Annual Planning Outlook

Ontario's electricity system needs: 2022-2040

December 2020

ieso
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Executive Summary

To help ensure the reliability and cost-effectiveness of Ontario's power system, the Independent Electricity System Operator (IESO) regularly evaluates future demand and supply, using the resulting forecasts as the basis to assess near-, medium- and long-term resource and transmission requirements. Informed by ongoing feedback from stakeholders, and taking into account demand drivers, the transmission system and other inputs, the IESO's Annual Planning Outlook (APO) provides a long-term demand forecast, and an assessment of whether resources will be ready and sufficient to meet that demand.

With the emergence of the COVID-19 global pandemic, greater emphasis is placed on the importance of effective planning for a reliable electricity system. Electricity demand forecasting anticipates future requirements for electricity services and is affected by many factors, including historical demand patterns, demographics, energy prices and, increasingly, energy-efficiency programming and distributed energy resources. While forecasts are, by definition, inexact, in 2020 the ongoing uncertainties associated with the duration and impact of COVID-19 have introduced an entirely new layer of complexity to the development process.

COVID-19 Scenarios Reflect Role of Pandemic in Electricity Planning

Given the unprecedented nature of the pandemic, the 2020 APO forecasts demand using two scenarios based on assumptions about the pace of economic recovery during the outlook period. In each scenario, demand is expected to be lower than 2019 APO forecasted levels in the early years of the outlook.

Scenario 1 assumes a shallow economic recession in 2020 and early 2021 followed by a rapid economic recovery in 2021 and 2022, with demand expected to reach pre-pandemic levels by the end of 2022. Under this scenario, net energy demand is expected to be 142 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period to 174 TWh in 2040, an overall increase of 32 TWh.

In contrast, Scenario 2 assumes a deep economic recession until the end of 2021, followed by a slow multi-year economic recovery starting in 2022, with demand not expected to reach pre-pandemic levels until 2024. The demand forecast for Scenario 2 projects annual net energy demand to be 138 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period to 166 TWh in 2040, an overall increase of 28 TWh.

In both scenarios, longer-term demand will exceed 2019 APO forecast levels for a number of reasons. These include the resiliency and stability of the industrial sector, an increase in residential usage reflecting work-from-home arrangements, and rapid growth in indoor agriculture, particularly in southwestern Ontario. Robust near-term growth in the mining sub-sector, new rail transit electrification projects and decreasing electricity prices will also contribute to increased demand over this time period.

As Ontario recovers from the COVID-19 pandemic, and helping consumers manage their energy costs becomes even more important, government has directed a new four-year electricity conservation and demand management (CDM) framework to come into effect January 1, 2021. The 2021-2024 CDM framework will be centrally delivered by the IESO under the Save on Energy brand and will focus on cost-effectively meeting customer needs and the needs of Ontario's electricity system, including achieving provincial peak demand reductions, as well as targeted approaches to address regional and/or local system needs.

Overall, savings from all energy-efficiency programs[1] in Ontario are forecast to grow to 8.3 TWh in 2040 in Scenario 1, and to 7.9 TWh in 2040 in Scenario 2, from a base year of 2019.

Nuclear Refurbishments, Retirements and Contract Expirations Increase Needs

Ontario's diverse supply mix – nuclear (28%), gas (26%), hydroelectric (23%), wind (14%), solar (7%), demand response (2%) and bioenergy (1%) – means that the province is generally well positioned to meet future resource adequacy needs. However, throughout the 2020s, many existing contracts will expire, nuclear refurbishments will be underway, and Pickering Nuclear Generating Station (NGS) will retire.

The capacity adequacy outlook indicates that needs continue to emerge through 2022, without assuming the continued availability of existing resources. Needs are largely summer driven, while winter needs are dependent on growth in the agricultural sector. These needs increase again in the late 2020s and through the 2030s, driven by the Pickering NGS retirement, nuclear refurbishments, expiring contracts, and demand growth. With the continued availability of existing resources, the needs can be met until 2024. The capacity need eventually becomes an energy need, driven by resources with contracts expiring in the late 2020s and early 2030s.

The energy adequacy outlook indicates that Ontario is expected to have a sufficient supply of energy, providing existing resources continue to be available post-contract expiry. That said, the ability of existing resources to remain available will depend on a number of factors, including asset age and condition, need for capital investment, market conditions and available acquisition tools.

Surplus baseload generation is forecast to decrease due to rising demand and the retirement of Pickering NGS, and can continue to be managed through existing market tools.

In 2019, Ontario imported 6.6 TWh of energy and exported 19.8 TWh. While increasing exports in the wake of falling demand in the early months of COVID-19 has significantly reduced costs for consumers, energy exports are expected to decrease sharply in the early 2020s with the retirement of Pickering NGS by 2026 and ongoing refurbishment outages.

In fact, Ontario is projected to become a net importer for the first time since 2005, with the balance of trade expected to return to exports following the completion of nuclear refurbishments in the 2030s. This will mean that the province will need to address transmission constraints at interties that hinder the province's ability to import more electricity.

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[1] Includes existing and committed IESO-funded energy-efficiency programs, programs funded by the federal government and the assumption of continued delivery of IESO-funded energy-efficiency programs at current savings levels through the outlook period.

With nuclear retirements, refurbishments and contract expirations driving the need for capacity, reinforcing transmission in key areas of the province will be essential to maintaining reliability. Over the next five years, several major transmission projects to improve the transfer capability of bulk transmission interfaces to and from neighbouring jurisdictions, and ties between the province's 10 electricity zones,[2] will come into service.

Innovation, New Procurement Options to Play Role in Meeting Future Needs

After a postponement as a result of COVID-19, the IESO held its first capacity auction in December 2020. These auctions, which will evolve over time to reflect lessons learned and open participation to more resource types, are expected to drive down costs through competition, and give the IESO the flexibility to adjust to changing system conditions. While capacity auctions will meet short-term needs, to keep off-contract resources in the market and procure new capacity, the IESO is currently exploring other acquisition tools as part of a Resource Adequacy engagement – target capacities for these will be informed by this APO and future editions.

Established, in part, as a result of stakeholder feedback on the limitations of having a one-size-fits-all procurement mechanism, the Resource Adequacy engagement will develop a robust framework of competitive mechanisms to meet Ontario's resource adequacy needs in the short, medium and long term. In addition to better balancing ratepayer and supplier risk, the framework is expected to support competition and produce efficiencies that will benefit suppliers, the system and ratepayers.

At the same time, the IESO and other system operators are continuing to explore the role of distributed energy resources (DERs) in addressing future energy and capacity needs. In addition to releasing a series of white papers, including two that focus on expanding DER participation in the IESO-administered markets, the IESO has supported a number of DER demonstration projects as outcomes of recommendations made in the IESO's Integrated Regional Resource Plans (IRRPs). The latter includes a York Region Non-Wires Demonstration Project, which is using a local electricity market to test the effectiveness of DERs in meeting escalating regional needs, while reducing costs.

As part of its commitment to address barriers to DERs, the IESO has also made headway in its efforts to integrate storage in the system. In September, the IESO released its long-term vision for energy storage and the interim Market Rule amendments will clarify the opportunities for storage in today's markets.

[2] Visit the IESO's zonal map illustrating the 10 electrical zones.

How to Read the Outlook

Grounded in data and market intelligence, the IESO's Annual Planning Outlook (APO), which addresses future system needs – and the factors that influence them – provides insights to help readers understand what is required to prepare for a reliable and affordable energy future. The findings will be key inputs into the target-setting process for the next capacity auction, and also inform the development of the IESO's Resource Adequacy Framework. The APO is intended to provide market participants with the data and analyses they need to make informed decisions, and communicate valuable information to policy-makers and others interested in learning more about the developments shaping Ontario's electricity system.

With the pace of economic recovery identified as the primary consideration influencing the level of electricity demand over the outlook period, Chapter 1 (Demand Forecast) explores long-term demand using a faster-recovery and a slower-recovery scenario. This chapter walks readers through the changing composition of demand by sector – and the resulting effect on overall demand – as well as the projected impact of energy-efficiency programs, evolving codes and standards and the Industrial Conservation Initiative, on reducing that demand.

Chapter 2 (Supply and Transmission Outlook) assesses the availability of resources over the outlook period, and on the ability of existing bulk transmission interfaces and interties to continue to supply electricity where it is needed. This chapter also looks at the transmission projects expected to come into service within the outlook period that are considered in the base case for resource adequacy and transmission security assessments.

Chapter 3 (Resource Adequacy) compares the demand forecast with anticipated resource performance, while taking into account transmission constraints and risks such as extreme weather conditions and equipment outages. This chapter also looks at Ontario's energy adequacy, the impact of energy production on imports and exports, and the implications of the evolving fuel mix on fuel security.

Chapter 4 (Transmission Security) explores system needs arising from the requirement to meet transmission planning standards. These needs will be referred to as transmission security needs in this report and could be more restrictive or less restrictive than the resource adequacy needs.

Building on the outcomes and findings of previous chapters, Chapter 5 (Integrating Electricity Needs) summarizes the system needs over the outlook period that were discussed in Chapter 3 and 4.

Chapter 6 (Meeting Electricity Needs) explores the potential role of imports, distributed energy resources, storage, energy efficiency, the current Resource Adequacy engagement and transmission expansion – to address a local or zonal need, or to improve access to resources located within a transmission-limiting region – in meeting future needs.

Chapter 7 (Outcomes and Other Considerations) concludes with a discussion on marginal resources and marginal costs, the impacts of carbon pricing in Ontario and neighbouring jurisdictions, and the expected increase in greenhouse gas emissions resulting from decreased nuclear production, increased gas-fired generation and growing demand.

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1. Demand Forecast

As the COVID-19 pandemic and the response to it evolve, the IESO continues to monitor and interpret electricity demand drivers and other factors to develop and update demand forecasts. Key uncertainties over the next few years relate to the:

- Impacts of the pandemic, including its magnitude and duration, subsequent waves, work-from-home arrangements, social distancing, travel restrictions, birthrates and exurban growth
- Economic environment, including recovery in the commercial and industrial sectors, pandemic-specific support policies, international trade relations and immigration levels
- Energy rate forecast for both electricity and natural gas in all sectors, as well as price and cost subsidies

1.1 Overview

Ensuring Ontarians have access to affordable power when and where they need it is at the heart of the IESO's mandate to promote a reliable and cost-effective electricity system. The long-term demand forecast sets the context for the Annual Planning Outlook (APO) and the bulk power system planning process. The demand forecast informs system reliability and investment decisions by anticipating future needs, which are affected by many factors, including the state of the economy, population, demographics, technology, energy prices, input fuel choices, equipment purchasing decisions, consumer behaviour, policy, conservation and other considerations.

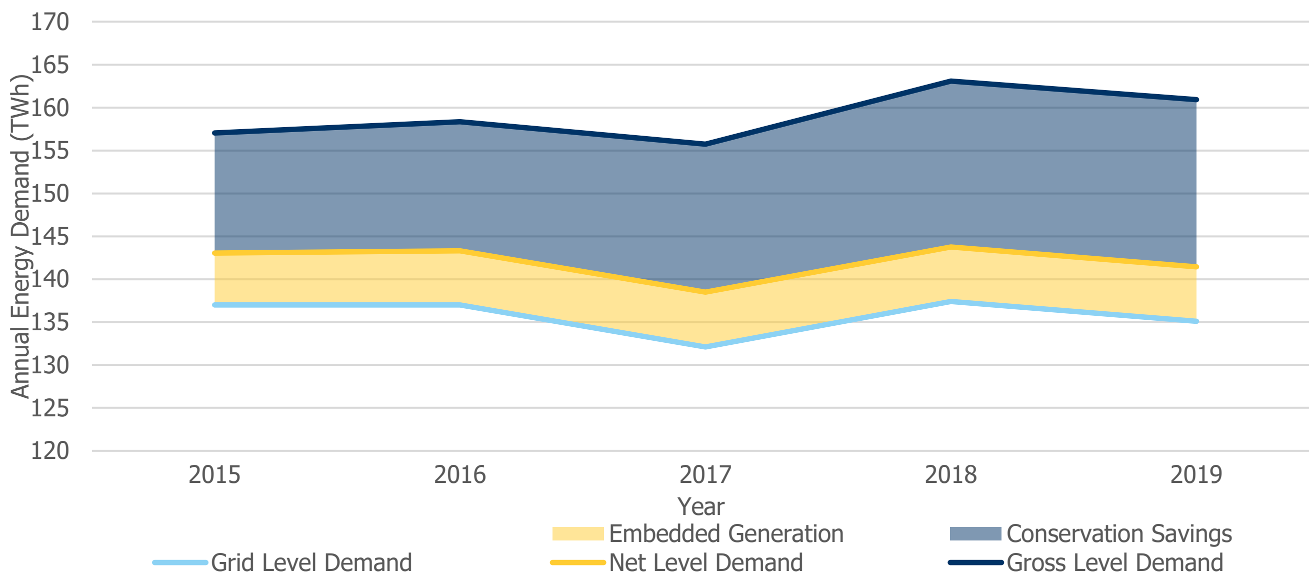
In 2020, Ontario's electricity demand experienced significant fluctuations as a result of the COVID-19 pandemic and its containment measures. Some of these resulted in near-term demand reductions. As the pandemic and its impacts on the grid evolve, the IESO continues to monitor and interpret the factors that affect the system, provide updated information to the market and regularly engage with stakeholders to enable them to make more informed decisions and investments.

Electricity demand is highly dependent on the state of the economy and has been greatly influenced by the pandemic, which has led to high levels of uncertainty. To address the uncertainties associated with the economic recovery, the APO includes two scenarios that reflect a potential range of economic conditions and resulting impacts on the electricity system over the outlook period.

To forecast demand, it is important to understand the composition of Ontario's electricity customers. For nearly the last decade, demand in Ontario has been driven primarily by the commercial (35%), residential (34%), and industrial (25%) sectors, and remaining (6%) being other sectors. In the wake of the pandemic, the traditional drivers of demand – the residential and commercial sectors – will be overshadowed by near-term recovery in the industrial sector, robust growth in agriculture and the adoption of electric vehicles.

Grid-level demand[3] has been mostly flat – ranging between 132 and 137 terawatt-hours (TWh) over the past five years, as shown in Figure 1. This is primarily the result of changes in the economy, conservation program savings, and embedded generation,[4] which reduce the need for grid-supplied energy. At between 138 and 144 TWh, net-level demand, which also includes embedded generation, has been approximately 6 TWh higher each year than grid-level demand.

Figure 1 | Historical Energy Demand



While historical energy demand has been presented on an actual weather basis and shown at the grid, net and gross levels, the demand forecasts subsequently presented are on a weather-normalized basis and at the net level.

1.2 Demand Forecast Scenarios

Demand forecasting anticipates future requirements for the services that electricity provides, and is affected by many factors. Analysis centres on understanding what is causing the changes in demand by focusing on end-uses and sector trends. That said, electricity demand forecasts are, by definition, inexact. They incorporate inherent uncertainty and reflect many dependencies, such as the impact of the pandemic on the economy, as well as future stimulus and policy frameworks. The uncertainties associated with any forecast will increase with the length of the outlook period and reflect the interdependencies of underlying assumptions.

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[3] Gross-level demand is the total demand for electricity services in Ontario prior to the impact of conservation (including programs and regulations), but including the effects of naturally occurring conservation (energy savings that occurs without the influence of incentives or education programs, and regulations). Net-level demand is gross-level demand minus the impact of conservation. Grid-level demand is net-level demand minus the demand met by embedded resources. It is equal to the energy supplied by the bulk power system to wholesale customers and local distribution companies.

[4] Embedded generation describes generators that are not registered participants in the IESO-administered wholesale electricity market, that are typically but not necessarily distribution system-connected, and reduces demand through the bulk electricity system.

To help acknowledge and mitigate uncertainties in the 2020 demand forecast, the IESO introduces the development of two demand forecast scenarios that reflect different assumptions regarding the rate of recovery from the effects of the pandemic on the electricity system. In each scenario, demand is expected to be lower than 2019 APO forecasted levels in the near term because of the pandemic and resulting economic slowdown. The pace of economic recovery is a primary factor in forecasting the level of electricity demand over the outlook period.

Table 1 summarizes the highlights in each of the two demand forecast scenarios in the 2020 APO.

Table 1 | Demand Scenarios Highlight Summary

#	Characteristic	Scenario 1	Scenario 2
1	Economic recession period	2020 - early 2021	2020 - end of 2021
2	Economic recovery period	2021 - 2022	2022 - 2024
3	Date demand returns to 2019 levels	End of 2022	Mid-2024
4	Residential sector	Slow demand growth in near term, accelerating in long term	Flat demand in the near and medium terms, slow growth in the long term
5	Commercial sector	Slow recovery	Demand lower than Scenario 1
6	Industrial sector	Swift recovery in near term, flat demand in medium term, growth in long term	Mild recovery in the near term Slow growth in long term
7	Agricultural sector	Strong growth in near and medium terms	Growth slower than Scenario 1
8	Electric vehicles	Strong growth over the outlook period	Growth slower than Scenario 1
9	Conservation energy savings	3 - 16 TWh	2 - 15 TWh
10	Annual energy demand	141 - 174 TWh	138 - 166 TWh
11	Summer peak demand	23,130 - 27,270 MW	22,470 - 25,970 MW
12	Winter peak demand	22,080 - 26,540 MW	21,690 - 25,280 MW

1.2.1 Scenario 1

Scenario 1 assumes a shallow economic recession in 2020 and early 2021, with a small-scale re-implementation of **temporary** restrictions and business closures in early 2021, followed by an economic recovery later in 2021 and 2022. While overall electricity demand is expected to recover to pre-pandemic levels by the end of 2022, the composition of that demand will have changed.

Overall growth in electricity demand in Scenario 1 is characterized by:

- Slow growth in the **residential sector** in the near term, accelerating in the long term, driven by increased household counts and decreasing electricity rates
- Strong growth in the **agricultural sector** in the near and medium terms, which will primarily impact winter energy and peak demand requirements
- Consistent growth in **electric vehicle** utilization over the outlook period
- A slow recovery in the **commercial sector** over the outlook period, after a significant decrease from the current economic recession
- A swift recovery in the **industrial sector** in the near term, primarily fueled by the mining sub-sector, followed by a period of flat demand and a return to overall growth in the long term

Scenario 1 accounts for conservation program frameworks divided into the current, near-term and long-term periods, as well as regulations. In total, energy savings are projected to be 16 TWh in 2040, with an average annual growth rate of 9.6 per cent.

Scenario 1 projects net energy demand to be 141 TWh in 2022, and to increase an average of approximately 1 per cent per year over the outlook period to 174 TWh in 2040, an increase of 33 TWh.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1 per cent, which is similar to the energy demand growth rate. Summer peak demand is projected to be about 23,130 megawatts (MW) in 2022, increasing to 27,270 MW in 2040, while winter peak demand is projected to be 22,080 MW in 2022, and 26,540 MW in 2040.

Figure 2 illustrates the energy demand over the planning horizon and Figure 3 shows the summer and winter peak demand[5] under Scenario 1.

[5] The summer season is from June 1 to September 30; the winter season runs from November 1 of the prior year to April 30.

Figure 2 | Scenario 1 – Energy Demand

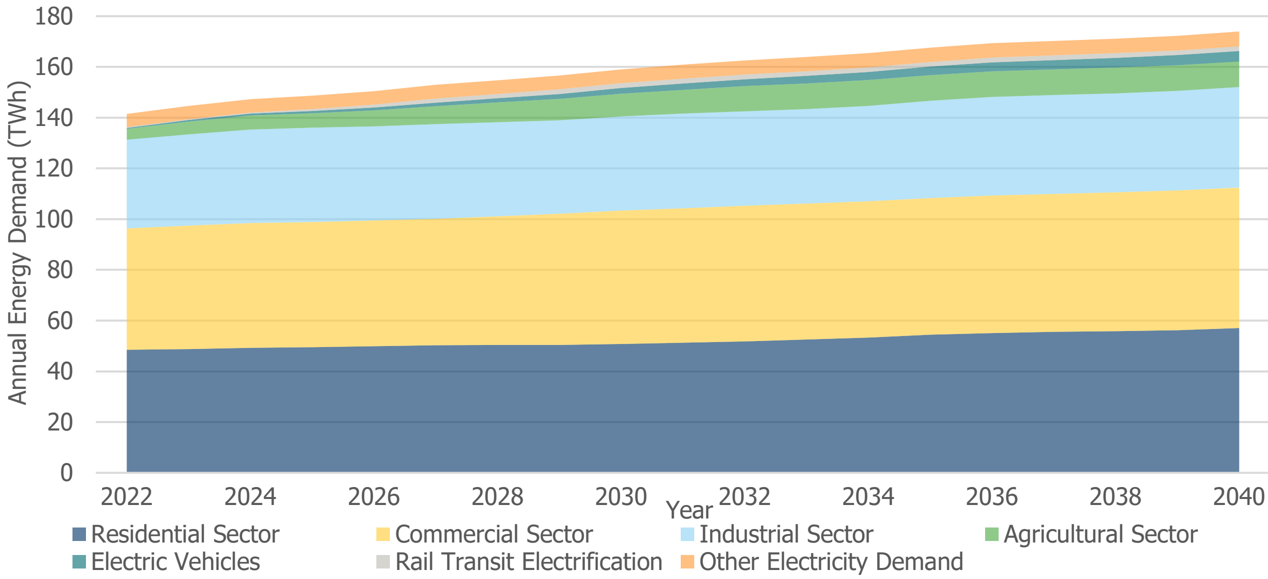
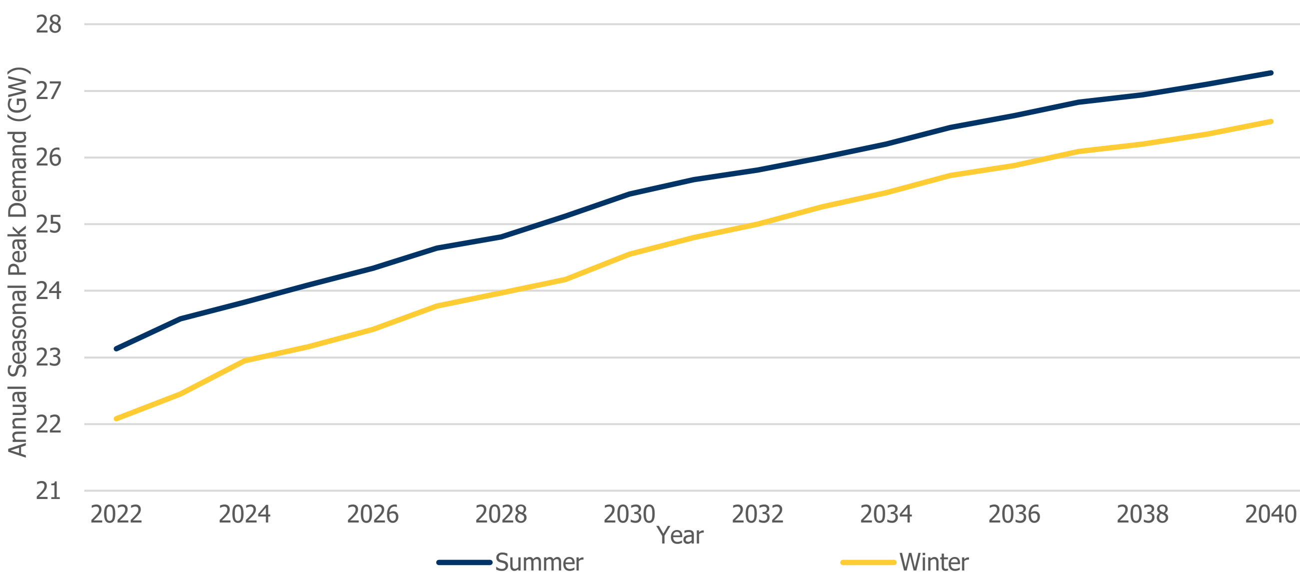


Figure 3 | Scenario 1 – Seasonal Peak Demand



1.2.2 Scenario 2

Scenario 2 assumes a deeper economic recession from 2020 to the end of 2021. Prolonged and significant pandemic impacts in this period will be followed by a slow, multi-year economic recovery starting in 2022. Overall electricity demand is expected to be lower than Scenario 1 in the near term and grow at a slower rate than Scenario 1 over the course of the outlook period.

Overall growth in electricity demand in Scenario 2 is characterized by:

- Flat demand in the **residential sector** in the near and medium terms, returning to slow growth in the long term

- Strong growth in the **agricultural sector** in the near and medium terms, though growth in this area will be slower than in Scenario 1
- Moderate growth in **electric vehicles** over the outlook period, though lower than the consistent growth in Scenario 1
- A slow recovery in the **commercial sector** over the outlook period, after a significant decrease from the current economic recession and less of a rebound prior to the start of the outlook period than Scenario 1
- A mild recovery in the **industrial sector** in the near term, followed by a period of flat demand and a return to slow growth in the long term
- Scenario 2 accounts for the same conservation categories and assumptions as Scenario 1. Current and near-term conservation program frameworks are projected to achieve the same levels of energy savings as Scenario 1, but long-term framework and regulations energy-savings projections are a function of the scenario-specific gross demand forecast. As the gross demand forecast is lower in Scenario 2, so are the energy savings attributed to the long-term framework and regulations. In total, energy savings are projected to be 15 TWh in 2040, with an average annual growth rate of 9.2 per cent.

In Scenario 2, annual net energy demand is projected to be 138 TWh in 2022, and to grow an average of approximately 1 per cent per year over the outlook period to 166 TWh in 2040, an increase of 28 TWh. Over the long term, despite lower electricity demand in a given year, demand growth rates return to near-2019 APO forecasted levels.

Summer and winter peak demands are expected to experience an average growth rate of approximately 1 per cent, similar to the energy demand growth rate. Summer peak demand is projected to be approximately 22,470 MW in 2022, increasing to 25,970 MW in 2040, while winter peak demand is projected to be 21,690 MW in 2022, and 25,280 MW in 2040.

Figure 4 illustrates the energy demand over the planning horizon and Figure 5 shows the summer and winter peak demand under Scenario 2.

Figure 4 | Scenario 2 – Energy Demand

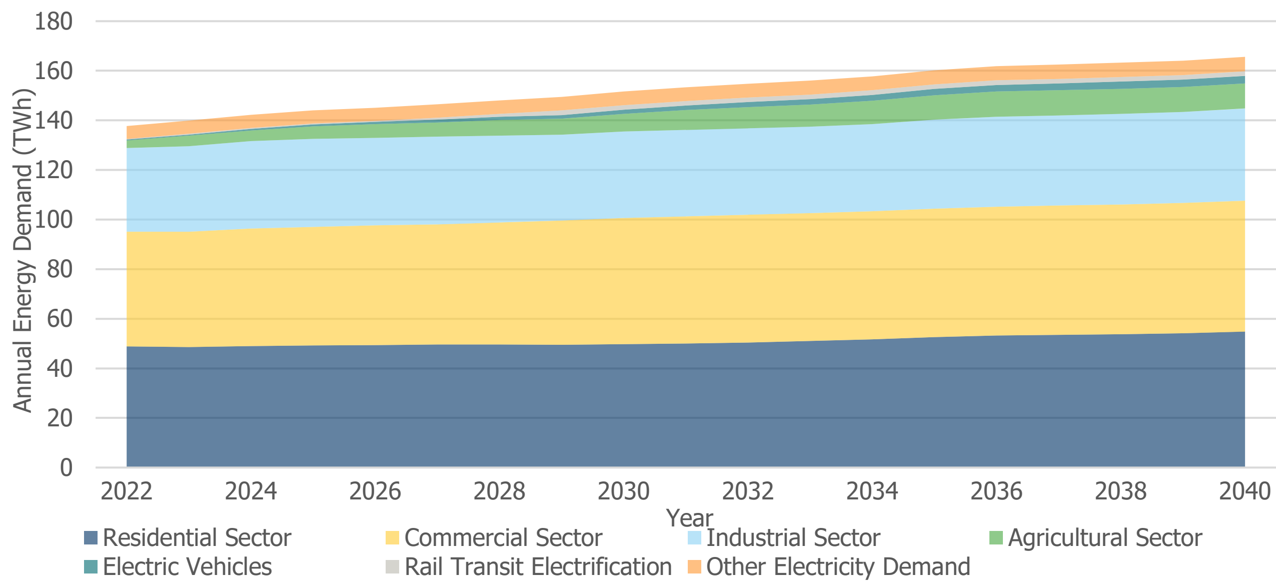
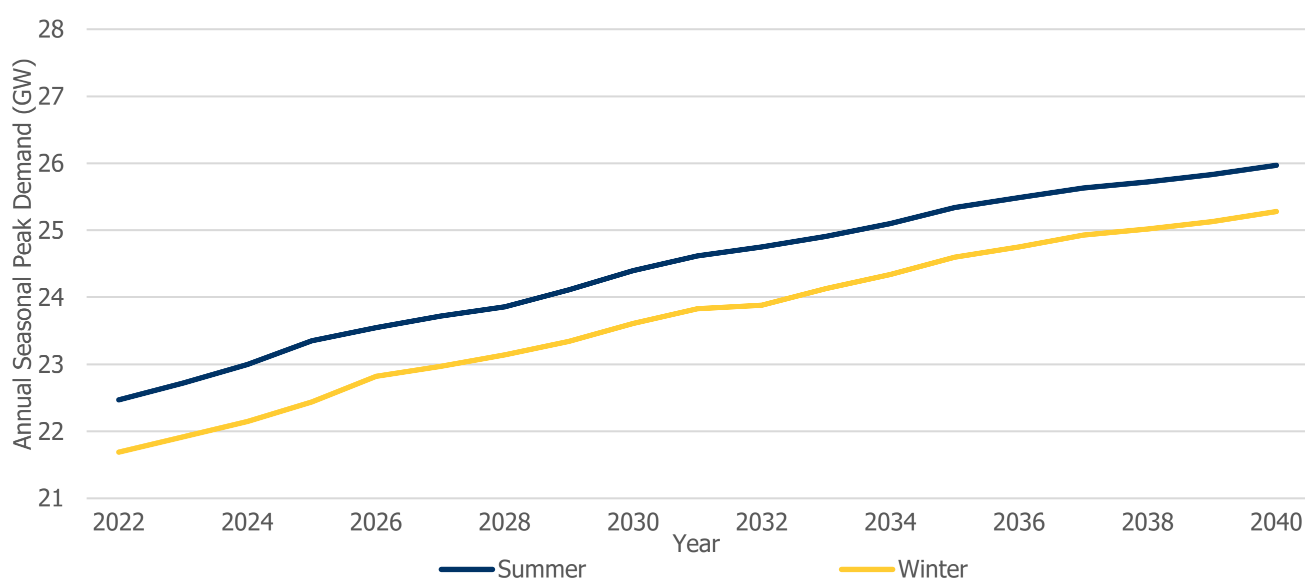


Figure 5 | Scenario 2 – Seasonal Peak Demand



1.3 Drivers of Demand

All electricity users – residential, commercial, institutional, industrial, agricultural and others – contribute to province-wide energy demand. This demand forecast has been developed using sector-level segmentation and corresponding individual assessments. Overall, an expected increase in demand over the outlook period will be largely driven by slow demand growth in the residential sector, emerging growth in the agricultural sector and electric vehicle utilization, and slow economic recovery in the commercial sector. This increase in consumption is supported by favourable electricity rates over the outlook period.

1.3.1 Residential Sector

Electricity demand from the residential sector continues to grow slowly in each scenario over the outlook period. In Scenario 1, household counts are lower in the near term and higher in the long term relative to projections in the 2019 APO. In Scenario 2, a prolonged economic recession is projected to result in a sustained lower household count relative to Scenario 1. High-level trends include a recovery in immigration rates concurrent with each scenario's recovery timeline. Emerging suburban and exurban migration is expected to lead to an increase in single-family homes with higher energy-intensity rates and changes in IESO zonal demands, lower electricity rates in the longer term (in real dollars), growth in both household occupancy and work-from-home arrangements, and the increasing adoption of electronics. All of these have been considered and integrated into the forecast, contributing to slowly growing sector demand over the outlook period.

Overall, residential sector electricity demand in Scenario 1 is forecast to grow from 48 TWh in 2022 to 57 TWh in 2040, an average annual growth rate of 0.8 per cent. In Scenario 2, demand is forecast to increase from 49 TWh in 2022 to 55 TWh in 2040, an average annual growth rate of 0.6 per cent.

1.3.2 Commercial Sector

Similar to the 2019 APO, electricity demand from the commercial sector continues to grow modestly in both scenarios over the outlook period. The shift to a digital economy is accelerating, impacting electricity demand in many sub-sectors. Remote working leads to decreases in electricity demand in offices; meal preparation and delivery services reduce electricity demand in restaurants; and e-commerce results in a decrease in bricks-and-mortar electricity demand in retail, but an increase in warehouses. The impacts of the current economic recession are especially evident in the commercial sector, with social distancing practices and travel restrictions reducing near-term electricity demand for the office, education, retail, restaurant and lodging hospitality sub-sectors. The magnitude of this reduction is especially evident in Scenario 2, but the commercial sector will experience a slow recovery in both scenarios.

Overall, commercial sector electricity demand in 2022 is reduced by about 3 TWh in Scenario 1 and by about 5 TWh in Scenario 2 relative to the 2019 APO. Commercial sector electricity demand is forecast to grow in Scenario 1, from 48 TWh in 2022 to 55 TWh in 2040, an average annual growth rate of 0.8 per cent, and in Scenario 2, from 46 TWh in 2022 to 53 TWh in 2040, an average annual growth rate of 0.8 per cent.

1.3.3 Industrial Sector

Ontario's industrial sector is expected to rebound from the current economic recession in the near term, remain flat for the medium term and grow slowly over the last third of the outlook period. This rebound is characterized by a return to 2019 APO levels by 2024 in Scenario 1, and a plateau at 2 TWh below 2019 APO levels by 2024 in Scenario 2. Average annual growth between 2032 and 2040 is expected to reach 0.7 per cent in both scenarios, which is in line with sub-sector-level GDP projections.

The top five sub-sectors[6] will continue to account for roughly 60 per cent of the total sector load. In the mining sub-sector, concentrated in northern Ontario, electricity demand is expected to grow robustly in the near term supported by favourable resource prices, then slowly decline as various mines reach end of life. Apart from mining, the primary metal sub-sector, spread across the Southwest (Hamilton, Cambridge, and Nanticoke) and Northeast (Sault Ste. Marie) Zones, is expected to grow steadily, while all other sub-sectors grow slowly. In general, the industrial sector is expected to be influenced by emerging de-globalization trends and support for increasing local industrial production capability.

Overall, total industrial sector electricity demand is forecast to grow, in Scenario 1, from 35 TWh in 2022 to 40 TWh in 2040, an average annual growth rate of 1 per cent, and in Scenario 2, from 34 TWh in 2022 to 37 TWh in 2040, an average annual growth rate of 0.8 per cent.

1.3.4 Agricultural Sector

Demand for electricity from Ontario's agricultural sector continues to grow, driven primarily by greenhouse expansion and the proliferation of artificial lighting in greenhouses. Grow lights enhance production and crop yields of various fruits, vegetables, flowers and cannabis.

Demand growth, incremental to the 2019 APO, has been identified in the West Zone, including the Kingsville-Leamington and Dresden areas. This growth is included in both scenarios and is outlined in the reference scenario in the West of London Bulk Study. Overall, sector electricity demand growth increases energy and peak demand primarily in the winter season, which is projected to increase by about 950 MW by 2033 in Scenario 1 and by 2036 in Scenario 2, accounting for potential timeline extensions of various major infrastructure construction projects needed to support the growth.

Overall, total sector electricity demand is forecast to grow, in Scenario 1, from 4 TWh in 2022 to 10 TWh in 2040, an average annual growth rate of 7 per cent, and in Scenario 2, from 3 TWh in 2022 to 10 TWh in 2040, an average annual growth rate of 7 per cent

1.3.5 Electric Vehicles

The number of electric vehicles (EVs), including mass transit buses and their electricity charging requirements, is currently relatively small, but will increase significantly over the outlook period. Government policy is a key driver for EV adoption. Policy measures include purchase incentives; tax benefits for business vehicles; and support for EV charging infrastructure, automobile manufacturers, and automobile parts suppliers. The federal government has set a long-term target to sell 100 per cent zero-emission vehicles by 2040, with interim sales goals of 10 per cent by 2025 and 30 per cent by 2030.

[6] The top five industrial sub-sectors in Ontario, by electricity demand are: 1) mining; 2) primary metals; 3) paper manufacturing; 4) chemical manufacturing; and 5) petroleum refining.

Many factors affect EV adoption and a wide range of EV adoption forecasts are available. The IESO's EV adoption forecast is based on historical trends and available information, such as industry sales data, government vehicle registration data and forecasts from other reputable organizations. The profile of EV charging is as important as the total charging electricity, when considering the impact on the demand forecast. Real-world charging data from the *Charge the North* project, the world's largest electric vehicle charging study, was used to develop the charging profile and EV hourly demand forecast.

The state of the economy has a compound effect on EV charging demand. Both EV sales and driving distance dropped in 2020 as a result of social distancing practices, temporary business closures, travel restrictions and the increase in people working from home. Each of the two scenarios reflects the various levels of EV charging demand growth.

The 2020 APO EV forecast is an adjustment of the 2019 APO EV forecast which projected the number of EVs in Ontario to reach approximately 0.7 million by 2030 and 1.2 million by 2040 with an annual charging demand of 4 TWh. In Scenario 1, EV charging demand rebounds fast, reaching the level of the 2019 APO in 2030. In Scenario 2, EV charging demand rebounds slower, reaching 75 per cent of the Scenario 1 level in the medium and long terms.

Overall, electric vehicle electricity demand is forecast to grow in Scenario 1, from 0.4 TWh in 2022 to 4.1 TWh in 2040, an average annual growth rate of 15.2 per cent, and in Scenario 2, from 0.3 TWh in 2022 to 3.1 TWh in 2040, an average annual growth rate of 14.5 per cent.

1.3.6 Rail Transit Electrification

Broad rail transit electrification is underway in Ontario, including:

- The GO rail system serving the Greater Toronto Area
- Local light rail transit (LRT) systems throughout the province
- Multiple subway expansion projects

Eight LRT projects and three subway projects are being planned or are at various stages of construction. The ION project connecting Kitchener and Waterloo and the Confederation Line in Ottawa have been in service since 2019. Early work on new subway projects, including the proposed Ontario Line and two subway line extensions in the GTA, is underway, as is the procurement process for the multi-year electrification of GO rail corridors.

Demand projected for new rail transit electrification is based on the most recent available information. Two scenario projections have been developed with the only variance being the GO rail electrification implementation timeline. Some rail transit electrification projects are at the early planning stage with little information on electricity requirements. The IESO will update the associated electricity demand projection, both in terms of magnitude and timing, when more information becomes available.

Overall, electricity demand associated with rail transit electrification is forecast to grow, in both Scenarios 1 and 2, from 0.3 TWh in 2022 to 1.8 TWh in 2040, an average annual growth rate of 15.5 per cent.

1.3.7 Other Electricity Demand

This demand forecast accounts for all electricity energy and peak demand in the province. However, certain loads do not fall under any of the previously discussed sectors and are classified as "other". These include:

- Connection of remote communities
- Electricity generators[7]
- Street lighting
- Municipal water treatment

Compared to the 2019 APO, over the course of the outlook period the IESO estimates an additional annual energy demand of less than 0.1 TWh by 2040.

Overall, "other sector" electricity demand is forecast to grow, in both Scenarios 1 and 2, from 5.2 TWh in 2022 to 5.9 TWh in 2040, an average annual growth rate of 0.7 per cent.

1.3.8 Energy-Efficiency Programs

Energy-efficiency program frameworks incorporated into the demand forecast include:

- Existing IESO-funded conservation frameworks
- Committed IESO-funded conservation framework
- Programs funded by the federal and municipal governments
- Assumed long-term conservation framework

On March 21, 2019, the 2015-2020 Conservation First Framework (CFF) and Industrial Accelerator Program (IAP) Framework were discontinued and replaced with an Interim Framework. Projects contracted under the CFF, IAP and Interim Framework are required to be in service by the end of 2022. Collectively, the wind-down of the CFF and IAP initiatives, and the Interim Framework, is expected to result in annual electricity savings of 2.5 TWh in 2023.

On September 30, 2020, the Minister of Energy, Northern Development and Mines directed the IESO to implement a new 2021-2024 Conservation and Demand Management Framework.[8] The forecasted annual savings are 3 TWh in 2026.

In addition to the Ontario electricity rate-funded programs, those funded and/or delivered by the federal and municipal governments, including the Green Municipal Fund and the Climate Action Incentive Fund, are expected to result in additional electricity savings in Ontario. That said, the amount is difficult to estimate in the absence of program details.

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[7] Electricity generators such as nuclear and gas/oil generating stations can have electricity demand when: 1) commencing operation of generating units; and 2) generating units are not in operation; for example, the facility would have electricity demand for lighting and HVAC loads.

[8] For more information, refer to the Ministerial Directive.

Beyond existing and near-term committed energy-efficiency program frameworks, there are potential opportunities to achieve greater electricity savings. Continued delivery of energy-efficiency initiatives after the new 2021-2024 Framework is assumed and projected savings are included in both demand forecast scenarios. Annual savings are estimated to be 0.46 per cent of gross demand (varying between Scenario 1 and 2), which is informed by the savings level of the 2021-2024 Framework. This will be updated when a post-2024 conservation framework policy decision is made.

Overall, electricity demand savings resulting from all energy-efficiency programs in Ontario are forecast to grow in Scenario 1 and Scenario 2 to 8.3 TWh and 7.9 TWh, respectively, from 2019 to 2040.

1.3.9 Codes and Standards Regulations

Building codes and equipment standards are an effective energy-efficiency tool, as they have no ratepayer cost, broad reach and a relatively high level of certainty when forecasting results. Codes and standards savings estimates are based on the expected improvement in the codes for new and renovated buildings and for specified end-uses through the regulation of minimum-efficiency standards for equipment. The IESO estimates savings attributable to codes and standards by comparing the demand forecast at the gross level to the demand forecast adjusted for the impacts of regulations. Most savings from improved codes and standards will come from the residential and commercial sectors.

Overall, electricity demand savings from codes and standards are forecast to grow, from a base year 2019, in Scenario 1, to 7.8 TWh in 2040, and in Scenario 2, to 7.2 TWh in 2040.

1.3.10 Industrial Conservation Initiative

The demand forecasts include the impact of the Industrial Conservation Initiative (ICI), a form of demand response that enables eligible large-consumption customers to reduce their electricity costs when they curtail electricity consumption during periods of peak electricity demand. While participant eligibility criteria have been revised several times since the ICI was introduced in 2011, current eligibility rules have been in effect since 2017 with ICI response relatively stable from 2017 to 2019. However, with the onset of the pandemic, the Ontario government introduced a one-year hiatus on the program, allowing consumers to focus on economic recovery rather than responding to system peaks (i.e., curtailing). During the hiatus, government released the 2020 Ontario provincial budget,[9] which included a reduction in electricity rates, resulting in a dampened price signal for curtailment.

This increases uncertainty in the future impact of the ICI, which is expected to contribute less than in previous years. The IESO forecasts ICI top five system peak-day, system peak-hour demand reduction impacts to be 1,000 MW, a reduction from 2019 APO levels, and does not forecast increased ICI response over the outlook period.

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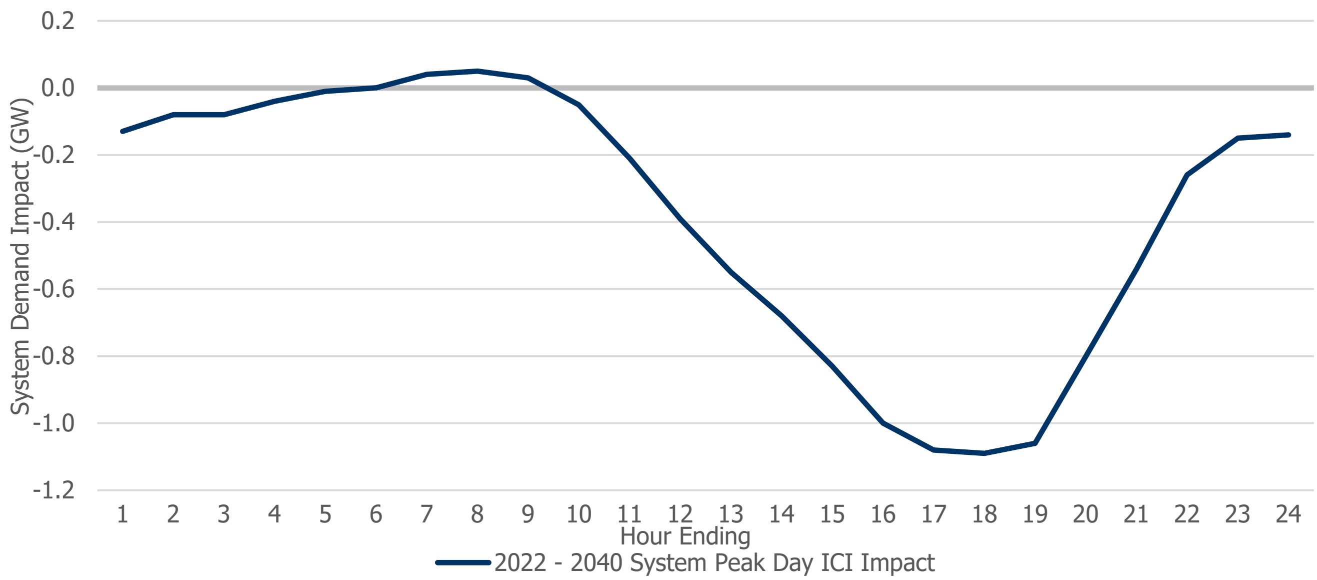
[9] The 2020 Budget includes "a plan to reduce the burden on employers of Ontario's high-cost contracts with non-hydroelectric renewable energy producers…Starting on January 1, 2021, a portion of the cost of these contracts entered into under the previous government, will be funded by the province, not the ratepayers." For more information, refer to the November 5 news release, Ontario's Action Plan: Protect, Support.

ICI drivers, including customer ICI program investment and Global Adjustment levels, will inevitably change over the course of the outlook period and the ICI impacts on the demand forecast methodology will be reassessed on an annual basis.

The projected impact from all ICI participants on the system peak day for each year in the outlook period is shown in Figure 6.

Figure 6 | Industrial Conservation Initiative Impact



2. Supply and Transmission Outlook

The majority of Ontario's installed supply capacity comes from nuclear, gas, and hydroelectric resources, with the remainder from wind, solar, demand response, and bioenergy. While most of Ontario's capacity is provided by transmission-connected market participants, Ontario also has a significant and growing number of distributed energy resources connected at the distribution level.

Nuclear refurbishments continue throughout the 2020s. The retirement of the Pickering NGS in the mid-2020s is a driver of incremental capacity needs looking ahead. Over the course of the outlook period, many resources with contracts or commitments with the IESO or the Ontario Electricity Financial Corporation will reach the end of their term. Most contracts or commitments expiring throughout the 2020s are with gas-fired generation and demand-response resources, while those with renewable resources begin to reach the end of their term in the 2030s.

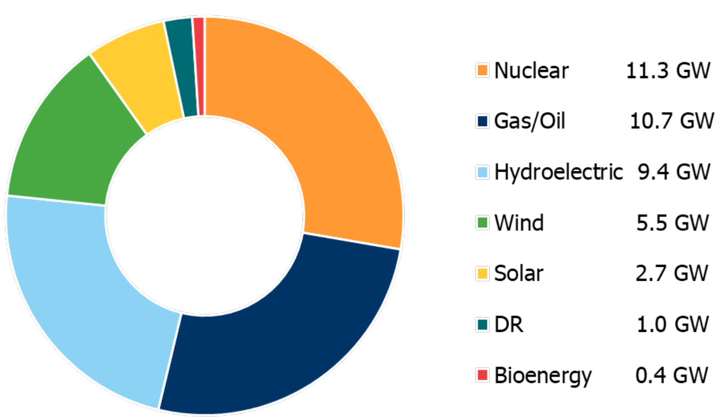
The bulk transmission system is critical to ensuring power can be delivered from the supply resource to the customer. The ability of the transmission system to transfer power across the province is defined by the capability of key interfaces.

Transmission reinforcements in the West of Chatham, Ottawa, eastern Ontario (near Napanee), and areas of northern Ontario are anticipated to come into service within the next five years, and will assist in maintaining a reliable transmission system.

2.1 Installed Capacity 2021

Ontario has 40.9 gigawatts (GW) of installed capacity made up of a diverse mix of resources.

Figure 7 | 2021 Installed Capacity by Fuel Type



As shown in Figure 7,[10] the majority of Ontario's installed capacity comes from nuclear (28%), gas (26%), and hydroelectric (23%) resources, with the remainder from wind (14%), solar (7%), demand response (DR) (2%) and bioenergy (1%). Most of Ontario's capacity is supplied by transmission-connected market participants and the rest is supplied by embedded generators. Both types of resources are included in the capacity assessment. The IESO did not consider scenarios in the supply outlooks, as information provided by asset owners to date has reinforced the IESO's confidence in their ability to continue to manage their assets during the pandemic.

2.2 Supply Outlook: Installed and Effective Capacity

There is a fundamental difference between installed capacity and effective capacity. No resource is capable of producing energy at maximum output levels at all times due to fuel availability, ambient conditions, or outages, making effective capacity a more meaningful measure of the amount of resources available to meet reliability needs in each season. Table 2 shows Ontario's effective capacity projected for each fuel type at the end of 2021, for the summer and winter seasons.[11] Going into the outlook period, total installed capacity for the entire fleet is about 40.9 GW, while summer and winter effective capacities are 28.2 GW and 30.4 GW, respectively. This supply outlook excludes the capacity acquired through the IESO's December 2020 capacity auction; this capacity will be included in future outlooks. More detail by fuel type is provided in the data tables.

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[10] This chart is inclusive of both transmission- and distribution-connected resources that are either market participants and/or contracted by the IESO and excludes energy storage. For further information, please see the 2020 APO Supply, Adequacy and Energy Outlook module.

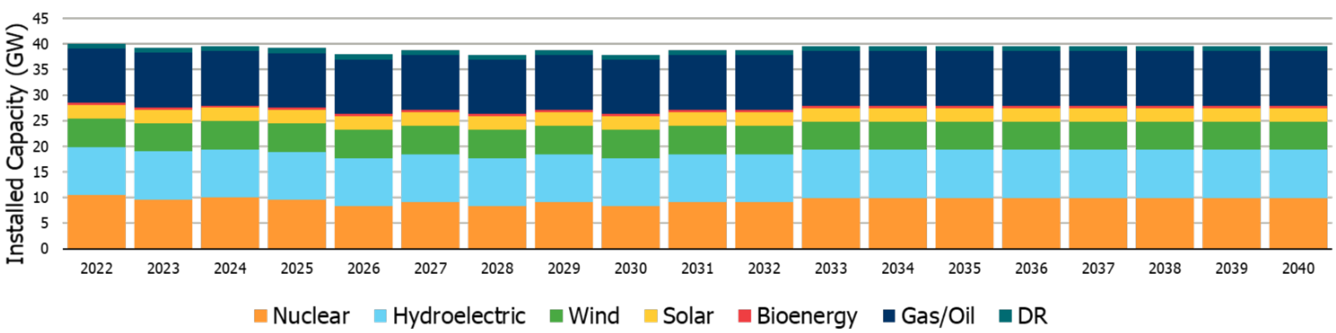
[11] Summer months are from May to October, and winter months are from November to April.

Table 2 | Ontario's Summer and Winter Effective Capacity by End of 2021

Fuel	2021 Installed GW	2021 Summer Effective GW	2021 Winter Effective GW
Nuclear	11.3	10.7	10.7
Gas/Oil	10.7	8.6	9.3
Hydroelectric	9.4	6.5	7.1
Wind	5.5	0.7	2.1
Solar	2.7	0.9	0.1
DR[12]	1.0	0.4	0.6
Bioenergy	0.4	0.4	0.4
Total	40.9	28.2	30.4

Figure 8 shows the installed capacity by fuel type for the outlook period (2022-2040). This reflects the continued availability of resources following the end of their contract term or commitment. Total installed capacity varies between 38 and 40 GW during the 2020s, due to the refurbishment and retirement of the nuclear fleet, before levelling off at 40 GW in the 2030s.

Figure 8 | Installed Capacity 2022-2040



[12] These reflect the results of the IESO's 2019 Demand-Response Auction.

Figure 9 and Figure 10 show the summer effective and winter effective capacities, by fuel type, for the outlook period. Summer effective capacity varies between 25 and 27 GW during the 2020s, due to the refurbishment of the nuclear fleet, and then levels off at 27 GW in the 2030s. Similarly, winter availability of the fleet ranges between 27 GW and 30 GW, plateauing at 29 GW in the long term. The supply mix over the course of the outlook generally reflects the supply mix shown in Table 2.

Figure 9 | Summer Effective Capacity 2022-2040

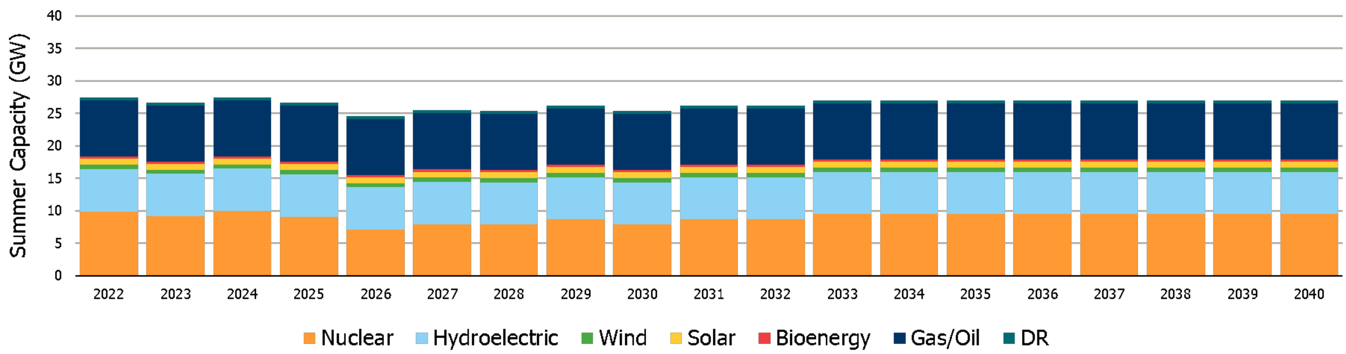
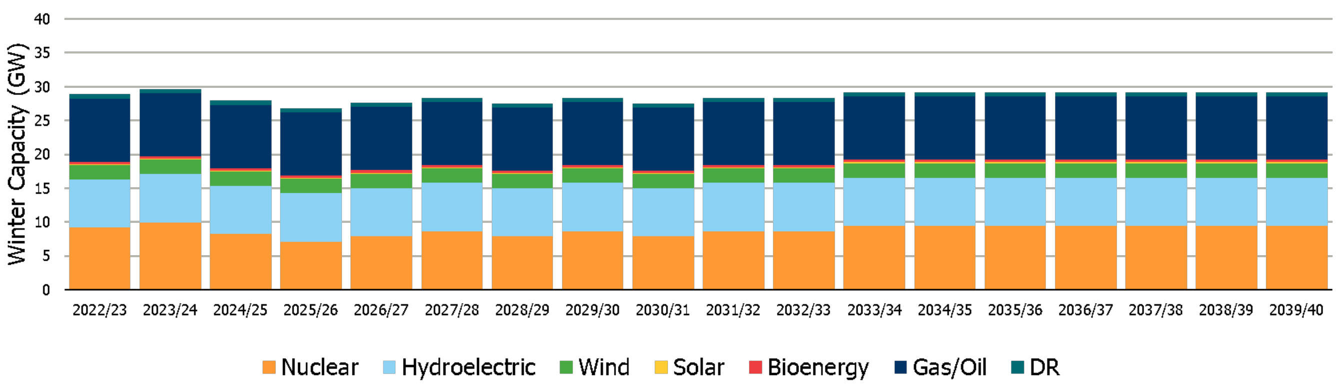


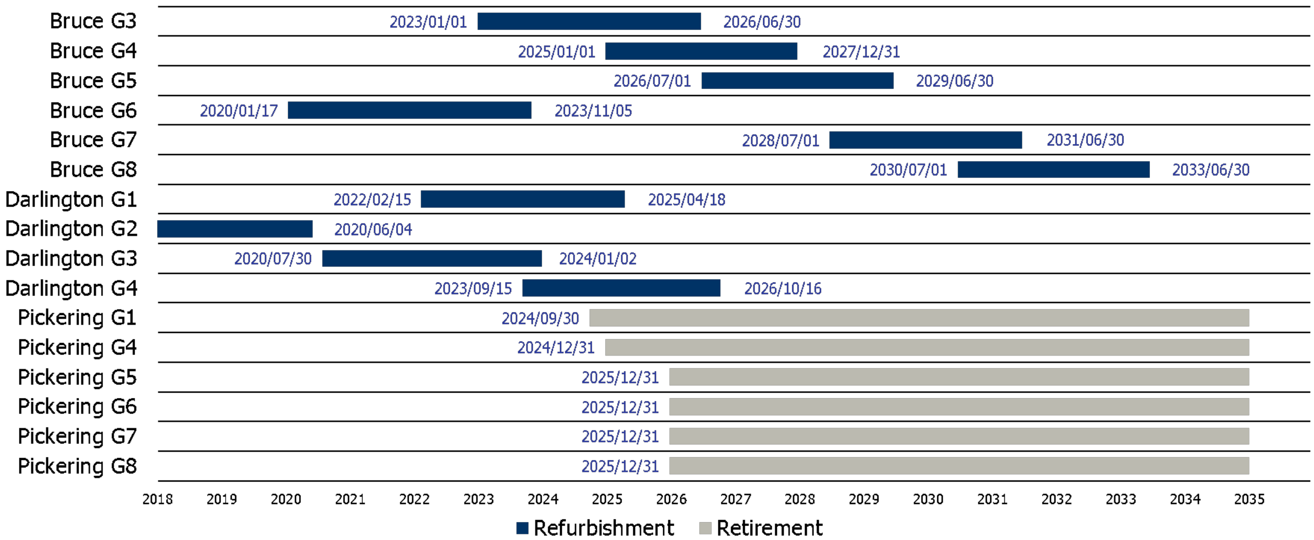
Figure 10 | Winter Effective Capacity 2022-2040



2.3 Nuclear Refurbishments and Retirements

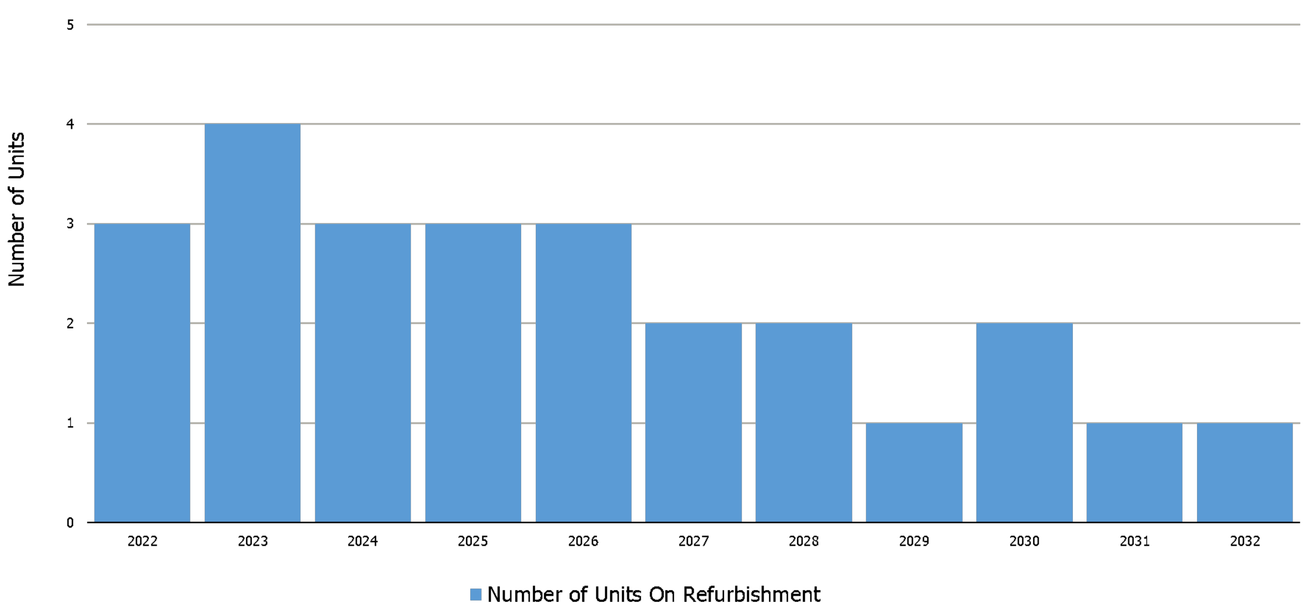
Throughout the 2020s, Ontario's electricity system will see significant change in the available capacity from its nuclear fleet, driven by nuclear refurbishments and retirements, as shown in Figure 11. The current schedule was provided to the IESO by Ontario Power Generation (OPG) and Bruce Power.

Figure 11 | Nuclear Refurbishment and Retirement Schedule



Long-term refurbishment outages at the Darlington and Bruce nuclear generating stations (NGS) will increase resource needs and introduce greater uncertainty in the resource outlook. By 2033, a total of 7.5 GW of nuclear capacity will undergo refurbishment. The first Darlington unit went offline for refurbishment in 2016 and returned to service in June 2020. Darlington and Bruce refurbishments are expected to be complete in 2026 and 2033 respectively. Figure 12 shows that refurbishment activity will increase in the 2020s, with between two and four units undergoing refurbishment concurrently over the summer period and an increase in the number of outages until 2026.

Figure 12 | Summer Refurbishment Outages

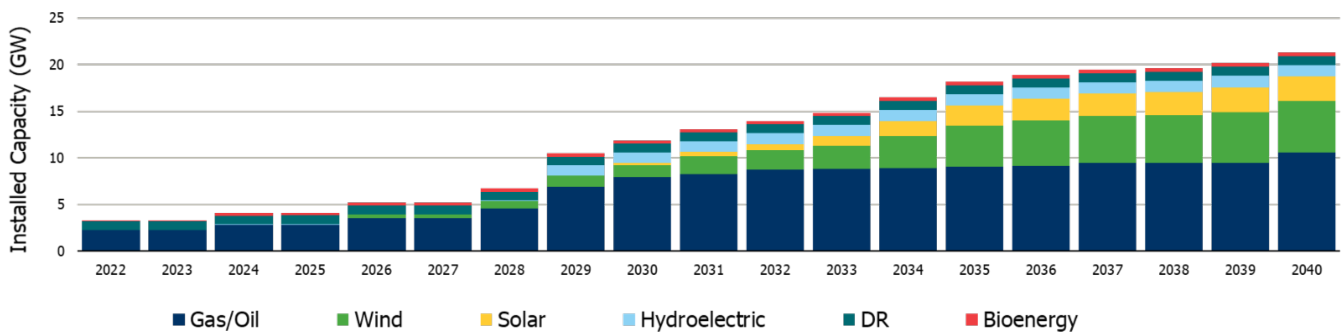


Pickering NGS is expected to retire in the mid-2020s, reducing Ontario's installed nuclear capacity by 3.1 GW. The two Pickering A units are scheduled to go out of service toward the end of 2024, with the remaining four units at Pickering B following in 2025. The Pickering NGS retirement is among the largest contributors to upcoming resource needs.

2.4 Contracts and Commitments Ending

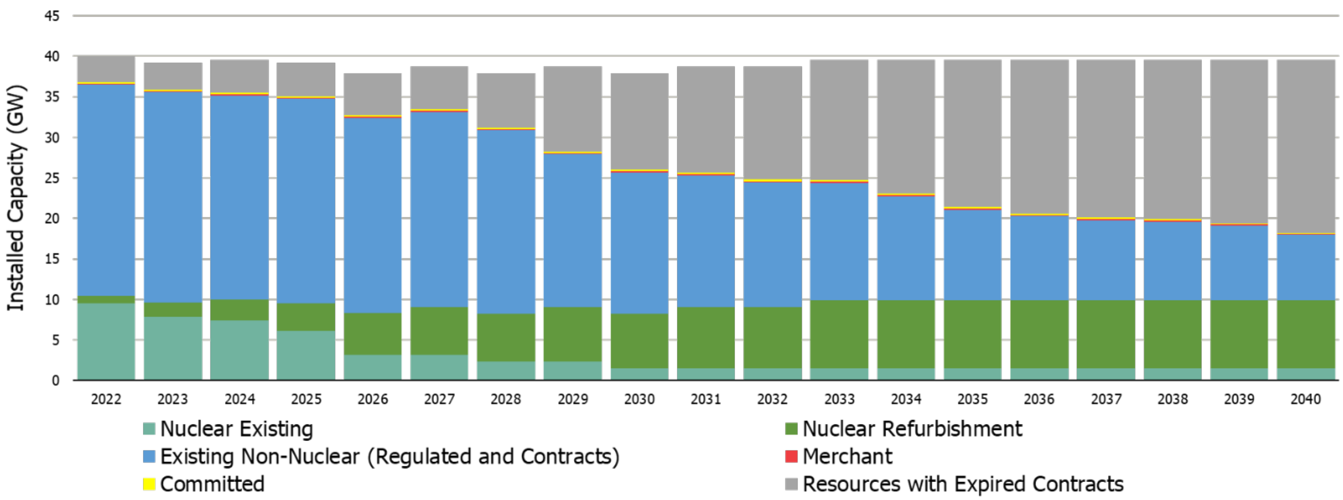
Over the course of the outlook, many commitments and generation contracts held by the IESO or the Ontario Electricity Financial Corporation will expire. The IESO is developing a Resource Adequacy Framework that will allow these resources to compete alongside new capacity to meet Ontario's needs. As shown in Figure 13, contracts begin to expire in the early 2020s, and expirations become more significant by the end of the decade. Contracts and commitments that expire in the 2020s are primarily with gas-fired generation and DR resources. Most wind, hydroelectric, and solar contracts begin to expire in the 2030s. Later in this report, scenarios with and without existing resources post-contact/commitment expiry will be examined.

Figure 13 | Existing Resources Post-Contract Expiry 2022-2040 by Fuel Type



The resource outlook includes considerable change through the 2020s and early 2030s due to the combined effect of nuclear retirements, refurbishment outages, and expiring contracts/commitments. The installed capacity outlook by contract/commitment type in Figure 14 illustrates the growing role of resources with expired contracts/commitments and units expected to complete nuclear refurbishment.

Figure 14 | Installed Capacity by Contract/Commitment Type: 2022-2040



2.5 Existing Bulk Transmission Interfaces and Interties

The ability of supply resources to meet system demand relies on the transmission system to transport the electricity to where it is needed. Within Ontario, bulk transmission interfaces form the boundaries of the 10 IESO electrical zones. The primary purpose of these interfaces is to describe power flows across the system, and associated phenomenon which may limit these transfers.

The bulk transmission system is also used to import power from or export power to neighbouring jurisdictions through a series of interties at specific points on the Ontario border. These interfaces and interties are shown in Figure 15.

Figure 15 | Ontario's Major Internal Transmission Interfaces

The maximum amount of power that these interfaces and interties can deliver is known as their transfer capability, which reflects constraints to ensure system stability, voltage performance, and acceptable thermal loading.

Interface transfer capabilities are used in resource adequacy and transmission security assessments, discussed later in Chapter 3 and Chapter 4. Resource adequacy assessments are probabilistic studies that consider interface transfer capabilities with all transmission facilities in-service, with regard to the impact of planned outages on transfer capabilities and the most limiting contingency (sudden, unplanned outage). Transmission security assessments are conducted at the zonal level and consist of deterministic assessments of various transmission system disturbances, as defined according to various regulatory obligations. Zonal adequacy or security assessments may be more restrictive than resource adequacy, depending on the characteristics of the zone(s) being investigated.

Intertie transfer capabilities are treated as interfaces in reliability assessments. Interties provide a number of system benefits, including stability, frequency support and voltage support following a contingency, and the opportunity to consider imports and exports to manage resource needs where cost-effective.

Each interface and intertie is described further in Section 2.5.1.

2.5.1 Bulk Transmission Interfaces

2.5.1.1 Buchanan Longwood Input (BLIP) and Negative Buchanan Longwood Input (NBLIP)

The BLIP interface comprises the circuits that connect the West Zone and the Southwest Zone, near London. This includes the three 500-kV circuits into Longwood TS, and the five 230-kV circuits into Buchanan TS. The NBLIP interface is defined identically to the BLIP interface, but the power transfer is measured in the opposite direction. BLIP transfer capability is important to reliably supply demand in the West Zone and facilitate exports to Michigan, while NBLIP transfer capability is important to deliver supply in the West Zone and imports from Michigan to the rest of the province.

Both transfers are generally thermally limited by circuits between Scott and Buchanan, Lambton and Longwood, or Chatham and Buchanan/Longwood, located west of where BLIP and NBLIP are measured.

2.5.1.2 Flow Away from Bruce Complex and Wind (FABCW)

The FABCW interface is the sum of all power flows away from the Bruce 230-kV and Bruce 500-kV stations (six circuits each), plus wind generation in the area. This transfer capability is important to deliver supply from the Bruce Zone, including nuclear generation from Bruce GS and surrounding wind plants, to the rest of the province.

FABCW transfers are not normally limited when all transmission facilities are in-service and are effectively managed through the Bruce Remedial Action Scheme under outage conditions.

2.5.1.3 Queenston Flow West (QFW)

The QFW interface comprises the circuits that connect the Niagara Zone and the Southwest Zone. This includes the four 230-kV circuits out of Beck 2 TS and three 230-kV circuits into Middleport TS. The QFW transfer capability is important to deliver supply from the Niagara Zone and imports from New York at Niagara to the rest of the province.

The QFW transfer capability was increased following completion of the Niagara reinforcement project in August 2019. QFW transfers are generally thermally limited, but are not expected to be restrictive under typical conditions, such as normal weather, expected imports, and all transmission facilities in-service.

2.5.1.4 Flow East Towards Toronto (FETT)

The FETT interface comprises the circuits that connect the Southwest Zone and the Toronto and Essa Zones. This includes the four 500-kV circuits into Claireville TS, two 230-kV circuits out of Orangeville TS to Essa TS, and four 230-kV circuits out of Trafalgar TS to Richview TS and Hurontario SS. FETT transfer capability is important for reliably supplying demand in the Toronto, Essa, East, Ottawa, Northeast and Northwest Zones and to deliver supply from the West, Southwest, Bruce and Niagara Zones.

FETT transfers are thermally limiting by the Richview TS to Trafalgar TS corridor in Mississauga, and can be critically binding with a transmission circuit initially out of service during summer peak demand periods, when the line ratings are low and demands are high. FETT transfer capability is highly dependent on the distribution of power that flows along the limiting path from Richview TS to Trafalgar TS, which will be affected by nuclear retirements and refurbishments, causing flows to increase and the distribution of flows to further restrict transfer capability.

2.5.1.5 Transfer East of Cherrywood (TEC)

Cherrywood TS is located in Pickering. The TEC interface comprises the circuits that connect the Toronto Zone and the East Zone. This includes the four 500-kV circuits out of Bowmanville SS, four 230-kV circuits – with one each into Dobbin TS, Almonte TS, Belleville TS and Havelock TS – and two 230-kV circuits into Chats Falls GS. TEC transfer capability is important for reliably supplying demand in the East and Ottawa Zones.

TEC transfers are generally thermally limited, but are not expected to be normally binding.

2.5.1.6 Flow into Ottawa (FIO)

The FIO interface comprises the circuits that connect the East Zone and Ottawa Zone. This includes two 500-kV circuits out of Lennox TGS, one 230-kV circuit into St. Isidore TS, one 230-kV circuit out of St. Lawrence TS, one 230-kV circuit out of Chats Falls TS and one 230-kV circuit into Merivale TS. The FIO interface is considered an open interface because the underlying lower-voltage 115-kV circuits that connect the East and Ottawa Zones are not measured by the interface. This is because flows on the 115-kV circuits do not materially impact the ability to transfer bulk quantities of power into the Ottawa Zone. FIO transfer capability is important for reliably supplying demand in the Ottawa Zone and facilitating exports to Quebec.

FIO transfers are not generally limiting with all transmission facilities in service. With one transmission circuit out of service, FIO transfers are limited to ensure acceptable voltage performance.

2.5.1.7 Claireville North (CLAN) and Claireville South (CLAS)

The CLAN interface comprises the circuits that connect the Toronto Zone and Essa Zone. This includes two 500-kV circuits and two 230-kV circuits north from Claireville TS, located in the Toronto Zone. The CLAS interface is defined identically to the CLAN interface, but the power transfer is measured in the reverse direction.

The CLAN and CLAS interfaces are generally not limiting.

2.5.1.8 Flow North (FN) and Flow South (FS)

The FN interface comprises the circuits that connect the Essa Zone and Northeast Zone. This includes the two 500-kV circuits north from Essa TS and one 230-kV circuit north into Otto Holden TS. The FS interface is defined identically to the FN interface, but the power transfer is measured in the reverse direction. FN transfer capability is important to reliably supply demand in the Northeast and Northwest Zones, as well as facilitate exports to Manitoba, Minnesota and Quebec; FS transfer capability is important to deliver imports and supply from the Northwest and Northeast Zones to the rest of the province.

FN and FS transfers can be limited under certain conditions to ensure acceptable voltage and stability performance (e.g., FN can be limiting under low water conditions and sensitive to demand; and FS can be limiting under heavy water conditions).

2.5.1.9 East-West Transfer East (EWTE) and East-West Transfer West (EWTW)

The EWTW interface comprises the circuits that connect the Northeast Zone and Northwest Zone. This currently includes the two 230-kV circuits into Wawa from Marathon, and will include the two additional 230-kV circuits into Wawa from Marathon that form part of the East-West Tie Reinforcement project. The EWTE interface is defined identically to the EWTW interface, but the power transfer is measured in the reverse direction. EWTW transfer capability is important to reliably supply Northwest Zone demand, while EWTE transfer capability is important for the delivery of Northwest supply and imports to the rest of the province.

EWTE and EWTW transfers are limited by voltage performance and the thermal capability of the underlying 115-kV path, and will be improved following implementation of the East-West Tie Reinforcement project. At that point, facilities that restrict transfers between Northwest Ontario and Northeast Ontario will be upstream and downstream of the EWTE and EWTW interfaces, notably the Mississagi East (MISSE) and West (MISSW) interfaces, as well as the Transfer West of Mackenzie (TWM) interface. Following the East-West Tie Reinforcement project, changes to the Northern Ontario zonal demarcations may be appropriate to align with these more limiting interfaces.

2.5.2 Bulk Transmission Interties

2.5.2.1 The Ontario-Manitoba Interconnection

The Ontario-Manitoba interconnection consists of two 230-kV circuits and one 115-kV circuit. The transfers on the 230-kV interconnection points are under the control of phase angle regulators (PARs)[13] and defined as Ontario-Manitoba Transfer East (OMTE) and Ontario-Manitoba Transfer West (OMTW). Ontario and Manitoba are synchronously connected[14] at 230-kV, while the 115-kV interconnection is operated normally open (i.e., no power flows) except under rare or emergency conditions.

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[13] A PAR is a specialized transformer that alters power angle to control the flow of power through paths different than how it would naturally flow.

[14] Synchronously connected means direct AC to AC connection, which allows for matching frequencies between the two connecting systems.

2.5.2.2 The Ontario-Minnesota Interconnection

The Ontario-Minnesota interconnection consists of one 115-kV interconnection point. The transfers on this interconnection are the Minnesota Power Flow North (MPFN) and the Minnesota Power Flow South (MPFS). The interconnection is under the control of a PAR. Ontario and Minnesota are synchronously connected.

2.5.2.3 The Ontario-Michigan Interconnection

The Ontario-Michigan interconnection consists of two 230/345-kV interconnection points, one 230/115-kV interconnection point, and one 230-kV interconnection point. The interconnection is under the control of PARs. Ontario and Michigan are synchronously connected.

2.5.2.4 The Ontario-New York Niagara Interconnection

The Ontario-New York Niagara interconnection consists of two 230/345-kV interconnection points and two 230-kV and one 115-kV interconnection points, the latter of which is used for emergency services only. The interconnection is free-flowing.

The Queenston Flow West (QFW) interface is downstream of the New York Niagara interconnection. All flows entering Ontario on the New York Niagara interconnection will impact flows on the QFW interface, including imports and unscheduled flows. Ontario and New York Niagara are synchronously connected.

2.5.2.5 The Ontario-New York St. Lawrence Interconnection

The Ontario-New York St. Lawrence interconnection consists of two 230-kV circuits. The interconnection is under the control of PARs. The failure of the PAR connected to the Ontario-New York 230-kV interconnection circuit L33P in early 2018 reduces the province's ability to import electricity from New York through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. The PARs are expected to be replaced in 2022/2023, restoring import capability and improving the ability to control flow on the intertie.

Ontario and New York are synchronously connected at St. Lawrence.

2.5.2.6 The Ontario-Quebec Interconnection

The Northeast Zone contains two radial[15] 115-kV interconnection points with Quebec. The East Zone contains four 230-kV and one 115-kV radial interconnection points with Quebec. The Ottawa Zone has one HVDC (non-synchronous) interconnection (consisting of two 230-kV circuits), as well as one 230-kV and one 115-kV radial interconnection points.

[15] A radial interconnection is a type of non synchronous connection where one or more generator(s) electrically is separated from the rest of the system to which it belongs, and supplies customers in the other jurisdiction.

2.6 Anticipated Transmission Projects

A number of major transmission projects are expected to come into service within the outlook time frame. These are considered in the base case for resource adequacy and transmission security assessments. The geographical locations of these anticipated transmission projects are shown in Figure 16 and a summary of each appears in Table 3.

Figure 16 | Transmission Zones and Anticipated Projects

Table 3 | Major Anticipated Transmission Project Details

Project	Description	Expected In-Service Date
West of Chatham Area Reinforcement	• Growth in the agricultural sector is one of the main drivers of increasing demand in Ontario, as discussed in Section 1.3.4, and has resulted in the need for additional electrical supply capacity to serve the Windsor-Essex region • The reinforcement project consists of: a new switching station at Leamington Junction (Lakeshore SS); and a new, double-circuit, 230-kV transmission line, approximately 50 km in length, from Chatham SS to Lakeshore SS	• Q4 2022 for Lakeshore SS • Q4 2025 for new line
Hawthorne - Merivale Reinforcement	• The Hawthorne-Merivale transmission path supplies load in western Ottawa and delivers eastern Ontario resources and imports from Quebec to southern Ontario load centres • The reinforcement consists of upgrading the two 230-kV circuits between Merivale TS and Hawthorne TS, a length of 12 km	• Q4 2022
Lennox Reactors	• Operational challenges due to high voltages in eastern Ontario and the GTA continue to occur during low-demand periods, and have recently been exacerbated due to impacts on minimum demand from COVID-19 • Two 500-kV line-connected shunt reactors will be installed at Lennox TS (near Napanee)	• Q1 2021 - Q4 2021
East-West Tie Reinforcement	• To provide long-term, reliable electricity supply to Northwest Ontario to enable forecast demand growth and changes to the supply mix in the region • New 230-kV transmission line roughly paralleling the existing East-West Tie Line between Wawa and Thunder Bay	• Q1 2022

3. Resource Adequacy

In Scenario 1, summer capacity needs continue to emerge through 2022 and long-term needs continue to be driven by the Pickering NGS retirement. Without the continued availability of existing generation and demand-side resources post contract/commitment, needs emerge in the winter of 2022/2023, influenced by strong growth in the agricultural sector. Should these resources continue to be available in the market, the need would be smaller and emerge later.

Major planned generator outages affect the need for capacity. The nuclear refurbishment program is particularly important, with two and four nuclear units out of service each summer until 2030. Major refurbishment activity occurs in summer 2023, when two to four nuclear units will be out of service over the summer.

Transmission limitations can restrict capacity from being delivered to where it is needed and will need to be considered when locating new capacity to meet future needs.

A component of power system reliability is resource adequacy, which describes the balance of supply and demand in the system. There are risks to every power system, such as extreme weather and generator outages, which could result in demand exceeding supply for a period of time. An adequate system has enough capacity to mitigate these risks. The IESO calculates capacity requirements by performing a resource adequacy assessment.

The probabilistic risk assessment compares the demand forecast with anticipated resource performance to simulate the range of possible future system conditions. Loss of load expectation (LOLE) is a measurement of resource adequacy, defined as the average number of days per year during which supply is expected to be insufficient to meet demand. Reliability standards[16] require that the IESO maintain enough capacity such that the LOLE is no greater than 0.1 days/year. Probabilistic assessments are standard practice across North America and are part of the IESO's regulatory requirements. Over time, as forecasted demand changes or resources enter and exit the market, the IESO's capacity requirements will change.

The IESO considers a number of risks in resource adequacy assessments. For example, actual demand may be higher or lower than forecast depending on weather conditions. Resources may be unavailable in real-time due to planned maintenance or equipment failures. Variable generators – like wind and solar – may provide relatively low levels of effective capacity since they are dependent on environmental conditions and cannot always produce energy when required. Finally, major projects, such as ongoing nuclear refurbishments, may face return-to-service delays and experience a higher failure rate after they return.[17]

[16] For additional information, refer to NPCC's Regional Reliability Reference Directory #1 Design and Operation of the Bulk Power System, Section R4, page 6; and the IESO's Ontario Resource and Transmission Assessment Criteria, Section 8.
[17] Consult the 2020 APO Resource Adequacy and Energy Assessment Methodology for additional information.

Resources are assessed in terms of effective capacity,[18] which is typically lower than installed capacity, as was discussed in the previous chapter. The capacity requirements in this section are in the same units (MW). The total resource requirement is the amount of effective capacity needed to meet resource adequacy standards, and the reserve margin requirement is the amount by which the total resource requirement exceeds peak demand under normal weather conditions.

In Ontario, summer capacity needs are generally much higher than winter capacity needs. The main driver of this difference is demand, with summer peaks tending to be higher and more variable than winter peaks. Existing resources, particularly gas, hydroelectric, and wind, also provide less effective capacity in the summer than in the winter.

3.1 Reserve Margin

The IESO maintains an adequate reserve margin to ensure there is enough electricity available to compensate for volatility in factors that impact supply and demand. Continued availability of existing resources is assumed in the reserve margin. Through the Resource Adequacy engagement, the IESO will work with stakeholders to develop a framework for competitive mechanisms to meet Ontario's resource adequacy needs.

In accordance with Section 8.2 of the Ontario Resource and Transmission Assessment Criteria (ORTAC), the IESO annually publishes a five-year forecast of reserve margin requirements at the time of projected annual peak. Requirements are compared to the amount of effective capacity available from existing resources. The reserve margin requirements for the next five years are shown in Table 4.

There are various reasons for year-to-year variations in the reserve margin requirement. The IESO includes additional reserve to account for risks associated with nuclear refurbishments, with the amount varying depending on the refurbishment schedule. A year with higher-than-average planned outages will also have a higher reserve margin requirement. The methodology to calculate effective capacity for each resource type also affects the reserve margin. The reserve margin requirements for the full outlook horizon are shown in Table 4 and Figure 17. The table reflects continued availability of existing resources post-contract/commitment. Should these resources become unavailable, the Reserve Margin Available would be less than what is shown.

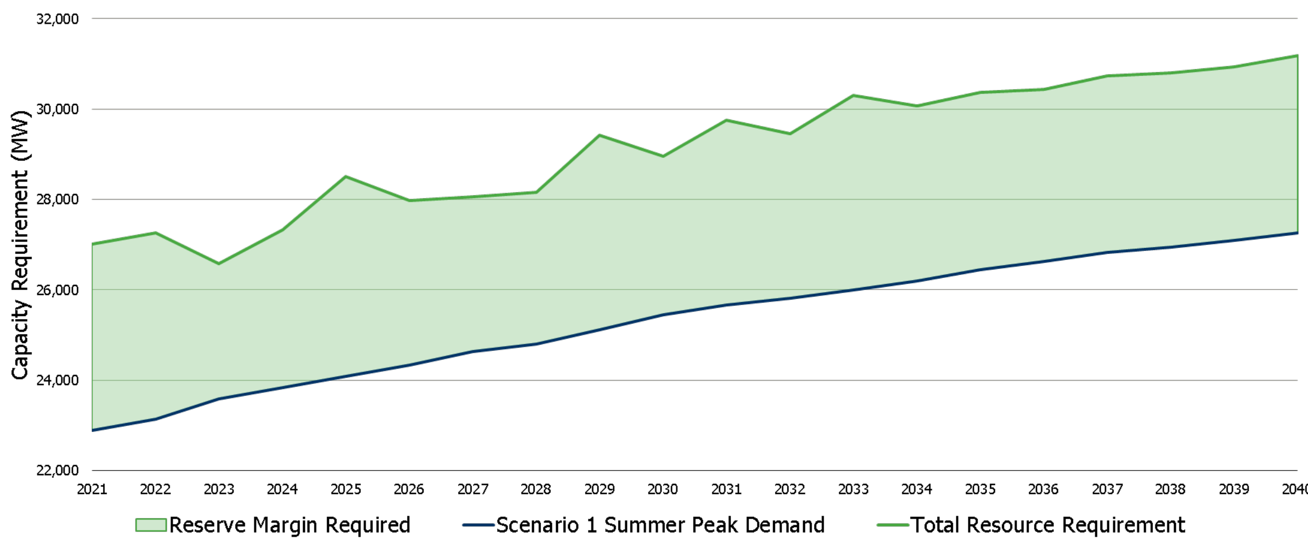
Table 4 | Five-Year Reserve Margin, with Continued Availability of Existing Resources

Five-Year Reserve Margin	2021	2022	2023	2024	2025
Scenario 1 Summer Peak Demand (MW)	22,882	23,131	23,583	23,833	24,093
Existing Summer Effective Capacity (MW)	28,207	27,388	26,659	27,446	26,588
Total Resource Requirement (MW)	27,019	27,262	26,587	27,334	28,505

[18] A resource's effective capacity is equivalent to its UCAP.

Five-Year Reserve Margin	2021	2022	2023	2024	2025
Reserve Margin Available (MW)	5,325	4,257	3,076	3,613	2,495
Capacity Surplus/Deficit (MW)	1,188	126	72	112	-1,917
Reserve Margin Available (%)	23%	18%	13%	15%	10%
Reserve Margin Requirement (%)	18%	18%	13%	15%	18%

Figure 17 | Reserve Margin Requirement, 2021-2040



3.2 Provincial Capacity Adequacy Outlook

Capacity adequacy can be understood in terms of surplus or deficit, relative to a set of demand and resource assumptions. Resource adequacy is assessed for the summer and winter seasons using the two demand forecasts outlined in Chapter 1, and the supply and transmission outlook presented in Chapter 2.

In this chapter, the capacity deficit represents the total amount of capacity, on an effective capacity or UCAP basis, that the IESO must acquire to satisfy LOLE requirements. Capacity needs calculated in this manner will inform target capacity for the capacity auction and future acquisition processes. The capacity surplus/deficits for summer and winter periods without availability of existing resources post-contract/commitment are shown in Figure 18 and Figure 19. In Scenario 1, summer capacity needs continue to emerge through 2022 and long-term needs are driven by the Pickering NGS retirement. Without the continued availability of existing generation and demand-side resources, needs emerge in the winter of 2022/2023.[19]

[19] Refer to the 2020 APO Supply, Adequacy and Energy Outlook Module for additional information on capacity needs and available options to meet these needs.

Figure 18 | Summer Capacity Surplus/Deficit, without Continued Availability of Existing Resources

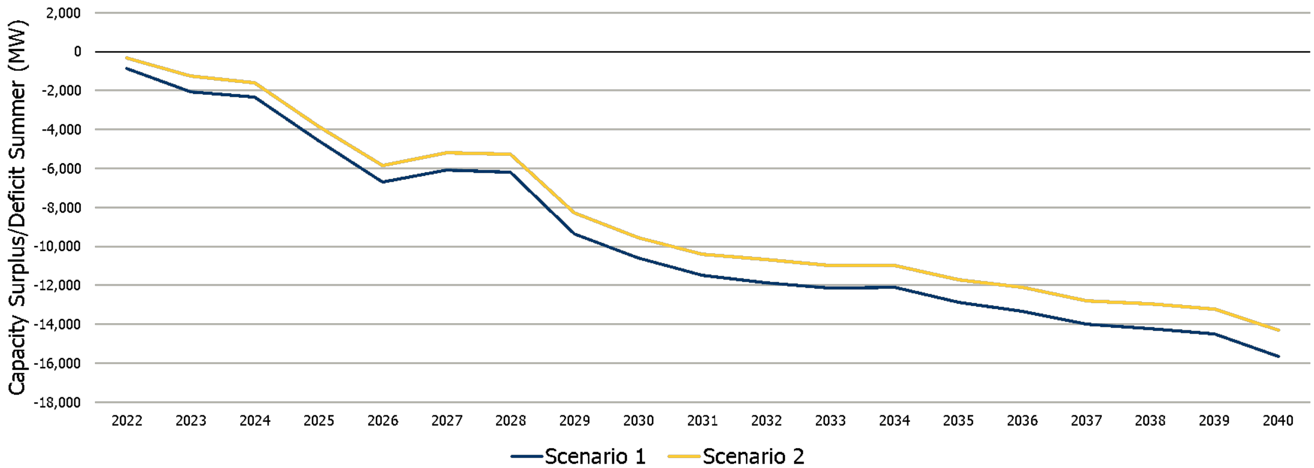
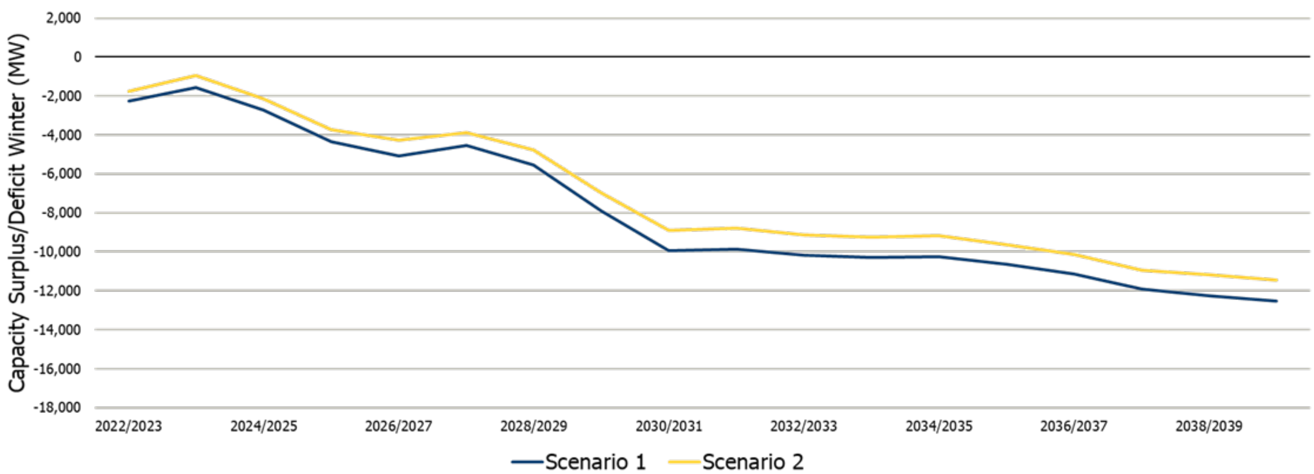


Figure 19 | Winter Capacity Surplus/Deficit, without Continued Availability of Existing Resources



The Lennox GS contract expected to expire at the end of 2022 along with major planned generator outages – such as the nuclear refurbishment program, with two and four units out of service each summer – greatly impact the capacity need. In the summer of 2023, at the height of refurbishment activity, four nuclear units (totaling 3,364 installed MW) will be out of service. The IESO will be negotiating an extension of the Lennox GS contract as a transition measure to reduce and delay this need.

Current forecasted ICI contributions to resource adequacy show an average reduction of 700 MW in the need over the course of the outlook. Potential changes to the ICI program could affect the timing of the need by a year or two.[20]

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[20] Refer to the 2020 APO Supply, Adequacy and Energy Outlook Module for additional information on the impact of ICI on resource adequacy.

3.2.1 Zonal Capacity Adequacy Outlook

The capacity requirements presented in this chapter are the total amount needed to reliably meet provincial demand for electricity. However, the location of resources on the system also affects resource adequacy. Transmission limitations can prevent capacity from being delivered to where it is needed. To manage the impact of major transmission limitations on capacity acquisition, the IESO applies minimum or maximum incremental capacity limits to certain regions of the province.

Transmission constraints in the resource adequacy assessment are modelled using the major transmission interfaces between the 10 IESO electrical zones as described in Chapter 2. Additional limits are presented for groups of zones that share a common limiting interface.[21] A zonal minimum represents the minimum required capacity in a zone necessary to meet provincial resource adequacy criteria. A zonal maximum represents the maximum amount of capacity that can be located in a zone, while still contributing to provincial resource adequacy criteria. The summer and winter zonal minimums and maximums for select future years are shown in Table 5 and Table 6, respectively.[22] The years chosen represent the main inflection points in capacity need growth over the next decade.

Given the existing transmission infrastructure, zonal constraint studies show that location-specific capacity needs will emerge in the mid-2020s, mainly in the GTA and eastern Ontario (i.e., Toronto, Essa, East, and Ottawa Zones). With the retirement of Pickering NGS and the Darlington refurbishment, this area will have less generation capacity available. Towards the end of the decade, some additional capacity will be required in the West Zone.

Capacity bottling on the Flow South interface will limit the amount of capacity that can be added in northern Ontario (i.e., Northwest and Northeast Zones). The Flow East Towards Toronto interface is also a key consideration. There are limits on the amount of capacity that can be accommodated in southwest Ontario (i.e., Southwest, West, Niagara and Bruce Zones).

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[21] The 2020 APO Resource Adequacy and Energy Assessment Methodology provides a description on the methodology on zonal limits. Also refer to the 2020 APO Supply, Adequacy and Energy Outlook Module for additional information on the zonal capacity adequacy assessments.

[22] For Table 5 and Table 6, a maximum limit of N/A indicates that the actual maximum is not expected to be practically limiting.

Table 5 | Incremental Summer Zonal Constraints, without Continued Availability of Existing Resources

Zone	2023 Min (MW)	2023 Max (MW)	2025 Min (MW)	2025 Max (MW)	2029 Min (MW)	2029 Max (MW)
Bruce	0	2,800	0	2,750	0	2,150
East	0	N/A	0	N/A	0	N/A
Essa	0	N/A	0	N/A	0	N/A
Niagara	0	900	0	900	0	900
Northeast	0	150	0	250	0	250
Northwest	0	50	0	100	0	100
Ottawa	0	N/A	0	N/A	0	N/A
Southwest	0	N/A	0	N/A	0	N/A
Toronto	0	N/A	0	N/A	0	N/A
West	0	1,000	0	1,450	400	3,900
Toronto+Essa+East+Ottawa	0	N/A	1,600	N/A	4,550	N/A
Northeast+Northwest	0	150	0	250	0	250
Bruce+West+Niagara+Southwest	0	2,250	0	2,550	0	4,150

Table 6 | Incremental Winter Zonal Constraints, without Continued Availability of Existing Resources

Zone	2023/2024 Min (MW)	2023/2024 Max (MW)	2025/2026 Min (MW)	2025/2026 Max (MW)	2029/2030 Min (MW)	2029/2030 Max (MW)
Bruce	0	N/A	0	5,000	0	2,300
East	0	N/A	0	N/A	0	N/A
Essa	0	N/A	0	N/A	0	N/A
Niagara	0	800	0	1,700	0	800
Northeast	0	600	0	1,800	0	1,550
Northwest	0	150	0	1,100	0	350
Ottawa	0	N/A	0	N/A	0	N/A
Southwest	0	N/A	0	N/A	0	N/A
Toronto	0	N/A	0	N/A	0	N/A
West	0	850	0	2,450	450	4,300
Toronto+Essa+East+Ottawa	0	N/A	200	N/A	4,200	N/A
Northeast+Northwest	0	600	0	1,800	0	1,550
Bruce+West+Niagara+Southwest	0	1,100	0	4,050	0	3,400

3.3 Provincial Energy Adequacy Outlook

The purpose of the energy adequacy outlook is to assess Ontario's ability to meet its own electricity needs and better characterize the nature of future needs. The energy adequacy assessment does not include any economic imports or exports across Ontario's interconnections. Contracted energy imports are included.

Ontario is expected to have an adequate supply of energy in the near term. In the long term, the extent to which an energy adequacy need emerges will depend on the availability of existing resources post-contract expiry, as existing renewable and gas-fired generation can continue to meet Ontario's energy needs. The energy adequacy outlooks for Scenarios 1 and 2 are shown in Figure 20 and Figure 21, respectively.

Figure 20 | Scenario 1 – Energy Adequacy Outlook, with Continued Availability of Existing Resources

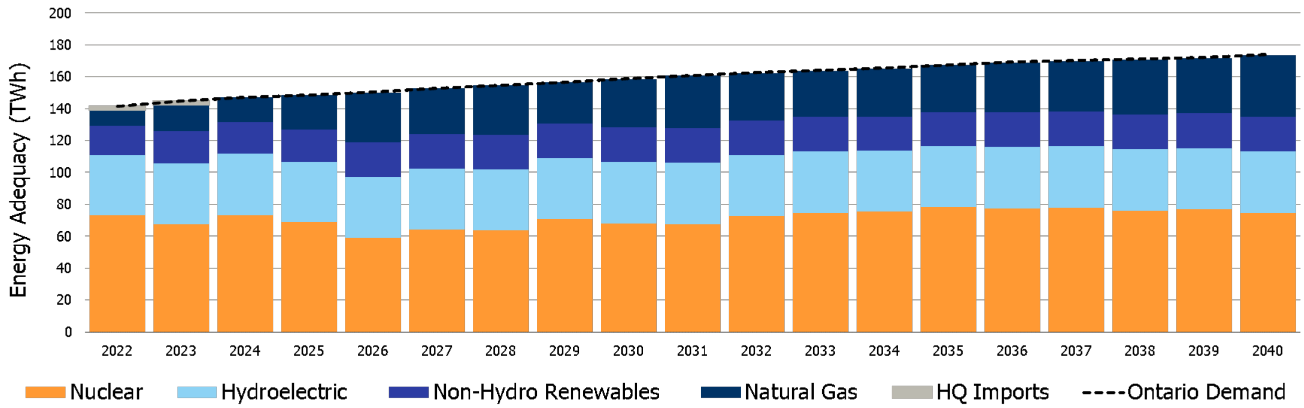
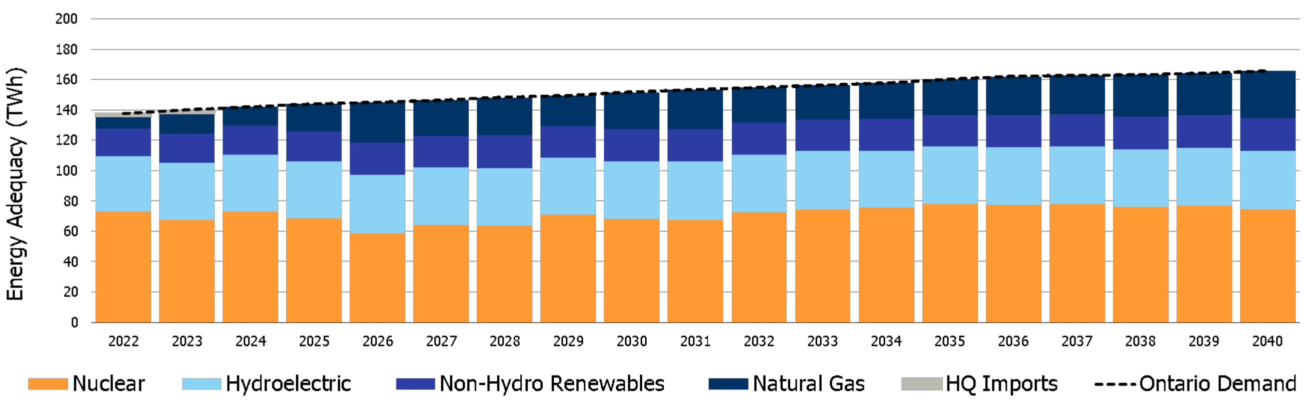


Figure 21 | Scenario 2 – Energy Adequacy Outlook, with Continued Availability of Existing Resources

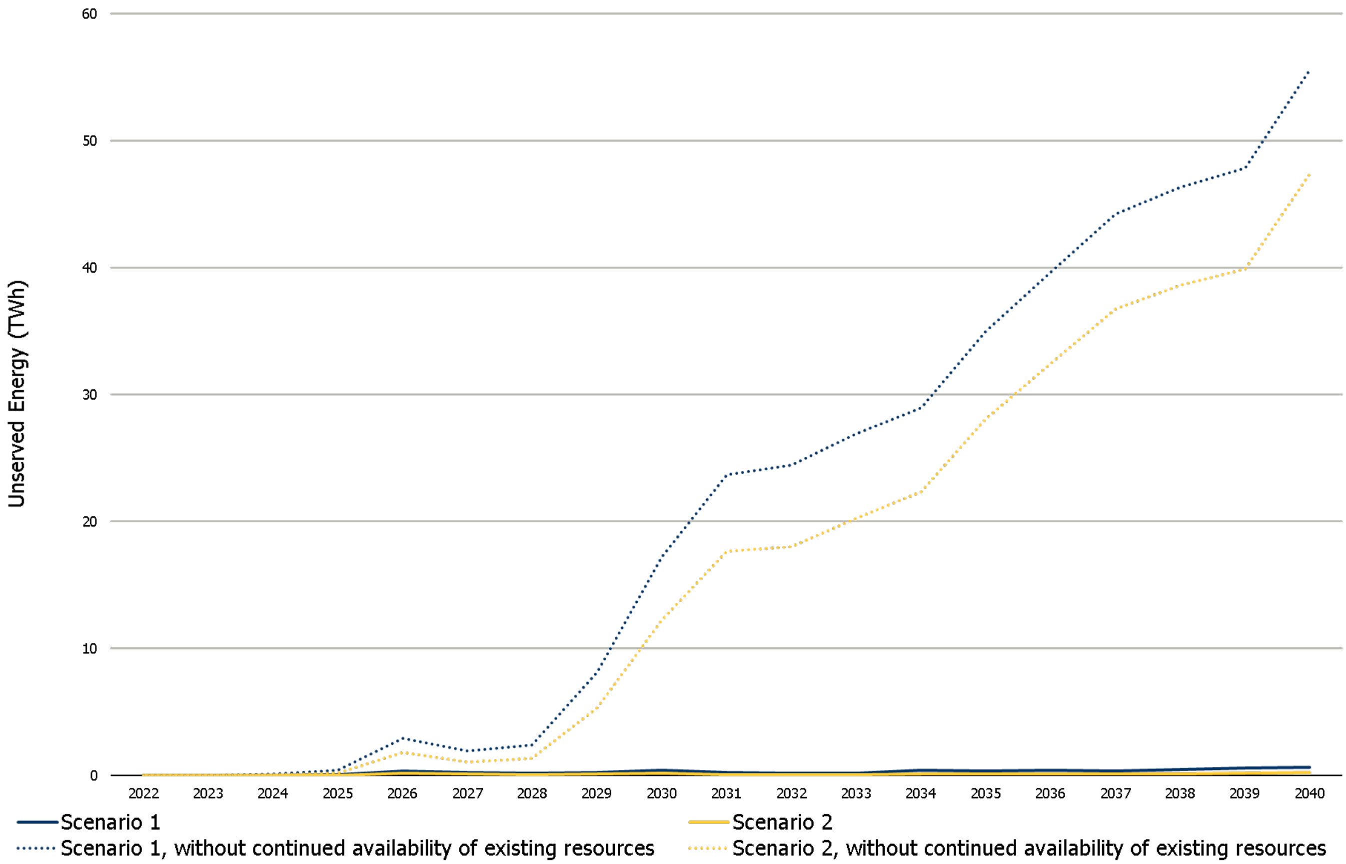


The energy adequacy outlook indicates that Ontario's supply needs over the next decade are principally for managing risks to the reliability of the grid. Existing resources can meet energy demands in most circumstances. The capacity requirement is peaking in nature and is required to help the system respond to lower probability events, such as extreme conditions (e.g. higher than expected demand or outages).

If existing resources exit the market post-contract expiry and the capacity shortfall grows, the potential for unserved energy begins in 2026. This would increase sharply after 2029, surpassing 56 TWh by the late 2030s in Scenario 1 and 47 TWh in Scenario 2, as shown in Figure 22. With a capacity need exceeding 10,000 MW, this resource scenario has considerable energy shortfalls through the 2030s, as combined gas cycle generation and renewable contracts expire.

Throughout the forecast period, the capacity need eventually becomes an energy need that is fairly dense, driven by resources with contracts expiring. However, if existing resources continue to be available, Ontario is generally expected to have enough energy to meet demand throughout the forecast period.

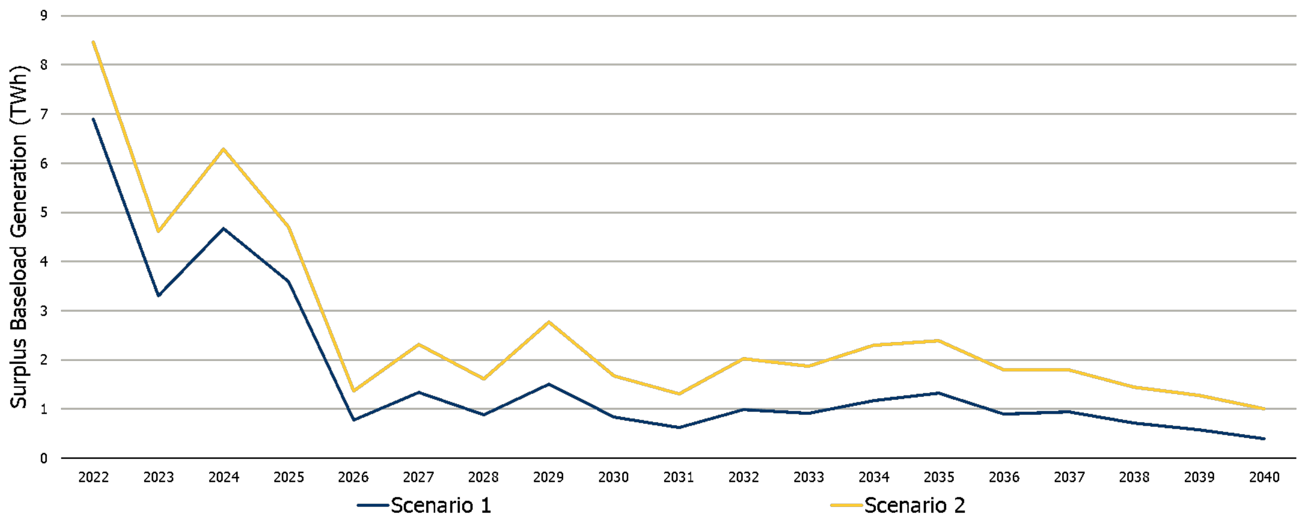
Figure 22 | Potentially Unserved Energy



Although existing resources are sufficient to meet future energy needs, new resources will have the opportunity to compete with existing resources in the energy markets. Resources can earn revenue by offering energy at a lower price than the marginal resource. Flexible, dispatchable resources can also quickly react to short-term energy price spikes or provide operating reserve.

Surplus baseload generation (SBG), as shown in Figure 23, occurs when output from baseload resources exceeds demand, and is a normal outcome of electricity markets with high portions of non-dispatchable (i.e., baseload and intermittent) resources. Periods of SBG require the IESO to use market mechanisms, such as exports, variable generation curtailment, and nuclear manoeuvers/ curtailment, to correct the imbalance. By the mid-2020s, SBG continues to fall as more nuclear units undergo refurbishment and Pickering NGS retires. Through the outlook period, SBG is expected to continue to be managed using existing market tools.

Figure 23 | Surplus Baseload Generation, with Continued Availability of Existing Resources



3.4 Provincial Energy Production Outlook

The IESO-administered energy markets are linked to Ontario's neighbours through interconnections. Imports and exports are scheduled in the real-time energy market to take advantage of price differences between jurisdictions. In 2019, Ontario imported 6.6 TWh of energy and exported 19.8 TWh. The model used to create this energy production outlook includes representations of Ontario's trading partners in order to more closely represent expected conditions and market outcomes. While the energy adequacy outlook is useful for characterizing resource needs, the energy production outlook is needed to forecast market outcomes, as illustrated in Figure 24 and Figure 25.

Figure 24 | Scenario 1 – Energy Production Outlook

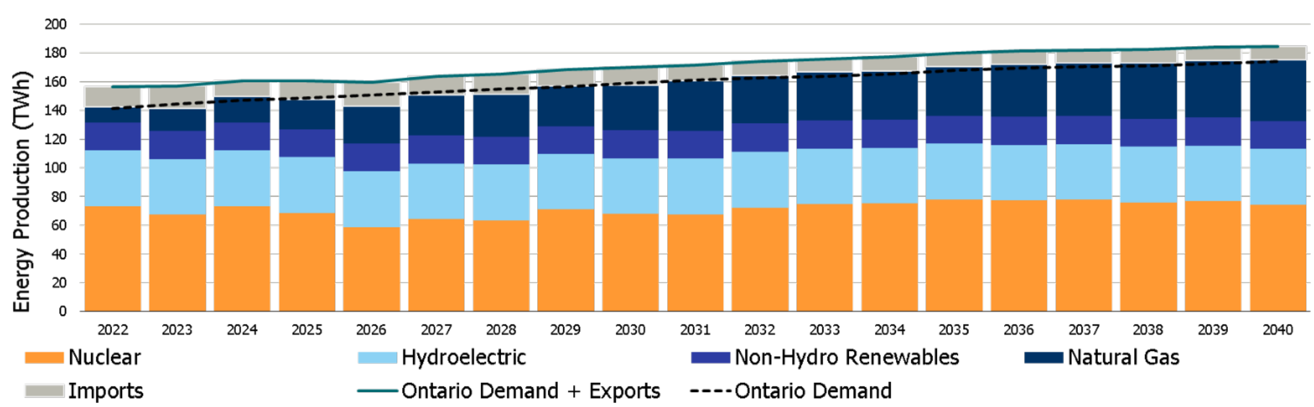
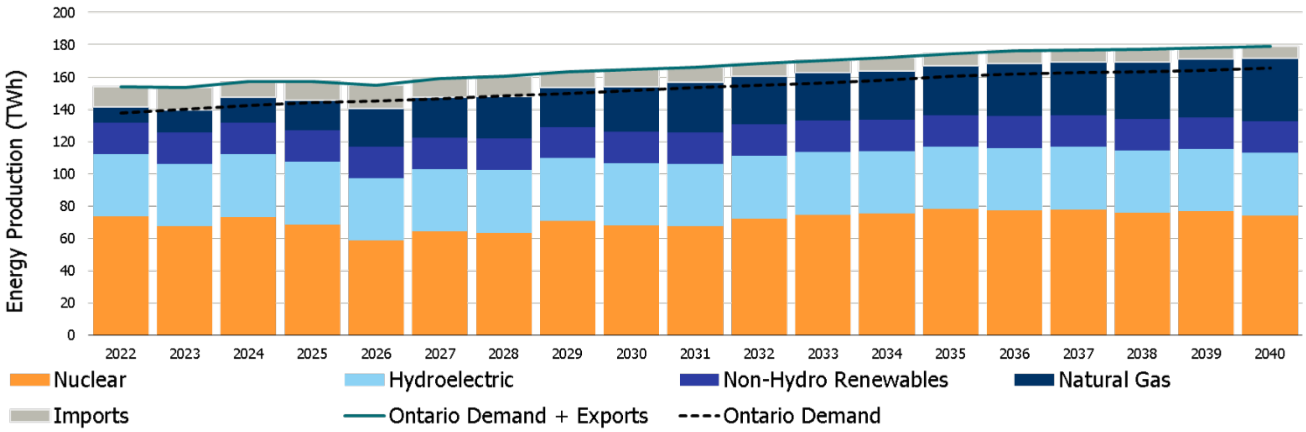


Figure 25 | Scenario 2 – Energy Production Outlook



Production by fuel type is similar to the energy adequacy outlook because production from baseload resources is generally insensitive to market prices. Gas production, which acts as a swing resource in the system, can vary depending on the extent to which these resources are more economic than imports in the real-time market. In addition, where opportunities exist, energy from Ontario's electricity fleet can also be exported.

In Figure 26 and Figure 27, energy exports decrease sharply in the early 2020s with the retirement of Pickering NGS and more nuclear generators on refurbishment outage. Coincidentally, imports increase from historic levels and Ontario becomes a net energy importer throughout the refurbishment period. The balance of trade is expected to shift back toward exports in the 2030s, following the conclusion of the nuclear refurbishment program.

Figure 26 | Energy Production Outlook, Imports[23]

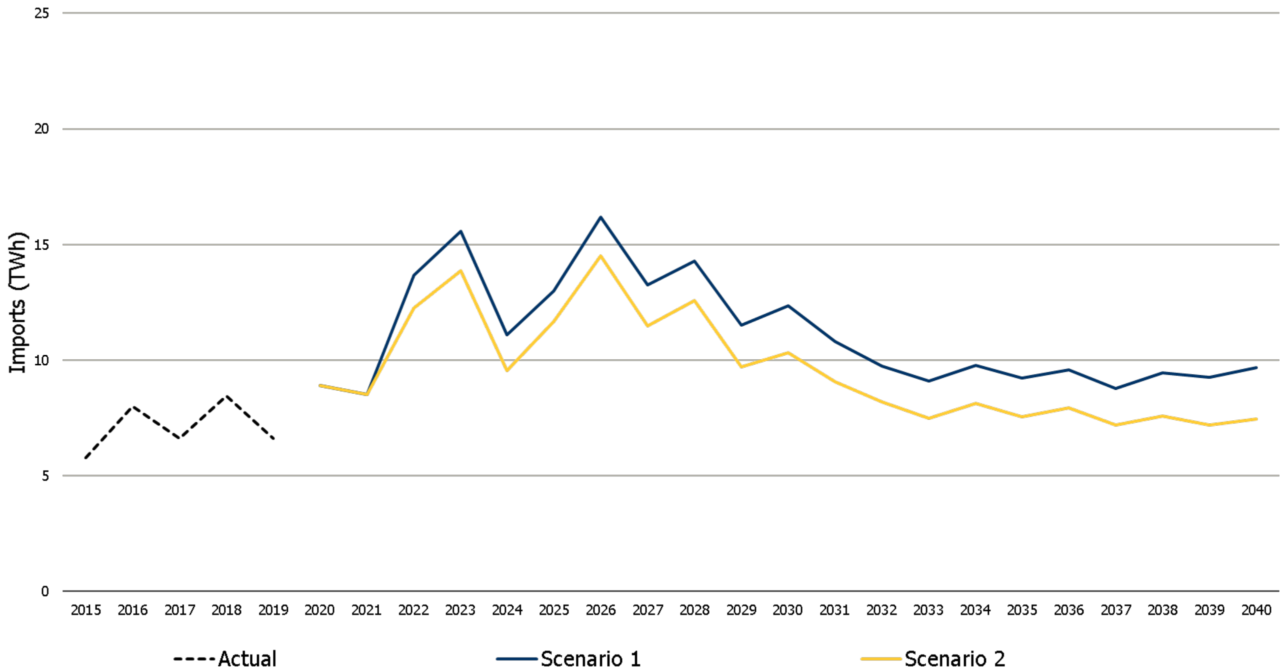
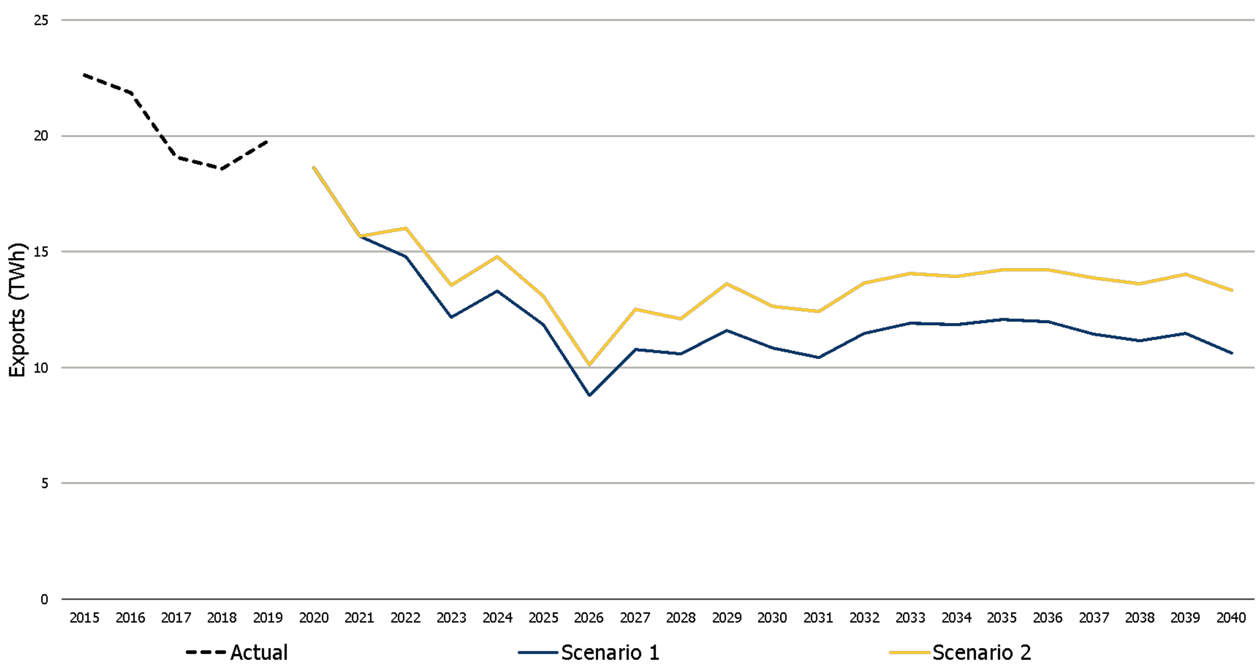


Figure 27 | Energy Production Outlook, Exports[24]

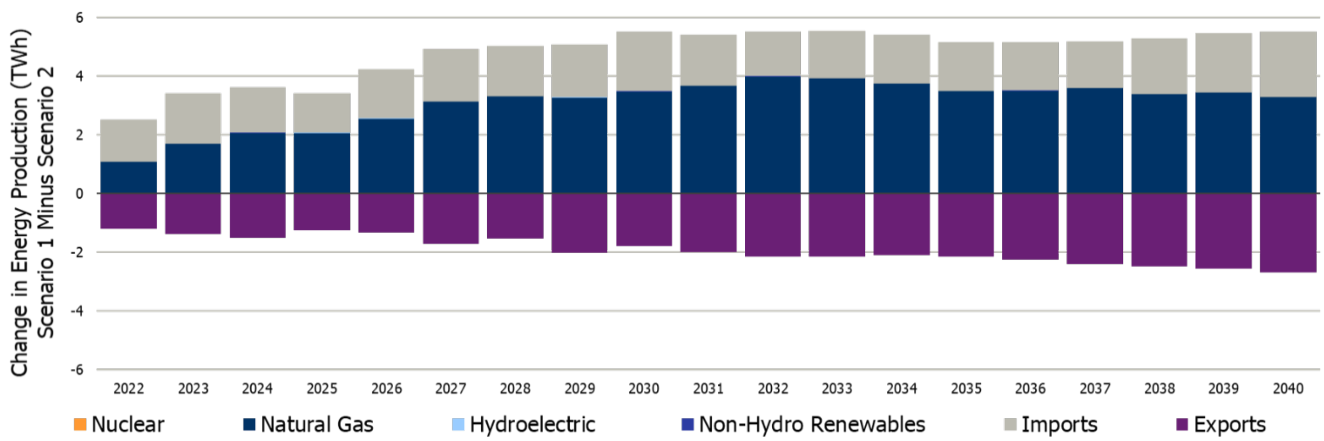


[23] For 2020 and 2021, the 2019 APO forecast values are shown.

[24] For 2020 and 2021, the 2019 APO forecast values are shown.

In Scenario 1, demand recovers to pre-pandemic levels in 2022 and steadily grows faster than previous forecasts. In Scenario 2, demand is expected to reach pre-pandemic levels in 2024. Electricity demand levels grow more slowly, with demand up to 8.2 TWh lower than that in Scenario 1 over the outlook period. This decreased demand leads to differences in the energy production outlook between the two cases. Scenario 2 sees decreased production from Ontario-based gas-fired generators, as well as fewer imports and more exports. Production from nuclear, hydroelectric, wind and solar resources is unchanged. This is illustrated in Figure 28.

Figure 28 | Change in Energy Production Outlook Between Scenario 1 and Scenario 2



Cost and emission outcomes from the energy production outlook, including avoided costs and emissions resulting from energy efficiency, are discussed in Chapter 7.

3.5 Fuel Security Considerations

Ontario has a diverse fuel mix, with nuclear and hydroelectric resources providing the majority of energy through the planning horizon. During the 2020s, nuclear refurbishments and the Pickering NGS retirement are projected to increase capacity factors of the combined cycle gas fleet to the 40 to 60 per cent range. As the fuel mix evolves through this period, interdependencies between the gas and electric systems will need to be monitored.

Fuel security risk reflects the possibility that thermal units will not have or be able to get the fuel (primarily natural gas) required to run. This could be due to the season (i.e., during winter, generating capacity may become unavailable due to priority demand for natural gas from building space heating), unexpected pipeline outages, or because increased utilization of the gas fleet creates uncertainty about whether power plants can arrange for fuel when needed.

Natural gas pipelines can become constrained during peak pipeline conditions, potentially limiting the use of natural gas-fired generation to meet Ontario's supply needs. Gas-fired generation is typically fuelled using just-in-time transportation and delivery with limited storage, and might be subject to interruption, depending on the gas delivery product. In constrained natural gas markets, these units may not be served during peak pipeline conditions. Natural gas pipeline constraints have serious implications for reliability and price volatility. Power generation facilities can mitigate these risks through the use of adequate firm transportation and storage capacity.

Fuel deliverability is of concern relative to the operating reliability of the infrastructure that delivers natural gas to the generating stations. In some areas, deliverability to the generation fleet is limited during winter months due to higher demand from space heating. As such, the risk of unavailability needs to be factored into the evaluation of the overall operational and planning reliability of the electricity system.

Following the Pickering NGS retirement and during the nuclear refurbishment period, incremental energy needs will be met primarily by the increased utilization of the gas fleet. Ontario currently benefits from having a diverse supply mix with no one dominant fuel source. With existing resources, fuel security is not expected to be a concern over the outlook as Ontario has robust gas supply. However, it will be important to consider fuel security in long-term planning as the demand and supply outlook evolves and as new resources enter the market.

4. Transmission Security

Under certain supply and demand conditions, transfer capability may become constrained between 2025 and 2030 along three major interfaces: Flow East Towards Toronto (FETT), Flow Into Ottawa (FIO) and Buchanan Longwood Input (BLIP).

Planning is underway in these areas to identify preferred solutions to address needs. Solutions must consider the impacts on reliability and security for local customers, and the broader impacts on resource adequacy resulting from potential changes to zonal transfer limits.

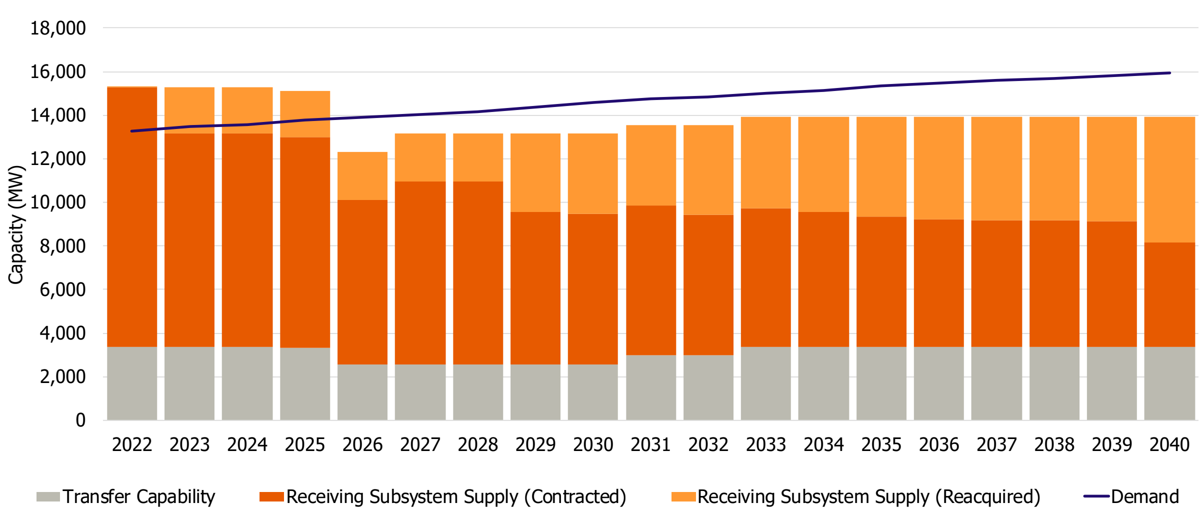
4.1 Transmission Outlook

Beyond meeting the provincial resource adequacy needs described in Chapter 3, capacity may need to be sited within specific zones to meet transmission planning standards. This transmission outlook focuses on the FETT, FIO and BLIP interfaces, since limitations to deliver power over these interfaces may result in additional requirements to site capacity in specific zones, over and above what was discussed in Section 3.2.1. To illustrate the need for local capacity, in each of the outlooks below, peak demand in the zones/subsystem that receive power from the interface under study is shown; this peak demand is compared to the amount of generation in the zones/subsystem and/or electricity transferred by the interface. The local supply need is the difference and will be referred to as the transmission security requirement.

4.1.1 Flow East Towards Toronto

Figure 29 illustrates the outlook for the system east of the FETT interface with respect to transmission security requirements.

Figure 29 | FETT Security Outlook



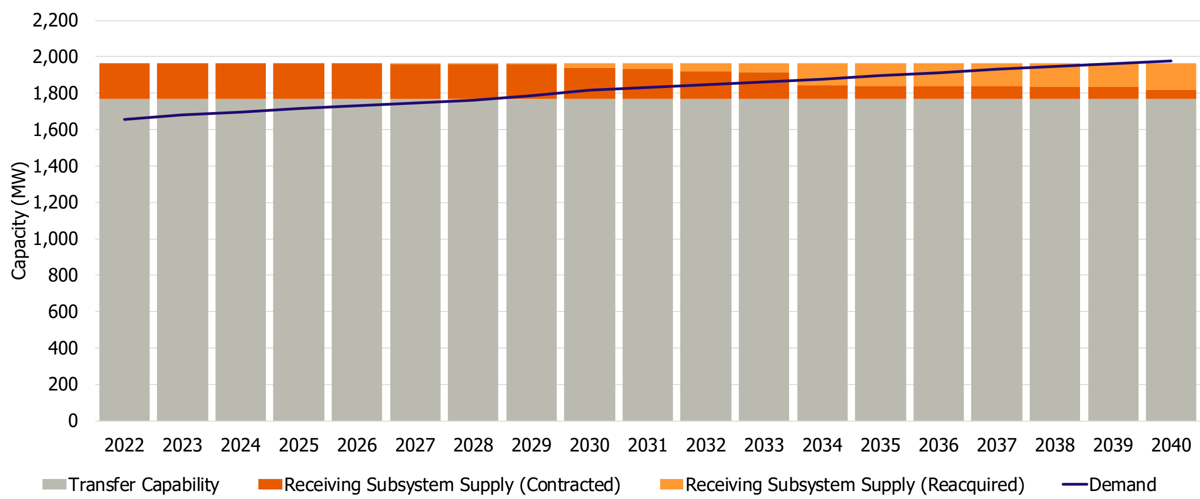
The FETT security outlook shows:

- If resources with expiring contracts are not re-acquired, a need for additional or reinforced capacity to supply the east of FETT portion of the system emerges, beginning with approximately 300 MW in 2023
- If resources with expiring contracts are re-acquired at the end of their contract terms, a need for additional or reinforced capacity to supply the east of FETT portion of the system of approximately 1,600 MW emerges in 2026
- This need for additional or reinforced capacity persists throughout the planning horizon, and increases, depending on demand growth and the future of firm supply resource acquisition. Proposed upgrades to address this need are described in Chapter 6.2.2.1.

4.1.2 Flow Into Ottawa

Figure 30 illustrates the outlook for the system east of the FIO Interface (Ottawa Zone) with respect to transmission security requirements.

Figure 30 | FIO Security Outlook



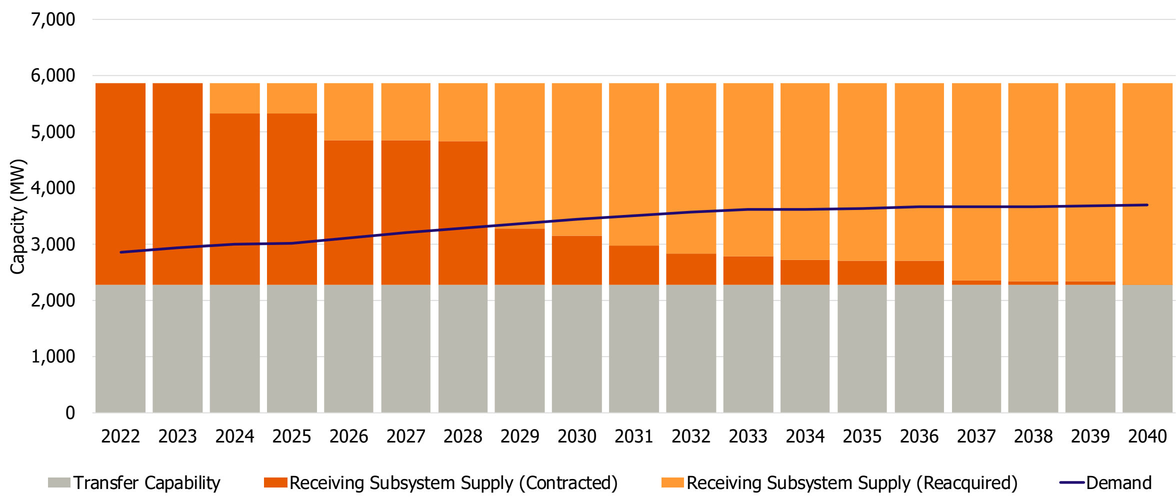
The FIO security outlook shows:

- The existing system is marginally secure
- A need for additional or reinforced capacity to supply the Ottawa Zone is highly sensitive to local demand scenarios, and is currently expected to emerge near the end of the planning horizon

4.1.3 Buchanan Longwood Input

Figure 31 illustrates the outlook for BLIP with respect to transmission security requirements.

Figure 31 | BLIP Security Outlook



The BLIP security outlook shows:

- A transmission security need in the West Zone may emerge in 2029, if resources with expiring contracts are not considered to be re-acquired
- Demand in the West Zone is largely driven by agricultural growth in the area, as described in Section 1.3.4.

5. Integrating Electricity Needs

Summer capacity needs continue to emerge through 2022 and, with continued availability of existing resources, these needs can be met until 2024. The capacity need eventually becomes an energy need that is fairly dense, driven by resources with contracts expiring in the late 2020s and early 2030s.

From a locational requirement, the Pickering NGS retirement and the Darlington refurbishment result in summer zonal capacity needs emerging in the mid-2020s in the GTA and eastern Ontario. Generation reaching the end of contract in the West Zone, along with significant growth in the agricultural sector in the Windsor-Essex and Chatham area, results in a zonal capacity need over the mid to long term. Load growth in the Ottawa area will contribute to a marginal capacity need in the Ottawa Zone over the medium term.

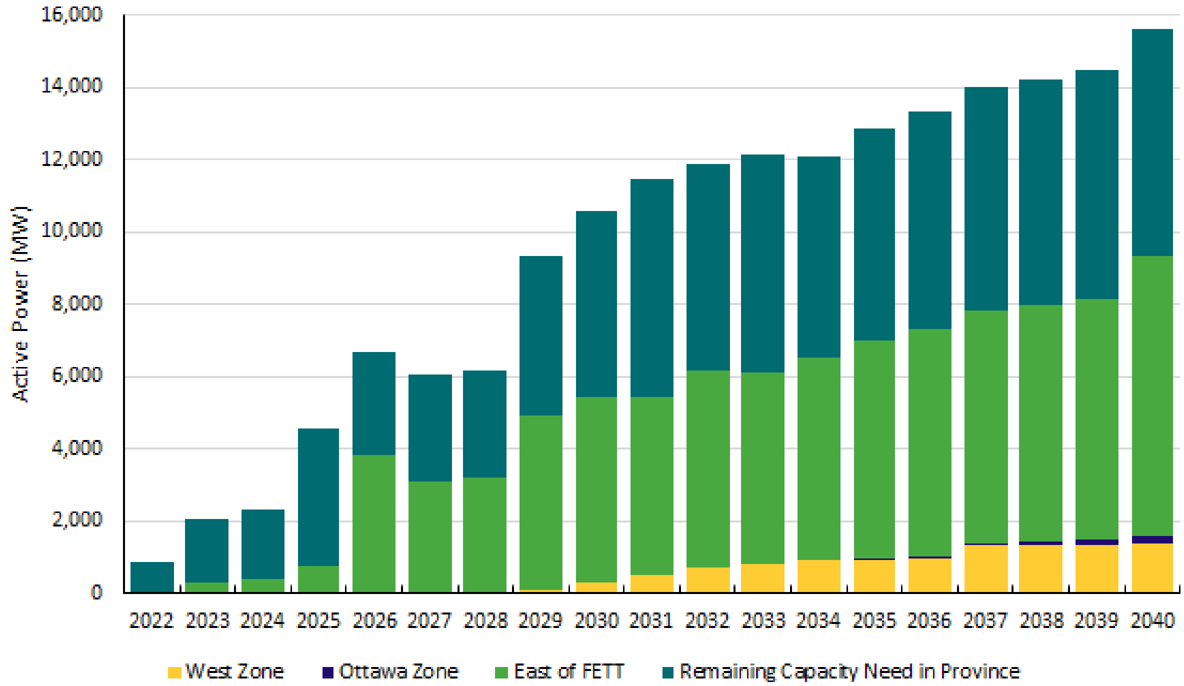
5.1 Overview

Chapter 3 and Chapter 4 presented the resources required to meet provincial resource adequacy and transmission planning standards. This chapter highlights the major outcomes and findings of those chapters, summarizing the magnitude of Ontario's needs, and when and where those needs occur.

5.2 Capacity Needs

Figure 32 summarizes the capacity need without considering re-acquisition of contracted resources once their term expires for Scenario 1, including the locational requirements arising from the need to meet transmission planning and resource adequacy standards.

Figure 32 | Scenario 1 - Summary of Summer Capacity Needs including Locational Requirements, without Continued Availability of Existing Resources[25]



The significant increase in the capacity need emerging in 2023 is primarily due to Lennox GS reaching the end of its contract term. In the 2024-2025 period, Pickering NGS is expected to retire. The nuclear refurbishment program will continue through the 2020s and into the 2030s, with between two- and four- nuclear unit refurbishments taking place concurrently during the summer until 2026. Over the next two decades, the majority of contracts with natural gas-fired and renewable generation are expected to expire. Continued availability of existing resources can address needs until 2024, after which incremental resources are required. Most of Ontario's natural gas-fired generation facilities are located in the West Zone and Toronto Zone. Less significant than Ontario's changing supply outlook, but still important, is that, in both Scenarios 1 and 2, the forecast growth in demand over the planning horizon contributes to capacity needs.

As Lennox GS, Pickering NGS and Darlington NGS are all located east of the FETT interface, the majority of Ontario's capacity needs are expected to emerge east of the FETT interface. Contracted natural gas-fired generation reaching the end of contract in the Toronto Zone exacerbates capacity needs east of the FETT interface. This results in a need to acquire new resources or re-contract existing resources east of FETT; or reinforce the interface and acquire new resources or re-contract existing resources west of FETT. Section 6.2.2.1 outlines the IESO's current planning activities to address capacity needs east of FETT.

[25] As the Ottawa Zone is located east of FETT, any additional capacity in that zone would contribute towards the amount required east of FETT.

Load growth in the Ottawa area will contribute to a marginal capacity need in the Ottawa Zone over the medium term. Plans to address asset replacement needs of existing infrastructure supplying eastern Ontario and ensure adequate supply to the Ottawa and Peterborough area will impact the future capability of the FIO interface. Section 6.2.2.2 outlines the IESO's current plans to address asset and reliability needs in eastern Ontario, specifically along the Gatineau transmission corridor.

Generation facilities reaching the end of their contracts in the West Zone result in a zonal capacity need over the mid to long term. Significant load growth in the Windsor-Essex and Chatham area in the agricultural sector is also contributing to this capacity need. Local constraints impacting the Windsor-Essex and Chatham area are common and restrict the ability to transport power into the entire West Zone. As a result, plans and acquisitions to support the Windsor-Essex and Chatham regional supply are closely linked to supply needs in the entire West Zone, and coordinated planning is being conducted in this area. Section 6.2.2.3 outlines the IESO's current plans to address the Windsor-Essex and Chatham area needs.

6. Meeting Electricity Needs

Supply, transmission, imports, distributed energy resources, storage and energy efficiency are all ways to meet the needs identified in the previous chapter.

In anticipation of future capacity shortfalls, the IESO will work with stakeholders through its Resource Adequacy engagement to enable a framework of competitive mechanisms to meet Ontario's resource adequacy needs in the short, medium and long term.

Reinforcing the transmission system can also address reliability needs and improve access to resources located within a transmission-limiting part of the system.

6.1 Overview

The APO is a technical document that describes the current demand, supply and transmission outlook, identifies future system needs, and highlights areas that may require greater attention.

This chapter presents a qualitative discussion of ways in which Ontario can meet its electricity needs. Depending on the location of these resources, transmission expansion may also be required to ensure resources are able to supply demand where needed.

6.2 Meeting Capacity Needs

Chapter 5 discussed Ontario's electricity needs from the perspective of resource adequacy and transmission security. Some of the needs identified can be met by the continued availability of existing Ontario resources once their contracts expire. Expansion of transmission may still be required to address transmission security needs within the next five years. Investment in increased zonal transfer capability, can also help address capacity needs by enabling resources located elsewhere to contribute towards resource adequacy needs. Firm and non-firm imports, distributed energy resources, storage and energy-efficiency can also provide benefits.

6.2.1 Continued Availability of Existing Ontario and New Resources

The extent to which resources with expired contracts/commitments will remain available depends on a number of factors, including asset age and condition, the need for capital investment, market conditions, and available acquisition tools. The IESO will work with stakeholders through its Resource Adequacy engagement to implement a framework of competitive mechanisms to meet Ontario's resource adequacy needs in the short, medium and long term. There are resources that are coming off contract over the next five years that impact the reliability and flexibility of the system due to their geographic location and capacity contribution to the system. Lennox GS contract will expire at the end of 2022. This resource is critical to system reliability due to its position in relation to the Greater Toronto Area load centre and the flexibility it provides for the electricity grid. With limited competition of resources to address needs, the IESO will be negotiating an extension of the Lennox GS contract as a transition measure until there is sufficient uncommitted capacity later in the decade for it to compete with. Figure 33 and Figure 34 illustrate the summer and winter capacity surplus and deficit, and the need that can be met with continued availability of existing resources.

Figure 33 | Summer Capacity Surplus/Deficit, with Continued Availability of Existing Resources

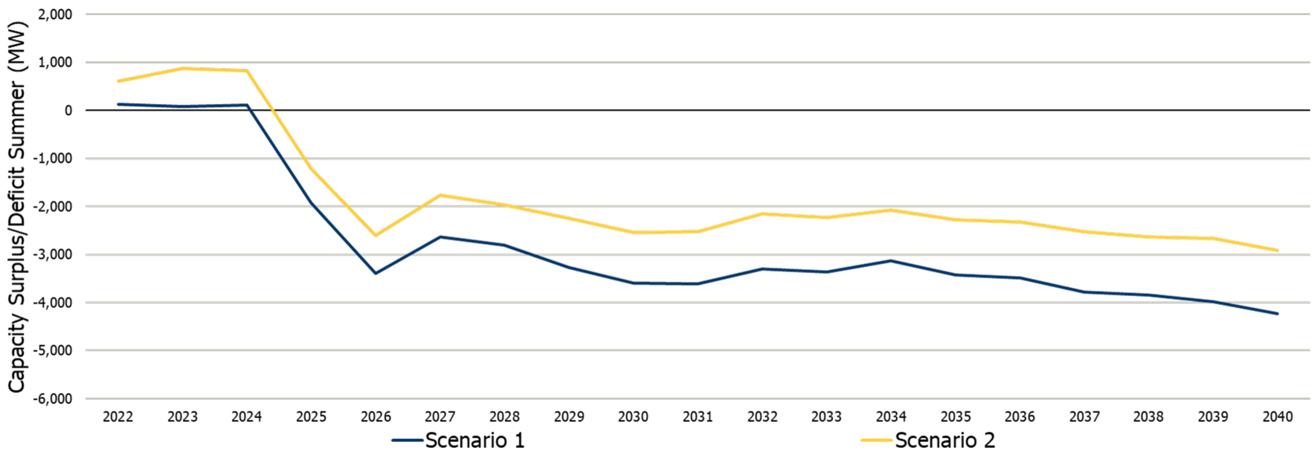
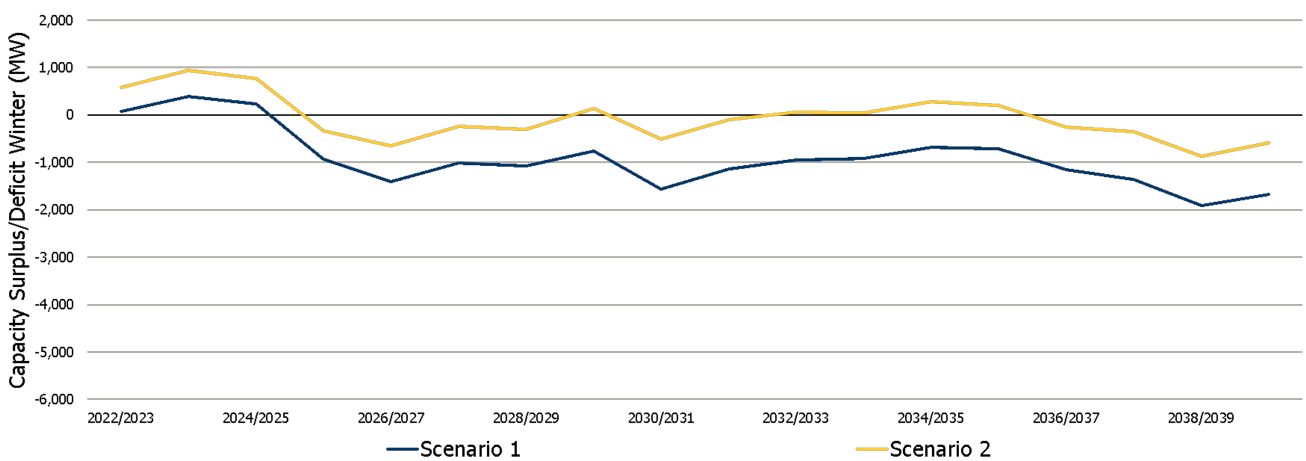


Figure 34 | Winter Capacity Surplus/Deficit, with Continued Availability of Existing Resources



6.2.2 Transmission Expansion

A number of transmission studies are currently underway to identify preferred solutions to address potential transmission reliability needs. Since the outcomes of these studies may affect interface transfer capabilities, they can impact provincial and local capacity adequacy. Reinforcing or expanding the transmission system is generally undertaken to address a local or zonal reliability need, or to improve access to resources located within a transmission-limiting region. The studies below have been selected as they are able to meet the transmission security and zonal adequacy needs identified earlier.

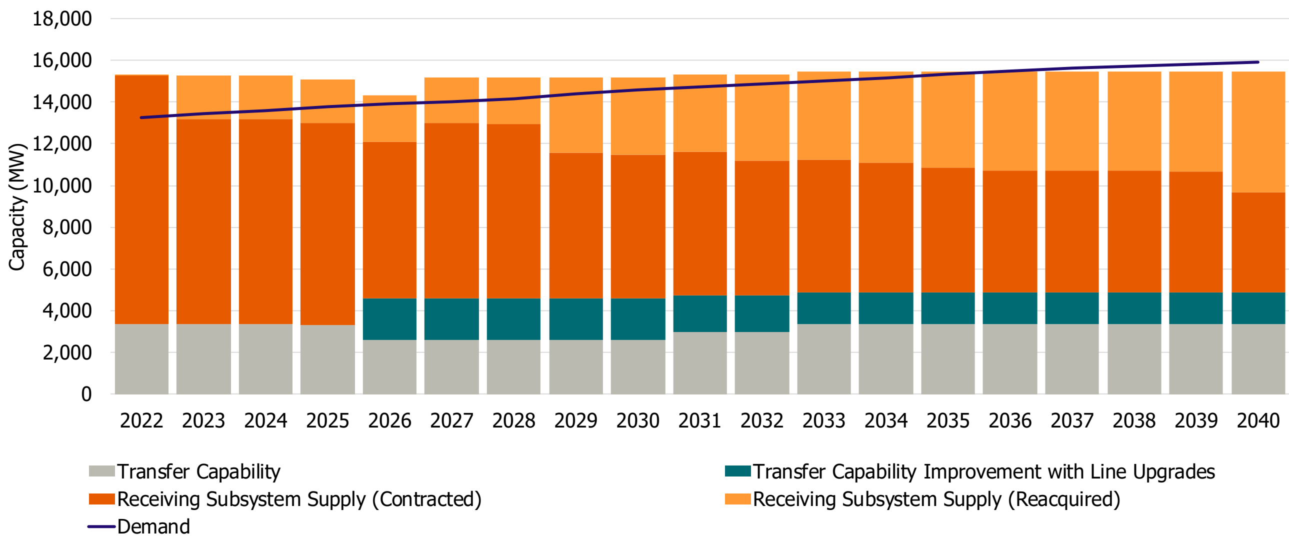
6.2.2.1 Planning for the FETT Transfer Capability Need

The FETT interface is located at the boundary between the Southwest and Toronto and Essa Zones. As described in Chapter 5, a significant amount of capacity must be sited east of the interface over the outlook period due to constraints on the FETT interface. Transmission enhancements that increase the transfer capability along the limiting section of FETT would reduce the amount of capacity that must be sited in that part of the province.

FETT transfer capacity can be increased by approximately 2,000 MW through an upgrade to a section of the Trafalgar TS x Richview TS 230-kV lines at an estimated cost of $50M and with an implementation timeline of four to five years. The IESO has requested that Hydro One carry out development work to confirm project feasibility and provide an updated cost estimate.

The resulting security outlook with this line upgrade is shown in Figure 35.

Figure 35 | FETT Security Outlook following Line Upgrade



The proposed line upgrade is a flexible solution, in that additional transmission upgrades to further increase transfer capability across FETT can be incorporated in a staged manner at a later date. While not currently anticipated in the near to medium term, the need in the second stage may be triggered depending on future resource acquisitions or other bulk and local transmission needs.

6.2.2.2 Planning for the Ottawa Zonal Supply Capacity Need

The need to address the Ottawa zonal supply capacity is currently being reviewed as part of the Gatineau Corridor End-of-Life Study. The major transmission corridor in eastern Ontario, the Gatineau Corridor consists of five transmission lines that total approximately 1,300 km, and run roughly between Pickering and Ottawa. Large portions of the corridor (many over 80 years old) will reach their end of life in the late 2020s, and refurbishment or decommissioning options will impact the FIO transfer capability, which is critical to the supply of the Ottawa Zone.

Without these circuits, the reliability of bulk and regional supply, generation incorporation, and imports from Quebec would be greatly impacted. However, even with the refurbishment of these circuits, the transmission system in eastern Ontario requires reinforcement to meet new needs, including the security of the bulk supply to the Ottawa region (FIO) in the medium term, a near-term requirement to improve supply to the Peterborough area and the ability to meet growing load demand in west Ottawa.

Since the need to refurbish the existing transmission facilities arises in the late 2020s, an integrated plan to address end-of-life and reliability needs is required in the near term (as any new transmission facilities recommended as part of the plan could require five to seven years of lead time).

The final recommendations for the Gatineau Corridor End-of-Life Bulk Study are expected to be complete by Q2 2021.

6.2.2.3 Planning for the West Zonal Supply Capacity Need

The BLIP interface is located between the boundaries of the Southwest and West Zones. As described in Chapter 5, capacity needs to be sited in the West Zone by 2029.

Further, there is a local need, not discussed in this report, to site capacity west of Chatham (a sub-region of the West Zone) to address limitations of interfaces within the West Zone. While the BLIP interface limits supply to the West Zone, interfaces within the West Zone further limit supply to pockets of load behind the BLIP interface. This need for local supply west of Chatham was not discussed earlier in this report, but is relevant because simultaneously considering both the local supply need west of Chatham and zonal supply need in the larger West Zone may lead to a lower-cost solution.

As such, the ongoing West of London Bulk Study that is underway to address the local supply need west of Chatham will also consider the need and options to increase BLIP transfer capability. In addition, the bulk study will:

- Ensure the bulk transfer capability to supply significant greenhouse growth forecast in the Kingsville-Leamington and Dresden areas in the near to mid term (2020-2035)
- Enable existing resources to operate efficiently for local supply and system adequacy to the rest of Ontario
- Maintain existing interchange capability on the entire Ontario-Michigan interconnection in Windsor and Lambton-Sarnia
- Address operability concerns related to the increasing complexity of the interim measures required to connect more loads in advance of transmission reinforcement

In fall 2020, a set of short-listed transmission, generation and storage options were developed, focusing on the first two near-term needs specified above. More information on the project can be found on the Southwest Ontario Bulk Planning web page. Information on engagement sessions (both those held to date and planned), can be found on the Windsor-Essex Regional Planning web page.

The final recommendations for the West of London Bulk Study are expected to be complete by the end of Q1 2021.

6.2.3 Imports and Interconnections

Electricity imports, either firm or non-firm, can help meet the need for capacity.

Firm imports are the result of a contractual agreement guaranteeing a reliable amount of imports when needed. The IESO currently has a firm import agreement with Quebec, with 500 MW of summer capacity to be delivered when requested before 2030. Non-firm imports are assumed capacity contributions from expected flow through the interties during peak periods that are not backed up with firm capacity contracts.

Enabling capacity imports from neighbouring jurisdictions will provide access to non-domestic resources that would reduce the need for additional capacity in Ontario. Firm imports can take three forms: system-backed, where the capacity is ensured by an entire power system (e.g., a province or state); portfolio-backed, where the capacity is ensured by a collection of resources; and resource-backed, where the capacity is being provided by a specific resource in another jurisdiction. The IESO is enabling firm imports for system-backed resources through its capacity auction and is investigating options for resource-backed imports.

Non-firm imports are currently not considered in the capacity assessment. As part of its Reliability Standards Review, the IESO is proposing a methodology for including some amount of non-firm imports in future resource adequacy assessments. The inclusion of non-firm imports is expected to reduce overall resource requirements.

In Ontario, the failure of the phase angle regulator (PAR) – a specialized transformer that alters power angle to control the flow of power – connected to the Ontario-New York 230-kV circuit L33P in early 2018 continues to hinder the province's ability to import electricity from New York through the New York-St. Lawrence interconnection and from Quebec through the Beauharnois interconnection. This has required enhanced coordination with affected parties and more focused management of St. Lawrence-area resources in real-time. Careful coordination of transmission and generation outages will continue to be required in the area.

PARs are unique pieces of equipment and replacements are not readily available. Replacement options for the unit are being investigated by the IESO, in conjunction with Hydro One, the New York Independent System Operator and the New York Power Authority. The replacement will provide greater flexibility to control both current and future intertie flows with New York. The return-to-service date is expected to be between March 2022 and March 2023.

6.2.4 Distributed Energy Resources

Most of Ontario's generation is connected to the high-voltage transmission system, but a growing number of smaller resources are connecting at the distribution level. Distributed energy resources (DERs) can provide an opportunity for the IESO to address future energy and capacity needs if they are effectively integrated into the IESO-administered markets (IAMs). Over 34,000 DERs are currently under contract with the IESO, the majority of which are small-scale solar projects, contracted through the microFIT program.[26] With the potential for further deployment of these resources in the province, DERs can be harnessed to reduce system costs, improve reliability, and enhance resilience.

The IESO is examining potential models to expand DER participation in the IAMs and identifying challenges and next steps through two white papers – one that looks at conceptual models for DER participation and the other that assesses the merits of various options to enhance participation in Ontario.[27] Following publication of the second paper in November 2020, the IESO will clarify next steps for DER integration, including potential market enhancements and demonstration opportunities, through the development of a DER roadmap/vision.

As outlined in integrated regional resource plans, communities and customers have been exploring opportunities to meet their own regional electricity system needs with DERs and community-based solutions. The IESO, with support from NRCan and Alectra Utilities, is undertaking a demonstration project in York Region to explore market-based approaches to secure energy and capacity services from DERs for local needs, while coordinating across the electricity system. This will allow the IESO to better understand the potential of using DERs in place of traditional infrastructure by enabling them to operate in real-world applications. The IESO is also exploring how DERs can contribute to meeting local and system needs in areas with rapidly growing greenhouse load through projects supported by the Grid Innovation Fund.

6.2.5 Storage

In September 2020, the IESO marked the conclusion of its Storage Design Project (SDP) with the publication of the long-term design vision for energy storage. Interim Market Rule amendments, set to take effect in Q1 2021, will clarify the opportunities for storage in today's IAMs. The IESO is also committed to updating the interim Market Rules and Market Manuals for storage in advance of the Market Renewal Program go-live date to ensure the progress made through the SDP endures. The IESO is reviewing the potential for further storage enhancements alongside other market development opportunities as part of its business planning process.

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[26] The microFIT program consists of over 31,000 contracts and represents about 260 MW.

[27] These papers are part of the IESO's Innovation and Sector Evolution White Paper Series, included in the Innovation Roadmap work plan, released in 2019. The IESO's white paper series aims to deepen the understanding of emerging economic, technical, environmental and social issues that could transform the future of the electricity markets in Ontario.

6.2.6 Energy Efficiency

Additional energy-efficiency programs, beyond those described in Section 1.3.8, can help meet future capacity needs by reducing electricity demand. The 2019 Conservation Achievable Potential Study (APS) identified cost-effective electricity savings attainable through energy-efficiency programs between 2019 and 2038. The APS identified potential peak demand[28] savings of 2,000 to 3,000 MW in 2038[29] and energy savings of 18 to 24 TWh in 2038, two to three times more than the savings included in the APO demand forecasts. The opportunity for increased energy-efficiency savings will be considered as part of the mid-term review of the 2021-2024 CDM Framework and through the development of future CDM Frameworks.

6.3 Bulk Planning Process Development

During a review of system planning activities, the IESO recognized a need to increase transparency and predictability in the development of power system plans. In response, the IESO is undertaking an initiative to formalize the bulk system planning process to move to a more consistent approach to identifying and addressing needs.

This renewed process will enable more consistent forecasting and reporting on system conditions to identify bulk power system needs, provide transparent signals to the market, and enable sector participants to plan ahead, prepare for, and participate in solutions. The bulk system planning process will help ensure solutions are identified transparently as needs materialize, opportunities for integrated solutions are pursued, and analyses are carried out as efficiently as possible.

A stakeholder engagement meeting was held in November 2020 to provide information on the status of the Bulk System Planning Process review. More information on the initiative can be found on the Bulk System Planning Process webpage.

[28] Peak demand potential in the APS study is defined as the average demand reduction during the period from 1 p.m. through 7 p.m. on non-holiday weekdays in June, July and August as per the IESO Evaluation, Measurement and Verification Protocols.

[29] The potential for savings is based on the cumulative adoption of measures over time (e.g., savings in 2038 represent the potential savings in 2038 of measures adopted in 2019 through 2038).

7. Outcomes and Other Considerations

Both the marginal cost of electricity production and electricity sector emissions are forecast to increase over the outlook period, as a result of growing demand, nuclear refurbishments and retirements, and the resulting increase in the use of Ontario's gas-fired generation fleet. In spite of increasing sector emissions, electricity remains a source of low-carbon energy in Ontario, and increased electrification of emissions-intensive sectors provides an opportunity to reduce province-wide emissions.

The results presented in this chapter are outcomes of the energy production outlook described in Section 3.4 and are based on the supply mix discussed in Chapter 2, which reflects the continued availability of existing resources following the end of their contract term or commitment. Should the supply mix change over the outlook period, the outcomes described below would also change.

7.1 Marginal Resources and Their Importance

Long-term power system plans use an economic dispatch model that schedules resources to meet system needs based on least cost. This considers each resource's production or variable costs, which typically include fuel costs and variable operating and maintenance costs. The most expensive resource scheduled is the marginal resource. This is important because costs associated with the marginal resource provide an indication of market price. This model is not meant to forecast prices but, given future conditions, the marginal resources scheduled indicate trends in energy production from different resources.

Supply resources are categorized as baseload (operating essentially constantly, e.g., nuclear), dispatchable (operating as needed, e.g., gas), or intermittent (operating when fuel is available, e.g., wind or solar). The variable cost required to produce a unit of energy is referred to as the production cost and typically consists of fuel costs, carbon costs, and variable operating and maintenance costs. Usually, baseload and intermittent resources have lower marginal energy costs than dispatchable resources.

The IESO strives to ensure Ontario's energy needs are met at the lowest cost. Resources are generally dispatched from lowest-production-cost baseload to higher-production-cost dispatchable resources that can adjust their output according to fluctuations in demand or supply of baseload and intermittent electricity.[30]

Marginal resources provide the next unit of energy needed on the system. For example, during the peak demand hours of hot summer days, the marginal resource is usually a natural gas-fired generator; overnight during autumn, gas-fired generation is less likely to be the marginal resource.

[30] Factors such as congestion or security constraints can lead to scenarios where this generalization does not hold.

7.2 Marginal Costs

The data underpinning this outlook are based on an economic dispatch model that simulates each hour of the outlook period. This model dispatches units in order of their production costs and identifies the marginal resource in each hour. The marginal cost in each hour is the production cost of the marginal resource.

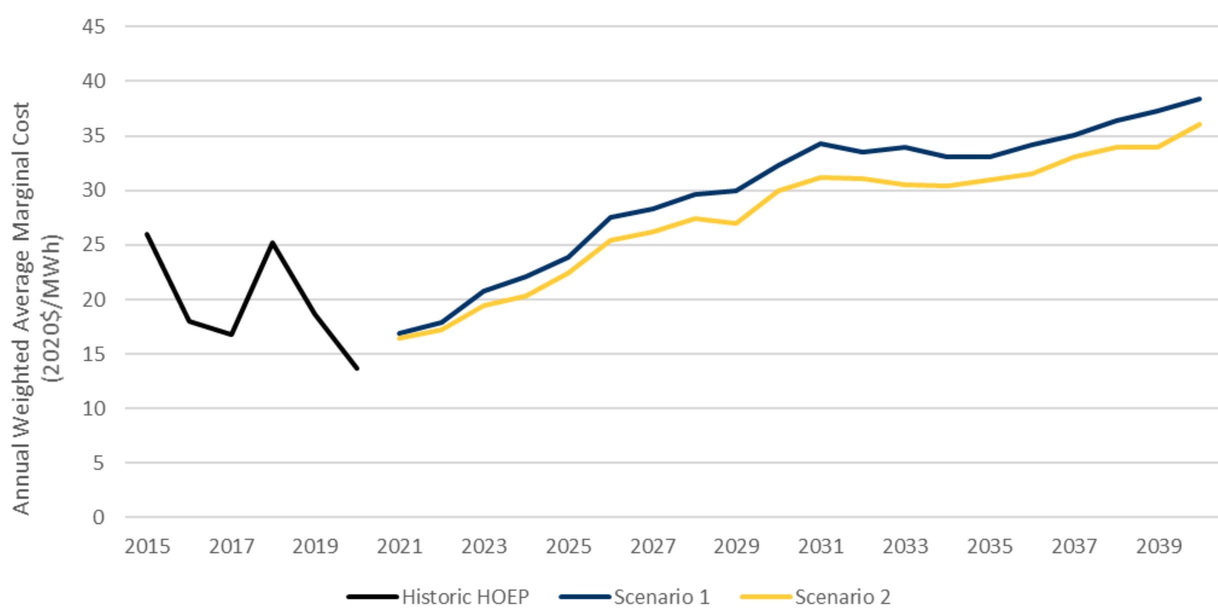
Marginal costs are not intended to be a forecast of market prices, such as the Hourly Ontario Energy Price or locational marginal prices, but can provide a directional indicator of where these prices may head over the outlook. Market prices are the wholesale prices for electricity and can differ widely due to market participant behaviour, congestion and other factors.

Marginal costs provide the trajectory of market prices. When a fundamental change to the supply mix occurs – such as the retirement or refurbishment of nuclear units – marginal costs illustrate the expected impact on the factors underpinning market prices as other higher-marginal-cost resources would need to be dispatched to meet load requirements. They provide an indication of the change in production costs due to variations in both supply and demand.

With the refurbishment of nuclear units and demand increases in the long term, marginal costs are expected to increase as gas-fired generation becomes the marginal resource more often.

Figure 36 illustrates the weighted average marginal costs forecast and the historical HOEP. The average marginal costs can also be found in the data tables.

Figure 36 | Weighted Average Marginal Costs Forecast, and Historical HOEP[31]



[31] 2020 Actual HOEP is year-to-date as of November 26, 2020

7.3 Carbon Pricing

Currently, the electricity sectors in Ontario and in neighbouring jurisdictions are subject to carbon pricing. This section details the carbon pricing policies currently in effect within the northeastern portion of the Eastern Interconnection, and how carbon pricing was modelled for this outlook.

Ontario imports from and exports to its five neighbours every day of the year. To forecast the impact of imports and exports, the IESO models the demand and supply in neighbouring jurisdictions and develops regional commodity and carbon price forecasts for fuels used to produce electricity.

The carbon pricing assumptions used in this outlook are based on the federal carbon pricing backstop, which was effective in Ontario as of January 1, 2019. The Ontario government recently announced a transition to a made-in-Ontario Emissions Performance Standards (EPS) program as an alternative to the federal output-based pricing system (OBPS); future editions of this report will reflect this change in carbon pricing policy.

The federal backstop has two components: the carbon levy applied to fossil fuels (effective April 1, 2019) and the OBPS for industrial facilities (effective January 1, 2019).

The OBPS applies a regulatory charge above an industry-specific benchmark emission rate for emission-intensive, trade-exposed (EITE) industry. The federal government considers the electricity sector as EITE and, as such, applies a benchmark emission rate to the sector for large emitters (those exceeding the threshold, with voluntary opt-in).

Having a benchmark applied to the electricity sector means there will be no charge associated with emissions up to a specific rate based on fuel type (e.g., 370 t CO_2e/GWh for natural gas). As such, the carbon pricing applied with the OBPS acts as a pro-rated carbon price. As different gas-fired generation facilities have different emission rates, each facility will be charged an amount based on its emissions and electricity production, leading to facility-specific carbon pricing. In order to more accurately forecast the impact of carbon prices on trade, the IESO has modelled the carbon pricing policies applied in neighbouring jurisdictions where there is a material impact on electricity sector emissions.[32] These include Nova Scotia,[33] New Brunswick,[34] and parts of the United States through the Regional Greenhouse Gas Initiative.[35]

7.4 Greenhouse Gas Emissions

Electricity sector emissions are forecast to increase to 12.2 megatonnes CO_2e by 2030 in Scenario 1 and 10.9 MT CO2e in Scenario 2, still well below 2005 levels, as shown in Figure 37. This expected increase is due to reduced nuclear production and growing demand, resulting in increased production from gas-fired generation.

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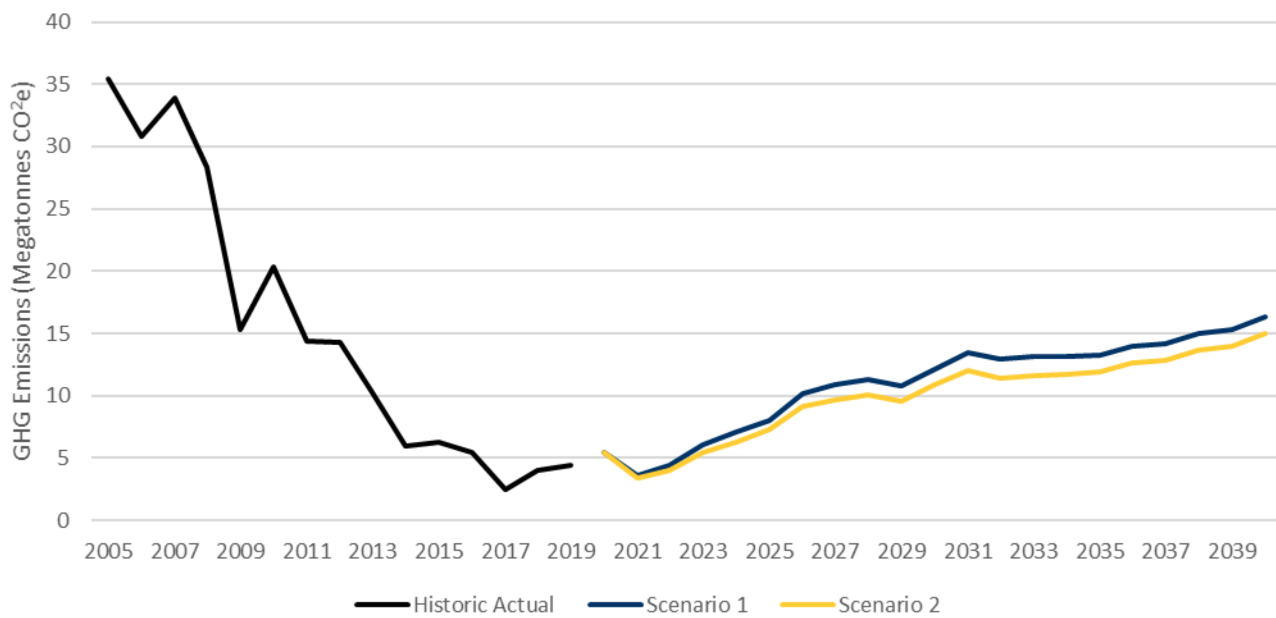
[32] Although carbon pricing is in effect in Manitoba and Quebec, these jurisdictions are considered essentially non-emitting.

[33] Nova Scotia's cap-and-trade program took effect January 1, 2019. More information is available at Nova Scotia's Cap-and-Trade Program.

[34] The federal output-based pricing system was in effect in New Brunswick as of January 1, 2019. For more information, see the Regulations Amending Part 1 of Schedule and Schedule 2 to the Greenhouse Gas Pollution Pricing Act.

[35] For more information, see the Regional Greenhouse Gas Initiative, currently in effect in 10 northeastern states.

Figure 37 | Electricity Sector Greenhouse Gas Emissions, Historical and Forecast[36]



An increase in electricity sector emissions does not necessarily mean an increase in economy-wide emissions. The carbon intensity of electricity remains far below that of other fuels, such as gasoline for automotive transportation or fuel oil for space heating. Switching from higher-emission fuels to low-carbon electricity could increase electricity sector emissions, while reducing province-wide emissions. As electricity consumption increases, the attendant rise in electricity sector emissions could be reduced by increased energy efficiency, or the entry of non-emitting resources (if successful) to the Ontario market.

7.5 Avoided Costs

The IESO's avoided-cost analysis considers the avoided energy and capacity costs from a reduction in demand. These avoided costs are considered benefits, and can be compared to the cost of other measures that would reduce demand. Any measures that are implemented should be cost-effective and lead to lower overall customer costs.

Marginal costs are used to estimate the avoided costs associated with changes in electricity consumption. To understand the impact of avoided generation, the hourly profile of the measures being considered is compared to the hourly profile of marginal costs.

In the near term, Ontario will have an abundance of resources with low production costs, meaning few system costs can be avoided.

In the medium and long terms, however, increased system costs can be avoided due to increased demand, decreased nuclear generation, and increased gas-fired generation.

[36] Emissions data is not available for 2020; values for 2020 are from the 2019 APO, Energy Efficiency case forecast.

The avoided energy costs change as demand and supply changes. Energy data are provided to show the changes during the day, during the seasons, and from year to year over the outlook period.

The avoided capacity costs reflect the cost of capacity in years where there is a capacity deficit, plus the avoided cost of additional resources to meet reserve margin requirements.

The avoided cost data can be found in the data tables.

7.6 Avoided Emissions

Similar to the avoided costs, the avoided emission factors consider the avoided emissions associated with a reduction in demand for electricity.

In order to estimate the avoided greenhouse gas emissions associated with lower consumption levels, the IESO considers emissions reflective of the marginal resource. Based on the hour and year being considered, a different mix of generators with different emission rates will represent the incremental increase or decrease in generation.

Similar to the avoided costs, there are fewer emissions to be avoided in the near term, when more non-emitting resources will be operating, and greater opportunities for emission reductions in the medium and long terms due to increased demand, decreased nuclear generation and increased gas-fired generation.

8. Conclusion

In 2020, with the outbreak of COVID-19, Ontario is experiencing major shifts in electricity demand. Resulting changes to the energy landscape have reinforced the importance of a reliable electricity system, and added further complexity and uncertainty to forecasting efforts, requiring the IESO to rethink existing assumptions.

To help account for the range of possibilities, the IESO forecast demand using two different scenarios based on the pace of economic recovery. The first, a faster-recovery version, assumes electricity demand will reach pre-pandemic levels by 2022, and steadily grow faster than previous forecasts; the second assumes a more protracted economic downturn, with demand not expected to recover until the end of 2024. In both scenarios, demand will be lower in the near term.

After a decade in which the composition of demand by sector remained relatively unchanged, COVID-19 shifted consumption patterns – particularly in the hard-hit commercial sector – but so too did other factors, including the shift to a digital economy. Work-from-home arrangements, and business closures reduced economic activity and resulted in fundamental shifts in demand in the near term. Demand drivers are expected to continue to evolve over the longer term as future consumption patterns – reflected in more rapid growth in agriculture, the residential household sector and electric vehicle adoption – contribute to a rebound in demand that will eventually outpace 2019 levels.

The supply mix over the course of the outlook remains fairly stable, with nuclear refurbishments continuing throughout the 2020s and early 2030s. Summer capacity needs continue to emerge through 2022 and long-term needs continue to be driven by Pickering NGS retirement. Ontario is expected to have adequate energy, provided existing resources continue to be available post-contract and production from gas-fired generators increases to meet growing demand. Supply needs for the next decade are principally for managing risks to grid reliability.

Given the existing transmission infrastructure, location-specific capacity needs emerge in the mid-2020s, mainly in the GTA and in eastern Ontario. Generation facilities reaching end of contract in the West Zone result in a locational capacity need in the mid to long term. Load growth in the Ottawa area will contribute to a marginal capacity need over the medium term. Work to resolve transmission constraints along three major interfaces – the Flow East Towards Toronto, the Flow into Ottawa, and the Buchanan Longwood Input – will address the need for additional or reinforced capacity to supply these zones.

Depending on how future capacity requirements are met, forecasts continue to show that surplus baseload generation (SBG) will decline as a result of rising demand and the retirement of Pickering Nuclear Generating Station. As SBG declines, energy exports will decrease sharply – and imports will increase until the conclusion of refurbishments in the early 2030s.

Ontario can meet its needs through continued use of existing resources, the expansion of transmission, imports, the growing use of distributed energy resources (DERs), storage, and incremental energy-efficiency savings. Efforts to enable new entrants to compete on a level playing field with existing generation, and to pilot or support projects to meet changing needs are underway, and can all play a role in meeting future needs.

In December 2020, with the launch of its first capacity auction, the IESO marked a milestone in its efforts to create a more competitive marketplace, by enabling resources to compete to meet fluctuating demand in the short term. Today, as part of its focus on better balancing supplier and ratepayer risk, and meeting resource adequacy needs in all time frames, the IESO is working with stakeholders to enable other competitive mechanisms.

That said, the transition to a more competitive environment will not happen overnight, and will require interim measures to maintain reliability until a resource adequacy framework is fully implemented. The IESO will be negotiating an extension of the Lennox generating station contract as a transition measure until there is sufficient competition in the area.

The electricity sector – and what it will look like in the future – is always transforming, whether in response to a pandemic, the enablement of new resources, such as energy storage, shifts in public policy, or efforts to create a more competitive and efficient marketplace. Grounded in the IESO's expert planning and stakeholder input, the Annual Planning Outlook provides a regular and predictable source of data and insights and sheds light on the issues – current and emerging – that present challenges and opportunities to system reliability and efficiency.

Whether revisiting reliability requirements to enable non-firm imports to meet capacity needs, or exploring the role of DERs in addressing local needs, the IESO will use the findings and outcomes outlined in this – and future editions of the Outlook – to meet its reliability requirements, and help build a more cost-effective and reliable energy future for all Ontarians.

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