Appendix 7.1

Modelling & Analysis Approach

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1 | Introduction

The analysis conducted for the 2025 IRP used a state-of-the-art capacity expansion model ("the model") to explore how Manitoba Hydro's electric system can help meet a range of potential future energy needs for the province. Further analysis and evaluation is conducted outside of the model, which is discussed in other appendices. This appendix discusses each of the modelling process components highlighted in Figure A7.1.1.

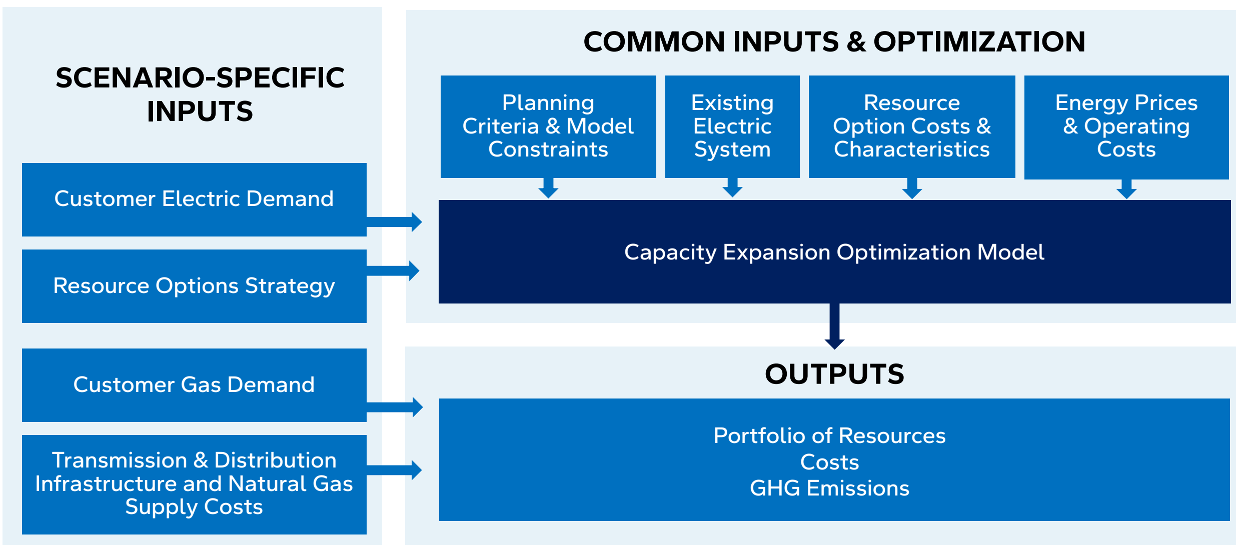


Figure A7.1.1 - Modelling Process Overview

The setup for each application of the model includes inputs specific to the assumed scenario, as well as common model inputs that are the same across all scenarios. Scenario assumptions provide the basis for all types of modelling runs, including scenarios, sensitivities, least-regrets, and shortlisted potential development plan runs. Scenario-specific inputs included in the optimization are forecasted electric demand and the resource option strategy. Transmission and distribution infrastructure and natural gas customer demand and supply costs are also scenario-specific inputs but are accounted for during post-processing of model results. Common model inputs include planning criteria requirements and modelling constraints, the representation of the existing electrical generation system, resource option costs and characteristics, and energy prices and operating costs. Once configured, the model considers investment and operating costs to identify a portfolio of resources that meets future energy needs and approaches a lowest cost solution, while also meeting all modelled criteria. The portfolio of resources is a model output that includes the timing, type, and magnitude of resource additions. Other model outputs include associated investment and operating costs, greenhouse gas (GHG) emissions, energy generated, and net export revenues.

Scenario and sensitivity analysis is a critical exercise for identifying portfolios of resources that are robust and adaptable to changing futures conditions. The 2025 IRP modelling results provide an understanding of potential resource options for meeting projected future needs in the most cost-effective way, as well as information on greenhouse gas (GHG) emissions impacts. Scenarios are used to explore a reasonable range of what the energy future may look like in Manitoba, regardless of how likely those scenarios are to occur. Sensitivity analysis builds off the scenarios by investigating changes to specific scenario assumptions or inputs, resulting in a deeper understanding of the impacts that future decisions could have. Together, the scenarios and sensitivities provide a basis for establishing the potential development plans. The robustness of these potential development plans under changing assumptions of future conditions is then tested during Least Regrets Analysis.

2 | Integrated Planning Methodology

Capacity, energy, and peak demand must all be considered together when planning the electrical system. The system must have the capacity to meet the peak demand that customers place on it and be able to provide the energy required throughout the day, every day of the year. Manitoba Hydro's two electrical generation planning criteria ("planning criteria") are used to ensure that peak electricity demand and day to day energy requirements continue to be met by the Manitoba Hydro electric system over the long term. These planning criteria are specific to Manitoba Hydro's predominately hydropower system but align with industry practice and underpin all generation planning decisions. The generation planning criteria are explicitly represented in the capacity expansion model.

Transmission and distribution planning requirements were incorporated into the 2025 IRP through guidance provided by internal Manitoba Hydro subject matter expert working groups and the development of modelling inputs that reflect transmission and distribution limitations and costs. Feasible portfolios of resources were ensured by initiating modelling work with a review of modelling concepts and constraints by the internal working groups. Transmission, Distribution, Natural Gas, and Generation planning perspectives continued to be integrated throughout the IRP process, including during the direct review of modelling results and the determination of evaluation metrics.

2.1. Transmission and Distribution Infrastructure

Transmission and distribution infrastructure includes the necessary overhead and underground infrastructure physically connecting customers to upstream generation sources. This infrastructure includes elements such as transmission towers, substations, and overhead and underground distribution circuits, where each of these elements are comprised of many different components (e.g. transformers, protection systems, capacitors, regulation, etc.) to ensure the safe delivery of electricity to customers. This infrastructure is designed to ensure reliable delivery of electricity to customers during peak demand hours.

Transmission refers to infrastructure that delivers large blocks of energy and is operated between 115 kV and 500 kV on the Manitoba Hydro system. These transmission lines typically supply multiple smaller substations and/or large industrial customers. Transmission voltages can also be reduced at terminal stations to supply lower-capacity sub-transmission networks (operated at 33 kV and 66 kV) which in turn supply distribution stations.

Distribution stations step down the supply voltage from transmission or sub-transmission voltages to between 4 kV to 25 kV. Except for very large customer loads, the vast majority of Manitoba Hydro's customers connect directly at the distribution level.

The impacts on transmission and distribution infrastructure were considered for each scenario in two distinct ways.

1. Transmission, sub-transmission & distribution costs as a result of increased load, and
2. Generator interconnection costs, which vary depend on specific resource options (further details of which are provided in Appendix 6 – Resource Options).

2.1.1. Electrical Transmission Costs

When the peak demand increases beyond the rated design of the infrastructure, new transmission and distribution infrastructure must be implemented to increase its capacity.

Steady state power flow analysis was completed to develop the scope and cost of new transmission infrastructure for load growth. A series of transmission system enhancement concepts were developed for several peak demand levels and adjusted until the final enhancement concept satisfied transmission planning design criteria. This high-level approach required the following simplifying assumptions:

- New generation resources are developed in southern Manitoba.
- Generation is situated at locations that minimize transmission enhancement costs when possible.
- Load growth was modelled at existing transmission stations and new transmission stations are developed once limits at existing stations are reached.
- Factors such as multiple generation dispatch patterns, steady state voltage ratings, and sub-synchronous oscillations require more detailed modelling and analysis and were not considered.
- New transmission lines were developed when line overloads were identified.
- Cost estimates for transmission enhancements are based on the Midcontinent Independent System Operator (MISO) report "Transmission Cost Estimation Guide: For MTEP24" and actual costs for projects completed by Manitoba Hydro.[1]
- Transmission lines have a service life of 81 years and stations have a service life of 43 years.

[1] *Transmission Cost Estimation Guide for MTEP24* https://cdn.misoenergy.org/20240501%20PSC%20Item%2004%20MISO%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24632680.pdf

2.1.2. Electrical Sub-Transmission & Distribution Costs

The approach used to establish the scope and cost of new sub-transmission and distribution load growth infrastructure is similar to that described above for Transmission. Manitoba Hydro's integrated system was divided into six zones, with peak electrical demand projections allocated to each zone. Enhancements to sub-transmission lines, distribution lines, and stations were determined that satisfy the relevant planning design criteria. Costs were developed for each zone and combined to establish a single composite cost for the entire system. This high-level approach required the following simplifying assumptions:

- The electrical sub-transmission & distribution cost study assumes there is capacity on either the 66kV or 115kV systems.
- When existing station/distribution service centre (DSC) capacity cannot accommodate load growth, the existing station /DSC is expanded, or a new station or DSC is constructed.
- Distributed Generation is not considered in the study.
- The cost estimation represents installation costs only, incremental to any operation and maintenance of new and existing equipment and infrastructure. The cost of improving existing distribution asset reliability and condition concerns is also not included.
- In congested and high traffic areas, such as downtown Winnipeg, underground duct-line installation is included in the cost.
- Cost estimates do not consider the time value of money, such as interest, discount rate, and escalation.
- A 24kV feeder length was assumed based on an average 10-12 km feeder distance, while a 12kV feeder length was assumed based on an average 6km feeder distance.
- System improvement cost (voltage conversion and reconductoring) to expand feeder capacity depends on the feeder topology and load allocation. All these costs may not be reflected in this study.
- Non-wires solutions such as managed electric vehicle charging are not assumed to be widely available during the study window, as Advanced Metering Infrastructure (AMI) necessary for these programs is still in development.
- Property is available as needed for new stations, DSCs, sub-transmission lines, and distribution feeders.
- Generally, load growth does not include new large, concentrated loads.

- The cost of connecting new generation at the distribution level is excluded, if the generation connection is not due to the load growth.
- Sub-transmission and distribution assets have a financial life of 71 years, while 43 years is assumed for lines and sub-stations.

The ability of Manitoba Hydro to successfully execute the necessary amounts of Transmission and Distribution capital projects to connect the anticipated load growth in the Integrated Resource Plan has been identified as a significant risk and is discussed in Appendix 9.2 – Risk Analysis.

2.1.3. Integrating New Transmission and Distribution Infrastructure Costs into the 2025 IRP

A marginal cost approach is used to account for major transmission, sub- transmission and distribution expansion costs. For each increment of peak demand growth in megawatts (MW) it is assumed there is a corresponding incremental infrastructure cost. The total costs are calculated for each scenario and sensitivity and are accounted for in the cost metrics developed during post-processing of model results, rather than being explicitly modelled. Table A7.1.1 provides the marginal cost of new transmission, sub-transmission and distribution that is assumed to be required to meet peak demand growth in the scenarios. Once peak electrical demand growth increases by more than 4,000 MW, as observed in the 2-Medium and 3-High load projections by the end of the study period, the cost of new transmission increases about 55% because the impact on the transmission system is more substantial.

Table A7.1.1 – Levelized Network Cost of New Transmission & Distribution for Electric Load Growth

New Transmission and Distribution	Cost
Transmission – Peak Demand Growth Less Than 4,000 MW	$35.20/kW-yr
Transmission – Peak Demand Growth Greater Than 4,000 MW	$50.40/kW-yr
Sub-Transmission & Distribution	$49.81/kW-yr

2.2. Natural Gas Supply and Infrastructure Planning Considerations

The variability in Manitoba customer natural gas demand is met through reliable and flexible supply arrangements in the integrated North American natural gas market. These arrangements include pipeline transportation from market hubs and the use of natural gas storage.

Customer natural gas consumption varies across the 2025 IRP natural gas load projections, resulting in different gas supply costs across the scenarios. 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 carbon pricing, and are estimated for analysis purposes for each load projection. Adjustments to transportation and storage capacity assumptions were made over the 2025 IRP study period to optimize these costs relative to the changing gas demand in the load projections.

Carbon pricing assumptions applied in the 2025 IRP analysis reflect the policy landscape as of the beginning of the 2025 IRP.

Natural gas supply costs to serve customer load are accounted for in the economic indicators developed during post-processing. Costs associated with supplying natural gas to new generators are described later in this appendix.

Assumptions related to the natural gas distribution network also vary by load projection, and are as follows:

- **1-Baseline load projection:** Assumptions impacting natural gas demand in this load projection result in new customers connecting to the natural gas system, where capital investments may still be required to connect customers and serve coincident peak (as natural gas volume usage becomes more weather dependent and may incur peak increases on specific discreet systems).
- **2-Medium load projection:** Assumptions impacting natural gas demand in this load projection would result in new natural gas infrastructure to support customer growth in the first 10 years. Natural gas infrastructure may also need to be upgraded to support the type of natural gas usage associated with this load projection, as more customers are assumed to utilize dual-fuel heating systems (electric air source heat pump for mild winter weather) that requires the natural gas distribution system to serve peak loading.
- **3-High load projection:** Assumptions impacting natural gas demand in this load projection result in no new natural gas customers connecting as of 2030 and no existing customers can replace aging systems after 2035. It is assumed that this scenario would not require new natural gas infrastructure to support this load projection.

While capital investments may be required to support natural gas distribution infrastructure under the 1-Baseline load projection and 2-Medium load projections, these specific costs were not included in the 2025 IRP analysis. Marginal changes for non-infrastructure related costs for natural gas transmission and distribution are accounted for in the economic indicators developed during post-processing.

For a full description of the assumptions used to build the 2025 IRP load projections, please see Appendix 5 – Load Projection.

2.3. Generation Planning

The foundation of generation system planning is the Generation Planning Criteria. Separate criteria have been established for capacity and energy, and both are detailed below.

2.3.1. Capacity Criteria

The capacity criterion requires that Manitoba Hydro plan to ensure there is sufficient generating capacity to meet Manitoba's peak load plus any committed export contracts. In addition, Manitoba Hydro must include a planning reserve margin intended to protect against capacity shortfalls resulting from the breakdown of generation and transmission equipment or increases in peak load due to extreme weather conditions. The planning reserve margin is calculated for every year of a load projection as 12% of the Manitoba peak demand.

The planning reserve margin of 12% has historically been adequate for Manitoba Hydro's predominantly hydropower system because of relatively low hydropower generator outage rates combined with the relatively small size of individual hydropower units. In comparison, reserve margins in predominantly thermal generation-based systems are typically in the 15% range, when expressed on an installed capacity basis.

2.3.2. Energy Criteria

Manitoba Hydro also has an energy criterion that recognizes the energy-constrained limitations of a hydropower system during drought conditions. The energy criterion requires that Manitoba Hydro plan to have adequate energy resources to supply firm energy demand if the lowest recorded coincident water supply conditions are repeated.

Dependable energy includes the amount of electrical energy supplied by the hydropower system during the lowest system inflow on record, which corresponds with the most severe drought on record in Manitoba. These water supply conditions are referred to as the dependable flow conditions. Dependable energy also includes generation from wind turbines, natural gas generators, and imported electricity.

Figure A7.1.2 illustrates how the volume of energy supplied by the system varies with water conditions, based upon existing supply resources. The bars in the chart show the total energy supplied by the Manitoba Hydro system under high, average, and low flow conditions. The chart also breaks out the relative supply contributions of individual resource types.

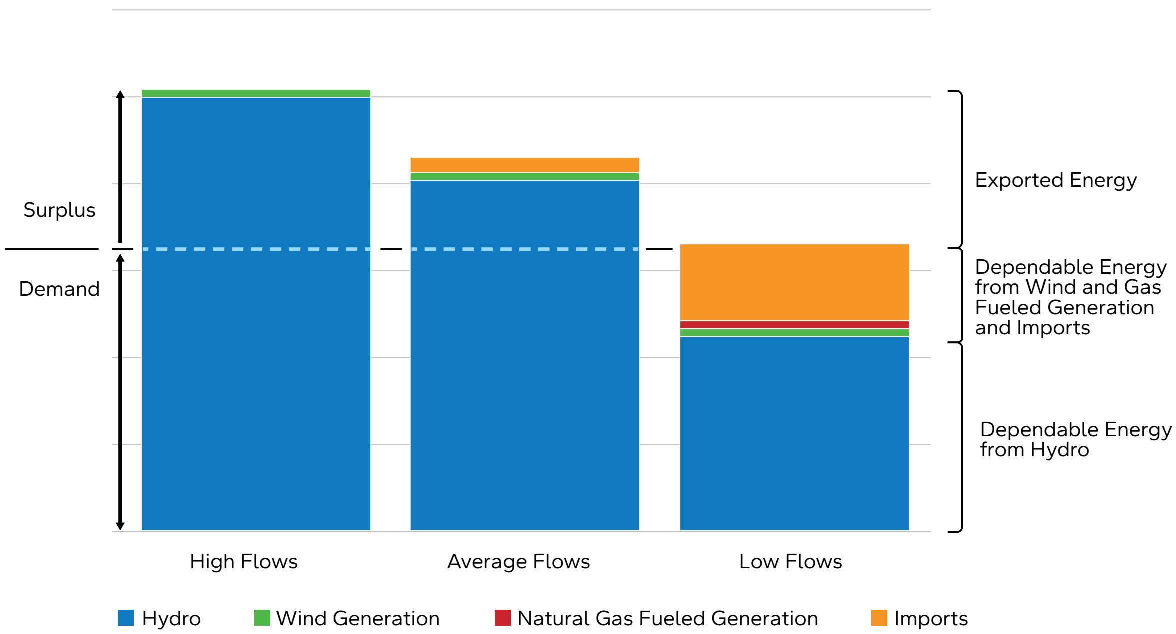


Figure A7.1.2 - Energy Supply Variation with Water Conditions

During low flow conditions, there is not enough energy from hydropower alone to meet demand and other sources of energy supply are required. This includes energy from wind farms, imported energy from markets, and use of Manitoba Hydro's natural gas turbines. The energy planning criterion ensures that sufficient energy supply is available from the system under these conditions.

Since Manitoba Hydro's system is designed to be reliable even under severe drought, higher inflow conditions result in more electrical energy from hydropower generation than is needed to meet demand, resulting in surplus energy. This is shown in Figure A7.1.2 by the high and average flow conditions. In the model, surplus energy can be used to avoid importing energy or running natural gas turbines, or it can be exported for revenue. However, as inflow conditions decrease, the amount of surplus energy also decreases with no surplus energy remaining under low flows.

The model represents the relationships between water conditions, energy supply, and market interactions.

2.3.3. Application of the Planning Criteria within the Capacity Expansion Optimization Model

The model represents Manitoba Hydro's planning criteria as seasonal constraints that the model must fulfill when identifying a portfolio of resources. Summer and winter peak demand (i.e., accredited capacity) and dependable energy requirements, determined in agreement with the planning criteria, are specified in the model for every year in the planning horizon. Similarly, summer and winter annual accredited capacity and dependable energy are assigned to every existing resource and new resource option ("accredited capacity" and "dependable energy").

The accredited capacity and dependable energy provided by new resource options are provided in Appendix 6 – Resource Options. Dependable energy for existing system resources was determined through dependable energy studies performed by Manitoba Hydro using the production costing software component of the capacity expansion model. Dependable energy from import markets is assumed to be equivalent to the amount of energy that can be imported during off-peak hours, while import markets are assumed to provide no accredited capacity unless guaranteed through contracts.

Fulfillment of the planning criteria constraints is checked for each summer and winter period of each study year. For each instance of the planning criteria constraints, the model ensures that the independent sums of accredited capacity and dependable energy associated with all new and existing resources in the system at that time meet or exceed the requirements

3 The Capacity Expansion Optimization Model

3.1. Modelling Tools

Manitoba Hydro uses specialized capacity expansion planning software designed specifically for electric utilities. This software was purchased from PSR, a Brazilian software developer with over 35 years of experience in providing technical expertise to the electricity and natural gas sectors. Manitoba Hydro selected the PSR suite of electrical system modelling tools in large part due to the explicit accounting of inflow uncertainty in these models, as well as PSR's experience with modelling hydropower systems.

The software that Manitoba Hydro used for this IRP included two tools. The first is a production costing model which is used to simulate the electrical system and determine the cost of producing energy. The second tool is a capacity expansion planning model which is used to explore adding new resources to an existing system to meet growing demand. Both models are integrated during capacity expansion planning, working together to identify low cost expansion plans that ensure the accredited capacity and dependable energy demands of the system are met, while also considering other system constraints.

3.2. Modelling Objective

Figure A7.1.3 depicts a growing need for new energy and capacity resources as demand grows, illustrating the basic problem that the capacity expansion planning model solves.

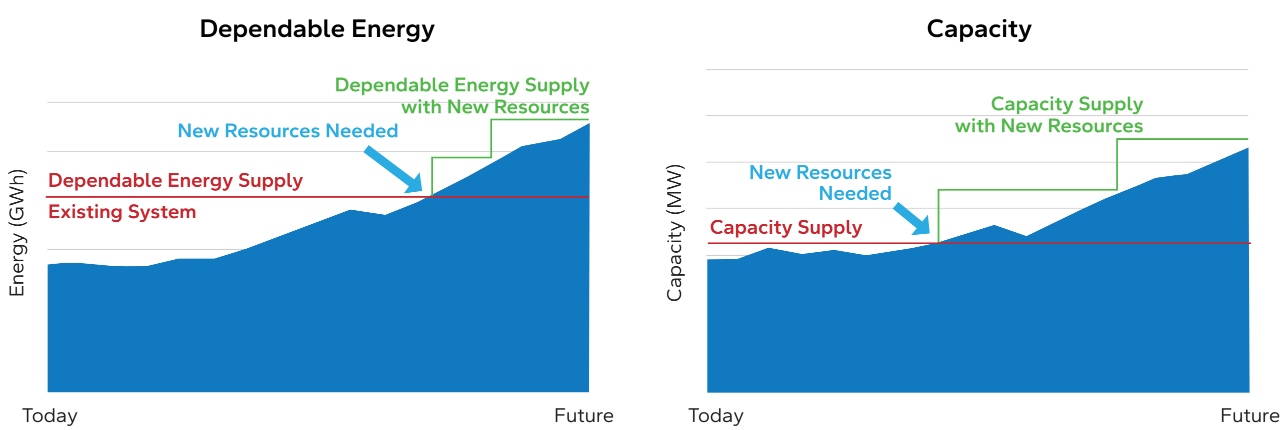


Figure A7.1.3 - Illustrative Example: Determining When Energy and Capacity are Needed

The red lines in Figure A7.1.3 display the amount of dependable energy and accredited capacity available from Manitoba Hydro's existing system. This includes hydropower, wind, combustion turbines (CTs), imports, and planned customer-side solutions (while these may have accredited values that change over time, the illustrative figure shows them as static for simplicity). The shaded blue areas show future projected demand, including Manitoba's load and existing export contracts. For the capacity chart, the shaded blue area also includes the planning reserve margin.

New supply is needed when the supply and demand lines intersect on either the capacity or energy graph. This is when new resources are added by the capacity expansion optimization model. The new resource(s) selected will vary depending on the timing, type (energy and/or capacity), and magnitude of need. Adding a new resource adjusts the energy and capacity balance for the remainder of the study period.

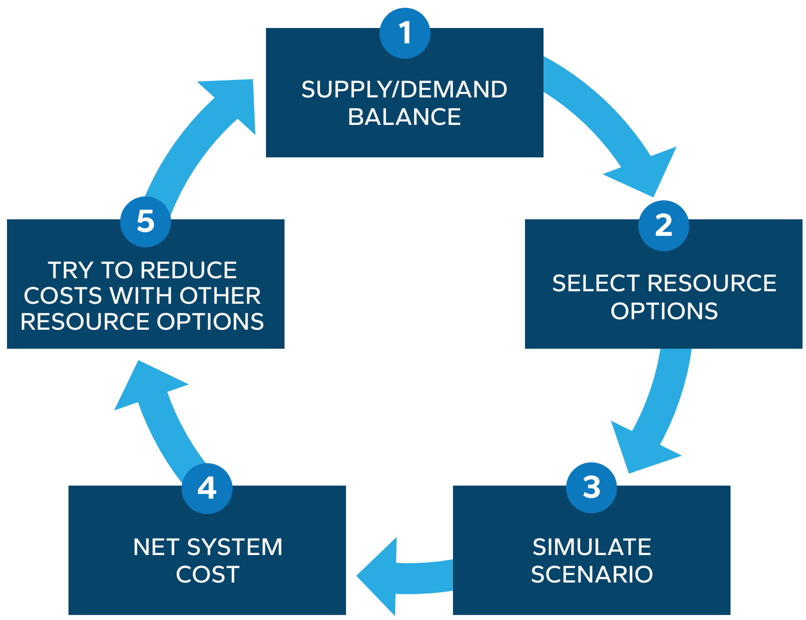
Optimizing to the lowest cost requires a long-term view of the future energy and capacity needs of the system, which are shown to change over time in Figure A7.1.3. The capacity expansion optimization model seeks the lowest cost portfolio of resources for the full study period while considering factors that vary in time such as customer demand, the ratio of dependable energy to accredited capacity need, the investment and operating costs of resources, and changes to the operation of the system in response to the addition of new resources. All these considerations are further subject to the constraints, planning criteria requirements, and resources assumptions input to the model.

An important feature of the model is that it solves for a portfolio of resources at an annual time step, and for system operating costs at a monthly time step. For computational efficiency, monthly modelling is based on a 21-block representation, where each hour of the month is assigned to one of the blocks. Hours are assigned to blocks based on similar electrical demand. Electricity energy market prices, set-profile generators, and applicable operational constraints are modelled using the same 21-block definition, preserving the relationships between coincident hours across these inputs.

Once a portfolio of resources is identified by the model, the dependable energy and accredited capacity needs of the system will be met for the entire study period, as shown by the green lines in Figure A7.1.3. The green lines show the system's dependable energy and accredited capacity after the addition of new resources identified in the model's expansion plan.

3.3. Modelling Optimization Process

Seeking to identify lowest cost expansion plans is an iterative process, as outlined in Figure A7.1.4 for a scenario. The same process is applied during all capacity expansion planning modelling, including sensitivities.



NET SYSTEM COSTS = CAPITAL COSTS + OPERATING COSTS - EXPORT REVENUE + IMPORT COSTS

Figure A7.1.4 - Capacity Expansion Planning Model Optimization Process

The capacity expansion optimization model follows these steps during each iteration:

1. The model determines when and how much new supply is needed to satisfy the planning criteria for both energy and capacity.
2. The model identifies a low-cost portfolio of resources for the study period, picking resources that meet demand based on the planning criteria, respect all modelled constraints, and which minimize capital costs and estimated operating costs. Estimated operating costs are not based on a production costing simulation but rather are based on approximations developed by the model for each resource, with the accuracy of those approximations improving with each iteration of the model.
3. The model optimizes and simulates the operation of the Manitoba Hydro system over the study period based on the proposed expansion plan, load projections, and inflow records. This simulation includes firm demands, existing generating resources, import and export market interactions, as well as the new resources identified by the model. The production costing simulation provides refined operating costs for the system.

4. The model calculates the final net system cost as the sum of all investment capital costs and the refined simulated operating costs returned from the production costing model in step 3, and which includes opportunity export revenues and import costs.

5. The model assesses if the updated net system cost for the proposed portfolio of resources is reasonably close to the estimated net system cost (which was based on estimated system operating costs in step 2, rather than the refined operating costs used in step 4). If so, the modelling process is concluded. If the discrepancy between the expected and final net system costs is too large, the model undergoes another iteration, using the results from the previous iteration to improve the operating cost estimates used during resource selection.

Figure A7.1.4 displays the modelling steps required to identify an expansion plan for a single model scenario or sensitivity. This process is repeated separately for each scenario and each sensitivity analyzed.

Once the modelling of a scenario or sensitivity is complete, an initial validation of the results is performed, followed by post-processing, analysis, and comparison of the model results against findings from other relevant scenarios and sensitivities.

Robust methodologies and tools designed to improve modelling, post-processing, and analysis efficiency have been developed, but strategic selection of scenarios and sensitivities to study was still required. These additional steps are discussed later in this Appendix.

3.4. Net-Zero Grid Modelling Constraint

Several of the 2025 IRP scenarios and sensitivities were designed to meet a net-zero grid by 2035 constraint to align with Manitoba Hydro's 2023 mandate letter.[2] For 2025 IRP analysis, Manitoba Hydro assumed any resource options strategy that included a net-zero grid constraint would be compliant with the federal government's Clean Electricity Regulations.[3]

For the 2025 IRP, net-zero grid means all direct (scope 1) GHG emissions from grid-connected fossil fuel generators located in Manitoba must be netted to zero, on an ongoing cumulative basis, from 2035 onwards. A net-zero grid target does not:

- include lifecycle or upstream GHG emissions (i.e., "embedded" GHG emissions);
- operate on an individual facility-level (it operates on a provincial-level);
- include GHG emissions related to imported electricity;
- need to be achieved on a daily, monthly, or annual basis (it is achieved cumulatively, on a multi-year average basis);

[2] https://www.manitoba.ca/asset_library/en/executivecouncil/mandate/hydro_mandate_letter_2023.pdf
[3] https://gazette.gc.ca/rp-pr/p1/2023/2023-08-19/html/reg1-eng.html

- require the elimination of fossil fuel generation (e.g., natural gas combustion turbines);
- require the elimination of GHG emissions from electricity generating units; and
- apply to off-grid diesel generation facilities.

3.4.1. Grid GHG Emissions Limit

To factor in GHG emissions limits, the model was constrained to limit the direct GHG emissions (scope 1 - as defined in the 2025 IRP Report Glossary) from grid-connected fossil fuel generators located in Manitoba. This limit was evaluated based on cumulative totals calculated at the end of each of the model's rolling horizons (typical between 4- to 9-year horizons, which is comparable to an ongoing cumulative basis). Without a GHG emissions limit, the model has no GHG emissions constraint and will potentially allow large increases in GHG emissions from grid-connected fossil fuel generators to avoid a small amount of cost.

For the scenarios and sensitivities based on Resource Option Strategy A, a limit of 25 tonnes of CO_2e per GWh of net Manitoba demand was applied. Manitoba Hydro analyses indicates that application of this limit aligns with the Clean Electricity Regulations, up to 2050, beyond which a net-zero grid constraint would be required.

A net-zero grid constraint is applied when the rolling horizon GHG emission limit is set to 0 tonnes of CO_2e per GWh starting in 2035. This is included in the modelling of scenarios and sensitivities based off resource option strategies B, C, and D. The 2025 IRP assumed the potential use of carbon offsets and biofuel credits to achieve net-zero grid targets as it may not be economically or technologically feasible to eliminate all GHG emissions.

GHG Emission Offsets

It is assumed that the bioenergy with carbon capture and sequestration (BECCS) resource option would function under an offset system. Negative GHG emissions produced by BECCS are assumed to produce removal offsets and are monetized at the assumed GHG price, which is discussed further in the appendix. Each offset produced by a BECCS unit is equal to negative one tonne CO_2e.

Offsets are otherwise not explicitly included in the capacity expansion model. However, due to the limitation of fuel available in Manitoba for BECCS, there is an inherent limit on available offsets in the capacity expansion model. See Appendix 5 – Load Projections for further discussion on assumed biofuel limits.

Non-Fossil Fuel and/or Biofuel Credit Systems

Some combustion turbine resource options are modelled with the ability to generate electricity using a non-fossil fuel or biofuel source, with the assumption that a credit system is in place. When non-fossil fuels or biofuel fuels are sourced it is assumed that the pipeline fuel consumed can be paired with a purchase of a credit so no net GHG emissions are produced. The cost of purchasing biomethane credits is assumed to be covered by the modelled fuel cost, which is conservatively[4] priced at a constant $40/MMBTU CAN$.[5] Every cubic meter (or MMBTU) of pipeline gas that has an associated credit cost is assumed to produce no net GHG emissions.

For the 2025 IRP, it is assumed that a credit system is in place that follows internationally recognized GHG accounting principles. The use of non-fossil fuel credit frameworks (i.e., book-and-claim systems) is a solution to the barriers of using non-fossil fuels or biofuels, including:

- For many applications it is not economically or technologically feasible to transport, distribute, and store non-fossil fuels (e.g., biofuels) separately from existing fossil fuel transportation, distribution, and storage infrastructure.
- The need for new dedicated pipelines, storage facilities, and other infrastructure.
- When blending occurs, the non-fossil fuel content of the fuel becomes uncertain.
- Relying on 100% non-fossil fuel sources in Manitoba at utility scale.

3.5. Practical Model Limitations

The final portfolio of resources identified by the model may not be the absolute lowest-possible cost solution. The model searches for the lowest cost plan through an iterative process that stops when the model meets the optimization threshold and convergence is achieved, indicating that the identified expansion plan is a low-cost solution based on well estimated operating costs in addition to assumed investment costs. It is possible that if the model's iterative process continued, an even lower-cost solution may be identified; however, this can lead to unmanageable model run times or an inability for the model to successfully complete the optimization process and is ultimately not practicable. Given that a lower cost portfolio of resources may exist, and that the model does not provide information on the next-best solutions identified during the optimization process, it is important to interpret the IRP modelling results as a collective set of results and to balance individual scenario or sensitivity insights with robust findings that are demonstrated repeatedly across model results.

[4] https://ghginstitute.org/2022/01/27/the-overlooked-mystery-of-the-missing-ghg-accounting-principle/

[5] This $40/MMBTU assumption is based on the cost Environment and Climate Change Canada was assuming for NextGrid in December 2022 (as shared in a document titled "Written Response to Questions Posed During the Modelling Webinars"); NextGrid is a tool used in the development of the Clean Electricity Regulations. $40/MMBTU is at the upper end of typical biomethane assumption and Manitoba Hydro has chosen to leave it as a base assumption in alignment with the principle of conservativeness – Manitoba Hydro's expectation is that biomethane will likely be procurable at a cost less than $40/MMBTU.

4 Electrical and Natural Gas Customer Demand

Electric Demand

The electric demand projections vary across each IRP scenario. Each was developed by Manitoba Hydro as outlined in Appendix 5 – Load Projections.

Electric load within Manitoba is modelled as a firm demand. The model uses an hourly electric load projection aggregated into 21 blocks per month, where the hourly electric load value assigned to each block varies by month. The assignment of hourly electric load data to each block is based on the 21-block definition applied to all time-varying inputs used in the model.

Natural Gas Demand

Customer natural gas demand is not explicitly represented in the model. However, post modelling processing of results to produce economic indicators incorporates customer natural gas demand projection information.

Energy Efficiency

Within the capacity expansion optimization model, future energy efficiency savings are represented as a set-profile generator. Modelling energy efficiency as a set-profile generator allows for a consistent representation of both the assumed energy efficiency from Efficiency Manitoba's Efficiency Plan Projection and for additional energy efficiency beyond that plan. The set-profile generator unit used to represent the Efficiency Plan Projection is set as an existing unit, making the associated energy efficiency savings a base assumption.

Demand Response

Demand response is represented in the model consistent with the Energy Efficiency representation. It is modelled as an existing set-profile generator and effectively functions as a load modifier.

5 Energy Price Forecasts for External Markets

Energy price forecasts are used in the model to determine opportunity export revenue and import costs so that net system costs can be determined. These prices are a key assumption in the model when optimizing market interactions. The United States (U.S.) MISO energy market provides the largest opportunity for export and import due to the large size of the MISO market and because Manitoba Hydro has a much larger transmission connection with MISO, as opposed to Saskatchewan and Ontario. While there is no energy market in Saskatchewan, bilateral opportunity imports and export interactions with Saskatchewan are modelled based on the same energy price forecast applied to the MISO energy market. Opportunity export interactions with Ontario also assume the MISO energy price forecast, and it is assumed that no opportunity imports are available. The MISO energy market, Saskatchewan, and Ontario are collectively referred to as "markets".

Market prices vary by block, month, and year throughout the study period. The same mapping from hourly information to aggregated blocked information is applied to both the market prices and the electric load forecast, maintaining the relationship between hourly electric load and market prices.

The model optimizes the dispatch of natural gas thermal units based on both a natural gas price forecast and a GHG emissions price forecast. The natural gas price forecast varies by month and year, whereas GHG emissions costs vary by study year only. The projection of GHG emissions costs is based on Output-Based Pricing System performance standards (more details are provided in Appendix 4 – Policy Landscape) and the Excess Emissions Charge schedule, as defined in Schedule 4 of the Greenhouse Gas Pollution Pricing Act.[6] Manitoba Hydro assumed the currently scheduled charge of $170/tonne CO_2e in 2030 escalates in real terms (i.e., it continues to escalate with inflation).

[6] https://laws-lois.justice.gc.ca/eng/acts/G-11.55/page-29.html#h-247156

6 Existing Electric System

Manitoba Hydro's existing electrical generation system is represented within the model as detailed in the following sections. The analysis assumes the existing system is maintained throughout the study period. Appendix 9.2 – Risk Analysis presents a risk assessment of potential development plans where this assumption is not upheld. The Pointe du Bois refurbishment project is assumed to be completed, and the expiration of existing non-utility generation power purchase agreements and the expiration of import and export agreements are reflected in the model.

6.1. General Configuration – Nodes and Transmission Links

The Manitoba Hydro electric system is modelled as a series of connected nodes that each represent a portion of the system. Generators and energy demand are assigned to nodes, while the transmission capability between nodes is defined based on a simplified representation of the Manitoba Hydro transmission system. Manitoba Hydro's high voltage direct current (HVDC) system is represented by the transmission link between the Northern DC (direct current) and Winnipeg nodes. The energy that is lost when electricity flows through AC (alternating current) and HVDC transmission systems is accounted for by the model.

In addition to the Manitoba system, the model includes interconnections to neighbouring markets that Manitoba Hydro interacts with, including MISO, Saskatchewan, and Ontario. Transmission links used to define the import and export capabilities are listed in Table A7.1.2 below.

Table A7.1.2 – Modelled Import and Export Capability of Manitoba Hydro's Transmission Lines

Node A	Node B	A → B (Export)	B → A (Import)
Western Manitoba	MB-SK	291.5 MW	60 MW
Winnipeg	MHEB (MISO)	2,858 MW	1,400 MW
Winnipeg	MB-ON	100 MW	0 MW

6.2. External Markets

Interactions with the markets includes firm electricity exports, opportunity energy exports, and imports. The total volume of import and opportunity plus firm energy exports within a block is restricted by the import and export capability provided in Table A7.1.2.

6.2.1. Firm Electricity Exports

Firm electricity exports are modelled as an electricity demand with associated accredited capacity and dependable energy requirements that must be served regardless of the cost to serve them, similar to the electric load. Firm electricity exports are modelled for each block, month, and year. The 2025 IRP assumes that as existing firm contracts expire, they are not renewed.

6.2.2. Opportunity Energy Exports

Opportunity exports are modelled as non-firm demands that are met only when it is economic to do so, with associated prices that dictate the revenues received for supplying them. The model chooses when and how much opportunity export demand to serve, based on system conditions (such as the availability of surplus energy). Opportunity export prices are determined based on the energy price forecast and are based on the same 21 block definition used to aggregate the hourly Manitoba customer electric demand projection.

6.2.3. Imports

Opportunity energy imports reflect the energy price forecast. The same 21-block representation is applied to import prices, opportunity export prices, and the Manitoba load. Physical imports, market settlements, and capacity purchases are all modelled. Opportunity imports are limited only by transmission constraints in the capacity expansion model during: the daily 8-hour over-night off-peak period; the lowest demand 6-hour weekday on-peak period; and, the 12-hour weekend day period outside of the top four hours of demand. For the remaining on-peak hours, opportunity imports are further limited to the energy specified in diversity contract agreements, and for certain lower-demand hours, to the amount of firm export contracts in place that are assumed to be eligible to be met through market settlements.

Opportunity energy imports have associated dependable energy equivalent to the amount of energy that can be imported during the off-peak hours and are assumed to provide no accredited capacity. Capacity imports can only be purchased through the selection of the Market Capacity Import resource option.

6.3. Hydropower Generation

The model includes all existing hydropower resources. Where applicable, licence restrictions on operations have been modelled at a monthly time step. This includes restrictions on reservoir operating ranges, flows through the west channel outlet of Lake Winnipeg, and flow through the Churchill River Diversion. Minimum generation requirements have also been imposed based on system operational requirements.

Uncertainty in energy production from hydroelectric generating stations is an important consideration when modelling the Manitoba Hydro electric system, due to variations in system water conditions from year to year. This uncertainty is captured by providing 112 years of historical monthly inflow data to the model. These inflows define the range and variability that the model considers each month of each year throughout the study horizon during production cost simulation. Monthly historical inflows are based on Manitoba Hydro's Long-Term Flow Data, shown in Appendix 3 – Existing System.

The calculation of generated electricity is based on a hydropower plant's turbine efficiency and the difference in its upstream reservoir and downstream tailwater elevations. Run of river hydropower stations assume a constant reservoir elevation, while hydropower stations with reservoir storage are modelled with a defined storage that varies with elevation. Tailwater elevations are determined using a relationship between total station outflow and tailwater elevation. Similarly, turbine efficiency also varies with flow through the turbine.

6.4. Fuel-Fired Generation

The Brandon Generating station is a natural gas fuelled thermal generator and is the only existing grid-connected fuel-fired generating station in the Manitoba Hydro electric system.

Generation for thermal resource options is optimized during the capacity expansion optimization model's system simulation phase. For any given block in the study horizon, the amount of electrical energy generated by a unit will vary depending on demand, the inflow conditions and corresponding hydropower generation, the amount of set-profile generation, the economics and resulting quantity of imports, operating costs, and GHG emissions constraints. Thermal generation is most often driven by the need to meet the system's energy demands during low-flow periods and peak demand hours. The fuel costs, variable operating, and maintenance costs, and GHG emissions costs associated with natural gas thermal generation are weighed against the economic advantages of dispatching the generator. GHG emission constraints restrict the dispatch of thermal generators that use fossil fuels to ensure compliances with GHG emission targets, such as a net-zero grid.

6.5. Wind Generation

Manitoba Hydro has power purchase agreements in place with the St. Joseph and St. Leon wind farms and both are modelled as existing set-profile generators. This wind generation is modelled with a constant annual pattern that varies from month to month but with no variation between blocks within a month, based on historical generation. The variability and uncertainty of wind generation is not represented in the model.

7 | New Electricity Resource Options

The model selects from all available resource options when establishing a portfolio of resources. Each of these resources have unique characteristics that are captured in the model, as discussed in Appendix 6 – Resource Options. These characteristics define the costs, energy production, accredited capacity, dependable energy contributions, and associated GHG emissions for each resource and are used by the model to compare and evaluate resource options while optimizing to lowest cost. This section provides a summary of the modelling details used to represent each resource option; assumptions that were made due to the practicalities of modelling are detailed here and supersede information presented elsewhere, whereas assumptions and characteristic requiring no additional modelling considerations are left to the discussions in Appendix 6 – Resource Options.

7.1. General Notes

All capacity values provided in this section are stated as installed (nameplate) capacities, unless explicitly noted as accredited firm capacity.

All units are assumed to be operational within the system as of April 1st of their in-service date (ISD) year, unless otherwise noted.

All assumptions are specific to the representation of each resource option in the model only and should not be assumed to be appropriate for other applications. For example, the GHG emissions assumptions are for the purposes of introducing GHG emission costs associated with resource dispatch within the model, and do not necessarily reflect other corporate enterprise reporting, provincial reporting, or monitoring assumptions.

Similarly, constraints on the maximum total and annual installed capacity of a resource are for modelling purposes only and are implemented in many cases to improve the computational efficiency of the model and improve the realism of results. Where possible, these constraints reflect the current understanding of Manitoba Hydro system's ability to accommodate a given resource type and the pace at which those resources can be added. For resources where the total and annual maximum additions to the system that can be accommodated is uncertain, attention was paid during analysis to ensure model limits were appropriately impacting the solution.

Resource type information is provided for each modelled resource option to give additional context around the relevant modelling constraints or capabilities that apply to the representation of a resource option. Resource option types available in the modelling are limited to the following, and all resource options included in the model must be represented using one of these types:

- **Hydropower Generators.** Key Parameters: installed capacity, associated inflows, associated reservoirs, reservoir hydraulic inputs, and reservoir operating constraints, power generation characteristics, maintenance and outage assumptions, and variable operating and maintenance costs. The model optimizes generation.
- **Thermal Generators.** Key Parameters: installed capacity, associated fuel(s), fuel costs, fuel limits, specific consumptions, GHG emissions characteristics and costs, maintenance and outage assumptions, and variable operating and maintenance costs. The model optimizes generation. Thermal generators can be used to represent any generator that produces electricity using heat energy derived from the combustion of a fuel. Fuels can include natural gas, diesel or biodiesel, biomass, or represent nuclear reactions.
- **Set-Profile Generators.** Key Parameters: installed capacity and generation profile. Generation is determined by the generation profile.
- **Batteries.** Key Parameters: Installed capacity, charge, and discharge efficiency. The model optimizes charging and discharging within a month, with no storage carryover from one month to the next.

All resource options also have accredited capacity and dependable energy inputs, investment and fixed operating and maintenance costs, and logical constraints defining the circumstances under which they can be added to the system. Each resource option can be represented as either a binary, integer, or continuous project. The characteristics of each project type are as follows:

- **Binary Project:** Only one instance of this project can be built.
- **Integer Project:** Multiple instances of this project can be built.
- **Continuous Project:** This type of project can only be built once, but it is possible to build only a portion of the project (i.e., anywhere from 0% to 100% of the installed capacity specified). Portions of the project can be built across multiple years throughout the study. The total amount of installed capacity for each increment of the project installed by the end of the study cannot exceed 100%.

7.2. Wind Generation

Modelled Resource Type: Set-Profile.

Generation Simulation Methodology: A generation profile is specified by month and by block and does not vary in response to simulated system operations.

Unit Representation and Availability: Eight wind units are available in the model, as shown in Table A7.1.3. This representation uses multiple wind units to capture:

1. Increasing transmission costs to accommodate increased amounts of wind installed in the system.
2. Decreasing firm capacity accredited to wind with increasing amounts of wind installed within the system.

Wind accreditation was based on an analysis of historical hourly wind generation that assessed reductions in peak demand caused by varying wind supply levels for an assumed level of system reliability.

Table A7.1.3 – Modelled Wind Resource Options

Project Name	Project Type	Installed Capacity [MW]	Accredited Firm Utilization Factor [%]
Wind 1	Binary	100	20%
Wind 2	Binary	100	20%
Wind 3	Binary	100	20%
Wind 4	Binary	100	20%
Wind 5	Binary	100	20%
Wind 6	Continuous	200	20%
Wind 7	Continuous	1,800	4%
Wind 8	Continuous	3,500	1%

To ensure that the accredited capacity from retiring wind projects is properly allocated to new ones, Manitoba Hydro assigns the accredited capacity of St. Leon to Wind 1 and the accredited capacity of St. Joseph to Wind 2. This means that when the St. Leon agreement retires, its accredited capacity will transfer to Wind 1, and when the St. Joseph agreement retires, its accredited capacity will transfer to Wind 2. As a result, Wind 1 can come into service as of the earliest in-service date for new wind in 2032 as this is after the St. Leon agreement ends, while Wind 2 can only come into service after the St. Joseph agreement ends in 2039.

For all scenarios and sensitivities based off resource option strategy C, the earliest in-service dates for wind projects were adjusted as follows:

- First tranche of 200 MW of installed capacity: 2029 (obligatory project)
- Second tranche of 200 MW of installed capacity: 2031 (obligatory project)
- Third tranche of 200 MW of installed capacity: 2033 (obligatory project)
- Any wind greater than 600 MW of installed capacity: 2032 (optional additional wind)

Constraints: Total and annual wind build limits are provided in Table A7.1.4. Constraints requiring the sequential build of wind units are also applied to encourage efficient optimization by the model. However, increasing capital costs and decreasing accredited firm capacity for wind units inherently enforce the sequential selection of wind projects.

Table A7.1.4 – Modelled Wind Constraint

Constraint	Type	Value [MW]
Total Build Limit	Total Installed Capacity, Maximum	6,000
Annual Build Limit	Incremental Installed Capacity, Maximum	600

Resource Costs: Wind generation costs are included in the model as a power purchase agreement (PPA) and are represented as a yearly fixed operating and maintenance cost ($/kW-yr) for the life of the wind farm. The wind PPA costs, system integration costs, and Investment Tax Credit (ITC) decline throughout the study period and are set based on the in-service date of new wind resources. The ITC applies only to wind built prior to 2035. Generation integration transmission costs (M$) and capital tax costs (M$/yr) are not assumed to vary through time.

Fuel Assumptions: No fuel is required.

GHG Emission Assumption: No operational GHG emissions.

7.3. Solar Photovoltaic Generation (Utility Scale)

Modelled Resource Type: Set-Profile.

Generation Simulation Methodology: A generation profile is specified by month and by block and does not vary in response to simulated system operations.

Unit Representation and Availability: Two single-axis, continuous solar units are available in the model, as shown in Table A7.1.5. This representation uses these two solar units to capture increasing transmission costs with increasing amounts of solar installed in the system.

Table A7.1.5 – Modelled Utility-Scale Solar Resource Options

Project Name	Project Type	Installed Capacity [MW]
Solar 1	Continuous	1,700
Solar 2	Continuous	1,300

Constraints: Total and annual solar build limits are provided in Table A7.1.6. No explicit constraints are used to force the build of Solar 1 prior to Solar 2, as this progression occurs automatically within the model due to the higher capital costs for Solar 2.

Table A7.1.6 – Modelled Utility-Scale Solar Resource Options

Constraint	Type	Value [MW]
Total Build Limit	Total Installed Capacity, Maximum	3,000
Annual Build Limit	Incremental Installed Capacity, Maximum	600

Resource Costs: Solar costs include capital investment (M$) and fixed operating and maintenance cost ($/kW-yr) components. Investment costs, system integration costs, and Investment Tax Credits are represented using future cost curves to reflect an expected decreasing magnitude in future years. Fixed operating and maintenance costs are held constant, as are generation integration transmission costs (M$) and capital tax costs (M$/yr).

Fuel Assumptions: No fuel is required.

GHG Emission Assumption: No operational GHG emissions.

Note: Behind-the-meter solar generation by Manitoba Hydro customers is a component of the load projections discussed in Appendix 5 – Load Projections. Behind-the-meter solar generation consumed by the customer/producer is included in the net demand used in the model, while excess behind-the-meter solar generation sold back to the Manitoba dual grid is modelled separately as a set-profile generator.

7.4. Market Capacity Imports

Modelled Resource Type: Thermal.

Generation Simulation Methodology: Generation during system simulation is optimized by the production costing module of the capacity expansion optimization model. Generation by this resource represents importing energy under a Capacity Purchase agreement and is limited to the 7x4 (peak 4-hour period, every weekday) period for which firm energy is assumed to be available as a component of the Capacity Purchase. The cost of generation is set to equal the cost of importing energy from the MISO energy market in a given block, month, and year.

Unit Representation and Availability: The types and number of units representing market purchases available in the model are presented in Table A7.1.7.

Table A7.1.7 – Modelled Capacity Purchases

Project Name	Type & Number	Installed Capacity [MW]
Capacity Purchase	Integer	25

Constraints: Total build limits are provided in Table A7.1.8. Note that the total build limit allows for additional capacity purchases to be selected up to 50 MW once the total nominal capacity in effect drops below 50 MW, which can occur when a previous capacity purchase ends after 5 years.

Table A7.1.8 – Modelled Capacity Purchase Constraints

Constraint	Type	Value [MW]
Total Build Limit	Total Installed Capacity, Maximum	50

Resource Costs: The investment cost of a capacity purchase is represented as a fixed operating and maintenance costs ($/kW-yr) and is assumed to be constant through time. This cost is set to be 20% above the cost of an aeroderivative combustion turbine, to enforce a preference for Manitoba-based capacity solutions over market solutions. As noted, any energy associated with the capacity purchase is assumed to incur additional variable costs equal to the cost of importing energy from the MISO market.

Fuel Assumptions: Market capacity imports are modelled similar to import markets, using a thermal generator resource type. Fuel costs and heat rates are calibrated to reflect MISO energy market prices. Generation is restricted to the 7x4 on-peak period for which the provision of firm energy is provided as part of a capacity import purchase.

GHG Emission Assumption: No operational GHG emissions. Net incremental regional (non-MB) electricity generation GHG emissions are calculated based on all export and import activity, which is accounted for during post-processing.

7.5. Natural Gas Combustion Turbines

Modelled Resource Type: Thermal.

Generation Simulation Methodology: Optimized by the production costing module of the capacity expansion optimization model. See the fuel-fired generation description in the Existing Electric System section of this appendix for further details.

Unit Representation and Availability: The types and number of natural gas units available in the model are presented in Table A7.1.9.

Table A7.1.9 – Modelled Natural Gas Resource Options

Project Name	Type & Number	Installed Capacity [MW]
CT-NG	Binary: 4; Integer: 1	248
CCCT-NG	Binary: 2; Integer: 1	382
Aeroderivative	Integer: 1	48

Constraints: Four natural-gas simple cycle gas turbines (CT-NGs) and two natural-gas combined cycle gas turbine (CCCT-NGs) binary units are used to represent options at an available brownfield site and have lower fixed operating and maintenance costs and associated transmission costs than the CT-NG and CCCT-NG integer units. Constraints are in place that relate the binary CT-NGs to matching CCCT-NG options as applicable, covering the available configurations that could be selected at the brownfield site. No explicit constraints are applied requiring expansion at the brownfield site prior to selecting the integer CT-NG unit since the model will make the most economic choice between these options. The aeroderivative integer project is not included as a possible candidate at the brownfield site. This assumption reduces modelling complexity while reflecting that the relatively higher levelized cost of capacity for aeroderivative units means they are unlikely to be preferentially selected as one of the first natural gas combustion turbine options. Constraints on the combined additions of CT-NG, CCCT-NG, aeroderivative, natural gas combined cycle combustion turbines with carbon capture and sequestration (CCCT-CCS), and biodiesel combustion turbines (CT-BD) units are provided in Table A7.1.10.

Table A7.1.10 – Modelled Combustion Turbine Constraints

Constraint	Type	Value [MW]
Total Build Limit	Total Installed Capacity, Maximum	10,000
Annual Build Limit	Incremental Installed Capacity, Maximum	800

Resource Costs: The investment cost of a capacity purchase is represented as a fixed operating and maintenance costs ($/kW-yr) and is assumed to be constant through time. This cost is set to be 20% above the cost of an aeroderivative combustion turbine, to enforce a preference for Manitoba-based capacity solutions over market solutions. As noted, any energy associated with the capacity purchase is assumed to incur additional variable costs equal to the cost of importing energy from the MISO market.

Fuel Assumptions: Forecasted natural gas prices ($/MMBTU) are used to determine fuel costs. Additional fuel transportation costs, as well as carbon pricing ($/t$CO_2$) costs, are also applied. Natural gas fuel supply is assumed to be unlimited. Natural gas transportation costs ($/yr/MW) are assumed to apply based on a tiered costing system, with costs increasing as more natural gas combustion turbines are installed. Due to modelling limitations and complexities, these costs are applied during the post-processing of modelling results only. When calculating the tiered costs, the total nominal capacity installed for each of the following groupings is considered: CT-NG and aeroderivative units, CCCT-NG units, and CCCT-CCS units.

All natural-gas-fuelled combustion turbines are assumed to have biomethane as an available alternative fuel that produces no net GHG emissions. This fuel is conservatively priced at a constant $40/MMBTU CAN$ throughout the study horizon and assumes an biomethane credit framework is in place. The production costing optimization determines when biomethane fuel is used instead of natural gas, balancing higher fuel costs with the avoidance of GHG emissions.

GHG Emission Assumption: Direct operational GHG emissions are produced at a rate of 0.054 tCO_2e per MMBTU input for generation from all natural-gas-fueled units. Limits on GHG emissions from natural-gas-fuelled generation from CT-NG, CCCT-NG, and aeroderivative units are controlled through an GHG emission constraint. When combustion turbine generation uses biomethane fuel credits, no GHG emissions are produced that count towards the GHG emissions limit.

7.6. Natural Gas Combined Cycle Combustion Turbines with Carbon Capture & Sequestration

Modelled Resource Type: Thermal.

Generation Simulation Methodology: Generation during system simulation is optimized by the production costing module of the capacity expansion optimization model. See the fuel-fired generation description in the Existing Electric System section of this appendix for further details.

Unit Representation and Availability: The types and number of natural gas combined cycle combustion turbine units with carbon capture and sequestration (CCCT-CCS) available in the model are presented in Table A7.1.11.

Table A7.1.11 – Modelled Natural Gas Combustion Turbine with Carbon Capture and Sequestration Resource Options

Project Name	Type & Number	Installed Capacity [MW]
CCCT-CCS	Integer	344

Constraints: CCCT-CCS projects are not included as possible candidates for the brownfield combustion turbine site. This is a modelling simplification. CCCT-CCS units are included in the total and annual build constraints described in Table A7.1.10. These constraints include an annual total build limit of 10,000 MW of installed capacity, and an annual build limit of 800 MW of incremental installed capacity.

Resource Costs: Future cost curves define declining future investment costs (M$) for CCCT-CCS projects. Fixed operating and maintenance costs ($/kW yr) are assumed to be constant through time, as are generation integration transmission costs (M$) and capital tax costs (M$/yr).

Fuel Assumptions: Forecasted natural gas prices ($/MMBTU) are used to determine fuel costs. Additional fuel transportation costs and GHG emissions costs ($/t$CO_2$) are also applied. Natural gas fuel supply is assumed to be unlimited. Natural gas transportation costs [$/yr/MW] are also assumed to apply based on a tiered costing system, with costs increasing as more natural gas combustions turbines are installed. Due to modelling limitations and complexities, these costs are applied during the post-processing of modelling results only. When calculating the tiered costs, the total nominal capacity installed for CT-NG, CCCT-NG, Aeroderivative, and CCCT-CCS units is considered.

GHG Emission Assumption: Direct operational GHG emissions are produced at a rate of 0.0054 tCO_2e per MMBTU input for CCCT-CCS units, assuming a capture rate of 90% of all GHG emissions. Limits on GHG emissions from CCCT-CCS units are controlled through a GHG emissions constraint, which specifies the total net GHG emissions permitted from these and other contributing electricity generation units.

7.7. Biodiesel Combustion Turbines

Modelled Resource Type: Thermal.

Generation Simulation Methodology: Generation during system simulation is optimized by the production costing module of the capacity expansion optimization model. See the fuel-fired generation description in the Existing Electric System section of this appendix for further details.

Unit Representation and Availability: The types and number of biodiesel combustion turbines available in the model are presented in Table A7.1.12.

Table A7.1.12 – Modelled Biodiesel Resource Options

Project Name	Type & Number	Installed Capacity [MW]
SCGT-BD	Binary: 4	248

Constraints: Biodiesel combustion turbines (CT-BD) are not included as possible candidates for the brownfield combustion turbine site as a modelling simplification. CT-BD units are included in the total and annual build constraints described in Table A7.1.10. These constraints include a total build limit of 10,000 MW of installed capacity, and an annual build limit of 800 MW of incremental installed capacity.

Resource Costs: Future cost curves define declining future investment costs (M$) for biodiesel combustion turbine options. Fixed operating and maintenance costs ($/kW-yr) are assumed to be constant through time, as are generation integration transmission costs (M$) and capital tax costs (M$/yr).

Fuel Assumptions: As discussed in Appendix 5 – Load Projections, biodiesel fuel supply is assumed to be limited based on the amount of fuel that could reasonably be produced within Manitoba with minimal disruption to established export markets for the required agricultural inputs (e.g., oilseed crops). Biodiesel fuel supply limits result in a maximum of four biodiesel generators that can be added to the Manitoba Hydro system, where each is assumed to be able to dispatch up to a maximum of 168 hours per year (1.92% utilization factor). A fuel cost forecast ($/MMBTU) was developed specifically for biodiesel.

All CT-BD units are assumed to have biomethane as an available alternative fuel that also produces no GHG emissions. This fuel is conservatively priced at a constant $40/MMBTU CAN$ throughout the study horizon and assumes an biomethane credit framework is in place. An additional cost is associated with the use of biomethane fuel during production costing optimization to require the use of all available biodiesel fuel prior to biomethane operation. These costs do not appear in the model's cost outputs. biomethane is not available as an alternative fuel under resource options strategy D.

GHG Emission Assumption: No operational GHG emissions are associated with biodiesel combustion turbines, regardless of whether biodiesel or biomethane fuel is used.

7.8. Hydrogen-Fuelled Combustion Turbines

Modelled Resource Type: Hydrogen Turbine – Thermal; Electrolyzer – Set-Profile Generator.

Generation Simulation Methodology: The dispatch of hydrogen-fuelled simple cycle turbine (CT-H2) and combined cycle turbine (CCCT-H2) generation is optimized during system simulation by the production costing module of the capacity expansion optimization model. See the fuel-fired generation description in the Existing Electric System section of this appendix for further details.

The electrolyzer, which uses electricity to produce hydrogen, results in a load to be met by the system (similar to charging a battery). This is represented using a set-profile generator that acts as a load, where the generation profile is specified for each month and block and does not vary in response to simulated system operations. Electrolyzer operation is assumed to occur at a constant level from April through September. It is set based on producing the total required hydrogen fuel needed to operate the associated turbine unit at its defined utilization factor.

Unit Representation and Availability: The types and number of CT-H2 and CCCT-H2 units available in the model are presented in Table A7.1.13. The CT-H2 and CCCT-H2 unit concepts includes a thermal generator to represent electrical generation from hydrogen fuel and an associated set-profile generator that acts as a negative load to represent electrolysis energy demands on the system. CT-H2 units with varying utilization factors are modelled to reflect the increasing number of generation hours required to provide incrementally more accredited winter capacity to the system.

Table A7.1.13 – Modelled Hydrogen-Fuelled Resource Options

Project Name	Installed Capacity (MW)	Average Annual Utilization Factor	Type & Number	Accredited Capacity [%] Summer/ Winter	Dependable Energy Factor [%] Summer/ Winter
CT-H_2 Generators	248	2%	11 Binary Units	0% / 100%	0% / 3.6%
CT-H_2 Generators	248	4%	13 Binary units	0% / 100%	0% / 7.2%
CT-H_2 Generators	248	8%	1 Binary Unit	0% / 100%	0% / 14.5%
CCCT-H_2 Electrolyzers	32	50%*	11 Binary Units	-100% / 0%	-100% / 0%
CCCT-H_2 Electrolyzers	64	50%	13 Binary units	-100% / 0%	-100% / 0%
CCCT-H_2 Electrolyzers	129	50%	1 Binary Unit	-100% / 0%	-100% / 0%
CCCT-H_2 Generators	382	12%	1 Binary Unit	0% / 100%	0% / 22%
CCCT-H_2 Generators	382	15%	1 Binary Unit	0% / 100%	0% / 29%
CCCT-H_2 Generators	382	19%	1 Binary Unit	0% / 100%	0% / 36%
CCCT-H_2 Electrolyzers	192	50%	1 Binary Unit	-100% / 0%	-100% / 0%
CCCT-H_2 Electrolyzers	256	50%	1 Binary Unit	-100% / 0%	-100% / 0%
CCCT-H_2 Electrolyzers	320	50%	1 Binary Unit	-100% / 0%	-100% / 0%

*50% represents 100% utilization factor over the summer period, from April through September.

Constraints: Constraints in the model on the selection of hydrogen-fueled combustion turbines are provided in Table A7.1.14. Precedence constraints specifying the order of the 2% and 4% CT-H2 and CCCT-H2-type units are included in the model to improve computational efficiency. The maximum amount of new nominal capacity added to the system from 2% and 4% CT-H2 units is limited to 3,225 MW, or 13 units total across the two utilization factor types. This ensures the applicability of firm capacity accreditation assumptions with increasing levels of hydrogen generation in the system.

Table A7.1.14 – Modelled Hydrogen-Fueled Combustion Turbine Constraints

Constraint	Type	Value [MW]
Total Build Limit (2% and 4% Projects only)	Total Installed Capacity, Maximum	3,225
Annual Build Limit	Incremental Installed Capacity, Maximum	800
CT-H2 2% Project Build Order	Precedence	In sequential order
CT-H2 4% Project Build Order	Precedence	In sequential order

Resource Costs: Future cost curves define declining future investment costs (M$) for hydrogen resource options. Fixed operating and maintenance costs ($/kW yr) are assumed to stay constant through time, as are generation integration transmission costs (M$) and capital tax costs (M$/yr). The investment costs and fixed operating and maintenance costs increase as the assumed utilization factor of the unit increases.

Fuel Assumptions: Electrolysis is represented as a set-profile generator acting as a negative load, requiring increased generation from other resources in the system from April through September. This ensures that hydrogen fuel is available for use to meet increased demand during the winter months. The cost for meeting the electrolyzer load is embedded within the total system operating costs.

The same hydrogen fuel supply assumptions used to define the summer electrolysis load are applied to hydrogen-fuelled combustion turbine generation. The total amount of hydrogen fuel available corresponds to the total energy production expected for the unit, based on its assumed installed capacity and utilization factor. The fuel produced by electrolyzers is assumed to be available to the hydrogen turbines at no additional cost.

The availability of hydrogen fuel assumed for each type of hydrogen unit, based on its average annual utilization factor, is outlined Table A7.1.15. For 2%, 4%, and 8% utilization factor units, it is assumed that 50% of available hydrogen fuel is used in January, while 25% is used in February and 25% is used in December. This reflects anticipated use of hydrogen units to meet peak winter demand. Units with utilization factors of 12% or more provide energy in additional months.

Fuel availability assumptions are required due to functional limitations within the model. While the amount of fuel available per month must be pre-specified, the per-block use of this fuel for hydrogen generation is optimized by the model. However, fuel supply cannot be carried over to another month. It is further assumed that hydrogen-fueled combustion turbines can only operate up to a maximum of 12 hours per day, which can further restrict generation and fuel allocation in a given month for higher utilization factor units.

Table A7.1.15 – Hydrogen Fuel Availability Assumptions

Utilization Factor	Month	% of Fuel Allocated	Constrained by Available Hours of Operation per Month
2%, 4%, & 8%	January	50%	No
2%, 4%, & 8%	February	25%	No
2%, 4%, & 8%	December	25%	No
12%	January	37%	Yes
12%	February	32%	No
12%	December	32%	No
15%	January	28%	Yes
15%	February	25%	Yes
15%	March	11%	No
15%	November	11%	No
15%	December	25%	Yes
19%	January	22%	Yes
19%	February	20%	Yes
19%	March	19%	No
19%	November	19%	No
19%	December	20%	Yes

GHG Emission Assumption: No operational GHG emissions.

7.9. Biomass Generation

Modelled Resource Type: Thermal

Generation Simulation Methodology: Generation during system simulation is optimized by the production costing module of the capacity expansion optimization model. See the fuel-fired generation description in the Existing Electric System section of this appendix for further details.

Unit Representation and Availability: Two biomass thermal generator options are available in the model, as outlined in Table A7.1.16.

Table A7.1.16 – Modelled Biomass Resource Options

Project Name	Installed Capacity (MW)	Type & Number	Average Annual Utilization Factor
Biomass 2%	32	Integer	2% (peaker operation)
Biomass 83%	32	Integer	83%

Constraints: Constraints applied to the modelled biomass and Biomass Generation with Carbon Capture & Sequestration (BECCS) projects are summarized in Table A7.1.17. These total build limits assume base-loaded dispatch of biomass and BECCS generators at their stated utilization factors, with a combined limit on the addition of biomass and BECCS generators dictated by the available supply of biomass fuel.

Table A7.1.17 – Modelled Biomass Constraints

Constraint	Participating Projects	Type	Value [MW]
Total Build Limit	Biomass 83%, BECCS	Total Installed Capacity, Maximum	90
Total Build Limit	Biomass 2%	Total Installed Capacity, Maximum	1,051

Resource Costs: Biomass generator costs include capital investment (M$) and fixed operating and maintenance cost ($/kW yr) components. Investment costs and Investment Tax Credits are represented using future cost curves to reflect an expected decreasing magnitude in future years. Fixed operating and maintenance costs are held constant, as are generation integration transmission costs (M$) and capital tax costs (M$/yr).

Fuel Assumptions: Biomass fuel costs are assumed to be constant throughout the study period. The 2% average annual utilization factor unit (peaker unit) is assumed to run in January only and fuel is available only during this month. Block-level dispatch of the unit within January is optimized by the model. The 83% average annual utilization factor unit assumes no monthly limits on fuel availability and dispatch of this unit is based on model optimization. Fuel supply limitations for this unit are instead captured by enforcing total build limits on biomass units, as outlined above in Table A7.1.17. These limits ensure that biomass and BECCS generators built in Manitoba can be supported by biomass fuel production within the province, without competing with the established primary uses of the feedstock in Manitoba.

GHG Emission Assumption: No operational GHG emissions.

7.10. Biomass Generation with Carbon Capture & Sequestration

Modelled Resource Type: Thermal.

Generation Simulation Methodology: Generation during system simulation is optimized by the production costing module of the capacity expansion optimization model. See the fuel-fired generation description in the Existing Electric System section of this appendix for further details.

Unit Representation and Availability: One biomass generation with carbon capture & sequestration (BECCS) option is available in the model, as outlined in Table A7.1.18.

Table A7.1.18 – Modelled BECCS Resource Option

Project Name	Installed Capacity (MW)	Type & Number	Average Annual Utilization Factor
BECCS	32	Integer	83%

Constraints: Constraints applied to the modelled biomass and Biomass Generation with Carbon Capture & Sequestration (BECCS) projects are summarized in Table A7.1.17. These total build limits assume base-loaded dispatch of biomass and BECCS generators at their stated utilization factors, with a combined limit on the addition of biomass and BECCS generators dictated by the available supply of biomass fuel.

Resource Costs: BECCS generator costs include capital investment (M$) and fixed operating and maintenance cost ($/kW yr) components. Investment costs and Investment Tax Credits are represented using future cost curves to reflect an expected decreasing magnitude in future years. Fixed operating and maintenance costs are held constant, as are generation integration transmission costs (M$) and capital tax costs (M$/yr).

Fuel Assumptions: Biomass fuel costs are assumed to be constant throughout the study period. There are no assumed monthly limits on fuel availability for BECCS units and dispatch is based on model optimization. Fuel supply limitations are instead captured be enforcing total build limits on biomass and BECCS units together, as outlined in Table A7.1.17. These limits ensure that biomass and BECCS generators built in Manitoba can be supported by biofuel production within the province, without competing with the established primary uses of the feedstock in Manitoba.

GHG Emission Assumption: BECCS generation produces negative GHG emissions that can be used to offset other electricity generation GHG emissions from the Manitoba Hydro system under a net-zero grid constraint. BECCS units are assumed to have a 95% capture rate, resulting in the production of negative GHG emissions at a rate of -0.046 tCO_2e per MMBTU. It is further assumed that surplus negative GHG emissions produced in Manitoba, beyond what is required to net out electric generation GHG emissions in the province, can be sold for revenue at the assumed GHG emissions price. A 32 MW BECCS unit is assumed to be able to produce net negative GHG emissions of 220 thousand tonnes of CO_2 per year when operating at full load (i.e., 83% annual utilization factor).

7.11. Hydropower Generation

Modelled Resource Type: Hydropower

Generation Simulation Methodology: Generation is based on the use of a mean production coefficient ($MW/m^3/s$). Conawapa and the hydropower supply side enhancement (Long Spruce SSE) projects have more detailed design characteristics available. See the hydropower discussion description in the Existing Electric System section of this appendix for further details.

Unit Representation and Availability: Available new hydropower resource options included in the resource options model are provided in Table A7.1.19. Refer to Appendix 6 – Resource Options for additional detail.

Table A7.1.19 – Modelled Hydropower Generation Resource Options

Project Name	Project Type	Installed Capacity [MW]
Pointe 4 Unit	Binary, Pointe du Bois Supply Side Enhancement	26*
Long Spruce 1 Unit	Binary, 1-Unit Lower Nelson Supply Side Enhancement	25 *
Long Spruce 2 Units	Binary, 3-Unit Lower Nelson Supply Side Enhancement	77 *
Kettle 1 Unit	Binary, 3-Unit Lower Nelson Supply Side Enhancement	77 *
Long Spruce 4 Units	Binary, 7-Unit Lower Nelson Supply Side Enhancement	179 *
Kettle 3 Units	Binary, 7-Unit Lower Nelson Supply Side Enhancement	179 *
Bladder	Binary, New Hydropower Generation	510
Conawapa	Binary, New Hydropower Generation	1,485
Early Morning	Binary, New Hydropower Generation	80
First Rapids	Binary, New Hydropower Generation	210
Gillam Island	Binary, New Hydropower Generation	1,080
Kepuche	Binary, New Hydropower Generation	210
Manasan – Low Head	Binary, New Hydropower Generation	90
Manasan	Binary, New Hydropower Generation	280
Notigi	Binary, New Hydropower Generation	120

*Nominal capacity reported is based on increases to winter accredited capacity.

Constraints: Modelling constraints applied to the hydropower generation resource options are summarized in Table A7.1.20. Additionally, Long Spruce, Kettle, and Pointe du Bois supply side enhancement units are required to respect the same minimum generation constraint as the existing Long Spruce, Kettle, and Pointe du Bois units.

Table A7.1.20 – Modelled Hydropower Generation Constraints

Projects Included	Type
Manasan, Manasan Low Head	Mutually Exclusive
Manasan, Kepuche	Mutually Exclusive
Long Spruce 2 Units, Kettle 1 Unit	Associated Projects
Long Spruce 4 Units, Kettle 3 Unit	Associated Projects
Lower Nelson 1-Unit SSE projects, **Lower Nelson 3-Unit SSE projects,** **Lower Nelson 7-Unit SSE projects**	Mutually Exclusive

Note: Associated Projects constraints require all listed projects to be selected, whereas Mutually Exclusive constraint allow only one of the listed projects to be selected.

Resource Costs: Conawapa and Notigi use future cost curves to reflect increasing capital costs over time, with both investment costs ($M) and fixed operating and maintenance costs ($/kW-yr) varying by study year. All other hydropower options assume static costs, including generation integration transmission costs (M$) and capital tax costs (M$/yr).

Fuel Assumptions: Inflows serve as the "fuel" for hydropower generation. Inflows (m^3/s) are multiplied by a mean production coefficient ($MW/m^3/s$) to determine generation. For Conawapa and the Hydropower SSE options, the conversion of inflow to electrical energy involves varying turbine efficiency and elevation difference across the hydropower station. See the Hydropower discussion in the Existing Electric System section for further details.

GHG Emission Assumption: No operational GHG emissions.

7.12. Small Modular Reactors

Modelled Resource Type: Thermal.

Generation Simulation Methodology: All small modular reactors (SMR) options are assumed to be base loaded with a 90% average annual utilization factor. They are modelled as must-run units operating at a 100% utilization factor with an outage in September and October for maintenance.

Unit Representation and Availability: Three SMR units are modelled, as outlined in Table A7.1.21. The SMR 77-1 unit is assumed to be sited closer to existing transmission and thus has reduced generation integration transmission costs and fixed operating and maintenance costs.

Table A7.1.21 – Modelled Small Modular Reactor Resource Options

Project Name	Capacity (MW)	Type & Number	Siting Assumptions
SMR 77-1	77	Binary	Near Existing Transmission
SMR 77-2	77	Integer	Greenfield
SMR 300	300	Integer	Greenfield

Constraints: Total and annual SMR build limits are provided in Table A7.1.22.

Table A7.1.22 – Modelled SMR Constraints

Constraint	Type	Value [MW]
Total Build Limit	Total Installed Capacity, Maximum	2,000
Annual Build Limit	Incremental Installed Capacity, Maximum	900

Future Cost Curves: All costs, including investment (M$), fixed operating and maintenance cost ($/kW yr) costs, generation integration transmission costs (M$), and capital tax costs (M$/yr) are assumed to stay constant through time.

Fuel Assumptions: Constant fuel costs are assumed. Information is not readily available on future projections of nuclear fuel costs.

GHG Emission Assumption: No operational GHG emissions.

7.13. Battery Storage

Modelled Resource Type: Battery.

Generation Simulation Methodology: Battery charging and discharging is determined at the block level and is based on system optimization. Due to model limitations, the net generation across any given month is 0 GWh, as the battery must start and end each monthly time step with the same amount of energy in storage.

Unit Representation and Availability: A single continuous battery unit is modelled using the assumptions outlined in Table A7.1.23. The battery is assumed to be operated to reduce peak demand, based on a 24 hour charge/discharge cycle, and has a 100% summer and winter accredited utilization factor. Due to charging and discharging efficiencies, the battery resource reduces overall firm energy available in the Manitoba Hydro system and has a dependable energy factor of -4% in summer and winter.

A nominal capacity of 350 MW was applied in the model, representing a useful battery size for sustainable reductions in peak demand for the Manitoba Hydro system based on the current hourly peak demand profile.

Table A7.1.23 – Modelled Battery Storage Resource Options

Assumption	Value [MW]
Installed Capacity	350 MW
Charge Efficiency	95%
Discharge Efficiency	95%

Constraints: No constraints are applied.

Resource Cost: Future cost curves define declining future investment costs (M$) and Investment Tax Credit (ITC) value (M$) for battery storage resource options. Fixed operating and maintenance costs ($/kW yr), generation integration transmission costs (M$), and capital tax costs (M$/yr) are assumed to stay constant through time.

Fuel Assumptions: No associated fuel.

GHG Emission Assumption: No operational GHG emissions.

7.14. Additional Energy Efficiency

Modelled Resource Type: Set-Profile

Generation Simulation Methodology: A generation profile is specified by month and by block and does not vary in response to simulated system operations.

Unit Representation and Availability: Additional energy efficiency programs, which are programs the model can choose above and beyond the amount of savings assumed in Efficiency Manitoba's Efficiency Plan Projection (as included in the load projections), are represented as groups of individual energy efficiency programs as explained in Appendix 6. Each group is represented as an individual resource option as listed in Table A7.1.24. Heat pump groupings include air source heat pumps (ASHP), cold-climate air source heat pumps (cc-ASHP), and ground source heat pumps (GSHP).

Table A7.1.24 – Modelled Selectable Energy Efficiency Resource Options

Project Name	Type
Residential - Home Insulation	Continuous
Residential - Energy Efficiency Assistance Program, Cold Climate Air Source Heat Pump	Continuous
Residential - Community Heat Pump, Cold Climate Air Source Heat Pump	Continuous
Residential - Air Source Heat Pumps	Continuous
Residential - Energy Efficiency Assistance Program, Ground Source Heat Pumps	Continuous
Residential - Community Heat Pump, Ground Source Heat Pumps	Continuous
Residential - Ground Source Heat Pumps	Continuous
Residential - Electric furnace with Electric Thermal Storage	Continuous
Residential - Electric furnace with Electric Thermal Storage & Cold Climate Air Source Heat Pump	Continuous
Commercial - Ground Source Heat Pumps	Continuous
Industrial - Custom Energy Solutions	Continuous

Constraints: Energy efficiency units are modelled as continuous resources with nominal capacities set at their maximum non coincident peak capacity values. Constraints are applied for each energy efficiency group, for each year of the study, to ensure that the amount of potential energy savings available to the model in each year does not exceed the market potential energy savings identified.

Resource Cost: Investment cost curves (M$) based on third party consultant market potential study are used to define program costs that change with time. Energy efficiency groups also have associated transmission and distribution cost deferral benefits, which are represented using fixed operating and maintenance ($/kW-yr) cost curves within the model. These transmission and distribution cost deferral curves vary with the annual accredited capacity achievable by each group throughout the study, which varies based on the load projection.

Fuel Assumptions: No associated fuels.

GHG Emission Assumption: No operational GHG emissions.

8 | Financial Assumptions

The following financial assumptions were used for all analyses, and are based on the Summer 2024 projections:

- Real Weighted Average Cost of Capital: 3.80%
- 2024 GDP Price Deflator: 2.6%
- 2024 Exchange Rate: 1.37 C$/US$

Note that the economic indicator calculations use gross domestic product (GDP) price deflator and exchange rates that vary annually for the entire study horizon and were also based on Summer 2024 projections.

9 | Model Outputs

The capacity expansion optimization model provides a range of outputs for analysis. Outputs with the type “Direct Output” are directly produced by the model. Outputs with the type “Calculated Output” are based on direct outputs from the model but calculated outside of the model within post-processing tools.

Expansion Plan

Type: Direct Output.

Details: Includes the timing and amount (in installed capacity) of each resource selected.

Application: Provides the basis for insights into how future system needs could be met with new resources.

Accredited Capacity and Dependable Energy

Type: Direct Output.

Details: Seasonal accredited capacity and dependable energy for each resource option, provided for each year of the study and based on the expansion plan. Can be summarized based on resource type.

Application: Accredited capacity and dependable energy output for the system (based on the expansion plan) can be compared against accredited capacity and dependable energy requirements. This helps to explain if the model has selected a new resource to meet either accredited capacity or dependable energy needs, or both. This also provides insight into the system’s overall accredited capacity and dependable energy composition and how it evolves throughout the study period.

This output can also be used to validate accredited capacity and dependable energy inputs for all resource options.

Costs and Revenue

Type: Direct Output.

Details: Includes generation capital costs (investment costs, generation interconnection costs, capital tax costs, Investment Tax Credits, system integration costs for intermittent resources, fixed operating and maintenance cost), operating costs (fuel costs, variable operating and maintenance costs, GHG emissions costs, import costs), and export revenue.

Application: Cost and revenue breakdowns highlight how resource selections contribute to the overall financial outlook for the system. They aid in interpreting the model's resource selection decisions, by providing insight into the balance between economics and the obligation to meet planning requirements.

Individual cost and revenue components also enable the validation of cost inputs.

Expansion Planning Constraints

Type: Direct Output.

Details: Includes all constraints related to accredited capacity and dependable energy requirements, as well as constraints governing total and incremental installed capacity additions.

Application: Used to validate that all necessary constraints are represented in the model, and that the expansion plan solution respects these constraints as intended.

Accredited capacity and dependable energy output for the system (based on the expansion plan) can be compared against accredited capacity and dependable energy constraints. This helps to explain if the model has selected a new resource to meet either accredited capacity or dependable energy needs, or both.

Energy Generation

Type: Direct Output.

Details: Presented for each resource category, on an annual basis and averaged across 112 inflow cases.

Application: Energy generation results show how resources included in the expansion plan would be operated together within the system, and how energy contributions of various resource types may change over time.

Model Optimization Information

Type: Direct Output.

Details: Includes final optimization convergence gaps, investment cost breakdowns by unit, and operational costs including deficit and penalty costs.

Application: These results are used to validate the model's optimization of the expansion plan and to ensure model constraints are being applied appropriately and are influencing results as intended.

GHG Emissions Data

Type: Direct Output & Calculated Output.

Details: Calculated based on the annual energy generation of emitting resources (averaged across all inflow cases) and combined with GHG emission sources not reflected in the model. Total provincial GHG emissions, and net incremental regional electrical generation GHG emissions are presented to provide additional perspective.

Application: GHG emissions provide another lens for assessing the costs and benefits of an expansion plan. Provincial and regional electrical generation GHG emissions perspectives provide a more holistic view of GHG emissions outcomes and enable more meaningful comparisons between model runs.

Economic Indicators

Type: Calculated Output.

Details: Calculations combine capital and operating costs with additional cost components not represented in the model. Additional costs that are sensitivity-specific and external to the model can also be accounted for with these indicators.

Application: Economic indicators provide a broader financial context for evaluating expansion plans, enabling comparisons across model results with different load assumptions.

9.1. GHG Emissions

GHG outputs from the model, and other 2025 IRP analysis, are presented in aggregate, in terms of carbon dioxide equivalents (CO_2e). For consistency with the Government of Canada,[7] Manitoba Hydro uses Fifth Assessment Report 100-year global warming potential (GWP) values in all its GHG emissions reporting and analysis to convert all the GHGs to CO_2e. The five GHGs most relevant in Manitoba Hydro's operations are listed in Table A7.1.25, along with their 100-year GWP value.

Table A7.1.25 – 100-year GWP of Relevant GHGs

Chemical Name	Chemical Symbol	GWP_{100}
Carbon Dioxide	CO_2	1
Methane	CH_4	28
Nitrous Oxide	N_2O	265
Sulphur Hexafluoride	SF_6	23,500
Carbon Tetrafluoride	CF_4	6,630

9.1.1. GHG Emissions Data

GHG Emissions Data summarizes the projected GHG emission implications associated with a given resource portfolio. The GHG emissions data presented in 2025 IRP, support understanding the impacts of different resource portfolios on Manitoba electricity generation GHG emissions, provincial GHG emissions, regional electricity generation GHG emissions, and embedded electricity generation GHG emissions.

The following GHG Emissions Data are available in post processed model results. While the capacity expansion optimization model accounts for GHG emissions and costs based on a simplified representation, some GHG Emission Data is re-calculated based on refined assumptions and model outputs.

GHG Emissions Data can be presented on a net basis, with negative GHG emissions aggregated into the total, or on a gross basis, with negative GHG emissions excluded or presented separately.

Manitoba Electricity Generation GHG Emissions

Manitoba electricity generation GHG emissions (tCO_2e) provide information on direct GHG emissions from Manitoba based, grid connected, electricity generation resources. The shorthand for this metric is "MH – Generation Emissions".

[7] *https://www.canada.ca/en/environment-climate-change/services/climate-change/greenhouse-gas-emissions/quantification-guidance/global-warming-potentials.html*

Manitoba GHG Emissions

Manitoba GHG emissions (tCO_2e) are presented in two formats: all GHG emission sources in the province and only GHG emissions resulting from fossil fuel combustion.[8] Manitoba GHG emissions are estimated based on the assumptions underlying each load projection as well as estimates of future electricity generation GHG emissions, based on modelling output. Provincial GHG emissions estimation methodologies and assumptions are discussed in Appendix 5 – Load Projections.

Net Incremental Regional Electricity Generation GHG Emission

Net incremental regional electricity generation GHG emissions (tCO_2e) presents a broader GHG emissions perspective that estimates the net incremental impact of Manitoba Hydro's system operations on the regional electricity generation sector. This data considers incremental GHG emission effects from fossil-fuel electricity generators in the U.S., Ontario, and Saskatchewan, in addition to GHG emissions from all of Manitoba Hydro's fossil-fuel generators. The flow of electrical energy across Manitoba's interconnections influences the amount of electricity produced by fossil fuel generators outside of Manitoba's borders and, also influences corresponding GHG emissions.

For example, if Manitoba Hydro's annual hydroelectric generation exceeds Manitoba's needs, surplus hydroelectric energy can be exported to MISO and some fossil fuel generators in MISO may reduce their annual output accordingly.[9] Backing down these fossil fuel generators with surplus hydroelectricity avoids[10] GHG emissions, as extra-provincial electrical energy needs are then met with less emitting generation resources than would have occurred in the absence of exported surplus hydroelectricity. In this example, the net incremental regional electricity generation GHG emissions output estimates the GHG emissions impact of that incremental change in extra-provincial fossil fuel generator output, net of any Manitoba electricity generation GHG emissions. If in a particular modelling result, Manitoba electricity generation GHG emissions are lower but dependence on imported electricity increases, the result could be a net incremental increase in regional electricity generation GHG emissions. The regional GHG emissions perspective reflects Manitoba's and Manitoba Hydro's impact on GHG emissions in the electricity generation sector outside of the province.

[8] A description of categories of provincial GHG emissions is included in Appendix 3 – Existing System

[9] Manitoba Hydro cannot claim the corresponding GHG emission reductions, they are attributed to MISO utilities.

[10] Note: Avoided GHG emissions are not negative GHG emissions.

Net Incremental Regional (non-MB) Electricity Generation GHG Emissions

Net incremental regional (non-MB) electricity generation GHG emissions (tCO_2e) presents the broader regional impact without netting in Manitoba electricity generation GHG emissions. In some instances, it can be useful to isolate the impact outside of Manitoba. Though Manitoba electricity generation GHG emissions are not considered in this category, the “net” refers to the consideration of net exports (i.e., not gross exports or gross imports) in the analysis. The shorthand for this metric is “Regional (Non-MB) GHG Emissions Impact”.

If Manitoba achieves a net-zero grid, net incremental regional (non-MB) electricity generation GHG emissions will be the same as net incremental regional electricity generation GHG emissions.

9.2. Economic Indicators

Economic indicators are financial insights calculated during the post-processing of model results. These indicators combine costs and revenues considered in the model with others that are considered exogenously. The primary economic indicators calculated for each model result are listed below, followed by descriptions of each:

- Present Value (PV) of Net System Costs (M 2024 CAN$)
- Annual Net System Costs (M 2024 CAN$)
- Average Base Combined Energy Unit Requirement (2024 CAN$/GJ)

9.2.1. Present Value of Net System Costs (M CAN$)

This indicator is intended to reflect the cost to serve all firm demand net of extra provincial revenues. The indicator combines inputs from three different categories:

1. Fixed costs and revenues from the base financial projections.
2. Incremental costs associated with different load projections.
3. Variable costs and revenues from each model run.

All inputs that vary based on the development plan and/or the operation of the system are required to be modelled and therefore fit in category 3 above. The remaining inputs have no bearing on the model’s decisions and are excluded from the resource optimization. These inputs are further broken down into those that vary by load projection (category 2) and those that do not (category 1).

While the first two categories of inputs have no bearing on the model’s decision, incorporating these into the economic indicator provides a holistic view of the outcomes of an expansion plan and creates a fair basis for comparisons between analyses with different electric and gas load assumptions.

For example, a sensitivity with less reliance on natural gas space heating will show increased electrical system costs. Corresponding reductions in natural gas supply costs (external to the model) must be accounted for to understand the full implications for Manitoba Hydro, and to compare against the outcomes of sensitivities with greater reliance on natural gas space heating.

The specific cost and revenue inputs that fit into each category are as follows:

Fixed costs and revenues from base financial projections

The inputs that make up this category are:

- Revenues from signed firm export contracts;
- Operating & administrative costs (includes the Program Administration Costs for Efficiency Manitoba's Demand Side Management (DSM) projected savings);
- Net financing costs;
- Depreciation & amortization costs;
- Taxes (Capital and Other) – partial, for serving existing system;
- Fuel & power purchase costs – partial, for serving existing system;
- Revenue categorized as other;
- Costs categorized as other; and
- Additional revenue requirement – includes net income to keep financial targets whole.

Incremental costs associated with different load projections

These inputs are calculated using the different load projections for electric and natural gas demand. Some are calculated in absolute terms, while others are simply the application of marginal costs associated with the change in the underlying load projection. These costs include the following:

- Cost of gas sold;
- Marginal changes to underlying expenses for gas and electric Transmission & Distribution, encompassing:
    - Operating & Administrative costs;
    - Net financing costs;
    - Depreciation & Amortization costs; and
    - Taxes.

Variable costs and revenues output from each model run

These inputs are extracted or calculated directly from each model result. They include:

- Opportunity export revenue;
- Fixed expenses associated with new supply resources, including:
  - Capital investments and fixed operating and maintenance costs;
  - Taxes; and
  - Total Resource Costs for selectable DSM.
- Variable production costs, including:
  - Fuel costs;
  - Variable operating and maintenance costs;
  - GHG emission pricing;
  - Market purchases (opportunity imports); and
  - Water rental costs.

Net system costs are reported on a cumulative present value basis, in 2024 CAN$.

Annual Net System Costs (M CAN$)

This indicator is a real dollar amount (2024 CAN$) calculated on an annual basis and represents annual costs net of opportunity export revenues. The annual net system cost indicator is a snapshot of costs in any given year. The change in annual net system costs over time is an indicator of financial sustainability beyond the study period, assuming similar system expansion and operating trends persist. Cost and revenue components that contribute to this indicator are identical to those defined above for net system costs.

Average Base Combined Energy Unit Requirement (CAN$/GJ)

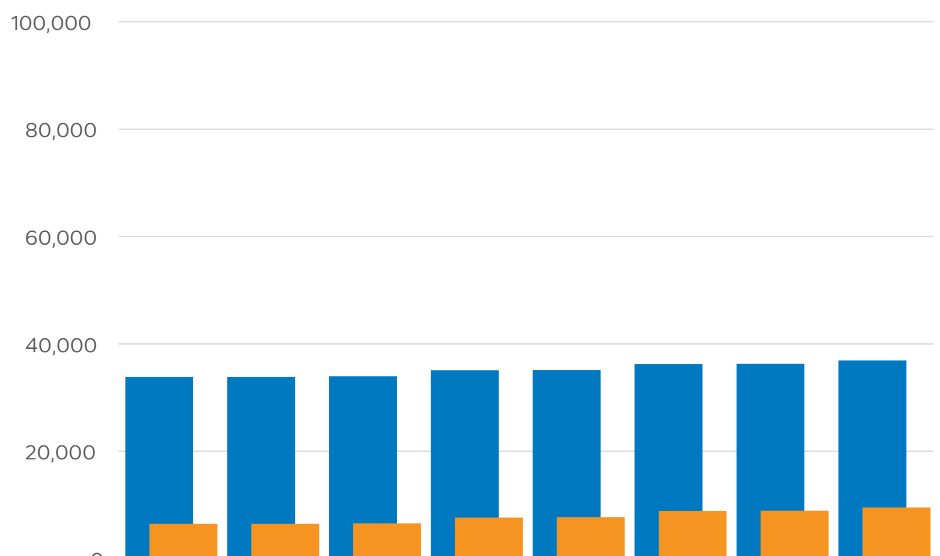
This is the average revenue required to offset the costs of supplying one unit of energy, considering electrical energy production from the system as a whole and as defined by the expansion plan and given the gas system and supply assumptions for the specific scenario or sensitivity. Total energy demand (GJ) is used as the denominator for this calculation and is calculated by converting net Manitoba electric load and gas demand into GJ. Cost and revenue components that contribute to this metric are the same as those for net system costs.

Calculation Details for Financial Indicators in the 2025 IRP

Projected net system costs (on an annual or present value basis) can be expressed either in absolute or incremental terms, as shown for illustration purposes in Figure A7.1.5 and Figure A7.1.6. When net system costs are presented as absolute values, they include the fixed costs and revenues from Manitoba Hydro's base financial projections, whereas the incremental version excludes these. Both incremental and absolute versions of net system costs include a combination of the incremental costs associated with different load projections and the variable costs and revenues output from each model run, including investment costs and system operating costs.

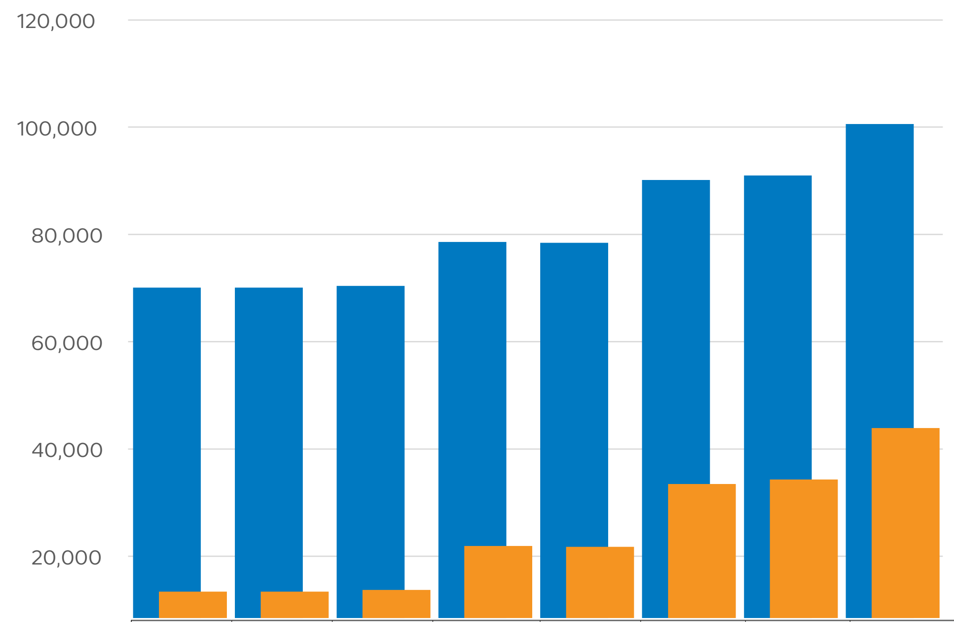
For simplicity, only incremental net system costs are presented, as they provide greater visibility of the differences in economic indicator results across cases. These differences can be overshadowed by the magnitude of the fixed costs and revenues when they are included, as they are in absolute net system costs.

All net system costs are incremented against the net system costs associated with Manitoba Hydro's 2024 Electric Load Forecast. As such, in addition to incrementing out fixed costs and revenues from the base financial forecast, there is a set level of costs associated with marginal changes to the underlying expenses for gas and electric Transmission & Distribution defined based on the 2024 Electric Load Forecast that is also incremented out.



	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Net Present Value of Net System Costs [M$]	33,883	33,881	33,952	35,049	35,131	36,274	36,322	36,903
Incremental Net Present Value of Net System Costs [M$/year]	6,494	6,491	6,562	7,659	7,741	8,884	8,932	9,513

Figure A7.1.5 - Illustrative Example of Absolute vs. Incremental Cumulative PV of Net System Costs (in 2035)



	S1A	S1B	S1C	S2B	S2C	S3B	S3C	S3D
Net Present Value of Net System Costs [M$]	70,067	70,092	70,415	78,594	78,439	90,134	90,992	100,579
Incremental Net Present Value of Net System Costs [M$/year]	13,382	13,407	13,730	21,909	21,755	33,450	34,307	43,895

Figure A7.1.6 - Illustrative Example of Absolute vs. Incremental Cumulative PV of Net System Costs (in 2050)

For the purposes of calculating net system costs for the 2025 IRP, annualized investment costs are used. Figure A7.1.7 provides an example of capital cost investments by year compared against annualized investment costs. To calculate the annualized costs, the investment capital costs for a project, defined per year by a payment schedule, are all referred to the in-service date assumed for the project based on the following formula[11]:

$$C_0 = \left(C^{inv} + \frac{C^{ele} * \omega}{1000}\right) * \sum_{n=1}^{N} \frac{p_n}{100} * (1 + t_x)^{(n^0 - n)}$$

Where:

- C^{inv} is the total investment cost of the project [M$];
- C^{ele} is the electrical system integration cost associated with incorporating the resource option into the existing electrical system [$/kw];
- ω is the installed capacity of the project [MW];
- N is the total number of investment capital cost disbursements, as indicated by the payment schedule;

[11] OptGen User Manual, Version 8.1, PSR Inc

- p_n is investment capital cost disbursement in year n [%];
- t_x is the discount factor [%]; and
- n^0 is year of entrance into operation assumed for the resource.

Once C_0 has been determined, the annualized costs are calculated as follows:

$$C_a = C_0 * \frac{t_x * (1 + t_x)^{(L-1)}}{(1 + t_x)^L - 1} + \frac{C^{o\&m} * \omega}{1000}$$

Where:

- L is the financial lifetime of the project, and
- $C^{(o\&m)}$ is the fixed operation and maintenance costs of the project [$/kw*year].

From the equations provided above, annualized investment costs for a project are dependent on numerous assumptions, including discount rate, financial lifetime, and the assumed in-service date. For example, the annualized costs shown in Figure A7.1.7 assume a 30-year financial lifetime for the project. If a different financial horizon was assumed this would change the final value of the annualized investment costs shown in the figure.

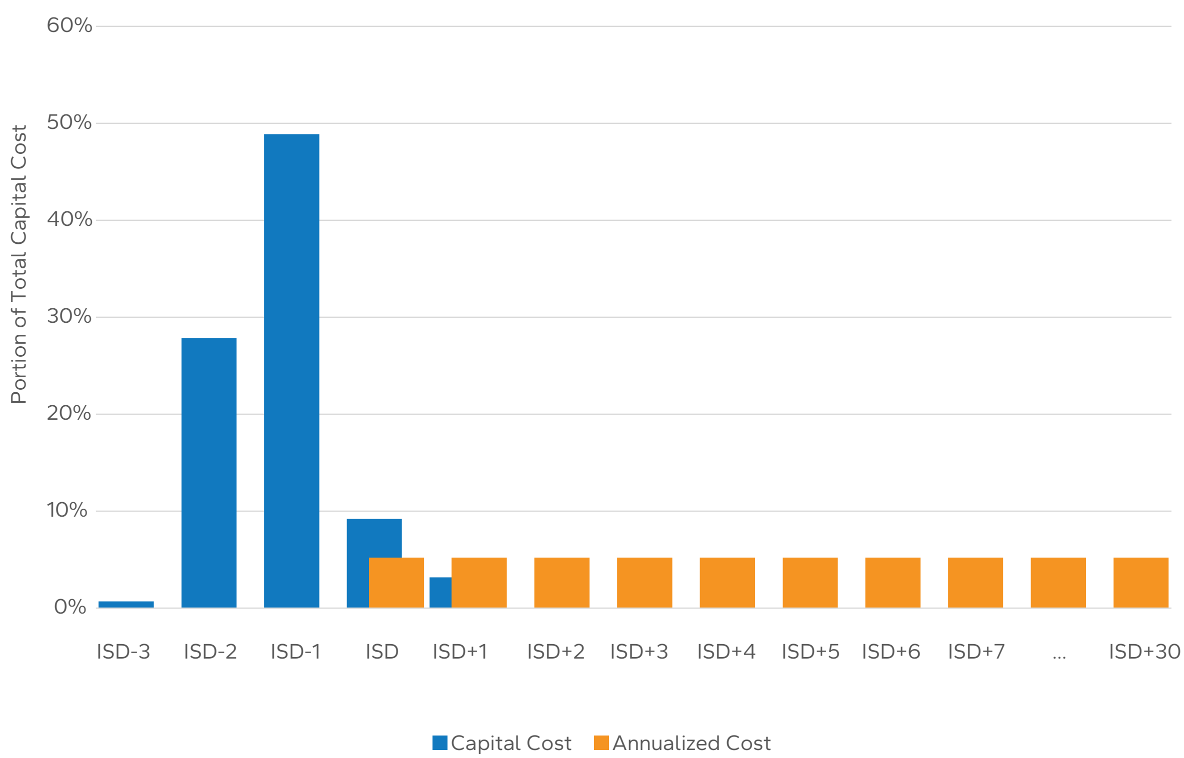


Figure A7.1.7 - Illustrative Comparison of Capital Cost Investments per Year versus Annualized Investment Costs for a Single Resource Option

Figure A7.1.7 also demonstrates that annualizing investment costs smooths out the capital requirements over the study period, resulting in equal capital costs incurred in every year included in the study horizon for which a project is in service, as opposed to potentially large capital costs incurred over a smaller number of years, typically distributed around the project's in-service date. This leads to the primary benefit of the annualization approach, which is the ability to consider equivalent proportions of investment costs and net operating expenses during analysis.

After investment costs are annualized across the financial lifetime of the project, only the annual costs incurred from the project's in-service date until the end of the study horizon are considered when calculating net system costs. In this way, only the portion of investment costs incurred during the period the resource is operating are included, matching the period for which net operating expenses associated with the project are also accounted for.

Annualized investment costs can introduce modelling noise towards the end of the study horizon if new resource options are added during at that time. Resource optimization decisions made near the end of the study horizon are based on just a few years of the new resource operating in the system, such that only a portion of the total investment and operating costs of the project are accounted for and there is no consideration for how operating costs and benefits may evolve with a changing system beyond the end of the study period. Furthermore, the capacity expansion model uses the present value of annualized costs during its optimization, which reduces the significance of capacity expansion decisions further out in the study horizon. This can all reduce confidence in specific capacity expansion modelling results at the end of the study period and requires that meaningful findings about the end of the study horizon are corroborated through trends identified across multiple cases.

10 Scenario and Sensitivity Modelling and Analysis

10.1. Modelling Methodology for Scenario Analysis

For the 2025 IRP, Manitoba Hydro analyzed four resource options strategies as detailed in Appendix 2 – 2025 IRP Development Process and summarized in Table A7.1.26.

Table A7.1.26 – 2025 IRP Resource Options Strategies

Resource Options Strategies	Assumptions
A - Technology Neutral	Compliant with federal Clean Electricity Regulations.
B - Net-Zero Grid 2035	Strategy A, plus requirement that electricity grid is net-zero by 2035.
C - Near Term Wind Generation Projects	Strategy B, plus up to 600 MW of Indigenous majority owned wind with dispatchable resources for reliability.
D – No Fossil Fuel-Based Resources	Strategy B, plus requirement of no fuel-based combustion turbines post 2035 (i.e., no natural gas combustion turbines)

Analyzing various resource options strategies potentially requires restricting some resource options, advantaging or disadvantaging some resource options, and/or locking in some resource selections within the model. All resource option strategies include Efficiency Manitoba's Efficiency Plan Projection, demand response, and curtailable rates programs. Additional energy efficiency programs were only available as a resource option in some sensitivities. Further details on each resource option strategy are as follows:

Strategy A: No adjustment to base model assumptions or the availability of resource options is required. As a result of the 25 tonne CO_2e per GWh limit base planning assumption and the assumed GHG price, application of Strategy A to the model produces development build-outs that are compliant with the draft federal Clean Electricity Regulations to 2050 (future operation of any fossil fuel-based generation resource will be compliant with the GHG emissions limits). Analysis indicates that the Regulations will have minimal impact on how Manitoba Hydro operates its system.

Strategy B: The net-zero grid constraint is achieved within the model when the rolling horizon GHG emission limit is set to 0 tonnes of CO_2e per GWh, starting in 2035.

Strategy C: When applying Strategy C, 200 MW of installed wind capacity was embedded into the model in each of 2029, 2031, and 2033, for a total of 600 MW of installed capacity.

Strategy D: The model is constrained such that it cannot select any natural gas combustion turbines, including those with carbon capture and sequestration. Existing generation units at Brandon generating station are assumed to cease operating from 2035 onwards. As biomethane is assumed to be utilized in natural gas combustion turbines via a credit system, no biomethane generation is permitted under Strategy D, including within biodiesel combustion turbines.

Scenarios represent a specific energy future in the 2025 IRP analysis. By combining a load projection and a resource options strategy, Manitoba Hydro creates a full representation of a specific energy future. Eight scenarios were developed by strategically combining the four resource option strategies with the three load projections. Only likely combinations of load projections and resource options strategies were analyzed. For the 2025 IRP, Scenarios 1A and 3D are bookends. Scenario 3D assumes the most restrictive energy policy and, on the opposite end, Scenario 1A assumes the least restrictive energy policy. The scenarios are shown in Table A7.1.27.

Table A7.1.27 – 2025 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

10.2. Ensuring Model Tractability

Each load projection represents different energy futures with different amounts of change, resulting in each electrical load projection eventually exceeding the existing system's supply of dependable energy and accredited winter capacity in a different year, as shown in Figure A7.1.8. The red lines indicate the existing electrical system's capabilities with respect to dependable energy and accredited winter capacity and including import/export agreements, while the shaded areas represent projected load growth of electricity adjusted for Efficiency Manitoba's Efficiency Plan Projections. The yellow dots indicate when the model must first add resources to ensure accredited capacity and dependable energy requirements are met. This information is based solely on model inputs and is not a modelling outcome.

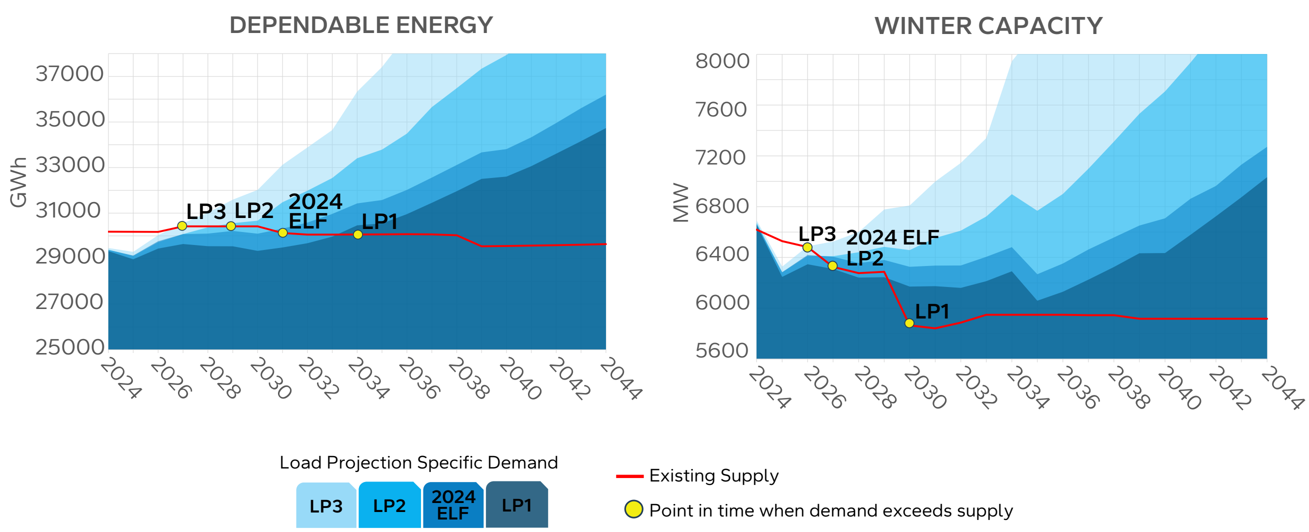


Figure A7.1.8 - Electricity Demand and Supply Comparisons Indicating when a Need for New Resources is Triggered

Table A7.1.28 summarizes the study years when the model must add new electric resources for each load projection, for both dependable energy and winter peak capacity.

Table A7.1.28 – Required First Additions of New Electricity Resources

Year	1-Baseline	2-Medium	3-High	2024 ELF
2026			Capacity	
2027		Capacity	Capacity & Energy	Capacity
2028		Capacity	Capacity & Energy	Capacity
2029		Capacity & Energy	Capacity & Energy	Capacity
2030	Capacity	Capacity & Energy	Capacity & Energy	Capacity

There can be instances, when the model must add new electric resources prior to 2030 in order to solve the capacity expansion modelling problem. There are limited resource options available that can be built and put into service in time to supply accredited capacity and dependable energy prior to 2030. This may lead to instances when faster load growth projections translate into accelerated capacity needs and accelerated energy needs that cannot be met within the model by the existing system and available resource options. An illustrative example is presented in Figure A7.1.9, where the total winter accredited capacity that can be supplied by the existing system (including imports) and potential new resource options are compared against the winter accredited capacity requirements associated with each load projection. When the load projection requirements outpace the maximum potential accredited capacity that can be supplied, an unmet capacity need exists.

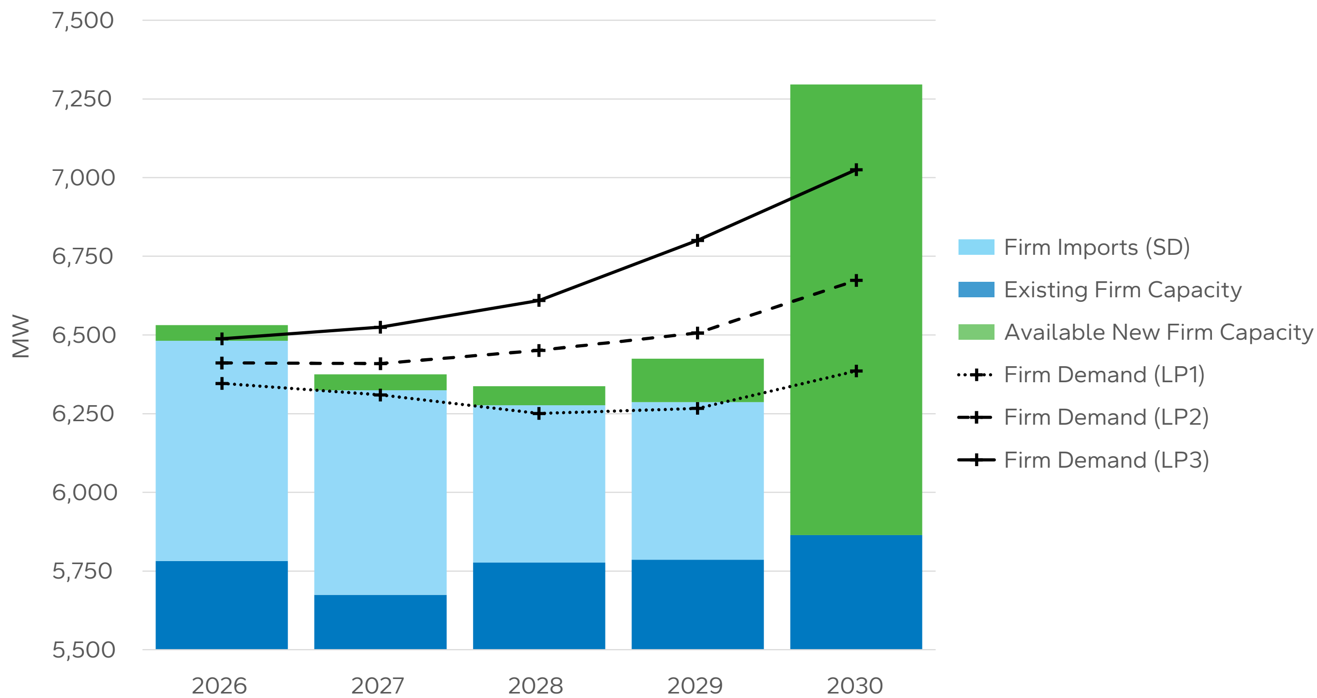


Figure A7.1.9 - Illustrative - Winter Accredited Capacity Need and Supply Potential by Study Year [MW] Winter Accredited Capacity Need and Supply Potential by Study Year [MW]

Unmet capacity and energy needs occur when the model cannot identify a portfolio of resources that meets generation planning criteria for a given year and load projection. This outcome reflects a rapid pace of load growth examined in the early years, which exceeds the ability to add resources quickly enough to meet demand.

To address unmet capacity and energy needs, three approaches can be considered:

1. Adjust the assumptions driving the load projections;
2. Revise the assumptions for resources included in the model; or
3. Apply a modelling technique that enables the model to continue optimizing for the remainder of the study period.

For the 2025 IRP neither the assumptions for the load projections or the resources in the model were adjusted. As such, modelling techniques have been applied to ensure the model can continue to optimize for the remainder of the study period when such instances may occur. In reality, any unmet capacity or energy needs before 2030 are addressed through operational planning.

Specifically, model tractability is ensured by employing a modelling technique to address times when capacity and energy needs cannot be met with available supply options. This technique uses thermal-type resources options that are exclusively for covering shortfalls in available accredited capacity or dependable energy. These resources were modelled as follows:

- The units can supply either only accredited capacity or dependable energy, (i.e., each unit can be used to either meet capacity planning requirements or energy planning requirements, ensuring a feasible model solution).
- The units were assigned punitively high investment costs to ensure actual resources are prioritized.
- Each unit has an in-service life of a single year.
- Each unit was modelled as a continuous thermal resource type (fractions of a unit can be built, perfectly matching shortfalls).
- Each unit has no fuel availability, to ensure no generation during production costing modelling.

10.3. Sensitivity Analysis

Sensitivity analysis is used to test the potential impact of an isolated assumption change on development plan results. Table A7.1.29 lists the selected sensitivities for the 2025 IRP, as well as the primary objective of each, and indicates the range of load projections and resource option strategies that were modelled for each sensitivity.

Table A7.1.29 – 2025 IRP Sensitivities

Sensitivity	Sensitivity Objective and Modelling Assumptions	S1A	S1B	S2B	S3B	S1C	S2C	S3C	S3D
Energy Market Prices	Test the influence of high and low energy market prices on resource selections.		✓		✓	✓		✓	
Capital Costs	Test the influence of high capital costs on resource selections.		✓	✓	✓	✓	✓	✓	
Selectable Energy Efficiency	Test the value of seeking energy efficiency at levels beyond the Efficiency Plan Projection by introducing selectable energy efficiency projects.		✓	✓	✓	✓	✓	✓	
Demand Response (DR) Availability	Test the value of DR to Manitoba Hydro's system by assuming no DR is included in the model and that the Curtailable Rates Programs is not extended beyond 2028.							✓	
Hydropower Enhancement Delays	Test how delaying Lower Nelson Supply Side Enhancement (SSE) projects influences their selection by assuming all enhancement options have a final unit in-service date of 2038.					✓		✓	
No Fuel Based Resources in Resource Options Strategy D	Test the implications of excluding CT-BD, H2-CTs, and Biomass as eligible resources from resource options strategy D. SMRs remain as an option.								✓
Lower Negative GHG Emissions Load	Test how load increases required to power negative GHG emissions technology affects the development plan by analyzing a modified load projection.							✓	
New Hydrogeneration	Test the value of hydropower resources to Manitoba Hydro's system by excluding new hydropower generation resource options.			✓					
Fossil Fuel Elimination in Ground Transportation and Space Heating	Test the impact on development plans of the load projection sensitivity.								✓
Climate Change Affected Inflows	Test the implications of higher or lower inflows due to climate change.					✓		✓	

11 Modelling Methodology for Least-Regrets Analysis

Least Regrets Analysis (LRA) was conducted by modelling commitments to resources in the short-term, with the implications of those commitments explored by modelling them subject to all three 2025 IRP load projections for the full study period out to 2050. The LRA was conducted with two focuses, each with slight methodology changes. The first focus aimed to measure the magnitude of regret for plans with committed new resources to 2032. The second focus aimed to test the regret around specific development plan attributes through to 2035. Each focus included a "locked-in" period for which the model simulated commitments to new resources. LRA runs were formulated to explore various commitments that could be made based on the scenario and sensitivity results.

Once defined, the LRA runs with each load projection results were compared to appropriate benchmark results to quantify the potential regret. LRA runs with the 1-Baseline load projection were compared to Scenario S1C, LRA runs with the 2-Medium load projection were compared to Scenario S2C, and LRA runs with the 3-High load projection were compared to S3C. These scenario benchmarks were appropriate as they represent cost-optimized results for the full study horizon with 600 MW of wind capacity included in 200 MW increments in 2029, 2032 and 2033. The regrets to be quantified included:

- **Overbuild Regret:** The pre-emptive expenses of a plan incurred, defined by the incremental present value of net system costs as measured out to 2045.
  - A positive incremental present value of net system costs implies that resources were installed before or in excess of requirements to meet the load. The locked-in development plan results in larger net system costs than the scenario it is benchmarked against when the amount or timing of resource additions specified in the plan exceed what the model identified as optimal.
- **Underbuild Regret**: Capacity not served by a plan, defined by the cumulative incremental deficits (in MW) that occur.
  - For each study year, the deficits that occur in the plan are compared against any deficits that occur in the same year for the corresponding benchmark. These annual deficits are then summed to find the total incremental deficit.

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

In this focus, LRA runs were defined by locking in the timing, sizing, and type of resource additions up to and including 2032. Beyond 2032, resource additions were optimized by the capacity expansion model to reflect the flexibility to adjust plans in response to changing conditions.

The LRA runs leveraged the observations from the scenario and sensitivity analysis to determine the quantity, timing, and types of resources that could be committed to in the near term. Two groups were developed for the LRA Focus 1 to further explore two different observations stemming from the scenario and sensitivity analysis.

11.1.1. Lower cost plans

The first observation to explore was that the lower cost plans include natural gas fuelled combustion turbines to meet capacity needs. This group of LRA runs tested how much capacity from combustion turbines fuelled by natural gas, along with alternative resources such as wind, minimized overbuild and underbuild regret. Four distinct LRA runs were modelled in this group.

- **LR1** – reflects resource selections from scenario S1C results. One natural gas fuelled combustion turbine unit (CT-NG) (248 MW) with a 2030 in-service date, among other resources are included. This scenario was used to represent the lowest cost option for reliably serving the 1-Baseline load projection.
- **LR2** – is the first increment between plans LR1 and LR4, with additional low-cost accredited capacity compared to LR1. This plan contains two CT-NG units (496 MW) with 2030 in-service dates, among other resources.
- **LR3** – is the second increment between plans LR1 and LR4, with additional low-cost accredited capacity beyond that assumed in LR2. This plan contains three CT-NG units (744 MW) with 2030 in-service dates, among other resources.
- **LR4** - reflects resource selections from scenario S3C results. Four CT-NG units (992 MW) with 2030 in-service dates, among other resources are included. This scenario was used to represent the lowest cost option for reliably serving the 3-High load projection.

11.1.2. Maximized alternatives plans

The second observation was that alternative resources, when paired with natural gas fuelled combustion turbines, can provide value to the electrical system. This group tested the amount of capacity from alternative resources that minimized overbuild and underbuild regret. Three distinct actions plans were modelled in this group.

- **LR5** – replicates the timing and sizing of resources in plan LR3, while limiting the number of CT-NGs to one unit (248 MW). Maximization of many alternative capacity resource options was required, including additional energy efficiency (roughly 200 MW), market purchases (50 MW), batteries (200 MW), and existing hydropower enhancements (26 MW).
- **LR6** – is an increment to plan LR5 and contains an additional 76 MW of hydropower enhancements.
- **LR7** – replicates the timing and sizing of resources in plan LR3 without the use of any CT-NGs. This was accomplished through the maximization of alternative capacity resources, including additional energy efficiency (roughly 200 MW), batteries (350 MW), market purchases (50 MW), and existing hydropower enhancements (26 MW).

11.2. LRA Focus 2: Testing Regret Around Specific Development Plan Attributes

Focus 2 of the LRA leveraged insights from LRA focus 1, where the Focus 2 plans were built to vary the amount of combustion turbine capacity and alternative capacity resources in order to test potentially better balance between the two resource types. LRA runs analyzed in Focus 2 were locked in until 2035, after which capacity expansion planning was based on the model's optimization. Regrets were quantified using the same analyses performed in Focus 1.

11.2.1. Diversified Capacity Plans

Three distinct LRA runs were modelled in this group.

- **P5** – is based on plan LR3 with modifications, since LR3 had the lowest risk of potential regret and the most balanced levels of regrets in the LRA Focus 1 analysis. Three CT-NG units (744 MW) are included with 2030 in-service dates, which is consistent with plan LR3. Additional energy efficiency was added (200MW). Hydropower enhancements (26 MW) provides accredited capacity as of 2029, when other resource options are limited. Battery storage (5 MW) was included to provide additional dispatchable capacity.

- **P5A** – is similar to P5 but includes only 95 MW of capacity from additional Energy Efficiency. This helps explore the regret associated with additional energy efficiency programs.
- **P5B** – is similar to P5 but includes adjustments to P5 to test the regrets of reducing CT-NG additions (down to 592 MW) with a corresponding increase in battery storage (86 MW). The CT-NG additions include some staging over time, with two initial CT-NG units (496 MW) added in 2030 and two smaller 48 MW units added in 2031 and 2034.

Results of the modelling and analysis are detailed in Appendix 7.2 – Modelling and Analysis Results.