Appendix 4 – Analysis Approach

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1 Introduction

The analysis conducted for the 2023 IRP used a resource optimization model to explore how Manitoba Hydro's electric system can help meet the province's future energy needs, for a range of different scenarios. This appendix discusses each of the modelling process components highlighted in Figure A4.1.

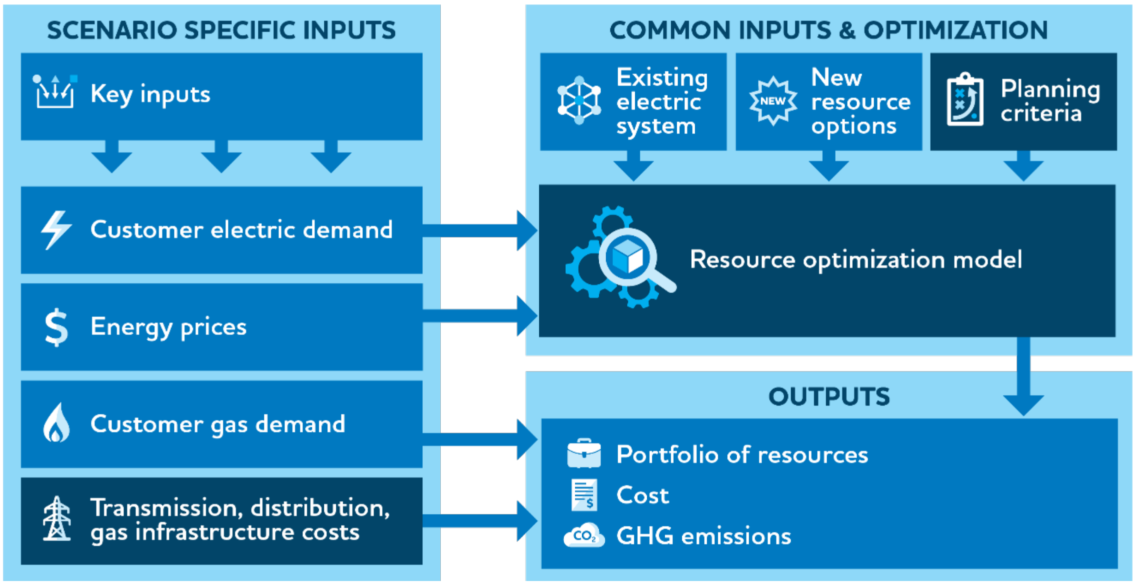

Figure A4.1 – Modelling Process Overview

The model setup for each scenario includes the key inputs specific to that scenario, as well as common model inputs that are the same for all scenarios. Scenario specific inputs include forecasted electric and natural gas demand, wholesale electricity and natural gas energy price forecasts used in the resource optimization model, and transmission, distribution, and natural gas infrastructure costs. Common model inputs include the representation of the existing electrical generation system, resource option assumptions, and planning criteria requirements. Once configured, the model considers investment and operating costs while optimizing to identify a portfolio of resources to meet future energy needs that approaches the lowest cost solution and meets all modelled criteria. The portfolio of resources is a model output, along with associated investment and operating costs, energy generated, and net export revenues.

The 2023 IRP modelling results inform a high-level understanding of the potential resource options to meet projected future needs in the most cost-effective way, as well as informing 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. Scenario and sensitivity analysis is a critical exercise for identifying a range of robust resource options that can adapt to changing future conditions. Appendix 2 – New Resource Options includes details on resource options, Appendix 3 – Scenario Specific Inputs includes a description of the scenarios, and Appendix 5 – Analysis Results includes details on the sensitivities explored and the assumptions and changes to inputs made for each.

To support the IRP analysis, direct model outputs are combined with fixed system costs and energy demands to generate net cost and GHG emission metrics.

2 Generation Planning Criteria

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.

Manitoba Hydro's 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. There are two planning criteria which ensure there is sufficient capacity to meet peak demand and sufficient energy supply during droughts. These planning criteria are specific to Manitoba Hydro's predominately hydropower system and underpin all generation planning decisions.

2.1 Capacity Criteria

The capacity criteria 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 as 12% of the Manitoba forecast peak demand in effect at the time for each year that is forecasted.

The planning reserve margin of 12% has 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.

2.2 Energy Criteria

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

Dependable energy is 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 dependable flows. Dependable energy also includes generation from wind turbines, natural gas generators, and imported electricity.

Figure A4.2 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.

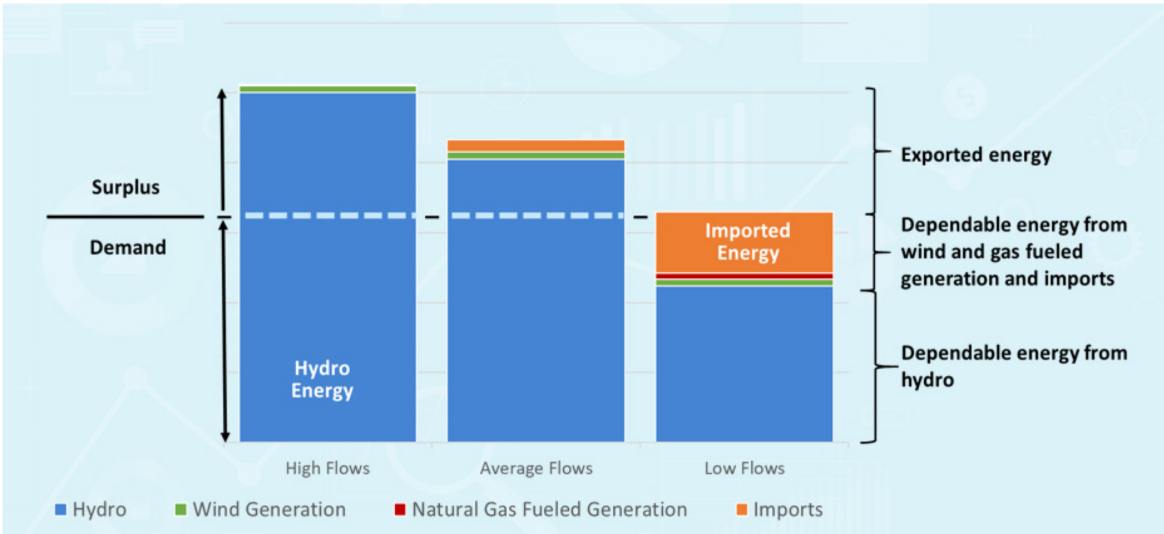

Figure A4.2 – Energy Supply Variation with Water Conditions

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 criteria 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 A4.2 for high and average flow conditions. Surplus energy can be used to avoid importing energy, running natural gas turbines, or it can be exported for revenue. However, as inflow conditions decrease, the amount of surplus energy decreases, so it cannot be relied upon as a dependable source of energy.

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

2.3 Application of the Planning Criteria to the Resource 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., firm 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 firm capacity and dependable energy are accredited to every existing resource and new resource option.

The firm capacity and dependable energy provided by new resource options are provided in Appendix 2. Dependable energy for existing system resources was determined through dependable energy studies performed by Manitoba Hydro using the model.

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 firm capacity and dependable energy associated with all new and existing resources in the system at that time meet or exceed the requirements.

3 Transmission, Distribution, and Natural Gas Infrastructure

3.1 Transmission and Distribution Infrastructure

Transmission and distribution infrastructure includes all steel and wood poles, overhead and underground wires, substations, and other components required to deliver electricity from generation resources to customers. This infrastructure is designed to ensure reliable delivery of electricity to customers during peak demand hours. The impacts on transmission and distribution infrastructure were considered for each scenario. Transmission and distribution infrastructure costs are separated into transmission, sub-transmission & distribution, and generation interconnection.

Generator interconnection costs vary for each of the resource options and are shown in Appendix 2 under the characteristics of each resource.

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. Transmission refers to infrastructure that operates at a voltage higher than 99 kV, between 115 kV and 500 kV in Manitoba and transmits bulk energy from the generating system to terminal substations or large industrial customers. At terminal substations, typically voltages are reduced to lower levels to supply smaller, regional substations or large customers. Sub-transmission operates at 33 kV and 66 kV, while distribution operates at 4 kV to 25 kV. Except for large customer loads, most customers connect directly at the distribution level.

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.
- Load growth was modeled 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, 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 MTEP21" 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.

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. 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:

- Approximately 40% of peak demand load growth impacts the sub-transmission system.
- When existing station capacity cannot accommodate load growth a new station or distribution service center (DSC) is developed.
- Property is available as needed for new stations, DSCs, transmission lines and feeders.
- Load growth does not include new large, concentrated loads.
- Costs for distribution level voltage conversion and reconductoring to expand feeder capacity depends on the feeder topology and load allocation and may not be fully accounted for.
- The cost of connecting new generation at the distribution level is excluded.
- Sub-transmission lines have a financial life of 81 years, distribution lines have a financial life of 51 years and both transmission and distribution substations have a financial life of 43 years.

[1] Transmission Cost Estimation Guide for MTEP21
https://cdn.misoenergy.org/20210209%20PSC%20Item%2006a%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP21519525.pdf

A marginal cost approach is used to account for 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 A4.1 provides the marginal cost of new 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 scenario 4, the cost of new transmission increases about 55% because the impact on the transmission system is more substantial. The Financial Metrics discussion in the Model Outputs section of this appendix includes further details.

Table A4.1 – Marginal Cost of New Transmission & Distribution for Electric Load Growth

Marginal Levelized Cost of New Transmission & Distribution for Electric Load Growth	
Transmission – Peak Demand Growth Less Than 4,000 MW	$27.82/kW-yr
Transmission – Peak Demand Growth Greater Than 4,000 MW	$43.31/kW-yr
Sub-transmission & Distribution	$46.10/kW-yr

3.2 Natural Gas Supply and Infrastructure

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.

As indicated in Appendix 3, projected customer natural gas consumption varies across the scenarios resulting in different total gas commodity costs in the scenarios. In addition, adjustments to transportation and storage capacity were made within scenario 3 and scenario 4 over the IRP study period to optimize these costs relative to the changing gas demand projected within these scenarios. Given the minimal change in customer gas demand projected in scenario 1 and scenario 2, no changes to transportation and storage capacity were assumed.

There is no scenario or sensitivity analysis that assumed a change to Manitoba Hydro's natural gas distribution infrastructure. As explained in Appendix 3, the gas load scenario projections assume a flat or decreasing gas load and no new gas infrastructure is assumed to be required for the scenarios.

Natural gas supply costs to serve customer load are accounted for in the cost metrics developed during post-processing, as described in the Financial Metrics section of this appendix. Costs associated with supplying natural gas to new generators are described in section 8.3 Natural Gas Thermal Units.

4 The Resource Optimization Model

4.1 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 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 includes 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 an expansion planning model which is used to explore adding new generating resources to an existing system to meet growing demand. Both models are integrated during expansion planning, working together to identify low-cost expansion plans that ensure the firm capacity and energy demands of the system are met.

4.2 Modelling Objective

Figure A4.3 depicts the growing need for new energy and capacity resources as demand grows, illustrating the basic problem that the resource optimization model solves.

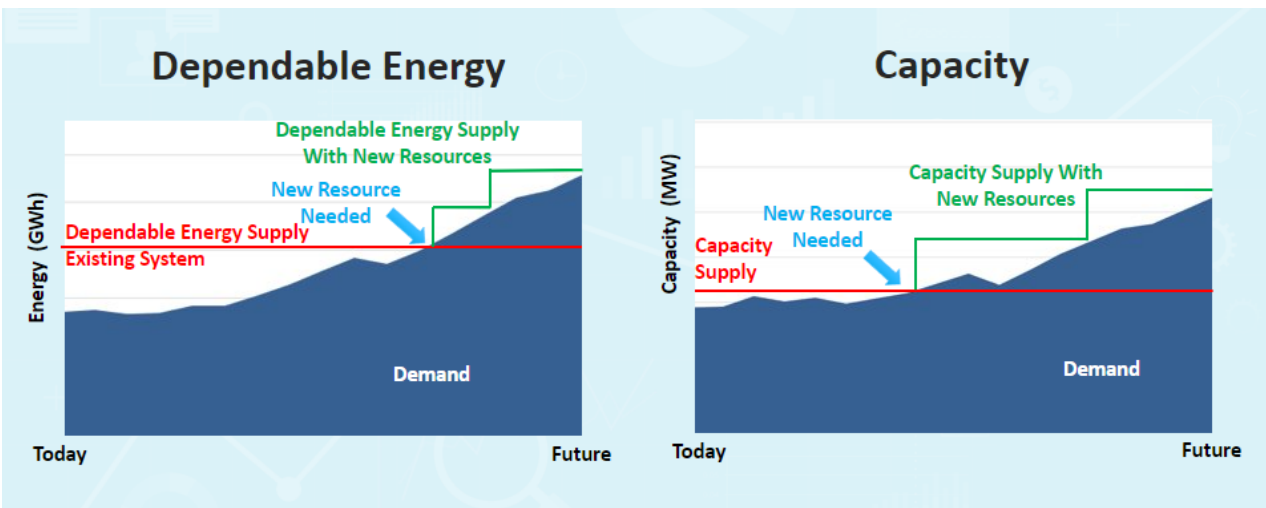

Figure A4.3 – Determining When Energy and Capacity are Needed

The red lines in Figure A4.3 display the amount of dependable energy and capacity available from Manitoba Hydro's existing system. This includes hydropower, wind, natural gas thermal units, and imports. 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 resource 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 depicted by the red line in Figure A4.3 for the IRP's 20-year study period. The resource optimization model seeks the lowest cost portfolio of resources for this period while considering factors that vary in time such as customer demand, the ratio of energy to 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, renewable energy generation, and applicable operational constraints. All of these inputs are modelled using the same 21-block definition, preserving the relationships between coincident hours across these forecasts. For example, Block 1 represents the top 4 hours of electrical demand for each weekday, and those same hours are used to define Block 1 for electricity energy market prices and all other time-varied inputs.

Once a portfolio of resources is identified by the model, the dependable energy and firm capacity needs of the system will be met for the entire study period, as shown by the green lines in Figure A4.3. The green lines show the system's dependable energy and firm capacity after the addition of new resources identified in the model's expansion plan.

4.3 Modelling Optimization Process

Seeking to identify lowest cost expansion plans is an iterative process, as outlined in Figure A4.4.

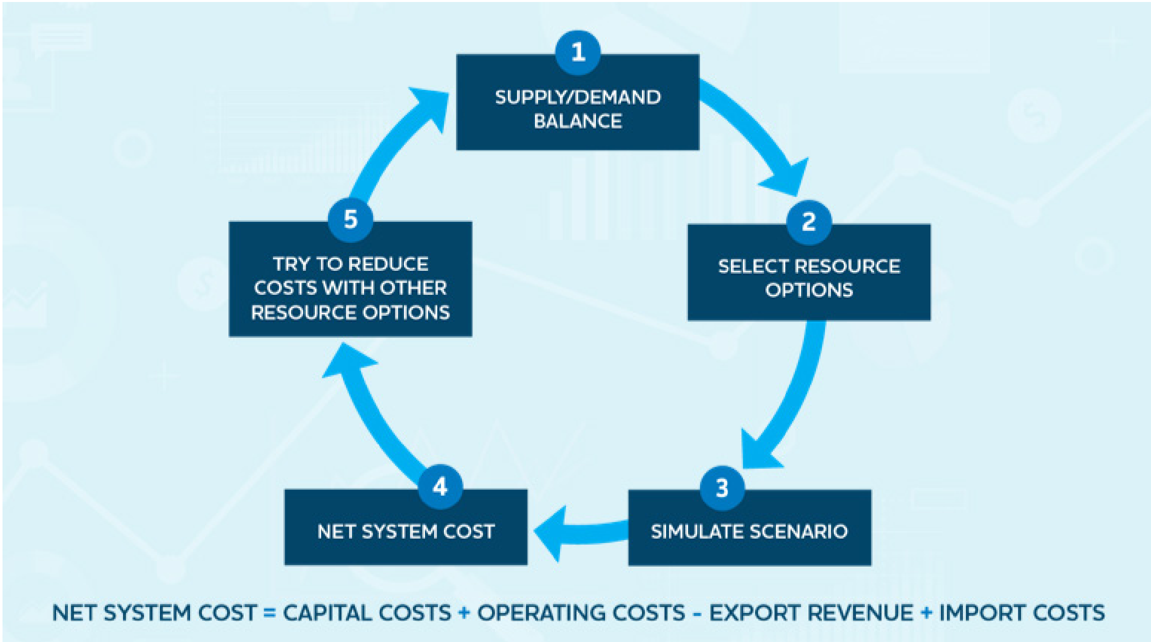

Figure A4.4 – Model Optimization Process

The resource 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 proposed portfolio of resources for the study period, picking resources that meet demand based on the planning criteria, and which minimize capital costs and estimated operating costs. Estimated operating costs are based on approximations developed by the model for each resource, and which are improved 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 and inflow records. This simulation includes existing generating stations, import and export market interactions, as well as the new resources identified by the model. The simulation outputs the true operating costs of the system given the proposed expansion plan.
4. The model calculates the final net system cost, which is the sum of all capital costs, simulated operating costs, export revenues, and import costs.
5. The model assesses if the net system costs for the proposed portfolio of resources were reasonably close to the estimated net system costs. 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 A4.4 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 to be 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.

Mitigation measures designed to improve modelling, post-processing, and analysis efficiency were implemented prior to and throughout the IRP, but strategic selection of scenarios and sensitivities to study was still required. Appendix 3 includes a discussion on how scenarios were developed. Appendix 5 includes a discussion of the sensitivities considered.

4.4 Practical Model Limitations

The final portfolio of resources identified by the model may not be the 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.

5 Electric and Natural Gas Customer Demand

5.1 Customer Electric Demand

The customer electric demand projections vary across each IRP scenario. Each was developed by Manitoba Hydro in accordance with the scenario assumptions outlined in Appendix 3.

Electric load within Manitoba is modelled as a firm demand. The model uses an hourly electric load forecast aggregated into 21 blocks, where the 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.

5.2 Energy Efficiency

Within the resource optimization model, future energy efficiency savings are represented as a renewable generator with a set generation profile, allowing the energy savings to be replicated instead of defined as a load modifier as in Appendix 3. Modelling energy efficiency as a renewable generator allows for it to be easily removed for sensitivity analyses; see Appendix 5 for sensitivities where all energy efficiency options are modelled as selectable resources.

5.3 Natural Gas Demand

Customer natural gas demand is not explicitly represented in the model. However, post-processing of model results incorporates customer natural gas demand forecast information.

6 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 due to Manitoba Hydro's much larger transmission capability with it, as opposed to Saskatchewan and Ontario. While there is no energy market in Saskatchewan, bilateral opportunity import 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, ensuring that the relationship between hourly electric load and market prices is preserved.

The model optimizes the dispatch of natural gas thermal units based on both a natural gas price forecast and a carbon price forecast. The natural gas price forecast varies by month and year, whereas GHG emissions costs vary by study year only. More details on the carbon price projections can be found in Appendix 3.

7 Existing Electric System

The existing Manitoba Hydro electrical generation system is represented within the model as detailed in the following sections. Note that the existing system is assumed to be maintained throughout the study horizon. There are no planned retirements of resources in the model. The Pointe du Bois Renewable Energy Project is assumed to be completed and the expiration of existing non-utility generation power purchase agreements and expiration of import and export agreements are reflected in the model.

7.1 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 neighboring 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 A4.2 below.

Table A4.2 – 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

7.2 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 A4.2.

Firm Electricity Exports

Firm electricity exports are modelled as an electricity demand that must be served regardless of the cost to serve them, similar to the electric load (refer to Electric and Natural Gas Customer Demand section for further details). Firm electricity exports are modelled for each block, month, and year.

Opportunity Energy Exports

Opportunity exports are modeled 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 forecast.

Imports

Imports reflect the energy price forecast. The same 21 block representation is applied to import prices as is used for opportunity export prices and the Manitoba load. Physical imports, market settlements, and capacity purchases are all modelled.

7.3 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.

Inflows and Hydropower Generation

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 110 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 1 – Existing System & Load.

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.

7.4 Thermal Generation

The Brandon Generating station is the only existing thermal generating station in the Manitoba Hydro electric system. It is included as a natural gas fueled generator in the model.

Thermal generation is optimized during the resource optimization model's simulation phase. At any given time in the model, the amount of thermal energy generated by a unit will vary depending on demand, the inflow conditions and corresponding hydropower generation, the amount of renewable generation, and the economics/quantity of imports. 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 emissions costs associated with natural gas thermal generation are weighed against the economic advantages of dispatching the generator.

7.5 Wind Generation

Manitoba Hydro has power purchase agreements in place with the St. Joseph and St. Leon wind farms and both are modeled as existing renewable resources. 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 and is based on historical generation. The variability of wind generation is not represented in the model.

8 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 2. These characteristics define the costs, energy production, firm capacity contributions, and 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 that is summarized in Appendix 2. Assumptions that were made due to the practical limitations of the model are detailed. Table A4.3 outlines some of the key terms used in the following sections.

Table A4.3 – Key Terms for New Resource Options Modelling Details

Term	Definition
Project	Refers to the development of a resource option within the model solution.
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 nominal capacity specified). Portions of the project can be built across multiple years throughout the study. The total amount of nominal capacity for each increment of the project installed by the end of the study cannot exceed 100%.
Future Cost Curve	A relationship used to represent how a resource option's investment cost, fixed operating and maintenance cost, or both, vary by year through the study period.
Resource Type	Refers to the modelling option selected for representing a resource in the model and is applicable for modelling purposes only. Available options are hydropower, thermal, renewable, and battery.

General Notes

All capacity values provided in this section are stated as nominal (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.

All assumptions are specific to the representation of each resource option in the model and should not be assumed to be appropriate for other applications. For example, the emissions assumptions are for the purposes of introducing 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 installed capacity of a resource are for modelling purposes only and are implemented in many cases to improve the computational efficiency of the model. Where possible, the maximums reflect current understanding of Manitoba Hydro system's ability to accommodate a given resource type. For resources where the maximum addition to the system that can be accommodated is uncertain, attention was paid during analysis to ensure model limits were not unreasonably impacting the solution.

8.1 Wind Generation

Resource Type: Renewable.

Generation 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 A4.4. 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 A4.4 – Modelled Wind Resource Options

Project Name	Project Type	Nominal Capacity [MW]	Accredited Firm Capacity 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%

Constraints: A total of 6,000 MW of wind is allowed to be built in the model.
Constraints requiring the sequential build of wind units are 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.

Future Cost Curves: All capital costs, with the exception of generation interconnection transmission costs, are annualized across the asset life of new wind and included as fixed operating and maintenance cost ($/kW-yr). These annual costs, as well as system integration costs, decline throughout the study period and are set based on the in-service date of new wind resources. While all wind unit costs decrease through time, the wind fixed operating and maintenance costs in scenario 1 are held constant post-2030 so that costs do not fall below the cost of imported electricity. This reflects an assumption that new wind generation could not be developed and operated in Manitoba at a lower cost than outside the province. Generation integration transmission costs are also modelled (M$) but are not assumed to vary through time.

Fuel Assumptions: No fuel is required.

Emission Assumption: No operational emissions are associated with wind generation.

8.2 Solar PV Generation

Resource Type: Renewable.

Generation 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 A4.5. This representation uses two solar units to capture increasing transmission costs with increasing amounts of solar installed in the system.

Table A4.5 – Modelled Utility-Scale Solar Resource Options

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

Constraints: A total of 3,000 MW of solar can be built in the system. No explicit constraints are used to force the build of Solar 1 prior to Solar 2 but this progression occurs by the model due to the increased capital costs for Solar 2.

Future Cost Curves: Solar costs include capital investment (M$) and fixed operating and maintenance cost ($/kW-yr) components. Investment costs and system integration costs are represented using future cost curves to reflect an expected decreasing cost in future years. Fixed operating and maintenance costs are held constant. While all solar unit costs decrease through time, the solar costs in scenario 1 are held constant post 2030 so that costs do not fall below the cost of imported electricity; similar to wind, this reflects an assumption that new solar generation could not be developed and operated in Manitoba at a lower cost than outside of Manitoba.

Fuel Assumptions: No fuel is required.

Emission Assumption: No operational emissions are associated with solar generation.

8.3 Natural Gas Thermal Units

Resource Type: Thermal.

Generation Methodology: Generation is optimized by the resource optimization model. The thermal generation description in the Existing Electric System section includes further details.

Unit Representation and Availability: The types and number of natural gas units available in the model are presented in Table A4.6.

Table A4.6 – Modelled Natural Gas Resource Options

Project Name	Type & Number
SCGT	Binary: 4; Integer: 1
CCGT	Binary: 2; Integer: 1
LM6000	Integer: 1
CCGT-CCS	Integer: 1

Constraints: Four natural-gas simple cycle gas turbines (SCGTs) and two natural-gas combined cycle gas turbine (CCGT) 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 SCGT and CCGT integer units. Constraints are in place that relate the binary SCGTs to matching CCGT 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 SCGT unit because the model will make the most economic choice between these options.

The total addition of new nominal capacity from SCGT, CCGT, and aeroderivative (LM6000) units over the study period is limited to 10,000 MW.

No constraints are applied to CCGT-CCS (carbon capture & storage) units.

Future Cost Curves: Future cost curves define declining future investment costs (M$) for all natural gas thermal resource options. Fixed operating and maintenance costs ($/kW-yr) are assumed to be constant through time.

Fuel Assumptions: Forecasted natural gas prices ($/MMBTU) are used to determine fuel costs. Additional fuel transportation costs and GHG emissions costs ($/tCO_2e$) are also applied. Natural gas fuel supply is assumed to be unlimited.

Emission Assumption: Direct operational emissions are produced at a rate of 0.054 tCO_2e per MMBTU input for generation from all natural gas-fueled units. CCS units are assumed to capture 90% of all GHG emissions, resulting in net GHG emissions of 0.0054 tCO_2e/MMBTU for CCS units. CCGT and CCGT-CCS units are differentiated in the model based on this GHG emissions factor difference, along with changes in heat rate and capital cost assumptions, as outlined in Appendix 2.

8.4 Hydrogen Thermal Units

Resource Type: Hydrogen Turbine: Thermal; Electrolyzer: Renewable

Generation Methodology: The selection and dispatch of hydrogen-fuelled turbine generation is optimized by the model. The thermal generation description in the Existing Electric System section includes 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 renewable 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 turbine unit at its defined capacity factor.

Unit Representation and Availability: The types and number of hydrogen units available in the model are presented in Table A4.7. The hydrogen unit concept includes a thermal generator to represent electrical generation from hydrogen fuel and an associated renewable generator that acts as a negative load to represent electrolysis energy demands on the system. Hydrogen units with varying capacity factors are modeled to reflect the increasing number of generation hours required to provide incrementally more winter firm capacity to the system.

Table A4.7 – Modelled Hydrogen-Fuelled Resource Options

Project Name	Nominal Capacity (MW)	Average Annual Capacity Factor	Type & Number
SCGT-Type	225	2% 4% 8%	11 Binary Units 13 Binary units 1 Binary Unit
CCGT-Type	325	12% 15% 19%	1 Binary Unit 1 Binary Unit 1 Binary Unit

Constraints: Precedence constraints specifying the order of the 2% and 4% SCGT- and CCGT-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% SCGT- and CCGT-type units is limited to 3,000 MW. This ensures the applicability of firm capacity accreditation assumptions with increasing levels of hydrogen generation in the system.

Future Cost Curves: 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. The investment costs and fixed operating and maintenance costs increase as the assumed capacity factor of the unit increases.

Fuel Assumptions: Electrolysis is represented as a renewable generator acting as a negative load, requiring increased generation from other resources in the system during the April to September months to ensure that increased demand is met during the winter months. The cost for meeting the electrolyzer load is embedded within the total system operating costs.

Hydrogen thermal generators are restricted by a limited hydrogen fuel supply. The total amount of hydrogen fuel available corresponds to the total energy production expected for the unit, based on its nominal capacity and capacity factor. The fuel produced by electrolyzers is assumed to be available to the hydrogen turbines at no additional cost.

The availability of hydrogen assumed for each type of hydrogen unit, based on its average annual capacity factor, is outlined Table A4.8. For 2%, 4%, and 8% capacity factor units, it is assumed that 50% of available hydrogen fuel is used in January, while 25% is used in each of February and December. This reflects anticipated use of hydrogen units to meet peak winter demand. Units with capacity factors greater than 8% 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.

Table A4.8 – Hydrogen Fuel Availability Assumptions

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

Emission Assumption: No operational emissions are associated with hydrogen generation.

8.5 Hydropower Generation

Resource Type: Hydropower

Generation Methodology: Generation is based on the use of a mean production coefficient (MW/m^3/s). Conawapa and the Long Spruce Supply Side Enhancement (Long Spruce SSE) project are among the most economical hydropower generation resource options and have more detailed design characteristics available. As such, generation estimation for these options is based on the methodology outlined in the hydropower discussion in the Existing Electric System section.

Unit Representation and Availability: Available new hydropower resource options included in the resource options model are outlined in Appendix 2.

Constraints: No additional modelling constraints are applied to new hydropower options. Long Spruce SSE is required to respect the same minimum generation constraint as is the existing Long Spruce station.

Future Cost Curves: 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.

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 Long Spruce 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.

Emission Assumption: No operational emissions are associated with hydropower generation because they are very small.

8.6 Biomass Thermal Units

Resource Type: Thermal

Generation Methodology: Generation is optimized by the resource optimization model. The thermal generation description in the Existing Electric System section includes further details.

Unit Representation and Availability: Two biomass thermal generator options are available in the model, as outlined in Table A4.9.

Table A4.9 – Modelled Biomass Resource Options

Project Name	Nominal Capacity (MW)	Type & Number	Average Annual Capacity Factor
Biomass3002	32	Integer	2% (peaker operation)
Biomass3083	32	Integer	83%

Constraints: No constraints are applied to the biomass units.

Future Cost Curves: Future cost curves define declining future investment costs (M$) for both biomass thermal resource options. Fixed operating and maintenance costs ($/kW-yr) are assumed to stay constant through time.

Fuel Assumptions: Biomass fuel costs are assumed to be constant throughout the study period. The 2% Average Annual Capacity Factor Unit (Peaker) plant 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 Capacity Factor Unit assumes no limits on fuel availability and dispatch of this unit is based on model optimization.

Emission Assumption: No operational emissions are associated with biomass generation. Operational emissions associated with biomass generation are considered biogenic and therefore excluded.

8.7 Small Modular Reactor (SMR) Thermal Units

Resource Type: Thermal

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

Unit Representation and Availability: Three SMR units are modelled, as outlined in Table A4.10.

Table A4.10 – Modelled Small Modular Reactor Resource Options

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

Constraints: The maximum new nominal capacity from SMR units that can be added to the system is 1,500 MW.

Future Cost Curves: Investment (M$) and fixed operating and maintenance cost ($/kW-yr) costs 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.

Emission Assumption: No operational emissions are associated with SMR generation.

8.8 Battery Storage

Resource Type: Battery

Generation 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 is modeled using the assumptions outlined in Table A4.11. The battery is assumed to be operated to reduce peak demand, based on a 24-hour charge/discharge cycle. It does not have dedicated generation associated with it.

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. Further details are provided in Appendix 2.

Table A4.11 – Modelled Battery Storage Resource Options

Assumption	Value
Nominal Capacity	350 MW
Charge Efficiency	90%
Discharge Efficiency	90%

Constraints: No constraints are applied.

Future Cost Curves: Future cost curves define declining future investment costs (M$) for battery storage resource options. Fixed operating and maintenance costs ($/kW-yr) are assumed to stay constant through time.

Fuel Assumptions: No associated fuel.

Emission Assumption: No operational emissions are associated with battery operation.

8.9 Energy Efficiency

Resource Type: Renewable

Generation 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: Selectable energy efficiency measures, including heat pumps and distributed solar PV are represented as groupings of individual energy efficiency measures as explained in Appendix 2. Each grouping is represented as an individual resource option as listed in Table A4.12. Appendix 2 includes further details, including a description of each grouping. Heat pumps include air source, cold-climate air source, and ground source heat pump types.

Table A4.12 – Modelled Energy Efficiency and Heat Pump Resource Options

EE & HP Market Potential Levels	Type & Number
EE at Enhanced Level – Incremental to the Efficiency Manitoba Plan	Continuous; 8 units
EE at Maximized Level – Incremental to the Efficiency Manitoba Plan	Continuous; 8 units
EE at Enhanced Level	Continuous; 8 units
EE at Maximized Level	Continuous; 8 units
Heat Pumps at Enhanced Level	Continuous; 8 units
Heat Pumps at Maximized Level	Continuous; 8 units

"Energy efficiency incremental to the Efficiency Manitoba Plan" refers to selectable energy efficiency chosen by the model above and beyond the amount of energy efficiency savings assumed in Efficiency Manitoba's 2020-23 Efficiency Plan extrapolated to the end of the 20-year planning horizon. Enhanced and maximized levels of energy efficiency savings potential were identified through a market potential study conducted for Efficiency Manitoba. For incremental selectable energy efficiency savings, the maximum potential for each energy efficiency grouping is reduced based on the corresponding amount of energy efficiency already assumed in the Efficiency Manitoba Plan. Energy efficiency at the enhanced and maximized market potential levels assume all energy efficiency is selectable and excludes the Efficiency Manitoba Plan energy savings.

As described in Appendix 3, electric demand projections include assumptions for air source heat pump (ASHP) and ground source heat pump (GSHP) adoption. The modelled market potential levels do not account for these embedded heat pump assumptions and the possibility of surpassing the market potential for heat pumps for electric heat customers exists for some scenarios. Further study is needed to confirm market potential levels for heat pumps in the Manitoba Hydro system.

The energy efficiency market potential levels are mutually exclusive sets of energy efficiency options, as are the heat pump market potential levels. For example, if heat pumps at the maximized level are assumed to be available options, then heat pumps at the enhanced levels are not included as options in the model.

Energy efficiency and heat pump group specific notes:

- There is no market potential for energy savings for the Commercial Lighting and Other Lighting groups beyond the energy savings included in the Efficiency Manitoba Plan. All available savings for these groupings are already included in the Efficiency Manitoba Plan.
- The selectable solar PV group is assumed to have no accredited winter firm capacity savings.
- ASHPs and cold climate ASHPs have no accredited firm winter capacity savings.

Constraints: Energy efficiency and heat pump units are modeled as continuous resources with nominal capacities set at their maximum non-coincident peak capacity value as of the end of the study period. Constraints are applied for each energy efficiency and heat pump unit, 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 for that group in that year.

Future Cost Curves: Investment cost curves (M$) are used to define program costs that change with time. Energy efficiency and heat pump units also have associated transmission and distribution cost deferral benefits, which are represented using fixed operating and maintenance cost ($/kW-yr) cost curves within the model. These cost curves vary with the annual accredited firm capacity achievable by each group throughout the study.

Fuel Assumptions: No associated fuels.

Emission Assumption: No operational emissions are associated with DSM and heat pumps.

9 Financial Assumptions

The following financial assumptions were used for all analyses:

- Real Weighted Average Cost of Capital: 3.70%
- Inflation Rate: 3.1%
- Exchange Rate: 1.25 C$/US$

10 Model Outputs

The resource optimization model provides a range of outputs for analysis. These outputs and their applications during analysis are summarized in Table A4.13. Outputs with the type "Direct Output" are directly produced by the model. Outputs with the type "Calculated Output" are calculated outside of the model, within post-processing tools, based on direct outputs from the model.

Table A4.13 – Model Outputs and their Application

Output	Type	Details	Application
Expansion Plan	Direct Output	Includes the timing and amount (in nominal capacity) of each resource selected	Provides the basis for insights into how future system needs will be met with new resources
Accredited Firm Capacity and Dependable Energy	Direct Output	Includes the amount of firm capacity and dependable energy (referred to as firm energy) associated with each resource category for each year in the study period, based on the expansion plan. Accredited firm capacity and dependable energy for each resource option is also output.	Used to validate firm capacity and dependable energy inputs for all resource options. Accredited firm capacity and dependable energy output for the system (based on the expansion plan) can be compared against firm capacity and dependable energy constraints. This helps to explain if the model has selected a new resource to meet firm capacity or firm energy needs, or both.

Output	Type	Details	Application
Costs and Revenue	Direct Output	Includes generation capital costs (investment costs, generation interconnection costs, fixed operating and maintenance cost), operating costs (fuel costs, variable operating and maintenance cost, import costs), and export revenue.	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 decision, 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	Direct Output	Includes all constraints related to firm capacity and dependable energy requirements, as well as constraints governing total and incremental nominal capacity additions.	Use to validate that all necessary constraints are represented in the model, and that the expansion plan solution respects these constraints as intended. Accredited firm capacity and dependable energy output for the system (based on the expansion plan) can be compared against firm capacity and dependable energy constraints. This helps to explain if the model has selected a new resource to meet firm capacity or firm energy needs, or both.
Energy Generation	Direct Output	Presented for each resource category, on an annual basis and averaged across 110 inflow cases	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 Metrics	Direct Output	Includes final convergence gaps, investment cost breakdowns by unit, and operational costs including deficit and penalty costs	These results are used to validate the model's optimization of the expansion plan and to ensure model constraints are being applied and are influencing results as intended.

Output	Type	Details	Application
GHG Emissions Metrics	Direct Output & Calculated Output	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 GHG emissions from the provincial and regional perspective are also presented and include GHG emissions from other energy use sectors.[2]	GHG emissions provide another lens for assessing the costs and benefits of an expansion plan. Provincial and regional GHG emissions perspectives provide a more holistic view of GHG emissions outcomes and enable more meaningful comparisons between model runs.
Financial Metrics	Calculated Output	Calculations combine capital and operating costs with additional cost components not represented in the model.[3] Additional costs that are sensitivity-specific and external to the model can also be accounted for with these metrics.	Financial metrics provide a broader financial context for evaluating expansion plans, enabling comparisons across model results with different load and/or natural gas supply mixes.

10.1 GHG Emissions Metrics

GHG emissions metrics summarize the anticipated GHG emissions from electrical system operations for a given resource portfolio. The GHG emissions metrics in the 2023 IRP allow Manitoba Hydro to understand the impact of different resource portfolios on Manitoba Hydro's GHG emissions, regional GHG emissions, and provincial GHG emissions.

The following GHG emissions metrics are available in post-processed model results. While the resource optimization model accounts for emission volumes and costs based on a simplified representation, GHG emission metrics re-calculate emission volumes based on refined assumptions and model outputs.

Manitoba Hydro's Electricity Generation GHG Emissions

Manitoba Hydro's electricity generation GHG emissions (tCO_2e) provide information on reportable GHG emissions for Manitoba Hydro.

Net Regional Electricity Generation GHG Emissions

Net regional electricity generation GHG emissions (tCO_2e) presents a broader GHG emissions perspective that estimates the net impact of Manitoba Hydro's system operations on the regional electricity generation sector. This metric includes net GHG emission changes 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 therefore also influences

[2] See the GHG Emissions Metrics section of this appendix for further details.
[3] See the Financial Metrics section of this appendix for further details.

corresponding GHG emissions. For example, if Manitoba Hydro's hydroelectric generation exceeds Manitoba's needs (on an annual basis), that electric energy can be exported to MISO and some fossil fuel generators will reduce their annual output accordingly, thereby avoiding GHG emissions. In this example, this metric estimates the GHG emissions impact of that change in output. A regional GHG emissions perspective reflects Manitoba Hydro's contribution to regional GHG emission reduction efforts; if in a particular modelling result, Manitoba Hydro's GHG emissions are lower but dependence on imported electricity increases, the result could be a net increase in regional GHG emissions.

Provincial GHG Emissions

Provincial 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[4]. Estimating provincial GHG emissions provides insight into how GHG emissions in different sectors are related and could change into the future based on a scenario or sensitivity. For example, sensitivities with varying levels of EV adoption will show changing levels of provincial transportation GHG emissions. Outputs for provincial GHG emissions and net regional electricity generation GHG emissions are also presented, as one combined metric, to provide insight into the overall net regional impact of Manitoba Hydro system expansion, and operation in combination with the impact of Manitoba load scenarios (or sensitivities). Estimates of provincial GHG emissions were made at a high level and intended to allow comparison between scenarios and sensitivities using a common set of baseline assumptions; they should not be used for purposes other than the 2023 IRP.

10.2 Financial Metrics

Financial metrics are key financial indicators calculated during the post-processing of model results. These metrics combine costs and revenues considered in the model with others that are not considered in the model. If a cost or revenue does not change based on the expansion plan or the operation of the system, then they have no bearing on the model's decisions and are excluded from the resource optimization. However, incorporating these excluded costs into the financial metrics provides a holistic view of the financial outcomes of an expansion plan and creates a fair basis for comparisons between analysis with different load and natural gas supply 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 financial implications for Manitoba Hydro, and to compare against the financial outcomes of sensitivities with greater reliance on natural gas space heating.

[4] A description of categories of provincial GHG emissions is included in Appendix 1

The primary financial metrics calculated for each model scenario and sensitivity are listed below and followed by descriptions of each:

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

Cumulative Present Value of Net System Costs (M CAN$)

The cumulative net present value of net system costs reflects the total revenue required to offset the costs of operating the system and meeting all system demand with the given expansion plan. Cost and revenue components that contribute to this metric are as follows:

- Costs and revenues output from the model:
  - Incremental fuel and power purchased costs, which include all variable costs associated with operating the system
  - Incremental fixed costs associated with new resource additions
  - Opportunity export revenues
- Costs and revenues external to the model:
  - Fixed transmission, distribution, electrical generation system, natural gas distribution system, and Efficiency Manitoba payment costs related to forecast expenditures already included in Manitoba Hydro's financial plans
  - Natural gas supply and associated carbon price (GHG emission price) costs
  - Incremental transmission and electrical distribution costs required for changes to domestic load
  - Financing costs associated with debt repayment for past investments
  - Revenues from firm export contracts

Annual Net System Costs (M CAN$)

This metric is a real dollar amount calculated on an annual basis and represents annual costs net of opportunity export revenues. The annual costs metric is a snapshot of costs in any given year. The change in annual 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 metric are as follows:

- Costs and revenues output from the model:
  - Incremental fuel and power purchased costs, which include all variable costs associated with operating the system.
  - Incremental fixed costs associated with new resource additions
  - Opportunity export revenues

- Costs external to the model:
    - Fixed transmission, distribution, electrical generation system, natural gas distribution system, and Efficiency Manitoba payment costs related to forecast expenditures already included in Manitoba Hydro's financial plans
    - Natural gas supply and associated carbon price (GHG emissions price) costs
    - Incremental transmission and distribution costs required to accommodate changes to domestic load
    - Financing costs associated with debt repayment for past investments

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 as follows:

- Costs and revenues output from the model:
    - Incremental fuel and power purchased costs, which include all variable costs associated with operating the system
    - Incremental fixed costs associated with new resource additions
    - Opportunity export revenues
- Costs and revenues external to the model:
    - Fixed transmission, distribution, electrical generation system, natural gas distribution system, and Efficiency Manitoba payment costs related to forecast expenditures already included in Manitoba Hydro's financial plans
    - Natural gas supply and associated carbon price (GHG emission price) costs
    - Incremental transmission and distribution costs required to accommodate changes to domestic load
    - Revenues from firm export contracts

END OF APPENDIX