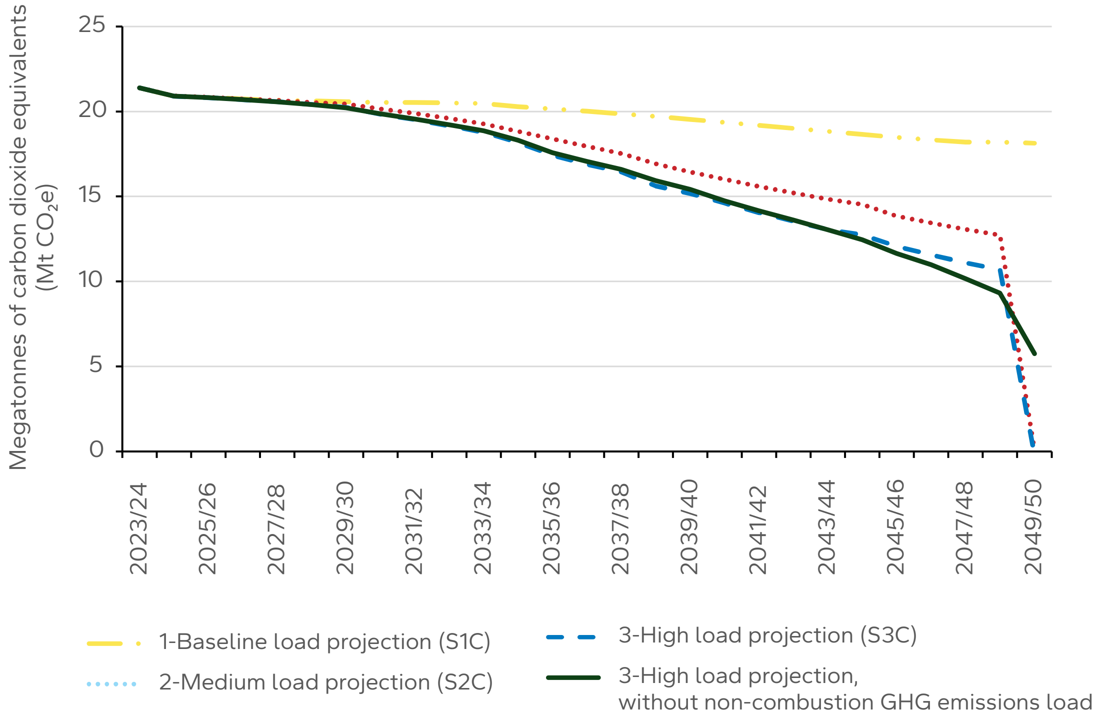


Figure A7.2.75 - Sensitivities – Lower Negative GHG Emissions Load: Manitoba GHG Emissions 2024-2050

3.8. No New Hydrogeneration

3.8.1. Objective

This sensitivity shows the effect of not allowing any new hydropower for the 2-Medium load projection compared to scenario 2B.

3.8.2. Key Takeaways

- Small modular nuclear reactors (SMRs) are built instead of new hydropower in the late 2040s to meet the negative GHG emissions load.
- By 2050, without hydropower, the model builds almost 1,000 MW of nuclear SMR and an additional 500 MW of wind generation and 150 MW of CT-NG.
- This sensitivity demonstrates that new hydropower is a possible alternative to resources such as nuclear SMRs and biodiesel combustion turbines (CT-BD).

3.8.3. Methodology

- The model was restricted to prevent any new hydropower from being included in the selected portfolio of resources. All other types of generation were allowed to be selected.
- Scenario 2B was used as a basis for this sensitivity, as this scenario included new hydropower.

3.8.4. Results

- In the sensitivity where no new hydropower is allowed to be built, the model needs to select other generation options to meet the large energy demands late in the study period. In Scenario 2B, new hydropower came into service in 2048; instead of new hydropower, the sensitivity builds almost 1,000 MW of nuclear SMR in 2049 and 500 MW more wind by 2050.

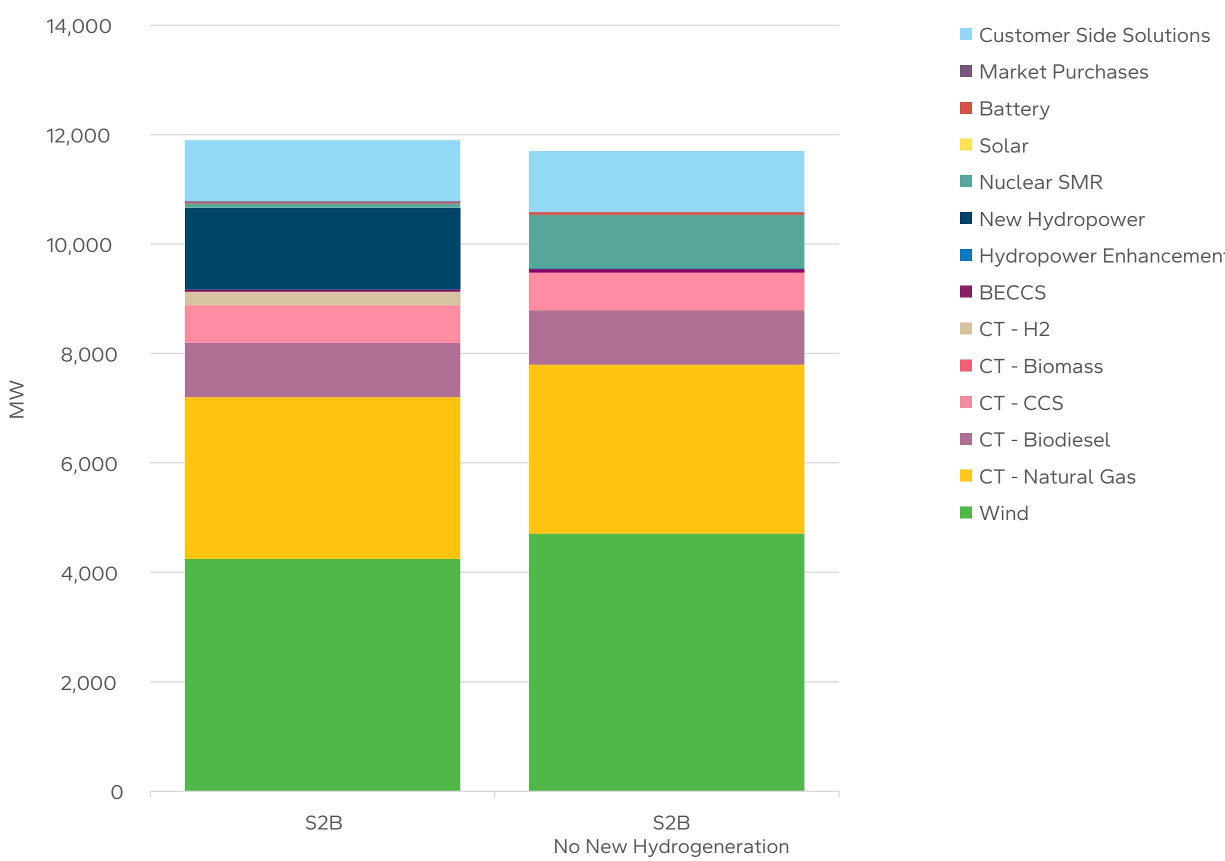
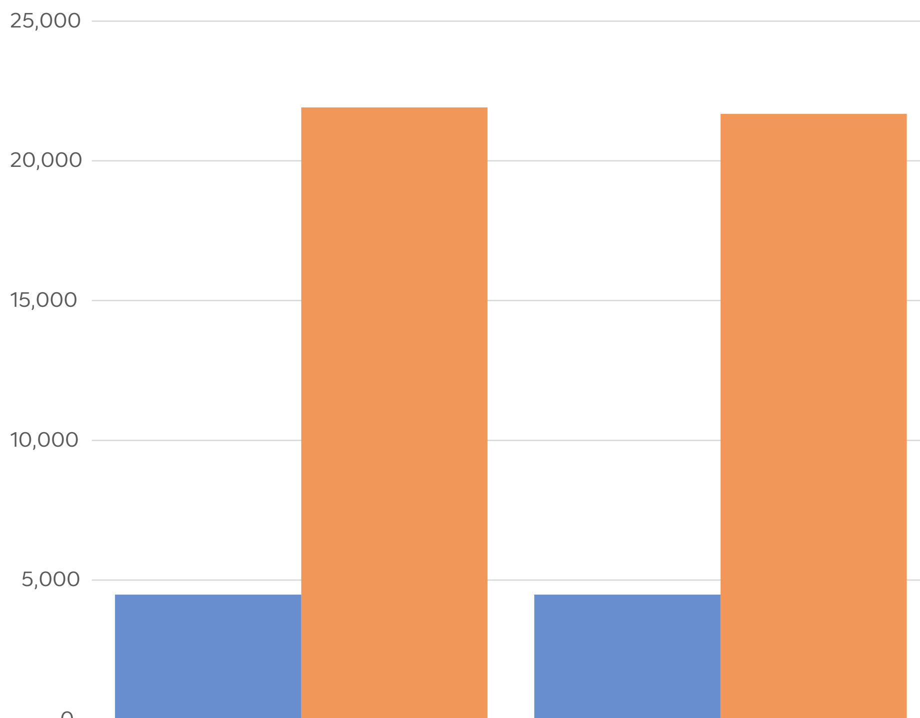


Figure A7.2.76 - Sensitivity - No New Hydrogeneration - Installed Capacity in 2050

- The annual net system costs are essentially the same when comparing the two cases as seen in Figure A7.2.77.
- New hydropower has long lead time costs and as a result, it is often built by the model more than 20 years in the future. Because of this, the costs of new hydropower in the model can have a greater effect on present values than cases with shorter lead time capital projects. Figure A7.2.77 shows the incremental present value of net system cost. Incrementally, sensitivity 2B No New Hydrogeneration costs $230 M 2024 CAN$ less over the study period than Scenario 2B. Large capital expenditures are needed for both cases after 2040 to meet the negative GHG emissions load ($15.9 B and $17.8 B 2024 CAN$ (No New Hydrogeneration and Scenario 2B respectively))



	S2B	S2B No New Hydrogeneration
Incremental Annual Net System Cost [M$/year]	4,477	4,479
Incremental Cumulative Present Value of Net System Costs [M$]	21,909	21,678

Figure A7.2.77 - Sensitivity - No New Hydrogeneration: Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2050

3.9. Fossil Fuel Elimination in Ground Transportation and Space Heating

3.9.1. Objective

During Round 1 Engagement, Manitoba Hydro heard that the IRP should consider what is required to eliminate fossil fuel use in the ground transportation and space heating sectors. This feedback resulted in Manitoba Hydro preparing a load projection sensitivity (LPS) that assumed Manitoba's economy eliminated fossil fuel consumption in Manitoba's ground transportation and space heating sectors by 2050, achieved by additional electrification beyond what was assumed for the 3-High load projection. This sensitivity tests the potential impact on the portfolio of resources of the LPS.

3.9.2. Key Takeaways

- In terms of electric system costs, associated net system costs, and energy rates, the Load projection sensitivity represents a less cost-effective pathway to a net-zero economy in Manitoba than what was assumed for 2-Medium and 3-High load projections.
- There are parallel takeaways between this sensitivity and the Lower Negative GHG Emissions Load sensitivity:
  - Lowering the load requirements of other decarbonization loads (e.g. pursuing additional dual-fuel systems, as assumed for the 2-Medium load projection) can be a more effective method of lowering electric system costs, associated net system costs, and energy rates than eliminating fossil fuel use in specific sectors.
  - Indirectly removing negative GHG emissions load, by eliminating fossil fuel consumption in certain sectors, increases energy rates. Due to relatively low peak load impacts, negative GHG emissions load is a relatively low-cost load to serve on a delivered energy (GWh) basis; comparatively, electric space heating load is a higher cost load to serve on a delivered energy basis.
- Even though negative GHG emissions load is assumed to be less (in 2050) for the LPS, annual system wide peak electrical demand is much higher (about 3,000 MW higher) due to much higher electric heating load during system peak.
- Manitoba would be expected to require more electric resources to support the elimination of fossil fuels in the sectors identified for this sensitivity.

- While both the 3-High load projection and the Load projection sensitivity represent a net-zero economy future in 2050, the Load projection sensitivity results in a modest reduction of 3 million tonnes CO_2e of cumulative GHG emissions in Manitoba (or a 0.7% reduction), prior to 2050. Manitoba Hydro cannot claim these GHG emissions reductions, they are typically attributed to other Manitoba entities.

3.9.3. Methodology

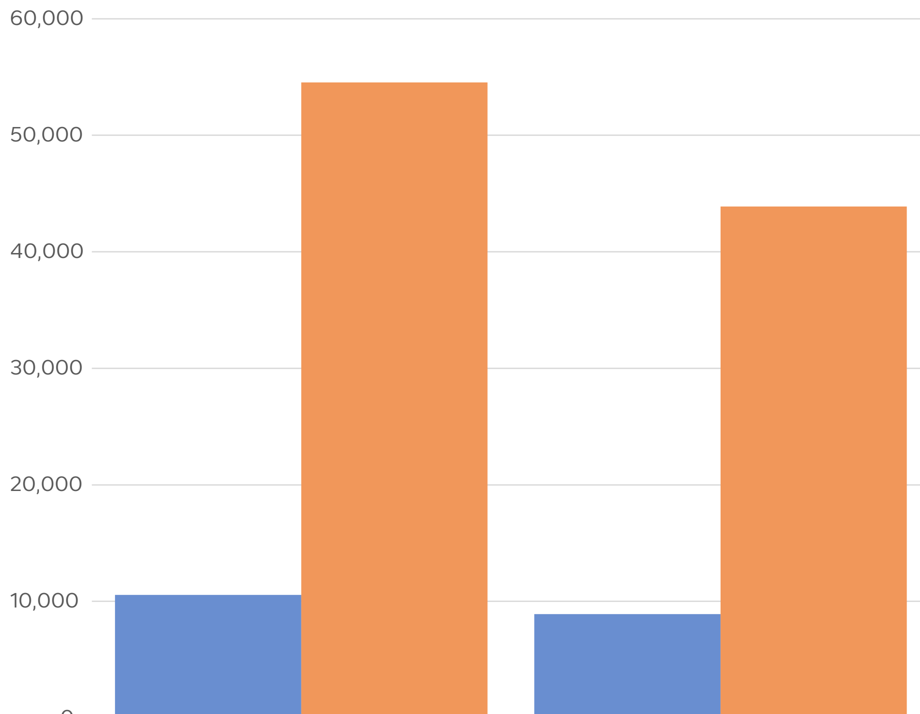
- The 3-High load projection was replaced in Scenario 3D with the LPS, with load impacts shown in Table A7.2.17.
- Results are compared to S3D: it was assumed that in a future where there was a requirement to eliminate fossil fuels from ground transportation and space heating, there would also be a requirement to eliminate fossil fuels from electricity generation.
- Sensitivity analysis was primarily focused on 2050 as that is when the fossil fuel elimination is assumed to be achieved.

Table A7.2.17 – Sensitivity - Fossil Fuel Elimination in Ground Transportation and Space Heating - System-Wide and Negative GHG Emissions Load in Annual Electrical Energy (GWh) and Annual Peak Electrical Demand (MW) in 2050

	3-High load projection (net-zero economy)	Load Projection Sensitivity (net-zero) economy
Negative GHG Emissions Annual Electric Energy (GWh)	19,000	13,300
System-Wide Annual Electric Energy (GWh)	75,400	76,700
Negative GHG Emissions Annual Peak Electrical Demand (MW)	640	440
System-Wide Annual Peak Electrical Demand (MW)	14,400	17,400

3.9.4. Results

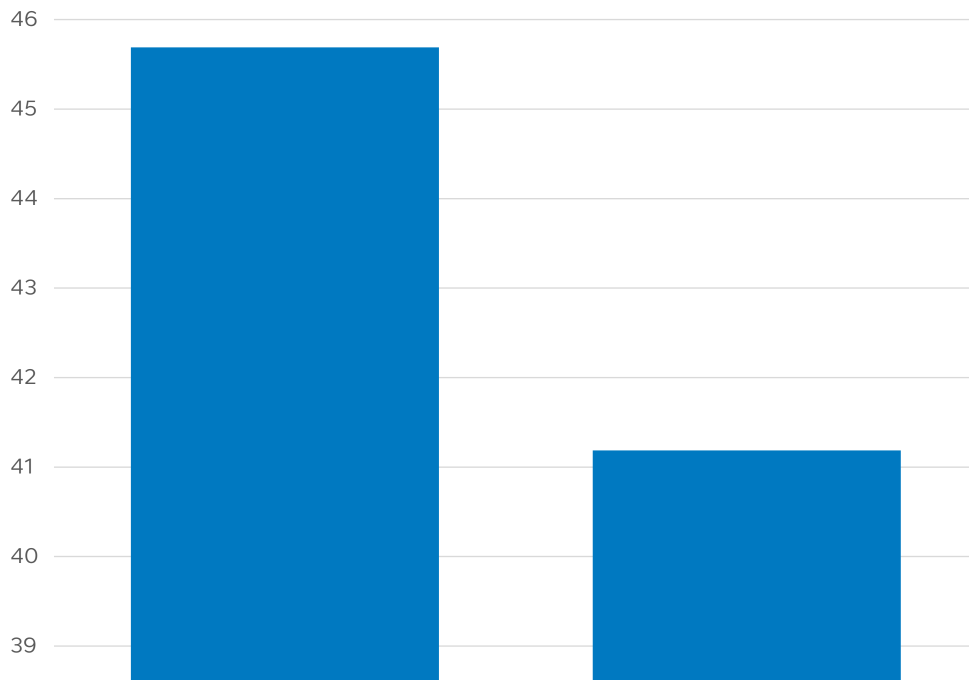
Figure A7.2.78 presents both the incremental annual net system cost (in 2050) and the cumulative net present value (NPV) of net system costs (2024-2050) for Scenario 3D as well as this sensitivity. As expected, since end-use load is higher, and all else is held equal, the net system cost metrics are higher in the sensitivity compared to Scenario 3D: the incremental NPV value is 24% higher and the incremental annual value is 18% higher.



	S3D LPS	S3D Baseline
Incremental Annual Net System Cost [M$/year]	10,557	8,916
Incremental Cumulative Present Value of Net System Costs [M$]	54,528	43,895

Figure A7.2.78 - Sensitivity - No New Hydrogeneration: Incremental Cumulative Present Value of Net System Costs [M 2025 CAN$] and Incremental Annual Net System Costs [M 2025 CAN$/yr] to 2050

While the incremental NPV of net system costs for this sensitivity is about 24% higher compared to Scenario 3D, it only assumes domestic electricity sales (in GWh) increase by less than 2% per year (i.e., costs increase without a corresponding source of revenue). The result is an increase in energy rates. Figure A7.2.79 presents the base combined energy unit requirement for Scenario 3D as well as this sensitivity. On a per unit basis, energy costs under this sensitivity are higher in 2050 ($45.7/GJ compared to $41.2/GJ in Scenario 3D). Eliminating fossil fuels for space heating results in relatively high-cost load to serve, on a delivered energy basis, due to the significant incremental increase in annual peak electrical demand.



S3D LPS	S3D Baseline
45.7	41.2

Figure A7.2.79 - Sensitivity – Fossil Fuel Elimination in Ground Transportation and Space Heating: Average Base Combined Energy Unit Requirement ($/GJ) in 2050)

The Load projection sensitivity lowered negative GHG emissions load by 5,700 GWh (annual electric energy), a substantial amount. The Lower Negative GHG Emissions Load Sensitivity lowered negative GHG emissions load by 11,400 GWh (annual electric energy), an even more substantial amount. In both cases, neither decrease in negative GHG emissions load produced favorable financial outcomes in terms of energy rates. Due to relatively low peak load impacts, negative GHG emissions load is a relatively low-cost load to serve on a delivered energy (GWh) basis.

Figure A7.2.80 presents the cumulative installed MW additions in 2050 for Scenario 3D and this sensitivity. Resource type additions are similar, but this sensitivity requires more resources – most significant differences include approximately 600 MW of additional new hydropower, 600 MW of additional hydrogen combustion turbines (CT-H2), and 400 MW of additional solar

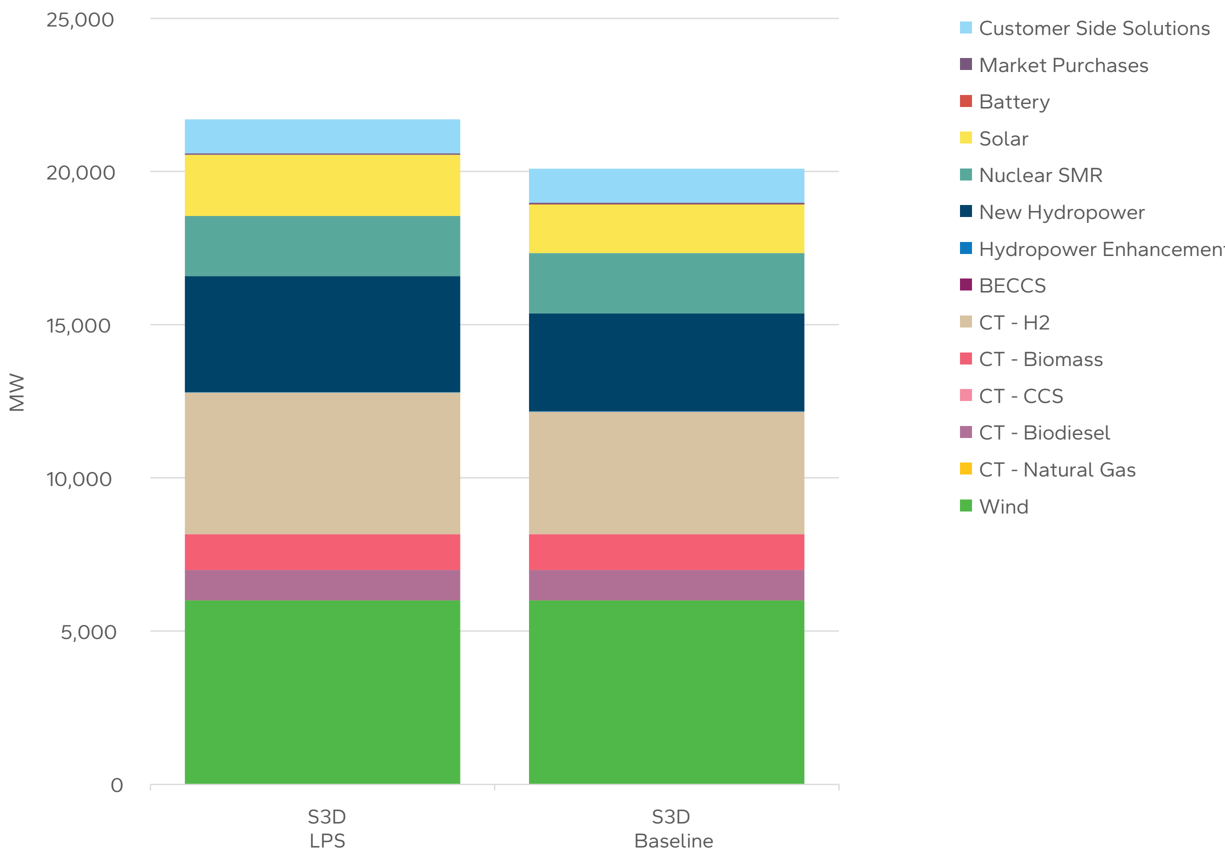


Figure A7.2.80 - Sensitivity – Fossil Fuel Elimination in Ground Transportation and Space Heating: Cumulative Installed Capacity [MW] Additions by Resource Type in 2050

Figure A7.2.81 presents an estimate of total provincial GHG emissions from 2024 to 2050 for scenario 3D as well as this sensitivity. Net-zero economies in 2050 are assumed for both; however, this sensitivity is assumed to have reduced net cumulative economy-wide GHG emissions in Manitoba from 459 Mt to 456 Mt, or a 0.7% reduction, over the study horizon.

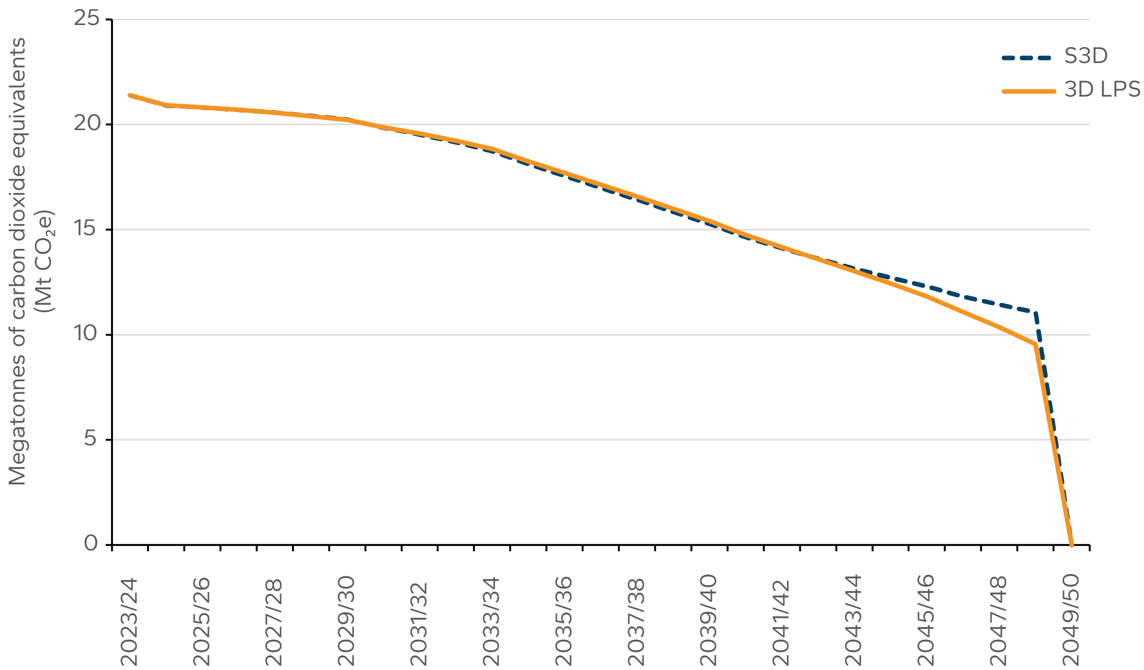


Figure A7.2.81 - Sensitivity – Fossil Fuel Elimination in Ground Transportation and Space Heating: Manitoba GHG Emissions 2024-2050

The elimination of fossil fuels in certain sectors could influence electricity generation GHG emissions throughout the entire interconnected region. Table A7.2.18 presents cumulative net incremental regional (non-Manitoba) electricity generation GHG emissions – the values are all negative as they represent avoided (but are not negative emissions) GHG emissions. Cumulatively, over the period from 2024 to 2050, the Load projection sensitivity resulted in approximately 2% (4 million tonnes) of additional avoided regional electricity generation GHG emissions, on average.

Table A7.2.18 – Sensitivity - Fossil Fuel Elimination in Ground Transportation and Space Heating -Cumulative (2024-2050) net incremental regional electricity generation GHG emissions

Scenario	Load Projection	Cumulative net incremental regional electricity generation GHG emissions from 2024 to 2050 (million tonnes CO_2e)
S3D	3-High load projection	-177
S3D – LPS Sensitivity	Load projection sensitivity	-181

3.10. Climate Change Affected Inflows

3.10.1. Objective

Climate change has the potential to impact Manitoba Hydro through its effect on the water supply used for generating hydropower. The purpose of this sensitivity is to explore potential high and low inflow cases determined through an analysis of future climate projections of temperature and precipitation, used to drive a hydrological model set up for watersheds relevant to hydropower generation in Manitoba. The range of implications from climate change affected inflows was assessed based on resource selections, system operations, GHG emissions, and costs.

3.10.2. Key Takeaways

- Near Term: The lower inflow sensitivity increases the selection of enhancements to existing hydropower, a non-emitting resource option. In the high inflow sensitivity, biodiesel combustion turbines (CT-BD) were advanced in the near-term as compared to 3C, partly replacing natural-gas fuelled turbines as a dispatchable capacity option.
- Long Term: Under the 3-High load projection, lower inflows result in increased additions of resource options in the long term that do not rely on fossil fuels for electricity generation.
- Regardless of the load projection or inflow conditions being considered (e.g., focusing on low or high inflow flow years from within the overall record, or when averaging across all flow years), the low inflow sensitivity results in reduced hydropower, reduced opportunity export, and increased imports compared to the high inflow sensitivity.
- Regional (non-Manitoba) avoided electricity generation GHG emissions are reduced in the low inflow sensitivities and increase in the high inflow sensitivities.
- The higher inflow sensitivities consistently showed improved financial metrics compared to the lower inflow sensitivities.
- 2035 net-zero grid requirements are met in all cases studied in this sensitivity.

3.10.3. Methodology

The climate change sensitivities that were analyzed were selected to reflect a representative range of potential changes in mean annual hydropower generation. Climate change implications specific to Manitoba Hydro were determined through analysis and modelling that relied upon future projections of temperature and precipitation derived from Global Climate Models (GCMs) driven by various future GHG emission scenarios (known as Shared Socio-economic Pathways; SSPs).

Changes to future inflows are derived from a modelling chain that begins with temperature and precipitation data from 42 GCM simulations from the latest Coupled Model Intercomparison Project Phase 6 (CMIP6). GCM-simulated daily time series of gridded temperature and precipitation were bias adjusted for the 1950-2100[6] period and used to drive calibrated and validated hydrological models to produce future inflow scenarios. For each GCM simulation, the time period coincident with a Global Warming Level (GWL) of +2°C above Pre-Industrial (PI; 1850-1900) conditions was identified and termed the 2°C GWLPI scenario. This approach aims to stay consistent with assessments by the Intergovernmental Panel on Climate Change (IPCC) and other globally recognized efforts such as the Paris Agreement,[7] but in practice Manitoba Hydro's approach assumes an observed GWL of 0.81°C from PI to the 1981-2020 baseline period and then identifies 40-year time periods with an additional +1.19° of global warming. Although each GCM will have a unique future time period which achieves the desired GWL, the central tendency from the ensemble of 42 GCM simulations (i.e., the median) projects this GWL scenario will occur in 2025-2064.

Simulated inflows in the future period (e.g., 2025-2064) are then compared against the baseline period (1981-2020), to infer changes in hydrological characteristics which are then further processed to adjust Manitoba Hydro's reference flow dataset (known as Long Term Flow Data; LTFD). More information on the future climate scenarios, hydrological models, and LTFD adjustment process can be found in Manitoba Hydro's most recent Climate Change Report[8] and in Ouranos' 2020 A Guidebook to Integrate Climate Data in Energy Production for Value Modelling.[9]

All climate-change affected inflows developed for this analysis are based on differences between the baseline period (1981 to 2020) and the future period (2°C GWLPI scenario), and these inflows are applied to every year in the study period; there is no transition from the unadjusted LTFD record (the standard inflows used for all other IRP scenarios and sensitivities) as the study progresses. This approach creates the potential to overestimate climate change impacts in the near term, as while the 2°C GWLPI scenario is considered representative of the 2025-2064 period, it is centered on 2044-2045.

[6] Lavoie, J., Bourgault, P., Smith, T.J. et al. An ensemble of bias-adjusted CMIP6 climate simulations based on a high-resolution North American reanalysis. Sci Data 11, 64 (2024). https://doi.org/10.1038/s41597-023-02855-z

[7] https://unfccc.int/sites/default/files/english_paris_agreement.pdf

[8] Manitoba Hydro's most recent climate change report can be found at https://www.hydro.mb.ca/environment/

[9] https://www.ouranos.ca/sites/default/files/2022-07/proj-201419-energie-fournier-guide_en.pdf

An analysis was performed to identify two GCM simulations that sample a range of the uncertainty in mean annual hydropower production resulting from the ensemble of GCM simulations. The two selected GCM simulations are listed in Table A7.2.19, along with their corresponding sensitivity name. These two sensitivities were selected based on changes in mean annual hydropower generation representing a high (80th percentile) and a low (20th percentile) case. For simplification, and due to good correlation between hydropower generation and flow magnitudes, Manitoba Hydro herein characterizes these cases as a low inflow and a high inflow case. Note that climate change implications for wind and solar energy production, and on energy demand,[10] were not considered in these sensitivities.

Table A7.2.19 – Sensitivity - Climate Change Affected Inflows

Sensitivity Name	Global Climate Model Simulation (Model Name and GHG Emissions Scenario)	Flow Characterization
CC 1	ACCESS-ESM1-5 SSP3-7.0	Low Inflows
CC 2	CNRM-ESM2-1 SSP2-4.5	High Inflow

Figure A7.2.82 shows the range in system-aggregated inflows defined by the high and low inflow climate change sensitivities, with the reference LTFD inflows used as a base assumption in all other scenarios and sensitivities included for comparison. There is an asymmetry in how the two climate change cases affect average annual inflow; compared to the LTFD inflows, the low inflows reduce the average annual inflow by 4%, while the high inflows increase the average annual inflow by 19%. It is important to keep in mind, however, that the scenarios were selected based on their changes to annual average hydropower generation, which puts an emphasis on where inflow changes occur rather than system-aggregated total inflows. For example, inflow changes on the Winnipeg River Basin have a stronger influence on hydropower generation than inflow changes in the local Nelson River Basin.

[10] Implications of climate change on energy demand was explored in Manitoba Hydro's 2023 IRP:IRP 2023 Appendix 5 - Analysis Results

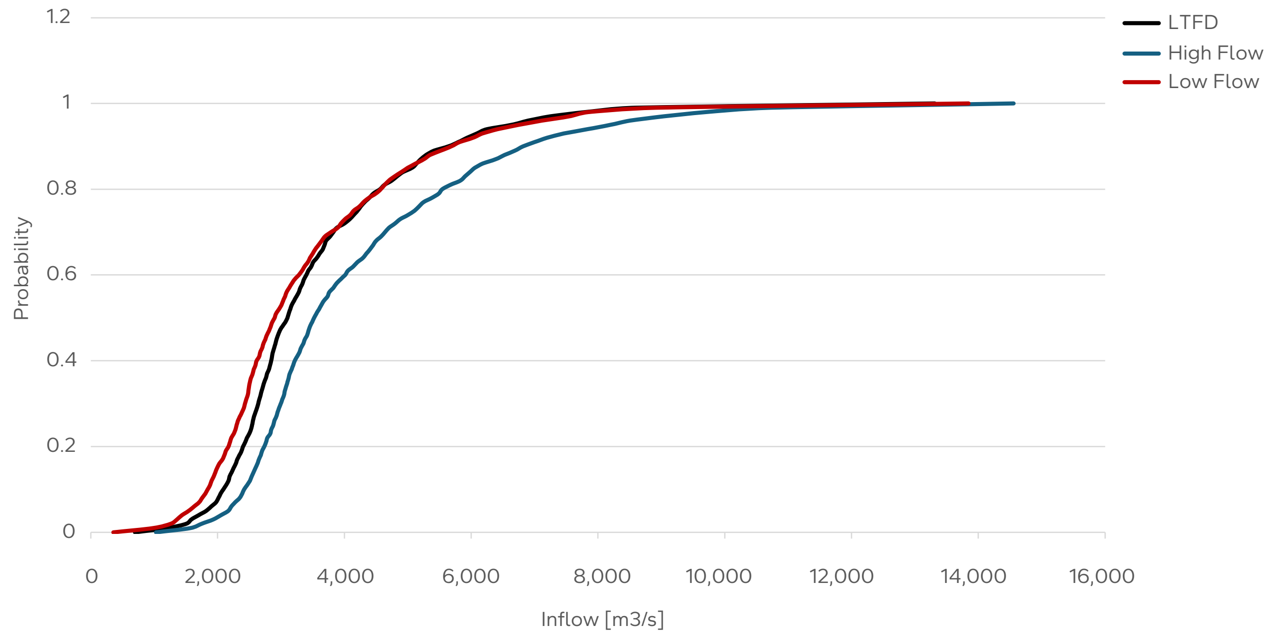


Figure A7.2.82 - Sensitivity – Climate Change Affected Inflows

(Note: Inflow reductions based on the Prairie Provinces Water Apportionment Agreement are applied assuming a 2025 study year.)

For the purposes of these sensitivities, the dependable energy for existing and potential new hydropower resources was not updated based on either low or high flows. The primary concern associated with not updating dependable energy is that the system will be planned assuming hydropower resources are providing more dependable energy than they are capable of when system operations are simulated. Production costing results confirmed that energy shortfalls were encountered in the low inflows sensitivity, but only in the near-term. In this timeframe, options to add new resources prior to 2030 are restricted and no additional insights would be gained by reducing dependable energy during this period. Furthermore, while climate change influence on inflows is assumed in this analysis to take effect immediately, a more gradual transition towards the modelled high and low inflow cases would be expected to occur; it is likely that inflow changes during this time would be more moderate than what was modelled, reducing the likelihood of the energy shortfalls observed.

3.10.4. Results

Cumulative installed capacity by 2035 across the climate change sensitivities is shown in Figure A7.2.83. Increased selection of hydropower SSE is observed under the 1-Baseline load projection in both sensitivities, but to a larger extent in the low-inflows case. When energy demand increases under the 3-High load projection, lower inflows continue to result in the increased selection of hydropower SSE options. Under high inflows, an increase in CT-BD additions and a corresponding reduction in natural-gas-fuelled additions is observed. Higher inflows and more hydropower energy production can lead to reduced dispatch of combustion turbines (CTs); CT-BDs have higher fuel costs than natural gas fuelled units, and so CT-BDs become a more competitive resource option under high inflow conditions when fuel costs are less impactful (average utilization factors are even lower).

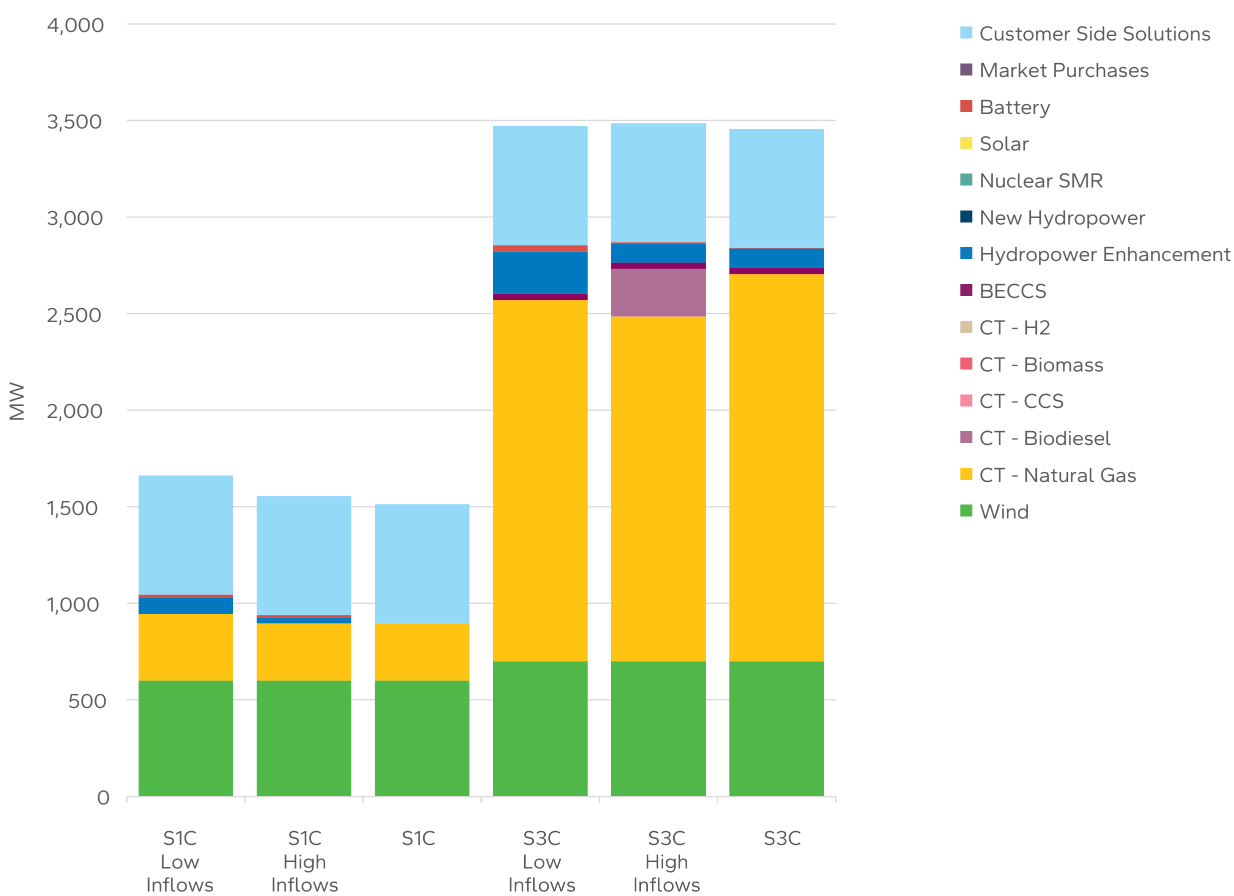


Figure A7.2.83 - Sensitivity – Climate Change Affected Inflows – Cumulative Installed Capacity by 2035

Figure A7.2.84 looks out to 2050 and continues to highlight how under high demand circumstances coupled with net-zero 2035 grid targets, changes in inflows in turn change the resource options selected to provide energy and capacity to the system. Comparing the low inflow sensitivity against the high inflow sensitivity yields the following observations for 2050:

- The composition of combustion turbines in the system shifts toward an increased reliance on hydrogen fuelled combustion turbines (CT-H2), while combustion turbine with carbon capture and sequestration (CCCT-CCS) additions are the same and CT-BD and CT-NG and combined cycle combustion turbine (CCCT-NG) additions are reduced.
- Solar resources are also added.
- Small modular nuclear reactor (SMR) additions are reduced.
- More wind is added.

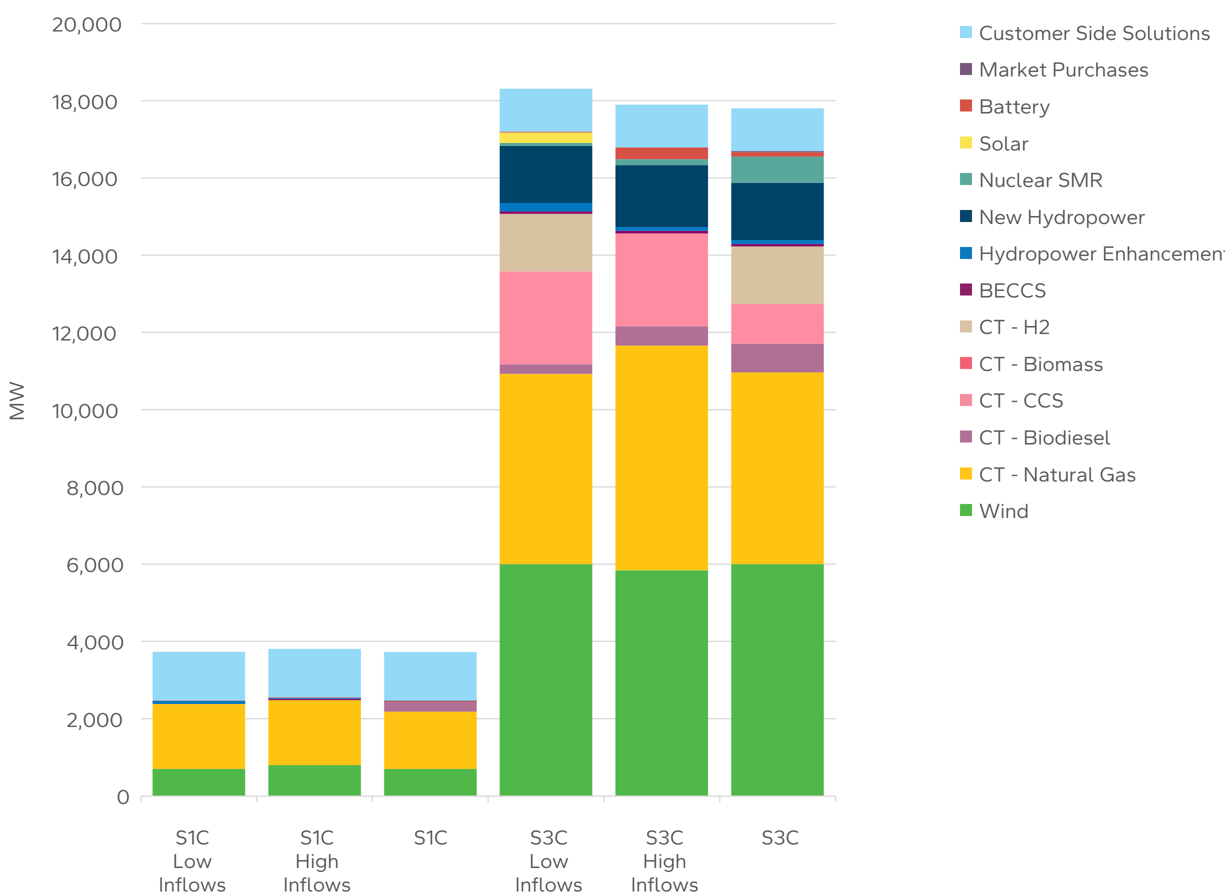


Figure A7.2.84 - Sensitivity – Climate Change Affected Inflows – Cumulative Installed Capacity by 2050

These results indicate the model's tendency to compensate for reduced hydropower by increasing the addition of capacity resources that have low GHG emissions intensities, such as CT-H2, and continuing to rely on other low GHG emission-intensity options such as CCCT-CCS and CT-BD. The model adjusts the balance of energy-focused resources to complement the selected dispatchable capacity resources, opting for adding solar and less nuclear SMRs in the low inflow sensitivity. Under the lower load projection, signals around resource selections are less clear.

Figure A7.2.84 also highlights how multiple long-term strategies around energy-providing resources can exist, none of which have been demonstrated to be the dominant choice through the IRP. For example, in both the low and high inflow sensitivities the model opts for more CT-CCS and less nuclear SMRs than in the 3C results, complementing changes to the additions of other resource as previously noted.

Figure A7.2.85, Figure A7.2.86, and Figure A7.2.87 together show how climate change may impact annual energy generation across resource types averaging across all inflows, under high flow conditions, and under low inflow conditions.

For both high and low load projections and under all inflow conditions (e.g., ranging from the flow year yielding the lowest hydropower to the flow year yielding the highest hydropower and considering average generation across all flow years), the following are observed:

- Hydrogeneration is reduced in the low inflow sensitivity and increased in the high inflow sensitivity.
- Imported energy increases in the low inflow sensitivity and decreases in the high inflow sensitivity.
- Opportunity exports decrease in the low inflow sensitivity and increase in the high inflow sensitivity.

Trends in combustion turbine dispatch are less clear. These units are dispatched infrequently, when required by low inflow conditions. However, how much they are dispatched is sensitive not only on inflow conditions, but on the load projection and the complement of other resource types and amounts present in the system.

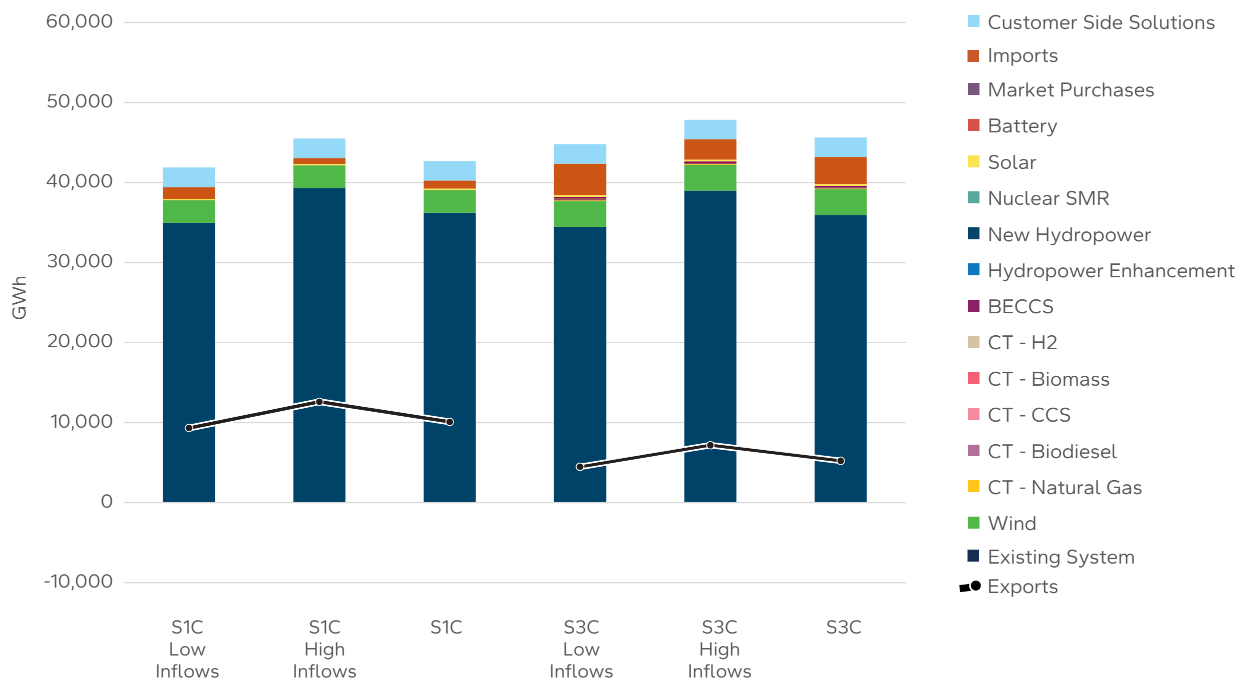


Figure A7.2.85 - Sensitivity – Climate Change Affected Inflows –Annual Energy Generation in 2035 by Resource Type based on the Average of All Inflows

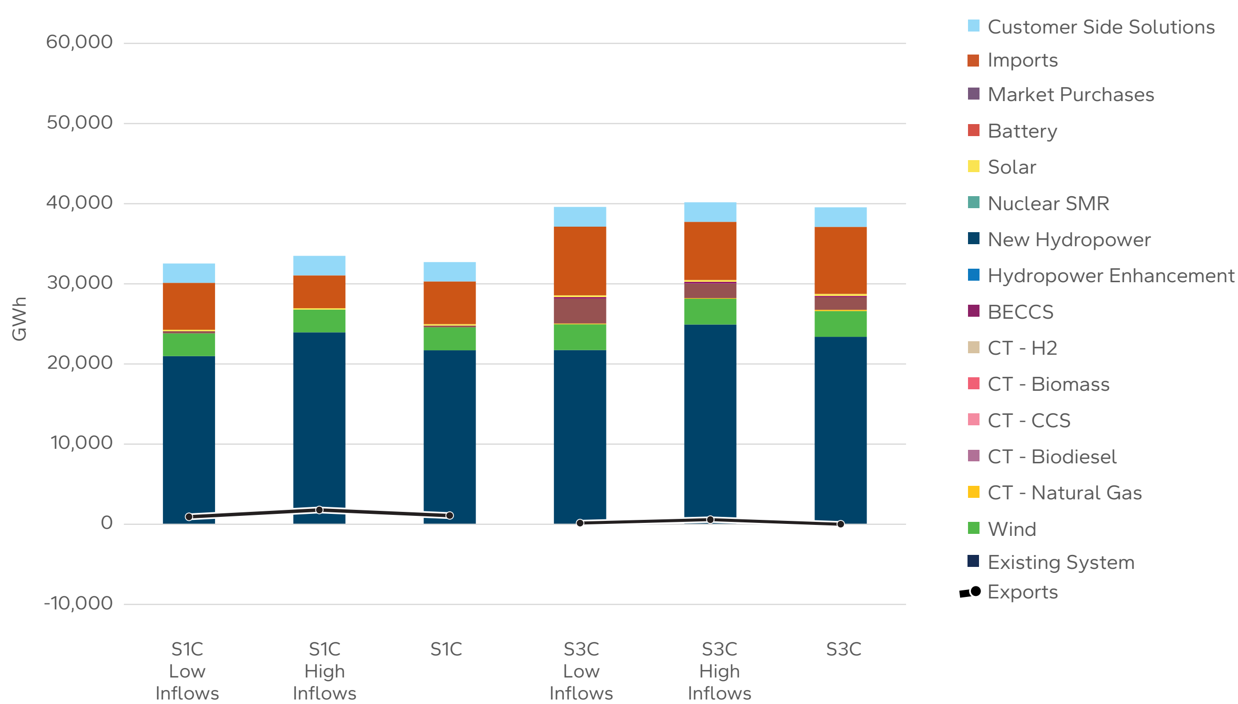


Figure A7.2.86 - Sensitivity – Climate Change Affected Inflows – Annual Energy Generation in 2035 by Resource Type for a Low Inflow Flow Year

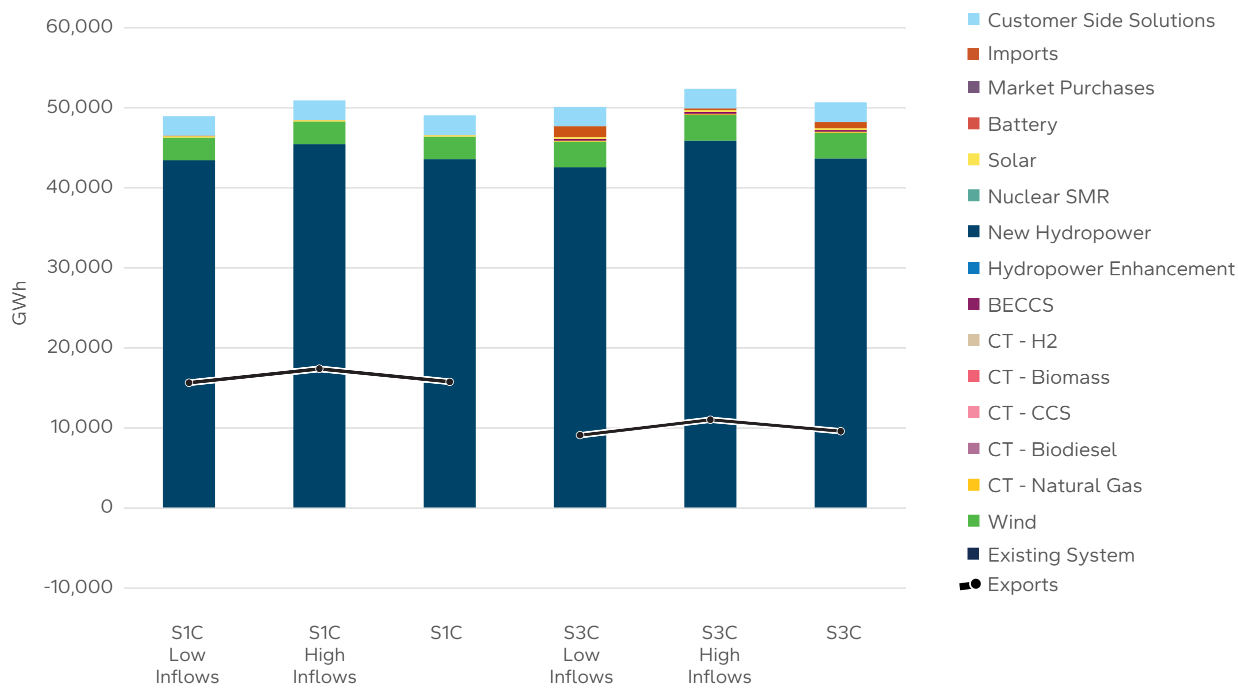


Figure A7.2.87 - Sensitivity – Climate Change Affected Inflows – Annual Energy Generation in 2035 by Resource Type for a High Inflow Flow Year

As discussed, changing inflows changes resource selections as well as energy generation and market interactions. This has direct implications for net incremental regional (non-Manitoba) electricity generation GHG emissions, as shown in Figure A7.2.88, where negative net incremental regional (non-Manitoba) electricity generation GHG emissions refers to an incremental reduction in regional electricity generation GHG emissions due to increased exports of Manitoba's electricity. Positive net incremental regional (non-Manitoba) electricity generation GHG emissions signifies an incremental increase in regional electricity generation GHG emissions due to Manitoba becoming a net importer of electricity. Increased imports in the low inflow sensitivities result in less avoided regional (non-Manitoba) electricity generation GHG emissions. Conversely, the higher inflow sensitivities result in decreased imports and the benefit of more avoided regional (non-Manitoba) electricity generation GHG emissions.

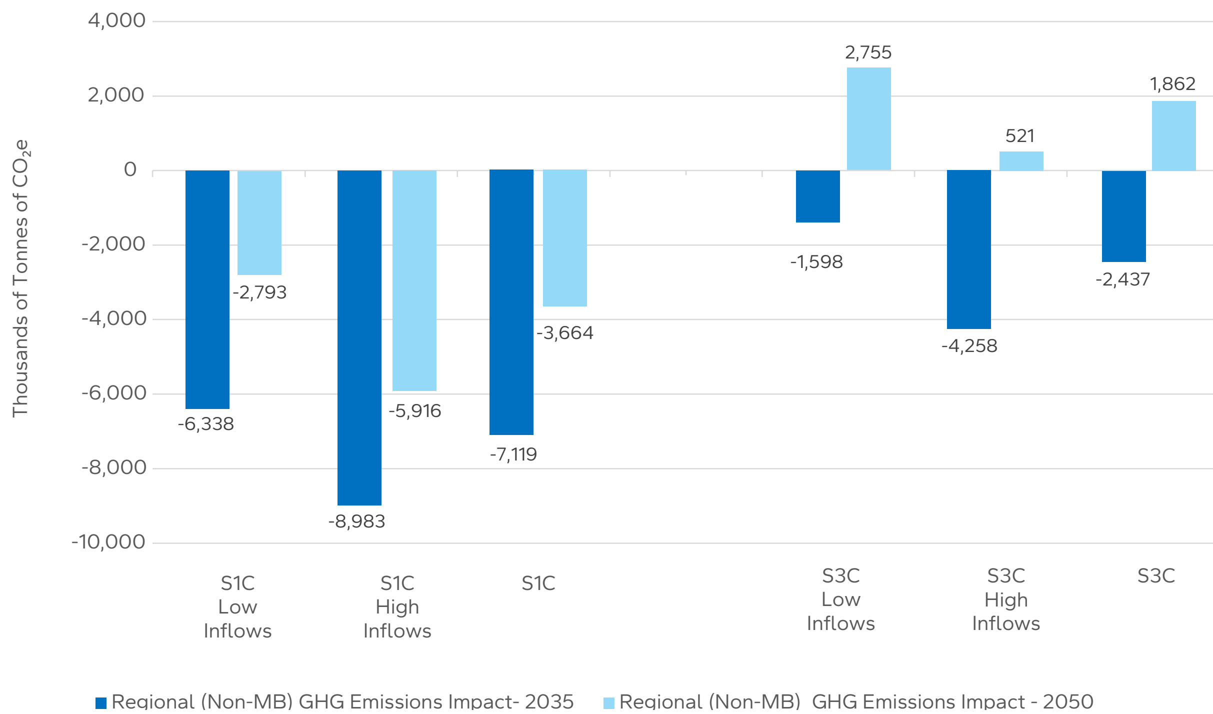


Figure A7.2.88 - Sensitivity – Climate Change Affected Inflows – Net Incremental Regional (non-Manitoba) Electricity Generation GHG Emissions

As shown in Figure A7.2.89, changes to the Manitoba electricity generation GHG emissions were not found to be significant in 2035. Figure A7.2.90 confirms that by 2050, the inflow sensitivities have more impact on net Manitoba electricity generation GHG emissions, but in all cases net-zero grid requirements, from 2035 onwards, are met. Under the 1-Baseline load projection, in 2050, Manitoba electricity generation GHG emissions net to 0 tonnes of CO_2e in both the 1C LTFD baseline and 1C Low Inflows sensitivities, while the 1C High Inflows sensitivity has net negative Manitoba electricity generation GHG emissions of 209 thousand tonnes of CO_2e.

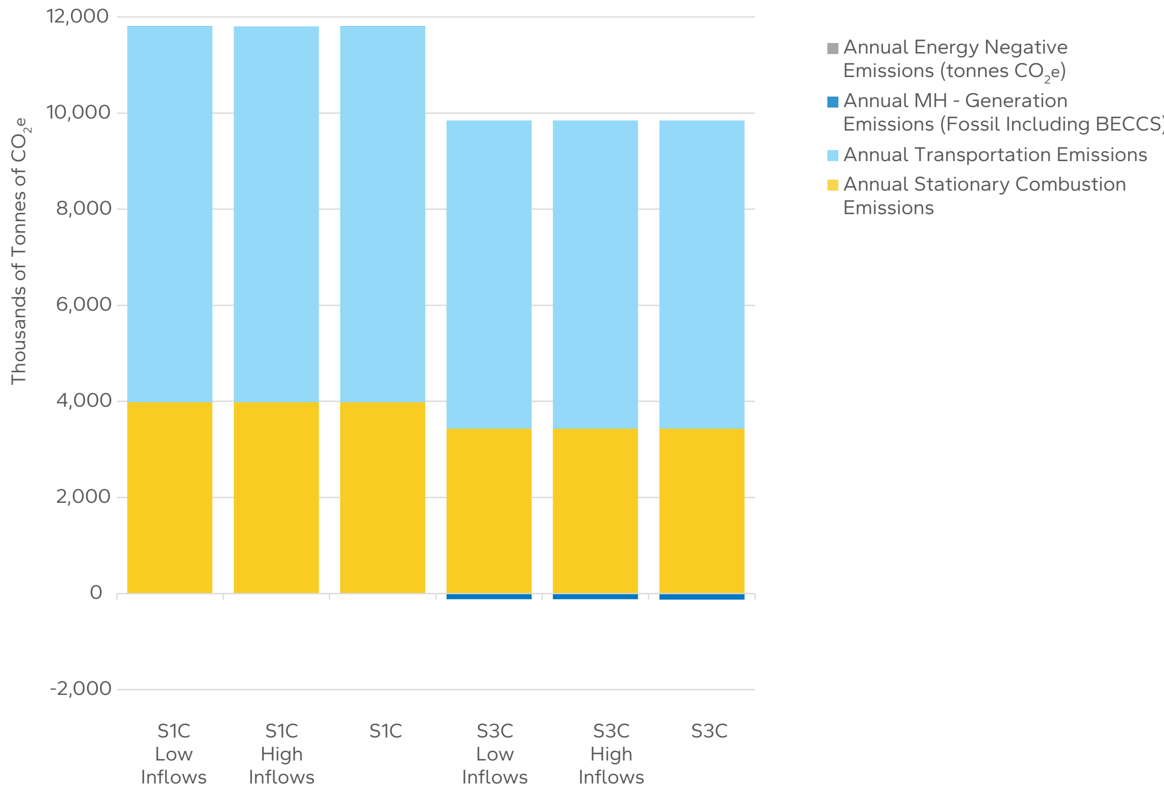


Figure A7.2.89 - Sensitivity- Climate Change Affected Inflows – Breakdown of GHG Emissions in 2035

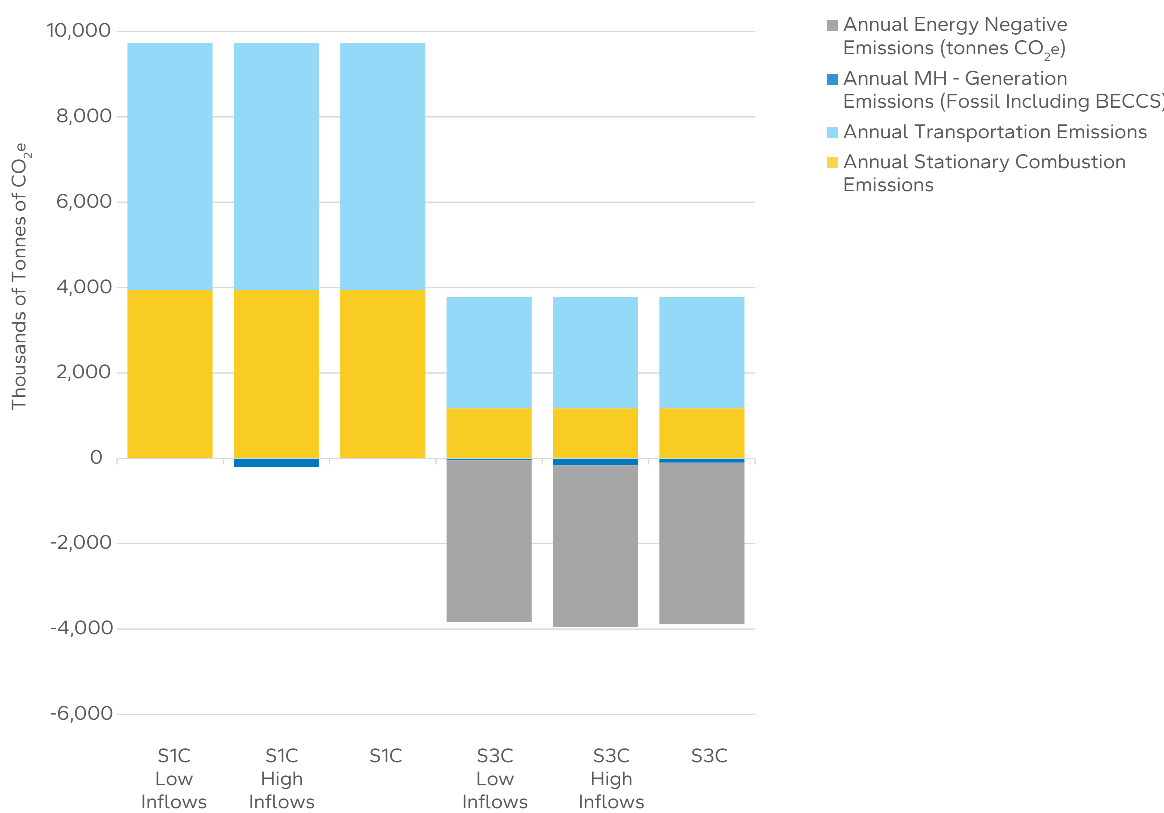
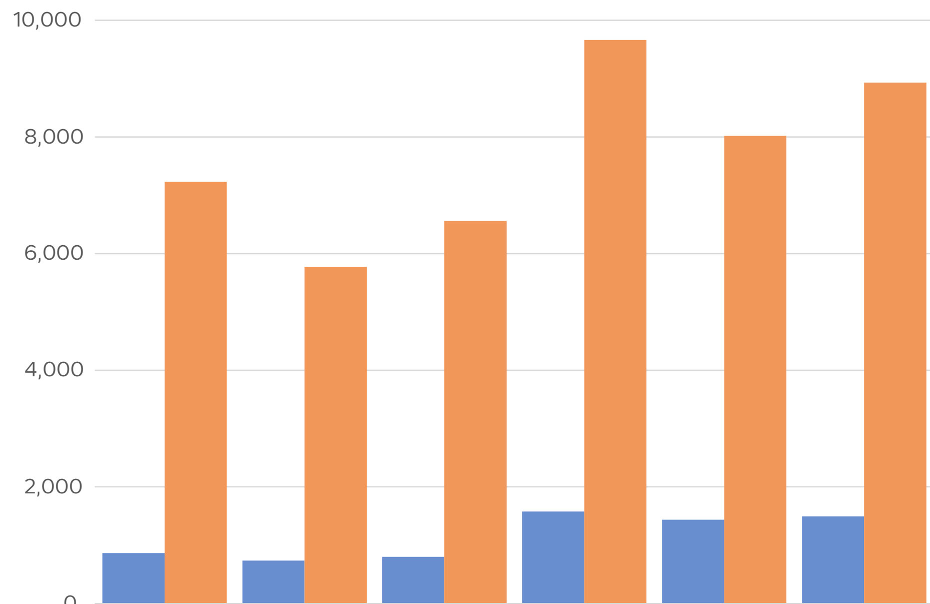


Figure A7.2.90 - Sensitivity- Climate Change Affected Inflows – Breakdown of GHG Emissions in 2050

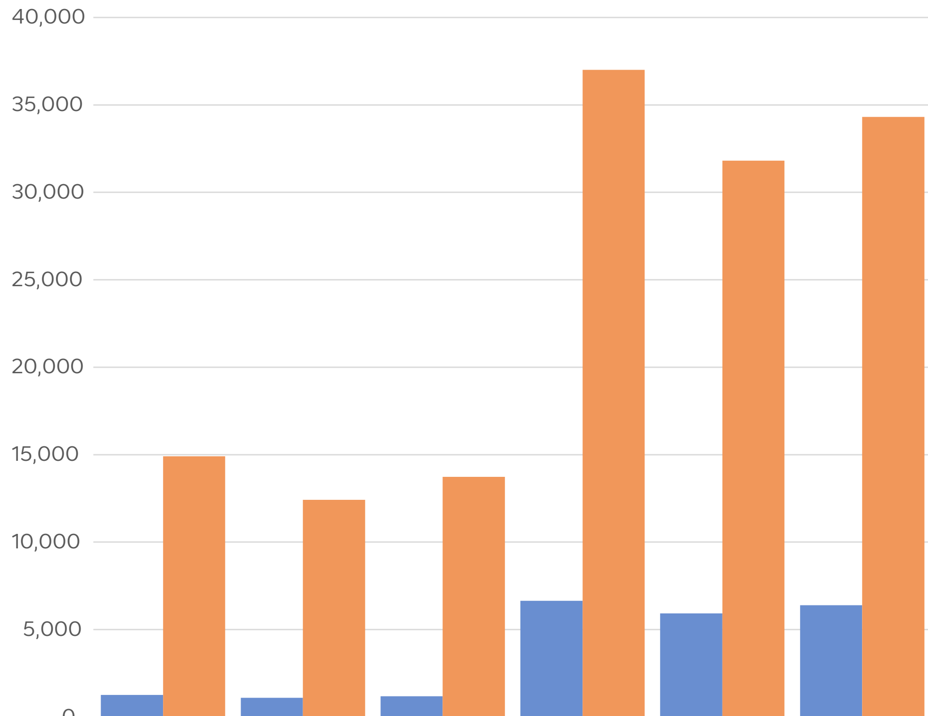
Under the 3-High load projection, in 2050, all Manitoba electricity generation GHG emissions are net negative, with an incremental increase in GHG emissions of 54 thousand tonnes of CO_2e in the low inflow sensitivity (54% increase over 3C), and a decrease of 65 thousand tonnes of CO_2e in the high inflow sensitivity (64% decrease from 3C).

The higher inflow sensitivities showed improved economic indicators than the lower inflow sensitivities. Higher inflows resulted in the incremental annual net system costs improving by $0.1 to $0.5 B 2024 CAN/yr, depending on the load projection and study year, as compared to the LTFD scenarios. The incremental cumulative present value of net system costs was also reduced, by $0.8 to $2.5 B 2024 CAN/yr, depending on the load projection and study year. Lower inflows consistently translated into worsened economic indicator results, with the incremental annual net system costs increasing by $0.1 to $0.3 B 2024 CAN/yr and the incremental cumulative present value of net system costs increasing by $0.7 to $2.7 B 2024 CAN/yr, depending on the load projection and study year and as compared to the LTFD scenarios. These results are shown in Figure A7.2.91 and Figure A7.2.92.



	S1C Low Inflows	S1C High Inflows	S1C	S3C Low Inflows	S3C High Inflows	S3C
Incremental Annual Net System Cost [M$/year]	864	736	802	1,578	1,435	1,495
Incremental Cumulative Present Value of Net System Costs [M$]	7,231	5,772	6,562	9,663	8,021	8,932

Figure A7.2.91 - Sensitivity - Climate Change Affected Inflows – Incremental Present Value of Net System Costs [M 2024 CAN$] and Incremental Annual Net System Costs [M 2024 CAN$/yr] to 2035



	S1C Low Inflows	S1C High Inflows	S1C	S3C Low Inflows	S3C High Inflows	S3C
Incremental Annual Net System Cost [M$/year]	1,267	1,095	1,187	6,652	5,920	6,389
Incremental Cumulative Present Value of Net System Costs [M$]	14,902	12,415	13,730	37,002	31,808	34,307

Figure A7.2.92 - Sensitivity - Climate Change Affected Inflows – Incremental Present Value of Net System Costs [M 2024 CAN$] and Incremental Annual Net System Costs [M 2024 CAN$/yr] to 2050

Figure A7.2.93 visualizes how the percent changes in the incremental annual net system cost and incremental cumulative present value of net system costs vary across inflow sensitivities, load projections, and study year. The direction of change is consistently based on the inflow sensitivity, and changes are also larger for the incremental cumulative present value of net system costs than the incremental annual net system cost. A symmetrical signal is observed around the magnitude of changes between the low and high inflow sensitivities; the low inflow sensitivity shows a worsening of the economic indicators to approximately the same extent as financial metrics are improved in the high inflow sensitivities.

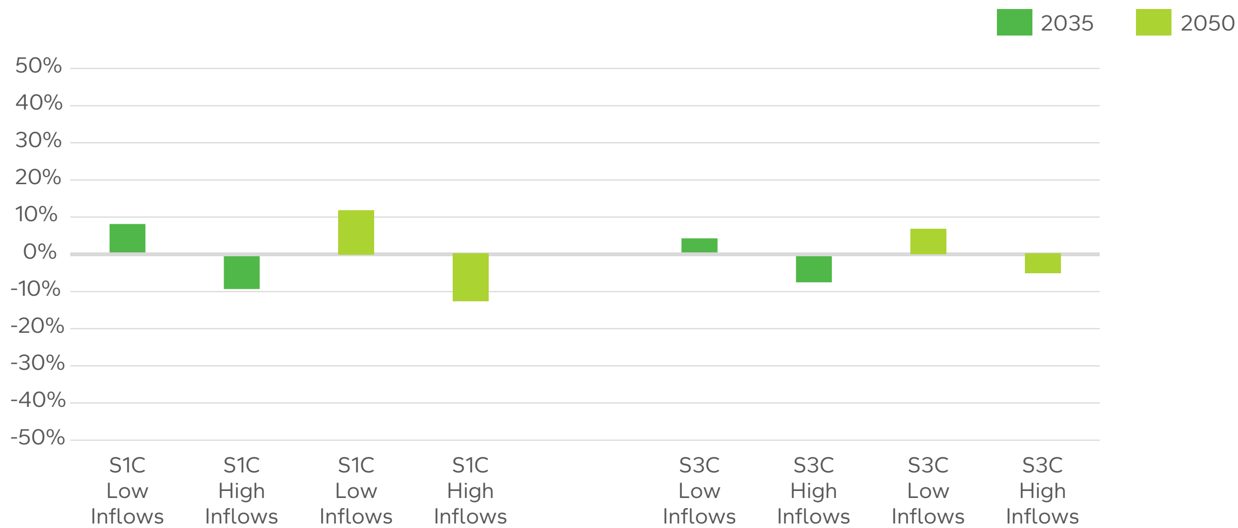
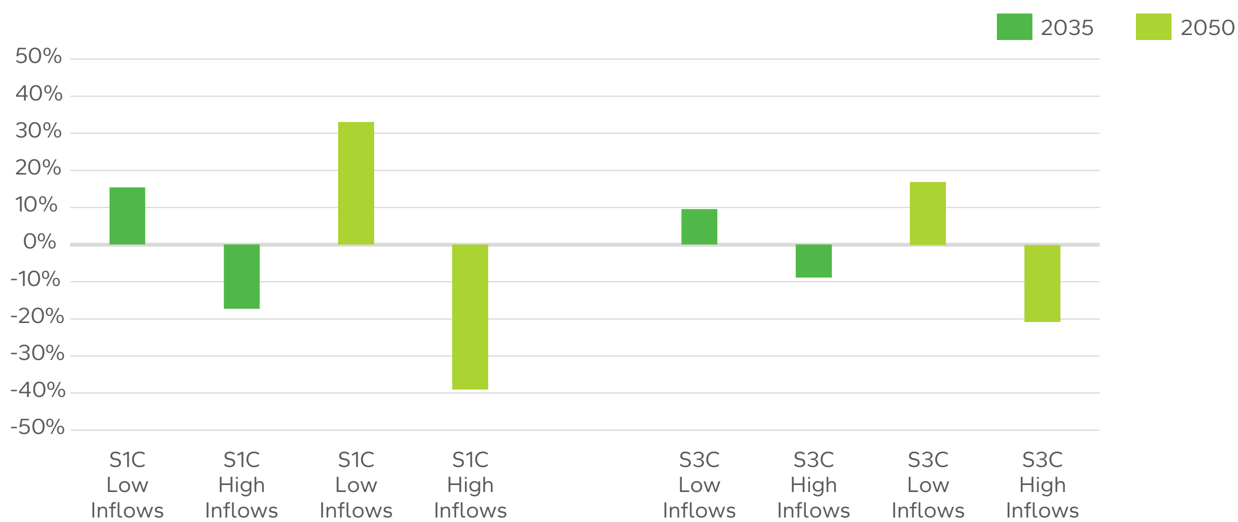


Figure A7.2.93 - Sensitivity - Climate Change Affected Inflows – Comparison of % Change in Incremental Annual Net System Cost in 2035 and 2050, Relative to LTFD Scenarios



Sensitivity - Climate Change Affected Inflows – Comparison of % Change in Incremental Cumulative Present Value of Net System Cost in 2035 and 2050, Relative to LTFD Scenarios

3.11. Near-Term Wind Generation Projects

3.11.1. Objective

The procurement of up to 600 MW of Indigenous majority-owned new wind resources aligns with the Manitoba's Affordable Energy Plan and was included in resource options strategy C. This analysis isolates the effect of including 600 MW of new wind on optimized portfolios of resources and aims to clarify the important planning considerations that accompany this resource strategy.

3.11.2. Key Takeaways

- Near-term wind may help address unmet capacity need risks in 2029 if committing to near-term wind makes a 2029 in service date feasible for the first 200 MW. It is otherwise assumed that the earliest ISD for new wind generation is 2032.
- By 2035, adding 600 MW of wind to the system changes the total addition of natural gas fuelled combustion turbine (CT-NG), biodiesel combustion turbine (CT-BD), and aeroderivative units by less than the equivalent capacity of a single CT-NG. There is no change to CT-NG selections under the 1-Baseline load projection.
- By 2050, no additional wind is added to the system under the 1-Baseline load projection when no near-term wind is assumed. In the absence of the resource options strategy C requirement, the model does not add any wind to the system.
- Under the 2-Medium and 3-High load projections, additional wind is added to meet 2050 demand levels. This indicates that the 600 MW of near-term wind would be an advancement of new wind, rather than an addition of new wind that would not otherwise occur based on capacity expansion optimization under these high load projections.
- Different long-term planning strategies were observed between the near-term wind sensitivities under the 2-Medium and 3-High load projections. This result reflects that any near-term planning decision can create ripple effects in capacity expansion planning optimizations and can ultimately influence long-term plan outcomes. Specific long-term planning results in such cases may not be meaningful independently but are useful for defining the range of possible strategies that should be considered as planning continues.
- 2-Medium and 3-High load projection sensitivity results are dominated by load projection signals by 2050, resulting in no discernable effects from near-term wind additions.

- Near-term wind additions have no effect on Manitoba electricity generation GHG emissions in 2035 under the 1-Baseline and 2-Medium load projections. Under the 3-High load projection, a bioenergy carbon capture and sequestration (BECCS) unit is advanced into the 10-year development time frame when near-term wind is not added to the system, resulting in 2035 Manitoba electricity generation GHG emissions of -0.1 M tonnes CO_2e. This is not considered a meaningful amount.
- Near-term wind additions support the reduction in net incremental regional (non-Manitoba) electricity generation GHG emissions consistently across all load projections in 2035. Although Manitoba Hydro will not claim these GHG emission reductions net incremental regional (non-Manitoba) electricity generation GHG emissions continue to be reduced with the addition of near-term wind under the 1-Baseline load projection in 2050. These results are consistent with the scenario results.
- Near-term wind additions increase the PV of net system costs consistently across all load projections in 2035. While annual net system costs in 2035 increase under the 1-Baseline and 2-Medium load projections with the addition of near-term wind, this annual cost decreases under the 3-High load projection. Under the 1-Baseline load projection, the PV of net system costs continues to be higher with near-term wind additions by 2050, but there is a small reduction in annual net system costs. There is no clear signal around near-term wind implications for financial indicators in 2050 for the 2-Medium and 3-High load projections.

3.11.3. Methodology

To isolate the implications of 600 MW of near-term wind generation projects (installed capacity basis), two portfolios of resources locked-in until 2033 were developed. The details of these portfolios are presented in Table A7.2.20. The only difference between these portfolios until 2033 is the inclusion of near-term wind. Both portfolios assume 744 MW of installed CT-NG capacity in 2030. The Table includes the assumed wind addition in 2033, but the model was allowed to add additional resources to the portfolio based on optimization beginning in that year.

Table A7.2.20 – Sensitivity - Near-Term Wind Generation Projects – Comparison of Sensitivity Portfolios (Additions per Year in Accredited Capacity [MW])[11]

		Locked-in Portfolio								
Plan	**Resource Type**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**
With Near-Term Wind	Wind	-	-	-	-	40	-	40	-	40
With Near-Term Wind	CT-NG	-	-	-	-	-	744	-	-	-
No Near-Term Wind	Wind	-	-	-	-	-	-	-	-	-
No Near-Term Wind	CT-NG	-	-	-	-	-	744	-	-	-

Using portfolios of resources locked-in until 2033 for this sensitivity appropriately captures the principal that decisions on portfolio resource additions are unlikely to be made in isolation; concurrent commitments to fill out the plan are more likely. The inclusion of 744 MW of CT-NG in 2030 represents a complementary near-term resource addition and was chosen based on resource selection signals from prior scenario and sensitivity analyses conducted during this IRP. The locked-in timeframe for the portfolio of resources further reflects that by 2033, it is likely that Manitoba Hydro would have sufficiently updated modelling inputs and planning insights, as well as regulatory opportunities, to adjust a development plan and that it is therefore reasonable to allow the model to optimize resource selection beginning in this year.

3.11.4. Results

Figure A7.2.94 and Figure A7.2.95 show the cumulative installed capacity for the system in 2035 and 2050, respectively. Results compare the sensitivity cases for each of the three load projections. By 2035, adding 600 MW of wind to the system most notably affects the amount of CT-NG and CT-BD units selected under the 2-Medium and 3-High load projections, with no change to CT-NG selection under the 1-Baseline load projection. However, when you consider the combined total incremental installed capacity addition of both combustion turbine (CT) types and aeroderivative units, results vary by less than the equivalent capacity of one CT-NG for both the 2-Medium and 3-High load projections. This stays true for these load projections in 2050 and also applies to the 1-Baseline load projection when adding near-term wind results in 140 MW less CT-NG additions by 2050. There is no conclusive effect of including near-term wind on the relative balance of CT-NG vs CT-BD units.

[11] 40 MW of accredited wind capacity equates to 200 MW of installed wind capacity.

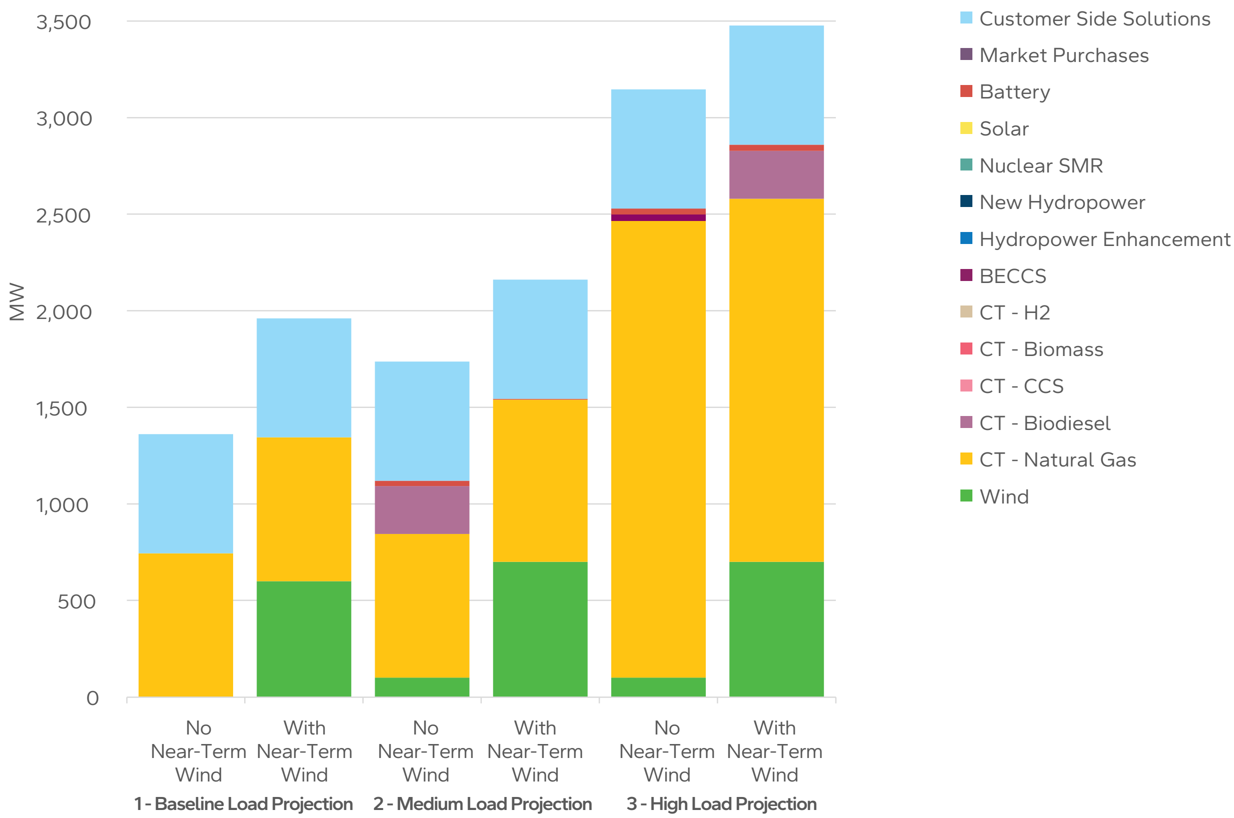


Figure A7.2.94 - Sensitivy - Near-Term Wind Generation Projects – Cumulative Installed Capacity by 2035

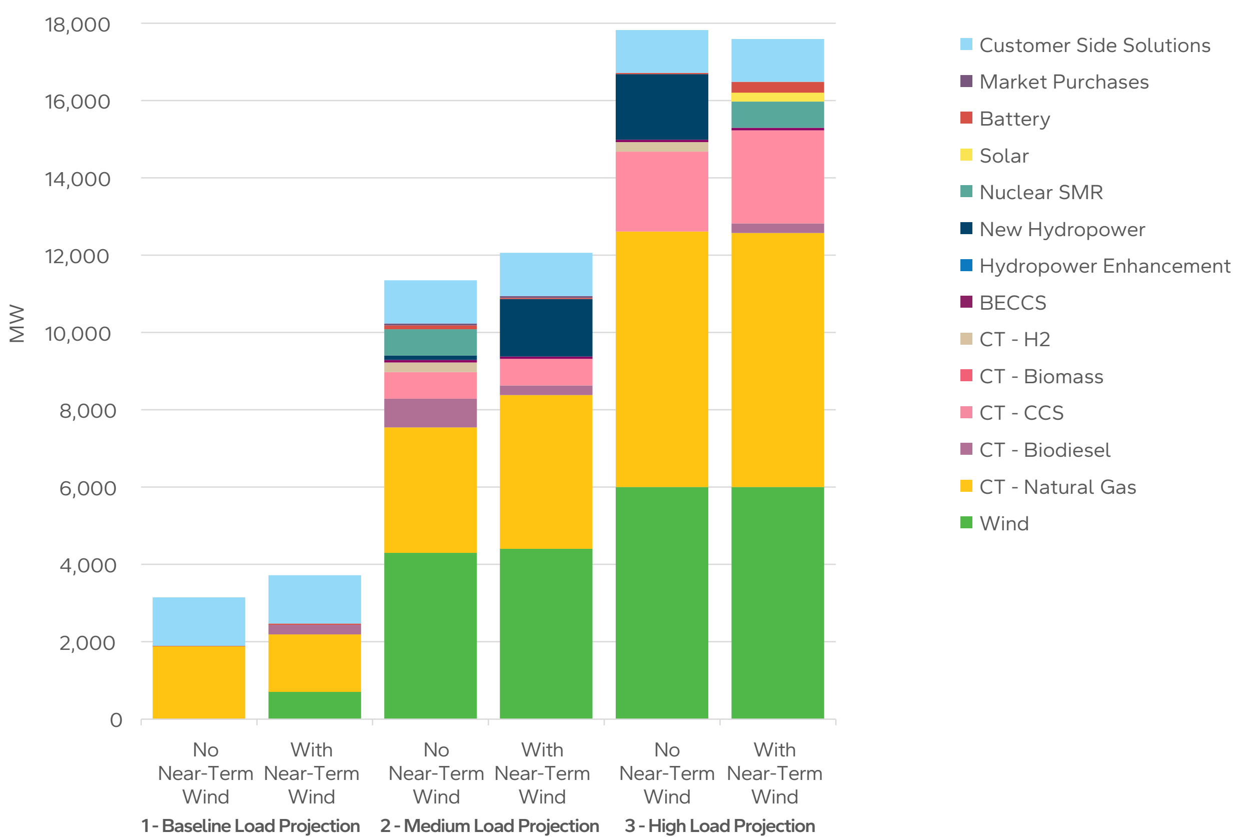


Figure A7.2.95 - Sensitivy - Near-Term Wind Generation Projects – Cumulative Installed Capacity by 2050

By 2050, all eligible wind is built under the 3-High Load projection, and more than 4,000 MW of installed wind capacity is added in the 2-Medium load projection, with only a 100 MW difference between the with and without near-term wind cases. This indicates that under higher load projections, the need to meet increased demand later in the study horizon results in significant levels of wind added to the Manitoba Hydro system, regardless of the timing of near-term additions. While near-term decisions influence the optimization trajectory of the model, and differences in the long-term buildout will be seen in the overall portfolio of resources and their corresponding GHG emissions data and financial indicators, it is not meaningful to assign specific long-term differences directly to the near-term wind additions. Similar changes can be observed in other sensitivities, where changes in other near-term decisions create long-term ripple effects that collectively outline a range of potential long-term planning strategies.

The 1-Baseline load projection does not exhibit the same long-term load growth as the 2-Medium and 3-High load projections do. By 2050, no wind is added under the 1-Baseline load projection when near-term wind is not assumed. If a 1-Baseline load projection transpires in the future, the choices around near-term wind generation projections will be more impactful on the portfolio of resources; unlike in the 3 -high load projection scenarios and sensitivities, the 1-Baseline load projection will not select the 600 MW of near-term wind generation unless it is locked-in the portfolio of resources in the early years.

The Manitoba GHG emissions implications of including near-term wind generation in 2035 is shown in Figure A7.2.96. Under the 3-High load projection, a BECCS unit is advanced to appear in 2035 when no near-term wind is included, resulting in negative Manitoba electricity generation GHG emissions of 0.1 million tonnes CO_2e. In all other cases, Manitoba electricity generation GHG emissions are negligible in 2035.

By 2050, near-term wind additions do not have a clear impact on net Manitoba electricity generation GHG emissions. There are no electricity generation GHG emissions in the 1-Baseline load projection cases in 2050, regardless of near-term wind assumptions. Under the 2-Medium load projection, including near-term wind reduces net Manitoba electricity generation GHG emissions from 0.1 to -0.1 million tonnes CO_2e. Conversely, under the 3-High load projection, including near-term wind increases net Manitoba electricity generation GHG emissions from -0.1 to 0 tonnes CO_2e. Net electricity generation GHG emissions depend on overall system operations which in turn reflects the long-term system portfolio of resources, and so near-term wind additions do not have a clear or direct influence on Manitoba electricity generation GHG emissions by 2050.

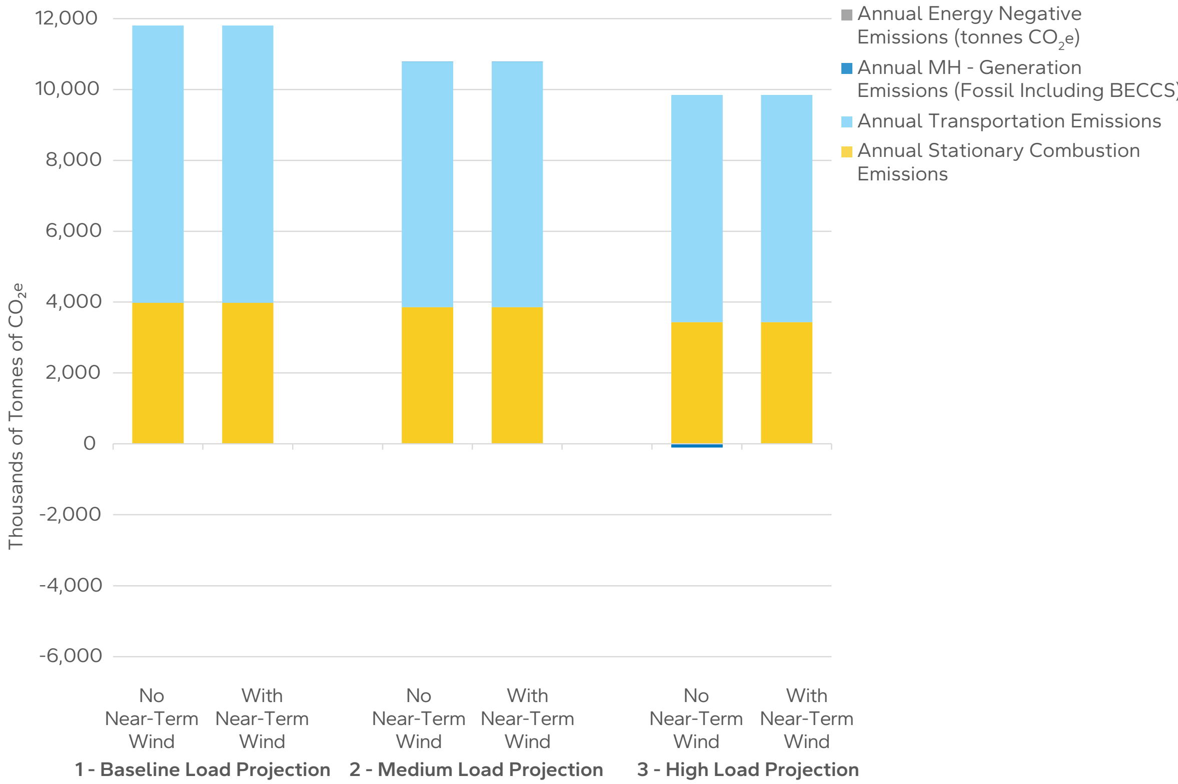


Figure A7.2.96 - Sensitivity - Near-Term Wind Generation Projects - Breakdown of GHG Emissions in 2050

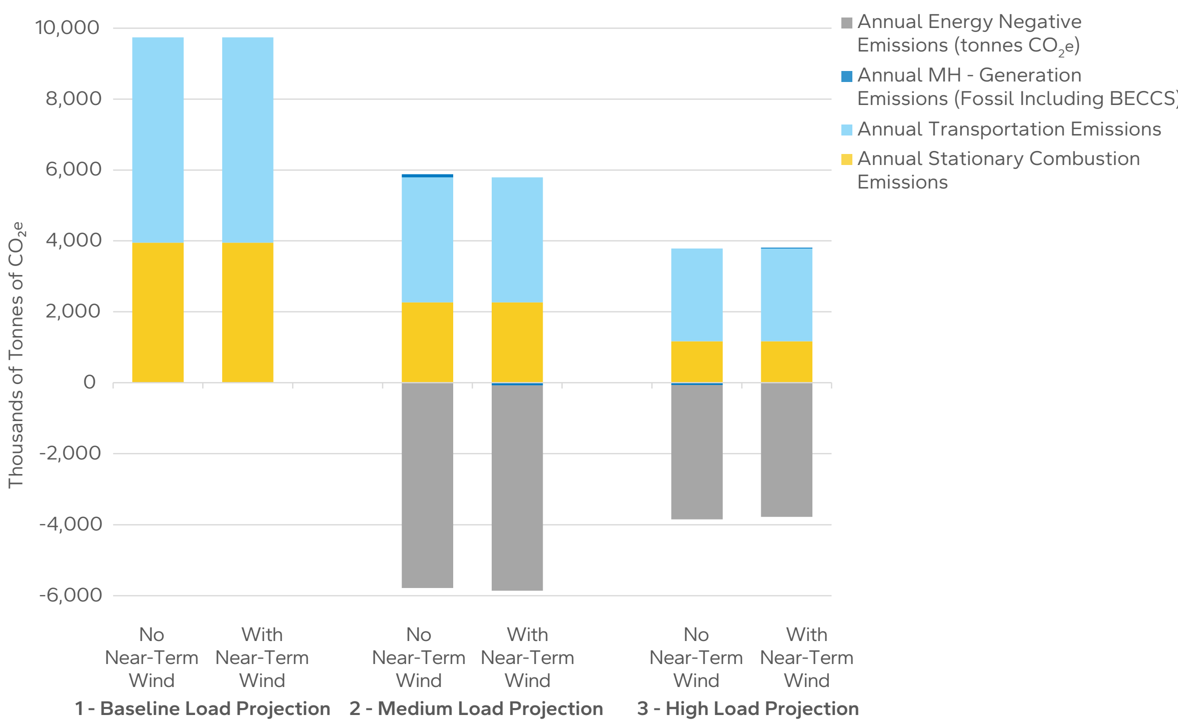


Figure A7.2.97 - Sensitivity - Near-Term Wind Generation Projects - Breakdown of GHG Emissions in 2050

As shown in Figure A7.2.98, near-term wind generation supports the reduction of 2035 regional (non-Manitoba) electricity generation GHG emissions by 1.4 million tonnes CO_2e under the 1-Baseline load projection, 1.4 million tonnes CO_2e under the 2-Medium load projection, and 1.2 million tonnes CO_2e under the 3-High load projection. These reductions in non-Manitoba electricity generation GHG emissions are driven by increased opportunity exports and reduced imports when near-term wind is added to the system, as shown in Figure A7.2.99. By 2050, near-term wind generation continues to support the reduction of net regional (non-Manitoba) electricity generation GHG emissions under the 1-Baseline load projection. However, the influence of near-term wind is no longer distinguishable under the 2-Medium and 3-High load projections by 2050, with net incremental regional (non-Manitoba) electricity generation GHG emissions reduced by 0.7 million tonnes CO_2e and increased by 0.8 million tonnes CO_2e, respectively, in these load projections. Once again, these changes in net regional (non-Manitoba) electricity generation GHG emissions reflect the net-exports for the with and without near-term wind sensitivities under the 2-Medium and 3-High load projections, shown in Figure A7.2.99.

Together, Figure A7.2.98 and Figure A7.2.99 highlight that regardless of near-term wind additions, net exports are reduced and the corresponding net incremental regional (non-Manitoba) electricity generation GHG emissions increase, or become less negative, when compared across increasing load projections in 2035. By 2050, net incremental regional (non-Manitoba) electricity generation GHG emissions switch from negative to positive under the 2-Medium and 3-High load projections, as Manitoba Hydro also switches to becoming a net importer. These results are consistent with the scenario results.

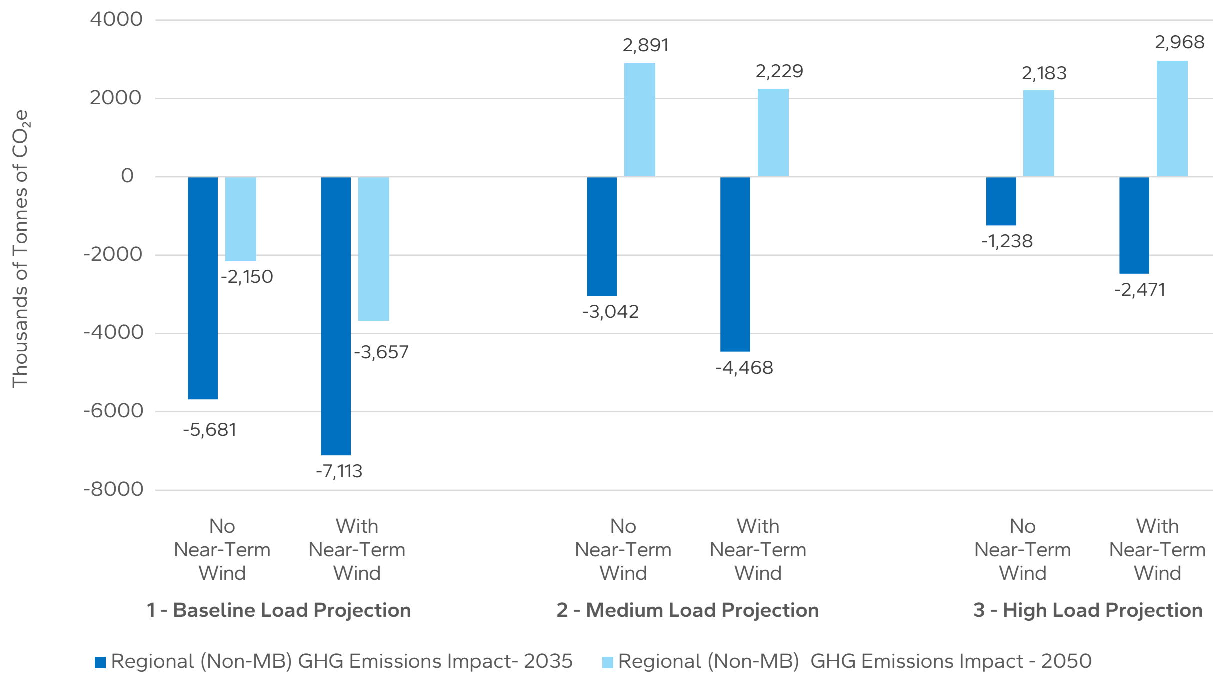


Figure A7.2.98 - Sensitivity - Near-Term Wind Generation Projects – Net Regional Electricity Generation GHG Emissions in 2035 and 2050

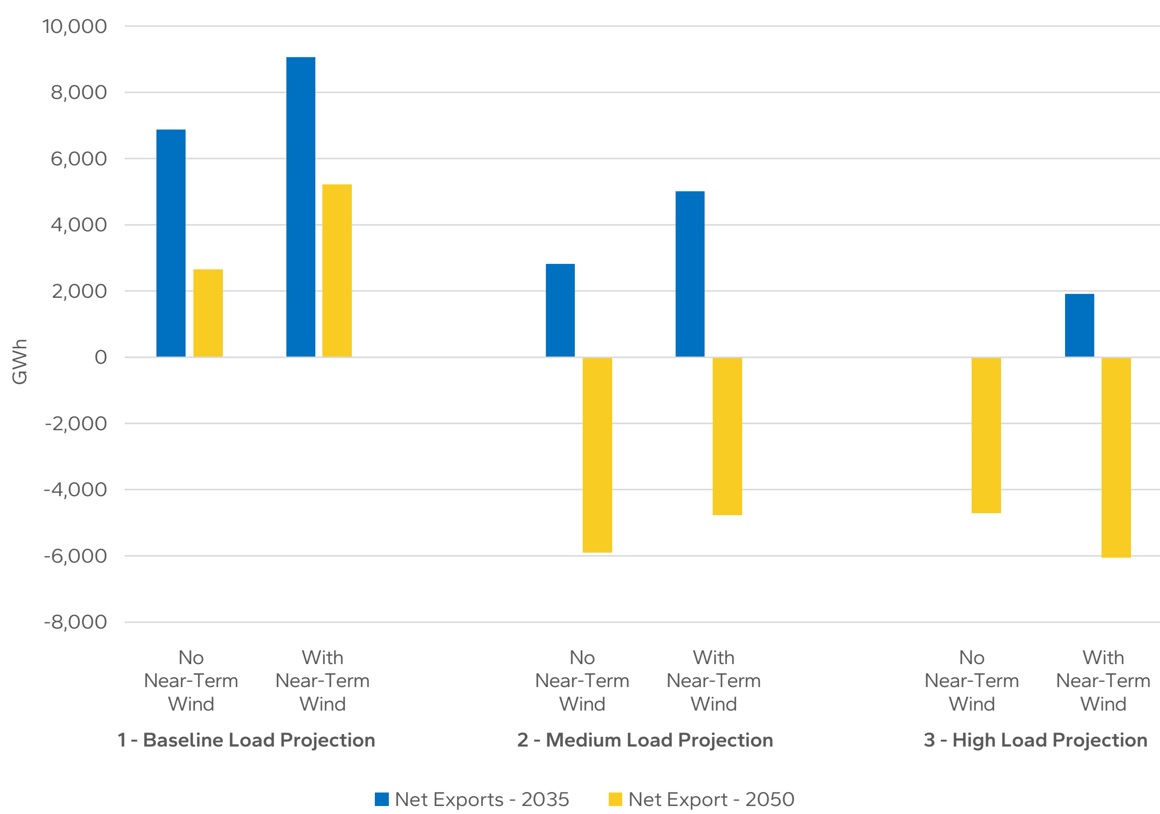
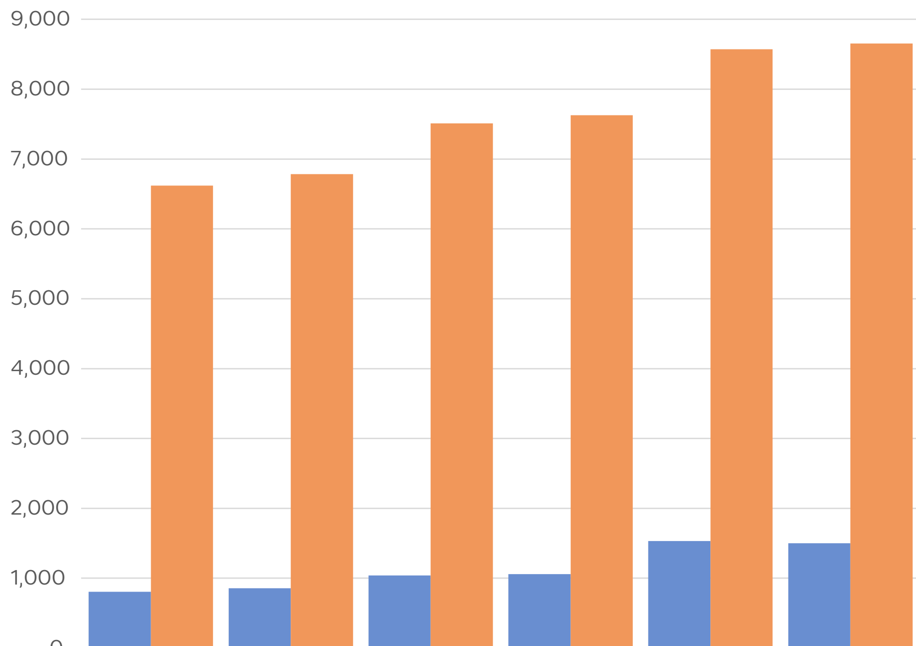


Figure A7.2.99 - Sensitivity – Near-Term Wind Generation Projects – Net Exports in 2035 and 2050

In 2035, the PV of Net System costs increases when near-term wind generation is included by $80 to $166 M 2024 CAN$ compared to the no near-term wind cases. Annual net system costs also increase with near-term wind in the 1-Baseline and 2-Medium load projections, by $49 and $20 M/yr 2024 CAN$, respectively. However, under the 3-High load projection, 2035 annual costs are reduced by $33 M 2024 CAN$ with the inclusion of near-term wind.



	No Near-Term Wind	With Near-Term Wind	No Near-Term Wind	With Near-Term Wind	No Near-Term Wind	With Near-Term Wind
	1 - Baseline Load Projection		2 - Medium Load Projection		3 - High Load Projection	
Incremental Annual Net System Cost [M$/year]	806	855	1,039	1,059	1,532	1,499
Incremental Cumulative Present Value of Net System Costs [M$]	6,618	6,784	7,511	7,627	8,573	8,653

Figure A7.2.100 - Sensitivity - Near-Term Wind Generation Projects – Incremental Cumulative Present Value of Net System Costs [M 2024 CAN$] and Incremental Annual Net System Costs [M 2024 CAN$/yr] to 2035

Near-term wind additions under the 3-High load projection result in a smaller increase in total annualized investment costs than under the 2-Medium load projection. This is shown in Figure A7.2.101. Since the increase in annualized total investment costs is smaller between the wind sensitivity cases under the 3-High load projection, it gets more than compensated for by the combined reduction in incremental fuel and power purchases and increased net export revenues with near-term wind additions, resulting in an overall reduction in annual net system. This reduction in the annual 2035 net system costs is in contrast to the increase in the PV of net system costs in 2035 because the PV of net system costs is cumulative and takes into account the evolution of the financial indicator for the entire 2025 – 2035 period and is less influenced by the increased investment costs specifically in 2035.

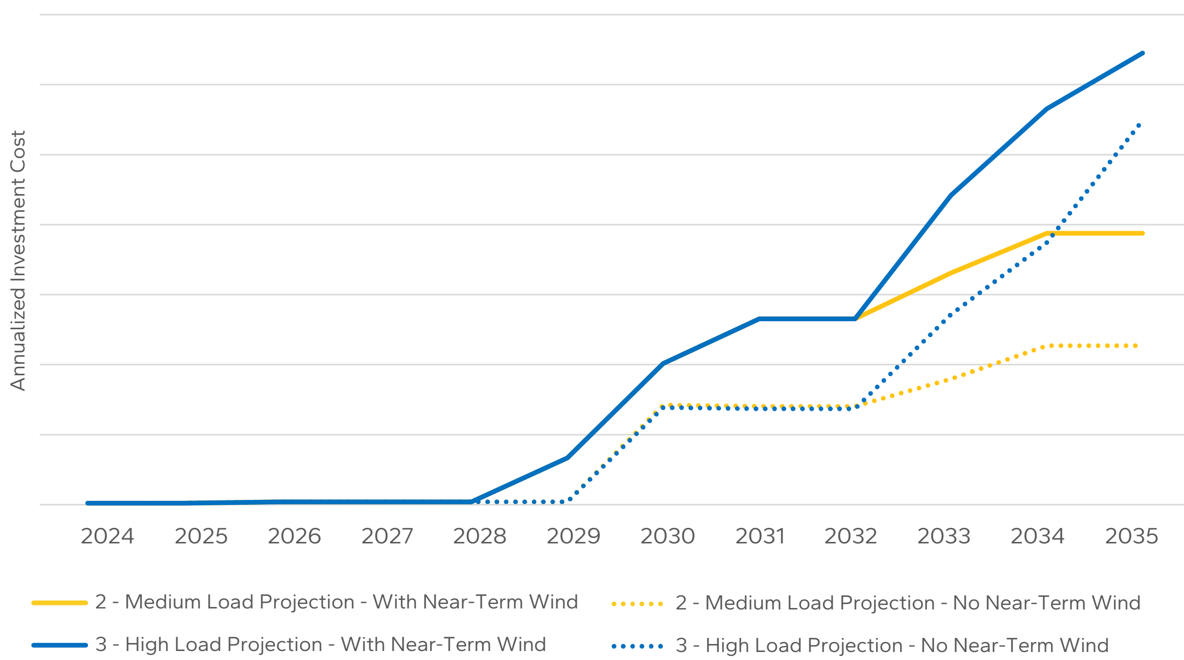
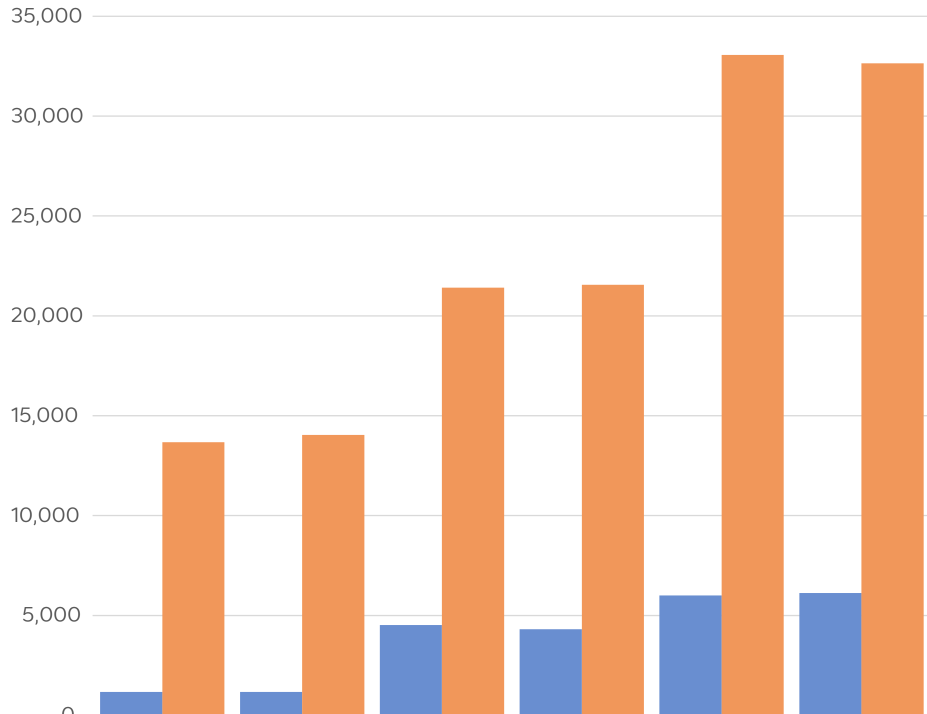


Figure A7.2.101 - Sensitivity - Near-Term Wind Generation Projects – Trends in Total Annualized Investment Costs, comparing With and Without Near-Term Wind Generation Projects for the 2-Medium and 3-High Load Projections

By 2050, the impact of near-term wind generation on the PV of Net System Costs is less clear. With near-term wind additions, the PV of Net System Costs increases by \$364 M 2024 CAN\$ under the 1-Baseline load projection, increases by \$145 M 2024 CAN\$ under 2-Medium load projection, and decreases by \$422 M 2024 CAN\$ under 3-High load projection. Annual Net System Costs decrease under load projections 1-Baseline and 2-Medium, by \$6 and \$211 M/yr 2024 CAN\$ respectively, but increase under the 3-High load projection by \$123 M/yr 2024 CAN\$. Opposite effects from near-term wind under the higher 2-Medium and 3-Medium load projections are influenced by the different long-term energy strategies that were chosen between the with and without near-term wind cases.



	No Near-Term Wind	With Near-Term Wind	No Near-Term Wind	With Near-Term Wind	No Near-Term Wind	With Near-Term Wind
	1 - Baseline Load Projection		2 - Medium Load Projection		3 - High Load Projection	
Incremental Annual Net System Cost [M$/year]	1,175	1,169	4,523	4,312	6,001	6,124
Incremental Cumulative Present Value of Net System Costs [M$]	13,670	14,034	21,415	21,560	33,060	32,638

Figure A7.2.102 - Sensitivity - Near-Term Wind Generation Projects – Incremental Cumulative Present Value of Net System Costs [M 2024 CAN$] and Incremental Annual Net System Costs [M 2024 CAN$/yr] to 2050

Finally, committing to near-term wind generation may be beneficial in reducing unmet capacity need risks in 2029. Including near-term wind generation projects assumes a staggered addition of new wind, with 200 MW of installed capacity added every 2 years beginning in 2029. This assumption allows new wind to be brought online three years earlier than the 2032 earliest ISD otherwise assumed for new wind, and 1 year earlier than the 2030 earliest ISD of new CT-NG units. If a 2029 ISD is achievable by pursuing near-term wind generation, unmet capacity need risks in 2029 under load projections 2-Medium and 3-High may be reduced.

4 | Least Regrets Analysis Results

4.1. Introduction

Results of the least regrets analyses (LRA) are presented as two independent focuses of analysis – each built on scenario and sensitivity observations. Focus 1 measured the reliability and cost magnitudes for over and underbuild regret within the development plan horizon (to 2035), with resources locked-in to 2032. Focus 2 incorporates the learnings from Focus 1 and analyzes additional runs that include a more diverse set of feasible resources, seeking a balance that enhances alignment with the 2025 IRP objectives. The runs considered in the LRA form the basis for the potential development plans which are further analyzed through subsequent steps in the 2025 IRP development process.

4.2. Six Feasible Resources to Explore in the LRA

The scenario and sensitivity results were analyzed with attention to typical sizing and types of resources selected prior to 2032. This was done to determine which resource options would be feasible to "lock-in" and simulate an investment commitment in each LRA run. The following is what was observed from the scenario and sensitivity results:

- **Energy efficiency:** All runs assumed 326 MW of energy efficiency savings from the Efficiency Plan Projection. Furthermore, in the sensitivities with additional energy efficiency enabled, some level of energy efficiency and ground source heat pumps (GSHP) are consistently selected prior to 2032 in quantities dependent on the load projection being served and the ability to defer (but not eliminate) CT-NGs.
- **Demand response and curtailable rate program:** All runs assume 280 MW total savings from demand response and the curtailable rate program by 2032.
- **Wind generation:** Scenarios and sensitivities assumed the inclusion of the near-term wind generation projects with 400 MW installed by 2032 (and the remaining 200 MW installed in 2033). Occasionally, additional wind outside of the assumed near-term generation projections (ranging from 100 MW-600 MW) was selected in 2032, but this was generally in the high market price sensitivities or the cases with 3-High load projection and/or restrictions excluding CT-NGs.

- **Hydropower enhancements:** Across scenarios and sensitivities, there was no clear signal with regards to hydropower enhancements. The amount selected ranged from zero in some of the scenarios for the 1-Baseline load projection, up to approximately 100 MW in the majority of the scenarios and sensitivities with the 3-High load projection.
- **Batteries:** Batteries tended to be selected in very small quantities by 2032, ranging from zero to 20 MW in the vast majority of scenarios and sensitivities. Only in the most extreme cases were batteries selected in large quantities, including the maximum available (350 MW) in the resource options strategy D cases.
- **Combustion turbines fuelled by natural gas (CT-NG):** All scenario and sensitivity results ended up selecting some level of CT-NGs in 2030 (with the exception of when this resource was excluded from the resource options available to the model). The quantity selected in 2030 ranged from one CT-NG (248 MW) in runs serving the 1-Baseline load projection with near-term wind, up to four CT-NGs (992 MW) in runs serving the 3-High load projections without the near-term wind generation projects. By 2032, additional CT-NGs units were required to serve the 3-High load projection, increasing the cumulative total to 1288 MW.
- **Market purchases:** Market purchases are not one of the six feasible resource options. While runs for the 2-Medium and 3-High load projections consistently selected the maximum amount of market purchases available in 2032 (50 MW), the signal was not clear compared to the 1-Baseline load projection runs (with most runs not selecting any market purchases for 2032). In the LRA runs, market purchases were only used as short-term stopgaps and not relied on as long-term solutions to serve capacity or energy needs.

4.3. LRA Focus 1 - Measuring the Magnitude of Regret for Plans with Committed New Resources to 2032

LRA Focus 1 was set up to further explore two different observations stemming from the scenario and sensitivity analysis. The first observation to explore was that the lowest cost portfolios of resources include natural gas fuelled combustion turbines to meet capacity needs. The second observation was that alternative resources, when paired with natural gas fuelled combustion turbines, can provide value to the electrical system. This was done by varying resource types, amounts, and timing to measure the regret impacts across the LRA runs. These runs can be organized into two groupings, labelled Lower Cost and Maximized Alternatives. The accredited capacity by 2032 for each LRA run can be seen in Table A7.2.21.

Table A7.2.21 – Least Regrets Analysis Focus 1 - Accredited Capacity in MW by LRA Focus 1 in 2032

	Lower Cost				Maximized Alternatives		
Resource Option	**LR1**	**LR2**	**LR3**	**LR4**	**LR5**	**LR6**	**LR7**
Customer Side Solutions: Efficiency Plan Projection	326	326	326	326	326	326	326
Customer Side Solutions: Demand response including curtailable rate program	280	280	280	280	280	280	280
Customer Side Solutions: Additional energy efficiency programs	0	0	0	0	201	201	201
Wind*	120	120	120	120	120	120	120
Battery storage	0	0	0	1	202	202	350
Upgrade existing hydropower**	0	0	0	103	26	103	26
Combustion turbines fuelled by natural gas	296	496	744	1,240	248	248	0

**Shown in the table is 120 MW of accredited capacity (the full 600 MW installed capacity) commitment for the near-term wind generation. Wind additions in 2032 only include the first 80 MW (400 MW installed capacity), with the full 120 MW (600 MW installed capacity) added by 2033.*

***Winter accredited capacity for hydropower supply side enhancements is -97 MW in 2032 for LR4 and LR6 which include the 3-unit Lower Nelson supply side enhancement option. For this option, initial reductions in Lower Nelson winter accredited capacity occur while unit upgrade work is being completed, including in 2032. By 2033, upgrade work is complete and winter accredited capacity for the hydropower supply side enhancements is 103 MW.*

Figure A7.2.103 provides an illustrative comparison of resource additions in 2032 across three groups: the eight scenario results, the over fifty sensitivity results, and the seven LRA Focus 1 runs. This comparison demonstrates that the range and average quantity of resource additions explored in the seven LRA Focus 1 runs are reasonably representative of the broader set of scenario and sensitivity outcomes, offering confidence in their coverage.

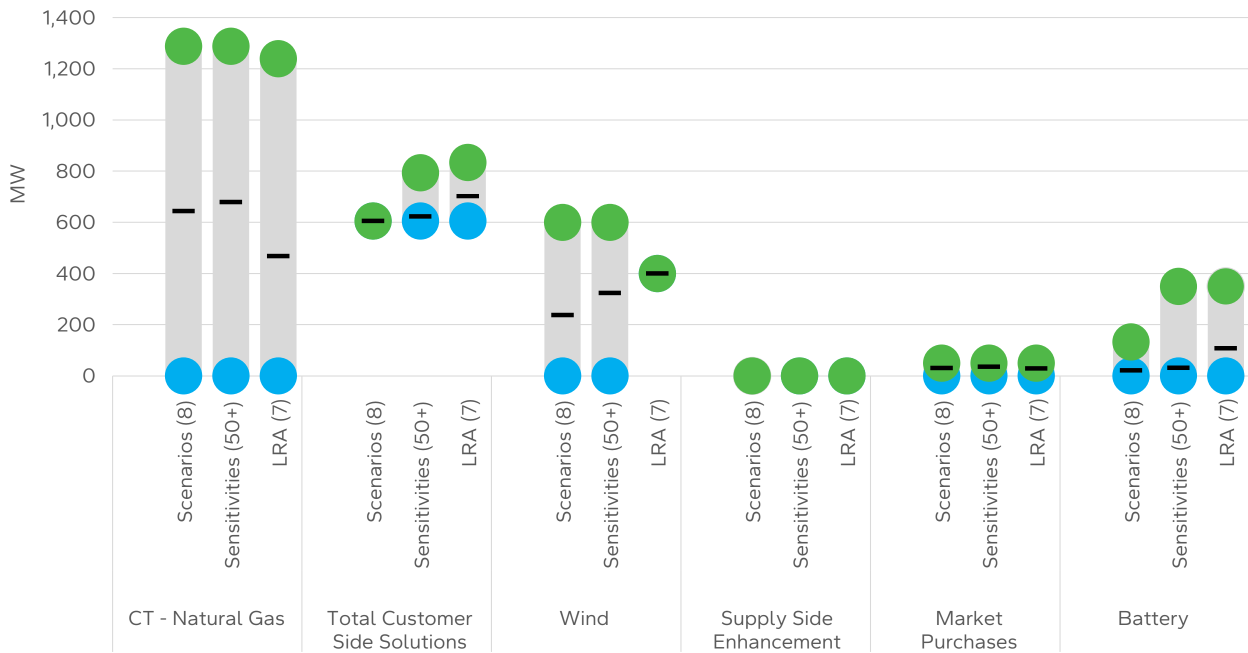


Figure A7.2.103 - Least Regrets Analysis Focus 1 – Comparison of Ranges of Resource Quantities in LRA Action Plans to Scenario and Sensitivities

4.3.1. Key Takeaways of Observations of Regret

Lower Cost Plans

The Lower Cost plans were run against the 2025 IRP load projections with their results compared to an appropriate cost-optimized result to quantify the potential regret of resources locked into the LRA runs, as described in Appendix 7.1 – Modelling & Analysis Approach. The potential regrets observed in the Lower Cost plans are as follows:

Underbuild Regret

- As shown in Figure A7.2.104, the maximum regret of 2,426 MW of cumulative unmet accelerated capacity need occurs when LR1 is run against the 3-High load projection, which projects more quickly increasing capacity needs than the locked-in portion of the LR1 run can supply.

- Underbuild regret occurs in all three of LR1, LR2, and LR3 for runs with both 2-Medium and 3-High load projections.
- No underbuild regret occurs with LR4.

Overbuild Regret

- The maximum regret of roughly $1.2 B 2024 CAN$ of additional costs occur when LR4 is run against the 1-Baseline load projection.
- Overbuild regret is apparent, to varying degrees, in all of LR1, LR2, LR3, and LR4 under the 1-Baseline load projection.

Overall Regret

- The quantities of under/overbuild regret can be seen in Figure A7.2.104, represented as percentages of the maximum regret for the given category.
- Without further evaluation of the trade-off between reliability and cost risks, LR3 appears to have both the lowest risk of potential regret and the most balanced levels of regret (between under/over build).
- The timing and sizing of resource additions from LR3 was therefore used as a template to evaluate runs with alternative resource types in the following section.

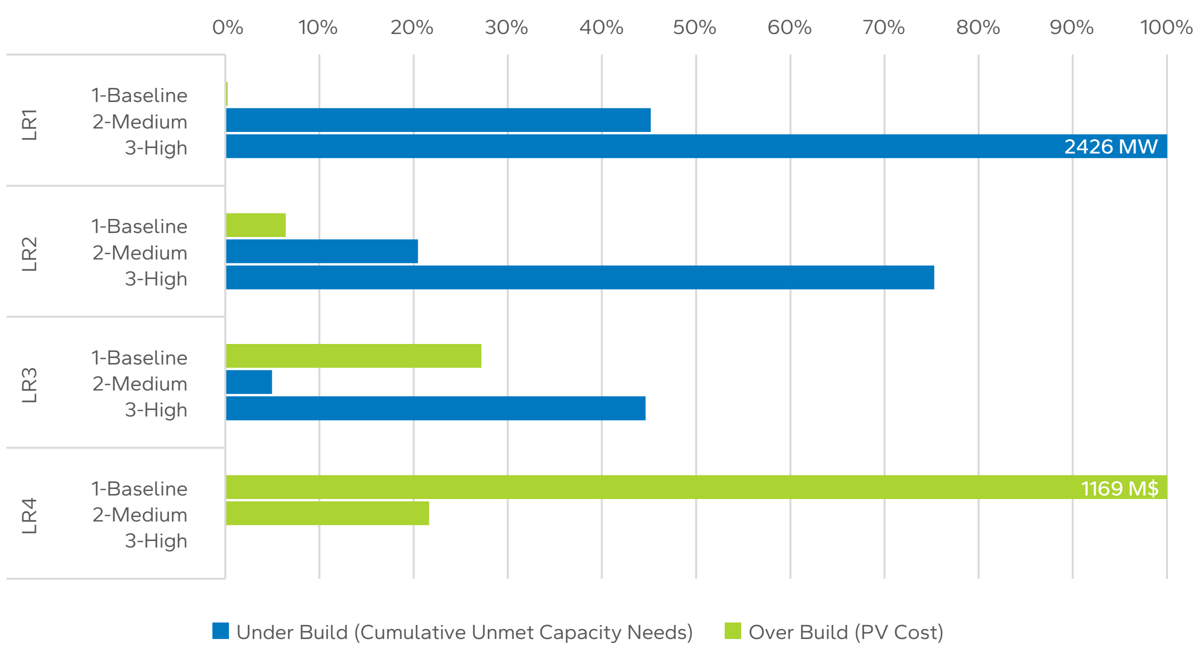


Figure A7.2.104 - Lower Cost Plan Regret to 2032

Maximized Alternatives Plans

The run with the least potential regret from the Lower Cost plan grouping was LR3. For this reason, the timing and sizing of resource additions in the Maximized Alternative plans were indexed to LR3 to define the next group of runs to be studied, with an aim to evaluate alternative resources to natural gas fuelled combustion turbines (CT-NG).

The quantities of under/over build regret from the Maximized Alternatives plans have been included in Figure A7.2.105. These results are incremented against benchmarks that vary based on the load projection (per Appendix 7.1 – Modelling & Analysis Approach).

The potential regrets observed in the Maximized Alternatives plans are as follows:

Underbuild Regret

- LR1 still results in the maximum observed regret of 2,426 MW of cumulative unmet capacity needs under the 3-High load projection.
- LR5, LR6, and LR7 all result in underbuild regret under the 3-High load projections. They have no underbuild regret under the 2-Medium or 1-Baseline load projection.

Overbuild Regret

- LR4 still results in the maximum regret of roughly $1.2 B 2024 CAN$ of additional costs, which occur under the 1-Baseline load projection.
- Overbuild regret occurs to varying degrees in all three of LR5, LR6, and LR7 under the 1-Baseline and 2-Medium load projections.

Overall Regret

- The quantities of under/over build regret can be seen in Figure A7.2.105, represented as a percentage of the maximum regret for the given category.
- Without further evaluation of the trade-off between reliability and cost risks, LR3 continues to appear to have both the lowest risk of potential regret and the most balanced levels of regret (between under/over build).
- LR5, LR6, and LR7 all appear to have greater potential for overbuild regret than underbuild regret when considering all three load projections.

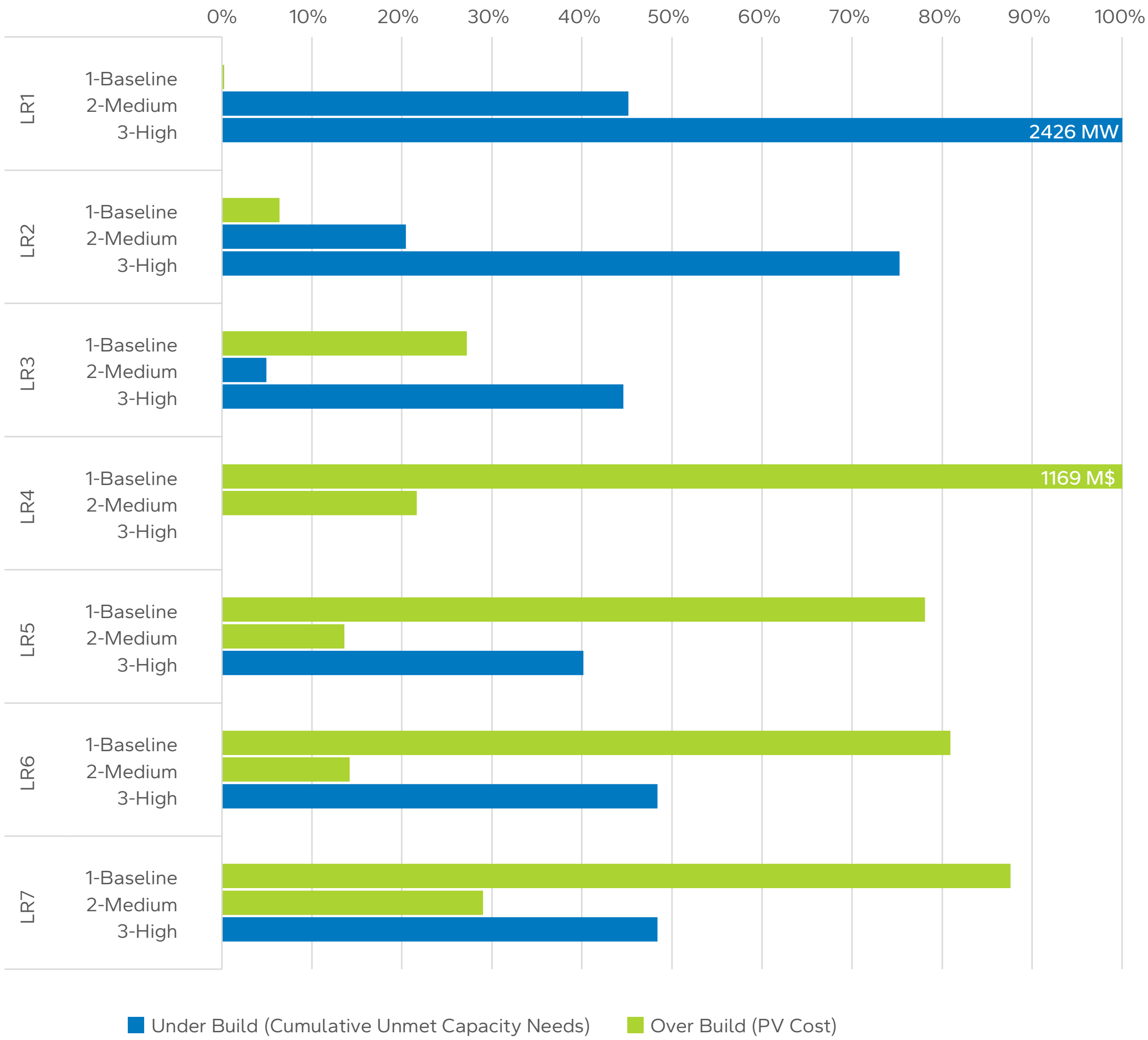


Figure A7.2.105 - Relative Regret of LRA Focus 1 Action Plans to 2032

4.3.2. Results

Installed Capacity

This section discusses how installed capacity outcomes in 2035 and 2050 were influenced by the locked-in resources in the LRA runs to 2032, further identifying the potential and drivers for regret.

The installed capacity distributions for the least regret analysis are shown (alongside the appropriate scenario for comparison) in Figure A7.2.106 through Figure A7.2.111 for the 1-Baseline, 2-Medium, and 3-High load projections, for study years 2035 and 2050. The figures show how the capacity expansion model filled out the LRA runs for the remainder of the planning horizon (post 2032, beyond the lock-in period), and call out the resource additions that are common to each result.

Note: In Figure A7.2.106 through Figure A7.2.111, total customer side solutions only include incremental additions above the Efficiency Plan Projection and the assumed DR and CRP. Additional customer side solutions and supply side enhancements cannot be selected past 2032. When solar additions are shown, they are marked with an asterisk to help distinguish from the CT-NG units.

1-Baseline Load Projection

Figure A7.2.106 and Figure A7.2.107 summarize the cumulative installed capacity additions for the LRA Focus 1 runs for the 1-Baseline load projection in 2035 and 2050, respectively. By 2035 none of the LRA runs have added any resources beyond the locked-in components and so the only common resource is the 600 MW of near-term wind. Although they are not shown in the figures, the Efficiency Plan Projection, demand response (DR), and the curtailable rates program (CRP) are included as a base assumption, common across all runs. These findings indicate that by 2035, the near-term decisions between LRA Focus 1 runs are all still subject to overbuild under the 1-Baseline load projection, with no further no-regret resource additions identified.

By 2050, all runs include at least 1,232 MW of natural gas fuelled combustion turbine (CT-NG) capacity, in addition to the 600 MW of near-term wind. This quantity of CT-NG is nearly identical to the 1,240 MW initially locked-in to LR4, suggesting that the full amount of CT-NG committed during the locked-in period is ultimately required by 2050—regardless of the LRA Focus 1 runs. Therefore, selecting any of the LRA Focus 1 runs would, at worst, result in an earlier deployment of CT-NG resources within the 20-year planning horizon.

Ultimately, the choice of LRA Focus 1 run has minimal impact on the majority of the optimal resource selection required to serve the 1-Baseline load projection by 2050, with approximately 70% of resources remaining consistent across all runs.

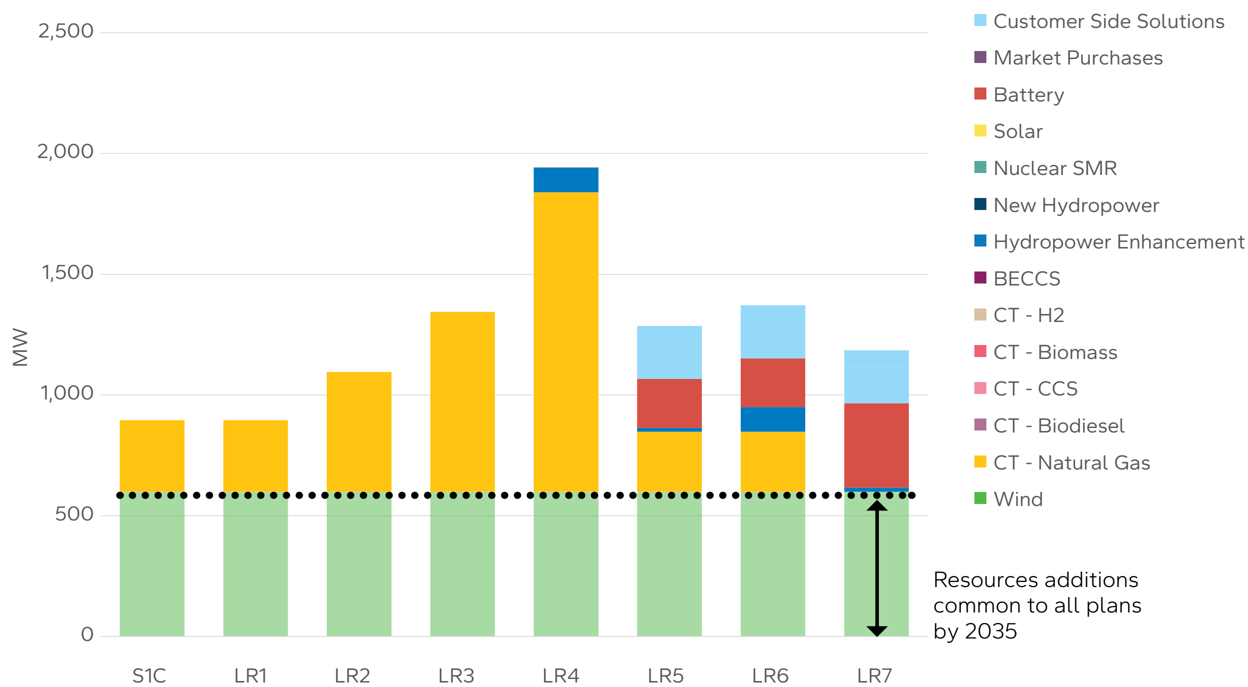


Figure A7.2.106 - Least Regrets Analysis Results – Focus 1: Robust Resource Additions by 2035 for the 1-Baseline Load Projection

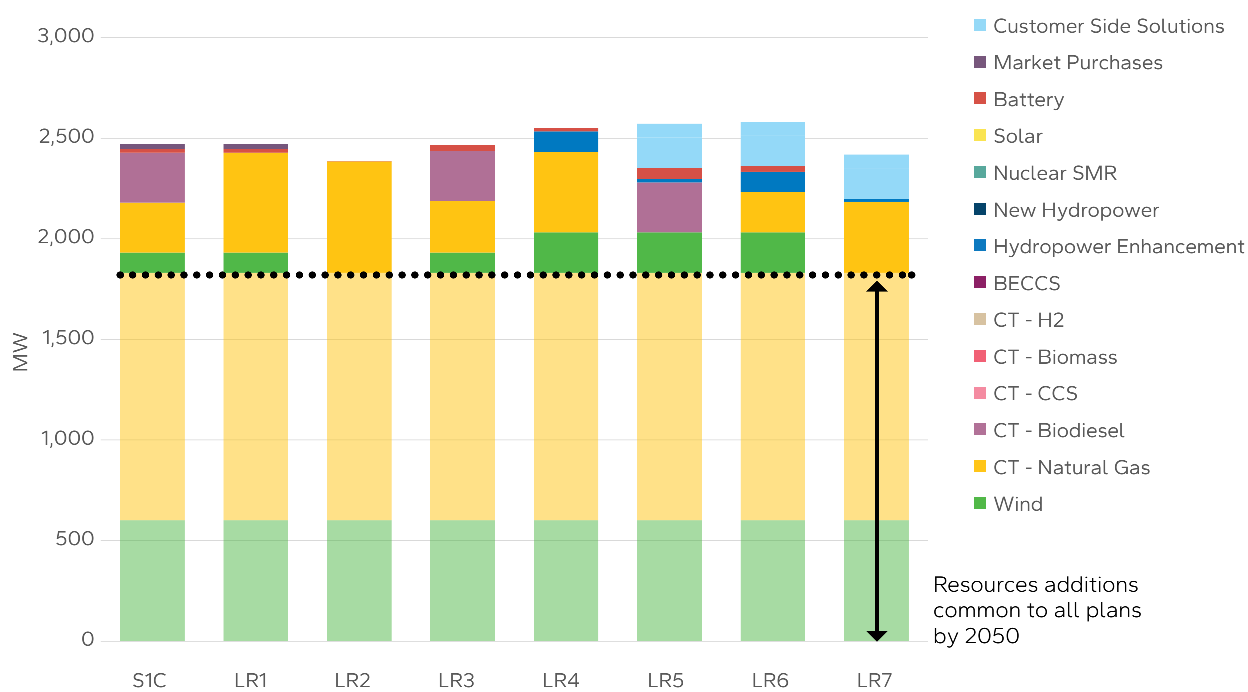


Figure A7.2.107 - Least Regrets Analysis Results – Focus 1: Robust Resource Additions by 2050 for the 1-Baseline Load Projection

2-Medium Load Projection

Under the 2-Medium load projection, additional resources are required to meet the higher load by 2035. Nearly all the LRA Focus 1 runs begin adding resources between 2033 to 2035. By 2035 all runs include at least 248 MW of CT-NG (in addition to the 600 MW of near-term wind), indicating that the first unit of CT-NG is, at worst, an advancement of the requirements to meet the 2-Medium load projection by that time.

By 2050, all the runs include at least 3,300 MW of CT-NG and 4,300 MW of wind. This clearly shows that any decisions made prior to 2032 with regards to CT-NG and wind are simply advancements of decisions that would be required to meet the 2-Medium load projections by 2050. Further analysis reveals that all runs exceed the 1,240 MW of CT-NG locked-in by 2032 for LR4 as early as 2045, meaning the advancement is, at most, by 15 years.

Ultimately the choice of LRA Focus 1 run has minimal impact on the majority of the optimal resource selection required to serve the 2-Baseline load projection by 2050, with approximately 70% of resources remaining consistent across all runs.

Figure A7.2.108 and Figure A7.2.109 summarize the cumulative installed capacity additions for the LRA Focus 1 runs for the 2-Medium load projection in 2035 and 2050, respectively.

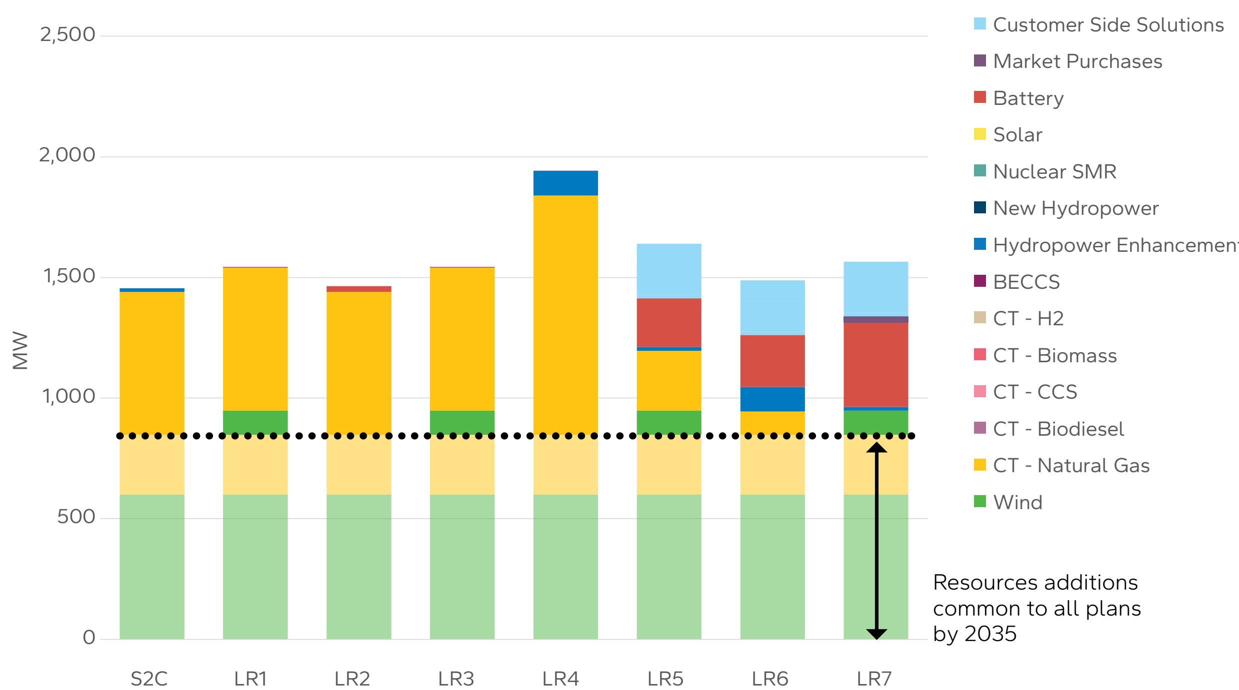


Figure A7.2.108 - Least Regrets Analysis Results - Focus 1: Robust Resource Additions by 2035 for 2-Medium Load Projection

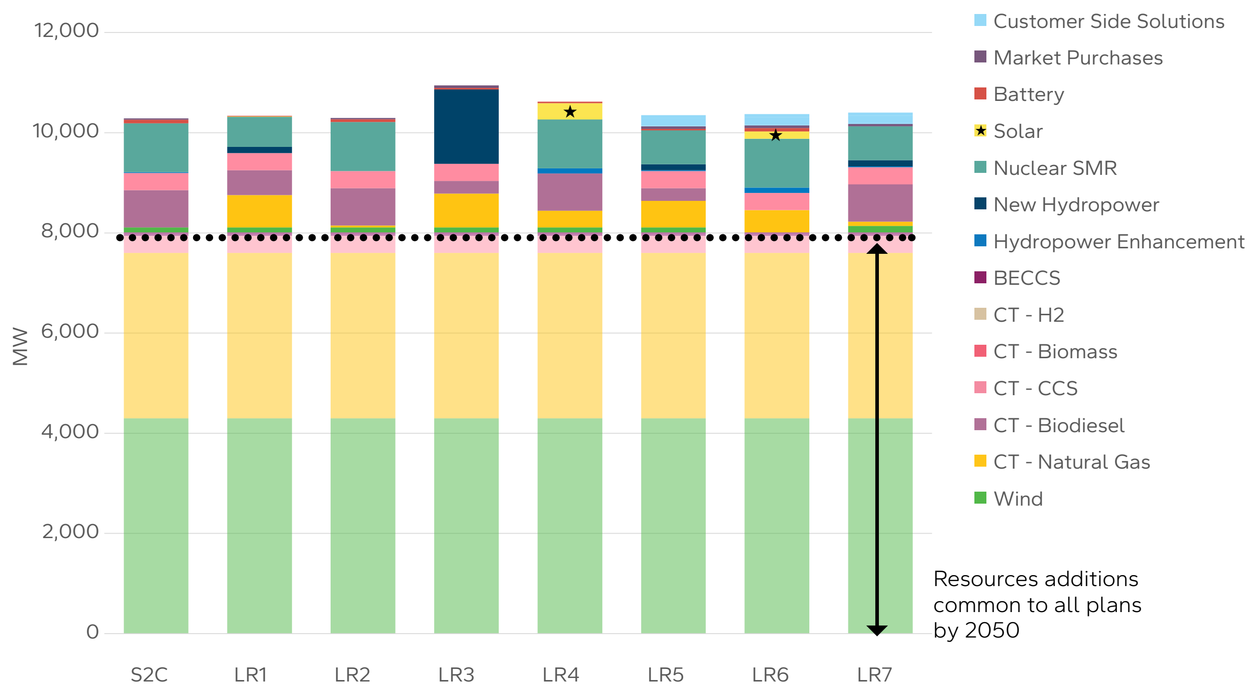


Figure A7.2.109 - Least Regrets Analysis Results - Focus 1: Robust Resource Additions by 2050 for 2-Medium Load Projection

3-High Load Projection

Figure A7.2.110 and Figure A7.2.111 summarize the cumulative installed capacity additions for the LRA Focus 1 runs for the 3-High load projection in 2035 and 2050, respectively.

For the 3-High load projection, more resources are needed to meet the higher load by 2035. All the LRA Focus 1 runs need to start adding resources in the 2033 to 2035 timeframe. By 2035 all runs have at least 1,374 MW of CT-NG (in addition to the 600 MW of near-term wind), suggesting that all locked-in CT-NG in the LRA Focus 1 runs are at worst an advancement of the requirements to meet the 3-Medium load projection by 2035 (5 years). By 2050, all the runs have at least 4,924 MW of CT-NG, 6,000 MW of wind, and 688 MW of combined cycle combustion turbine with carbon capture and sequestration (CT-CCS).

Once again, the choice of LRA Focus 1 run has little to no effect on the vast majority (roughly 70%) of the optimal resource selection required to serve the 3-High load projection by as early as 2035.

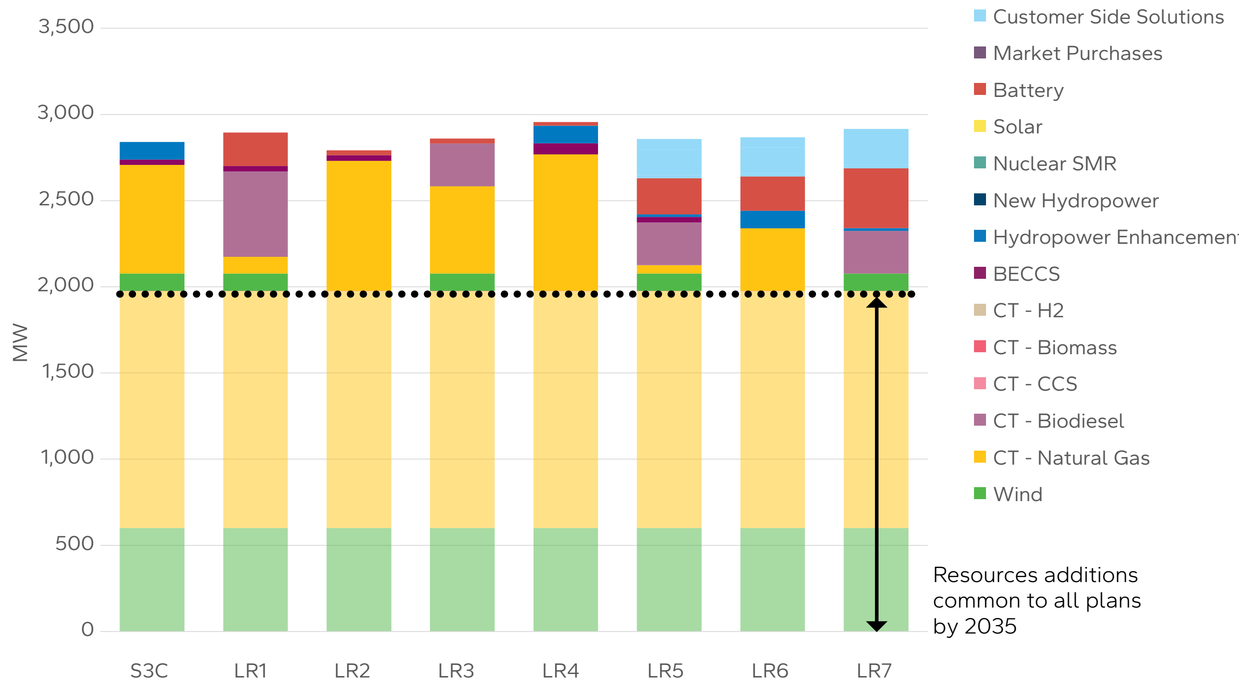


Figure A7.2.110 - Least Regrets Analysis Results - Focus 1: Robust Resource Additions by 2035 for 3-High Load Projection

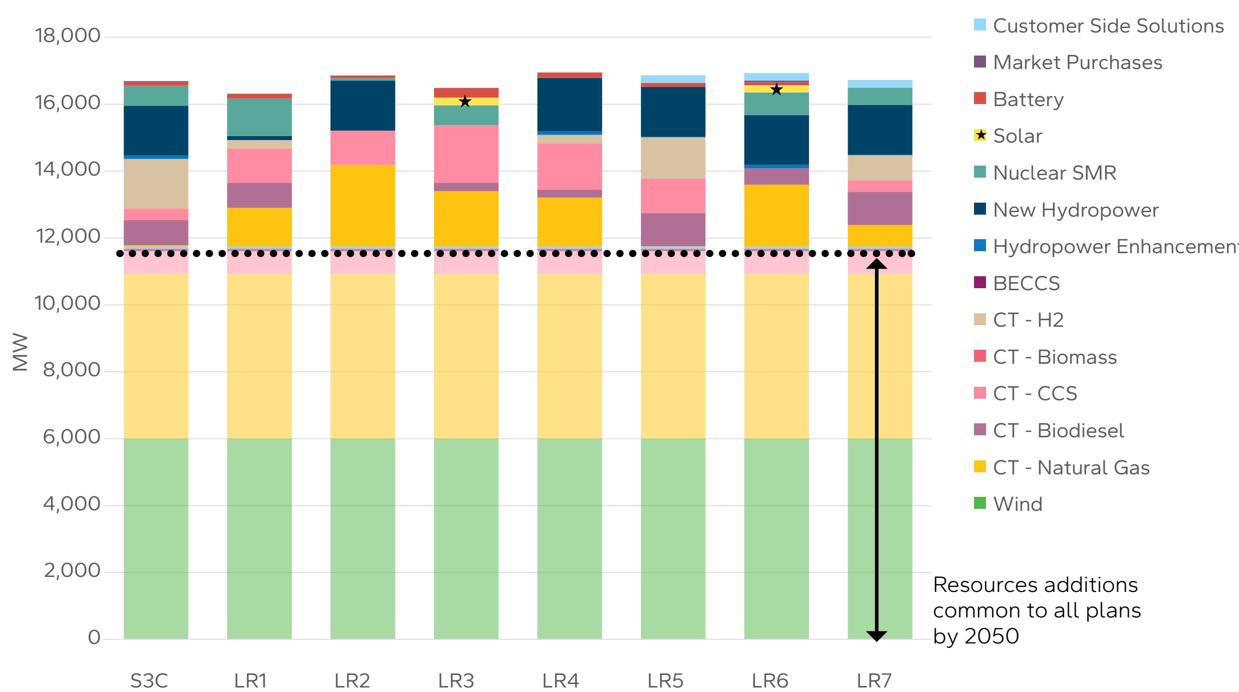


Figure A7.2.111 - Least Regrets Analysis Results - Focus 1: Robust Resource Additions by 2050 for 3-High Load Projection

Capability of Resource Options to Meet Near Term Capacity and Energy Needs

With the modelling of fixed LRA runs across the range of load projections, underbuild regrets are observed when locked-in and subsequently added resources (post 2032) cannot supply sufficient accredited capacity or dependable energy to meet the needs of the load projection being applied. This highlights that meeting an accelerated pace of decarbonization and electrification would be a challenge in the early years. Capacity and energy needs are defined based on the Generation Planning Criteria and reflect the load projection, committed exports, planned generator outages, and a Planning Reserve Margin. As shown in Figure A7.2.112, all LRA runs contain some level of unmet capacity need compared to the need defined by the 2-Medium load projection and the 3-High load projection. There is no unmet capacity need, and thus no underbuild regret, associated with the 1-Baseline load projection.

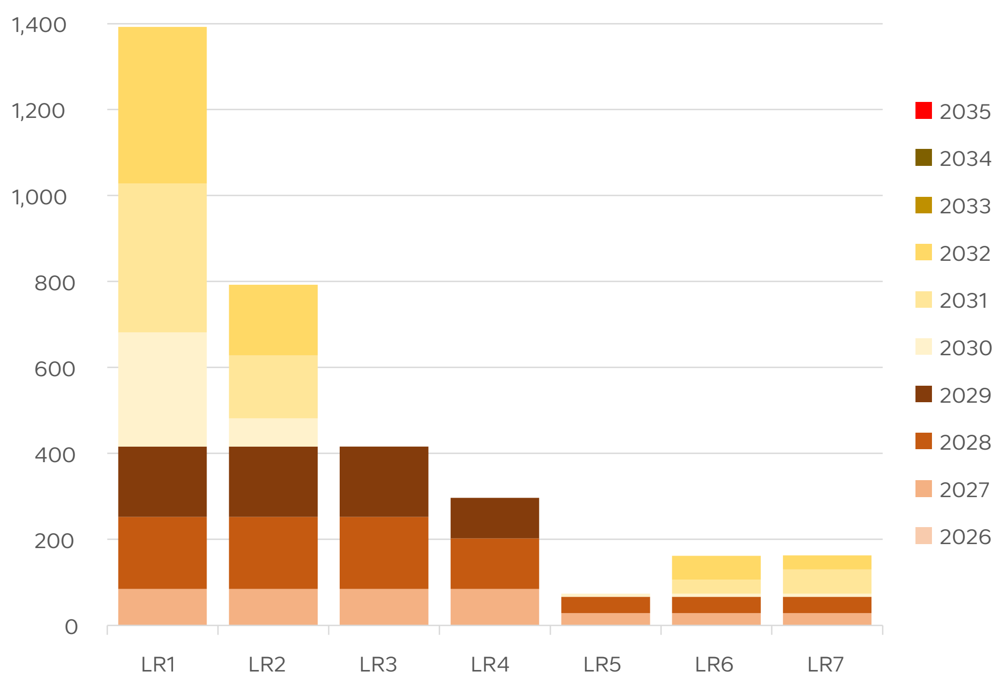


Figure A7.2.112 - Least Regrets Analysis Results – Focus 1: Absolute Unmet Capacity Needs – 2-Medium Load Projection

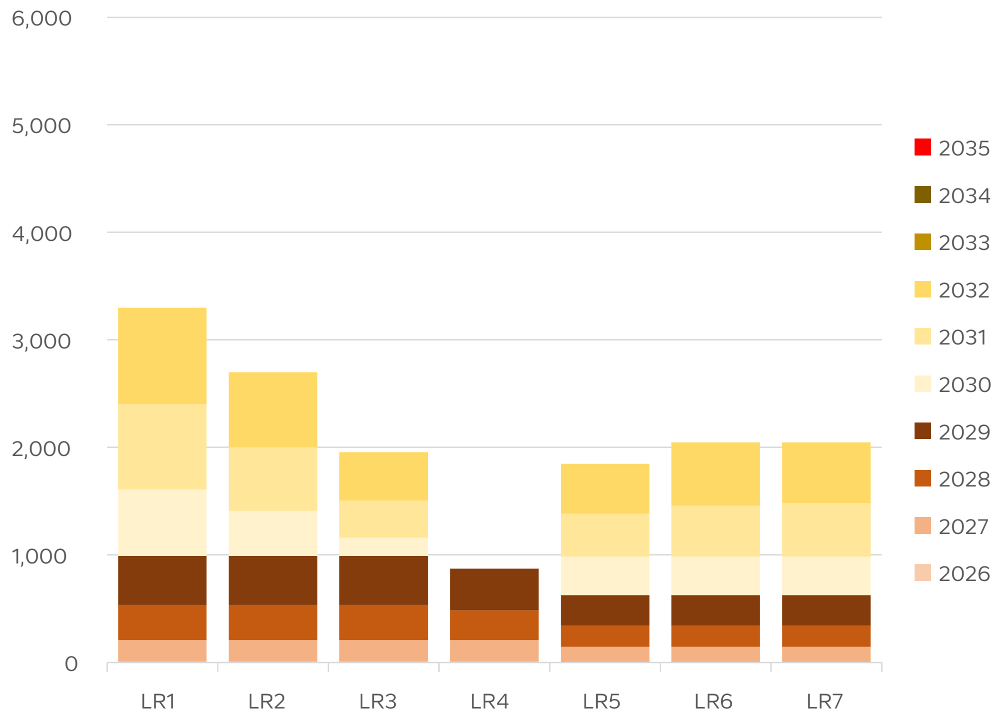
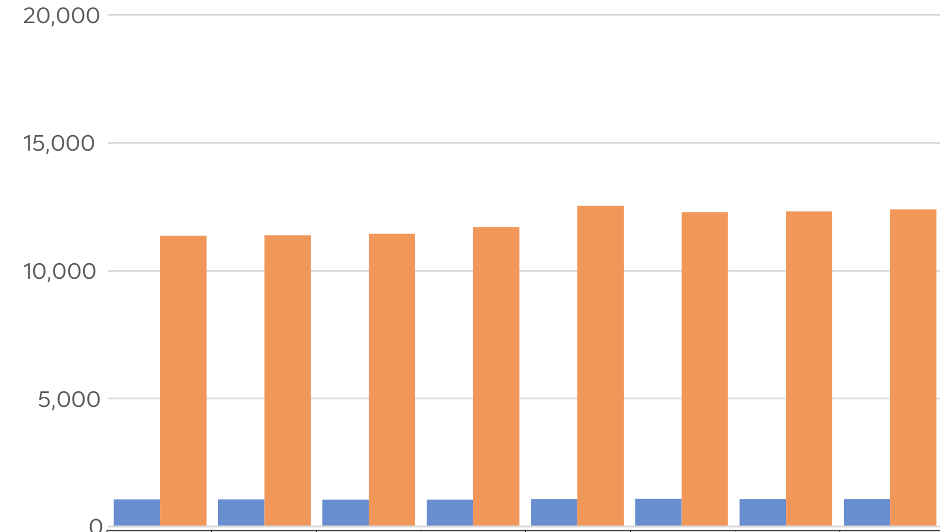


Figure A7.2.113 - Least Regrets Analysis Results – Focus 1: Absolute Unmet Capacity Needs – 3-High Load Projection

Annual and Net System Costs

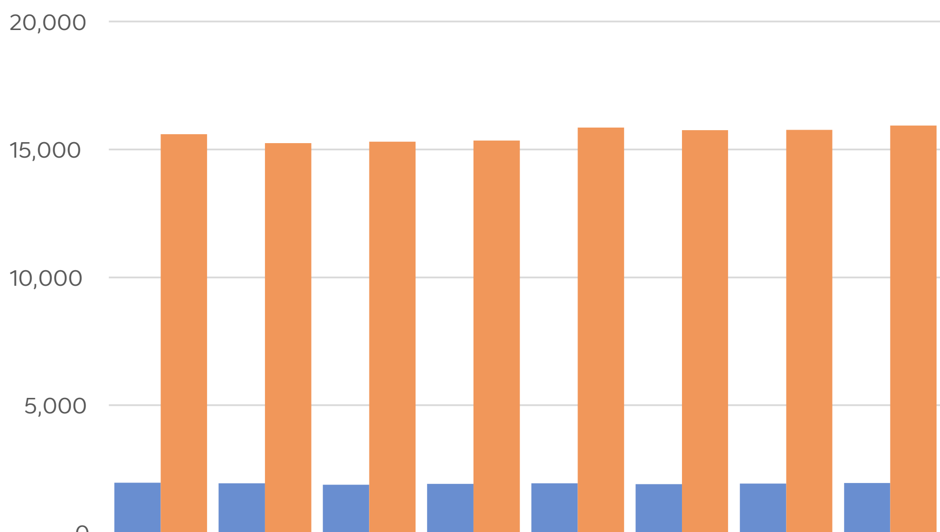
Figure A7.2.114, Figure A7.2.115, and Figure A7.2.116 provide the incremental net system costs for each of the seven LRA Focus 1 runs in the forecast year of 2045 for each of the 1-Baseline, 2-Medium, and 3-High load projections respectively. Results are provided in 2045 for consistency with the overbuild regret analysis, and is sufficient to capture insights into longer-term net system costs without introducing potential modelling noise at the end of the study horizon. Each result is stated in terms of both the cumulative present value of net system costs up to that point, as well as the corresponding annual costs in the given year.

The range in the incremental cumulative present value of net system costs between the seven LRA Focus 1 runs is roughly $1.2 B 2024 CAN$ to serve the 1-Baseline load projection but drops to approximately $700 - $900 M 2024 CAN$ to serve each of the 2-Medium, and 3-High load projection to 2045, respectively. This drop is expected, as the potential for overbuild regret is largest in the lowest load growth projections.



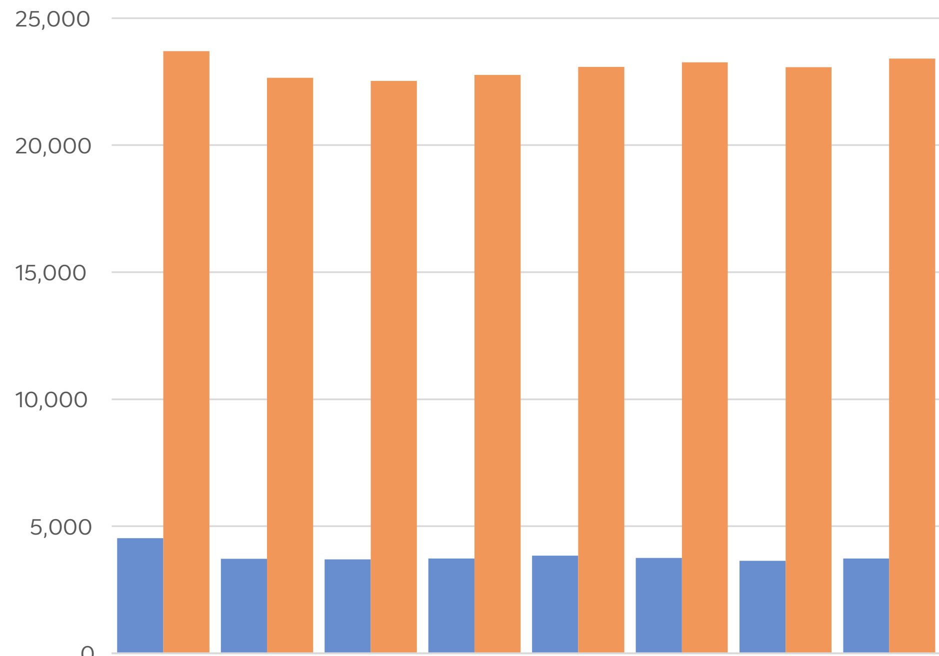
	S1C	LR1	LR2	LR3	LR4	LR5	LR6	LR7
Incremental Annual Net System Cost [M$/year]	1,058	1,056	1,041	1,040	1,067	1,082	1,073	1,068
Incremental Cumulative Present Value of Net System Costs [M$]	11,375	11,378	11,451	11,693	12,544	12,288	12,321	12,399

Figure A7.2.114 - Least Regrets Analysis Results - Focus 1 - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2045) for the 1-Baseline load projection



	S2C	LR1	LR2	LR3	LR4	LR5	LR6	LR7
Incremental Annual Net System Cost [M$/year]	1,973	1,942	1,896	1,922	1,946	1,914	1,933	1,962
Incremental Cumulative Present Value of Net System Costs [M$]	15,598	15,245	15,305	15,350	15,852	15,757	15,764	15,937

Figure A7.2.115 - Least Regrets Analysis Results - Focus 1 - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2045) for the 2-Medium load projection



	S3C	LR1	LR2	LR3	LR4	LR5	LR6	LR7
Incremental Annual Net System Cost [M$/year]	4,531	3,714	3,696	3,732	3,845	3,749	3,639	3,725
Incremental Cumulative Present Value of Net System Costs [M$]	23,696	22,652	22,525	22,770	23,075	23,257	23,071	23,405

Figure A7.2.116 - Least Regrets Analysis Results - Focus 1 - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2045) for the 3-High load projection

4.4 LRA Focus 2 - Testing Regret Around Specific Development Plan Attributes

LRA Focus 2 was undertaken to test the regret around variations of the attributes of the runs from Focus 1. Focus 2 narrowed in on the results that showed reasonable levels of underbuild and overbuild regret. However, the runs studied in LRA Focus 2 specifically included additional combinations of resources that were well aligned with all the considerations for our potential development plans outlined in Appendix 2 – 2025 IRP Development Process. While Focus 1 runs aligned with some of the considerations, Focus 2 studied the potential regret of including more combinations of feasible resources. LRA Focus 2 explored the long-term impacts of varying the timing and magnitudes of feasible resources by locking in different combinations throughout the entire development horizon ending in 2035, seeking a balance that met all the objectives of the IRP.

As noted previously, LR3 was observed to have a robust level of under/over build regret and the lowest overall potential regret, so formed the basis for the additional runs studied in LRA Focus 2. Runs modelled in Focus 2 included a lower amount of combustion turbine capacity than LR3, but with varying amounts of customer side solutions, hydropower enhancements, and batteries.

The LRA Focus 2 introduces runs P5, P5A, and P5B, characterized as the Diversified Capacity plans. P5, P5A, and P5B were run against the 2025 IRP load projections with their results compared to an appropriate cost optimized result to quantify the potential regret of resources locked in for the LRA runs.

Table A7.2.22 provides a summary of the LRA Focus 2 runs, based on winter accredited capacity in 2035, which is the final year of the locked-in buildout assumed for each run for this analysis.

Table A7.2.22 – Least Regrets Analysis Focus 2 - Locked-In Plan Summary based on Accredited Winter Capacity

	Diversified Capacity		
Resource Option	**P5A**	**P5**	**P5B**
Customer Side Solutions: Efficiency Plan Projection	456	456	326
Customer Side Solutions: Demand response including curtailable rate program	312	312	312
Customer Side Solutions: Additional energy efficiency programs	95	200	200
Wind	120	120	120
Battery storage	5	5	86
Upgrade existing hydropower	26	26	26
Combustion turbines fuelled by natural gas	744	744	592

4.4.1. Key Takeaways of Observations of Regret

Diversified Capacity Plans

The potential regrets observed in the Diversified Capacity plans are as follows:

Underbuild Regret

- No underbuild regret is experienced under the 1-Baseline load.
- Negligible underbuild regret is experienced under the 2-Medium load, by design (47 – 80 MW, or 2 – 3 % compared to the max regret from LR1 in the LRA Focus 1 analysis). Near-term unmet capacity needs end in 2029 for all runs.
- Under the 3-High load projection, underbuild regret increases. P5B yields the largest cumulative regret (4,251 MW), P5A yields the second largest regret (3,681 MW), and the P5 results in the least regret (3,261 MW). This is consistent with the intentional design of P5A and P5B to incorporate less additional accredited capacity. Underbuild regret begins in 2026 and persists until 2035 in all cases.
- Underbuild regret for P5, P5A, and P5B can be compared to LRA Focus 1 results when analyzed in 2032. For the 2032 study year, all three runs performed similar to LR5, LR6, LR7, and LR3 under the 3-High load projection.

Overbuild Regret

- P5, P5A, and P5B all experience overbuild regret under the 1-Baseline load projection. This regret is greatest for P5B ($835 M CAN$, 71% compared to max regret from LR4), while P5 has the second highest level of regret ($819 M CAN$, 70% compared to LR4), and P5A has the least overbuild regret ($621 M CAN$, 53% compared to LR4). These runs showed less overbuild regret under the 1-Baseline load projection than LR5, LR6, and LR7, but more than LR3.
- P5, P5A, and P5B have no overbuild regret under the 2-Medium and 3-High load projections.

General

- P5A had the least overbuild regret, and moderate underbuild regret performance compared to the other two runs. P5 had the least potential for underbuild regret, but moderate overbuild regret. a template to evaluate runs with alternative resource types in the following section.

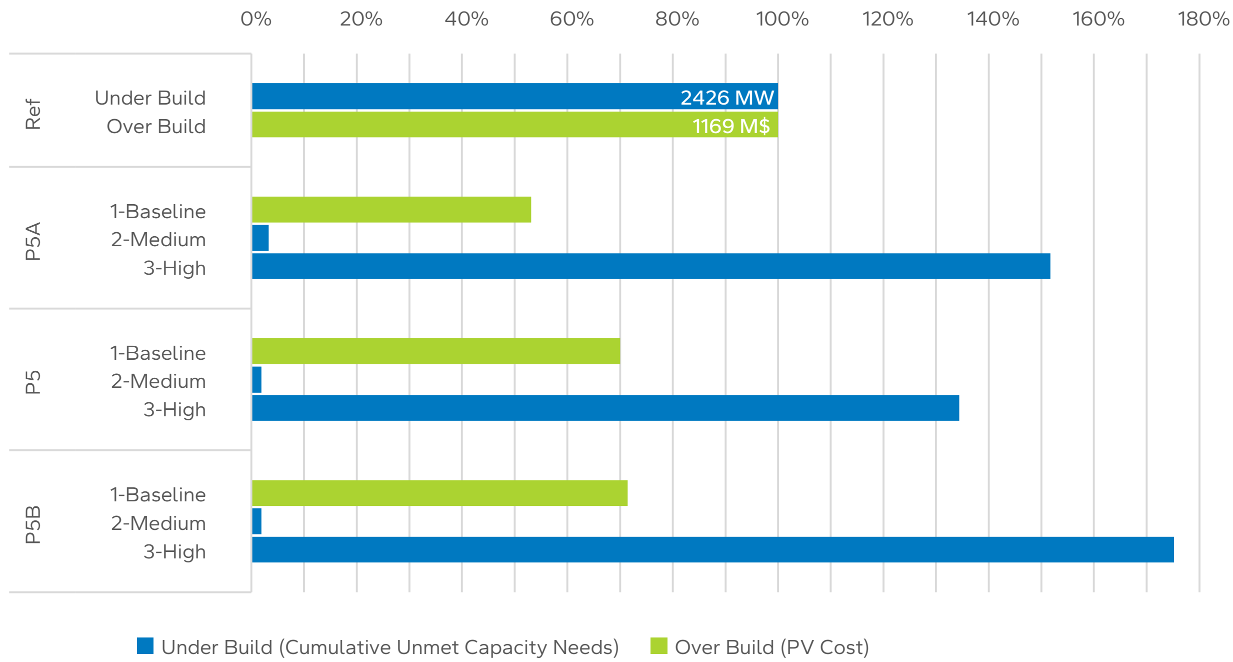


Figure A7.2.117 - Relative Regret of Diversified Capacity Plans to 2035

4.4.2. Results

Installed Capacity

This section discusses how installed capacity outcomes in 2050 were influenced by the locked-in resources in the LRA runs to 2035, identifying the potential and drivers for regret.

The installed capacity distributions for the least regret analysis are shown (alongside the appropriate scenarios for comparison) in Figure A7.2.118, Figure A7.2.119, and Figure A7.2.120 for 1-Baseline, 2-Medium, and 3-High load projections for the 2050 study year. The figures show how the capacity expansion model filled out the LRA runs for the remainder of the planning horizon (post 2035, beyond the locked-in period), and call out the resource additions that are common to each result. Installed capacity in 2035 is not shown, since runs were locked in until 2035 and no resource addition decisions were made by the capacity expansion model in this timeframe.

Note, when solar addition are shown in Figure A7.2.118, Figure A7.2.119, and Figure A7.2.120, they are marked with an asterisk to help distinguish from the CT-NG units.

1-Baseline Load Projection

Figure A7.2.118 highlights the differences in installed capacity across the LRA Focus 2 runs by 2050. All runs add a minimum of 640 MW of natural gas fuelled combustion turbine (CT-NG) and 248 MW of biodiesel combustion turbine (CT-BD) by 2050, for a combined total minimum of 888 MW of dispatchable combustion turbine (CT) capacity resources. This suggests that the 744 MW of CT-NG included in P5A and P5 are robust dispatchable capacity additions, that at worst could result in the advancement of dispatchable capacity resources. The potential to convert CT-NG to CT-BD units in the future, should circumstances warrant it, mitigates risk around the choice of CT for providing dispatchable capacity. All runs also add an extra 100 MW of installed capacity of wind in addition to the assumed 600 MW of near-term wind generation projects. Common resource additions comprise approximately 60% or more of the total installed capacity additions across the runs.

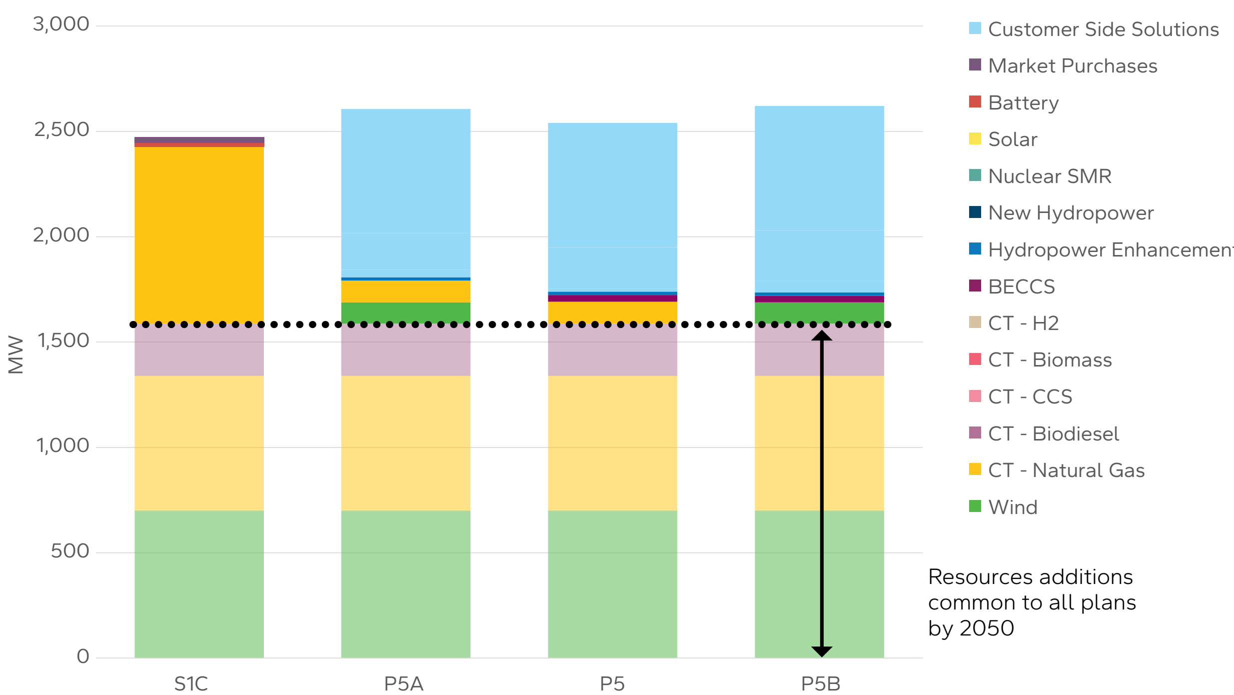


Figure A7.2.118 - Least Regrets Analysis Results – Focus 2: Robust Resource Additions by 2050 for the 1-Baseline Load Projection

2-Medium Load Projection

Installed capacity variations across the LRA Focus 2 runs by 2050 under the 2-Medium load projection are shown in Figure A7.2.119. All runs include a minimum of 2,366 MW of CT-NG, 496 MW of CT-BD, and 688 MW of combustion turbine with carbon capture and sequestration (CT-CCS), for a combined total of a minimum of 3,550 MW of dispatchable capacity provided by combustion turbines. More CT-NG is added across all runs by 2050 than is included in the locked-in resources of the runs by 2035, indicating the CT-NG units included in the LRA Focus 2 runs could advance the timing of these units.

All runs also add a minimum of 63 MW of bioenergy carbon capture and sequestration (BECCS), and 377 MW of small modular nuclear reactor (SMR). A total minimum installed capacity of 4,200 MW of wind is also observed across the runs. Common resource additions comprise approximately 70% or more of the total installed capacity additions across the runs.

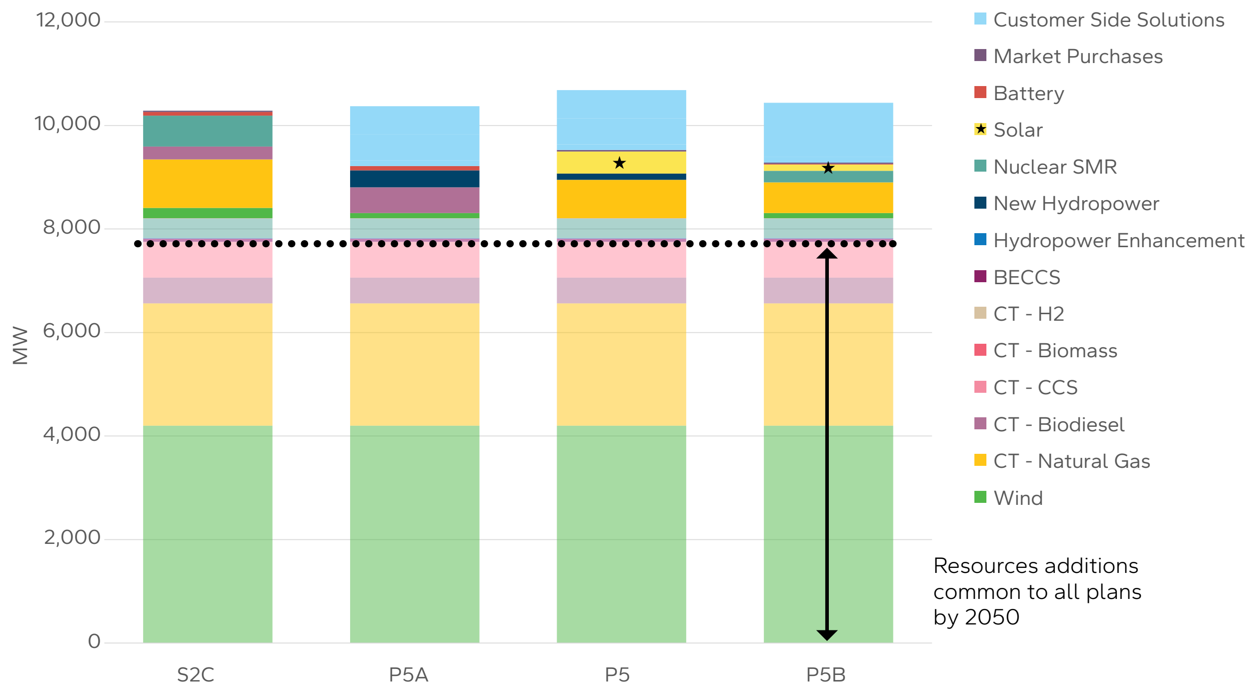


Figure A7.2.119 - Least Regrets Analysis Results – Focus 2: Robust Resource Additions by 2050 for the 2-Medium Load Projection

3-High Load Projection

Figure A7.2.120 shows how installed capacity changes across the LRA Focus 2 runs under the 3-High load projection. In all cases, a minimum of 4,628 MW of CT-NG and 688 MW of CT-CCS is added, for a total minimum of 5,316 MW of dispatchable capacity provided by combustion turbines. Consistent with the findings for the 2-Medium load projection, CT-NG additions beyond what is assumed in any of the runs are observed by 2050, indicating that the amount of CT-NG included in the runs is robust under load uncertainty, and could at worst result in advancements of CT-NG units.

All runs also include a minimum total installed capacity of 6,000 MW of wind, 744 MW of CT-H2, 63 MW of BECCS, and 77 MW of nuclear SMR. Common resource additions comprise approximately 70% or more of the total installed capacity additions across the runs.

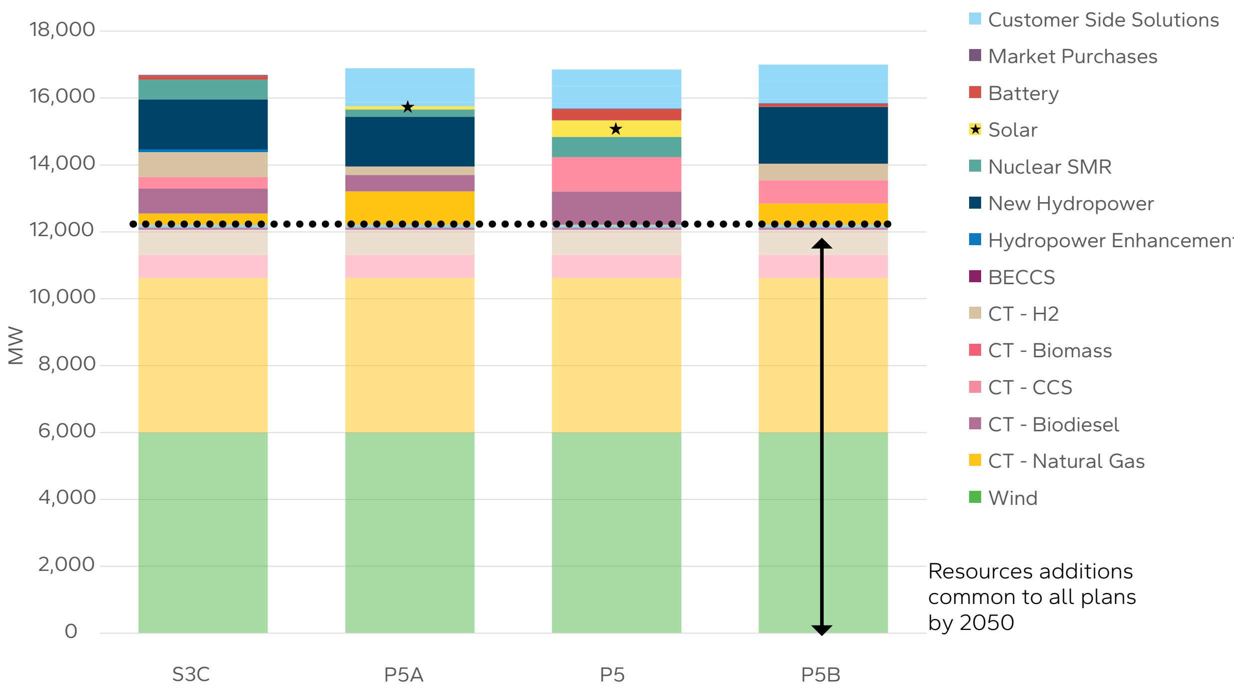


Figure A7.2.120 - Least Regrets Analysis Results – Focus 2: Robust Resource Additions by 2050 for the 3-High Load Projection

Capability of Resource Options to Meet Near Term Capacity and Energy Needs

Similar to LRA Focus 1, underbuild regret is observed in the results when locked-in and subsequently added resources (post 2032) cannot supply sufficient accredited capacity or dependable energy to meet the needs of the load projection being applied. LRA highlights that meeting an accelerated pace of decarbonization and electrification would be a challenge in the early years. As shown in Figure A7.2.121, all LRA runs contain some level of unmet capacity need compared to the need defined by the 2-Medium load projection. This indicates that the resources in the LRA Focus 2 runs or the assumptions about the timing and magnitude of demand may require adjustment, or some other measures need to be included, to eliminate accredited capacity shortfalls and mitigate underbuild regrets. Similarly, all LRA runs contain some level of unmet capacity need compared to the need defined by the 3-High load projection, as shown in Figure A7.2.122. All capacity needs associated with the 1-Baseline load projection can be met by the accredited capacity supplied by the LRA portfolios of resources, resulting in no underbuild regrets.

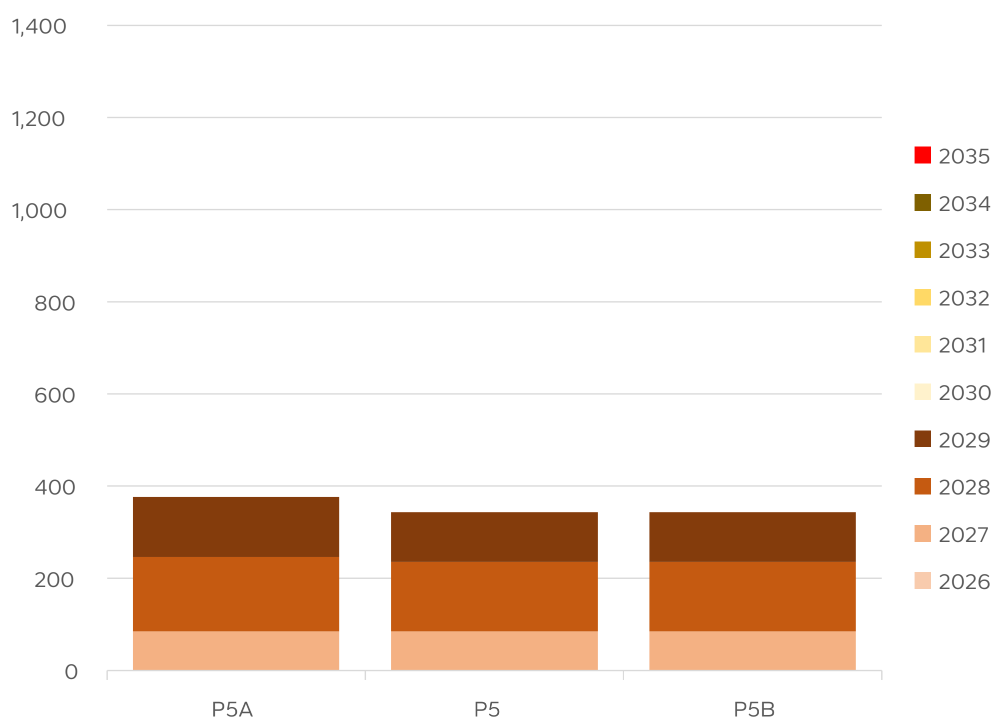


Figure A7.2.121 - Least Regrets Analysis Results – Focus 2 – Absolute Unmet Capacity Need – 2-Medium Load Projection

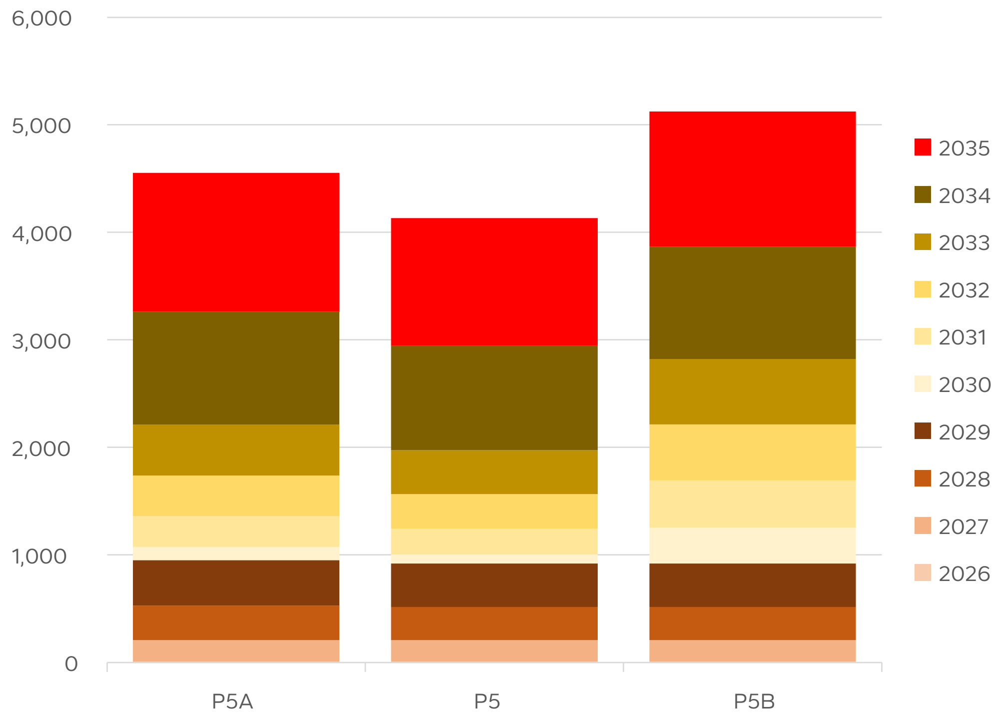
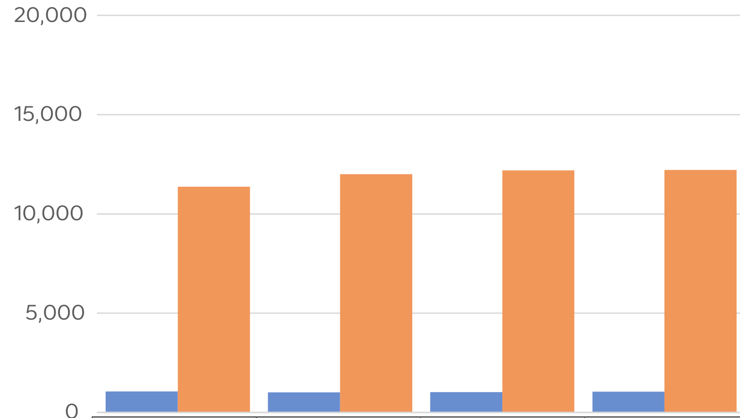


Figure A7.2.122 - Least Regrets Analysis Results - Focus 2 - Absolute Unmet Capacity Need – 3-High Load Projection

Annual and Net System Costs

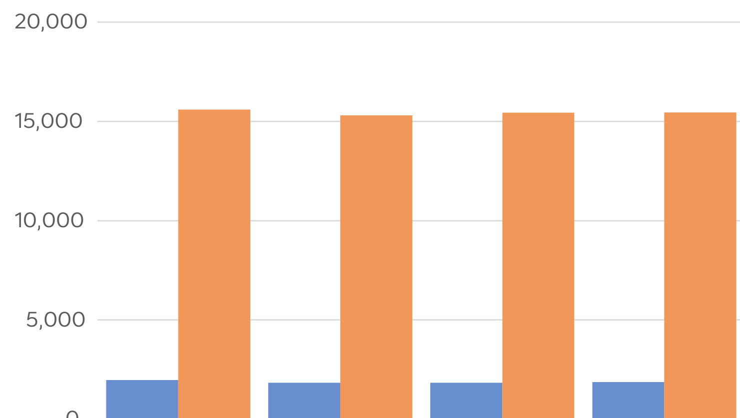
Figure A7.2.123, Figure A7.2.124, and Figure A7.2.125 provide the incremental net system costs for each of the three LRA Focus 2 runs in the forecast year of 2045 for each of the 1-Baseline, 2-Medium, and 3-High load projections respectively. Results are provided in 2045 for consistency with the overbuild regret analysis, and is sufficient to capture insights into longer-term net system costs without introducing potential modelling noise at the end of the study horizon. Each result is stated in terms of both the cumulative present value of net system costs up to that point, as well as the corresponding annual costs in the given year.

The range of incremental cumulative present value of net system costs between the three LRA Focus 2 runs is only roughly $200M 2024 CAN$ to serve the 1-Baseline and 2-Medium load projections, but further drops to negligible levels to serve the 3-High load projection to 2045. Furthermore, all the incremental cumulative present value of net system cost numbers fall within the same range as the seven LRA Focus 1 runs.



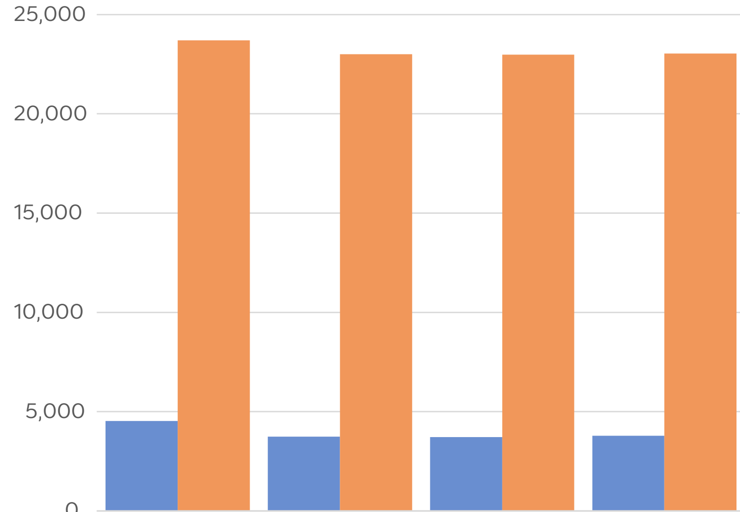
	S1C	P5A	P5	P5B
Incremental Annual Net System Cost [M$/year]	1,058	1,015	1,028	1,043
Incremental Cumulative Present Value of Net System Costs [M$]	11,375	11,996	12,194	12,210

Figure A7.2.123 - Least Regrets Analysis Results - Focus 2 - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2045) for the 1-Baseline load projection



	S2C	P5A	P5	P5B
Incremental Annual Net System Cost [M$/year]	1,973	1,833	1,833	1,867
Incremental Cumulative Present Value of Net System Costs [M$]	15,598	15,307	15,439	15,453

Figure A7.2.124 - Least Regrets Analysis Results - Focus 2 - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2045) for the 2-Medium load projection



	S3C	P5A	P5	P5B
Incremental Annual Net System Cost [M$/year]	4,531	3,738	3,718	3,789
Incremental Cumulative Present Value of Net System Costs [M$]	23,696	23,004	22,983	23,032

Figure A7.2.125 - Least Regrets Analysis Results - Focus 2 - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2045) for the 3-High load projection

5 | Shortlisted Potential Development Plans

Appendix 2 – 2025 IRP Development Process outlines the process used to identify the shortlisted potential development plans, which was based on the outcomes of the evaluation process.

Shortlisted development plan results are presented here in detail as a comprehensive and consistent set of outputs. This was done to cultivate an understanding of the characteristics and performance of the plans and to provide context for the next steps of evaluations and financial and risk analyses performed on the shortlisted plans. All results are based on modelling locked-in development plans to 2035 under the 2-Medium load projection. P3 and P7 represent updates to plans originally explored in LRA Focus 1, and correspond to LR3 and LR6, respectively. P5, P5A, and P5B are directly based on LRA Focus 2 modelling.

Table A7.2.23 provides a summary of the shortlisted potential development plans.

Table A7.2.23 – Shortlisted Potential Development Plans – Locked-In Plan Summary based on Accredited Winter Capacity in 2035

	Lower Cost Plans	Diversified Capacity Plans			Maximized Alternative Plans
Resource Option	**P3**	**P5A**	**P5**	**P5B**	**P7**
Customer Side Solutions: Efficiency Plan Projection	456	456	456	456	456
Customer Side Solutions: Demand response including curtailable rate program	312	312	312	312	312
Customer Side Solutions: Additional energy efficiency programs	0	95	200	200	200
Wind*	124	120	120	120	120
Battery storage	4	5	5	86	216
Upgrade existing hydropower	0	26	26	26	103
Combustion turbines fuelled by natural gas	840	744	744	592	344

**P3 includes 700 MW of installed wind capacity by 2035, 100 MW more compared to the other plans. This extra 100 MW is accredited at only 4%, resulting in a total added accredited winter capacity in 2035 of 124 MW.*

5.1. Installed Capacity

The installed capacity breakdowns in 2035 for the shortlisted potential development plans are provided in Figure A7.2.126. The installed capacity results are a direct reflection of the assumed development plan buildouts for the shortlisted plans, which were locked-in until the end of 2035. Therefore, variation in the total installed capacity is expected and intentional, exploring the benefits of development plans with varying levels of total installed capacity additions.

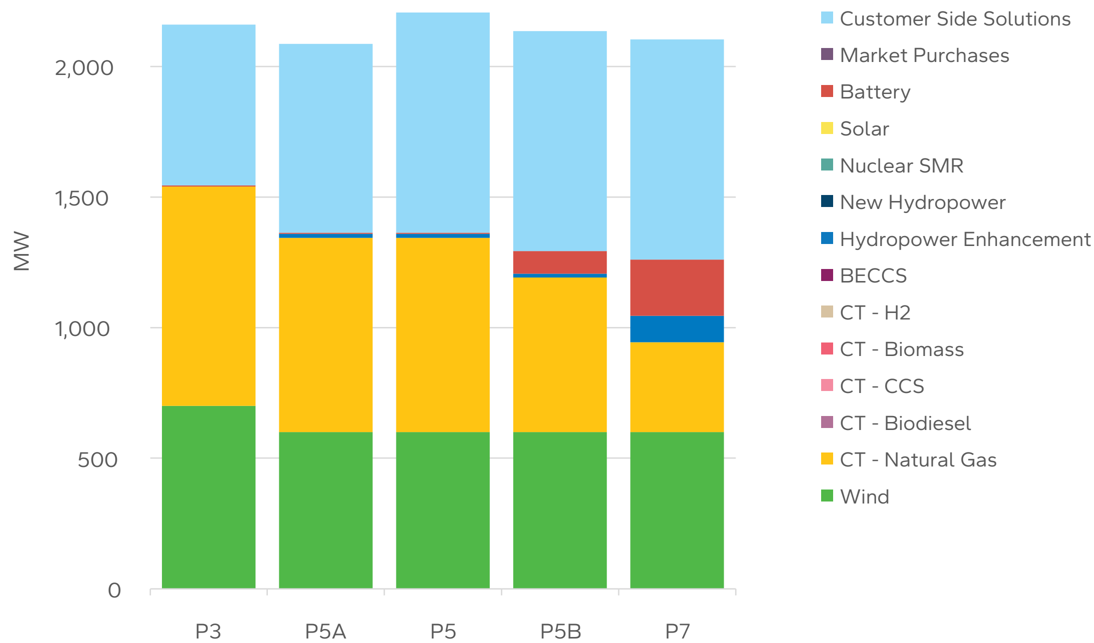


Figure A7.2.126 - Shortlisted Plans – Installed Capacity Additions in 2035 for the 2-Medium Load Projectios

5.2. Accredited Capacity and Dependable Energy

Accredited capacity and dependable energy are primarily influenced by installed capacity, but the unique accredited capacity and energy contributions of each resource type also influence the final profiles of each plan.

5.2.1. Accredited Capacity

Figure A7.2.127 and Figure A7.2.128 detail the summer and winter accredited capacity in 2035, respectively, and that the existing system still contributes significant accredited capacity – approximately 75% of the total system. By 2035, additional winter accredited capacity is provided primarily by natural gas fuelled combustion turbines (CT-NGs), total customer-side solutions, and to a lesser extent, wind. All plans also include some accredited capacity from batteries, with the largest amounts in P7, followed by P5B. P7 also includes the largest accredited capacity addition from hydropower enhancements, with smaller amounts appearing in P5, P5A, and P5B. Summer accredited capacity profiles in 2035 are consistent with the winter profiles.

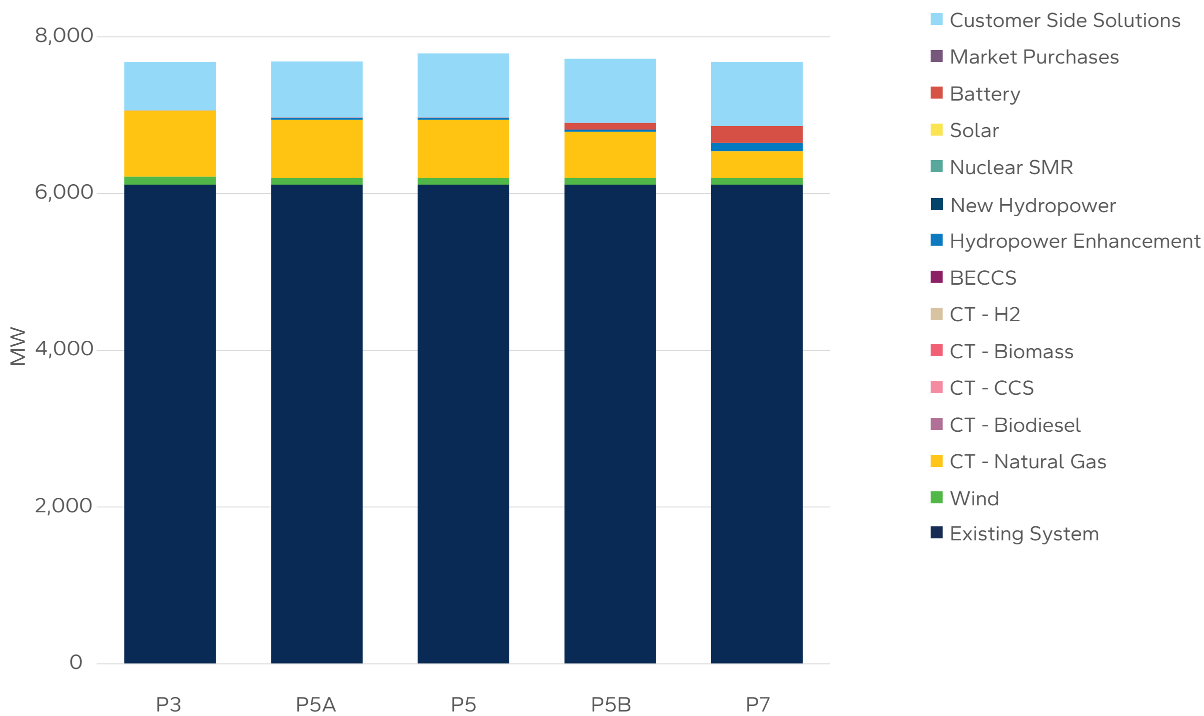


Figure A7.2.127 - Shortlisted Plans - Winter Accredited Capacity in 2035 for the 2-Medium Load Projection

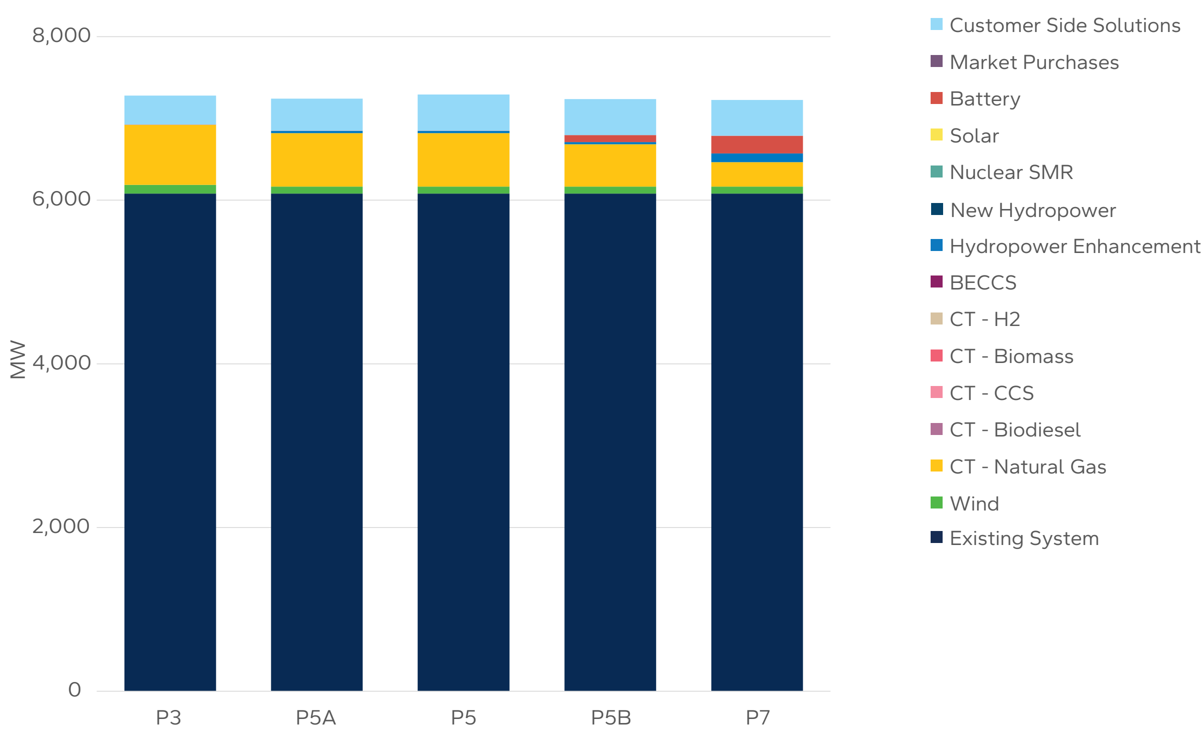


Figure A7.2.128 - Shortlisted Plans - Summer Accredited Capacity in 2035 for the 2-Medium Load Projection

Table A7.2.24 provides insight into how the accredited capacity of the shortlisted plans grows in response to increasing demand. By 2035, the shortlisted plans increase MH system's seasonal accredited capacity from 28-30% in the winter and from 20-22% in the summer.

Table A7.2.24 – Shortlisted Plans - Average Cumulative Accredited Capacity Additions by Season in 2035, as a Percentage Increase over the Existing System for the 2-Medium Load Projection

	P3	P5A	P5	P5B	P7
Winter	28%	28%	30%	28%	28%
Summer	21%	21%	22%	21%	20%

5.2.2. Dependable Energy

Figure A7.2.129 and Figure A7.2.130 detail the winter and summer dependable energy in 2035, respectively. Consistent with the accredited capacity results, the existing system provides significant dependable energy – approximately 75% of the total system. Imports are an additional source of dependable energy and are included in the existing system total. Wind is a significant contributor of new dependable winter energy in 2035. While batteries and hydropower enhancements are sources of accredited capacity, these resources do not provide dependable energy. Although not visible in Figure A7.2.129 and Figure A7.2.130 due to the relatively small quantities involved, batteries ultimately lower system dependable energy, due to their round trip energy losses during charging and discharging.

Summer dependable energy profiles in 2035 for the shortlisted plans are similar to their winter profiles, with fluctuations owing to individual technology characteristics.

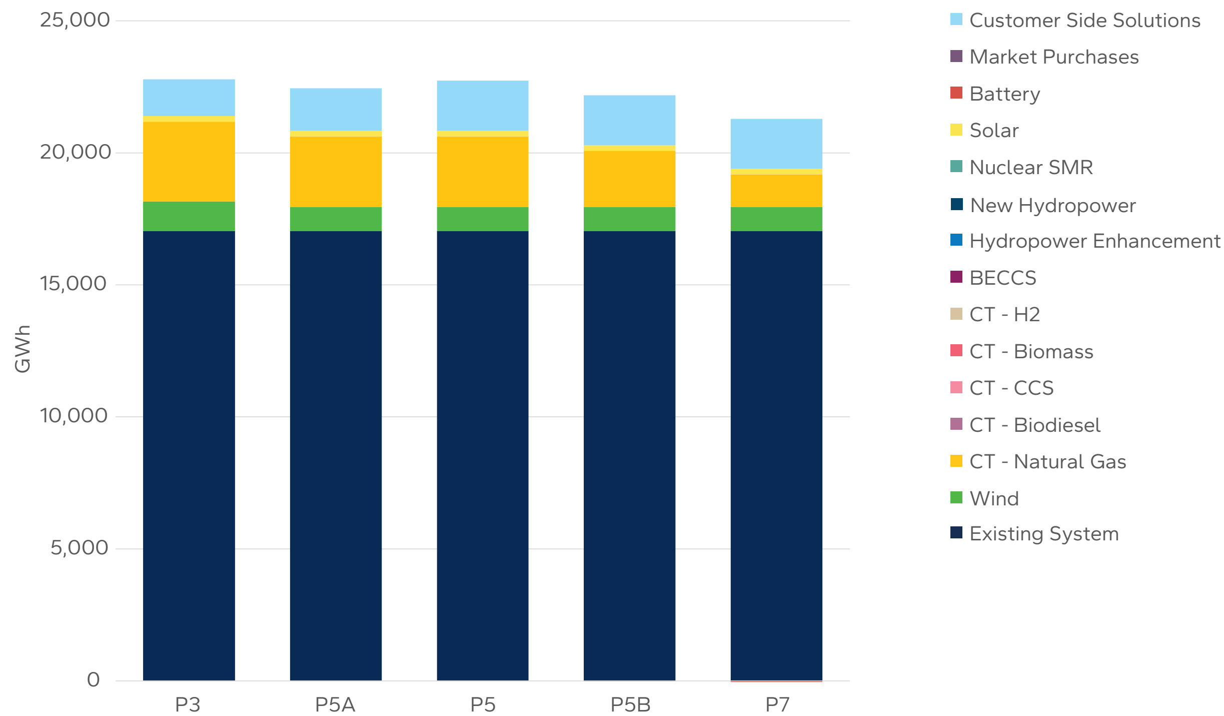


Figure A7.2.129 - Shortlisted Plans - Winter Dependable Energy in 2035 for the 2-Medium Load Projection

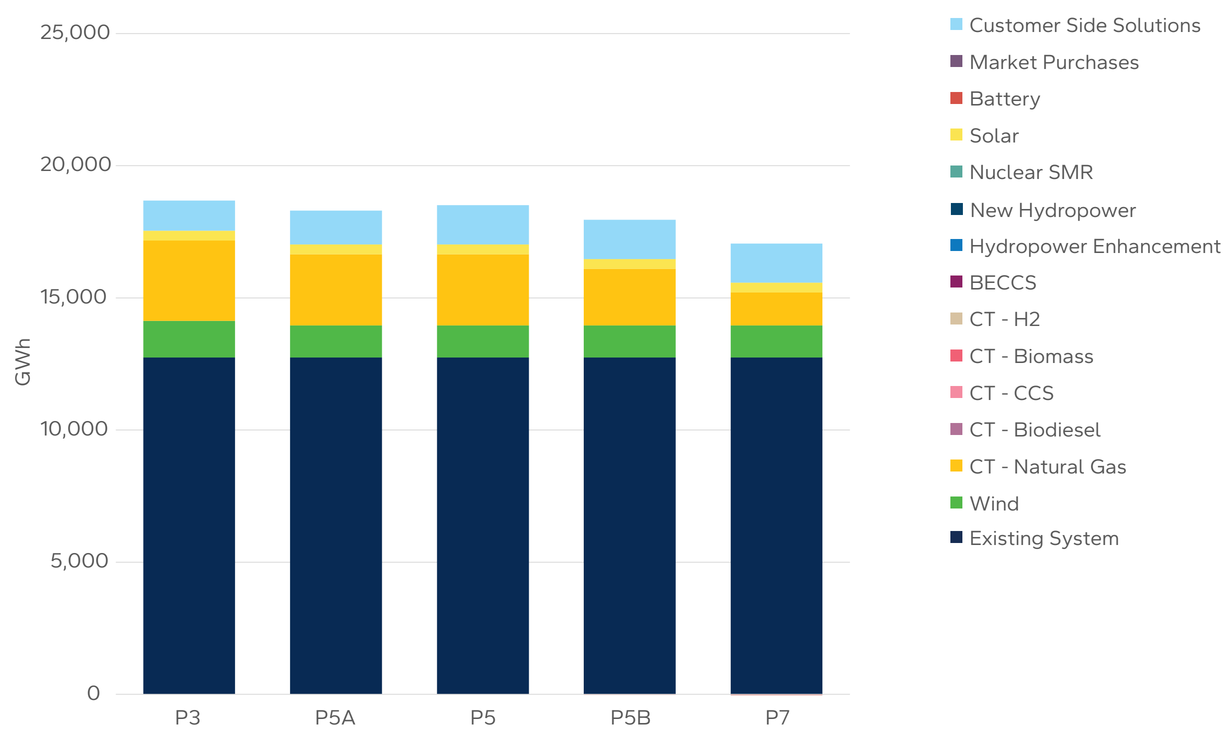


Figure A7.2.130 - Shortlisted Plans - Summer Dependable Energy in 2035 for the 2-Medium Load Projection

Table A7.2.25 provides insight into how the dependable energy of the shortlisted plans grows in response to increasing demand. The growth in seasonal dependable energy by 2035 ranges from 50-59% in the winter and from 53-66% in the summer. Comparing dependable energy (Table A7.2.25) with accredited capacity (Table A7.2.24) shows that growth in dependable energy is greater than the growth seen in accredited capacity, owing largely to the addition of new wind, which supplies more dependable energy than accredited capacity.

Table A7.2.25 – Shortlisted Plans - Average Cumulative Dependable Energy Additions by Season in 2035, as a Percentage Increase over the Existing System for the 2-Medium Load Projection

	P3	P5A	P5	P5B	P7
Winter	59%	57%	58%	55%	50%
Summer	66%	63%	64%	60%	53%

Figure A7.2.131 shows how the portfolios of resources across the shortlisted plans meet the accredited capacity and dependable energy requirements of the system in 2035. These ratios reflect the accredited capacity and energy contributions of the resource additions in each portfolio, as well as the changing requirements of the system over time. In 2035, available winter accredited capacity is most closely matched to the system requirements.

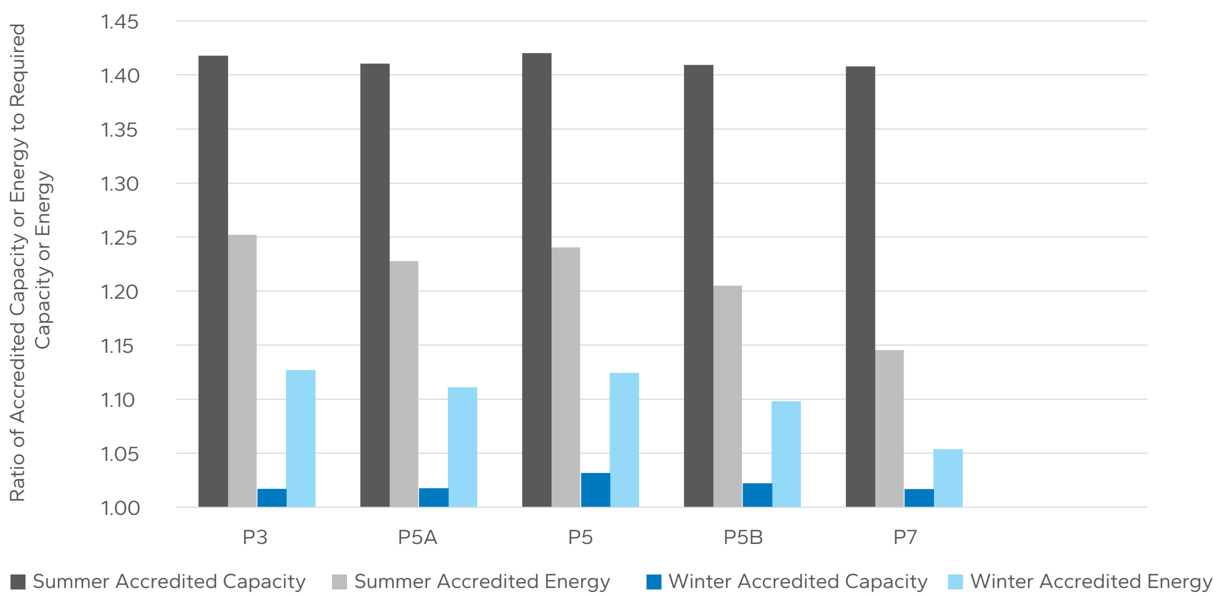


Figure A7.2.131 - Shortlisted Plans – Ratio of Available Accredited Capacity or Dependable energy to System Requirements by Season, for 2035, for the 2-Medium Load Projection

5.3. Average Energy

From a modelling standpoint, wind and customer side (solar as well if it is in the mix) solutions are treated as fixed, predetermined energy contributions that do not vary with flow conditions, as shown in Figure A7.2.132 for average flow conditions and Figure A7.2.133 and Figure A7.2.134 for drought and flood conditions respectively. Conversely, Manitoba's existing electrical system is predominantly hydropower and generation levels largely influenced by hydrological conditions. The total energy demand – comprised of Manitoba's internal load, firm export commitments, and system losses – is met through a combination of wind, customer side solutions, hydroelectric generation, and, when necessary, dispatchable resources, imports, or financial settlements. During favorable hydrological conditions, the need for supplementary generation sources is reduced, and surplus energy may be exported as opportunities allow.

Average energy refers not to a single hydrological scenario, but to the mean energy output across all simulated flow years for each generation mix. Figure A7.2.132 presents the average energy generation from selected resources for the five shortlisted development plans in the year 2035.

By 2035, Manitoba's electricity system remains dominated by hydroelectric generation across all development plans, which is captured by the existing generation category. On average, hydropower is sufficient to meet provincial load, firm export obligations, and system losses. When hydropower is sufficient, most of the energy produced from new wind and savings achieved through customer side solutions are directed to the opportunity export market. Even though market purchases may be required in less favorable hydrological years, on average, Manitoba continues to operate as a net energy exporter. On average, generation from natural gas fuelled combustion turbine (CT-NG) resources (both existing and new) is minimal. All the shortlisted development plans have an almost identical energy generation mix for the average flow conditions.

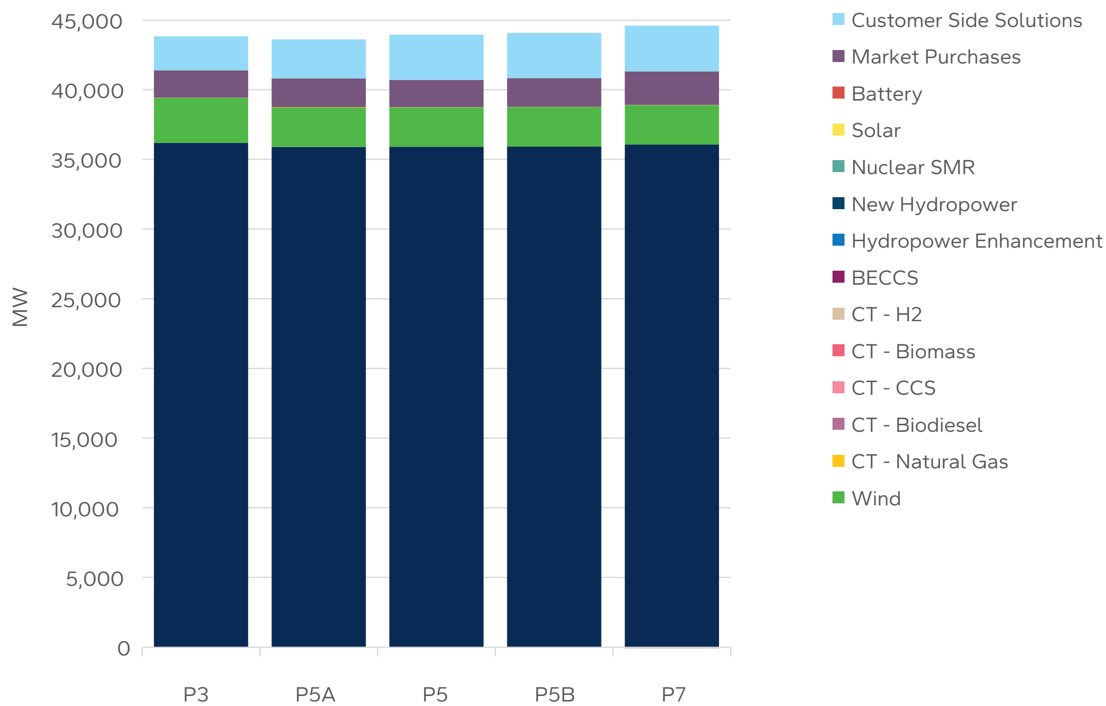


Figure A7.2.132 - Shortlisted Plans - Average Energy Generation in 2035 for the 2-Medium Load Projection

5.4. System Operations under Different Flow Conditions

This section examines the performance of Manitoba's electrical system under extreme water flow conditions. Changes in system operations projected for the year 2035 under dependable low-flow (drought) and high-flow (flood) scenarios are illustrated in Figure A7.2.133 and Figure A7.2.134, respectively. In 2035, all five shortlisted development plans demonstrate similar performance under both dependable low-flow and high-flow conditions.

Currently, hydropower production in Manitoba varies between 23 TWh and 45 TWh annually, depending on water flow conditions. By 2035, under dependable drought conditions, hydropower is expected to supply approximately 60% of the electricity demand. The remaining demand will be met through a combination of the other resources.

Under drought conditions, modelling results show that annual wind generation is four to five times greater than combustion turbine generation. Despite their low utilization factors, combustion turbines remain essential for providing capacity during periods of low wind generation.

Under flood conditions, hydropower generation is sufficient to meet all provincial electricity needs, firm export commitments, and system losses. As a result, market purchases and combustion turbine generation are not required during such periods.

Given the fluctuations in energy imports and exports under varying flow scenarios, cross-border electricity trade will continue to play a crucial role in cost-effectively meeting electricity demand. Opportunities for import and export are explored further in this appendix.

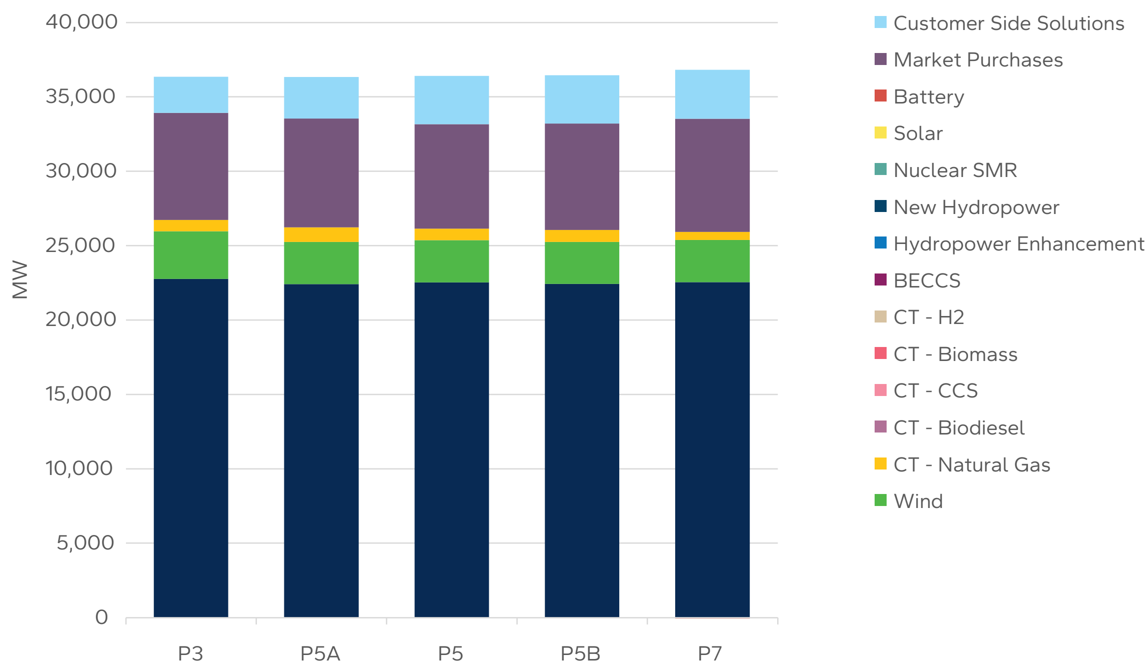


Figure A7.2.133 - Shortlisted Plans - Energy Generation in 2035 for Drought Condition for the 2-Medium Load Projection

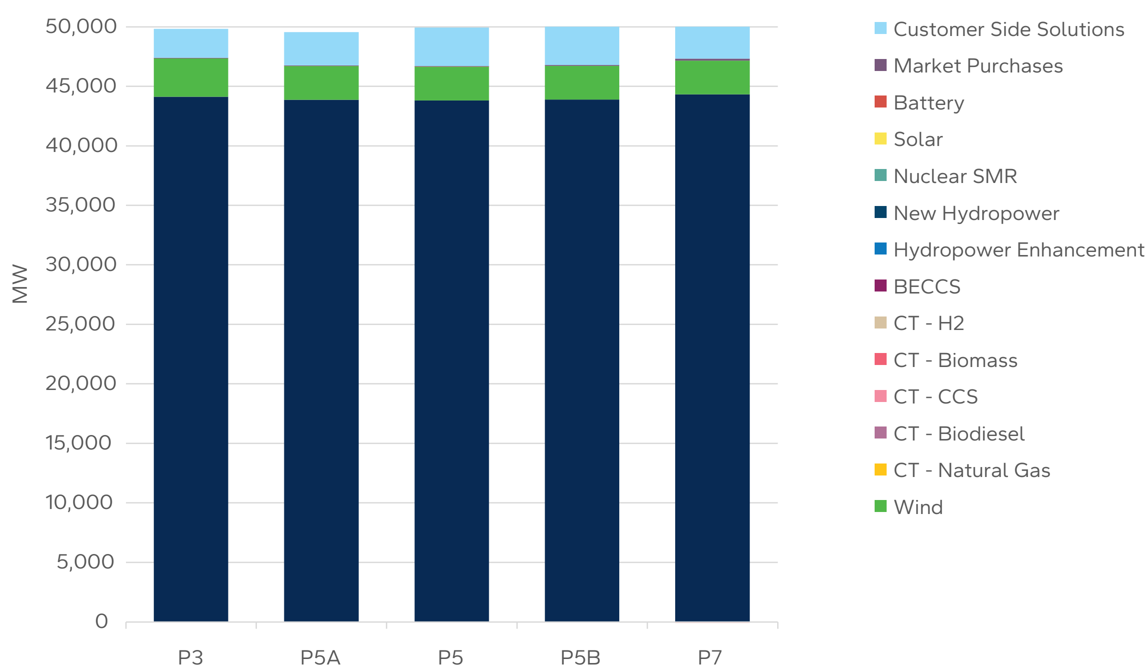


Figure A7.2.134 - Shortlisted Plans - Energy Generation in 2035 for Flood Condition for the 2-Medium Load Projection

5.5. Interconnections & Market Activities

Manitoba Hydro's predominantly hydropower generation system is supported by its interconnections with neighboring electricity markets. These cross-border links provide mutual benefits by enabling both the import and export of electricity, contributing to system reliability, economic efficiency, and environmental sustainability:

- **Reliability:** Electricity imports enhance system resilience during droughts or unexpected supply disruptions such as equipment failures.
- **Economic Efficiency:** Surplus hydropower power can be exported when available. Conversely, during periods of low market prices, Manitoba can import electricity instead of relying on more expensive local thermal generation, improving overall system economics.
- **GHG Emissions Reduction[12]:** Exporting hydropower helps reduce fossil fuel-fired electricity generation and related GHG emissions in neighboring jurisdictions.

While imports are valuable for maintaining reliability, they are subject to certain limitations. Within these constraints, imports are utilized for:

- Diversity power trades;
- Additional capacity purchases; and
- Economic opportunities that support optimal system operation.

Electric energy trades with neighboring markets are a fundamental part of Manitoba Hydro's operations. Surplus electric energy—beyond Manitoba's domestic demand and firm export commitments—is either:

- Exported to opportunity markets, or
- Stored in reservoirs for future use, or
- Spilled if operational constraints prevent it from being exported or stored.

Opportunity exports are limited by interconnection capacity and existing firm contracts. Figure A7.2.135 illustrates opportunity export volumes under low-flow (drought), average, and high-flow (flood) conditions, while Figure A7.2.136 shows opportunity imports during drought, average and flood conditions. Notably, opportunity imports during flood conditions are negligible.

Key observations:

- Opportunity exports during drought conditions are roughly 10% of the average opportunity export volume.
- During flood conditions, opportunity exports increase by approximately 75% compared to the average.

[12] Manitoba Hydro cannot claim these GHG emission reductions; they are attributed to non-Manitoba utilities.

- Opportunity imports during drought conditions are about 3.5 times higher than during average conditions.
- The highest levels of market interaction occurs under the P7 shortlisted potential development plan, which has roughly half the installed dispatchable combustion turbine (CT) capacity compared to the other four shortlisted development plans.

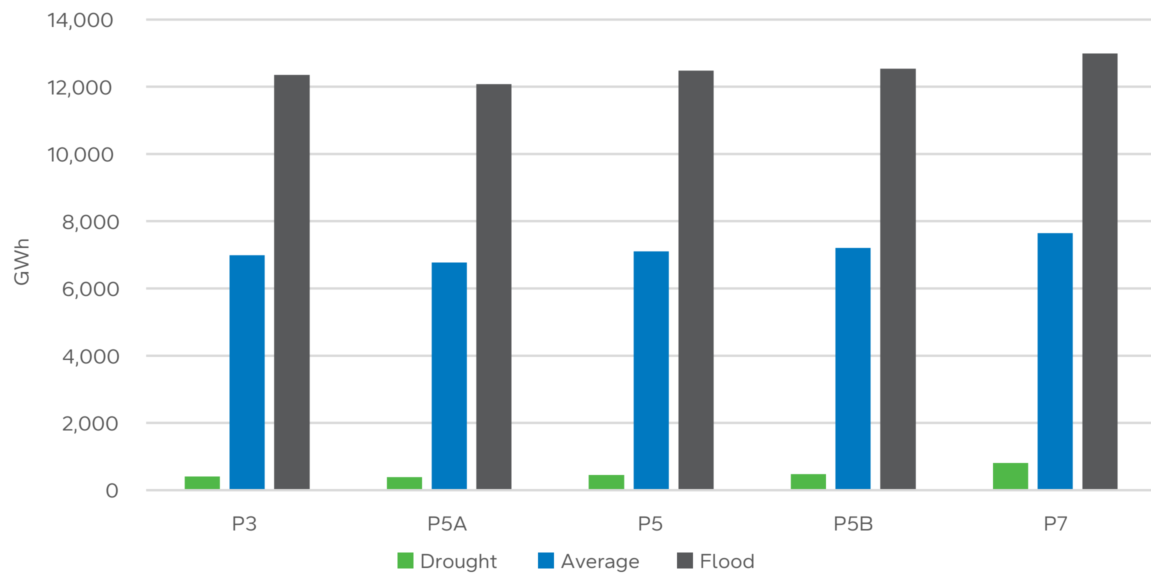


Figure A7.2.135 - Shortlisted Plans - Opportunity Exports in 2035 for the 2-Medium Load Projection

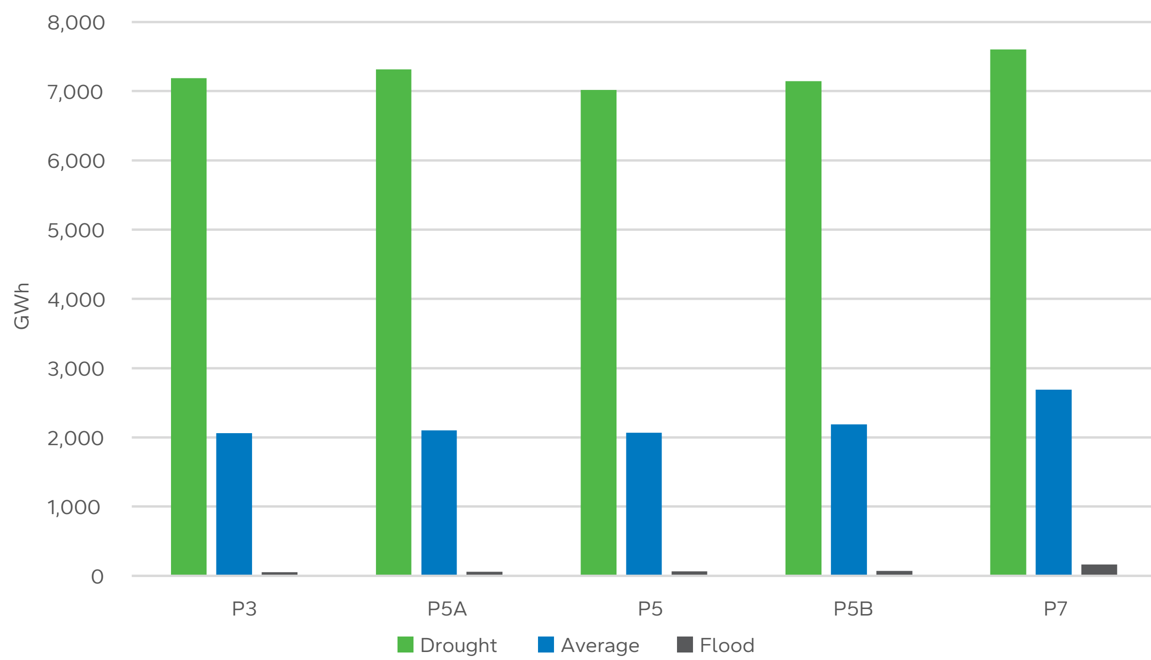


Figure A7.2.136 - Shortlisted Plans - Energy Imports in 2035 for the 2-Medium Load Projection

5.6. Capital Costs

The capital costs in 2035 reflect the locked-in portfolios of resources in each shortlisted potential development plan. While system operations can be a large factor in the overall economics of a resource, this section compares the capital costs only. Figure A7.2.137 shows the yearly cumulative capital costs for each shortlisted plan and Figure A7.2.138 and Table A7.2.26 show the cumulative capital costs by resource type, with P5A as the lowest cost plan on a cumulative capital basis to 2035.

Within the capital costs presented, there includes costs occurring before 2035 that are attributed to resources with in-service dates occurring after 2035. This reflects how the model handles cash flows for future resources, as all resources have lead times for planning, approval and construction before they are in-service. All shortlisted potential development plans have less than $50M of these capital costs.

As wind is assumed to be owned and operated by a third party, with energy being purchased by Manitoba Hydro through a power purchase agreement (PPA), the capital costs for this resource included in the total cumulative capital costs shown Figure A7.2.137, Figure A7.2.138, and Table A7.2.26 are for the associated transmission and capital tax. The impact of wind PPA costs are calculated based on the full 25 years of the power purchase agreement.

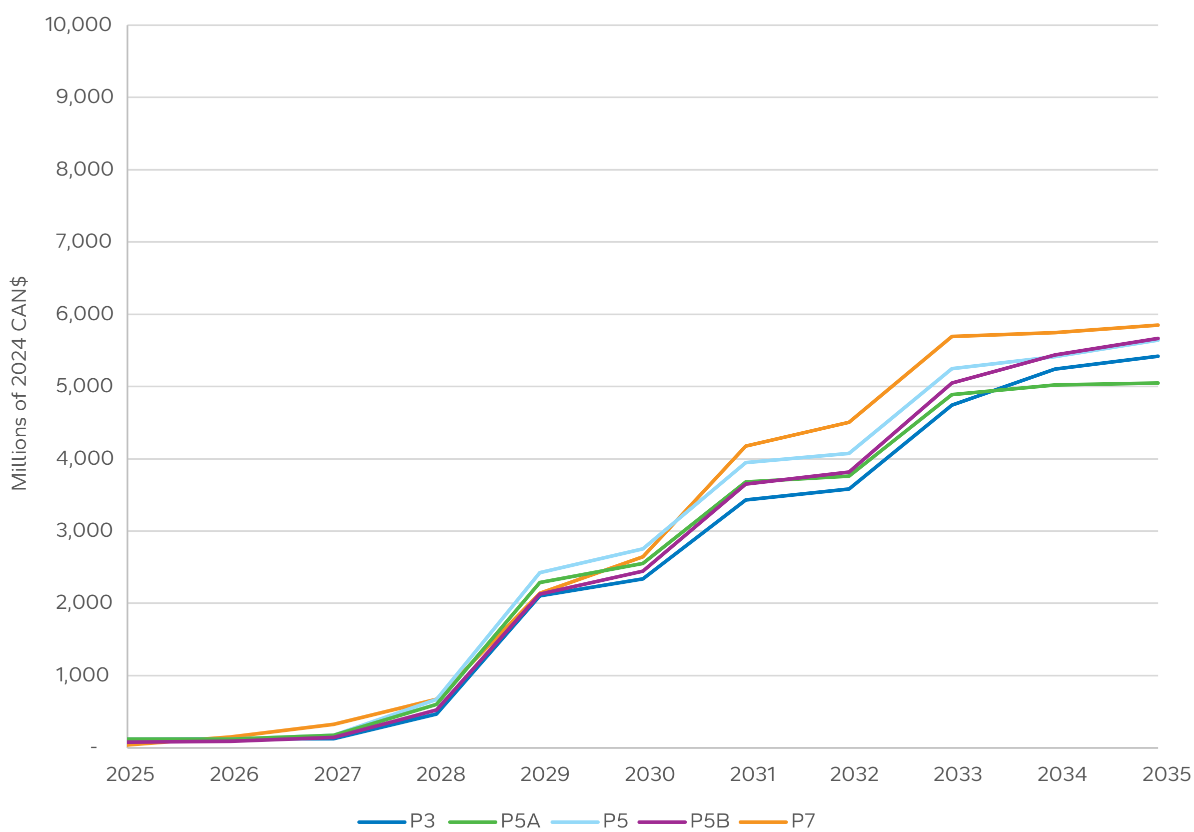


Figure A7.2.137 - Shortlisted Plans - Cumulative Resource Capital Costs to 2035 for the 2-Medium Load Projection

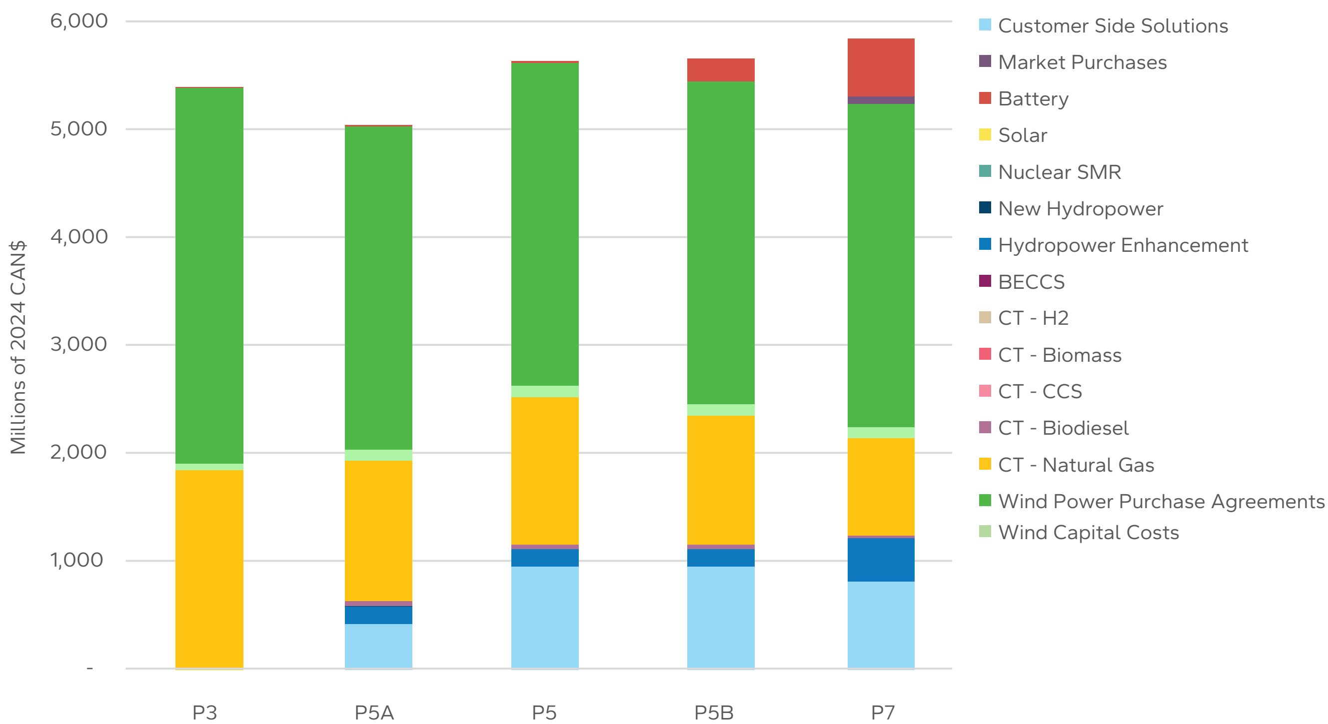


Figure A7.2.138 - Shortlisted Plans - Cumulative Resource Capital Costs in 2035 by Resource Type for the 2-Medium Load Projection

Table A7.2.26 – Shortlisted Plans - Cumulative Resource Capital Costs to 2035 (Millions of 2024 CAN$) for the 2-Medium Load Projection

	P3	P5A	P5	P5B	P7
Additional Energy Efficiency	-	427	959	959	819
Hydropower Enhancements	-	161	161	161	405
New Hydropower	-	6	-	-	-
CT-H2	-	-	-	-	-
CT-BD	18	44	44	44	20
CT-Biomass	-	0	0	-	-
CT/CCCT-NG	1,850	1,301	1,366	1,195	905
Nuclear SMR	-	-	-	-	-
Wind PPA and Capital Costs	3,542	3,098	3,098	3,098	3,098
Market Purchases	-	-	-	-	69
Solar	-	-	-	-	-
Battery	10	12	12	208	533
Total	**5,419**	**5,050**	**5,640**	**5,666**	**5,850**

5.7. Transmission and Distribution Systems

Figure A7.2.139 illustrates the costs for the new transmission, distribution, and generation interconnection infrastructure for each of the shortlisted potential development plans in 2035. By 2035, the net present value (NPV) of the costs ranges from $7.6B to $7.8B.

Generation interconnection infrastructure costs were included in the model, while transmission growth and distribution growth costs were included in post processing. Appendix 7.1 – Modelling & Analysis Approach details the assumptions used in modelling.

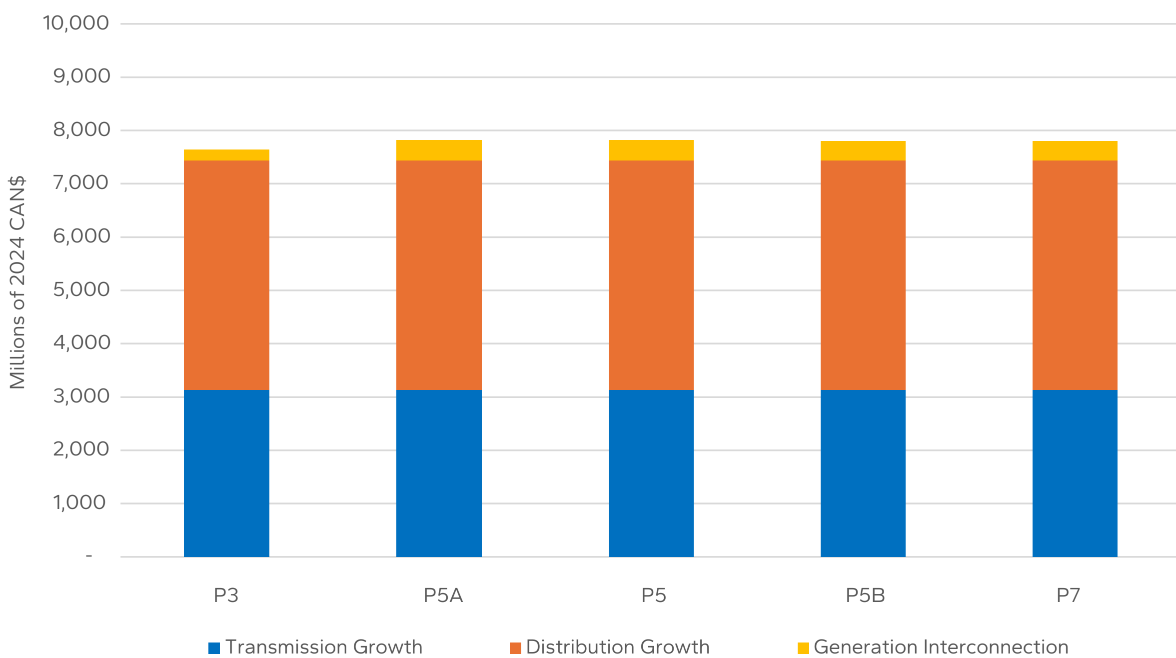


Figure A7.2.139 - Shortlisted Plans - Net Present Value of Transmission and Distribution Capital Costs to 2035 for the 2-Medium Load Projection

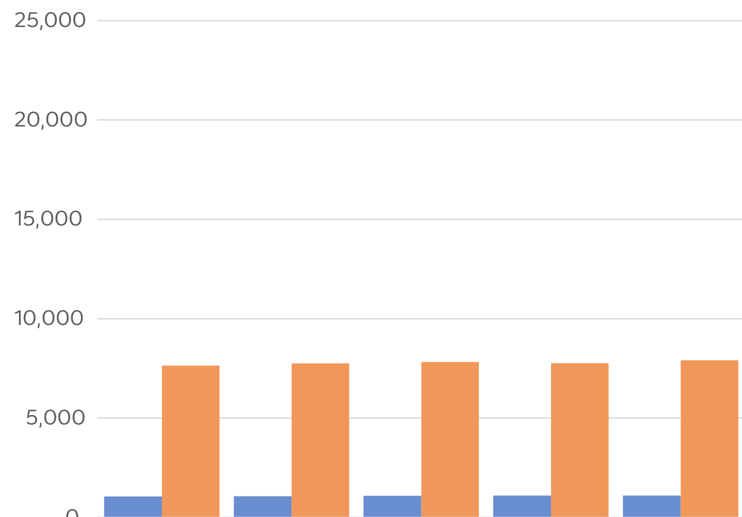
5.8. Natural Gas Supply Costs

Increasing costs to supply natural gas fuel to new combustion turbine (CT) generation resources are incorporated directly in the annual system costs and PV of net system costs, per the methodology described in Appendix 7.1 – Modelling & Analysis Approach. These costs vary across the shortlisted potential development plans, as they are based on optimized combustion turbine dispatch within a system that reflects each shortlisted plan's portfolio of resources.

5.9. Annual and Net System Cost

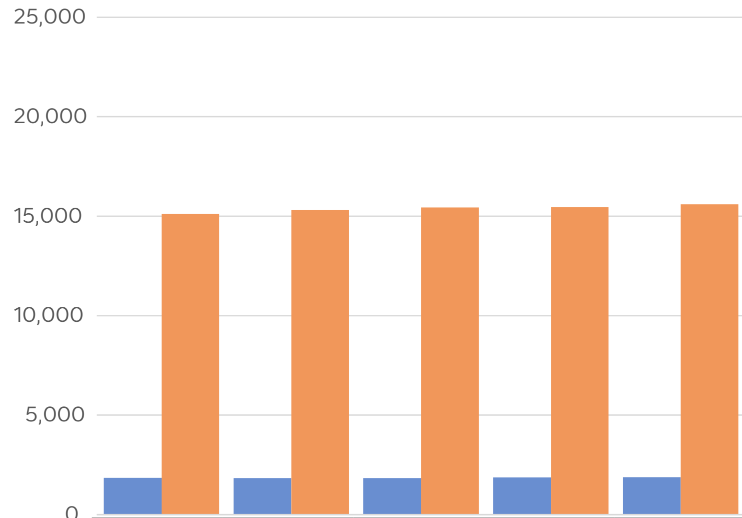
Figure A7.2.140, Figure A7.2.141, and Figure A7.2.142 provide the incremental net system costs for each of the shortlisted potential development plans in the forecast years of 2035, 2045, and 2050. Each result is stated in terms of both the cumulative present value of net system costs, as well as the corresponding annual costs.

The range of differences in incremental cumulative present value of net system costs between the shortlisted potential development plans grows from $260M in 2035, to $480M in 2045, and finally to $550M in 2050.



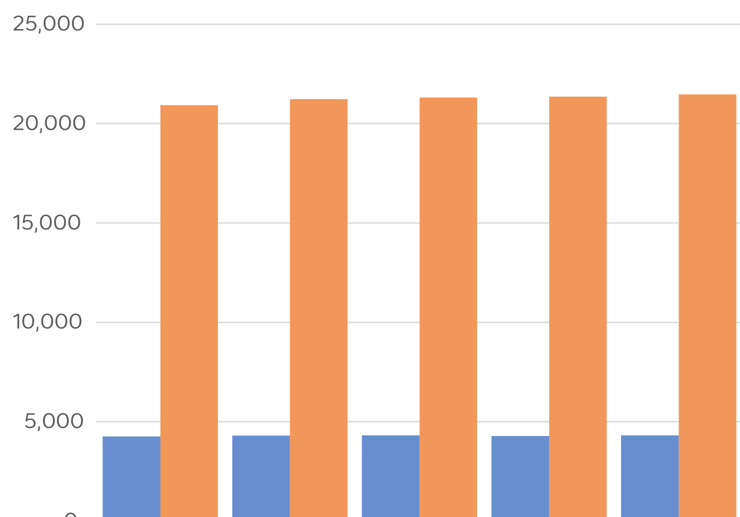
	P3	P5A	P5	P5B	P7
Incremental Annual Net System Cost [M$/year]	1,061	1,072	1,096	1,102	1,099
Incremental Cumulative Present Value of Net System Costs [M$]	7,641	7,751	7,823	7,769	7,906

Figure A7.2.140 - Shortlisted Potential Development Plans - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2035) for the 2-Medium Load Projection



	P3	P5A	P5	P5B	P7
Incremental Annual Net System Cost [M$/year]	1,843	1,833	1,833	1,867	1,883
Incremental Cumulative Present Value of Net System Costs [M$]	15,116	15,307	15,439	15,453	15,596

Figure A7.2.141 - Shortlisted Potential Development Plans - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2045) for the 2-Medium Load Projection



	P3	P5A	P5	P5B	P7
Incremental Annual Net System Cost [M$/year]	4,256	4,301	4,312	4,282	4,313
Incremental Cumulative Present Value of Net System Costs [M$]	20,925	21,233	21,316	21,353	21,473

Figure A7.2.142 - Shortlisted Potential Development Plans - Incremental Annual Net System Costs and Incremental Cumulative PV of Net System Costs (2050) for the 2-Medium Load Projection

5.10. GHG Emissions Data

This section presents GHG emissions for the five shortlisted potential development plans, with data presented for province-wide and electricity generation-specific GHG emissions.

5.10.1. Manitoba GHG Emissions

Figure A7.2.143 presents an estimate of all Manitoba GHG emissions from 2024 to 2050 under each of the shortlisted potential development plans (and under average flow conditions). Consistent with the scenario results, Figure A7.2.143 shows nearly identical trend lines for shortlisted potential development plans. This further demonstrates that regardless of the resource options strategy selected, provincial GHG emissions are primarily influenced by activities in the economy outside of the electricity generation sector. While the electricity generation sector can support GHG emission reductions in other economic sectors (e.g., decarbonization via electrification), the electricity generation sector itself has a minimal direct contribution to total provincial GHG emissions.

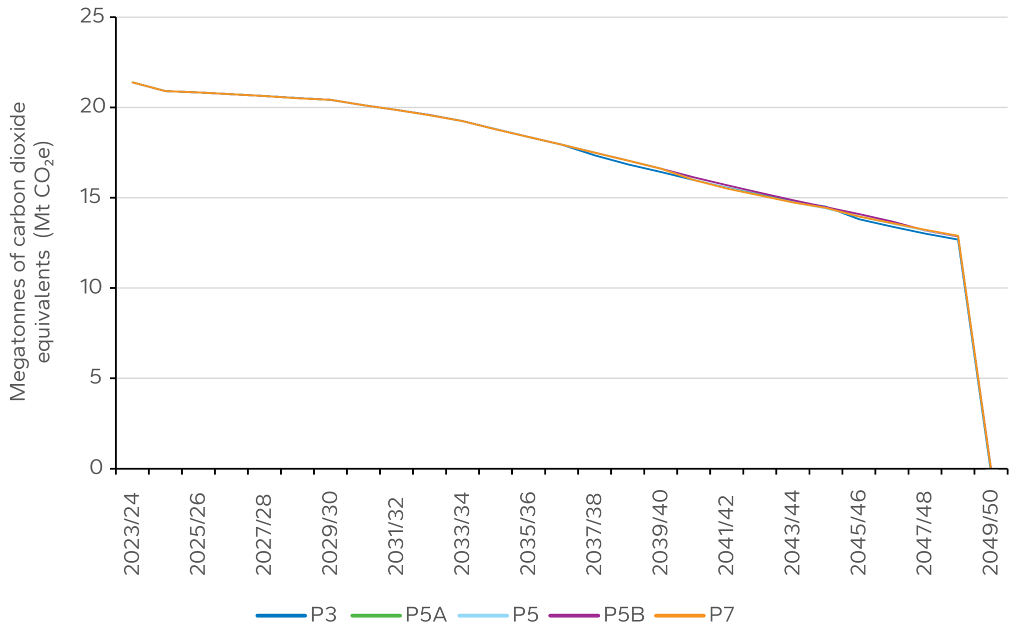


Figure A7.2.143 - Manitoba GHG Emissions by Shortlisted Potential Development Plans Assessed at the 2-Medium Load Project from 2024-2050

Figure A7.2.144 and Figure A7.2.145 present a detailed Manitoba GHG emissions breakdown in 2035 and 2050 under the average of all flow conditions. The figures further reinforce the concept that net and gross GHG emissions from electricity generation are not projected to meaningfully contribute to Manitoba's GHG emissions inventory directly; however, the charts also reinforce that the build-out of the electrical system in Manitoba can support GHG emission reductions in other areas of the province.

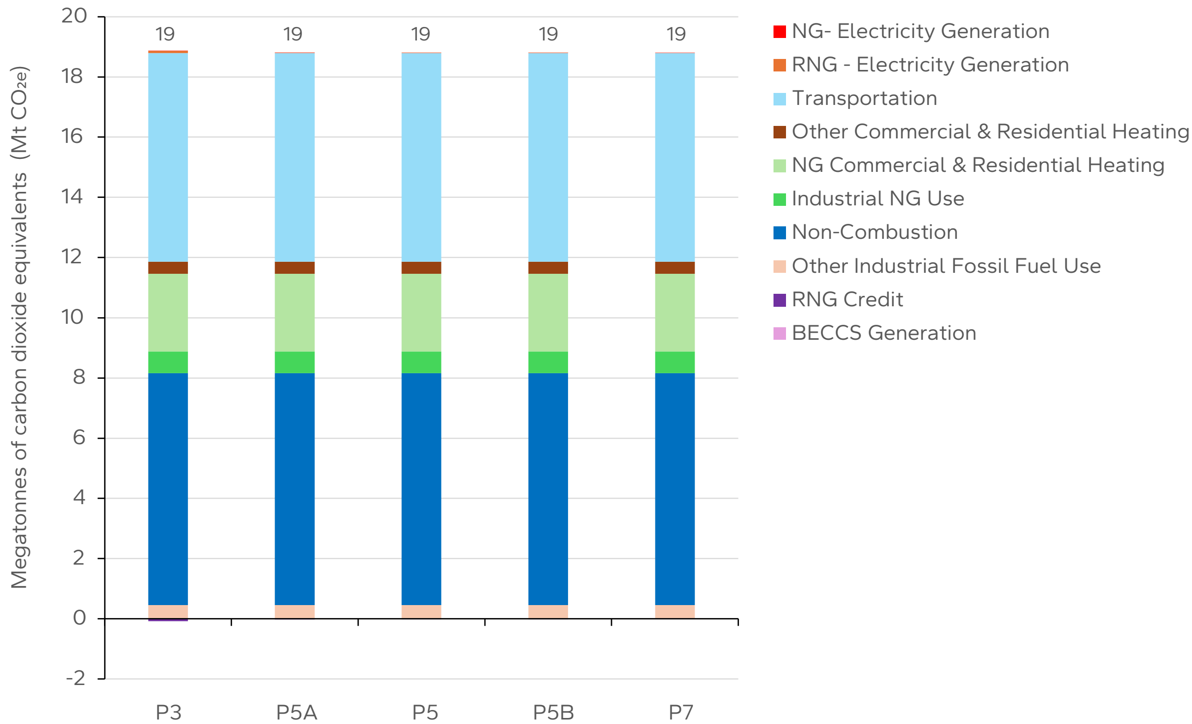


Figure A7.2.144 - Manitoba GHG Emissions in 2035 by shortlisted potential development plan for the 2-Medium Load Projection

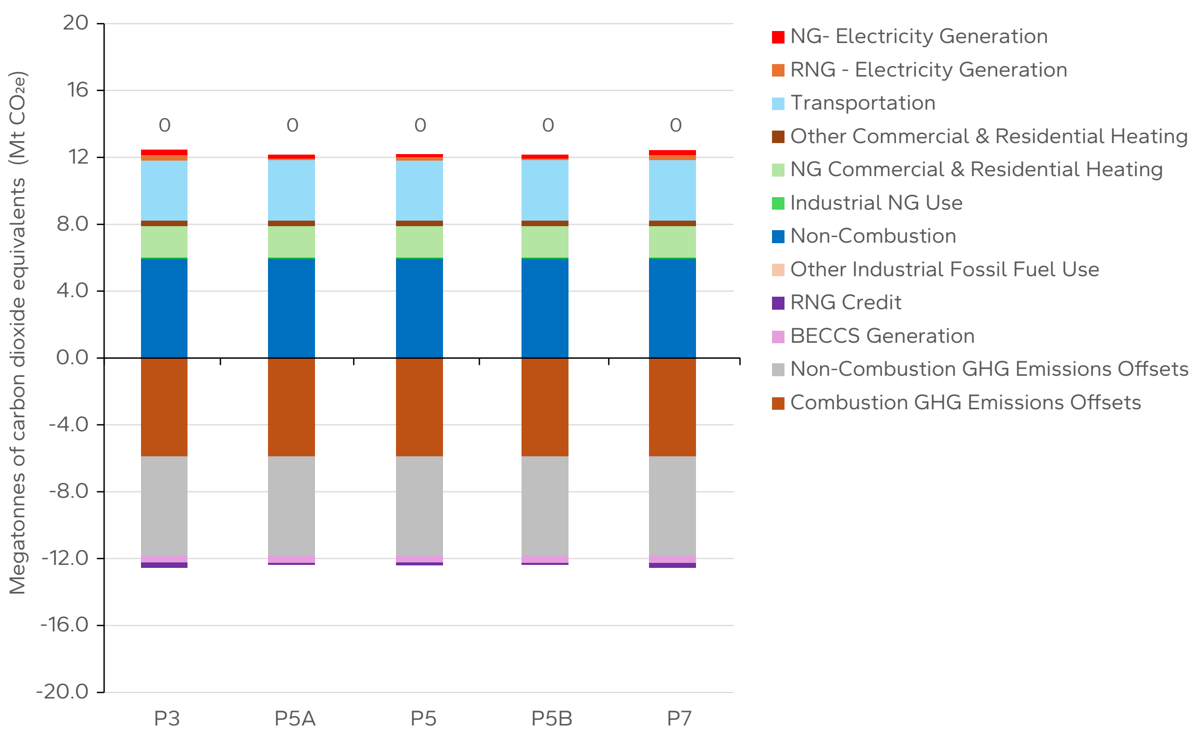


Figure A7.2.145 - Manitoba GHG Emissions in 2050 by shortlisted potential development plan for the 2-Medium Load Projection

Figure A7.2.144 and Figure A7.2.145 show the components of electricity generation GHG emissions in addition to economy wide GHG emissions. Both natural gas (NG) electricity generation and biomethane electricity generation GHG emissions are shown as positive. Biomethane electricity generation is net-zero because every cubic meter of gas consumed is assumed to be coupled with a biomethane credit. Biomethane generation is presented in this manner for transparency; however, biomethane credits are not negative GHG emissions.

Bioenergy carbon capture and sequestration (BECCS) generation is a negative emission technology (i.e., a GHG removal). As the summation of Combustion Turbine emissions is relatively small (compared to Manitoba GHG emissions), prior to 2048 one BECCS unit is sufficient for all shortlisted potential development plans to be net-negative.

Cumulative net Manitoba grid-connected electricity generation GHG emissions for each of the shortlisted potential development plans is presented in Table A7.2.27. All shortlisted potential development plans resulted in negative cumulative Manitoba electricity generation GHG emissions over the study period, indicating that any shortlisted potential development plan could align with a net-zero grid requirement. The differences in cumulative GHG emissions are uncertain and not considered meaningful, so it is not reasonable to conclude that one shortlisted potential development plan will result in more cumulative negative Manitoba electricity generation GHG emissions than another.

Table A7.2.27 – Cumulative (2024-2050) net Manitoba electricity generation GHG emissions by shortlisted potential development plan under the 2-Medium Load Projection

	P3	P5A	P5	P5B	P7
Cumulative net electricity generation GHG emissions from 2024 to 2050 (million tonnes CO_2e)	-2.7	-1.3	-1.3	-0.3	-1.2

5.10.2. Net Incremental Regional Electricity Generation GHG Emissions

Future Manitoba Hydro resource buildouts can influence electricity generation GHG emissions throughout the entire interconnected region. Table A7.2.28 presents cumulative net incremental regional (non-Manitoba) electricity generation GHG emissions – the values are all negative as they represent avoided GHG emissions in interconnected regions. There is no meaningful difference in cumulative net incremental regional (non-Manitoba) electricity generation GHG emissions over the study period between the shortlisted potential development plans. Cumulative net incremental regional electricity generation GHG emissions range from -101 to -104 million tonnes of CO_2e.

In all shortlisted potential development plans, cumulatively over the study horizon Manitoba continues to support GHG emission reductions outside of the province through the net export of electricity; however, to serve the negative GHG emissions load requirement to meet a net-zero economy by 2050 in Manitoba, Manitoba becomes a net importer of electricity under the modelling constraints and set-up used for the 2025 IRP.

Table A7.2.28 – Cumulative (2024-2050) net incremental regional electricity generation GHG emissions by shortlisted potential development plan under the 2-Medium Load Projection

	P3	P5A	P5	P5B	P7
Cumulative net electricity generation GHG emissions from 2024 to 2050 (million tonnes CO_2e)	-104	-101	-103	-103	-103

5.10.3. Cost per Tonne Reduced

All of the shortlisted potential development plans have similar impacts when considering direct electricity generation both within and outside of Manitoba; therefore, no meaningful cost per tonne analysis can be undertaken.

5.10.4. GHG Emissions Summary

All the shortlisted potential development plans have similar impacts when considering electricity generation GHG emissions both within and outside of Manitoba generation GHG emissions, as well as total Manitoba GHG emissions. From a GHG emission perspective, there is no meaningful difference between the shortlisted potential development plans. The quantity of combustion turbines (CTs) built in the development plan timeframe is not a determining factor in GHG emissions impact – all shortlisted potential development plans could be compatible with a net-zero grid requirement.