21. Although the key objective of climate policies is to reduce GHG emissions, not to electrify, there appears to be some partiality at all three levels of government towards achieving GHG reductions and meeting net-zero via electrification. Although electrification often receives the focus, there are no policies mandating electrification or that provide specific direction on the future of the gas delivery system in Ontario. Furthermore, there appears to be a lack of consideration about the magnitude of infrastructure and costs required to replace the critical role that the gas system currently plays in safely and reliably heating homes and fueling industry and electricity generation in Ontario. Considering this in detail would enable a discussion about what role the gas delivery system can play in supporting Ontario in achieving its climate and energy transition goals.

22. What is clear to Enbridge Gas, however, is that the governments' ambitious GHG reduction targets will require a reduction in energy use in combination with a shift from unabated fossil fuels to low-carbon sources of energy.

23. The federal 2030 Emission Reduction Plan and federal discussion papers combined with the Made-in-Ontario Environment Plan and discussion papers demonstrate that these two levels of government are taking action to reduce GHG emissions through a diverse set of policies and funding across all sectors, including buildings, industry, transportation, and electricity generation. Actions being explored include support for energy efficiency, electrification, low-carbon fuels, and carbon capture, utilization, and sequestration (CCUS).

24. Reduction in energy usage via energy efficiency programs has been, and continues to be, fundamental to emission reduction plans at all levels of government. For example, in the 2030 Emissions Reduction Plan, the federal government states "Energy efficiency measures such as upgrading the building

143 million tCO_2e. The Made-in-Ontario Environment Plan aims to achieve these reductions through a range of sources, including higher uptake of clean fuels (ethanol gasoline, renewable natural gas etc.), natural gas conservation through gradual expansion of energy efficiency programs delivered by utilities, low-carbon vehicle uptake, industry performance standards regulating large GHG emitters and innovation in energy storage and fuel switching.

10. Ontario's GHG emissions have declined relative to the 2005 target baseline year (204 million tCO_2e). Ontario's GHG emissions were 19% below 2005 levels in 2019 (166 million tCO_2e) and 27% below 2005 levels in 2020 (150 million tCO_2e).[7]

11. Depending on any potential rebound in emissions post-pandemic, the province requires additional reductions of 3% to 11% to achieve its 2030 target. Ontario has released an updated forecast[8]. It does not include sectoral targets, but it shows that the remainder of the GHG reductions by 2030 will be achieved predominantly from the Emissions Performance Standards (EPS), gasoline renewable content requirements and supporting industrial coal phase-out via natural gas. Additional GHG reductions will be achieved through natural gas conservation, transit initiatives and reducing emissions from landfills.

12. Ontario is taking important additional steps to review the impact of energy transition in the province. In April 2022, the Government of Ontario announced the launch of

[7] National Inventory Report 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada, Part 3, p.50, https://unfccc.int/documents/461919
[8] Ontario Emissions Scenario as of March 25, 2022, 2022, https://prod-environmental-registry.s3.amazonaws.com/2022-04/Ontario%20Emissions%20Scenario%20as%20of%20March%2025_1.pdf

net-zero by 2050. These targets replace those previously announced in the Pan-Canadian Framework.

7. To date, Ontario has not committed to the steeper 2030 GHG target set by the federal government in the Canadian Net-Zero Emissions Accountability Act and has not set GHG reduction targets beyond 2030. Ontario, however, is the second largest emitting province in Canada and, therefore, further GHG reductions will need to occur in Ontario for the country to achieve net-zero emissions by 2050.[5]

8. While both the federal and provincial governments are aligned on the need to reduce GHG emissions, the disparity between 2030 targets and the lack of provincial targets beyond 2030 creates uncertainty about the amount and pace of future GHG reductions in Ontario.

1.3 Provincial Climate Policies

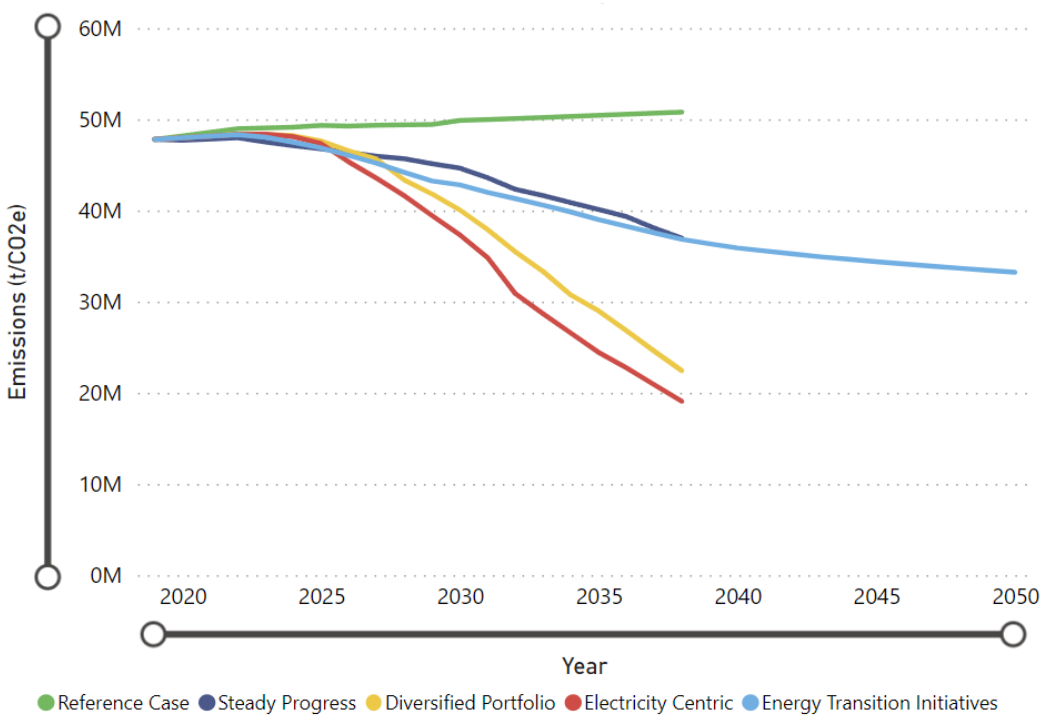
9. To achieve the province's GHG emission reduction targets, the Ontario government developed the Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan (Made-in-Ontario Environment Plan) in November 2018.[6] The plan is intended to guide development of new environmental policies in Ontario to create a focused approach to mitigating the impacts of climate change and reducing the province's GHG emissions. The actions outlined in the Made-in-Ontario Environment Plan aim to achieve a reduction of 18 million tCO_2e to reach Ontario's 2030 emissions target, which equates to annual GHG emissions of

[5] Government of Canada, Greenhouse gas emissions, Environment and natural resources, https://www.canada.ca/en/environment-climate-change/services/environmental-indicators/greenhouse-gas-emissions.html

[6] Preserving and Protecting our Environment for Future Generations: A Made-in-Ontario Environment Plan, 2018, https://prod-environmental-registry.s3.amazonaws.com/2018-11/EnvironmentPlan.pdf

2050 net-zero emission needs. Figure 1 provides a comparison of the GHG emissions for the ETI and ETSA scenarios, which are provided at Attachment 1, page 22.

Figure 1: Annual GHG Emissions by Scenario



105. Figure 1 demonstrates that Enbridge Gas's current and proposed energy transition initiatives will make a meaningful impact on GHG emissions in Ontario, including achieving the 2030 GHG emission reduction target, and making a significant contribution to achieving net-zero in the future. However, these initiatives on their own will not be enough to achieve Enbridge Gas's vision of a diversified pathway to net-zero.

Leadership, over the life cycle of each asset class.

3.2 EGI Integration and Continual Improvement

This document reflects the integrated utility's Asset Management Plan for the next 10 years, with assets for the rate zones (the EGD and the Union North and South rate zones) being maintained separately for capital planning purposes in 2023 and as EGI from 2024 through to the end of 2032.

EGI continues to evolve its asset management practices to produce a comprehensive Asset Management Plan. As a result, the following changes were implemented:

- **Energy Transition**
  This AMP incorporates assumptions for customer additions, peak hour demand and peak day demand, each of which have been adjusted to reflect EGI's current view of the impacts of the Energy Transition (see Exhibit 1, Tab 10, Schedule 4). EGI acknowledges that energy transition is evolving and that investment decisions will be based on the best information at the time, including consideration of IESO's forecast electricity demand. EGI maintains its obligation to serve and is committed to implementing IRP with the intent of evaluating and comparing both supply-side and demand-side options to meet an energy system need in the immediate, medium and longer term.

- **Integrated Resource Planning (IRP)**

  IRP represents a significant change to the facility planning that EGI has performed in the past and, as such, EGI is taking steps to develop processes, resources and capabilities to integrate new IRP requirements into its existing asset management process and other processes. EGI's AIPM process now incorporates the IRP assessment process. The IRP assessment step of the AIPM process (see **Section 4.3.4.1**), determines if an IRPA evaluation is required for each system need, and, if so, a cost-effective IRPA exists. Further details on the IRP assessment process can be found in EGI's IRP Annual Report.

  Through the IRP assessment process, EGI has performed IRP Binary Screenings on eligible projects, consistent with the guidance provided by the OEB in its Decision. The IRP Binary Screening results and the associated IRPA evaluation statuses, by project, can be found in **Appendix B – IRP**.

- **Alignment with Enbridge Inc.'s 2022 Enbridge Strategic Priorities**

  Enbridge Inc. published a revised Strategic Plan in 2022. The alignment of EGI's Asset Management Policy, Asset Management Strategies and dimensions of risk have been reviewed to confirm alignment and are found in **Section 4**.

- **Organizational structure changes to align roles and responsibilities within the integrated utility**

  The phase two Boundary and Real Estate initiative has been completed. EGI's regional boundaries and real estate assets across the province were reviewed to align current boundaries and strategically locate EGI's operating depots. The second phase of the initiative evaluated the area between the GTA West and Southeast regions. In January 2022, the regional borders were realigned to optimize the facilities within each new region.

- **Consolidation of asset data**

  The systems of record for asset data in the Union rate zones include Maximo for meter, work, damage and condition data; SAP-PM for station work and asset data; GIS for pipe data; and CORR for corrosion data. Some data that supports the Asset Management Plan is now being migrated to a datamart as part of the integration of work and asset management systems. Ongoing documentation and consolidation of these datasets will enable EGI to analyze inventories more efficiently for the combined utility and better support the Integrity and Asset Management functions.

- **Evolution of asset condition and strategies**

  Section 5, which addresses asset inventory, condition, risk/opportunity and strategy outcomes, has been updated to reflect the current understanding of assets. Specific project and program information is provided in **Section 6** to support each asset class's strategic plans. Key changes are:

  - Review, comparison and integration where feasible of asset strategies, asset classes, asset condition, inventories, programs and processes between the two legacy companies
  - Mapping the capital expenditures presented in **Section 5** to the asset class strategy
  - Identification of outstanding items that remain in legacy programs until they can be integrated

- **Integration items to highlight**

  Standards for installation, inspection, operation, maintenance, and asset decommissioning continue to be integrated. This work is ongoing; some legacy practices continue to be followed for each rate zone as analysis deemed it as appropriate for the assets at this time. Other design changes may be implemented on a go-forward basis. These new

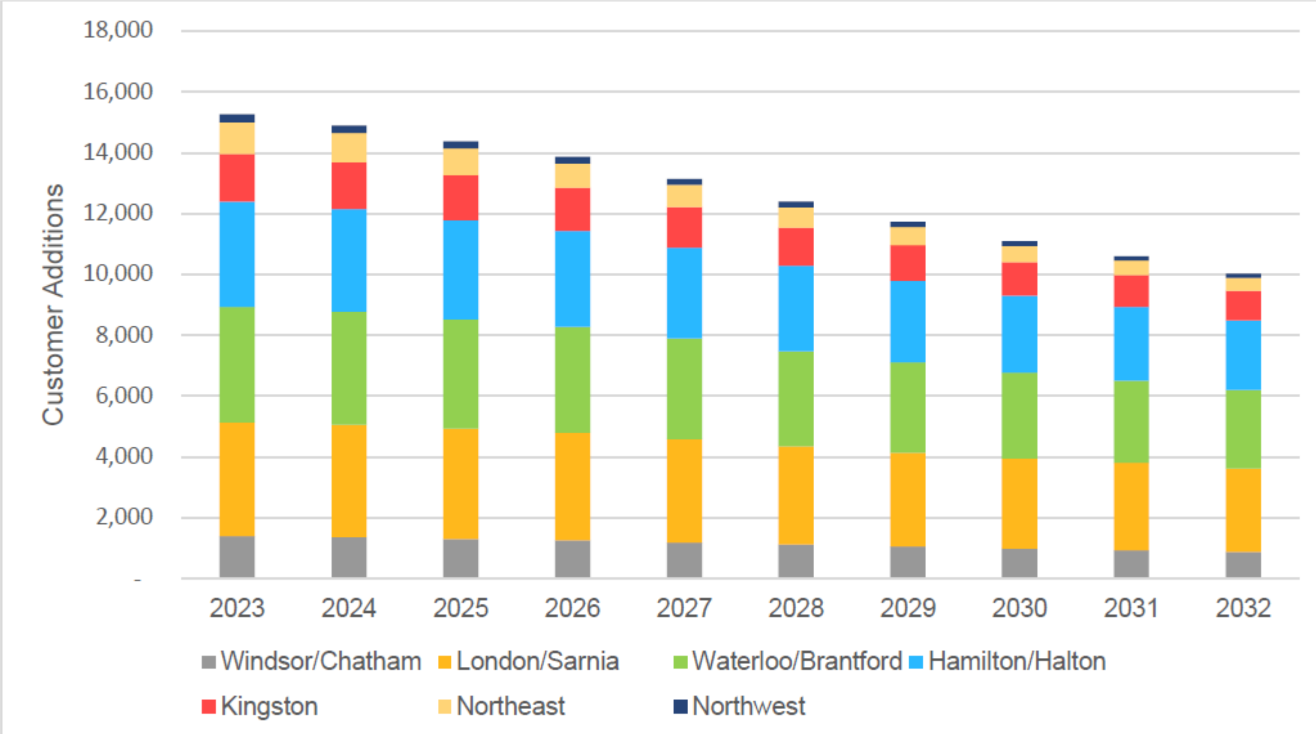


Figure 5.1-3: 10-Year Customer Growth Forecast - Union Rate Zones[5]

Over the 10-year forecast, the number of customer connections decline when factoring in energy transition. Customer additions, connections and growth are projected to remain flat in the short term and slightly decline thereafter.

- Due to the increasing scarcity of land supply and the associated increase in housing prices in EGI's franchise areas, particularly in the Greater Toronto Area (GTA), non-apartment housing starts in the area have seen a decline.
- Urban density in EGI's franchise areas is reflected in the fact that apartments have been accounting for a larger share of total housing starts. Given that one building counts as a single customer because of the use of bulk meters, lower customer additions do not reflect lower loads served, but simply a shift in the makeup of the sectoral source of growth.

[5] Based on 2022 LRP with Energy Transition Assumptions

Powering Ontario's Growth

Ontario's Plan for a Clean Energy Future

ontario.ca/energy

Ontario

The Canada Infrastructure Bank (CIB) has invested $970 million in the project to date, its largest investment in any clean energy project. The investment marked major step forward in demonstrating the significant opportunities of SMRs, and the important role of nuclear power in meeting future demand for reliable, zero-emissions power.

Ontario's leadership in new nuclear technologies, particularly SMRs, is raising the province's international profile to an unprecedented level.

Last November, the Minister of Energy concluded a successful trade mission to Czech Republic, Poland, and Estonia to discuss SMRs, strengthen existing relationships and support European allies looking to build their energy independence in the face of Russian aggression and to help reduce their reliance on coal power. The mission resulted in signing agreements with major European energy companies ČEZ and Synthos Green Energy.

Other jurisdictions are following Ontario's lead. Earlier this year, Estonia's Fermi Energia chose GE Hitachi's SMR technology – the BWRX-300 – for deployment, citing the Darlington SMR project as a factor in their selection decision. Poland's Synthos Green Energy has also signed agreements with Ontario manufacturers to build components in Ontario for SMRs that will be deployed in Poland, as well as a letter of intent with OPG to provide nuclear expertise to Synthos in developing its SMR program.

3.2 Competitive Procurements for New Build Electricity Generation and Storage

In October 2022 the Minister of Energy directed the IESO to acquire 4,000 MW of new electricity generation and storage resources through competitive procurements to ensure the province has the electricity it needs this decade to support a growing population and economy. This procurement will target 2,500 MW of stand-alone energy storage resources and a maximum of 1,500 MW of natural gas generation.

Energy Storage

As Ontario becomes a leader in the batteries of the future by connecting resources and workers in northern Ontario with the manufacturing might of southern Ontario, the procurement of a targeted 2,500 MW of clean energy storage represents the largest battery procurement in Canada's history.

In the first round of the procurement which concluded in May 2023, the IESO has acquired seven new battery storage projects, representing 739 MW of new storage supply.

These facilities will support the operation of Ontario's clean electricity grid by drawing and storing electricity off-peak when power demand is low and intermittent renewable generation is high and returning the power to the system at times of higher electricity demand. The grid will benefit from using more non-emitting energy at peak. Grid-scale energy storage also offers the potential to provide critical flexibility to help keep the system in balance.

Natural Gas Generation

Natural gas generation currently plays a key role in supporting grid reliability, with the ability to respond to changing system needs in ways other forms of supply cannot.

When electricity demand spikes on hot summer days, Ontario's natural gas generators can be turned on and ramped up quickly to ensure the province does not need to be reliant on emergency actions such as conservation appeals and rotating blackouts to stabilize the grid, according to the IESO.

While during most hours throughout the year Ontario can meet its electricity generation needs with nuclear, hydroelectric, bioenergy, wind and solar power, natural gas generation also acts as the province's insurance policy that can be turned on if the wind is not blowing or sun is not shining, or another generator is offline for repairs (see figure 3.3). There is currently no like-for-like replacement for natural gas and the IESO has concluded it is needed to maintain system reliability until nuclear refurbishments are complete and new non-emitting technologies such as storage mature.

This means natural gas will be needed until reliable replacements (such as hydrogen) have been identified, put into service, and demonstrated their capability.

To meet this near-term need the IESO has secured 586 MW of new natural gas capacity from expansions and efficiency upgrades at existing sites through the first round of procurements.

"The government and the IESO are taking a prudent approach by procuring a diverse portfolio of non-emitting resources, with limited natural gas to ensure system reliability over the short-term."

– Rocco Rossi
President and CEO, Ontario Chamber of Commerce

Enbridge Gas consumers have the option of adding RNG to their natural gas supply for $2 per month through the voluntary OptUp program. All the funds generated from the OptUp program are used by Enbridge to purchase locally produced RNG from StormFisher's facility in London, Ontario.

Natural gas will continue to play a critical role in providing Ontarians with a reliable and cost-effective fuel supply for space heating, industrial growth, and economic prosperity. With developments in energy efficiency, and low-carbon fuels such as RNG and low-carbon hydrogen, the natural gas distribution system will help contribute to the province's transition from higher carbon fuels in a cost-effective way.

1.3 Oil and Refined Petroleum Products

Petroleum products, derived from crude oil, comprise just under 40 per cent of Ontario's end-use energy consumption. Petroleum products are critical fuels to move goods and people, heat homes and have non-energy applications.

Transportation fuels account for about 80 per cent of Ontario petroleum consumption —gasoline (49 per cent), diesel (22 per cent), and jet fuel (8 per cent). Non-energy uses of petroleum include inputs to the petrochemical sector (7 per cent) and asphalt (3 per cent). Other applications – including lubricants and heating oil – account for about 10 per cent of overall petroleum demand.

While the first oil well in North America was drilled in Oil Springs, near Sarnia, Ontario crude oil production now accounts for less than one per cent of Ontario refinery requirements today. Ontario relies almost entirely on imported crude oil, primarily delivered by interprovincial and international pipelines. The main pipeline network (Enbridge Mainline) supplying Ontario with crude oil originates in Western Canada and passes through the U.S. before entering Canada near Sarnia (Enbridge Line 5 and Line 78). U.S. crude oil production can also access the U.S. portion of the Enbridge Mainline and supply Ontario. In 2021, about 86 per cent of Ontario's crude oil requirements came from Alberta, Saskatchewan, and British Columbia; 14 per cent came from the U.S.

Ontario's four refineries supply approximately 78 per cent of Ontario's refined product demand, with Quebec and the U.S. supplying the remainder. Pipelines, rail, marine (during the shipping season) and trucks (for delivery to retail gasoline stations) are all part of the supply chain to move fuel from refineries to end-users. Petroleum product infrastructure (terminals, bulk plants, pipelines, retail stations) is owned by private companies in Ontario.

The Sarnia Natural Gas Liquids (NGL) factionator is one of the main sources of propane and butane for eastern Canada. It processes NGL mix delivered from western Canada by the Enbridge Mainline (Lines 1 and 5). From Sarnia, propane is delivered by rail and truck to locations in Ontario, Quebec, other eastern Canadian provinces, and to export markets in the U.S. Midwest and East Coast.

Planning Ahead For 2030-2050

Planning Ahead For 2030-2050

4.0 Introduction

While the Ontario government is moving forward on many fronts to secure the electricity the province needs for the decade, additional action is needed t o plan for and meet expected long-term demand between 2030 and 2050.

IESO forecasts that the need for electricity system capacity in Ontario could, under one potential scenario, more than double, from 42,000 MW today to 88,000 MW in 2050. Over this time, up to 20,000 MW in capacity may be needed just to replace generation that will come to the end of its life or be phased out.

While some forms of generation like natural gas generation or intermittent renewables can be built relatively quickly, large infrastructure which can provide baseload power such as hydroelectric, nuclear facilities, and the transmission to get it to population and economic centres, can take 10 to 15 years to build.

The Ontario government is acting now to develop new generation capacity including assessing site potential for the first large-scale nuclear build since 1993, expanding the province's SMR program, and adv ancing long-duration storage projects so that these facilities are ready when they are needed.

In keeping with its forward-thinking approach to energy planning, the Ontario government asked the IESO to deliver critical reports to inform next steps. These reports and input from Ontarians have formed the basis for the additional actions the Ontario government is taking to meet the province's needs in the longer term which are described in this chapter.

4.1 Pathways to Decarbonization

In October 2021, the Minister of Energy asked the IESO to develop a *Pathways to Decarbonization* report. Released in December 2022, the report recommends "no-regrets" actions that could be taken today to develop needed electricity resources with long-lead times.

1. Accelerating current efforts to acquire new non-emitting supply, including the implementation of recent conservation and demand management directives.

2. Beginning the planning, siting and environmental assessment work needed for new nuclear, long-duration storage and hydroelectric facilities, as well as transmission infrastructure, to allow for faster implementation.

3. Investing in emerging technologies like low-carbon fuels. Further work is needed to determine if they can replace at scale some of the flexibility that natural gas currently provides the system.

4. Galvanizing collaboration among stakeholders and Indigenous communities.

5. Ensuring that regulatory, approval and permitting processes are ready to manage future investment at scale.

Annual Planning Outlook

Ontario's electricity system needs: 2024-2043

December 2022

Connecting Today.
Powering Tomorrow.

Executive Summary

Ontario's economy, projected to see continued development over the coming decades in a number of sectors, is increasingly being driven by decarbonization and electrification. The 2022 APO demand forecast anticipates increased consumption from projects such as new battery manufacturing facilities and mining operations that support decarbonization.

The forecast also illustrates how electrification is changing the shape of Ontario's demand. Accelerated electric vehicle adoption and charging profiles, new building electrification policy, and changes to agricultural sector demand profiles are expected to shift the overall annual system peaks from mid-summer afternoons to mid-winter mid-night periods.

The result is a moderate rise in the average growth of demand, reaching about 1.9 per cent annually compared to 1.7 per cent in the 2021 forecast. This increasing rise, coupled with the impact of nuclear retirements and refurbishments, and expiring generation contracts over the next decade, is contributing to anticipated capacity shortfalls in the mid-2020s.

The IESO has been planning for these needs and over the past two years has made great progress in meeting them — this year's report shows a significant reduction in the mid-2020s gap as a result of actions taken, including the rescheduling of refurbishments, government decisions, and supply procurements through the IESO's Resource Adequacy Framework, including the successful conclusion of this year's first Medium-Term RFP.

The framework continues to successfully procure competitive resources for short, medium and long-term reliability, as with the annual December Capacity Auction. Currently, 4,000 MW of new capacity is also being targeted in the first Long-Term RFP to help address the remaining reliability concerns demonstrated in this report. Final results will be incorporated into next year's planning outlook.

This is a pivotal point for the electricity system, and looking further ahead, it is clear that ensuring reliability, sustainability and affordability in the future depends on maintaining this momentum. New supply must be secured as needs continue to grow and evolve and Ontario sees an expanding reliance on the electricity grid. In addition, as a requirement for more energy production emerges toward the end of the decade, a broader range of supply options could be considered for future procurements.

The APO, along with the *Annual Acquisition Report* (AAR), is a tool that directly informs these types of resource acquisition decisions. The APO is a planning document, using current, confirmed information projecting forward, and giving the sector the most predictive signals possible to serve as a guide for near-term investment decisions and activity.

- Government policy on small hydroelectric program
- 2022 AAR Capacity Auction forward guidance targets
- Bilateral negotiations for Lennox GS and Brighton Beach GS

Case 1 reflects resources until their contract/commitment period ends.[8] It defines system needs where some of which can be met by existing resources. Case 2 includes the resources in Case 1, and assumes that these resources continue to be available post-contract/-commitment expiry for the duration of the study period. Case 2 helps identify minimal new incremental resources that will be needed to meet system needs.

Within the cases, and due to the timing of this report's data analysis, Pickering NGS Units 5-8 are assumed to retire by the end of 2025 and therefore do not reflect the Ministry of Energy announcement made on September 29 regarding continued operation and refurbishment. The proposal also requires CNSC approval. The supply cases also do not include resources expected through the expedited long-term procurement, long-term 1 RFP and same-technology upgrades procurements, targeting of approximately 4,000 MW of capacity. Once the successful proponents are announced, these resources will be reflected in subsequent APO outlooks. The hydroelectric fleet is assumed to be available for the duration of the outlook in both cases, given its long technical life.

The supply outlook is shown for both installed capacity, or a resource's maximum output, and effective capacity at summer and winter peak, taking into account factors such as fuel availability, ambient conditions and/or outages (see Table 1). This makes effective capacity a more meaningful measure of a resource's ability to meet reliability needs.

Table 1 | Ontario's Summer 2023 and Winter 2023/2024 Effective Capacity

Fuel	2023 Installed GW	2023 Summer Effective GW	2023/24 Winter Effective GW
Nuclear	10.5	8.4	10.1
Gas/oil	10.6	8.7	9.4
Hydroelectric	9.4	6.5	7.3
Wind	5.5	0.6	1.6
Solar	2.7	0.7	0
DR[9]	1.2	0.8	0.6
DL	0.3	0.2	0.1

[8] Case 1 assumes that hydroelectric resources are available post-contract expiry.

[9] Demand response (DR) and dispatchable loads (DL) reflect the results of the IESO's 2021 Capacity Auction.

In this section, the capacity deficit represents the total amount of capacity, on an effective capacity basis, that the IESO must acquire to satisfy LOLE requirements. The capacity deficits for summer and winter periods for supply Cases 1 and 2 are shown in Figure 19 and Figure 20. Summer capacity needs emerge in 2026 with long-term needs being driven by nuclear retirement and refurbishment, resources reaching the end of their contracts, and increased in demand. Even with the system forecasting a transition to a winter peak in 2036, system needs are generally greater in summer than in winter due to seasonal differences in resource performance.

Figure 19 | Summer Capacity Surplus/Deficit

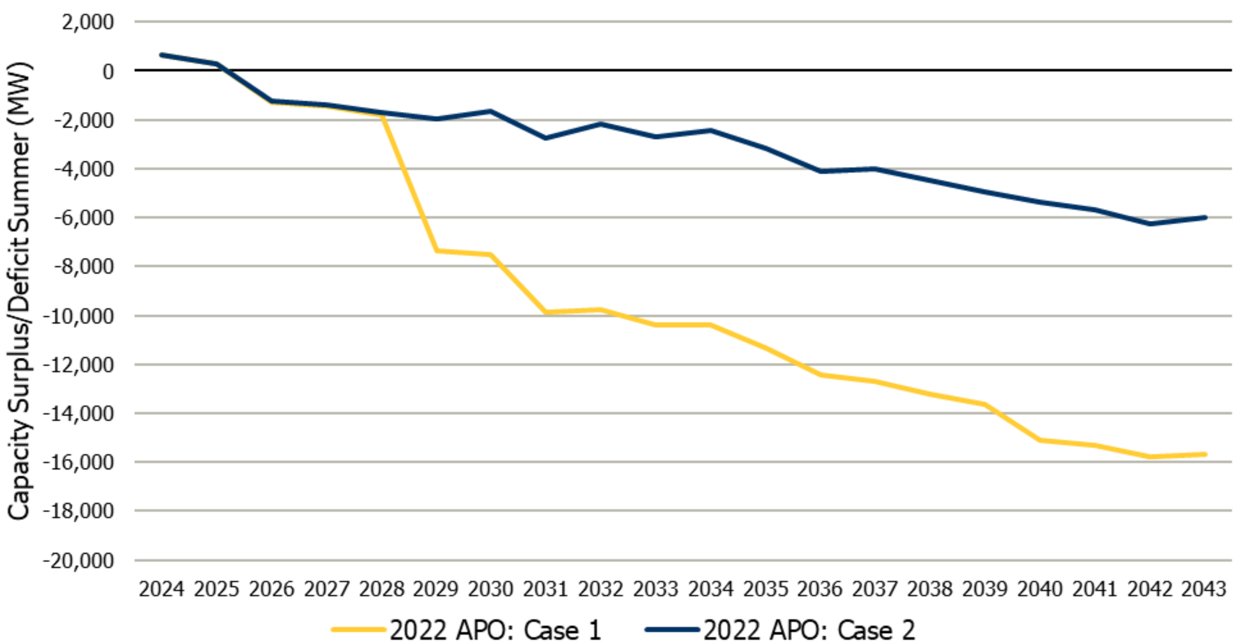


Figure 21 | Energy Adequacy Outlook (Case 1)

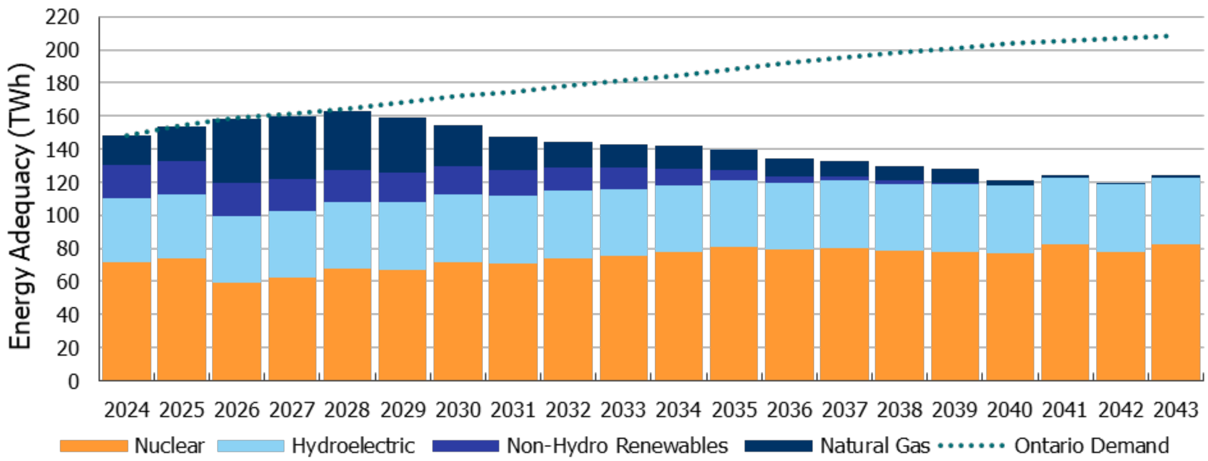
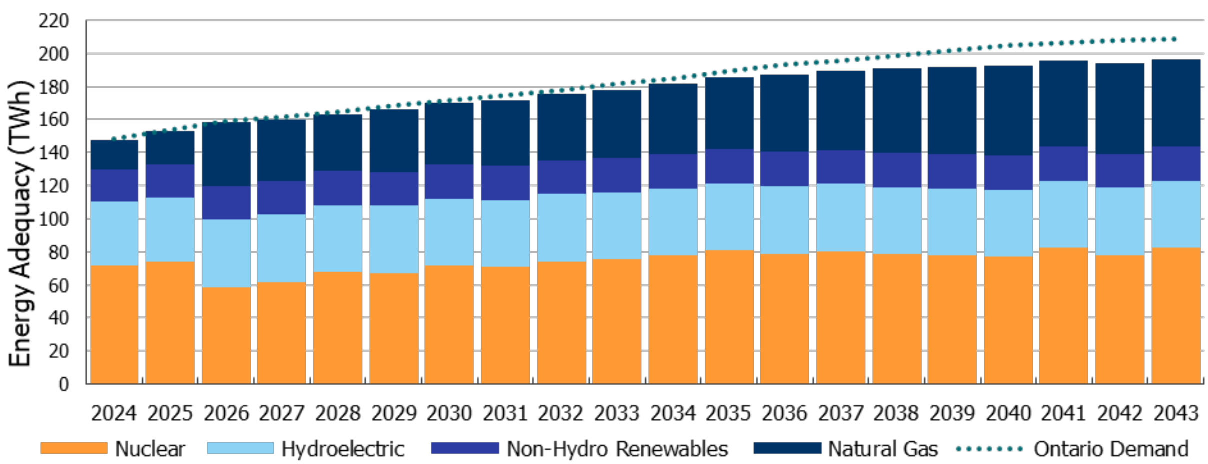
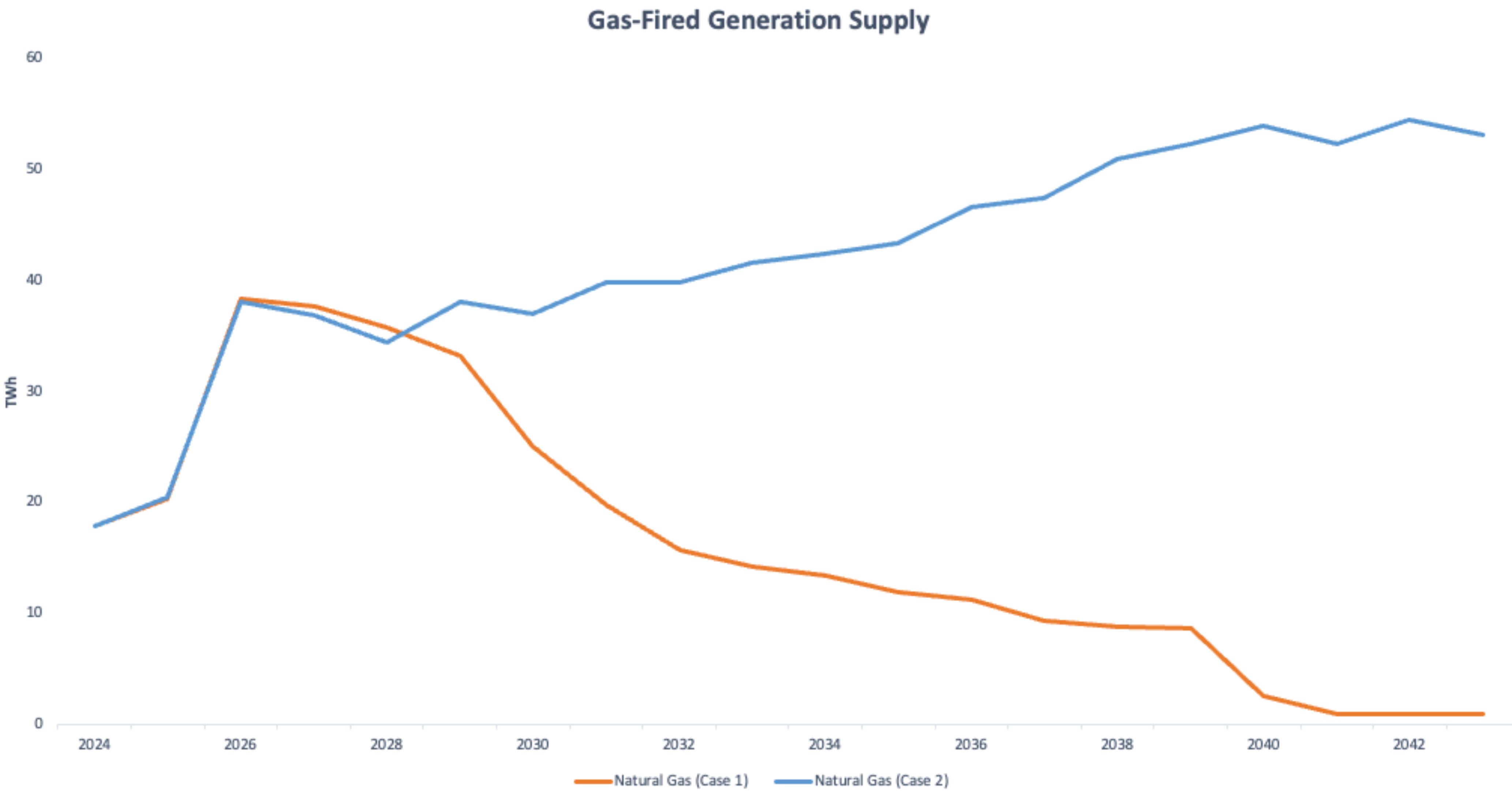


Figure 22 | Energy Adequacy Outlook (Case 2)



Utilizing the existing and committed fleet, absent the availability of existing resources post contract expiry in Case 1, an energy shortfall is observed in the late 2020s. Some of this can be met should existing resources remain available post contract expiry. In Case 2, existing resources, should they continue to be available post contract expiry, can meet energy demands in most circumstances until the mid-2030s. An energy shortfall begins to emerge near the end of the planning horizon, driven largely by increases in demand, indicating a need for new incremental resources. The inclusion of interactions of imports and exports with IESO's neighbouring system will change the dynamics of the generation output.


Gas-Fired Generation Supply
TWh
60
50
40
30
20
10
0
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Natural Gas (Case 1)
Natural Gas (Case 2)

PATHWAYS TO NET ZERO EMISSIONS FOR ONTARIO

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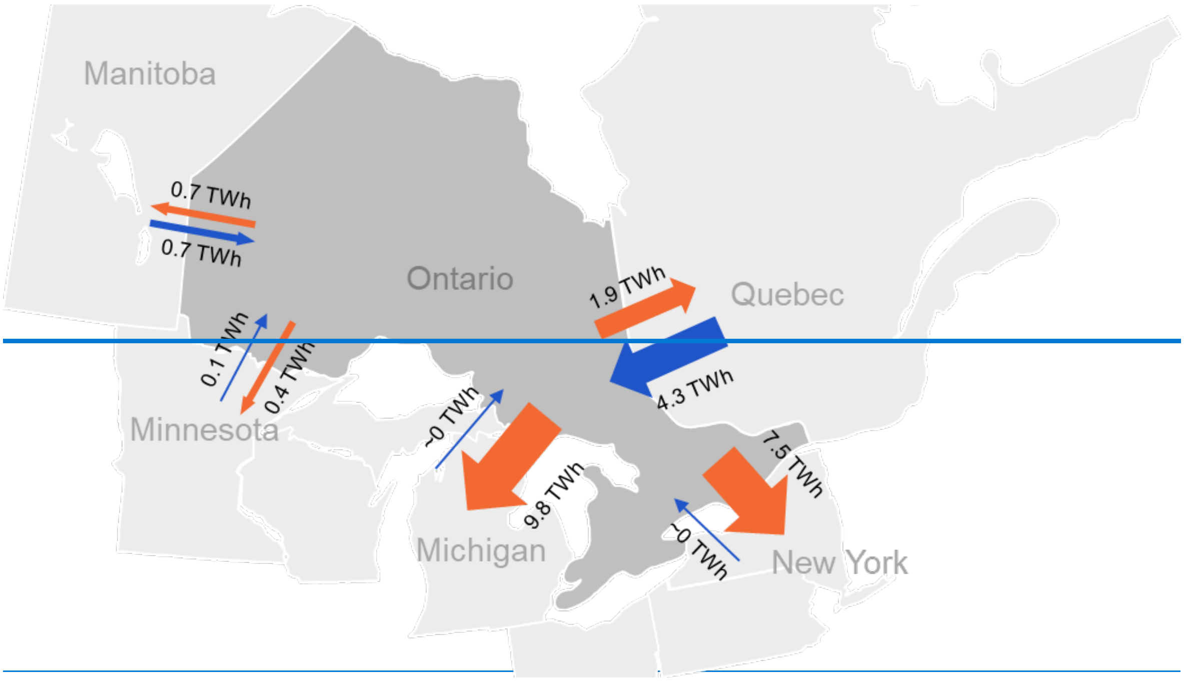
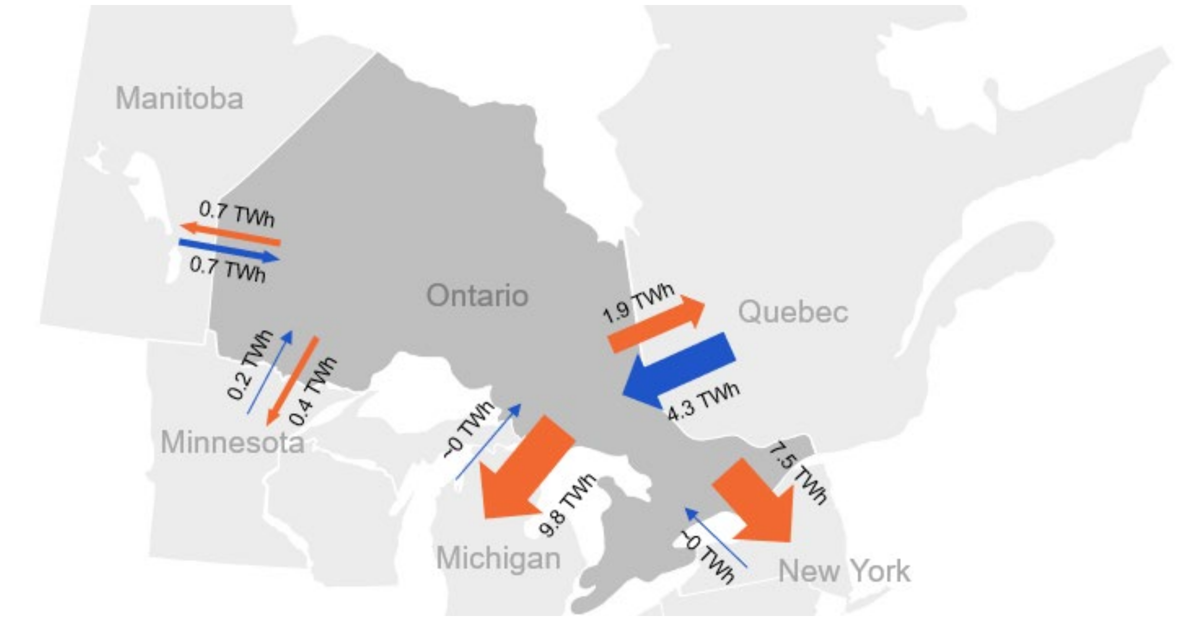
While this study aims to adequately simulate an increasingly integrated electricity and gas system in Ontario, the results of this analysis are not intended to dictate when and where infrastructure investments will take place. The results presented in this report are purely reflective of a cost optimization modelling exercise and may not reflect specific technical, operational, and locational (spatial) constraints of the Ontario electricity and gas systems. The pathway results presented in this report are contingent on developments in provincial and federal energy policy, regulation, and other related areas. All analysis is based on credible assumptions, but these are subject to the uncertainty typical in long-term forecasting exercises. Findings from this study should be read in this context and should take into consideration limitations of the analysis.

Figure 3. Electricity Imports and Exports with Neighboring Regions (2020)





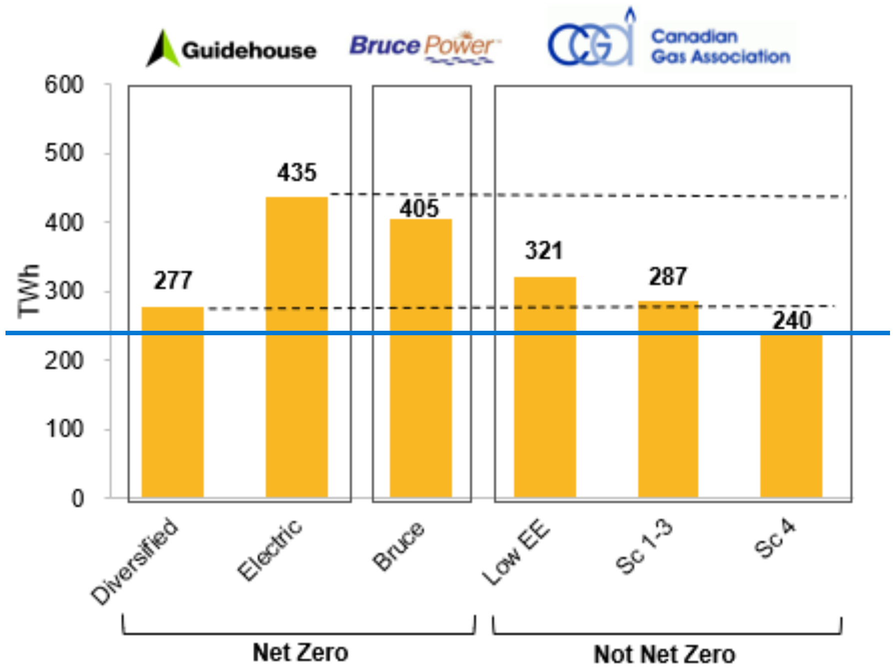
2.2 Ontario's Natural Gas System

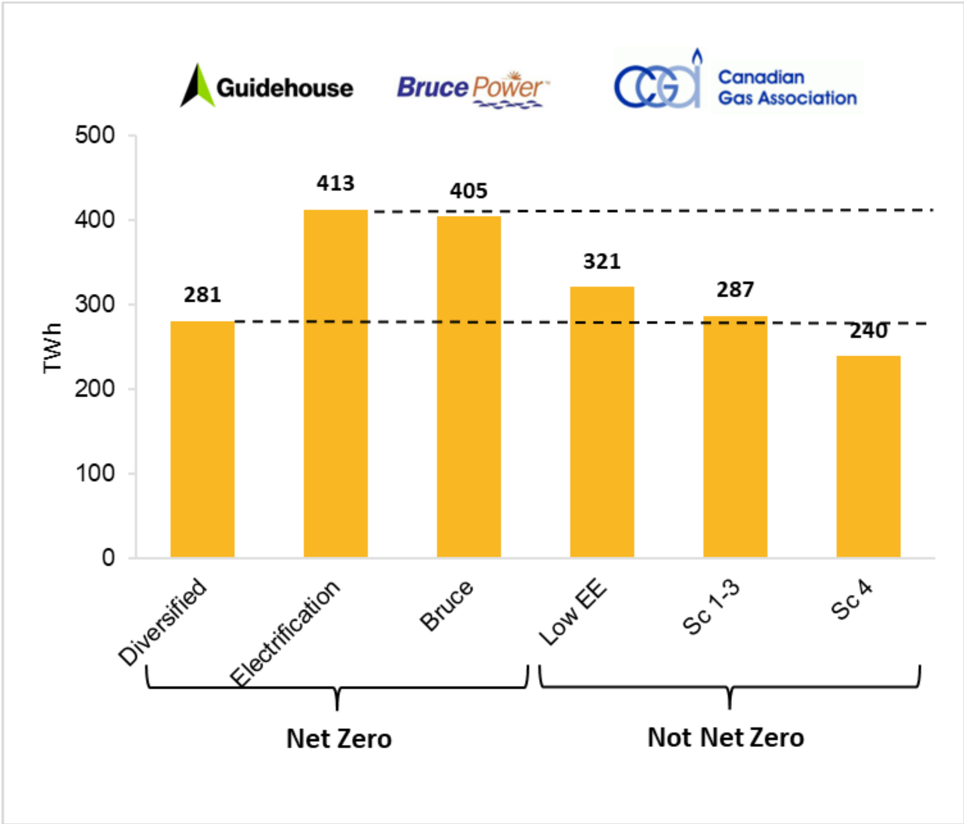
In 2019, Ontario consumed approximately 940 PJ of natural gas.[27] Converted to electricity units, this is roughly 261 TWh, which is almost twice the province's annual electricity consumption (~135 TWh/year). Figure 4 shows this comparison of annual electricity and gas demand.

Natural gas demand is primarily driven by building heating (63% of demand) and industry (37% of demand), with very limited use in transport. Most of the natural gas consumed by buildings is used for heating during the winter months, and more than 80% of building heating in Ontario is fueled by natural gas.[28] Natural gas is also used in industrial processes such as the manufacturing of metals, chemicals, and fertilizers, and pulp and paper processes.[29]

target for 2050, and therefore the scope of the emission reductions contemplated in the study do not achieve net zero. In comparison, both Guidehouse demand scenarios do achieve net zero.

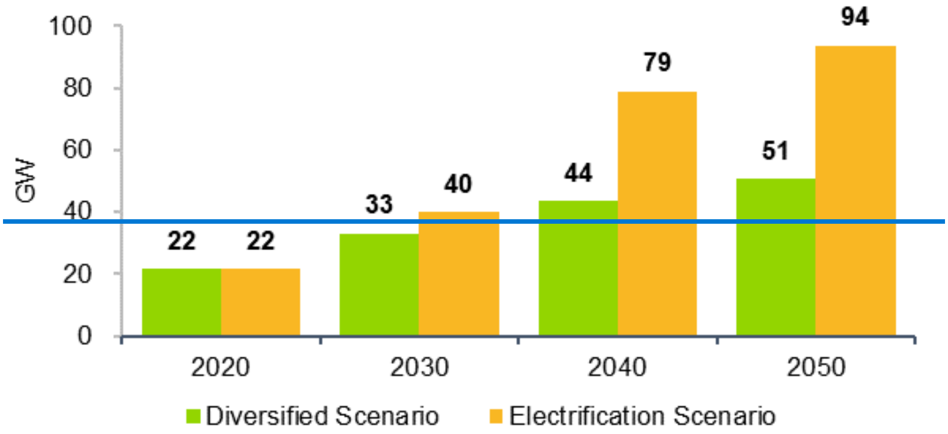
Figure 12. Comparison of Electric Demand Projections, 2050

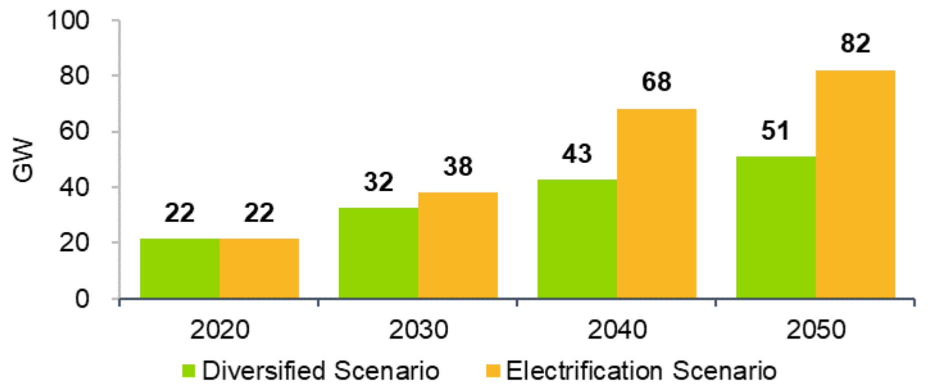




Source: Guidehouse analysis and reports listed in text above need to be well-insulated and weatherized to minimize heat leakage. This analysis assumes that homes with electric heat pumps undergo deep energy efficiency retrofits. The Electrification scenario assumes that, by 2050, 85% of all buildings will convert to electric heating systems and most will adopt cold climate air-source heat pumps over geothermal heat pumps due to the up-front cost of geothermal systems. This results in a ~~three~~nearly four-fold increase in system peak compared to ~~today~~2020. In contrast, the Diversified scenario assumes that 55% of buildings will be heated by gas heat pumps, and that the penetration of electric heat pumps only climbs to 40% by 2050. This results in an increase in electricity system peak to more than double what it is today. The change in electricity system peak over the study period for both scenarios can be seen in Figure 9 below.

Figure 9. Electricity System Peak Demand





Gas system peak demand in the province today is 11 million m³/hr which is equivalent to 121 GW. In both net zero scenarios, the peak energy demand rapidly decreases as imported conventional natural gas from fossil reserves is replaced by electricity, hydrogen, and RNG. In some industry sector cases, conventional natural gas is outfitted with CCS technology to reduce emissions. The Diversified scenario assumes that methane in the form of RNG and NG + CCS will play a larger role in the energy system in 2050 compared to the Electrification scenario.

Hydrogen peak demand starts at zero in 2020 in both scenarios. In the Diversified scenario, hydrogen, as a proportion of peak demand scales up considerably to power industry, transportation, and buildings. In the Electrification scenario, hydrogen is mostly used in the industrial sector for processes that are difficult to electrify, such as high temperature heating. The methane and hydrogen peak demands over the study period can be seen in Figure 10 below.

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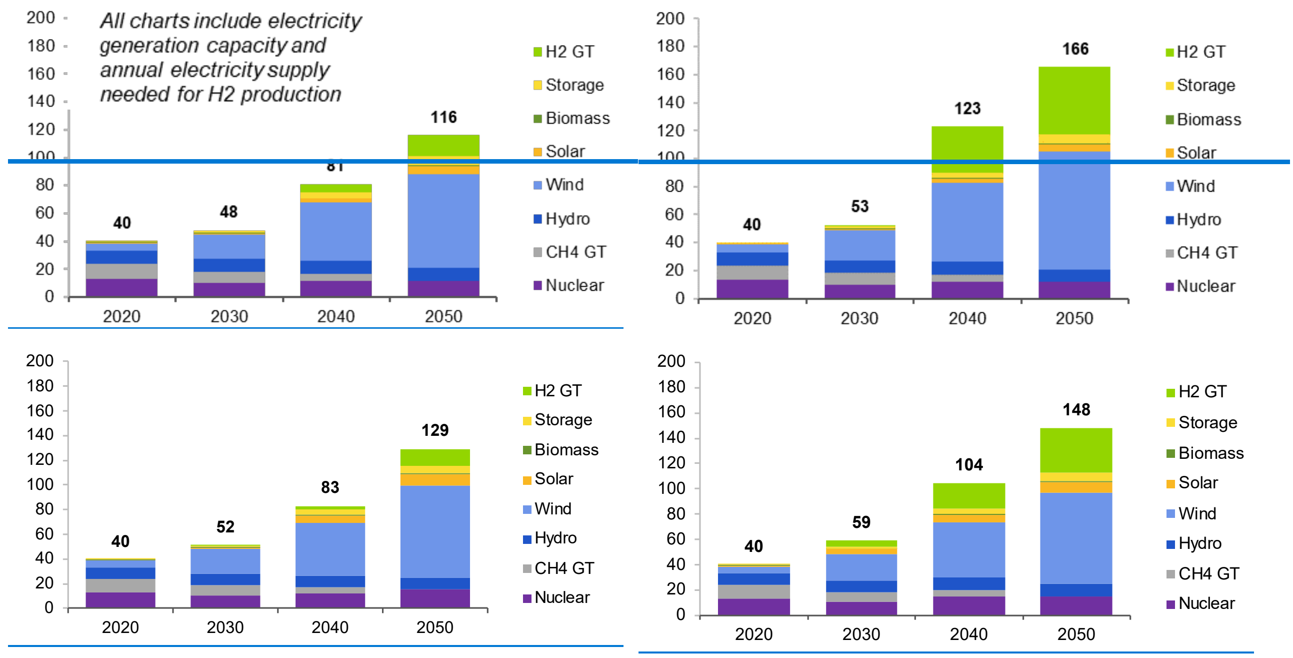
Study	Pathways to Decarbonization	Pathways to Decarbonization	North American Renewable Integration Study (NREL)	North American Renewable Integration Study (NREL)	Shifting Power Zero-Emissions Electricity Across Canada by 2035 (David Suzuki Foundation)	Pathways to Net Zero Emissions for Ontario (Enbridge)	Pathways to Net Zero Emissions for Ontario (Enbridge)	Canada's Energy Future (Canada Energy Regulator)
Year	2022	2022	2021	2021	2022	2022	2022	2021
Jurisdiction	Ontario	Ontario	Canada and US	Canada and US	Ontario	Ontario	Ontario	Canada
Scenario description	Moratorium in gas	Net zero with high electrification	92% reduction in electricity emissions (compared to 2005) by 2050	92% reduction in electricity emissions (compared to 2005) by 2050. Electrification doubles demand from 2020 to 2050	Zero electricity sector emissions plus electrification	Net Zero, with diversified resource mix including clean fuels	Net zero with high electrification	Evolving Policies to Decrease CO2 Emissions
Energy Demand (TWh)	166	300	154	278	~290	277 TWh (plus 193 for H2 production)	435 (plus 53 for H2 production)	194
Peak Demand (GW)	26 (Summer peak)	60 (Winter peak)				51	94	
Wind (GW)	6	18	17	46	80	68	84	22.00
Solar (GW)	6	6	8	34	20	5	5	11.10
Water (GW)	9	10	9	9	10	10	10	9.80
Bioenergy (GW)	0	0				1	2	0.50
Nuclear (GW)	11	26	3	3	0	12	12	10.90
Storage (GW)	3	2	0	1		5	5	0.00
Natural Gas (GW)	8		21	30	0			11.20
Hydrogen (GW)		15				15	48	
Scenario Timeline	2035	2050	2050	2050	2035	2050	2050	2050
Technology exclusions	Carbon capture, utilization and storage	Carbon capture, utilization and storage	No new hydro Nuclear retires at end of life	No hydrogen/RNG	No new hydro Nuclear retires at end of life; no new nuclear No offshore wind No hydrogen/RNG	None	None	None
Operability Analysis	Mix assessed against attributes of flexibility, durability and diversity	Not performed	Production-Cost model dispatch on hourly and 5-min basis; Probabilistic	Production-Cost model dispatch on hourly and 5-min basis; Probabilistic	Hourly dispatch analysis	Four representative days for hourly dispatch	Four representative days for hourly dispatch	Hourly dispatch analysis
Investment costs	Analysed	Analysed	Analysed	Analysed	Analysed	Analysed	Analysed	Analysed
Siting Requirements	Not Considered	Not Considered	Not Considered	Not Considered	Not Considered	Not Considered	Not Considered	Not Considered
Transmission	Copper Plate in model, transmission analysis performed exogenously	Copper Plate in model, transmission analysis performed exogenously	Four Ontario Transmission Zones; Interconnections to neighbours	Four Ontario Transmission Zones; Interconnections to neighbours	Interconnections between Provinces	Interconnections to neighbours	Interconnections to neighbours	N/A

Figure 14. Electricity Supply for the Diversified and Electrification Scenarios[78,79]

Diversified	**Electrification**
Electricity Supply Capacity (GW)	**Electricity Supply Capacity (GW)**



[78] The electricity supply capacity and supply mix graphs reflect the capacity and supply needed to produce green hydrogen.
[79] Direct demand is the electricity needed to meet end user demand without any conversion across energy carriers (i.e., converting electricity into hydrogen). Indirect demand is the electricity needed to produce hydrogen via electrolyzers.

Electricity Supply Capacity

	GW		2020	2030	2040	2050
Electricity	ON	Battery Storage	0.0	1.3	3.9	6.5
Electricity	ON	Hydro Pumped Storage	0.2	0.2	0.2	0.2
Electricity	ON	O/CCGT - CH4 Existing	10.8	7.2	3.6	0.0
Electricity	ON	O/CCGT - CH4 New	0.0	1.0	1.6	0.0
Electricity	ON	O/CCGT - H2 New	0.0	5.1	20.1	34.5
Electricity	ON	Biomass	0.6	0.6	0.6	0.6
Electricity	ON	Fossil Fuel Thermal (Coal, Pea	0.0	0.0	0.0	0.0
Electricity	ON	Generic - Generator	0.0	0.0	0.0	0.0
Electricity	ON	Hydro	9.3	9.3	10.0	10.0
Electricity	ON	Nuclear	13.1	10.0	11.6	11.6
Electricity	ON	Solar PV	0.5	3.7	5.9	8.5
Electricity	ON	Wind Offshore	0.0	0.0	0.0	0.0
Electricity	ON	Wind Onshore	5.5	20.7	42.9	71.8
Electricity	ON	Electricity Transmission Line	0.0	0.0	0.0	0.0
Electricity	ON	Biomass + CCS	0.0	0.0	0.3	0.6
Electricity	ON	Nuclear SMR	0.0	0.3	3.3	3.3

		2020	2030	2040	2050
1	Nuclear	13.09	10.31	14.94	14.94
2	CH4 GT	10.77	8.18	5.19	0.00
3	Hydro	9.25	9.27	10.02	10.02
4	Wind	5.53	20.68	42.93	71.83
5	Solar	0.48	3.65	5.95	8.49
6	Biomass	0.56	0.56	0.83	1.11
7	Storage	0.17	1.47	4.10	6.70
7	H2 GT	0.00	5.11	20.11	34.53
Total		**40**	**59**	**104**	**148**

Increase 2020-2050	**3.70**

for hydrogen production. These trends can be observed in greater detail in Figure 14.

Both scenarios require a large scale-up in wind capacity and hydrogen-fired gas turbines.[75] Most of the increase in generation capacity results from an increase in installed wind. In the Diversified scenario, wind capacity increases in the near term to ~~18~~21 GW in 2030 and ~~42~~43 GW in 2040, rising to ~~68~~75 GW in 2050. In the Electrification scenario, it increases ~~even more dramatically~~at a similar rate, to 21 GW in 2030, ~~57~~43 GW in 2040 and ~~84~~72 GW in 2050. To meet peak demand and to enable this large scale-up in variable generation capacity, there is a significant need for dispatchable generation such as hydrogen-fired gas turbines and battery storage, particularly in the Electrification scenario. By 2040, ~~33~~20 GW of hydrogen gas turbine capacity is installed in the Electrification scenario, and this number rises to ~~48~~35 GW by 2050. In the Diversified scenario, only ~~15~~13 GW of hydrogen gas turbine capacity is installed by 2050 due to the lower electricity--system peak~~ and less reliance on wind generation~~. In both scenarios, new battery storage capacity complements the build out of hydrogen gas turbine capacity to provide the electricity system with flexibility and resiliency.~~[76]~~

Electricity peak demand increases substantially in both scenarios. In the Diversified scenario, peak demand ~~increases over 2 times~~more than doubles, from 22 GW in 2020 to 51 GW by 2050. In the Electrification scenario, peak demand increases almost 4 times, to ~~94~~82 GW by 2050. The Electrification scenario sees a drastic increase in peak demand for the 2030-2040 period (Figure 14) as a result of the high degree of electrification in buildings, driven by the government's goal that by 2035, all space heating technologies for sale in Canada meet an energy performance of more than 100%.[77] The Diversified scenario shows a slower growth in peak demand post-2030 because it assumes a higher portion of homes switch to gas heat pumps, which have a small impact on peak electric demand. The Electrification scenario is primarily dependent on a single energy system (electricity) and the implications on energy system resilience should be studied in more depth. Consideration of energy system resilience is important given the increased risks of extreme weather events and potential cyberattacks.

Annual electricity generation is comparable in both scenarios. While electricity demand is significantly higher in the Electrification scenario compared to the Diversified scenario, the Diversified scenario also requires significant electricity supply to produce hydrogen. By 2050, roughly ~~193~~181 TWh of electricity supply is used in the Diversified scenario for hydrogen production, whereas ~~53~~37 TWh of electricity supply is needed in the Electrification scenario.

[75] Guidehouse's analysis focuses on the use of hydrogen gas turbines in both scenarios rather than natural gas-fired gas turbines. Hydrogen gas turbines are intended to reflect natural gas-fired gas turbines retrofitted to hydrogen or new hydrogen gas turbines. Our analysis does not make any explicit assumptions on whether existing gas turbines are retrofitted, nor when. For simplicity, we assume all hydrogen gas turbines are costed out as new gas turbines.

~~[76] In the Electrification scenario, the amount of battery storage capacity decreases from 2040 to 2050. This is because storage capacity installed in 2030 is retired in 2045 based on a storage lifetime of 15 years. In 2030, 7 GW of battery storage is installed. An additional 2 GW is installed in 2040, for a total capacity of 9 GW of storage available in 2040. By 2050, the 7 GW of storage capacity installed in 2030 is retired, and while new additional storage capacity is installed in 2050, there is a drop in total storage capacity between 2040 and 2050. This drop in storage capacity does not impact the resiliency and reliability of the electricity system because there is a large increase in hydrogen gas turbine capacity over the same time period (2040-2050).~~

[77] Energy and Mines Ministers' Conference (2017). Market transformation strategies for energy-using equipment in the building sector. p.16. Available: https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/Market-Transformation-Strategies_en.pdf

Pathways to Decarbonization

A report to the Minister of Energy to evaluate a moratorium on new natural gas generation in Ontario and to develop a pathway to zero emissions in the electricity sector.

DECEMBER 15, 2022

ieso
Connecting Today.
Powering Tomorrow.

PUBLIC

Resource Build-out

By 2050, about 20,000 MW of today's supply is still in operation, made up primarily of large nuclear reactors and hydroelectric. Most existing renewable generation is assumed to have reached its end of life, while natural gas is phased out consistent with the zero-emissions goal.

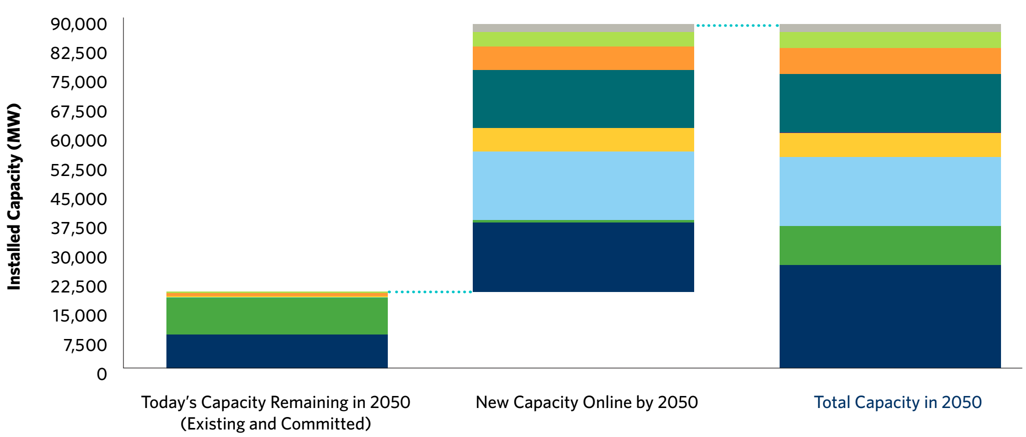
In order to reliably meet the new winter peak demand of 60,000 MW, an additional 69,000 MW of installed capacity is added, in addition to nearly 5,000 MW of CDM that is already included in the demand forecast (see Figure 12).

This scenario includes an additional 17,800 MW of nuclear supply. By 2050, as most of Ontario's existing wind facilities will have reached their end of life, this scenario also includes an additional 17,600 MW of wind and 650 MW of new hydroelectric.

Solar resources provide value during summer peaks in the early years of the scenario. As the system transitions from summer to winter peaks, the value of these resources diminishes and incremental capacity levels off at 6,000 MW in 2036. In addition, as under the Moratorium scenario, the existing 2,500 MW of batteries limited the value of further short-term storage through to 2035. An additional 2,000 MW of long-duration storage is added in the late 2030s to meet adequacy needs.

Assuming its availability in 2036, the analysis suggests that hydrogen becomes a cost-effective[10] resource for reducing peak demand.

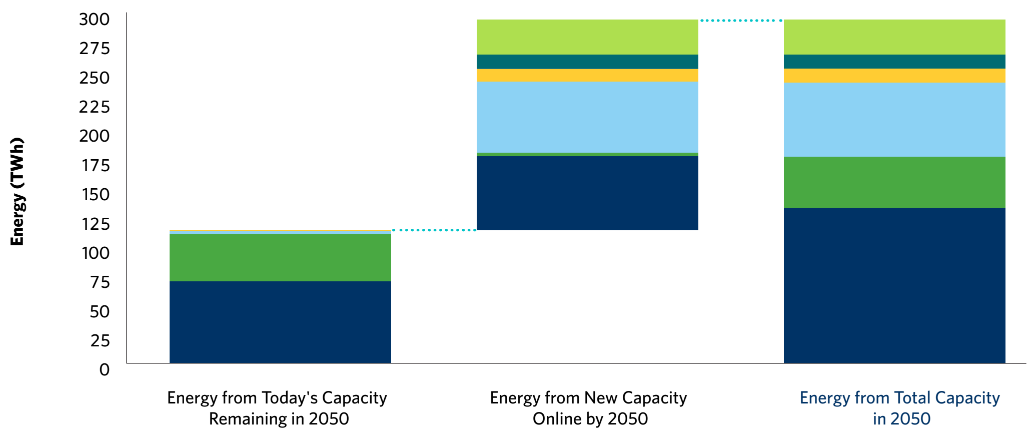
Figure 12 | Pathway Scenario – Installed Capacity in 2050



	Today's Capacity Remaining in 2050 (Existing and Committed)	New Capacity Online by 2050	Total Capacity in 2050
Storage	0	2,000	2,000
Imports	331	3,800	4,131
Demand Response	808	5,936	6,744
Hydrogen	0	15,000	15,000
Bioenergy	41	0	41
Solar	259	6,000	6,259
Wind	160	17,600	17,760
Hydroelectric	9,348	657	10,005
Nuclear	8,653	17,800	26,453
Total MW	**19,600**	**68,793**	**88,393**

[10] Although estimates are based on the most reliable information available at the time of writing, considerable uncertainty remains around cost assumptions for various fuels over the study time period.

Figure 13 | Pathway Scenario – Energy in 2050



	Energy from Today's Capacity Remaining in 2050	Energy from New Capacity Online by 2050	Energy from Total Capacity in 2050
Storage	0	0	0
Imports	0	30	30
Demand Response	0	0	0
Hydrogen	0	12	12
Bioenergy	0	0	0
Solar	1	11	12
Wind	2	62	63
Hydroelectric	41	3	44
Nuclear	70	63	133
Total TWh	**113**	**181**	**294**

Using Ontario's existing interties with Hydro-Québec, as well as incremental new infrastructure in both Ontario and Québec,[11] this scenario includes 4,000 MW of imports. Given Hydro-Québec's current winter capacity constraints, which are outlined above, we assumed that the firm imports would be from new hydroelectric and new wind facilities built in Québec.

By 2050, the total installed capacity reaches about 88,400 MW. In contrast, current installed capacity is about 40,000 MW.

This mix was found to be capacity and energy adequate.

Operability and the future electricity grid

As discussed throughout this report, ensuring reliability is of paramount importance. For a system to be reliable, it must have the flexibility to respond to sudden changes as well as extreme conditions. Future supply mixes will not have some of the traditional resources that currently provide these services, and ensuring reliability without them contains many unknowns. It will require detailed planning studies that incorporate novel approaches, tools and a thorough understanding of the location and technological features of individual resources as they are integrated into the electricity grid. As a result, the IESO has not performed an operability assessment on this scenario. The IESO will work with peers and industry experts over the coming years to address this challenge.

[11] Incremental new infrastructure would include a new intertie between the two provinces and additional reinforcements in Ontario to deliver the capacity to the load centre in the GTA. It would also include necessary reinforcements on the Québec side.

Transmission

The transmission requirements for the Pathways scenario are extensive. In order to achieve a starting point for a system that is capable of incorporating the resources identified and reliably supplying the forecast demand, a significant build-out of Ontario's existing 500 kV network would be required, focusing on paralleling the existing network where possible. Beyond reviewing the impact of different levels of reinforcement to the 500 kV network, the need for an additional 230 kV of bulk reinforcements was also identified to enable the supply mix. (Full details are available in Appendix B, section 2.)

Meeting Forecasted Demand

The challenge of connecting the forecasted demand can be illustrated by considering some high-level assumptions around how many new load supply stations (i.e., transformer stations supplying distribution customers) would be required throughout the province:

- Taking into account existing load supply stations, and assuming that a new station would supply approximately 250 MW of winter load, it would require anywhere from 150 to more than 280 new stations to meet forecasted demand, depending on whether if those stations are fully utilized.
- Costs range between $5 billion and $10 billion based on recent figures for a standard load supply station in a non-urban environment, assuming no work is required on the upstream transmission system and not accounting for downstream distribution costs.
- This would mean that between five and 10 new stations a year, on average, would be needed to meet forecast winter demand in 2050, with a yearly pace potentially outstripping the number of new stations that have been developed across the province in the last decade.

Overall, the cost of building out the bulk 500 kV and 230 kV system to meet the Pathways scenario is estimated to be between $20 billion and $50 billion. This estimate includes new 500 kV and 230 kV network lines and terminations, and new 500/230 kV and 230/115 kV auto-transformation. If 500 kV reinforcement through northwestern Ontario to Manitoba were also needed due to load growth or constraints on resource siting, this could result in an additional $7 billion to $16 billion in costs. The costs for 500 kV lines and terminations are directly informed by the 500 kV reinforcements modelled. The range of cost for 230 kV lines, terminations and for all auto-transformation was informed both by the reinforcements modelled and the unit costs per MW of load growth, assuming typical equipment capabilities.

Many of the needed investments will be challenging to implement given their location within major load centres and populations, which makes land more challenging to acquire, permitting more contested and construction more expensive if undergrounding is necessary. Aside from the bulk reinforcements needed to support growth in the load centres, the Pathways scenario also necessitates major investments in the local distribution system, including step down stations required between the transmission and distribution network, and distribution infrastructure for final connection to the customer. The cost and siting challenge for the required stations and distribution infrastructure will also be substantial.

Pathways: Conclusion and Outcomes

This scenario illustrates the magnitude of the effort required for Ontario to decarbonize its electricity system while responding to economic development and electrification. Focusing on 2050 to align with international targets, this study highlights the goals we are attempting to achieve. It demonstrates an immense build-out of the province's transmission, distribution systems and resources that could more than double Ontario's installed capacity, and that would need every known or potential resource available today. It also requires replacing the necessary services provided by gas, which no resource alone today can do.

We can garner many insights from this scenario, but it is also important to acknowledge its limits. This resource mix was assessed for energy and capacity adequacy in 2050; an operability assessment was not performed. In addition, we did not perform adequacy assessments for the years before 2050. Further planning work is necessary to understand how to manage the transition in a reliable way from now to 2050.

This scenario relies heavily on low-carbon fuels for intermediate, peaking and flexibility needs. Currently there is no like-for-like replacement for the operating characteristics of natural gas. Low-carbon fuels might be able to fill this gap and would be a valuable addition to the supply mix, but they do not yet exist at scale and there are many barriers to commercialization. (See Appendix A, Tab 9.) If low-carbon fuels do not materialize, replacing natural gas will be an even more complex task, requiring more research and analysis into understanding how generation, demand, transmission and storage can be combined to replace gas. It may be possible to overcome all of these barriers, but it will require concerted effort by government and innovators.

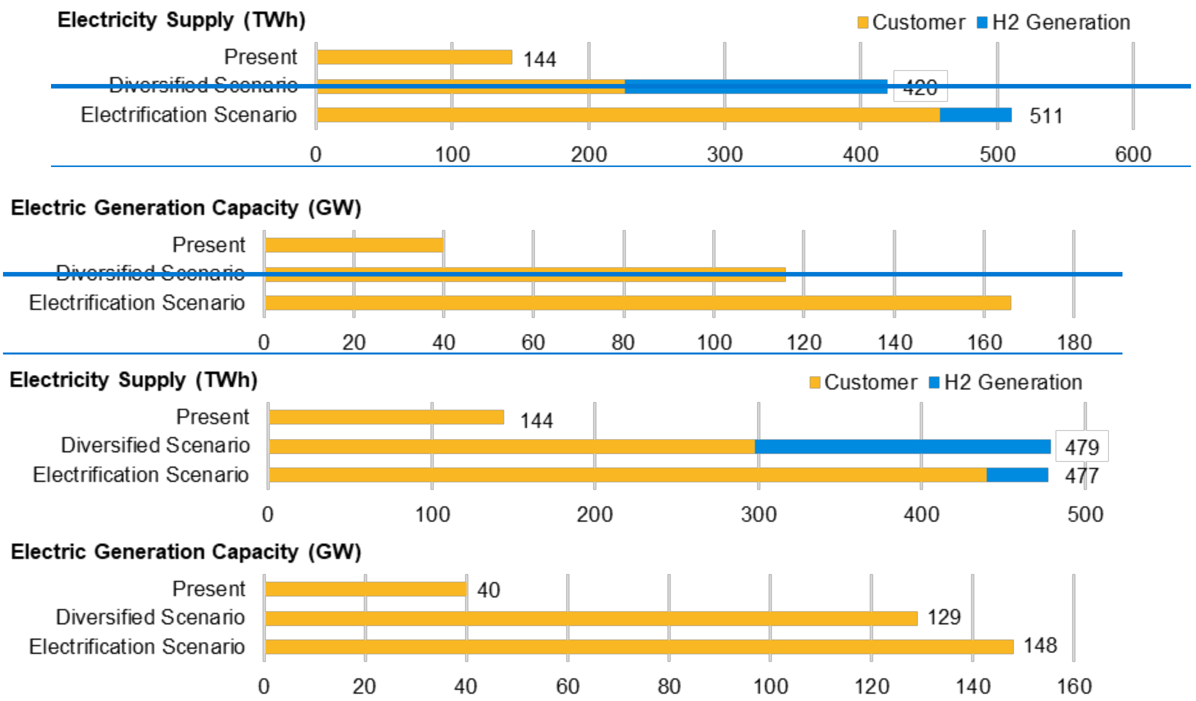
In terms of both transmission and supply, the Pathways scenario would need $375 billion to $425 billion in new infrastructure investment, and result in an annual total system cost of approximately $60 billion by 2050. Alternatively, annual system costs can be considered per unit of demand at $200 to $215/MWh, an increase of between 20 per cent and 30 per cent from current unit rates.

Regarding consumer bills, it is difficult to determine a potential rate impact given the changing nature of energy consumption. However, an increased reliance on electricity will significantly increase the volume of consumption on bills compared to today's patterns. (Further information on system costs is available in Appendix A, Tab 8.) However, as noted above, some studies suggest that actual impact on total energy costs could be modest due to offsets and increased efficiency.[12]

[12] Canadian Climate Institute op. cit., p. 26

~~3.~~1. In all scenarios and sensitivities, the magnitude of the increase in electricity demand will require a significant buildout of generation capacity, T&D infrastructure, and storage capacity. Our analysis forecasts generation capacity increasing from 40 GW today to ~~116~~129 GW in the Diversified scenario and to ~~166~~148 GW in the Electrification scenario. An increase in scale of this magnitude will require changes in the way electricity generation capacity and transmission infrastructure is planned and evaluated, and the speed at which it is developed.

Figure 28. Comparison of Present and Future Electricity Supply and Generation Capacity



~~4.~~2. **The electricity and gas systems will become increasingly integrated.** These two energy delivery systems will grow more interconnected on the journey to net zero. Our analysis has shown how important energy conversion between electricity and hydrogen will be in the future. Electricity supply will be critical to scale up green hydrogen supply and meet hydrogen demand. Hydrogen supply will also be critical in meeting peak electricity demand through hydrogen-fired gas turbines. Hydrogen will become an important long-term electricity storage option. Hydrogen will be produced during periods of electricity oversupply, and it will be used in periods of peak demand. This integration can also happen behind the meter, with dual fuel technologies like hybrid heating systems operating intelligently to optimize the use of electricity and gas for space heating. Hybrid heating systems can reduce electricity system costs by reducing peak electric load. Our analysis shows that significant adoption of residential hybrid heating systems can save Ontario $2~~1~~9 billion compared to the base Diversified scenario.

~~5.~~3. **Reducing GHG emissions from the gas system will be a less disruptive and more cost-effective option than full electrification.** The analysis shows that the Diversified scenario can save Ontario $~~181~~41 billion by 2050 relative to the Electrification scenario. The benefits from this scenario are not only limited to costs savings, but also largely to ease of implementation. The Diversified scenario avoids highly disruptive building retrofits and heating equipment upgrades, both of which are required in the Electrification scenario. With more than 65% of residential buildings in Ontario already equipped with either gas furnaces or boilers,[103]~~,~~ replacing them with electric heat pumps will require extensive and disruptive renovation to ensure buildings are adequately heated and insulated. Despite these energy efficiency improvements, electricity peak demand will

[103] NRCan (2018). Residential Sector Heating System Stock. Available: https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/showTable.cfm?type=CP&sector=res&juris=on&rn=21&page=0

Annual Acquisition Report

April 2022

Connecting Today.
Powering Tomorrow.

Executive Summary

Ontario's electricity sector is undergoing a period of significant transformation. New decarbonization policies coupled with rapid growth in the mining, greenhouse and industrial sectors are accelerating electricity demand growth across the province and heightening needs in certain regions.

The IESO's most recent Annual Planning Outlook (APO) reflects these trends. It projects a steady rise in electricity demand that highlights the strengths of Ontario's communities and economy to navigate the challenges of the pandemic, pursue electrification and support economic growth.

To address this changing environment, the IESO established the Resource Adequacy Framework in 2021 to provide a flexible and cost-effective approach for competitively securing the resources necessary to meet demand. Within the framework's annual cycle, the APO's 20-year forecast identifies Ontario's power system needs, while the Annual Acquisition Report (AAR) specifies the mechanisms that the IESO will use to meet them.

Since initiating the framework, the IESO has responded to Ontario's needs by growing the annual capacity auction for short-term commitments, and making substantial progress on designing and implementing competitive procurements to ensure reliability in the coming decade and beyond.

The 2022 AAR continues on this path, defining actions to address reliability needs identified in the most recent APO. It also responds to the pace of change in Ontario's electricity sector through updated demand and supply forecasts, incorporating the latest information on decisions and potential risks into this year's adequacy assessment of Ontario's electricity resources. It accounts for a range of events and uncertainties, as well as more resource-specific information such as location, technological capability and energy or fuel limitations.

The results show that capacity needs in the years up to and including 2024 are expected to be met through existing resources and the plans already identified in the 2021 AAR. Needs emerging in 2025 based on increased demand, the retirement of the Pickering Nuclear Generating Station and expiring contracts, however, will require action beyond what was projected last year. The broad trends of these needs have been reflected in previous forecasts, but their specific timing and magnitude continues to evolve as plans and policies of consumers and governments change.

Initiatives identified in last year's AAR, like the first medium-term RFP, are currently underway and will contribute to meeting the mid-decade need. In addition, a number of accessible options to secure more supply already exist, including the potential for nuclear operators to adjust outage schedules and using capacity from the Hydro Quebec Capacity Sharing Agreement. The possibilities for additional energy efficiency and new procurements will also be discussed in greater detail with sector participants and Indigenous communities.

Further needs, described in last year's AAR, emerge in the late 2020s and will require the acquisition of incremental capacity, including new-builds, expansions and upgrades of existing resources. The IESO is currently engaging with sector participants, municipalities and Indigenous communities on the first Long-Term RFP, with a focus on ensuring new investment in the province.

Allocating the Target to Secure New-build Resources

With resource adequacy needs over the 2027 to 2034 period ranging from approximately 2,500 to 3,900 MW, a possible solution to address these needs is for Long-Term I RFP to acquire 2,500 MW of qualified capacity for delivery by 2027 (or earlier) and a subsequent target in Long-Term II RFP to acquire an anticipated 1,500 MW by 2030 (or earlier). The two long-term RFPs would total 4,000 MW of new incremental capacity by 2030, which is prudent, given the potential for uncertainties to materialize. These target capacities would be set recognizing that if various uncertainties were to materialize, the adequacy need for this period would likely increase. Targeting the upper end of the range of needs as opposed to the lower end would help to ensure that resource adequacy is maintained. In addition, a cumulative 4,000 MW target capacity is sufficiently high that it is anticipated to drive investment in new projects.

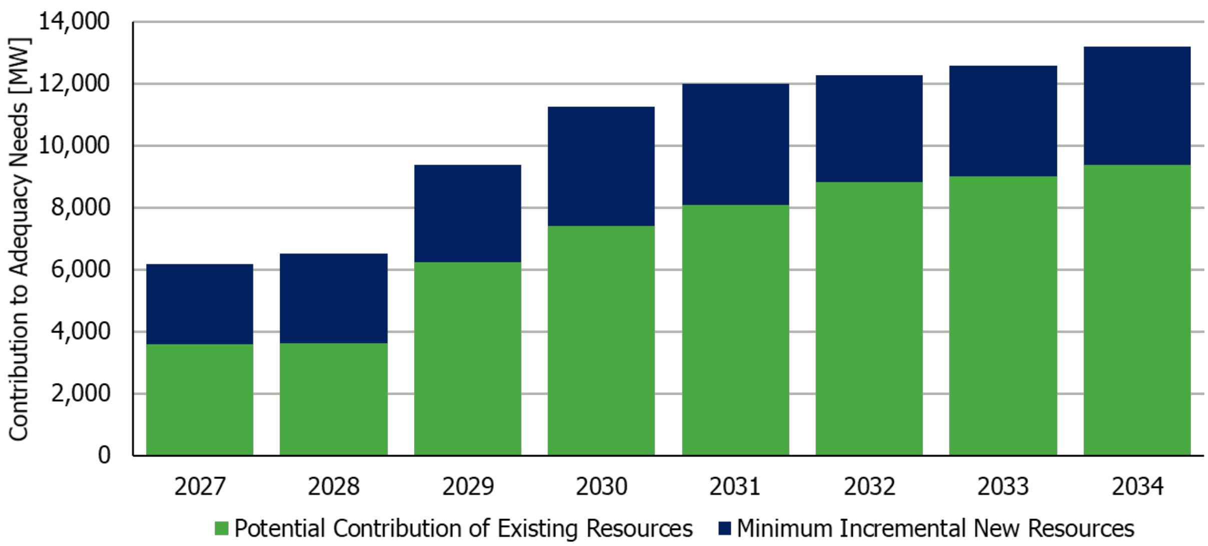


Figure 13 | Size of Need Between 2027 and 2034 (from 2021 APO)

From a resource adequacy perspective, incremental capacity can be provided by new-build facilities, or through uprates and expansions at existing facilities. The IESO will work with sector participants and communities to identify approaches for resources that are successful in the Medium-Term I RFP and wish to participate in the Long-Term I RFP by investing in upgrades or installing new energy storage resources.

Long-Term I RFP Design Considerations

To ensure high quality resources that can satisfy emerging reliability needs, the Long-Term I RFP should aim to acquire capacity from facilities that meet the following criteria:

- **Ability to Reach Commercial Operation by May 1, 2027**: Successful projects should be ready to deliver services for a core period beginning in 2027. Since the APO projects capacity needs enduring beyond 10 years, and to provide greater certainty to investors, it may be prudent to consider a term length exceeding 10 years. Due to the immediacy of resource adequacy needs and the importance of ensuring reliability, the RFP should take into consideration whether there is a high degree of confidence in the project being delivered in advance of when needs arise. This could be demonstrated by resources that have met all permitting, regulatory and engagement requirements prior to commercial operation.

5.1.1.6. System Issues in Northern Ontario

Significant transmission reinforcements that are currently planned or being implemented in northwestern and northeastern Ontario will alter the voltage profile in the north. There are already significant challenges with voltage control in northern Ontario today, and the IESO's system operations rely heavily on local generators to provide reactive support services. As a follow up to the Northeast Bulk System Plan,[21] a study is underway to address these reactive compensation needs. The scope of this study will include all 230 kV and 500 kV equipment in Northern Ontario. Planning scenarios will include both system peak and minimum loading conditions as well as long-term conditions after future planned transmission reinforcements are in-service. As details about this study emerge, they will be communicated to stakeholders.

Future changes to the provincial supply mix, including potential for expansion of hydroelectric generation in the north, will also require assessment of potential impacts to the bulk transmission system and the capability of the grid to deliver these resources to load centres.

5.1.1.7. Interties with Neighbouring Jurisdictions

Ontario's interties are critical for enabling import and export activity, as well as enhancing system stability through participation in the Eastern interconnection. The IESO recently conducted a screening study of Ontario's interties, including those with Manitoba, Minnesota, New York and Michigan. The study focused on identifying interties where a long-duration outage, caused by the unexpected failure of a unique piece of equipment such as a phase shifter,[22] could result in reliability impacts for Ontario electricity customers. Consistent with established North American reliability standards,[23] the screening study considered factors such as utilization of the tie, the age and condition of equipment, the impact of outages on intertie limits or operation and any known operability concerns. The study found that major equipment at the Ontario—Manitoba intertie is approaching its end-of-life, including two phase shifters and two step-up transformers. The Manitoba–Ontario interconnection has been in-service since 1972.

The IESO will initiate a joint study with Manitoba Hydro and Minnesota Power in 2023 to plan for the end of life of this critical equipment.

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[21] For more information, please visit the IEO website: https://www.ieso.ca/en/Get-Involved/Regional-Planning/Northeast-Ontario/Bulk-Planning

[22] Also known as a Phase Angle Regulator. These are specialized pieces of equipment that help control the power flow between two interconnected transmission systems.

[23] NERC TPL-001, R2.1.5

Exports

	TWh		2020	2030	2040	2050	SubRegion_To
Electricit	ON	Electricity Transmission Line	-0.0	0.0	-0.1	0.0	WC
Electricit	ON	Electricity Transmission Line	-1.2	-2.7	-3.5	-2.9	QC
Electricit	ON	Electricity Transmission Line	-6.3	-3.7	-5.4	-5.9	NY
Electricit	ON	Electricity Transmission Line	-6.2	-0.2	-4.5	-3.2	MI
Electricit	ON	Electricity Transmission Line	0.0	-2.2	-7.4	-7.9	PJ
	Total		-13.7	-8.7	-20.9	-20.0	

Imports

	TWh		2020	2030	2040	2050	SubRegion_From
Electricit	ON	Electricity Transmission Line	0.1	1.7	3.5	2.3	WC
Electricit	ON	Electricity Transmission Line	2.0	3.8	3.6	4.0	QC
Electricit	ON	Electricity Transmission Line	1.8	5.3	9.7	11.7	NY
Electricit	ON	Electricity Transmission Line	0.3	8.0	9.4	9.0	MI
Electricit	ON	Electricity Transmission Line	0.0	3.2	8.6	10.7	PJ
			4.3	21.9	34.9	37.7	

Exports	-14	-9	-21	-20
Imports	4	22	35	38
Exports	**-9**	**13**	**14**	**18**

Exports	-9.5	0.0	0.0	0.0
Imports	0.0	13.2	14.0	17.8
Net	**-9.5**	**13.2**	**14.0**	**17.8**

2022 Regional Resource Assessment

A RELIABILITY IMPERATIVE REPORT

NOVEMBER 2022

Highlights

- MISO's Regional Resource Assessment (RRA) provides a collective view of how members' resource plans are evolving, revealing insights and implications that can inform the work that members, states, and MISO are doing to balance reliability, affordability, and sustainability priorities.

- RRA modeling indicates a continued near-term capacity risk, highlighting the immediate importance of coordinated resource planning and additional investment.

- Reliably achieving the decarbonization targets set by many MISO members and states will require a shared understanding of how operational risks emerge and shift over time. The RRA improves that understanding and informs the proactive problem-solving that is needed to meet the region's Reliability Imperative.

MISO

misoenergy.org

It is important to understand that the RRA provides a "snapshot in time" view of MISO member and state plans; Figure 1 is based on the publicly available resource plans as of January 2022. Resource plans are continuously being evaluated by MISO members and states, and final generation investment decisions are most often made and publicly announced only as the need for them draws closer. That said, the distinction between installed and accredited capacity is a key consideration for resource adequacy and the RRA survey trend highlights a continued capacity risk for the MISO region.

KEY INSIGHT 2: The RRA modeling indicates a continued near-term capacity risk, highlighting the urgent need for coordinated resource planning and additional investment.

The region's combined levels of existing resources (dark blue) and planned resources (light blue) meet the anticipated load-plus-reserve level (black line) on a region-wide basis for the next four years, but the margin of error is small (Figure 2). That said, the risks and the timing of potential capacity shortfalls differ across MISO's 10 Local Resource Zones (LRZs), as shown here. The risk of capacity shortfalls will increase if load growth exceeds the RRA's assumptions or if retirement schedules are accelerated without sufficient replacement. These risks will be further heightened if any planned resources are delayed beyond their currently scheduled in-service dates and other solutions are not promptly implemented.

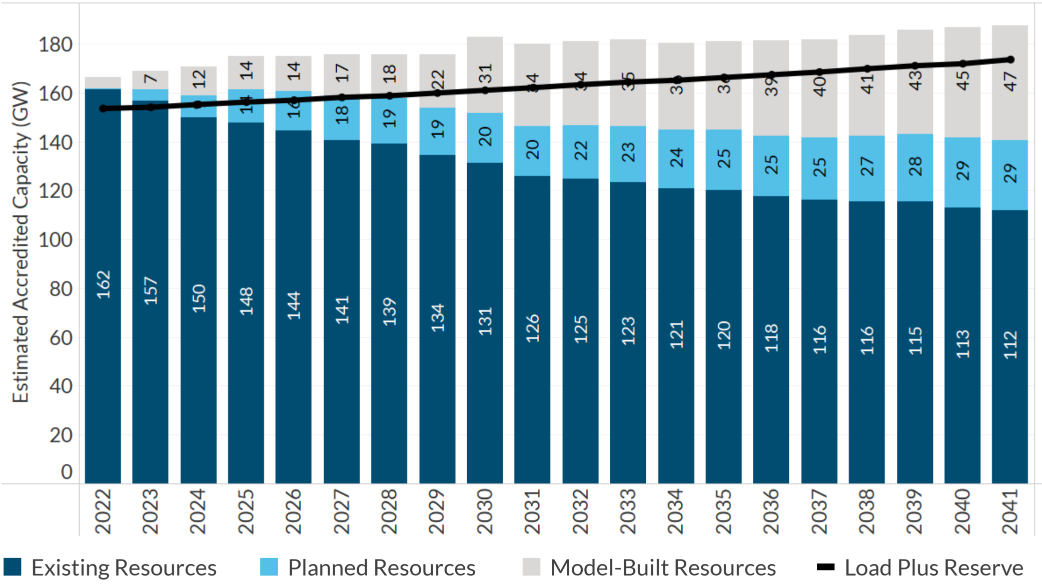


Figure 2: System-wide existing, planned, model-built resources, and load plus reserve

Figure 2 also shows that in 2027, the combined levels of existing resources (dark blue) and planned resources (light blue) fall just short of the forecasted load plus reserve level (black line), potentially putting the region at risk of a capacity shortfall. That apparent gap remains roughly flat in 2028, then steadily increases out to 2041.

Manitoba Hydro
2023/24 & 2024/25
General Rate Application

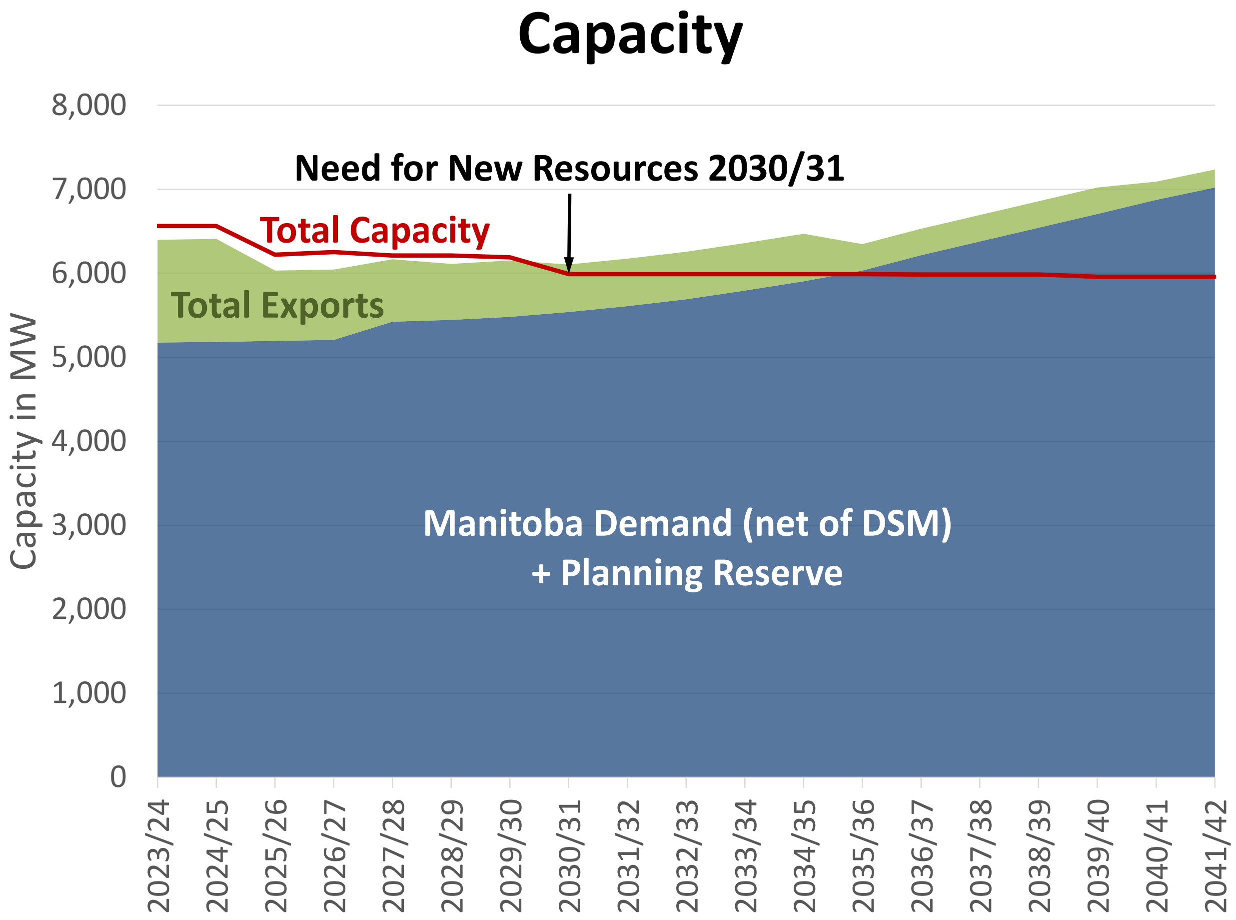
May 16th, 2023

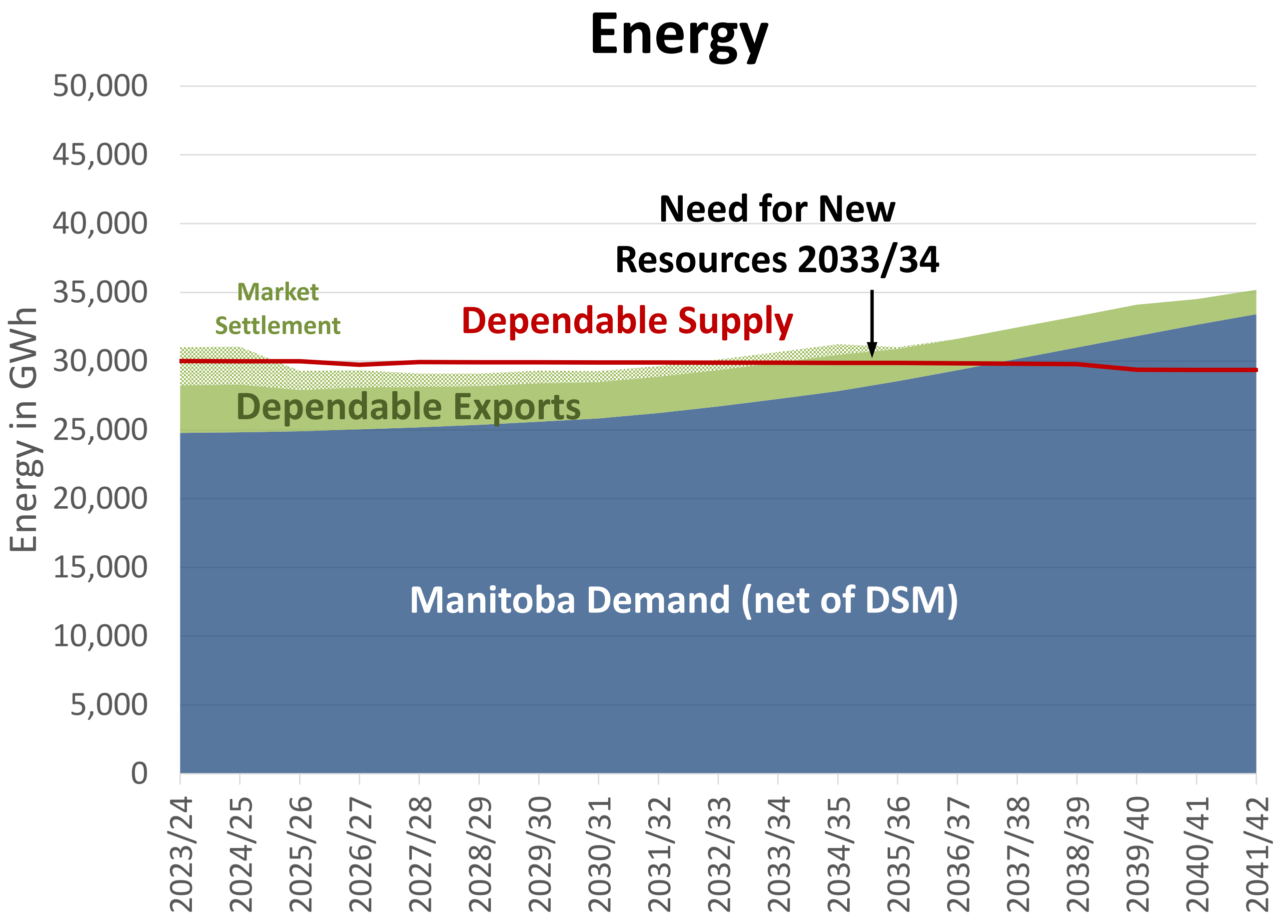
Exports, Drought Management and Hydrology Panel

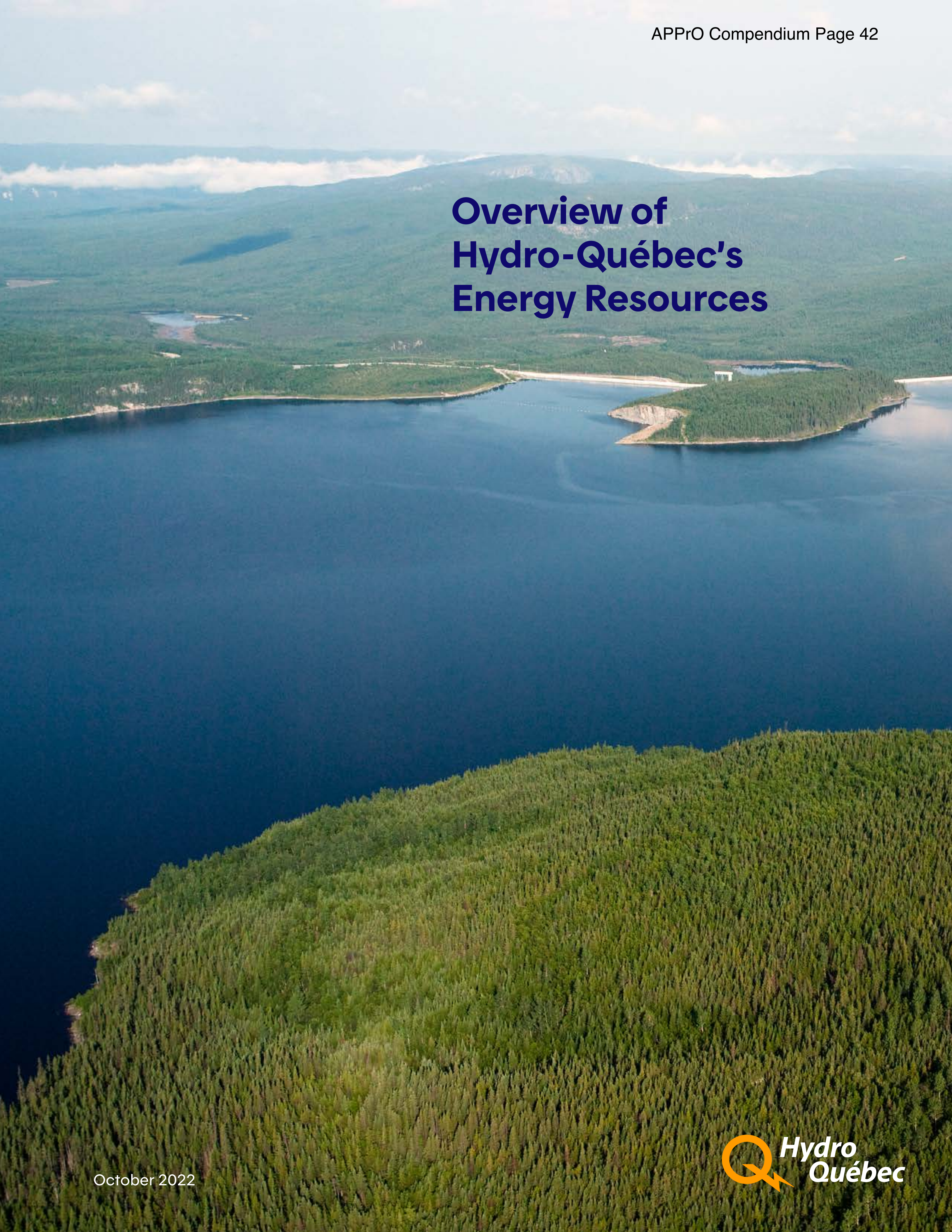
Manitoba Hydro
energy for life

Anticipate the need for resources in early 2030s

Note: Numerous factors can and do change over time that affect supply and demand. This creates uncertainty in the need date for new resources.







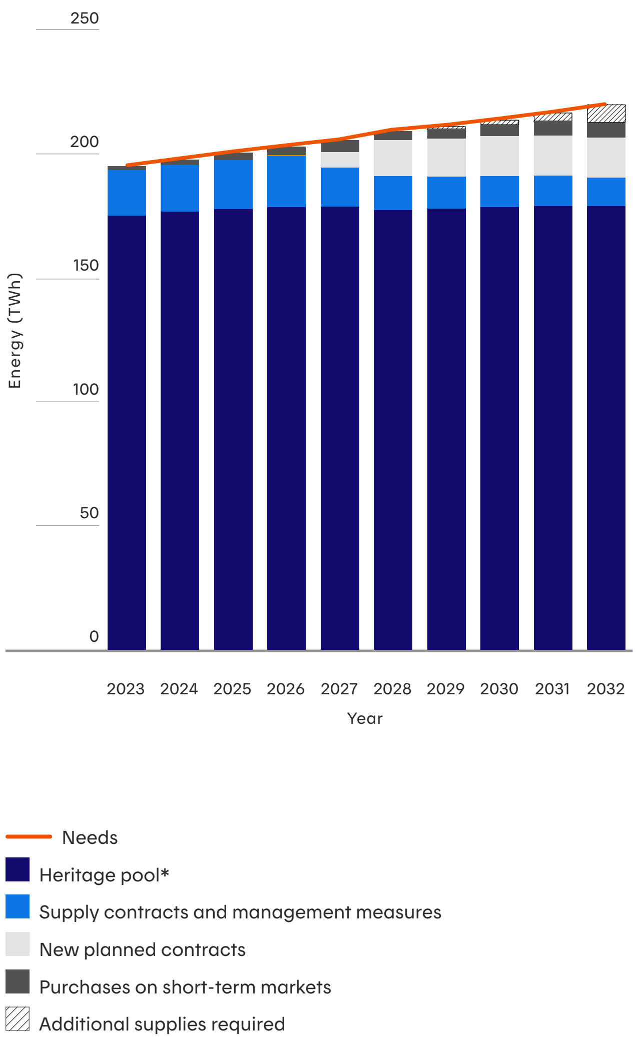
Overview of Hydro-Québec's Energy Resources

October 2022

Hydro Québec

Energy balance

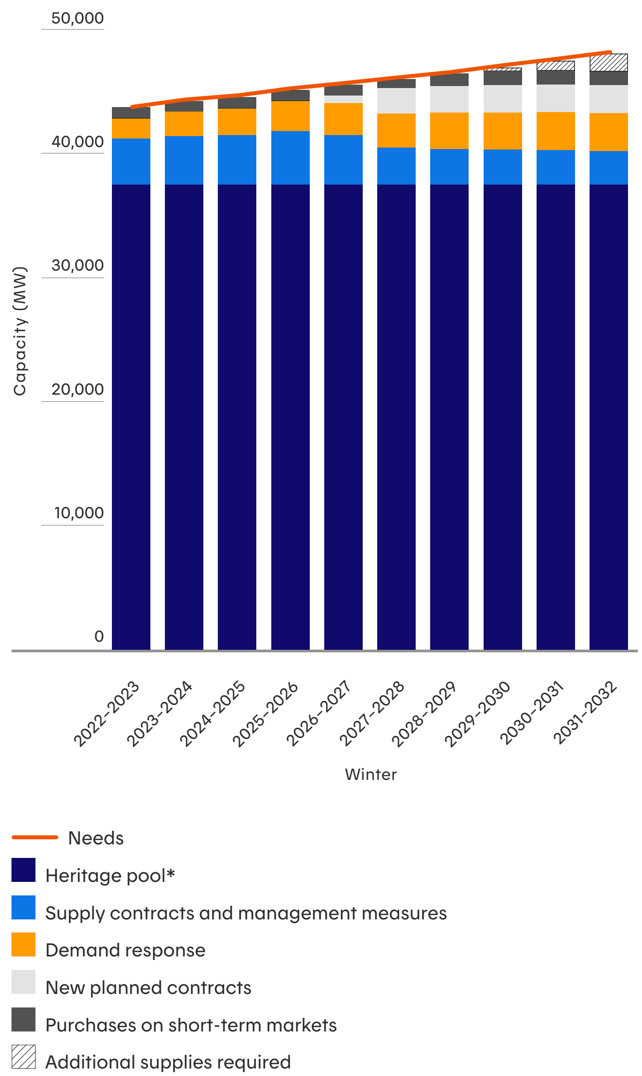
The energy balance presents the current and planned means that Hydro-Québec will use to meet Québec's anticipated energy needs, including supplies resulting from calls for tenders that have already been launched or announced (new planned contracts). It shows that additional tender calls will have to be issued in the coming years.



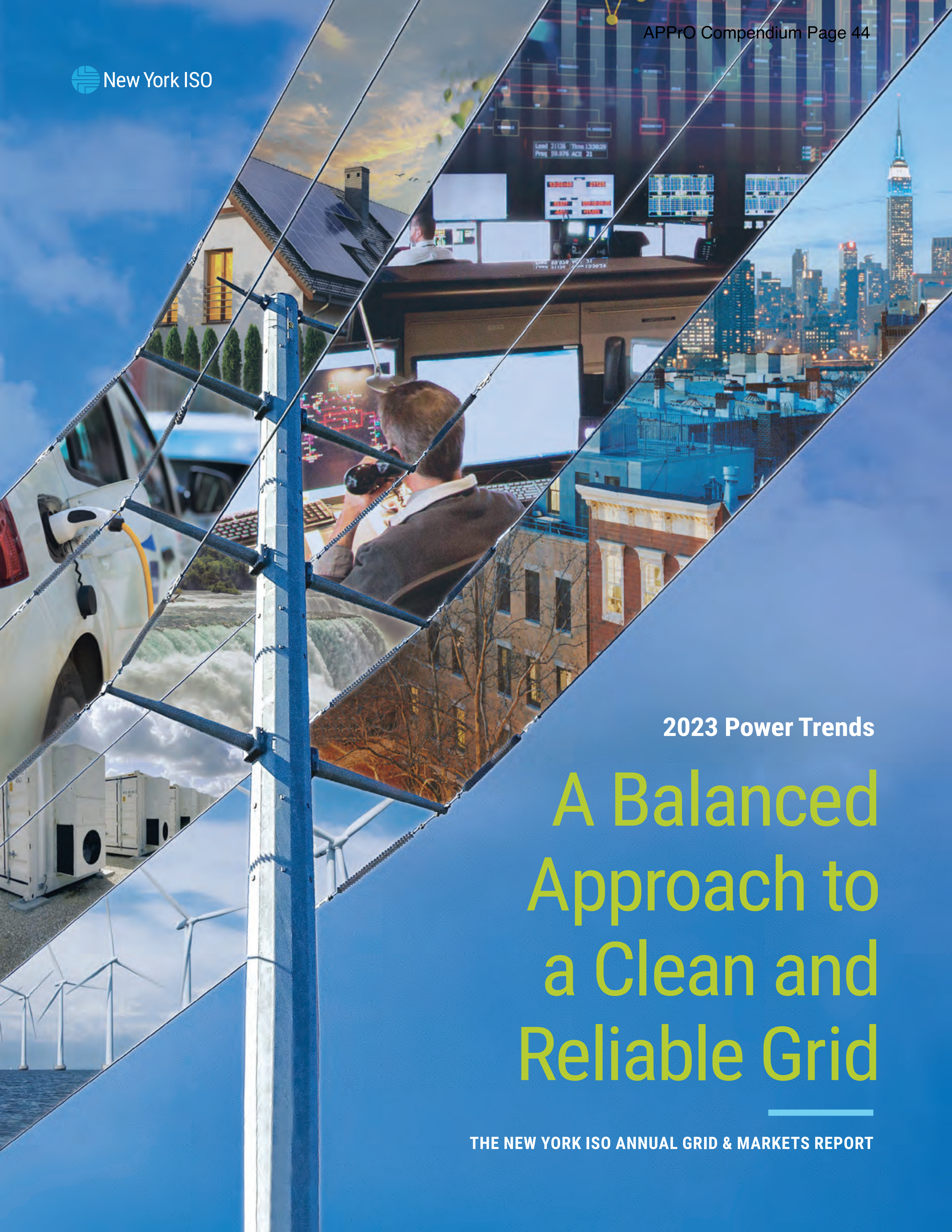
** Including transmission and distribution losses*

Capacity balance

The capacity balance compares Hydro-Québec's current and planned means with Québec's anticipated capacity needs at the annual peak, i.e., when electricity consumption is at its highest. It shows that in addition to the new planned contracts, other long-term supplies will be required as of winter 2029–2030.



New York ISO



2023 Power Trends

A Balanced Approach to a Clean and Reliable Grid

THE NEW YORK ISO ANNUAL GRID & MARKETS REPORT

Executive Summary

The reliability of the electric system is an essential component for a vibrant economy, and necessary to ensure the health and safety for all New Yorkers. At the same time, battling the detrimental effects of climate change is imperative. The NYISO is committed to a carefully planned approach to enable a reliable grid transition. We are also committed to meeting state and federal policy objectives.

State climate and energy policy objectives are driving rapid and dynamic change to decarbonize New York's electric system, building stock and transportation sector. The New York State power system is operated to the strictest reliability standards in the nation. This places New York at the forefront in balancing the need to address the harmful impacts of climate change, while delivering reliable electric service to consumers.

The pace of change is accelerating with the increased adoption of electric vehicles, and electric heating equipment to replace fossil fuel sources of building heat. In the New York City metropolitan area, data shows a continued rise in economic activity coming out of the pandemic. Across upstate New York, energy intensive microchip manufacturing facilities are developing in several locations. Together, these elements are increasing

Power Trends Key Messages

> Public Policies are driving rapid change in the electric system in the state, impacting how electricity is produced, transmitted, and consumed.

> Reliability margins are shrinking. Electrification programs are driving demand for electricity higher. Generators are retiring at a faster pace than new renewable supply is entering service. The potential for delays in construction of new supply and transmission, higher than forecasted demand, and extreme weather could threaten reliability and resilience to the grid.

> Driven by public polices, new supply, load and transmission projects are seeking to interconnect to the grid at record levels. NYISO's interconnection process balances developer needs with grid reliability. Efforts are underway to make this process more efficient while protecting grid reliability.

> To achieve the mandates of the CLCPA, new emission-free supply with the necessary reliability services will be needed to replace the capabilities of today's generation. Such new supply is not yet available on a commercial scale.

> New wholesale electricity market rules are supporting the grid in transition. These markets are critical for a reliable transition.

The NYISO is committed to a carefully planned, balanced approach to enable a reliable grid transition. We are also committed to meeting state and federal policy objectives.

FIGURE 11: **ACTUAL & FORECAST ANNUAL PEAK DEMAND (MW): 2022-2053**

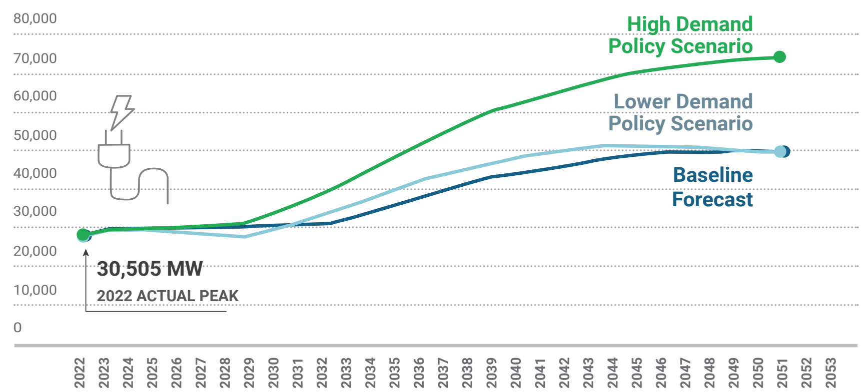


FIGURE 11 | This figure presents three scenario forecasts, a baseline forecast that the NYISO assumes is the most likely outcome based on current observations and assumptions, and two policy scenarios that represent different paths to achieving full compliance with all state policy targets. Key differences between the policy scenarios include the types of technologies adopted to comply with policy requirements as well as the expected adoption of peak-mitigating measures. For example, the Lower Demand Policy Scenario assumes a higher adoption rate of hydrogen-fueled vehicles to support the state's transportation goals and that higher percentages of plug-in electric vehicles practice managed charging to avoid charging during peak demand periods. The Higher Demand Policy Scenario reflects a greater reliance on plug-in vehicles and a greater degree of unmanaged charging that can contribute to higher peaks.

FIGURE 12: **SUMMER & WINTER PEAK DEMAND FORECASTS (MW): 2022-2053**

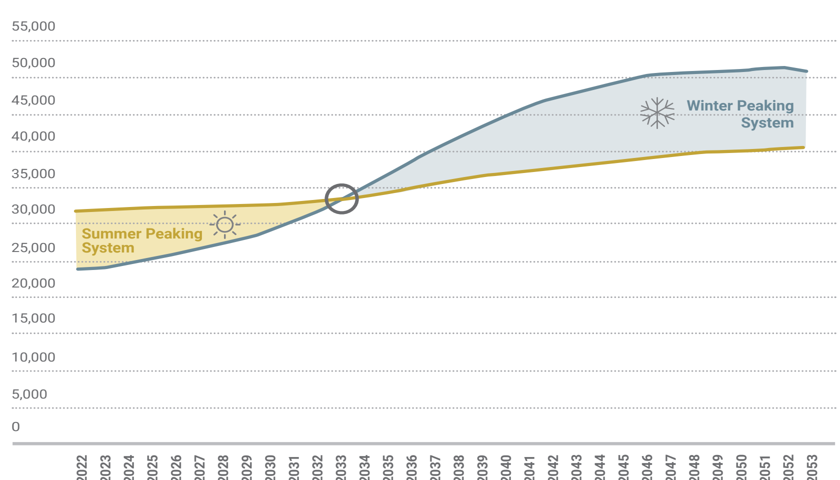


FIGURE 12 | Electrification of the transportation and building sectors will drive winter peak demand higher in the future. In fact, only 10% of New York's homes rely on electricity for heat today. To meet state policy targets, that level would need to grow to 90% by 2050, with electric heat pumps considered the leading technology to convert fossil-fuel-based furnaces and boilers. As heat pump technology proliferates, peak demand on New York's grid is expected to shift from summer to winter.