   

Scenarios for a Net-Zero Electricity System in Ontario

Prepared for: The Atmospheric Fund

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EXECUTIVE SUMMARY

The Government of Canada is targeting a net-zero electricity supply mix by 2035. However, Ontario currently has no target date for achieving net-zero electricity, and based on current plans and IESO forecasts, electricity emissions are expected to increase through to 2040. To investigate the net-zero potential, the Ontario government has directed the Independent Electricity System Operator (IESO) to prepare a Pathways to Decarbonization report. The results of the report are expected to inform future policy decisions related to Ontario's electricity supply mix.

The Atmospheric Fund (TAF) and Power Advisory LLC (Power Advisory) identified the need for a study that explored feasible pathways to achieving a net-zero grid in Ontario by 2035. A clean, affordable, and reliable system is necessary to both comply with upcoming federal regulations and ensure Ontario can support expected growth in demand from its building, transportation, and industrial sectors. TAF has retained Power Advisory to prepare a scenario-based analysis of the Ontario electricity system to highlight potential pathways for achieving those goals. The study strives to determine what resource mix is required to achieve net zero and what might be the pace of investments to reach that goal. The report considers multiple scenarios to assess the impact of different supply mix choices and demand-side solutions in achieving net zero and to understand the broader impacts on the Ontario electricity system and economy.

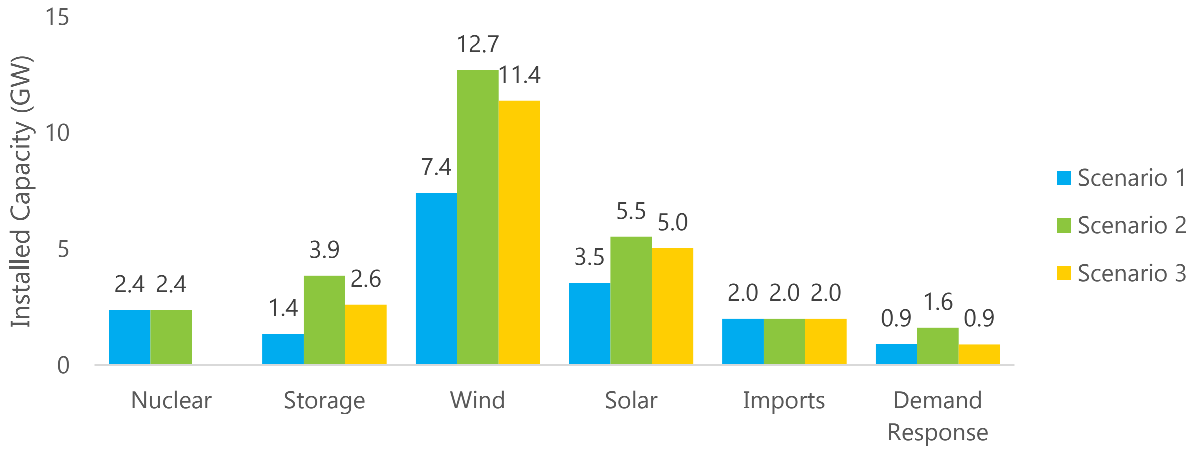
Three scenarios were explored. Each scenario was based on specific assumptions about demand, conservation, nuclear expansion, and demand response capabilities (see Table 1). From there, solar, wind, and storage were added to address system need and determine overall GHG emissions by 2035.

Table 1: Scenario Assumptions

Assumption	Scenario 1	Scenario 2	Scenario 3
Incremental Conservation	23 TWh	0 TWh	23 TWh
New Nuclear	2.4 GW	2.4 GW	0 GW
New Firm Imports	2.0 GW	2.0 GW	2.0 GW
Maximum Summer Demand Response	1.7 GW	1.8 GW	1.7 GW
Maximum Winter Demand Response	2.2 GW	2.5 GW	2.2 GW

Scenario 1 explored a supply mix with accelerated investment in conservation and continuation of current nuclear expansion plans (i.e., new Small Modular Reactor and refurbishment of Pickering Nuclear Generation Station). Scenario 2 considered no commitment to accelerated conservation. Scenario 3 explored no new nuclear generation. The resulting supply mix across all three scenarios is diverse and requires significant investment.

Figure 1: Added Capacity by Scenario, 2022 to 2035 (GW)



The results of the scenario analysis offered several key takeaways for modernizing the Ontario electricity grid:

- Investment must start immediately. Modernizing Ontario's electricity grid will require significant development activities and the deployment of capital to install the needed new resources. Major infrastructure developments will likely face delays and unforeseen challenges, and additional time will provide flexibility to manage the uncertainty.

- All resources need to be considered for net-zero. No single technology or approach will offer a fulsome net-zero solution. Instead, a diversified and balanced mix of non-emitting resources is required. The core challenge is determining the appropriate balance of different resources, which will be dependent on broader policy decisions (e.g., land use, provincial financing liability, market design)

- Conservation can reduce new supply needs. Investments in conservation will significantly reduce the scale of long-term resource development needed and offer an opportunity to further assess technology innovation and develop an optimal power system plan.

- Transmission expansion is required for long-term options. Achieving net-zero will require the expansion of Ontario's bulk transmission network to enable new resource connections. New bulk system transfer capability between resource rich areas and growing load centers will need to be pursued as soon as possible (e.g., new north-south transmission line)

- Wholesale electricity costs compared to current rates. Even with rapid demand growth from electrification of other economic sectors, a net-zero electricity grid could have similar wholesale electricity prices to today's prices. This is partly due to Ontario's largely fixed cost supply mix and partly from increased reliance on renewables, the lowest cost option for new supply. These costs could be higher if this energy were instead delivered by expanded gas-fired generation assuming carbon tax and emissions performance standard expectations used in our analysis (i.e., >$170/tonne and EPS threshold reduced to 0 tonnes/GWh)

Based on the key takeaways, Power Advisory recommends the following actions be prioritized to ensure an affordable and reliable net-zero grid by 2035:

1. Enhanced and continued support for conservation efforts. Conservation can reduce long-term supply needs required to achieve net zero by 2035. Further, conservation can be implemented

quickly and provide the needed buffer to plan, design and build net-zero compliant supply-side and grid infrastructure that carry longer lead times.

2. Establish a consistent and long-term procurement roadmap. Significant amounts of capital and resources will need to be organized to support Ontario's growing electricity demand. Consistent procurements under a long-term framework can support investor confidence and ensure Ontario ratepayers have access to the benefits of infrastructure investment funded by lowest cost of capital. In addition, regular procurements can offer system planners the ability to adjust objectives to meet evolving system needs. Renewable generation provides the lowest cost new supply of energy and should be targeted first in procurements. Low-cost renewables could also moderate or lower supply costs in the near-term.

3. Complete a net-zero transmission system study and action plan. The use of the power system will change under a net-zero supply mix. A detailed plan focused on investments for a net-zero transmission network can identify priority projects and establish an action plan for implementation. The action plan could also offer the potential for streamlining approval processes.

4. Explore multiple solutions in parallel. No single technology will provide a fulsome net-zero supply mix. Technology innovation, cost reductions and evolving customer preferences will influence the final supply mix details. A pragmatic parallel plan should be used to ensure the future supply mix is diversified and the benefits of easy to implement solutions are balanced with long-term foundational investments. The plan would include near-term actions (e.g., conservation) coordinated with long-term investments (e.g., bulk transmission).

1. INTRODUCTION

1.1 Current Net-Zero Context for Ontario's Electricity System

The Government of Ontario is currently navigating a series of challenges and opportunities in the electricity sector: a looming capacity and energy need amid worldwide cost inflation, rapidly evolving technology, and commitments to reduce greenhouse gas emissions.

The federal government has targeted net-zero emissions from the electricity sector by 2035. On October 7, 2021, the Minister of Energy sent a letter to the Independent Electricity System Operator (IESO) requesting a study to "develop an achievable pathway to zero emissions in the electricity sector."[1] In response to the Minister's letter, the IESO launched its Pathways to Decarbonization engagement and study. The study will include two scenarios: the first considers a moratorium on new natural gas generation, and the second considers full decarbonization from 2024 to 2050.

The IESO consulted on study assumptions through the spring and summer of 2022, and results are expected to be published in December 2022. An interim report on resource eligibility of carbon-emitting generation in upcoming procurements to meet future energy and capacity needs was published on October 7, 2022. In the report, the IESO stated, "a maximum target of 1,500 MW of new natural gas capacity will address short-term energy needs and contribute to the province's longer-term energy transition". Therefore, the IESO's Pathways to Decarbonization report is expected to include assumptions for new natural gas capacity. The interim report on resource eligibility did not provide significant depth of analysis to support the conclusions, and the Pathways to Decarbonization report will hopefully provide more information on the interim conclusions.

The IESO approach to Pathways to Decarbonization models the set of investments needed to achieve cost-effective decarbonization as an optimization problem, based on a set of fixed assumptions and constraints (e.g., rate of wind and solar buildout). The IESO study will seek to identify which supply resources should be acquired, under these constraints, to minimize system costs. The modelling assumptions underpinning the study, which specify the costs and operational capabilities of the various supply options, are critical to producing reasonable, reliable, and implementable results.

Developing robust modelling assumptions is challenging. For example, costs are very uncertain and may depend on project execution, policy choices, technological change, and financial conditions. Power Advisory believes that the best study outcomes can be achieved with meaningful public engagement, debate, and oversight on the development of assumptions. Greater transparency from the IESO on the modelling assumptions for the Pathways study is required.

1.2 Purpose of This Study

This report aims to provide a set of pragmatic scenarios that would achieve a reliable, affordable, net-zero electricity system in Ontario. The study focuses on a target date of 2035, including the investments in new transmission and resources needed over the next 13 years to enable each scenario.

[1] Available at https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-Minister-Gas-Phase-Out-Impact-Assessment.ashx

This report provides a complementary perspective to the approaches that will be presented in the IESO's Pathways to Decarbonization study. The report adopts many of the modelling assumptions used by the IESO, such as levelized cost of energy assumptions from the National Renewable Energy Laboratory. There are also certain notable exceptions:

- A much greater role for demand side participation. Two of the scenarios include significant new investments in conservation and demand management. With rapid demand growth and escalating carbon prices, additional conservation measures should be even more cost effective than previous assessments have identified.
- A greater role for price-responsive loads such as electric vehicle charging, smart appliances, and flexible industrial loads. With greater penetration of variable renewable energy resources (i.e., wind and solar), generation output is expected to be more volatile. When generation output drops suddenly, price-responsive loads can maintain supply/demand balance and avoid the need for expensive (and likely carbon-intensive) peaking generation.
- No limits imposed on the annual growth rate of wind and solar capacity, which allows the most cost-effective quantity to be installed. Arbitrary limits on the amount of annual installed generation capacity can severely influence modelling results and lead to flawed conclusions. Decarbonizing Ontario's electricity supply will require difficult trade-offs to be made by policymakers and the public. Setting limits in the analysis restricts understanding of the potential trade-offs and options.

Overall, the report is intended to provide a better understanding of the challenges and opportunities that exist as Ontario pursues a net-zero electricity supply mix. In particular, the report strives to answer two key questions. First, can a reliable, net-zero system be built by 2035 without relying on additional fossil fuel generation capacity. Second, what is the pace of investments required to achieve net-zero in the electricity supply mix. The core value add of the study is a clear outline of the many actions required to achieve net-zero, the timelines of investment needed, and the challenges that will need to be overcome.

1.3 Organization of the Report

Section 2 provides more information on the three scenarios and modelling assumptions in this analysis.

Section 3 outlines modelling results, including new supply additions, sources of energy used in 2035, and system cost estimates.

Section 4 includes qualitative considerations that are not fully captured by the modelling, such as land use impacts.

Section 5 offers key takeaways and recommendations for building out a net-zero grid in Ontario by 2035.

2. DECARBONIZATION SCENARIOS

2.1 Scenario Based Analysis

This study examines three scenarios to transition Ontario's supply mix to net-zero by 2035 while supporting electrification activities for net-zero across the broader economy by 2050. In Power Advisory's view, all non-emitting resource options require advancement in some form to support a net-zero future. For example, there is no certainty that renewable generation costs will continue to decline steeply or that nuclear generation technology will evolve to address past liability risks.

What is needed is an understanding of how different technologies and resource options interact on a pathway to net zero. Exploring these interactions through scenarios can help planners and policymakers identify fatal flaws in net-zero approaches as well as recognizing beneficial combinations. For example, early investment in quick development of demand-side resources (e.g., conservation and distributed energy resources) can enable long lead-time resources such as large hydro, nuclear, and transmission-enabled renewables. These scenarios can inform how much effort should be directed towards different options over various timeframes to support the primary objective of a net-zero supply mix in Ontario by 2035.

Since there are so many different variables and variations of assumptions that must be considered, it is not practical to assume there will be a clear, single long-term path that will achieve net-zero. Instead, examining different scenarios can provide guidance on common near-term actions that must be taken with respect to policy development and investments to ensure the highest probability of achieving net-zero in a safe, reliable, and cost-effective manner. The scenarios should provide insight into the balance between maximizing immediate cost-effective results while ensuring long-term net-zero capabilities are supported.

What is Net Zero?

A net-zero electricity system is one in which direct electricity sector greenhouse gas emissions are balanced by the removal of emissions elsewhere.

All three of our scenarios assume that natural gas capacity continues to operate in 2035 for reliability. Investment in non-emitting resources to minimize the use of fossil fuels is incentivized by carbon pricing. This report prioritizes resources that are technologically and economically viable today, but recognizes that other resources, such as renewable natural gas and hydrogen, may emerge over the next decade.

Our working definition in this study of a viable pathway to net-zero is one in which fossil fuels make up less than 3% of all generation by 2035. Addressing the remaining emissions could be achieved through emerging but not yet viable fossil fuel alternatives or financial instruments reflecting the cost of carbon offsets.

Ontario already has roughly 38 GW of installed generation capacity. In most respects, existing supply in Ontario is retained or replaced like-for-like. The repowering of renewable generation for higher capacity and energy production is explored in each scenario. Technology costs and policy direction are assumed to be similar for all scenarios. This allows the effect of additional nuclear and conservation on outcomes to be more clearly understood.

2.2 Approach to Scenario Development

This report examines three scenarios for Ontario's electricity system out to 2035, which are consistent with Canada's long-term emissions reduction targets. Given the number of variables to consider, Power Advisory constructed each scenario based on foundational assumptions for select key resources. Each scenario includes specific adjustments to the number of key resources expected.

Selected key resources include:

- Conservation – energy efficiency, codes & standards impacts, and technology evolution
- New nuclear generation – Small modular reactors and refurbishment at Pickering Nuclear Generating Station
- Firm Imports – Expansion of transmission for firm import contracts, primarily with Hydro Quebec
- Demand Response – Traditional demand response (i.e., temporary shut down of consumption), load shifting (e.g., smart thermostats) and behind-the-meter resources (e.g., energy storage and cogeneration). Demand response is explored for both summer and winter peak periods.

The key resource assumptions for each scenario are presented in Table 2. Scenario 1 assumes balanced commitments to conservation, new nuclear, and demand response. In Scenario 2, the impact of no commitment to conservation is explored. There is higher demand under Scenario 2, which allows for greater potential for demand response in both summer and winter. In Scenario 3, no new nuclear is explored beyond the existing Bruce and Darlington plants. Under all three scenarios, a 2 GW expansion of Quebec intertie and firm capacity is included. As we describe in Section 4.1.5 this study does not explore the cost effectiveness of the new intertie nor the potential for greater intertie capacity.

Table 2: Scenario Assumptions

Assumption	Scenario 1	Scenario 2	Scenario 3
Incremental Conservation	23 TWh	0 TWh	23 TWh
New Nuclear	2.4 GW	2.4 GW	0 GW
New Firm Imports	2.0 GW	2.0 GW	2.0 GW
Maximum Summer Demand Response	1.7 GW	1.8 GW	1.7 GW
Maximum Winter Demand Response	2.2 GW	2.5 GW	2.2 GW

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All remaining electricity needs are met by a mix of wind, solar, storage, and demand response. No restrictions are placed on the amount of wind and solar that can be built, but the cost of additional transmission is considered.

2.3 Inputs and Assumptions

The modelling assumptions are intended to represent cost-effective and implementable pathways for a net-zero electricity sector that supports broader economy-wide decarbonization by 2050. The magnitude and pace of the necessary demand growth is far higher than Ontario has seen for many decades. Policy changes will be needed to drive emissions reductions and enable the continued improvement of new, non-emitting resources. For example, to achieve the conservation outcomes modelled in Scenarios 1 and 3, commitment to best-in-class energy systems through consistently updated codes and standards may be required.

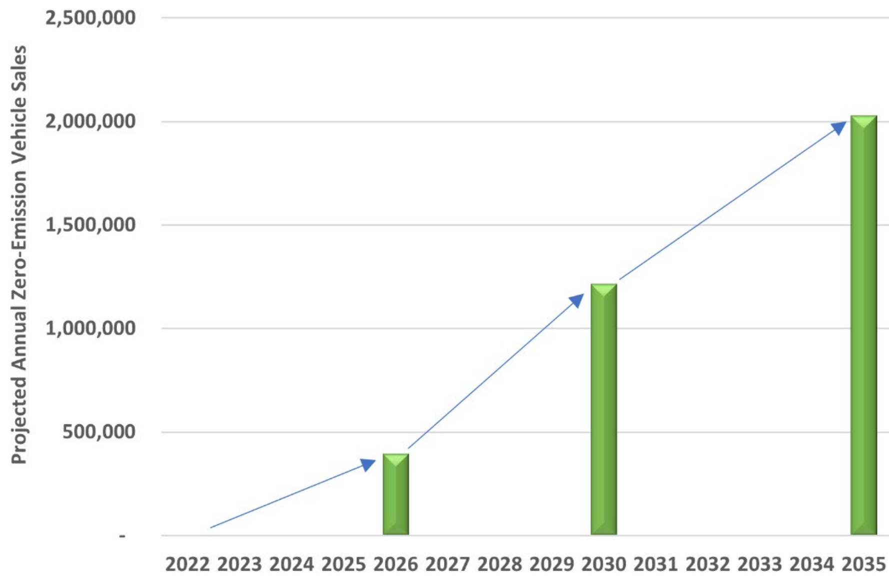
The following summarizes primary assumptions and inputs across all three scenarios.

2.3.1 *Demand Forecast*

The demand forecast has similar assumptions to the IESO's Pathways to Decarbonization Study. It is based on the 2021 Annual Planning Outlook (APO), with additional demand reflecting stronger efforts to replace fossil fuel consumption (e.g., space heating and transportation) with electric alternatives. In total, electrification adds 40 TWh (22%) to the APO's forecast for 2035 in the absence of conservation efforts.

Transportation electrification includes meeting the federal government's zero-emission vehicle policy targets entirely with battery electric vehicles (BEVs). There is a mandatory target of 100% of new light-duty vehicle sales by 2035 and an interim target of 60% of new sales by 2030. Our modelling estimates that compliance with these targets will result in 4.9 million BEVs in Ontario (47% of all vehicles) by 2035, a total of 17 TWh in overall demand.

Figure 2: Transport Canada's Projected Annual New Zero-Emission Vehicle Sales in Canada [2]



Similarly, fossil fuel equipment for space heating, water heating, and cooking is slowly phased out over the next 13 years with a complete ban on new sales starting in 2035. Fully electrified space heating could lead to extremely high demands on the electricity system on the coldest winter days. Instead, Power Advisory assumes dual fuel (electric heat pump and natural gas) systems will become the most common option until 2035. When powered by zero-carbon electricity, hybrid dual fuel systems can reduce building emissions by 75-95% as much as all-electric heating at a much lower cost.[3]

Reasoning for Dual-Fuel Assumption

Analysis and application by Hydro-Québec and Énergir in Quebec is a helpful guide on the comparative impact of all-electric space versus dual-fuel heating over the next decade. In the application, Hydro-Québec and Énergir proposed and were approved to offer a Dual Energy Offer to residential and commercial/institutional customers for space heating. The application considered two scenarios: all-to-electricity scenario and Dual Energy Offer scenario. Under Hydro-Québec's 2030 forecast, electricity usage under the Dual Energy Offer would be two-thirds of the all-to-electricity (i.e., ~3 TWh compared to ~2 TWh) the peak demand contribution would practically be negligible under the dual-energy offer while the all-to-electricity would add almost 2 GW to peak demand requirements. The peak demand contribution directly requires new supply resources in a very short time period. The difference in peak demand impact is the primary reason Power Advisory has assumed dual-fuel usage for 2035.

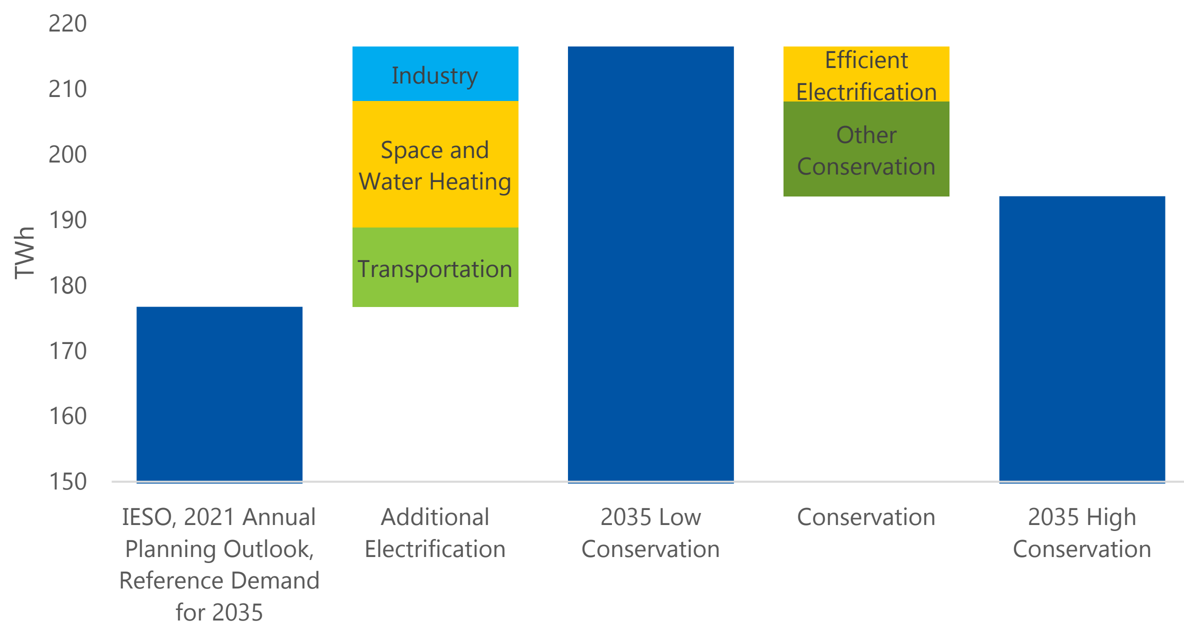
[2] Projected Annual Zero-Emission Vehicle Sales and Stock (canada.ca) as of early 2022

[3] Based on the supplemental information accompanying the MaRS Advanced Energy Centre's Future of Home Heating Study, available at https://www.marsdd.com/research-and-insights/future-of-home-heating/

Industrial electrification is more uncertain. The forecast includes an additional 8.3 TWh of industrial and agricultural demand, which is a combination of higher growth expectations and partial electrification.

Scenario 2 uses a higher demand forecast, while Scenarios 1 and 3 assume that new investments in conservation lead to a 23 TWh (11%) reduction in demand compared to Scenario 2. An important component of this additional conservation is incentives to install higher efficiency heat pumps and improve building insulation, further reducing both the amount of energy needed and the capacity needed for seasonal electricity peak demand. Other conservation efforts are distributed among conventional sources of electricity demand in the residential, commercial, and industrial sectors.

Figure 3: 2035 Net Energy Demand Forecasts



2.3.2 *Demand Response and Dual Fuel Heating*

As discussed above, the demand forecast assumes that dual fuel heating becomes common for new build and replacements. These systems would automatically switch over to natural gas on very cold days when heat pumps are less efficient and demand on the electricity system is higher. In addition, 30% of heating demand is assumed to operate in the electricity market as a dispatchable load. Bids for these dispatchable loads are set just below the variable cost of a natural gas generator. In other words, these consumers will switch to natural gas backup for heating before prices in the electricity market rise high enough to trigger the use of fossil fuel generation.

The scenarios also assume an expanded role for demand response (DR) due to increasing awareness and new flexible demand from electric vehicle charging. For the capacity expansion model, Power Advisory assumes that no more than 1.8 GW of summer DR and 2.5 GW of winter DR can be accommodated in Scenario 2, with approximately 10% lower caps in Scenarios 1 and 3 to reflect lower overall demand.[4]

It is not fully clear how much capacity may be available from demand response by 2035 or how much can be reliably integrated into the system. Policy and regulatory changes (e.g., enabling DER aggregation for participation in wholesale markets and the ability to offer reliability services to local utilities) are likely needed to enable the flexible demand envisioned in this study and maximize the amount of cost-effective demand response that is used by 2035. The recently released IESO DER Potential Study[5] estimates a significant potential for flexible, disaggregated loads to offset the need for additional transmission-connected generation. DERs can reduce system losses and offer additional non-electricity market values (e.g., customer resiliency)

2.3.3 *Clean Electricity Regulations, and the Role of Natural Gas*

The Government of Canada has committed to a net-zero electricity grid by 2035 and is currently developing the Clean Electricity Regulations (CER) as part of its effort to achieve this goal.[6] Proposed regulations are expected to be published by the end of 2022. Some information on the CER has been published as part of the public engagement process.

Most studies of electricity sector decarbonization find a continued need for a resource that is flexible, dispatchable, and able to operate for multiple consecutive days if necessary. A gas-fired generator is capable for this role; however, fuel supply for gas-fired generators is currently provided by carbon-intensive natural gas. With a rising carbon price and higher commodity cost due to a more integrated global demand[7], the cost-effectiveness of natural gas generation is expected to decrease. There are limited existing, cost-effective, low carbon-intensity fuel alternatives available with the required supply, transportation, and storage capabilities to fuel gas-fired generation. Green hydrogen (i.e., hydrogen produced from renewable generation) and renewable natural gas offer some promise with continued improvement in technology and cost. The CER is expected to recognize this problem and allow limited use of natural gas for electricity generation beyond 2035:

> *"[W]ith the current suite of technologies, continued use of natural gas may be required especially for emergencies and in some circumstances to complement variable wind and solar, but this use should decline over time as technologies evolve. Requiring financial*

[4] The maximum DR capacity is based on an analysis of hourly demand and the peak reduction that could be achieved with a 6-hour resource that is used no more than eight times per year.

[5] The IESO DER Potential Study can be found at https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/DER-Potential-Study

[6] For more on the CER, see https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity-regulation.html

[7] The Russia-Ukraine War and western sanctions of Russian energy exports are expected to increase North American natural gas prices as increased Liquified Natural Gas (LNG) export leads to more integrated natural gas global trade.

compliance that could take the form of offsets or payments corresponding to the federal carbon price will help ensure that this is the case."[8]

Power Advisory has modelled CER implementation for this study using a $185/tonne carbon price applied to all emissions from natural gas generation. The average natural gas price in 2035 is set at $7.79/MMBtu, which is based on natural gas futures at Dawn.[9] Using these assumptions, the marginal operating cost (combined fuel and carbon cost) for a typical combined-cycle natural gas plant is $127/MWh.[10] In all three scenarios, a carbon price provides a technology-neutral incentive for non-emitting generation and reduces the fossil share of Ontario's electricity generation to below 3%.

2.3.4 *Technology Costs and Capabilities*

Assumptions for wind, solar, and nuclear costs and capabilities are outlined in Table 3. However, increasing the amount of wind and solar generation reduces their energy market revenue since energy production profiles for those technologies are similar across various sites. For example, solar generation in California has resulted in very low midday energy prices when aggregate output is highest.

To determine a reasonable amount of wind and solar generation additions, the amount of wind and solar capacity in each scenario is increased until the energy market revenue of the marginal megawatt of capacity is equal to its levelized cost of energy (LCOE). In other words, Power Advisory assumes that new wind and solar generation will be installed only if energy market economics can support the project. The wind or solar project may rely on energy market revenues, or a load customer may be willing to sign a power purchase agreement to reduce their energy costs. This is a conservative approach because wind and solar also provide capacity value to the system. For wind, energy market revenue must cover the LCOE plus the levelized cost of $300/kW of transmission expansion.[11] There is also the potential for corporate renewable Power Purchase Agreements (PPAs) for renewable generation to support corporate Environment, Social and Governance (ESG) objectives. The non-monetary value that may be sold through corporate renewables PPAs could provide additional cost reduction for renewable generation resources.

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[8] Proposed Frame for the Clean Energy Regulations, July 2022: https://www.canada.ca/en/environment-climate-change/services/canadian-environmental-protection-act-registry/publications/proposed-frame-clean-electricity-regulations.html

[9] Natural gas futures price based on information published by S&P Global Market Intelligence

[10] Calculation uses a heat rate of 7,200 Btu/kWh and carbon dioxide emission coefficient of 52.91 kg/MMBtu for natural gas.

[11] In the input assumptions for the IESO's Pathways to Decarbonization Study, 9.1 GW of onshore wind potential is identified with a weighted average transmission cost of $207/kW in 2021 USD. This study uses a slightly higher estimate of $300/kW in 2021 CAD. Scenarios 2 and 3 include more than 9.1 GW of new wind, which would most likely be sited in more remote areas with greater transmission cost.

Table 3: Cost and Capabilities, Energy Resources

Assumption	Wind	Solar	Nuclear
Levelized Cost of Energy ($CAD/MWh)[12,13]	41.96	47.44	130.00
Capacity Factor	41%	20%	93%
Summer Effective Capacity[14]	20%	15%	93%
Winter Effective Capacity	28%	0%	93%

The remaining capacity requirements, after considering the contribution of wind, solar, nuclear, and Quebec imports, are met by a combination of storage and demand response. Cost and performance assumptions for capacity resources are outlined in Table 4.

Table 4: Cost and Capabilities, Capacity Resources

Assumption	Storage	Demand Response
Levelized Cost of Capacity ($CAD/kW-year)	4-hour: 207 6-hour: 285 8-hour: 363 10-hour: 441	61
Summer Effective Capacity	95%	69%
Winter Effective Capacity	95%	78%
Maximum Installed Capacity	4-, 6-, and 8-hour: 1,000 MW each 10-hour: 2,000 MW	Summer: 1.8 GW Winter: 2.2 GW Summer (with Conservation): 1.7 GW Winter (with Conservation): 2.2 GW

[12] Wind and solar LCOE is based on the National Renewable Energy Laboratory's Annual Technology Baseline Moderate Case, plus a 15% adder to reflect market risk and other factors. Cost is the average of projected costs for the period from 2027 to 2035. For nuclear, the assumptions used in the IESO's Pathways to Decarbonization study are levelized using a 5.47% cost of capital.

[13] On November 3rd, 2022, the Canadian government released their Fall Economic Statement (FES) that included the intent to launch Investment Tax Credits (ITC) for non-emitting generation and energy storage resources. Power Advisory's LCOE estimates do not include the impact of ITC.

[14] Effective capacity for wind and solar is based on the expected reduction in the 50th highest demand hour before and after adding the incremental capacity expected for 2035. Wind capacity is tested assuming that solar is already installed, and solar is tested assuming wind is already installed. The resulting effective capacity values are lower than the assumed effective capacity for the IESO's Pathways to Decarbonization study.

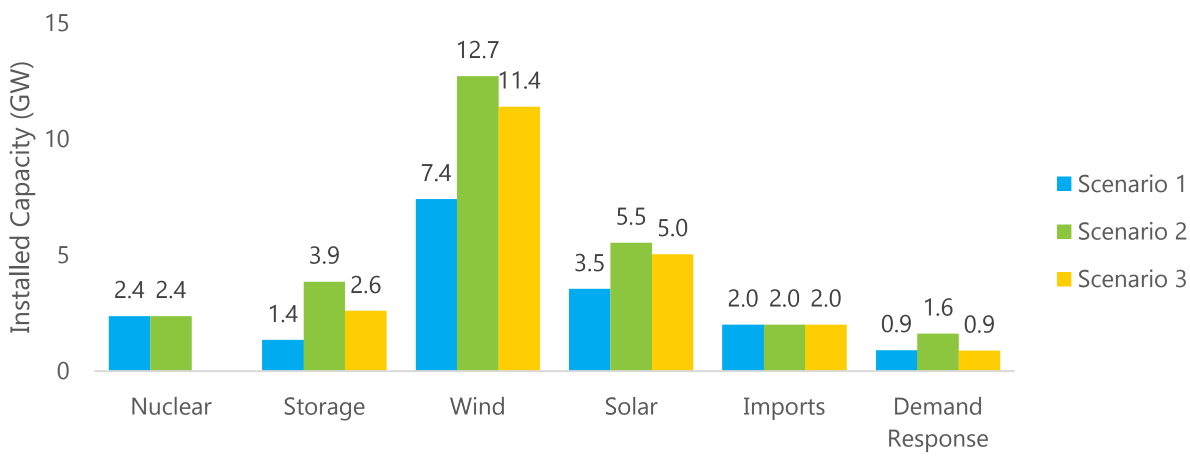
3. SCENARIO OUTCOMES

For each scenario, Power Advisory utilized our proprietary dispatch model that simulated hourly energy production by resource to meet the hourly demand forecasted in the model. The dispatch model is used to determine energy market revenues and energy production by resource. Power Advisory also utilized its Global Adjustment (GA) settlement model to determine total wholesale energy costs to customers. In Ontario, wholesale electricity costs are a combination of real-time energy market prices (i.e., Hourly Ontario Energy Price (HOEP)) and GA payments. The total wholesale electricity price is an important value to consider when assess the cost-effectiveness of different pathways since that is the price Ontario ratepayers ultimately pay for electricity.

3.1 Capacity Additions

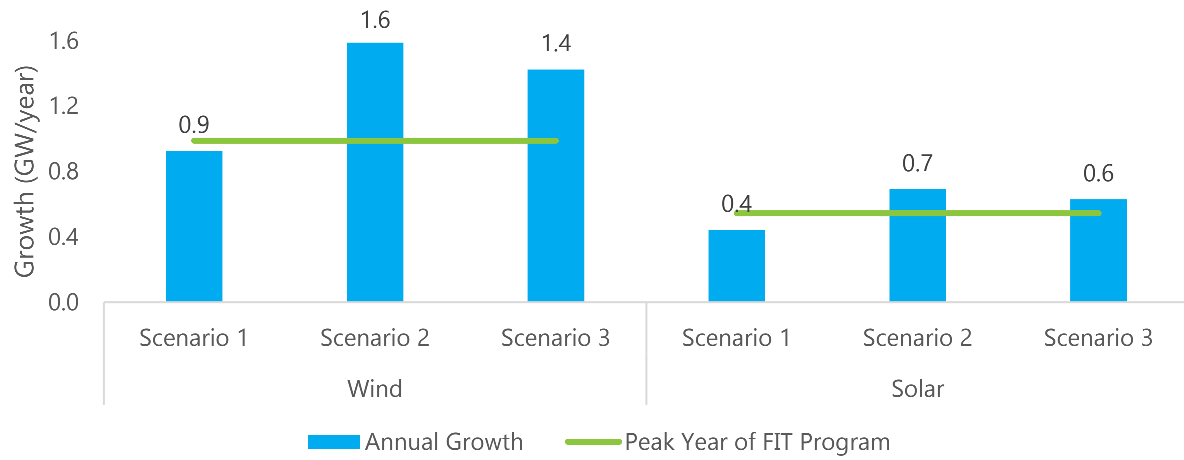
In all scenarios, wind has the largest growth in installed capacity. It is expected to have an LCOE slightly lower than solar and significantly lower than any other supply option. In addition, the study assumes that new wind generation is installed in a broad geographic area, including parts of Ontario's north. Geographic diversification leads to a smoother overall output profile compared to the current wind fleet, which is concentrated in Southwestern Ontario. Scenario 2, which has no additional conservation, requires more wind and storage than the other scenarios.

Figure 4: Added Capacity by Scenario, 2022 to 2035 (GW)



In Figure 5, the incremental wind and solar is presented as an average annual growth rate, assuming that it is installed in the 8-year period from 2027 to 2035. The required growth rates are compared to the amount of wind and solar that were installed at the peak year of the FIT program in 2014/15.

Figure 5: Wind and Solar Growth Rates Required



The required growth rates across scenarios are high but achievable. The difference in annual wind and solar growth rates is important to consider since they would provide a significant strain on existing permitting, approvals, and connection assessments required to connect new generation resources. Supportive policies for siting, community engagement, and First Nations consultation will be required to achieve the growth rates indicated above.

Power Advisory assumes nearer-term wind generation investments are through the repowering of existing wind generation facilities in Southern Ontario. There are also opportunities for faster development by supporting distributed solar development (e.g., behind-the-meter rooftop solar), which can be completed more quickly than utility-scale solar and reduce the need for incremental transmission and distribution investments. The IESO DER Potential Study demonstrated the opportunity for behind-the-meter and distribution connected resources to meet Ontario's supply needs.[15]

3.2 Annual Energy

Figure 6 presents the change in expected annual energy generation, imports, and exports between 2021 and 2035 for the three scenarios. Additional conservation in Scenarios 1 and 3 is also shown.

Wind generation is the single highest contributor across scenarios, with between 27 and 44 TWh of increased output. All scenarios also include higher imports, enabled by the new Quebec intertie, and lower energy exports compared to 2021.

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[15] The IESO DER Potential Study can be found at https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/DER-Potential-Study

Figure 6: Change in Energy Mix by Scenario, 2021 to 2035 (TWh)[16]

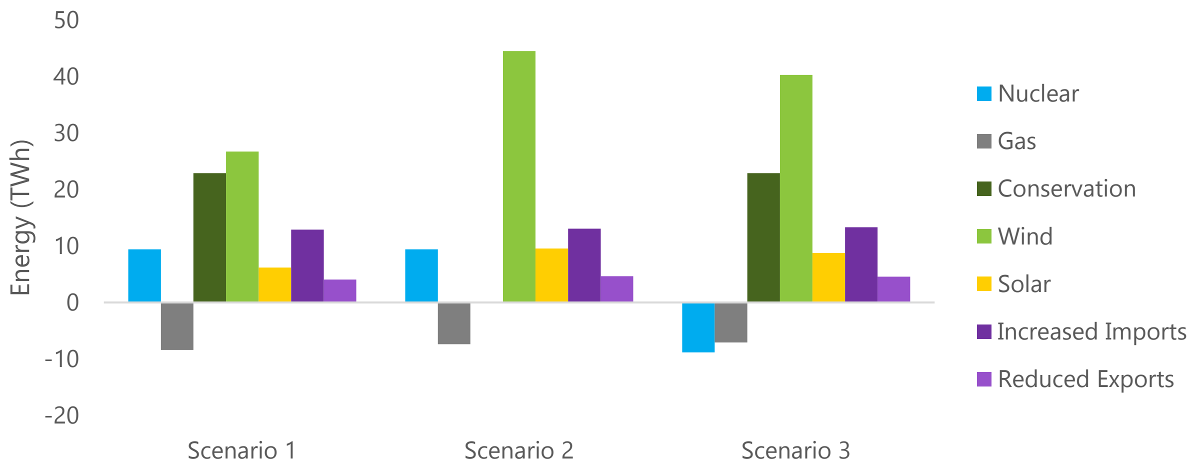
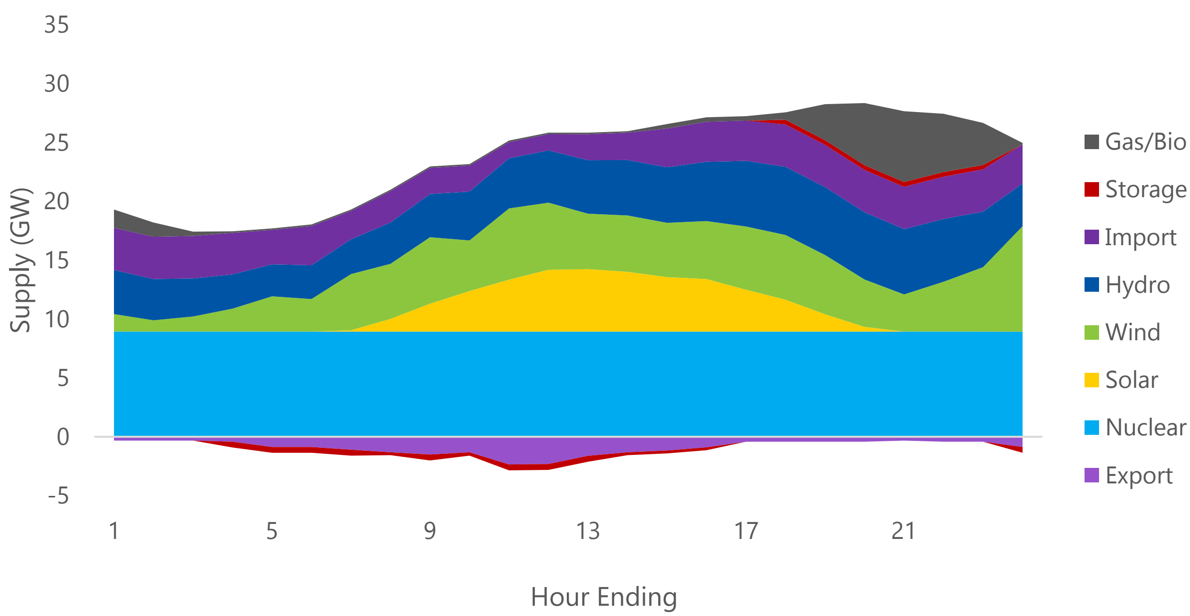


Figure 7 shows an example of a summer day in Scenario 3 with high demand. Nuclear operates steadily though the day. The midday solar peak leads to exports and storage charging. During the evening, demand rises and supply from solar falls. Hydro, imports, and storage ramp up but energy from natural gas generation is also needed to manage the evening demand peak. Some of the storage and all demand response is held back for reliability and operating reserve.[17]

Figure 7: Illustrative Summer Day with High Demand, Scenario 3



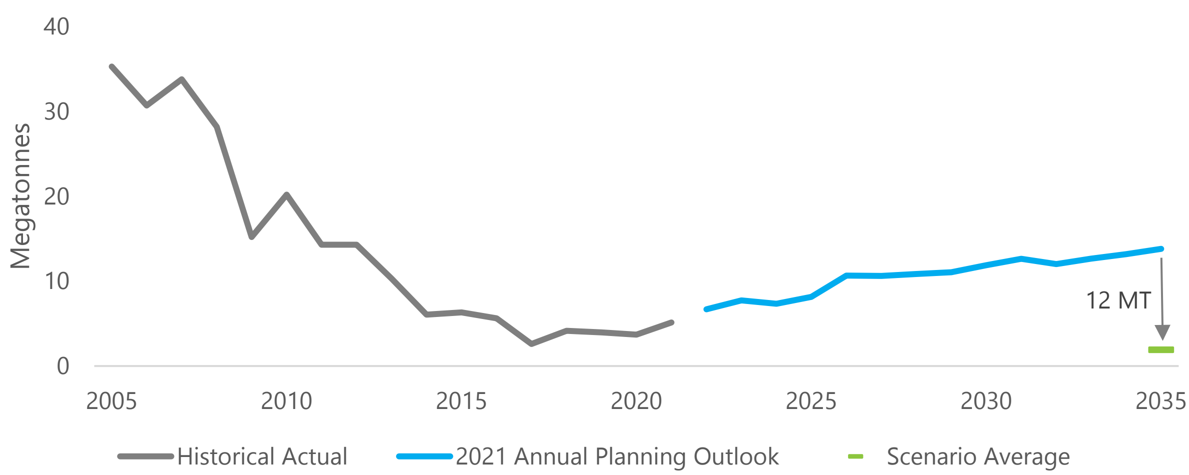
[16] Note that the incremental conservation is incremental to the APO 2035 conservation forecast

[17] Operating reserve requirements are primarily based on the largest single contingency in an electricity market. For Ontario, that would typically be nuclear generation unit(s) outage; Power Advisory assumes the amount of Operating Reserve scheduled does not change by 2035.

3.3 Greenhouse Gas Emissions

In all three scenarios, greenhouse gas emissions from the electricity sector will fall to approximately two megatonnes (MT) by 2035 (Table 5). The level of emissions is comparable to 2017, the lowest year since Ontario phased out coal generation (Figure 8). This level of annual emissions is achieved even while an additional 40 TWh of demand is added to the system. Like other outcomes presented in this study, emissions represent a typical year. Depending on weather conditions, annual emissions may be higher or lower.

Figure 8: Electricity Sector Greenhouse Gas Emissions



In addition to significantly lower annual emissions by 2035, there is a potential to reduce cumulative emissions over the study period through the support of DERs. The development and connection process for DERs is shorter than for transmission-connected resources. Further, DERs can be sited within load centers avoiding the need for time consuming transmission expansions that can delay the emissions reduction benefits. Scenario 1 assumes that a majority of the 3.5 GW of solar generation is developed by 2030 with a large share developed as distribution-connected solar (e.g., commercial and residential rooftop, infill developments, etc.). Scenario 2, by contrast, assumes only 1 GW is developed by 2030 with the remaining solar generation requiring transmission expansion that will not reach in-service until after 2030. As shown in Table 5, emissions in 2030 are estimated to be 6 MT lower in Scenario 1 compared to Scenario 2 due to faster development of distributed solar and early investment in conservation. All three scenarios assume significantly higher demand growth by 2030 and 2035 compared to the 2021 APO.

Table 5: Electricity Sector Greenhouse Gas Emissions and Intensity by Scenario

Year		Scenario 1	Scenario 2	Scenario 3
2030	Emissions (MT)	10.9	16.9	10.8
	Intensity (t/GWh)	66	97	66
2035	Emissions (MT)	1.6	2.0	2.2
	Intensity (t/GWh)	9	10	11

3.4 Wholesale Electricity Cost

Power Advisory estimated the total wholesale electricity cost[18] to each of the three scenarios, with summary results presented in Table 6. Scenario 2, with no additional conservation, has a higher total cost than the other two scenarios but lower rates in terms of dollars per MWh. The cost of conservation is assumed to be $40/MWh, but Scenario 3 remains lower cost than Scenario 2 for unit conservation costs up to $140/MWh.

Scenario 3, which has no new nuclear, is also slightly lower cost than Scenario 1, which has the same amount of conservation and 2.4 GW more nuclear capacity. Comparing expected costs between Scenario 1 and Scenario 3 is only the first step when considering the role of nuclear in a net-zero future. The cost of any large nuclear project is highly uncertain, and the risk of cost overruns would almost certainly be borne by Ontario ratepayers or taxpayers. Wind, solar, and storage can be installed incrementally by private developers at more predictable prices. However, wind and solar may require more investment in transmission with higher land impacts than a nuclear generator.

Although an escalating carbon price is applied in the 2035 forecast and the marginal cost of a typical gas plant exceeds $125/MWh, the demand-weighted average price of energy ranges from $65 to $69/MWh across the three scenarios. The remaining costs, which would be recovered mainly through the Global Adjustment under current rules, range from $47 to $56/MWh. The forecasted total wholesale electricity cost of $116 to $121/MWh is comparable to the average $118/MWh (in 2022$) wholesale cost of electricity over the past five years (2017 – 2021).[19]

As-modelled wholesale electricity costs show that Scenario 2 has the largest cost of the three scenarios; this is logical given the higher amount of demand associated supply resource build out. The impact of conservation reduces the wholesale electricity cost for Scenarios 1 and 3. For a comparison, Power Advisory considered the wholesale electricity cost in 2035 if incremental wind and solar generation output was replaced by gas-fired generation inclusive of the 2035 carbon price (i.e., $185/tonne). The results show that Ontario's wholesale electricity costs would be higher under all scenarios if the energy were instead delivered with gas-fired generation.

[18] Wholesale electricity cost represents the energy and operating reserve market, plus the cost of regulated generation and any other procurements needed for capacity and ancillary services. Wholesale electricity costs do not include transmission and distribution.

[19] https://www.ieso.ca/en/Power-Data/Price-Overview/Global-Adjustment

Table 6: Wholesale Electricity Costs, 2035

Wholesale Electricity Costs ($billions)	Scenario 1	Scenario 2	Scenario 3
As-Modelled Scenarios	22.7	24.3	22.0
Replacement of Incremental Wind & Solar Energy with Gas-Fired Generation	27.1	31.5	28.6

For clarity, this analysis does not consider the flexibility and operational requirements of the power system, particularly day-ahead and intraday considerations that are offered by gas-fired generation. This analysis has only considered the cost impact for annual energy consumption and peak demand capacity needs. This difference in wholesale electricity costs show the potential benefit of deploying low-cost renewable generation to replacement gas-fired generation energy output. The inflection point for replacement will need to consider day-to-day and hour-by-hour operational requirements (e.g., at some point additional solar generation has limited energy and capacity value on top of existing solar generation).

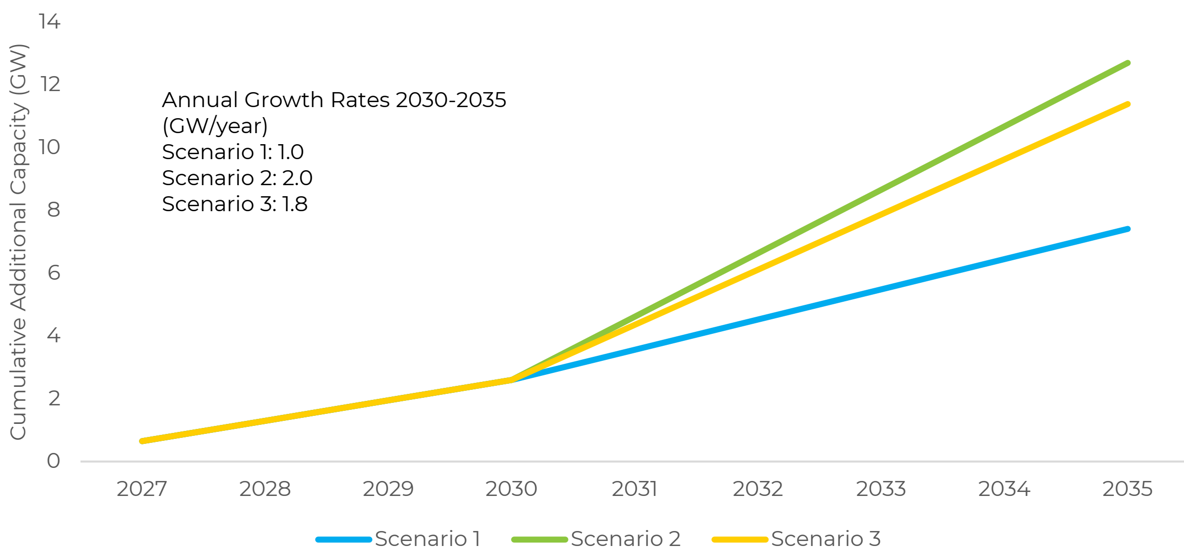
3.5 Transmission Expansion

Proactive transmission expansion would be needed to enable the amount of wind generation growth in these scenarios. Specifically, it is very unlikely that significant renewable generation can be installed without new transmission expansion between southern and northern Ontario. While the southern Ontario power system is relatively congestion free, the connection capability is limited. In addition, population density and renewable resource potential hamper the ability to significantly expand wind generation capability in southern Ontario. Bulk transmission expansion from southern Ontario to northern Ontario is needed under all three scenarios.

Figure 9: New North South Bulk Transmission Expansion

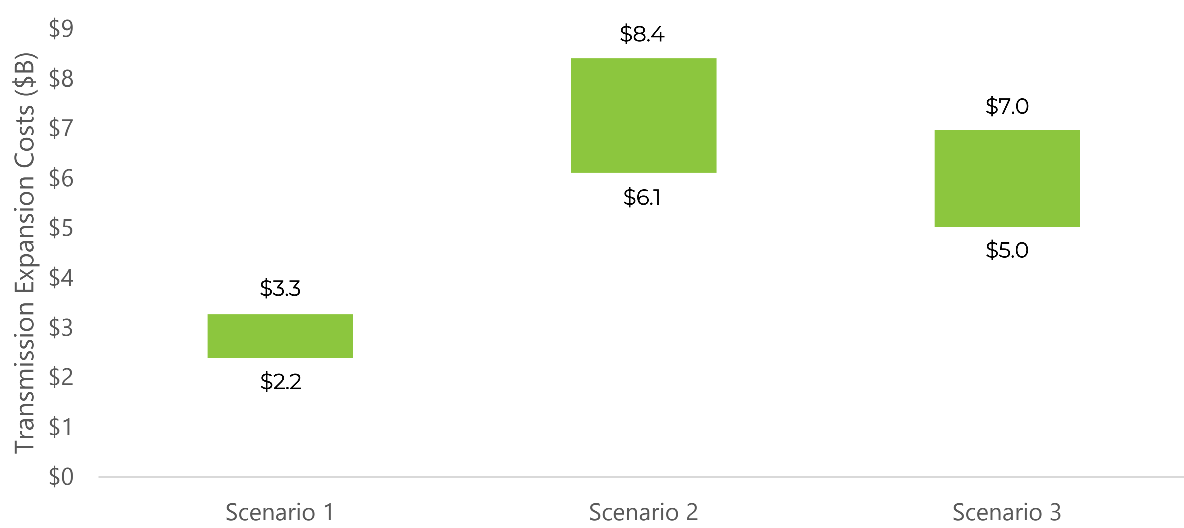
Realistically, only roughly 50% of the existing wind generation capacity (i.e., ~2.6 GW) can be installed through repowering until a new transmission line to the north is in-service. Bulk transmission expansion typically takes 7 to 10 years; therefore, the earliest new transmission could come into service would be in 2030. Considering this restriction, wind growth rates increase significantly, reaching close to 2x as much as peak FIT program levels under Scenario 2.

Figure 10: Wind Generation Expansion with Transmission Restrictions



The greater amount of wind generation required to be developed in the north to meet net-zero objectives, the larger and more expensive the new transmission expansion will be. Power Advisory has constructed a high-level transmission expansion to ensure the deliverability of wind generation to load centers in Ontario under each scenario. The range of costs for each scenario is presented in Figure 11.

Figure 11: High-Level Transmission Expansion Cost Estimate Ranges



With higher installed capacity of wind generation expected in Scenario 2 and 3, the transmission costs are expected to be higher. Further, multiple bulk transmission expansions will be required to ensure the capability of the power system to deliver the amount of energy required to southern Ontario load centers.

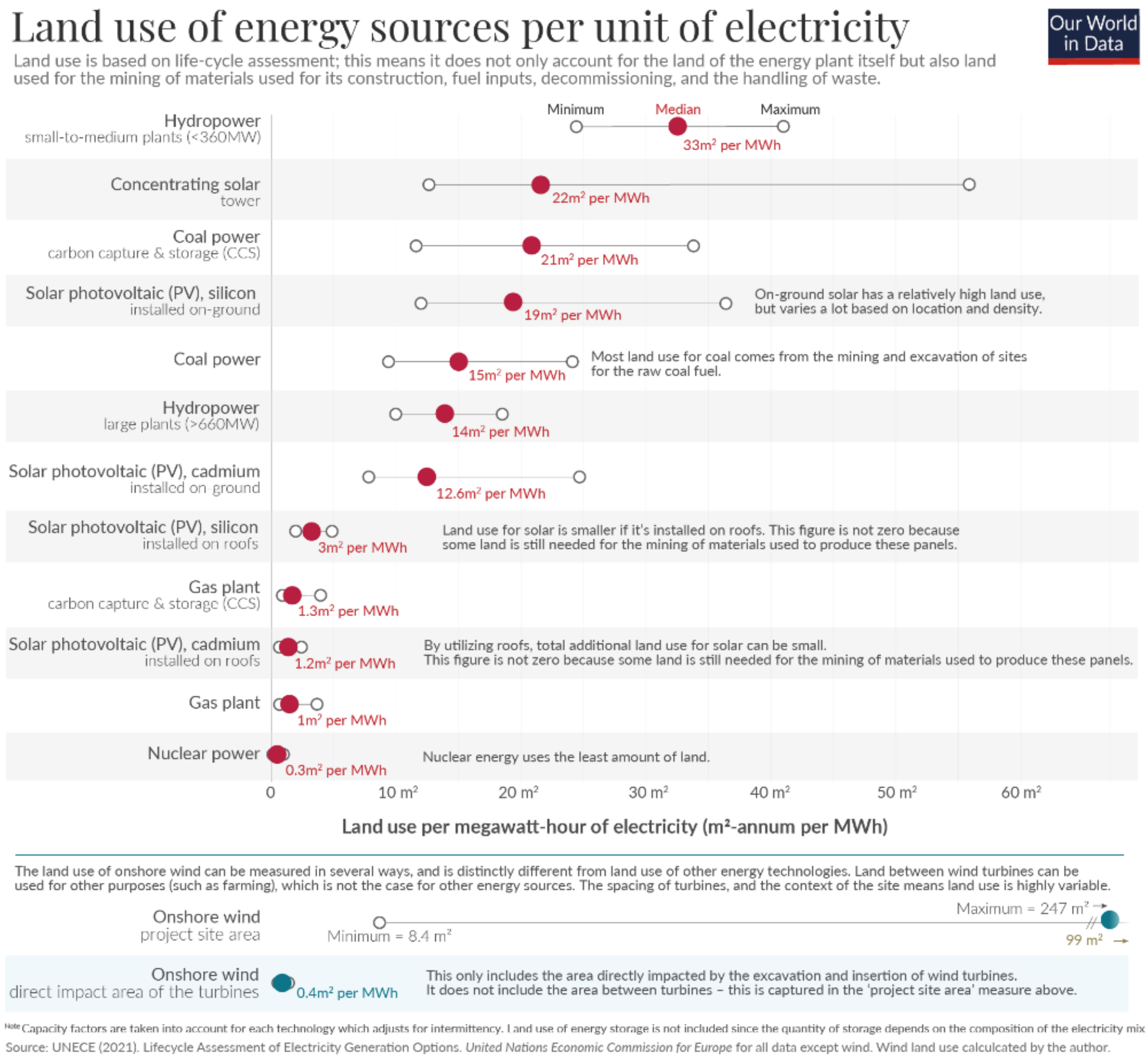
4. QUALITATIVE CONSIDERATIONS

The scenario analysis presented above has presented a number of quantitative outcomes. In addition to these results, there are qualitative considerations to achieving net-zero by 2035 that should be acknowledged.

4.1 Land use

Developing and constructing new supply resources to meet future system needs under a net-zero future should be considered. Different resources require different land use to produce energy for consumption (see chart below). Ontario is blessed with a significant land area compared to many other jurisdictions allowing for more options to develop energy resources. However, energy resources need to be capable of delivering their energy to customers. Energy resources developed away from existing power system networks can result in further land use for transmission network expansion. The variation in land use requirements by different resources is justification to consider a diversified resource mix to optimize the overall energy system. It also underlines the value of a conservation-first approach to limit the scale of supply and transmission growth required moving forward.

Figure 12: Land Use of Energy Sources per Unit of Energy[20]



4.2 Timelines to build infrastructure

As discussed in the transmission expansion section above, energy infrastructure is not an overnight process and requires time for planning, developing, permitting, constructing, and commissioning before the resources can reach in-service. Experience in neighbouring jurisdictions suggest that most large, transmission-connected energy resources require between 5-7 years to reach in-service from initial development. Smaller, distribution-connected and behind-the-meter resources and demand-side resources can be completed in much shorter timelines and should be considered for early actions. With little over a decade until the 2035 net-zero target, time is of the essence. Planning and procurement

[20] https://ourworldindata.org/land-use-per-energy-source

activities must be initiated immediately to ensure the required resources for a net-zero electricity supply mix are underway in time for 2035.

4.3 Labour and material limitation

Related to infrastructure timelines, the ability to develop and construct net-zero resources can be limited by available labour and materials. For example, one of the key challenges Ontario Power Generation and Bruce Power faced as part of the Ontario nuclear refurbishment program was ensuring there would be enough skilled trades. Net-zero scenarios with higher rates of annual installed capacity may reach limitations due to major equipment limitations (e.g., wind turbines, solar panels, critical nuclear components) or a skilled labour shortage. When assessing the impact of net-zero scenarios, limitations from labour and major equipment should be considered to understand potential pinch points or areas that will require flexibility. Labour and material limitations are also a compelling reason for a procurement roadmap that has regular purchases of resources. This ensures that labour and materials needs are not overloaded. Further, a regular procurement schedule can allow for adjustments to external factors such as global supply chain issues or evolving technology capabilities.

4.4 Large hydroelectric and offshore wind potential

The provincial government has asked Ontario Power Generation and Ontario Waterpower Association (OWA) to evaluate the potential for sizeable hydroelectric generation in northern Ontario to meet future supply needs. Large hydroelectric has been a major net-zero energy resource and is expected to play a significant part in the future. A key drawback of large hydroelectric is the long development time of planning, permitting, and construction. In addition, large hydroelectric projects typically require significant expansion of the transmission system to deliver energy from the geographically specific hydroelectric resource potential to load centers.

Power Advisory expects that new large hydroelectric generation would take between 12 to 15 years to develop and likely would not be available in time for 2035. The absence of large hydroelectric from the three scenarios considered in this report should not be taken as a reason to ignore the potential for large hydroelectric in meeting Canada's long-term supply needs. Instead, large hydroelectric is likely a significant resource option for post-2035 supply need. The same timeline considerations should be applied for offshore wind in Ontario. There is policy uncertainty with respect to the current moratorium on offshore wind. In addition, transmission system expansion will likely be required to integrate offshore wind energy production into the existing transmission grid.

4.5 Challenges with relying on imports

Imports from neighbouring jurisdictions have been offered as options to address net-zero resource options. Power Advisory has included 2,000 MW of firm import capacity in all three scenarios enabled by expanded interties. Many significant challenges and uncertainties are associated with relying on this quantity of imports for future long-term net-zero needs.

First, Ontario is not alone in considering a net-zero electricity supply mix. Available capacity from neighbouring jurisdictions is expected to be limited as each jurisdiction seeks to develop internal resources to meet their own net-zero needs. For example, Hydro Quebec's recent Strategic Plan 2022-2026 indicates that it will require additional winter capacity and energy supplies by 2027.[21]

Second, new resources developed for export are not expected to be as cost-effective as Quebec's existing generation supply mix. For example, Hydro-Quebec expects their new hydroelectric generation to cost ~$100/MWh compared to previous estimates of ~$65/MWh related to the recently completed Romaine River project.[22]

Third, Ontario will continue competing with New York, New England, and the Maritimes for access to energy and capacity from potential export jurisdictions such as Quebec.

Finally, and perhaps more importantly, large quantities of imports from neighbouring jurisdictions will require significant bulk transmission system expansion within Ontario and the neighbouring jurisdiction. Further increasing import capacity beyond the 2,000 MW assumed in this report would lead to escalating complexity and costs. Ontario is not resource-constrained, and as discussed, there is ample land to determine an appropriate supply mix to meet net-zero objectives. If large bulk transmission expansion is required for imports, it is likely more politically and socially acceptable to invest in the transmission infrastructure within the province first.

To be clear, Power Advisory believes that enhanced intertie capability to trade with neighbouring jurisdictions is beneficial and should be explored to provide flexibility, resilience, and cost reducing competition to Ontario's electricity markets. Other federal-level studies have demonstrated the value of increased intertie capacity to all provinces in Canada. Large firm capacity import agreements are different and must be considered in the same manner as any other large energy resource option.

[21] https://www.hydroquebec.com/data/documents-donnees/pdf/strategic-plan.pdf?v=2022-03-24

[22] https://www.theglobeandmail.com/business/commentary/article-legault-hydro-quebec-megadams/

5. KEY TAKE-AWAYS AND RECOMMENDATIONS

The scenario analysis completed in this study demonstrates that achieving a net-zero electricity system by 2035 is possible, but there are many challenges that must be overcome. Many key takeaways can be drawn from the analysis.

5.1 Investment needs to start immediately

A significant amount of new resources will be required on both the supply and demand side regardless of the net-zero supply mix objective. New demand growth alone is expected to require between 5,000 MW and 8,000 MW of new supply by 2030, based on the 2021 APO. The sheer magnitude of investment is daunting and will only grow without immediate action. Any major infrastructure development will face challenges (e.g., global supply chain issues, labour shortages, etc.) that can impact the timing of delivery. Compressing the delivery schedule increases the impact of delivery risk. To mitigate delivery risk, development of resources should be spread out as much as possible to provide time and flexibility. With a target delivery of a net-zero supply mix by 2035, investments must start as soon as possible. Further, initial investments can target the lowest cost new resources to mitigate overall system costs and provide clarity on long-term decision-making requirements.

5.2 All resources need to be considered for net-zero

The scenario analysis clearly shows that a wide array of resource investments is required to achieve a net-zero supply mix. Restricting investments or commitments to a subset of resources will strain the power system and development capabilities of the electricity industry. Further, future technology innovation and cost reductions are uncertain and will influence long-term decision making. Selecting preferred technologies today can limit options in the future and compromise the affordability of the system overall. Instead, all resource types should be supported, and targeted competitive procurements should be used to ensure that ratepayers are offered the most cost-effective solutions that balance system needs and costs.

5.3 Reducing new supply need through conservation efforts can reduce the amount of resource development

Conservation initiatives can reduce long-term system needs. Incremental conservation modelled in this study reduce the amount of wind generation needed by ~5 GW and solar generation by ~2 GW. In addition to reducing total investment requirements, conservation can allow system planners and policymakers more time to assess the absolute investment requirements and the best technology options. As the decarbonized economy materializes, technological innovation for energy systems is expected to accelerate (e.g., more efficient heat pump design, and smart appliance control). Conservation programs can be used to support best-in-class consumer spending that could offer additional value long-term (i.e., more dispatchable and flexible load).

5.4 Transmission expansion support for long-term options

Regardless of the supply mix, it is clear that all net-zero scenarios will require transmission expansion. As discussed, bulk transmission system expansion is a long process requiring significant study and analysis. Given the timelines, transmission expansion options should be supported immediately. Further, transmission options explored should include scalability to allow flexibility of implementation for whatever resource options are selected long-term.

5.5 A net-zero electricity supply mix can be cost-effective

Wholesale electricity rates (i.e., the cost per megawatt-hour of reliably generating electricity) in the net-zero scenarios are comparable to costs in the last five years. Ontario's existing nuclear and hydroelectric capacity provides a significant amount of affordable, non-emitting energy and firm capacity. Wind and solar prices are expected to continue declining in real terms, which offsets inflation in other components of wholesale electricity costs. The cost estimates in this report assume that future resources are acquired and priced competitively and that cost-effective options like demand response and storage are enabled to participate fully in electricity markets. Wholesale rates are also reduced by investments in transmission to access low-cost renewables and better integrate with neighbouring jurisdictions.

5.6 Recommendations

The following are Power Advisory's high-level recommendations to support a net-zero future. The recommendations are drawn from the scenario analysis key takeaways and the qualitative considerations. The recommendations are a mixture of policy and technical.

- Enhanced and continued support for all cost-effective conservation investments. Reducing long-term system needs while supporting demand-side innovation is critical to achieving a net-zero ready grid by 2035. All cost-effective conservation should be strongly considered to minimize the scale of supply-side and grid expansion needed. Conservation investments can include consistent updates to codes and standards to prioritize best-in-class technologies, support through centralized conservation programs, and local and targeted conservation efforts. These efforts should also include supporting utilities in the investment of conservation and demand management to meet power system needs at both the local and provincial levels. In many respects, the updated Conservation and Demand Management Guidelines published by the Ontario Energy Board (OEB) aligns with the general direction of these recommendations and should be expanded upon. In addition to direct conservation efforts, indirect support should be provided. This can include financial support for training of skilled labour for installation of energy efficiency equipment and expedited DER connection processes.

- Establish a consistent and long-term procurement roadmap. Achieving net zero will require continuous construction of new supply resources to meet growing electrification demand and replace carbon-intensive generation. To protect against the potential shortfalls in materials and labour and manage unknown development challenges, a consistent, predictable, and long-term procurement roadmap should be established to support the build out of resources. Consistent procurements can provide optionality to adjust the objective of resources to target the best option at the time and provide flexibility to address constraints or issues with resource development. Ontario will be competing for capital for net-zero investments with many other jurisdictions. A long-term procurement roadmap with consistent iterations will support investor confidence and ensure Ontario has access to low-cost capital to fund needed electricity infrastructure investments. Finally, consistent procurements can also adapt to external private investments in renewables that may occur outside of resource adequacy needs (e.g., corporate renewable PPAs to meet ESG objectives. This can reduce the overall cost to ratepayers and support greater capital injection into the Ontario electricity sector. Similar considerations can be given to DER investments by customers.

- Complete a net-zero transmission system study and action plan. To achieve net-zero, transmission expansion will be required to support new load growth as well as ensure new supply resources are capable of delivering energy to growing load centers. The change in supply mix to non-emitting resources that are located in different geographic locations and have different output characteristics will lead to different power flows on the transmission network. The overall change to the power system will be complex and must be assessed holistically. A net-zero transmission system study that envisions the use of the power network in 2035 should be completed. The net-zero transmission study should identify priority bulk system plans and establish an action plan for development. The study could look at potential streamlining for regulatory and permitting approvals as part of a holistic power system plan.

- Explore multiple solutions in parallel. Technology evolution and changing societal preferences will influence the path to net-zero. The scenario analysis clearly shows multiple paths for achieving a net-zero grid by 2035. Multiple solutions should be pursued pragmatically and in parallel. This should include quick implementations (e.g., DERs) and long-term resources (e.g., transmission-connected renewables). The path to net-zero should avoid concentrating on a single preferred technology and instead focus on creating a diversified and balanced supply mix.

6. APPENDIX A: MODELLING METHODOLOGY

6.1 Demand Forecast

The demand forecast for this study is based on the Reference Demand Forecast from the 2021 Annual Planning Outlook, with additional demand representing incremental electrification supporting long-term economy-wide decarbonization targets. Assumptions for demand electrification are broadly aligned with the assumptions presented in July 2022 for use in the IESO's Pathways to Decarbonization study.[23]

Demand is disaggregated into four categories in Power Advisory's forecast: conventional demand, transportation, additional heating, and additional industrial demand. Conventional demand represents the current mix of electricity consumers, while the other three categories are the subsectors of demand expected to change the most due to fuel switching and other emissions reduction efforts.

The forecast growth of conventional demand is aligned with the 2021 Annual Planning Outlook Reference forecast, while industrial demand growth is an assumption consistent with the Pathways to Decarbonization study assumptions. For light-duty vehicle and space heating electrification, Power Advisory forecasts the stock of electric and fossil-fueled equipment over time assuming the electric share of new sales steadily increases to 100% by 2035, and federal interim targets for zero-emission vehicle sales are met. Inputs to these equipment stock forecasts include Government of Ontario population projections,[24] information on vehicle sales and registrations from Statistics Canada,[25] historical baseline heating energy consumption by fuel source from Natural Resources Canada's Comprehensive Energy Use Database,[26] and assumed average lifetimes of 15 years for light vehicles and 20 years for heating equipment.

Hourly load shapes were then applied to the categories of demand to produce total hourly demand for the dispatch model. The load shape for conventional demand is based on historical Ontario demand patterns. The load shape for transportation and electric vehicles is from NREL's EVI-Pro Lite tool.[27] The heating profile was developed by Power Advisory based on historical weather data and residential natural gas consumption. The industrial demand profile is based on Other Industrial in EPRI's Load Shape Library 8.0.[28]

6.2 Energy Dispatch and Costs

Power Advisory's forecast model simulates the mechanisms and offer behaviours of market participants that drive pricing in Ontario's wholesale energy market. Offers from all resources are sorted from lowest to

[23] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/ptd/ptd-20220719-input-assumptions-table-feedback.ashx

[24] https://data.ontario.ca/dataset/population-projections, July 2022 version

[25] Tables 23-10-0067-01, 20-10-0001-01, and 20-10-0025-01

[26] https://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/menus/trends/comprehensive_tables/list.cfm

[27] 70% "Immediate – as fast as possible" and 30% "Immediate – as slow as possible." Available at https://afdc.energy.gov/evi-pro-lite

[28] https://loadshape.epri.com/enduse

highest, and the market is cleared when supply meets demand. The resource that sits at the nexus of the supply stack and the demand curve is the price-setting (or marginal) unit. Resources with offers below the hourly clearing price are assumed to be dispatched.

Various market participants have a range of incentives underpinning their offers in the wholesale market. In the current market, most market participants are incented to offer their marginal cost and receive out-of-market payments (via the Global Adjustment) to make them financially whole. We assume that in 2035 the Ontario market will continue to operate in this manner.

Wind, solar, nuclear, and hydroelectric resources are assumed to receive a guaranteed price per megawatt-hour through either rate regulation or a contract for differences. Gas, storage, demand response and firm import resources are assumed to receive capacity payments through either the Capacity Auction mechanism or a contract which preserves the incentive to offer at marginal cost in the energy market.

Table 7: Marginal Costs and Offer/Bid Strategies

Resource Type	Offer/Bid
Nuclear	-$1,999/MWh, limited flexibility at -$5/MWh
Wind	$0/MWh
Solar	$0/MWh
Hydroelectric	Run-of-river component: -$500/MWh Dispatchable component: $7 to $21/MWh, with some water reserved to compete with peaking gas plants at high prices
Gas	Marginal cost offer based on the formula: Fuel Price ($/MMBtu) * Heat Rate (MMBtu/MWh) + Variable O&M ($/MWh). For most plants, variable O&M ranges from $3 to $7/MWh
Storage	Charges opportunistically at low prices. Approximately half of the storage capacity offers below the cost of gas-fired generation, and the other half reserves energy for high price events.
Import and Export	Bid and offer curves are calibrated to observed historical behaviour. Changes in these curves are then forecasted based on changes in the long-term electricity forward curves for neighbouring markets (NYISO and MISO).
Demand	Space heating demand: 30% of demand bids at just below the cost of gas-fired generation Demand response, aggregated EVs, and other price-responsive loads: bid at a range of prices between $250 and $2000/MWh

Like all electricity grids, a seasonal and weather-dependent component can alter demand and the supply stack at different times of the year. To preserve weather-driven correlations between variables, a single representative weather year is used for conventional demand and available supply from run-of-river hydro, wind, and solar resources.

Generator outages are simulated based on observed historical availability. Planned outages have a longer duration and are concentrated in the spring and the fall. Forced outages have a shorter duration and are distributed randomly.

6.3 Capacity Expansion

The study assumes that all existing generation remains in service except Pickering Nuclear Generating Station, which will be partially refurbished by 2035 in Scenarios 1 and 2. Nuclear and firm import capacity additions are also treated as assumptions for each scenario.

For each scenario, an iterative process is used to determine the mix of wind, solar, storage, and demand response which satisfies the overall seasonal capacity requirements, does not exceed the assumed maximum demand response capacity, and enables new wind and solar additions to earn sufficient energy market revenue to cover their projected levelized cost over the 2027 to 2035 period, plus a $300/kW adder for wind capacity.

Different quantities of wind and solar capacity are input in the dispatch model to calculate hourly clearing prices and market revenue. If market revenue is higher (or lower) than needed, wind or solar capacity is added (or removed) in the next iteration of the model. This process continues until market revenue is within 0.5% of the target value.

For each iteration, any remaining capacity requirements are met by the lowest cost non-emitting capacity available. Demand response is added until the maximum quantity is reached, followed by battery storage with the shortest allowable duration. The maximum amounts of each storage duration are identical to those assumed in the IESO's Pathways to Decarbonization study.