ONTARIO ENERGY BOARD

## Market Surveillance Panel

# State of the Market Report 2024

**For the period of January 2024 to April 2025**

**March 2026**

Ontario

Ontario Energy Board

# TABLE OF CONTENTS

# List of Figures

# List of Tables

# List of Abbreviations

| | |
|---|---|
| CMSC | Congestion Management Settlement Credit |
| DA-PCG | Day-Ahead Production Cost Guarantee |
| FIT | Feed-In-Tariff |
| GA | Global Adjustment |
| HDR | Hourly Demand Response |
| HHI | Herfindahl-Hirschman Index |
| HIM | Hydro Incentive Mechanism |
| HOEP | Hourly Ontario Energy Price |
| IAMs | IESO-Administered Markets |
| IESO | Independent Electricity System Operator |
| IOG | Intertie Offer Guarantee |
| IZP | Intertie Zonal Price |
| LMP | Locational Marginal Pricing |
| MCP | Market Clearing Price |
| MRP | Market Renewal Program |
| MSP | Market Surveillance Panel |
| NERC | North American Electric Reliability Corporation |
| OEB | Ontario Energy Board |
| OER | Ontario Electricity Rebate |
| OPG | Ontario Power Generation Inc. |
| OR | Operating Reserve |
| PD | Pre-Dispatch |
| RSI | Residual Supplier Index |
| RT-GCG | Real-Time Generation Cost Guarantee |

# 1 EXECUTIVE SUMMARY

The Market Surveillance Panel (MSP) serves as the market monitor for the Ontario wholesale electricity markets, which are administered by the Independent Electricity System Operator (IESO). Mandated to monitor, investigate, review and report on the wholesale electricity markets, with a focus on their efficiency and competitiveness, the MSP is an integral part of the oversight framework. The MSP provides independent evaluation and analysis of the wholesale electricity markets – which includes authoring public reports and making recommendations to other oversight authorities in alignment with its mandate. Appendix A provides a more detailed description of the MSP's role. The work of the MSP is supported by the Market Assessment Unit within the IESO, in accordance with a Protocol between the IESO and the Ontario Energy Board (OEB).[1]

**This is the final *State of the Market* report for the legacy wholesale markets.** It covers the period from January 1, 2024, to April 30, 2025, and is intended to close off the MSP's reporting on the legacy markets up to the date on which the renewed markets were launched by the IESO. As a result of the significant changes to the design of the IESO-administered markets (IAMs) that took effect on May 1, 2025, with the deployment of the Market Renewal Program (MRP), some of the metrics and data series contained in this final *State of the Market* report will necessarily have to change in future editions. However, other indicators of efficiency and competition are of a fundamental nature and will continue to provide important insights for future reporting periods. Further details regarding this may be found in ***The Market Surveillance Panel in the Renewed IESO-Administered Markets*** report released August 27, 2025.

The MSP intends for the next edition of the *State of the Market* report to commence reporting on the renewed electricity markets, for a period spanning May 1, 2025, to the end of 2025 and then resume a calendar year reporting cycle thereafter.

**Consumer Electricity Cost:**

- For this reporting period, the MSP continues its assessment of all-in consumer costs, both in aggregate and in terms of unitized costs expressed in dollars per megawatt hour.
- Calendar year 2024 showed that consumer costs rose to $24.15 billion, a 3.1% increase from the previous calendar year. This change included a decline in wholesale market electricity-related costs offset by an increase in the Global Adjustment (GA) which, among other things, recovers costs for Ontario's contracted supply portfolio. In 2024, government spending on electricity cost mitigation rose to $6.8 billion from $5.8 billion in 2023.

**New approach for this *State of the Market* report*:***

- In this report, the MSP has taken a new approach to examine supply and demand factors and isolate their price impact effects.
- The approach is intended to isolate fundamental supply and demand factors that prevailed prior to the deployment of the renewed electricity markets. The data series used are relatively independent of the design of the electricity market itself and provide potential comparators for performance of the renewed markets.
- This new approach includes an examination of:
  - relative, year-over-year output performance for various segments of the generation fleet; and
  - natural gas price changes relative to demand and average price outcomes.

**Specific highlights from the January 2024 – April 2025 reporting period:**

- There is a marked departure in price outcomes over the reporting period up to the end of calendar year 2024 versus the first four months of 2025. The final months of uniform pricing in Ontario saw some of the highest energy prices since market opening.
- Operating reserve costs in 2024 fell to $42 million from $47 million in 2023. This is the second lowest annual operating reserve costs observed since 2019.
- The MSP notes the continuation of the relative economic inefficiency between Ontario's import and export trade. The observations in this report highlight the impact of systemic differences between the hour ahead pre-dispatch price, which facilitates intertie scheduling, and real-time prices in the legacy markets. In addition, the MSP continued to observe contributions to this inefficiency through the Intertie Offer Guarantee (IOG) program. In the *State of the Market Report 2023*, the MSP recommended that the IESO conduct a review of IOG payments following the launch of the renewed markets. In this report, the MSP provides new insights into the frequency of IOG payments relative to the supply conditions prevailing in the hours in which those payments are made.
- In this report, the MSP continues its practice of cataloguing a normalized data series of the cost of capacity procurement across the IESO's long-term, medium-term and short-term capacity procurements.

# 2 CONSUMER ELECTRICITY COST

This *State of the Market* report covers the period spanning January 1, 2024, to April 30, 2025. Annual data shown in this section reflects the calendar year 2024, but a monthly breakdown in Appendix B extends to April 2025.

The total cost of serving Ontario electricity consumers in 2024 was $24.15 billion, a 3.1% increase from the previous calendar year. The average cost (the total cost per MWh of Ontario demand) of serving Ontario consumers in 2024 was $160.6/MWh, a 0.4% decrease from the previous year.

Average consumer cost is equal to total consumer cost divided by Ontario demand. When the growth of Ontario demand out paces the growth in total consumer cost on a percentage basis, average consumer cost will increase slower than total consumer cost and perhaps decline as more of the system fixed costs are recovered over a larger base of Ontario consumers.

Figure 1 and Figure 2 present the annual total consumer cost and average consumer cost (referred to as all-in costs and all-in unit costs, respectively, in previous *State of the Market* reports) for the period 2015 to 2024.[2] Over the last 10 years, total consumer cost increased by 31.8%. However, after adjusting for inflation, total consumer cost increased by 3.7%. For the same period, the average consumer cost increased by 25.5% but declined by 1.2% after adjusting for inflation.

[2] Monthly breakdowns of total and average consumer cost, including January to April 2025, are provided in Appendix B.

Figure 1 – Total Annual Consumer Cost (All-In Costs), 2015-2024

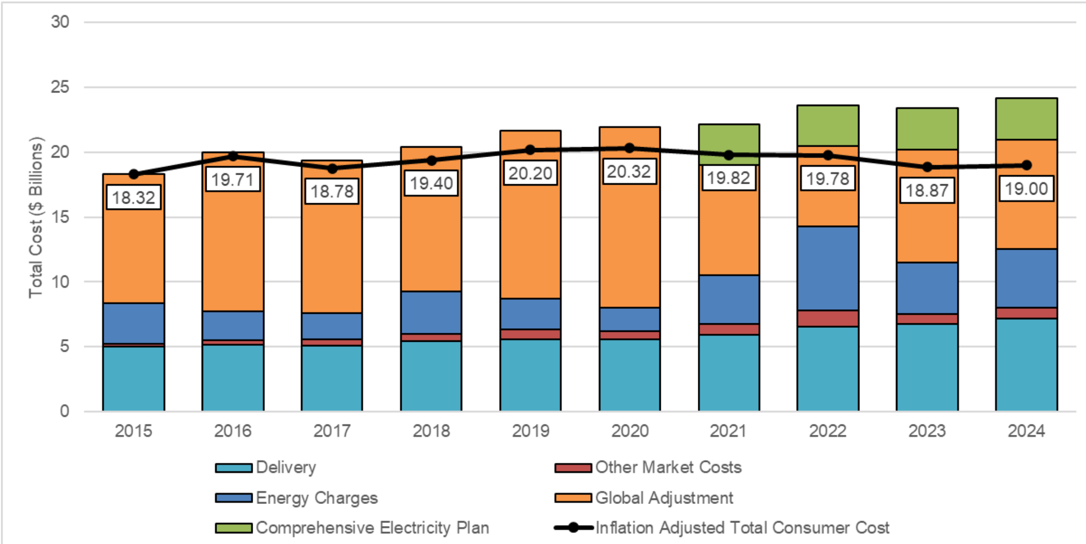



Figure 2 – Average Consumer Cost (All-in Unit Costs), 2015-2024

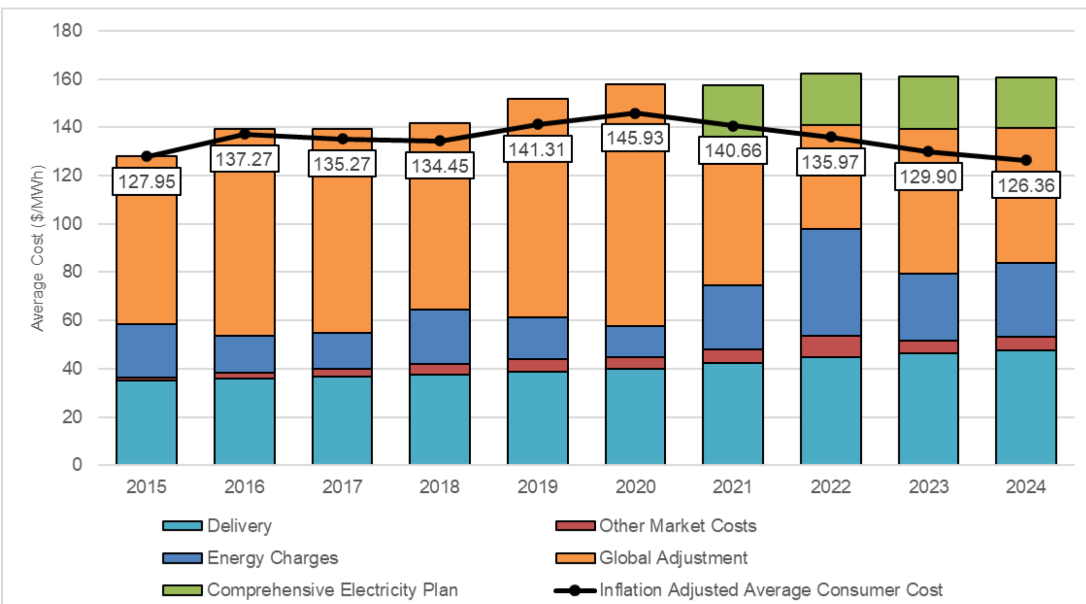


Table 1 provides a breakdown of the total and average consumer cost by component for 2023 and 2024.[3]

Table 1 – Total and Average Consumer Cost by Component, 2023 and 2024

| | Total Consumer Cost ($ million) | | Average Consumer Cost ($ per MWh)[4] | |
|---|---|---|---|---|
| | **2023** | **2024** | **2023** | **2024** |
| Energy Charges | 3,989 | 4,581 | 27.47 | 30.47 |
| GA | 8,713 | 8,419 | 60.00 | 55.99 |
| Comprehensive Electricity Plan | 3,190 | 3,155 | 21.96 | 20.98 |
| Other Market Costs | 765 | 809 | 5.27 | 5.38 |
| Delivery | 6,748 | 7,182 | 46.46 | 47.76 |
| Total Before Government Programs | **23,406** | **24,146** | **161.16** | **160.58** |
| Government Programs | - 5,793 | - 6,807 | - 39.89 | - 45.27 |
| Total Net of Government Programs | **17,613** | **17,339** | **121.27** | **115.31** |

***Note:*** *The 2023 values in this table slightly differ with the one reported in the State of the Market Report 2023 due to the following: (1) settlement adjustments that take place after the data has been first extracted, (2) estimation of the distribution cost component of Delivery Cost which data only became available late 2024.*

### *Energy Charges*

The total energy charge is equal to the annual sum of the product of the Hourly Ontario Energy Price (HOEP) and hourly Ontario demand. The average energy charge is equal to the annual sum divided by the annual sum of hourly Ontario demand. The average energy charge is equivalent to the demand-weighted HOEP.

### *GA*

The GA is the mechanism used to: (i) reconcile differences between payments made to generators at the wholesale market price and payments made at regulated rates or under contracts that differ from the wholesale market price; and (ii) fund the province's conservation and demand management programs. In Ontario, most generators are provided with price or revenue guarantees through contracts with the IESO or, in the case of provincially-owned Ontario Power Generation (OPG), through payments regulated by the OEB.[5]

[3] Further breakdown is provided in Table 6 – Detailed Breakdown of Consumer Cost, 2023-2024 of Appendix B.

[4] Ontario gross demand in 2024 was 150.4 TWh, 3.6% higher than the 145.2 TWh in 2023.

[5] Certain generation assets owned and operated by OPG, including the Lennox generating station (gas and oil), the Atikokan generating station (biomass) and a few hydroelectric generating stations (a significant portion of which comes from the Mattagami River cascade) are not rate-regulated by the OEB. Payments related to generation assets owned by Atura, an OPG subsidiary, are not regulated by the OEB.

*The Comprehensive Electricity Plan and Other Government Programs*

About 85% of contractual payments owed in respect of 33,000 non-hydroelectric, renewable energy contracts have been transferred from the GA to the tax base as part of a government program referred to as the Comprehensive Electricity Plan. The Comprehensive Electricity Plan, along with other government programs, is described in more detail in Section 2.4.

*Other Market Costs*

Other market costs include payments to generators and bulk loads (i.e., dispatchable loads and demand response resources) for reliability and ancillary services. They also include payments for congestion management, IESO administration charges, out-of-market commitment programs, including the IOG, Day-Ahead Production Cost Guarantee (DA-PCG) and Real-Time Generation Cost Guarantee (RT-GCG) programs, as well as the debt retirement charge that was phased out by 2018.

*Delivery*

The delivery cost represents the amount paid to transmission and distribution companies to cover the cost to build, maintain and operate the high-voltage (transmission) and low-voltage (distribution) power lines that conduct electricity from generation stations to consumers. The OEB approves the rates that most transmitters and distributors may charge. The delivery component of the total consumer cost grew by 6.3% in 2024, higher than the 10-year average growth rate of 4.1%.

## 2.1 Analysis of Consumer Cost by Components

The following provides an assessment of the key month-by-month market trends influencing the components of the total and average consumer costs between 2023 and 2024 as well as for the first four months of 2025. The assessment focuses on the components that are directly affected by wholesale market outcomes, namely, the energy charge, GA, Comprehensive Electricity Plan and other market cost components.

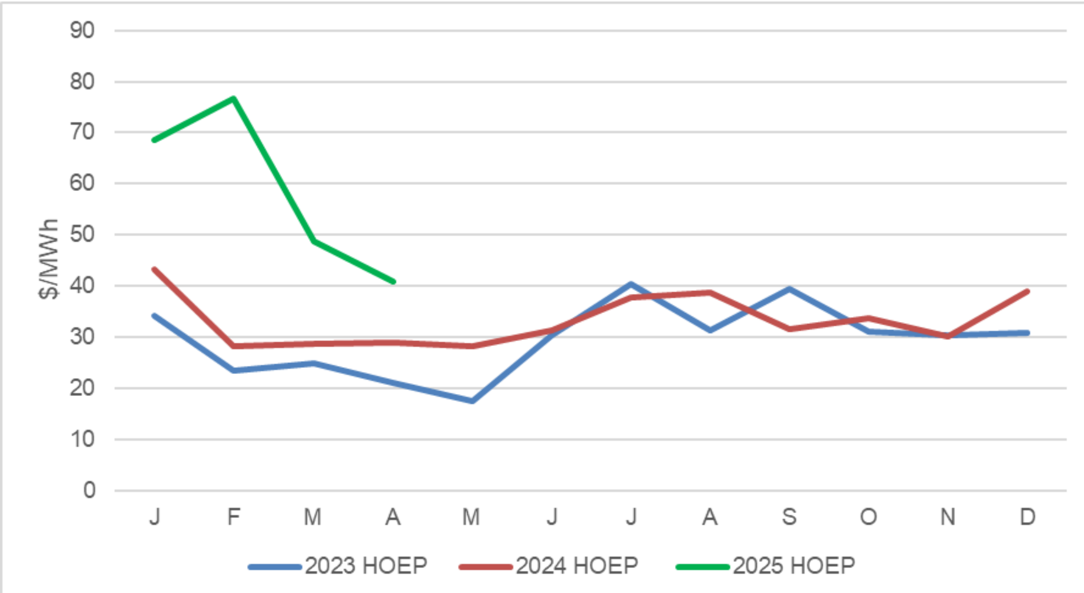
### 2.1.1 Energy Charges

The energy charge represented 17% and 19% of the total and average consumer charge, respectively, before accounting for government programs in 2023 and 2024. The total energy charge increased by 15% from 2023 to 2024. The average energy charge, equivalent to the demand-weighted average HOEP, increased by 11% from 2023 to 2024. Figure 3 provides a comparison of the monthly demand-weighted average HOEP for the monitoring period.[6] The demand-weighted average HOEP was higher in 2024 versus 2023 in all months except July, September and November. Throughout the first four

[6] A graphical comparison of the monthly total energy charge for 2023 and 2024 illustrates a similar pattern as the graphical monthly demand-weighted HOEP comparison.

months of 2025, the demand-weighted HOEP was higher than the corresponding months in 2023 and 2024.

Figure 3 – Monthly Demand-Weighted Average HOEP, January 2023 – April 2025




The energy charge is affected primarily by wholesale market factors. The next three sections examine the various factors affecting the monthly trends in the energy charge as reflected by the demand-weighted average HOEP. The first section focuses on the demand factors, while the second section considers the supply factors. All else held constant, higher levels of electricity demand contribute to higher demand-weighted average HOEPs. In contrast, higher levels of supply contribute to lower demand-weighted HOEPs. The third section provides a side-by-side comparison of both the monthly demand side and supply side factors to discern the net effect of these factors on the monthly demand-weighted average HOEP.

### 2.1.1.1 Demand Factors

Monthly energy demand can be described as the composite of monthly Ontario demand plus the net monthly energy demand from external jurisdictions, measured as net exports (exports less imports). All else held constant, higher monthly demand levels place upward pressure on monthly average market prices (i.e., demand-weighted HOEP). The following first examines the monthly trends in Ontario demand and net export demand separately and then collectively as overall demand.

Figure 4 provides a comparison of average hourly Ontario energy demand, by month for 2023 and 2024 and the first four months of 2025. Monthly average hourly Ontario demands for 2023 and 2024 are relatively similar with higher average hourly demands in most months in 2024 except for February, March, October and November. The first four months of 2025 also saw higher average hourly Ontario demand compared to the same months in 2023 and 2024.

Figure 4 – Average Hourly Ontario Demand, Monthly, January 2023 – April 2025

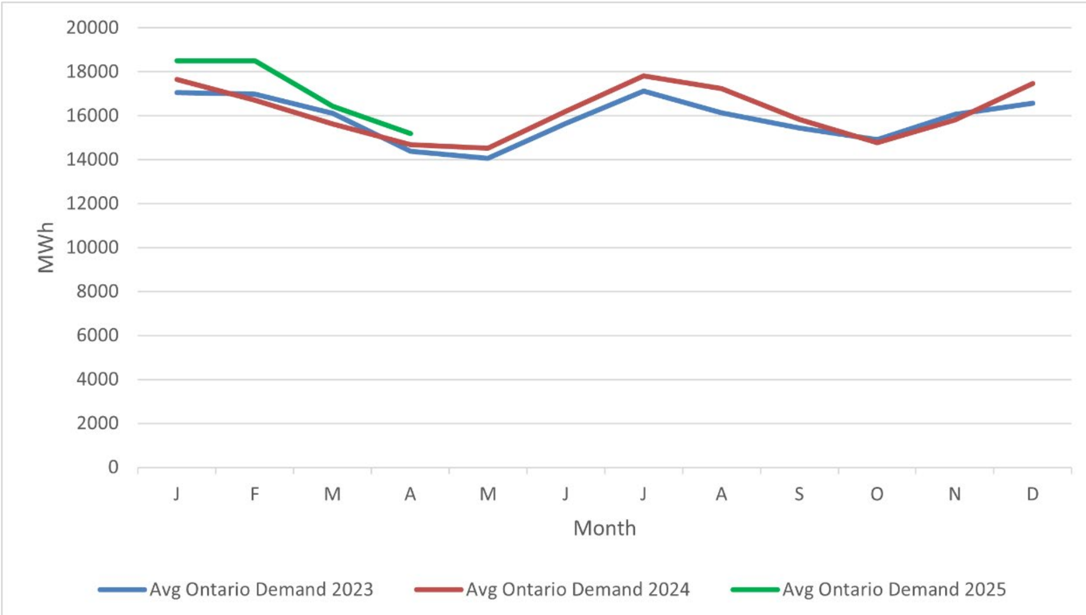
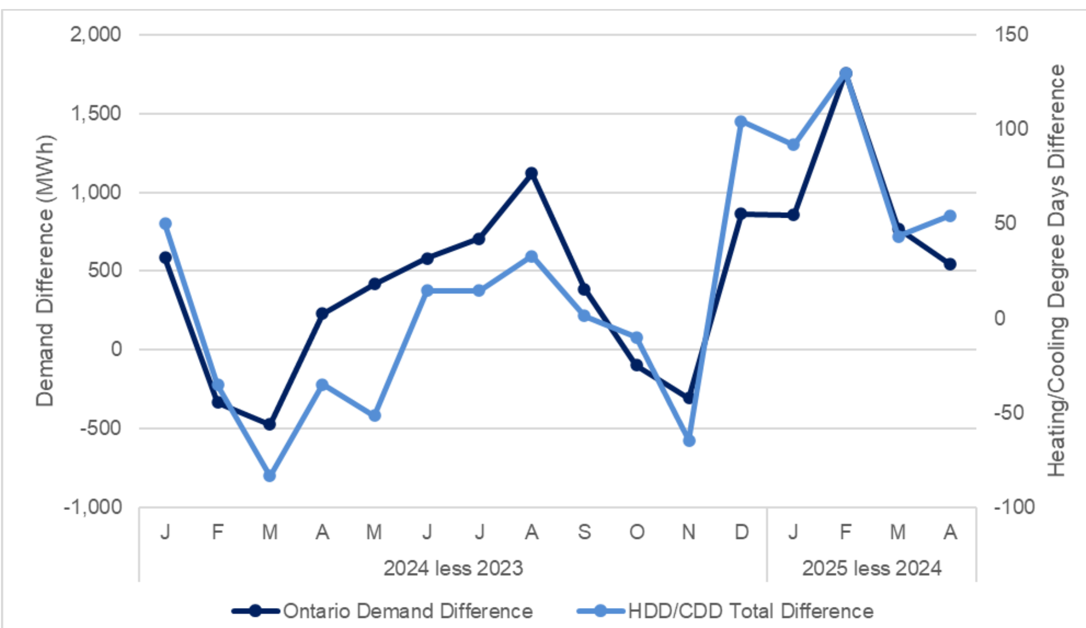



Figure 5 – Heating and Cooling Degree Days, Monthly, January 2023 – April 2025

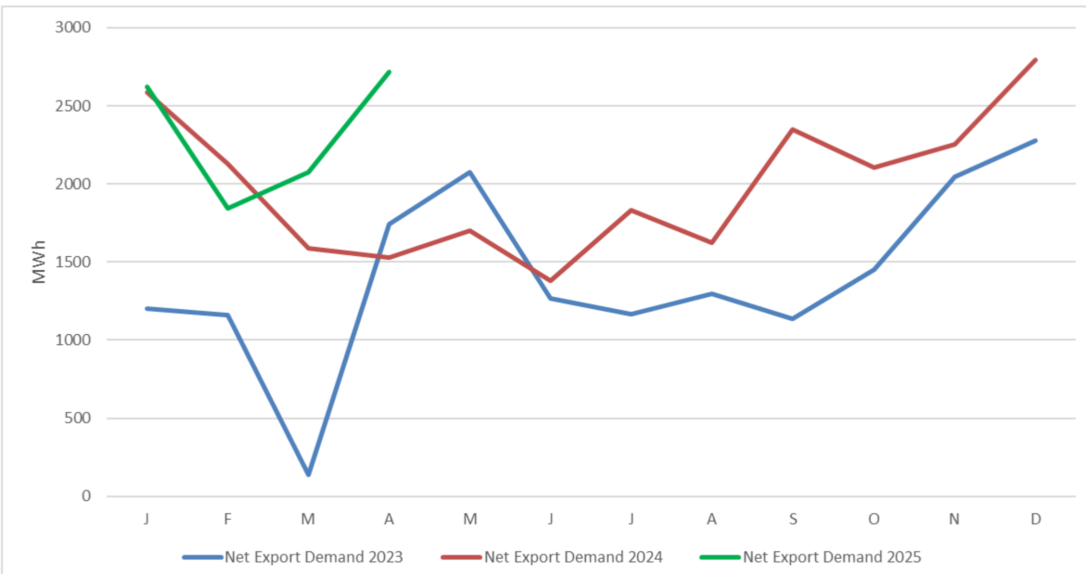



Monthly energy demand is largely driven by weather factors.

Figure *5* presents the number of heating and cooling degree days (HDD & CDD)[7] by month for 2023 and 2024 and the first four months of 2025. There is a positive correlation between the number of HDDs & CDDs and the level of Ontario demand.

Figure 6 provides a comparison of average hourly net export demand, by month for 2023 and 2024 and the first four months of 2025. Ontario was a net exporter of electricity every month throughout that period. Net export demand was higher in 2024 than 2023 in all months other than April and May. It was also higher in 2025 than the corresponding months in 2024 except for the month of February.

Figure 6 – Average Hourly Net Export Demand, Monthly, January 2023 – April 2025




Net export demand is influenced by the prevailing supply and demand conditions in Ontario and in the jurisdictions neighbouring Ontario. On a monthly basis, when Ontario is a net exporter of energy, it generally implies that prices in other jurisdictions are higher than prices in Ontario.

Figure 7 plots the monthly average HOEP against the monthly average real-time clearing prices in neighbouring jurisdictions with competitive wholesale markets.[8] The monthly

---

[7] Heating and Cooling Degree Days are meteorological indexes that measure how much energy is needed to heat or cool a building on a given day. They are calculated by finding the difference between the day's average outdoor temperature (mean of the high and low) and a standard "base" temperature, typically 65°F (18°C). For HDDs, when the average temperature is below the base, the difference is added to the HDD total; for CDDs, when the average temperature is above the base, the difference is added to the CDD total.

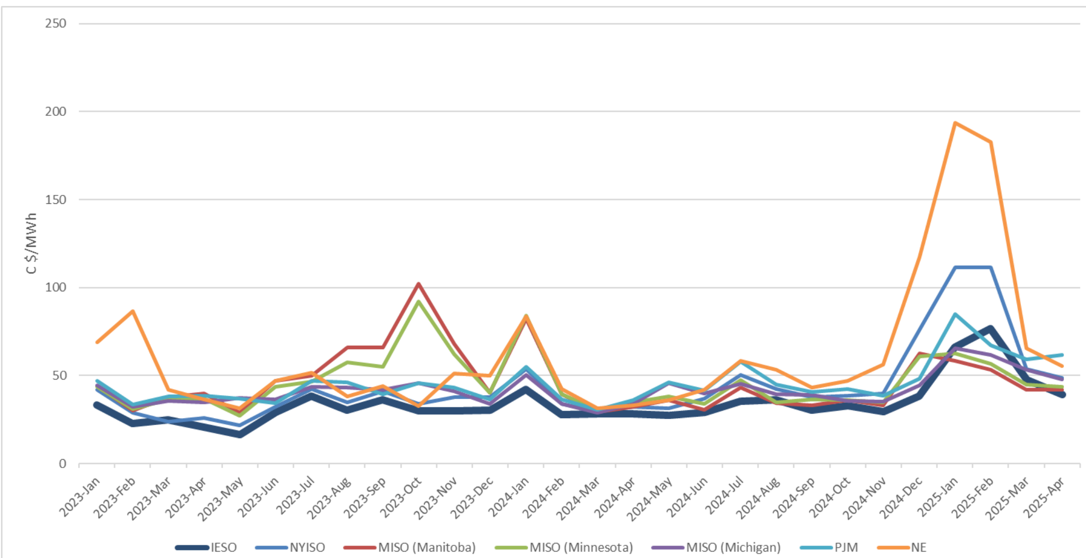
[8] The hubs associated with each jurisdiction are as follows:

1. New York ISO (NYISO)
2. Midcontinent Independent System Operator (MISO) – Michigan

average HOEP was persistently lower than the monthly average hourly price in neighbouring jurisdictions. This is consistent with Ontario being a net exporter on average in each month from January 2023 to April 2025.

Figure 8 presents average hourly total energy demand in Ontario (Ontario demand plus net exports) by month, for the same period. The average hourly total energy demands in 2024 exceed the average hourly total energy demands of 2023 in all months except for November. Average energy demand in November 2024 was slightly lower than November 2023 by about 100 MW. In addition, the first four months of 2025 saw higher average hourly total energy demands compared to the corresponding months in 2024. All else held constant, higher overall monthly demand contributes to higher demand-weighted average HOEPs. Section 2.1.3 considers the combined effects of demand and supply conditions to explain the monthly price differences across the years.

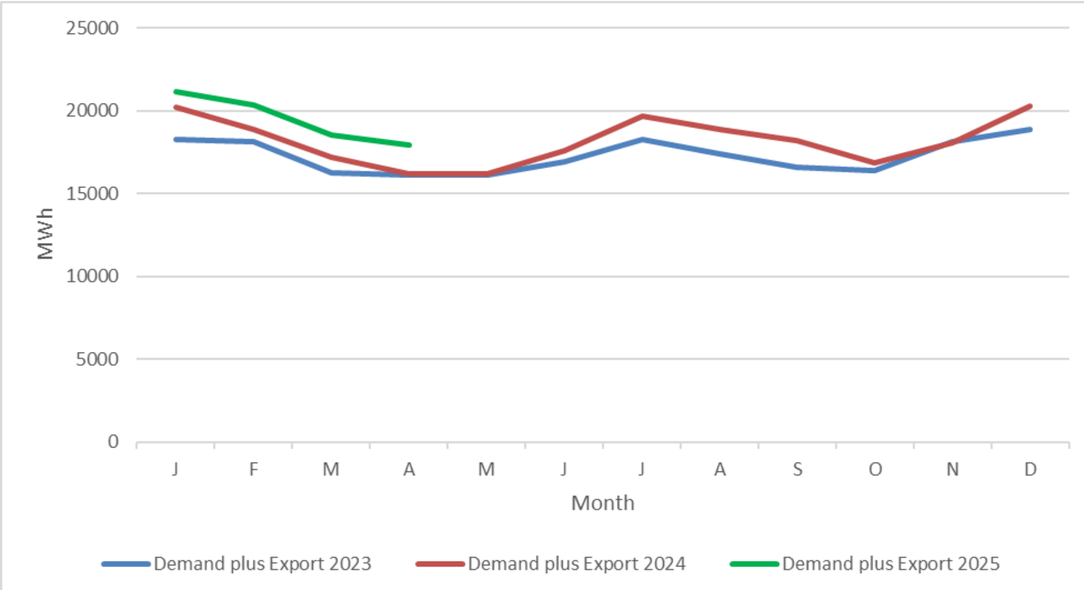
Figure 7 – Average Hourly Prices in Ontario and Surrounding Jurisdictions, Monthly, January 2023 – April 2025




3. MISO – Manitoba
4. MISO – Minnesota
5. Pennsylvania–New Jersey–Maryland (PJM) electricity market
6. New Engeland (NE) electricity market

The USD to CAD conversion is based on the Monthly exchange rates - Bank of Canada.

Figure 8 – Average Hourly Ontario Demand plus Net Exports, Monthly, January 2023 – April 2025




### 2.1.2 Supply Factors

Monthly average HOEPs are a function of the availability of key sources of supply such as nuclear, wind, solar and hydroelectric generation. All things being equal, higher available monthly output from these resources leads to lower HOEPs.[9] Table 2 and

Table 3 provide the hourly average energy output in MWh from nuclear, wind, solar and hydroelectric generation by month for 2023, 2024 and the first four months of 2025. The year with the highest output for a given source in a given month is identified in red.

Table 2 – Average Hourly Hydroelectric, Nuclear, Wind and Solar Energy Output, Monthly, January 2023 – December 2024

| Month | Hydroelectric | | Nuclear | | Solar | | Wind | |
|---|---|---|---|---|---|---|---|---|
| | 2023 | 2024 | 2023 | 2024 | 2023 | 2024 | 2023 | 2024 |
| January | 4,553 | 4,295 | 9,795 | 9,919 | 25 | 22 | 1,450 | 1,811 |
| February | 4,378 | 3,987 | 9,566 | 9,117 | 62 | 72 | 2,155 | 1,832 |
| March | 4,014 | 3,960 | 8,417 | 7,949 | 89 | 86 | 1,987 | 2,024 |

[9] Available output from nuclear, wind, solar and run-of-river hydroelectric generation is offered regularly at low prices and scheduled ahead of other higher cost sources of generation. Peaking hydroelectric generation uses a reservoir to store water and releases it through turbines only during periods of high electricity demand. The amount of precipitation in a month, including snowmelt, directly impacts river discharge and reservoir levels. Seasonal variations, such as spring melt or prolonged droughts, significantly influence the water available for power generation.

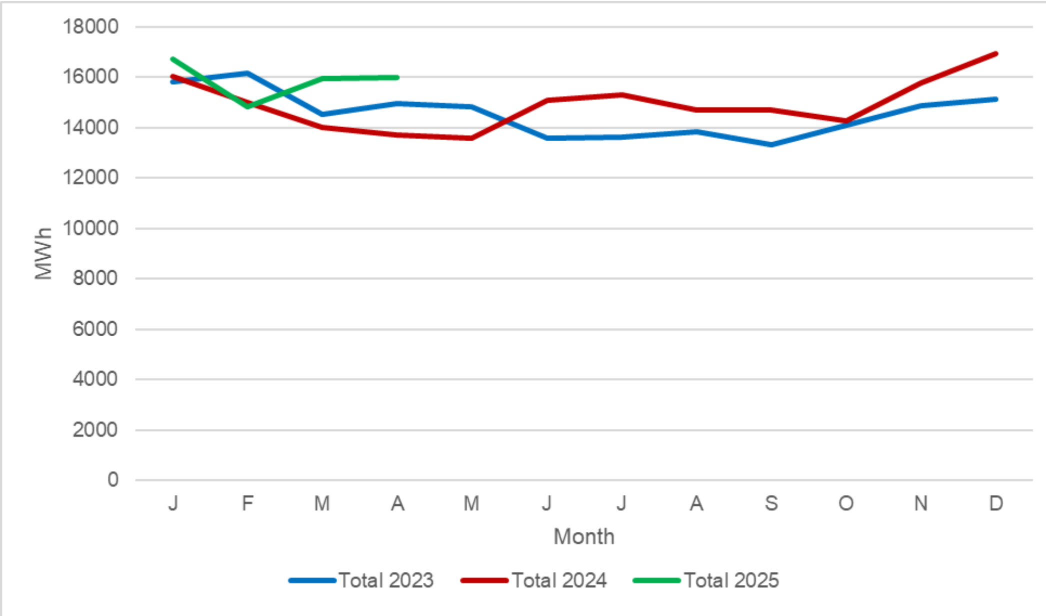
| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| April | 4,604 | 4,517 | 8,605 | 7,111 | 106 | 98 | 1,634 | 1,994 |
| May | 5,038 | 5,064 | 8,647 | 7,177 | 138 | 121 | 1,012 | 1,211 |
| June | 3,771 | 4,334 | 8,809 | 9,378 | 122 | 117 | 891 | 1,251 |
| July | 3,779 | 4,393 | 9,090 | 10,117 | 117 | 123 | 645 | 661 |
| August | 3,351 | 3,869 | 9,379 | 9,892 | 112 | 111 | 975 | 821 |
| September | 3,380 | 3,644 | 9,046 | 9,932 | 110 | 110 | 801 | 996 |
| October | 3,605 | 3,643 | 8,841 | 8,877 | 66 | 93 | 1,602 | 1,674 |
| November | 3,706 | 4,466 | 9,006 | 9,226 | 48 | 50 | 2,093 | 2,026 |
| December | 4,048 | 4,356 | 9,473 | 10,509 | 28 | 28 | 1,576 | 2,035 |

Table 3 – Average Hourly Hydroelectric, Nuclear, Wind and Solar Energy Output, Monthly, January–April 2024 and January-April 2025

| Month | Hydroelectric | | Nuclear | | Solar | | Wind | |
|---|---|---|---|---|---|---|---|---|
| | 2024 | 2025 | 2024 | 2025 | 2024 | 2025 | 2024 | 2025 |
| January | 4,295 | 4,428 | 9,919 | 9,814 | 22 | 41 | 1,811 | 2,451 |
| February | 3,987 | 4,475 | 9,117 | 8,479 | 72 | 37 | 1,832 | 1,832 |
| March | 3,960 | 4,509 | 7,949 | 8,933 | 86 | 89 | 2,024 | 2,416 |
| April | 4,517 | 4,952 | 7,111 | 9,156 | 98 | 107 | 1,994 | 1,770 |

Figure 9 presents the total hydroelectric, nuclear, wind and solar output by month for the same period. Between 2023 and 2024, output from these sources was typically higher during the first five months of 2023 compared to the same months of 2024 but lower for the remainder of the months in 2023 compared to 2024. The 2025 output from these sources was higher than 2023 and 2024 for January, March and April.

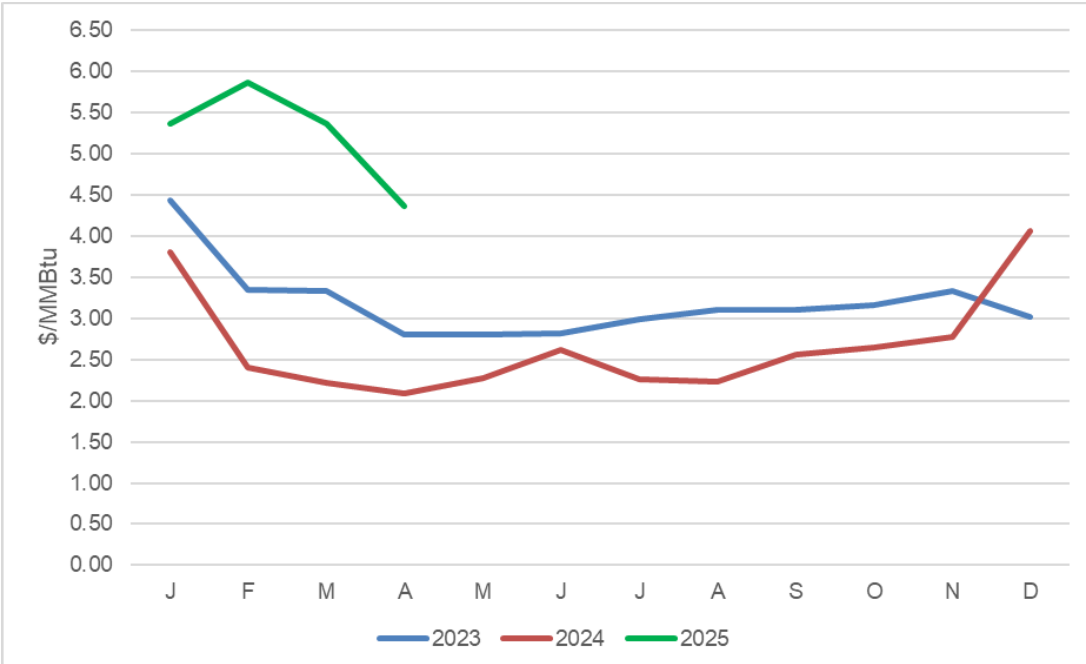
Figure 9 – Average Energy Output from Hydroelectric, Nuclear, Wind and Solar, Monthly January 2023 – April 2025




Another key supply factor affecting monthly average HOEPs is the price of natural gas. Natural gas generators generally produce after nuclear, wind, solar and run-of-river hydroelectric generation. The offer price of natural gas generation is positively correlated with the price of natural gas, meaning higher gas prices imply higher natural gas generation offer prices, and all else held constant, higher HOEPs when natural gas generators are the marginal price-setting resources. As demand rises and the marginal gas unit's efficiency worsens (i.e., higher heat rate), the correlation between the natural gas price and HOEP may be less obvious. Table 3 (in section 21.1.3) provides a few cases where this might have been at play; namely the (i.e. months of January, August and October 2024).

Figure 10 presents the average Dawn Daily Natural Gas price, by month for 2023 and 2024 and the first four months of 2025. Comparing 2023 and 2024, the natural gas price was higher in 2023 compared to 2024 for all months other than December. On the other hand, the gas price was higher throughout the first four months of 2025 compared to the corresponding months in 2023 and 2024.

Figure 10 – Average Dawn Daily Natural Gas Price, Monthly, January 2023 – April 2025




### 2.1.3 Combined Effects of Demand and Supply on HOEP

Differences in the monthly average HOEPs across the monitoring period are driven by the combined effects of the monthly differences in the key demand and supply factors.

Table *4* presents the year-to-year difference (2024 less 2023 and 2025 less 2024) in the average hourly total demand (Ontario demand and net exports), average hourly total supply (hydroelectric, nuclear, wind and solar), and average hourly natural gas price by month. Numbers in red represent a difference that would contribute to a higher average monthly HOEP in 2024 and 2025. While other factors, such as the availability of natural gas generation, demand response and operating reserve, may have contributed to the direction and size of the yearly price differences, these are the three primary factors.

The combination of higher total demand and lower total supply from hydroelectric, nuclear, wind and solar resources contributed to higher HOEPs in 2024 in the months of February to May relative to the same months in 2023, offsetting the effects of lower gas prices.

Relatively high total demand levels offset the higher levels of total supply and the lower natural gas prices in the months of January, August and October, contributing to higher HOEPs in these months in 2024.

The higher HOEPs starting in December 2024 until April 2025 were mainly attributed to higher demand and a higher Dawn Hub gas price.

In contrast, higher total supply and lower natural gas prices offset the higher total demand in the months of June, July and September contributing to lower HOEPs in these months in 2024. In November 2024, all factors contributed in the lowering of HOEPs.

It is less obvious from

Table *4* which factors were the dominant factors affecting average HOEPs in the month of October.

It is noteworthy that during the monitoring period the highest HOEP difference was registered when all three factors contributed to increasing HOEPs in February 2025 compared to February 2024.

Table 4 – Average Hourly Difference in Total Demand, Total Supply, Gas Prices and HOEP, January 2023 - April 2025

| | Month | Demand Delta (MWh) | Supply Delta (MWh) | Natual Gas Price Delta ($/MMBtu) | HOEP Delta |
|---|---|---|---|---|---|
| 2024 less 2023 | 1 | 1,966.93 | 223.36 | -0.63 | 8.99 |
| | 2 | 638.22 | -1,151.59 | -0.94 | 5.26 |
| | 3 | 979.58 | -487.75 | -1.12 | 3.60 |
| | 4 | 13.36 | -1,228.26 | -0.71 | 7.59 |
| | 5 | 46.78 | -1,261.24 | -0.53 | 10.76 |
| | 6 | 694.06 | 1,488.16 | -0.20 | -0.12 |
| | 7 | 1,372.04 | 1,662.57 | -0.73 | -3.10 |
| | 8 | 1,445.80 | 876.17 | -0.88 | 5.81 |
| | 9 | 1,598.87 | 1,345.74 | -0.55 | -5.84 |
| | 10 | 557.12 | 171.60 | -0.53 | 2.77 |
| | 11 | -97.50 | 914.69 | -0.56 | -0.58 |
| | 12 | 1,378.74 | 1,803.20 | 1.04 | 8.12 |
| 2025 less 2024 | 1 | 894.35 | 687.26 | 1.55 | 23.71 |
| | 2 | 1,467.64 | -185.90 | 3.45 | 48.74 |
| | 3 | 1,262.08 | 1,926.54 | 3.15 | 19.08 |
| | 4 | 1,733.56 | 2,263.83 | 2.28 | 11.12 |

## 2.2 Global Adjustment

The largest component of the total and average consumer cost is the GA, representing 37% and 35% in 2023 and 2024, respectively. The total GA decreased by 3.4% and the average GA by 7% from 2023 to 2024.

Several factors can affect the GA: the GA includes payments to contracted and regulated generators to make up the difference between the payments guaranteed at regulated rates or under contracts and payments made at the wholesale market price. It is generally understood that on an hourly basis, a higher HOEP implies a lower GA as contracted and regulated generators receive a larger payment through the wholesale market and hence a lower payment at regulated or contracted rates.

Other factors can influence the annual amount of the GA. For example, higher output from generation resources that receive a fixed price per output produced (wind, solar and nuclear output) puts upward pressure on the annual GA. An increase in contract prices[10] and regulated payment amounts during the year puts upward pressure on the annual GA. Contracts that expire during the year put downward pressure on the annual GA, while new contracts added in the year put upward pressure on the annual GA.

Table 5 lists the components of the GA for 2023 and 2024 along with the annual difference (2024 less 2023). A few components are worth noting. Payments for output from the Bruce nuclear generating station accounted for the largest increase in the GA from 2023 to 2024, largely as a result of an 11.6% increase in Bruce total output in 2024. Payments to solar generation increased in 2024 due to a slight uptick in solar output and more money was spent on conservation in 2024. In contrast, payments to natural gas generation, wind, and OPG rate-regulated nuclear and hydroelectric facilities all decreased in 2024. The decrease in GA payments for OPG rate-regulated nuclear and hydroelectric facilities is mainly attributed to a relatively higher HOEP in 2024 than in 2023, as well as a decline in nuclear energy output due to higher outages at Darlington and the end of commercial operation of Pickering A.

[10] IESO contracts prices are typically indexed to account for inflation.

Table 5 – GA by Components Expressed in $000,000, 2023 - 2024[11]

| Category | 2023 | 2024 | Difference |
|---|---|---|---|
| Conservation | 162.9 | 218.1 | 55.2 |
| Hydro | 684.0 | 679.7 | -4.3 |
| Bruce Nuclear | 2,763.2 | 3,141.1 | 377.9 |
| Natural Gas | 1,222.4 | 1,115.2 | -107.2 |
| Other Programs - IEI and Storage | 71.1 | 24.0 | -47.1 |
| Financing Charges and Funds | -0.6 | -5.1 | -4.6 |
| Wind | 1,691.0 | 1,631.8 | -59.2 |
| Solar | 1,572.2 | 1,583.7 | 11.5 |
| Biomass, Landfill and Byproduct | 220.9 | 211.5 | -9.4 |
| Ontario Electricity Finance Corporation - Non-Utility Generation | 30.3 | 29.2 | -1.1 |
| Ontario Power Generation - Regulated Nuclear and Hydro | 3,477.9 | 2,953.5 | -524.4 |
| **Total by Components** | 11,895.3 | 11,582.7 | -312.6 |
| **Comprehensive Electricity Plan** | -3,190.0 | -3,155.1 | 34.9 |
| **Total Global Adjustment** | 8,705.3 | 8,427.5 | -277.8 |

In future *State of the Market* reports, the MSP will provide a more detailed assessment of the factors affecting annual changes in the GA.

## 2.3 Other Market Costs

Other market costs consist of several market-driven uplift charges, including Operating Reserve (OR), other ancillary services, capacity auction costs and the regulated IESO Administration Charge. Other market costs represent roughly 3% of the total and average consumer cost before accounting for government programs. Other market costs increased on a total basis (from $765 million to $809 million or 6%) as well as on an average basis (from $5.27/MWh to $5.38/MWh or 2%) from 2023 to 2024.

Two notable market-driven uplift costs are OR and other ancillary services. These costs declined both on a total cost and an average cost basis from 2023 to 2024. This is illustrated in Figure 11.

OR is stand-by power or demand reduction which can be called upon with short notice to deal with an unexpected supply shortage. OR is divided into three classes: 10-minute spinning, 10-minute non-spinning and 30-minute operating reserves. The three types of OR are co-optimally scheduled with energy, and like energy, OR prices are determined every five minutes. The need for OR is based primarily on reliability standards set by the

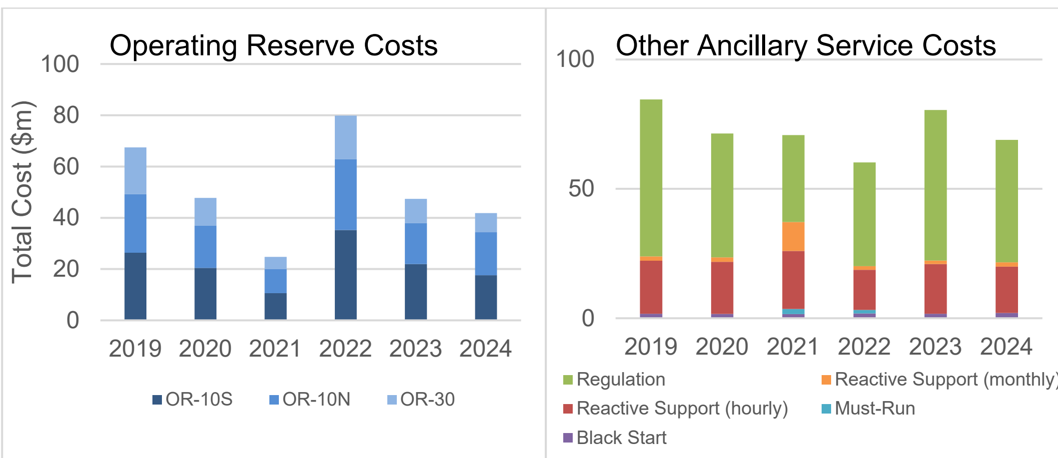
[11] The GA amounts for each component in 2023 and 2024 are taken from the IESO website (GA by components) which are tabulated in monthly resolution and in a longer time period. A description of each component can be found in the GA tab of this link: Monthly Market Report Archive.

North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council.

The other ancillary services are ones that the IESO contracts for and include black-start service, regulation service, reactive support and voltage control service, and reliability must-run services.[12] Like OR, the demand for these services is based primarily on reliability standards and with respect to regulation, based on annual planning assessments. The IESO anticipates an incremental need of approximately 30 MW of regulation capacity beginning as early as 2026 and the need is anticipated to grow to 110 MW in 2035.[13] The IESO's incremental regulation needs are driven by forecast load growth from highly fluctuating industrial loads, public transit electrification and expansion, and increased renewable generation variability. Future needs may change based on updates to demand forecasts, timing and size of industrial projects, transit load profiles, actual operating experience and variable generation output.

As a matter of compliance with the reliability standards set by NERC, a minimum of ±100 MW of regulation is required to maintain the balance between Ontario's supply and demand.[14]

Figure 11 – Operating Reserve and Other Ancillary Service Costs, 2020-2024




In 2024, $42 million was spent on OR and $69 million on other ancillary services, 68% of which ($47 million) was regulation cost. These costs represent less than 1% of the total consumer cost of electricity.

[12] For more information on each of the ancillary services, see the IESO's webpage on Ancillary Services.

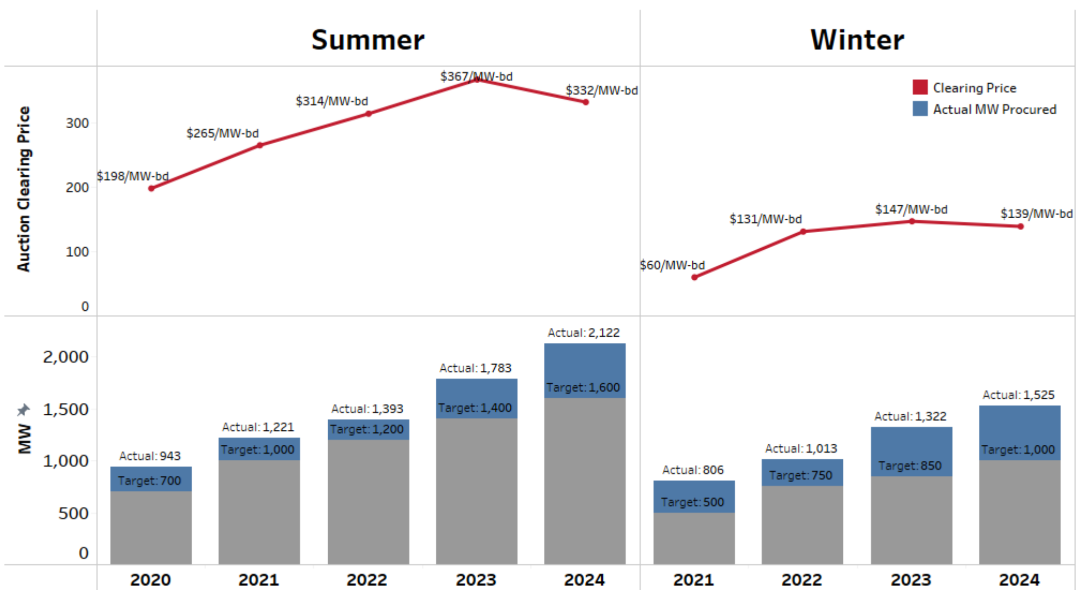
[13] See Section 6.1 of the IESO's 2025 Annual Planning Outlook Report (April 2025).

[14] See Chapter 5, Section 4.4 of the Market Rules.

Another notable market-driven uplift charge is capacity auction uplift. The auction is designed to ensure that there is sufficient available capacity[15] of eligible off-contract generators, demand response, energy storage or system/generator-backed imports to meet the IESO's resource adequacy reliability standards for the following calendar year. Unlike the medium- or long-term procurements, the capacity auction is intended to be a short-term, flexible capacity procurement. The auction provides the successful resources with an "availability" payment covering two six-month obligation periods, summer and/or winter. Successful resources must be able to produce energy or reduce load by the amount of their selected capacity.

Figure 12 provides the results of the 2024 capacity auction together with the outcomes from past years. In the 2024 auction, 2,122 MW of capacity was acquired for the summer 2025 period at a clearing price of $332.40/MW-business day and 1,525 MW was acquired for the winter 2025/2026 period at $139/MW-day. Capacity auction uplift increased by 40% from 2023 to 2024. On an average cost basis, this uplift increased by 35%.

Figure 12 – Historical Capacity Auction Results




In 2023, the IESO introduced several amendments to the capacity auction rules that helped ensure that only reliable capacities are enrolled and duly compensated.[16] The 2024 auction participants qualified based on their unforced capacity (UCAP), a discounted

[15] This is capacity availability that is neither rate-regulated nor already committed to the IESO through long-term IESO contracts.

[16] See the IESO Capacity Auction Stream 1 Enhancements approved by the IESO Board on June 26, 2023, and the Stream 2 Enhancements effective as of November 29, 2023.



Ontario Energy Board

version of installed capacity that accounts for historical availability and performance. New resources without historical data will use the fleet average availability de-rating factor. For Hourly Demand Response (HDR) resources, an in-period UCAP adjustment has been implemented that would essentially bring down the contractual obligation and payment for an HDR resource if it fails to meet the new and tighter performance dead band. This is in addition to non-performance charges that may also be imposed.

In *Monitoring Report 35*, the MSP made several recommendations about the capacity auction. In particular, the MSP recommended using stronger penalties to ensure auction participants do not have an incentive to over-represent their expected capacity contributions, and to encourage dispatch compliance.[17] The MSP understands that the enhanced measures implemented by the IESO are to provide a financial incentive for auction participants to improve performance with much stronger financial consequences for poor performance. The MSP will monitor the performance of these resources to see if the enhanced measures are having the desired effect.

## 2.4 Government Cost Mitigation

While the nominal total and average consumer costs have been increasing since 2014, the Ontario government's cost mitigation programs have helped to moderate the effects of the increases on ratepayers. Government cost mitigation programs were expanded significantly in 2017, leading to a year-over-year reduction in the average consumer's bill. In the years following, several programs have helped sustain the reduction in average annual consumer costs and continue to hold them below 2016 levels. In 2024, government spending on electricity cost mitigation rose to $6.8 billion from $5.8 billion in 2023.

The two largest programs are the CEP and the Ontario Electricity Rebate (OER). The CEP transfers roughly 85% of the costs of non-hydroelectric renewable energy contracts from electricity ratepayers to provincial taxpayers. It was introduced in January 2021 - the plan is designed to help lower electricity prices and reduce upward cost pressures for customers. The OER, on the other hand, provides eligible residential customers, small businesses, farms and long-term care homes a rebate on the pre-tax subtotal of their electricity bill and is intended to reduce their overall cost.[18] Together, the two programs represent over 80% of the annual government cost mitigation amounts in 2024. In 2024, government cost mitigation held total consumer costs to $17.2 million and average consumer cost to $115/MWh, 28% below the total consumer cost of $24 million and average consumer cost of $160/MWh.

---

[17] See MSP 35 Recommendation 3.2, page 52.

[18] For ease of reference, references in this report to the Ontario Electricity Rebate, introduced in 2019, includes predecessor programs under the *Ontario Rebate for Electricity Consumers Act, 2016* and the *Ontario Clean Energy Benefit Act, 2010*. The total bill impact for individual customers across the province may vary depending on the customer's electricity usage and utility that serves them. From January to October 2024, the OER was 19.3%. On November 1, 2024, the OER was reset at 13.1%.

The Fair Hydro Plan is another government program introduced in 2017 which reduced residential electricity bills by roughly 25% and temporarily limited future bill increases to the rate of inflation. It did this through a combination of subsidies and refinancing electricity system costs, before being replaced by the OER in 2019. The rest of the government programs that comprised “Other” are as follows:

1. Northern Energy Advantage Program (NEAP) – The NEAP, which began on April 1st, 2022, provides large industrial facilities in Northern Ontario with a rebate of 2 cents per kilowatt-hour to reduce electricity costs. It supports energy-intensive sectors such as mining and manufacturing by improving competitiveness and encouraging long-term investment.
2. Rural or Remote Electricity Rate Protection (RRRP) – The RRRP, established in 2001, lowers electricity costs for customers in rural and remote communities where distribution is significantly more expensive. It provides ongoing financial support funded through a province-wide charge, ensuring more equitable electricity pricing across Ontario.
3. First Nations On-Reserve Delivery Credit (FNDC) – The FNDC, introduced in 2017, eliminates electricity delivery charges for eligible First Nations residential customers living on reserve. The credit is applied automatically and provides significant ongoing bill relief for on-reserve households.
4. Distribution Rate Protection (DRP) – the DRP, introduced in 2017, caps the base distribution charges for eligible rural and remote residential customers facing high distribution costs. The program ensures that customers in specific service areas pay no more than the provincially set maximum monthly distribution charge.
5. Ontario Electricity Support Program (OESP) – the OESP, launched in 2016, provides an ongoing monthly credit on electricity bills for low-income households. Credit amounts vary by family size and income, with higher support available for Indigenous households, electrically heated homes, and medical-device-using customers.

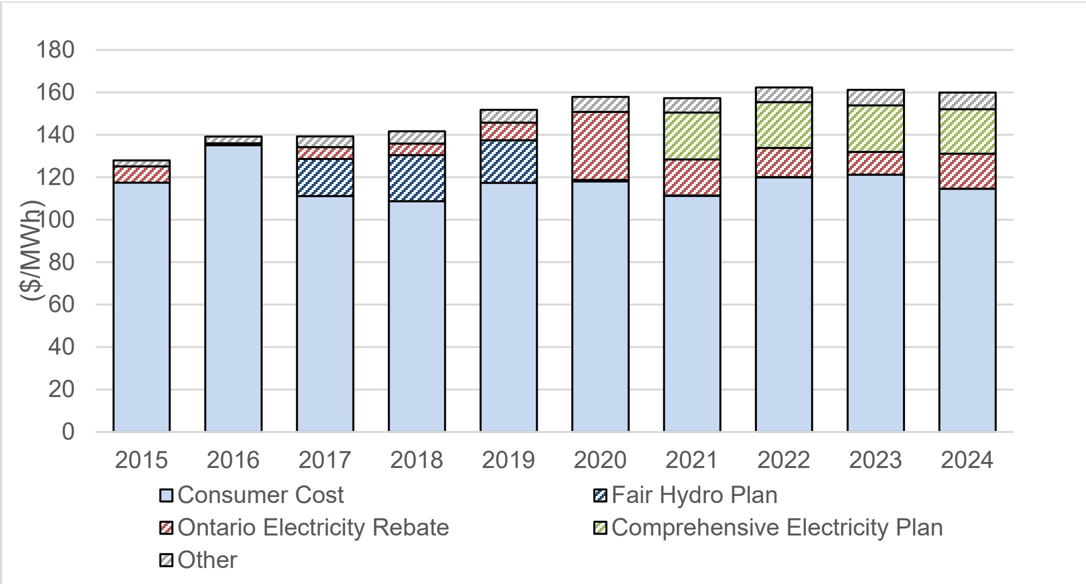
Figure 13 illustrates the effect of government cost mitigation programs on total consumer costs (as noted by the solid blue bars). The total height of the bars in Figure 13 are gross consumer costs (i.e., actual costs paid by Ontario consumers plus the costs covered by government programs).[19]

[19] Government program spending totals are illustrated in Appendix B, Figure 33 – Government Program Spending, 2015-2024.



Ontario Energy Board

Figure 13 – Government Program Spending and Consumer Cost, 2015-2024



# 3 MARKET MONITORING ACTIVITIES

The MSP monitors the IESO-administered markets to identify inappropriate or anomalous market conduct by market participants. activities of the IESO that have a detrimental impact on market efficiency or effective competition, and flaws in the market rules, market design, procedures and the overall market structure which result in outcomes that are inconsistent with the efficient and fair operation of a competitive market. This chapter reports on select monitoring activities in the IESO-administered markets between January 2024 and April 2025.

## 3.1 External Transactions

Intertie trading can facilitate the efficient use of the transmission interfaces that connect Ontario and its neighbouring jurisdictions. Intertie trading allows low-cost resources in one jurisdiction to compete with resources in neighbouring jurisdictions to serve consumers with energy, operating reserve and capacity. It also allows the interconnected jurisdictions to share emergency services to help maintain reliability, including emergency energy and shared activation of reserve.

Ontario is interconnected with five other jurisdictions: New York, Michigan, Québec, Manitoba and Minnesota. These interconnections provide direct connections to two open wholesale electricity markets, MISO[20] and NYISO, and indirect connections to two additional markets, PJM and ISO-NE. Ontario interconnections also provide direct connections to Québec and Manitoba, which do not have wholesale electricity markets.[21]

Over the past several years, Ontario has been a net exporter of electricity. Figure 14 shows yearly imports, exports and net exports since 2020.

Figure 15 shows a monthly breakdown.

[20] MISO manages the flow of high-voltage electricity across 15 U.S. states, including Michigan and Minnesota.

[21] Note that Manitoba Hydro joined MISO in September 2001 through the execution of a Coordination Agreement with MISO (and not the Transmission Owners' Agreement) which sets out the various rights and obligations of the parties related to transmission service and pricing, tariff administration, generation and transmission outage coordination, transmission planning coordination, sharing of contingency reserves and reliability coordination.

Figure 14 – Yearly Imports, Exports and Net Exports, 2020-2024[22]

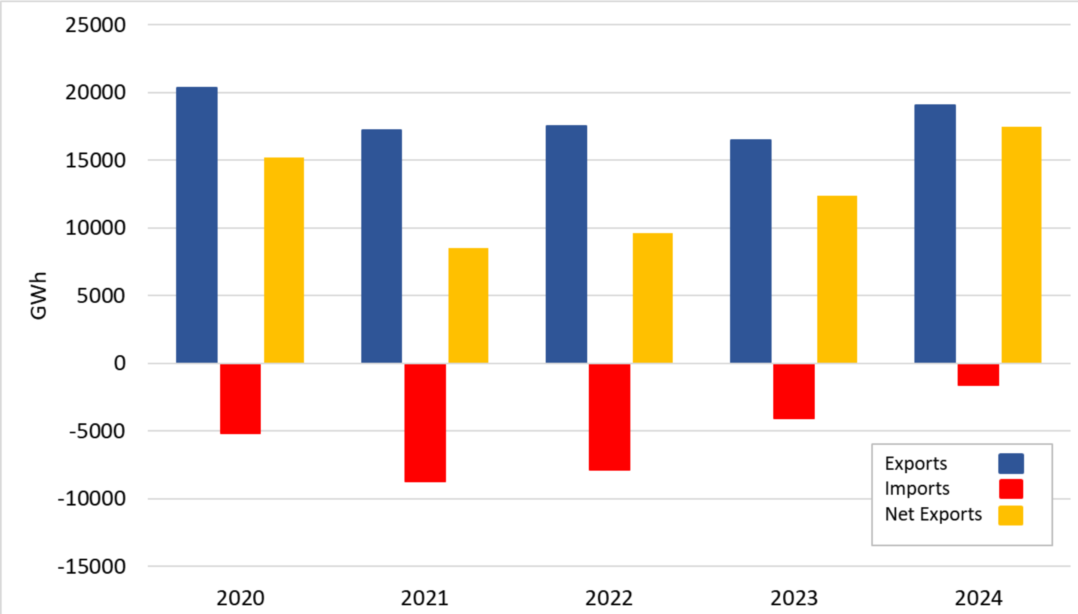
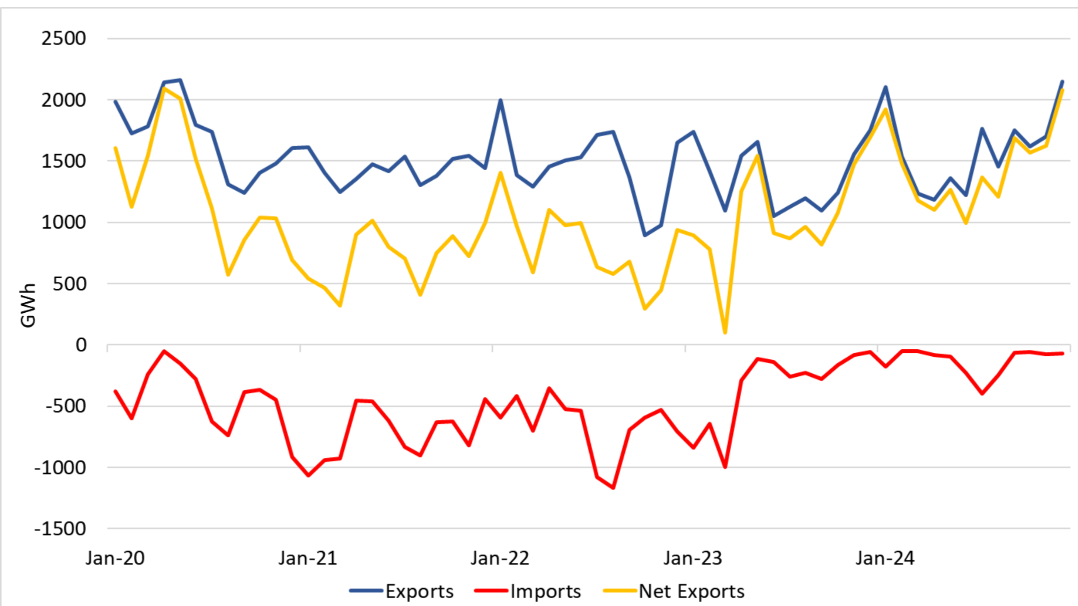



Figure 15 – Monthly Imports, Exports and Net Exports, 2020-2024




[22] In this figure, import quantities are assigned a negative value, export quantities are assigned a positive value, and net exports are calculated as the sum of the two values.

### *Efficiency Assessment*

Intertie trading can improve regional efficiency when entities export energy from regions with a relative excess of lower cost energy and import that energy to regions with relatively higher cost energy.

This section examines the relative efficiency of intertie trading between 2020 and 2024.[23] Intertie trading efficiency with the U.S markets is assessed on an ex-post basis by comparing the hourly average real-time locational marginal price (LMP) in the neighbouring market with the real-time IESO nodal or shadow price at buses near the interties of the corresponding transactions.[24,25] An import energy flow is considered efficient ex-post if the real-time LMP at the source market is lower than the real-time IESO nodal shadow price near the relevant intertie.[26] An export energy flow is considered efficient ex-post if the real-time LMP at the destination market is higher than the real-time IESO nodal shadow price near the relevant intertie. For simplicity, the transaction costs associated with trading (i.e., transmission tariffs and uplifts) are not accounted for in the efficiency assessment. The assessment is on a bilateral basis and does not consider a third neighbouring market.[27] Figure 16 presents a breakdown of imports from the four U.S. markets from 2020 to 2024. The sources and destinations of energy flows are determined based on the NERC Tag ID.

---

[23] Only imports into Ontario and exports from Ontario are considered (i.e., wheel throughs are excluded from the assessment).

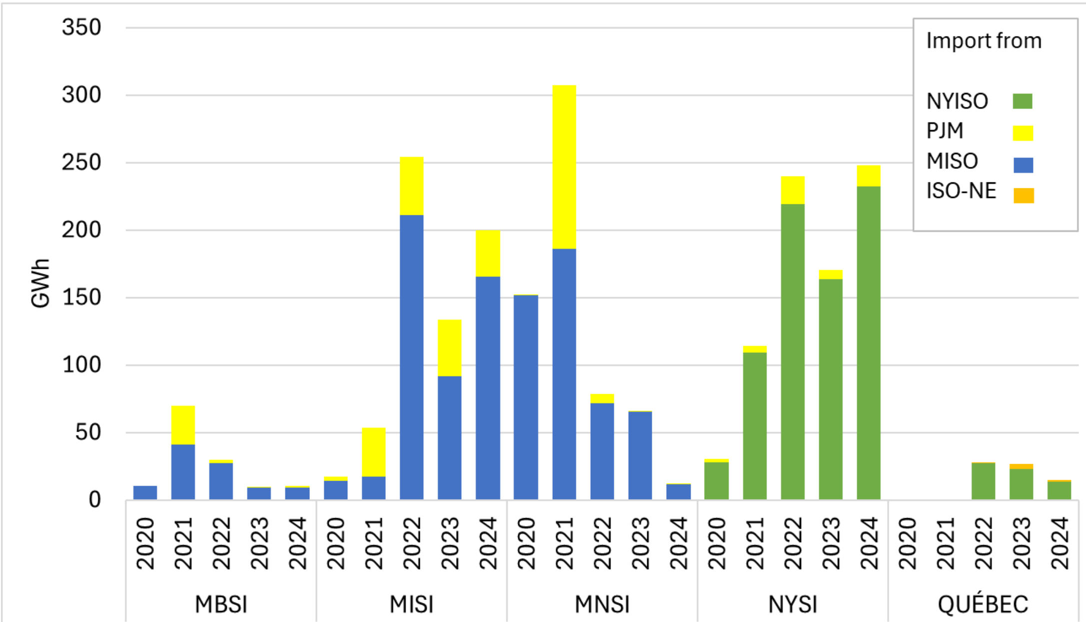
[24] IESO nodal shadow prices, produced by the constrained mode of the dispatch algorithm, are used as a proxy for the marginal cost of energy at a location and are the best alternative for the efficiency assessment. However, intertie traders are settled based on unconstrained intertie zone prices and thus the profitability of a trade can be different from the efficiency of the trade. To be clear, the profitability of traders is not the main subject of this section.

[25] This analysis does not provide an efficiency assessment of day-ahead imports in the IAMs.

[26] Intertie transactions are scheduled on an hourly basis and do not change during the hour (unless a change is needed for reliability reasons). Therefore, the trading efficiency is assessed using the hourly average prices.

[27] For example, the efficiency assessment between Ontario and PJM does not consider the concurrent market prices of MISO or NYISO.

Figure 16 – Imports from the U.S. Markets by Intertie Zone, 5 Years[28,29]




Among the four markets, Ontario imported the most energy from NYISO through the New York intertie (NYSI), representing 16% of total imports in 2024, followed by MISO through three interties, (i.e., the Manitoba intertie [MBSI][30], the Minnesota intertie [MNSI], and the Michigan intertie [MISI]).

Figure 17 presents a breakdown of exports to the four U.S. markets from 2020 to 2024. In 2024, Ontario exported the most energy to NYISO through NYSI, followed by MISO through MISI. These exports respectively represented 34% and 23% of total exports in 2024.

---

[28] Traders can use Québec intertie zones to flow energy between Ontario and U.S. markets.

[29] The high volumes of PJM imports through MBSI and MNSI in 2021 were attracted by the availability of high CMSC payments in Northwest Ontario. For more discussion on these events see Chapter 3 of MSP Monitoring Report 37 .

[30] Imports via MBSI could come from Manitoba, MISO or PJM and are distinguished by the associated NERC Tag ID.

Figure 17 – Exports to the U.S. Markets by Intertie Zone, 5 Years

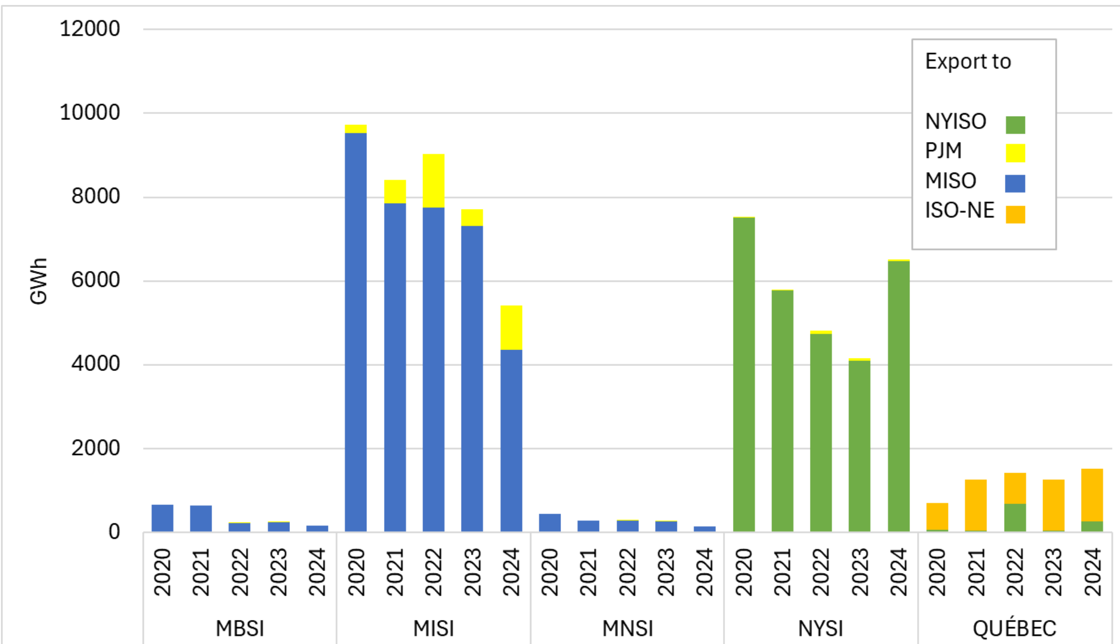



Figure 18 presents the percentage of import energy flows from three U.S. markets via four interties that were ex-post efficient from 2020 to 2024.[31]

[31] Not all imports are assessed. Imports from ISO-NE, and imports from PJM via MBSI and MNSI are excluded because of zero volume in some years. Imports from PJM via NYSI, and from NYISO via Québec are excluded because of consistently low volume.

- Externally, MISO real-time LMPs of locations MHEB, ONT_W, and ONT_DECO.PSOUT are used for assessing MBSI, MNSI and MISI intertie transactions respectively with MISO. PJM real-time IMO interface price is used for assessing MISI intertie transactions with PJM. NYISO real-time IESO interface price (Zone OH) is used for assessing NYSI intertie transactions with NYISO.
- Internally, the IESO's real-time nodal shadow prices for Kenora, Fort Frances and Beck2 are used for assessing MBSI, MNSI and NYSI intertie transactions, respectively. Average nodal shadow prices of Keith and Sarnia are used for assessing MISI intertie transactions.

Figure 18 – Efficiency of Energy Imports from U.S. Markets by Intertie Zone, 5 Years

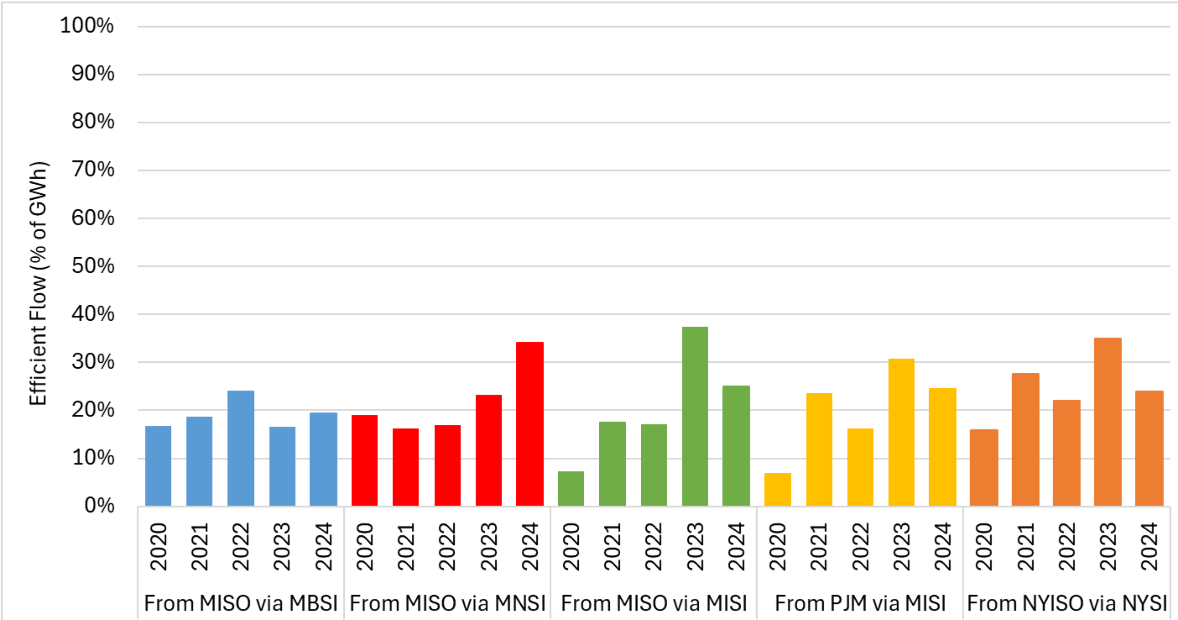
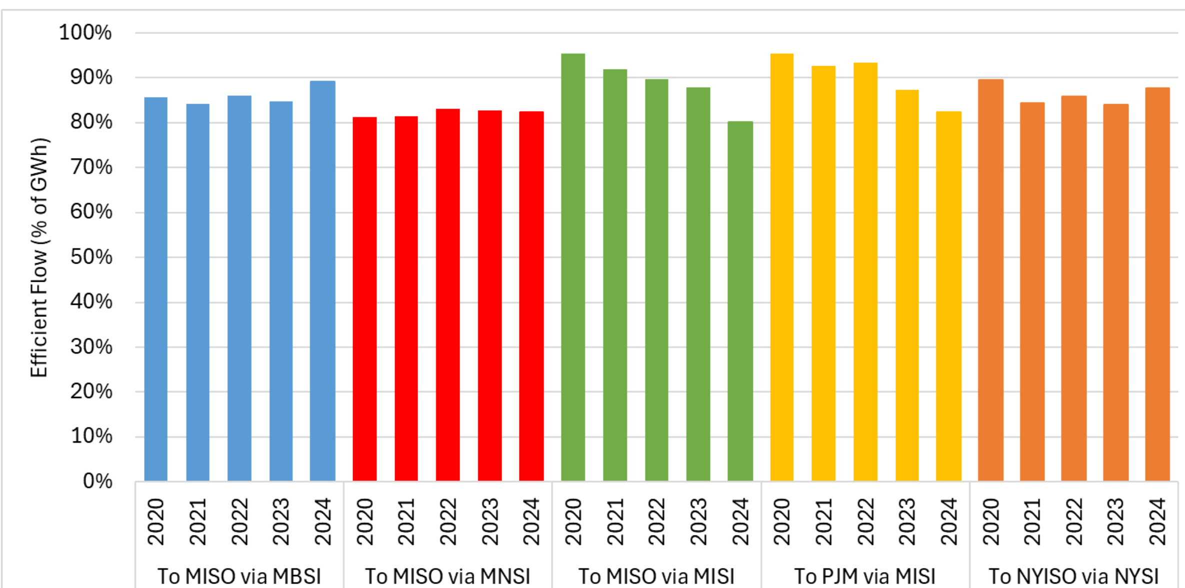



Figure 19 presents the percentage of export energy flows to the three U.S. markets that were ex-post efficient from 2020 to 2024.

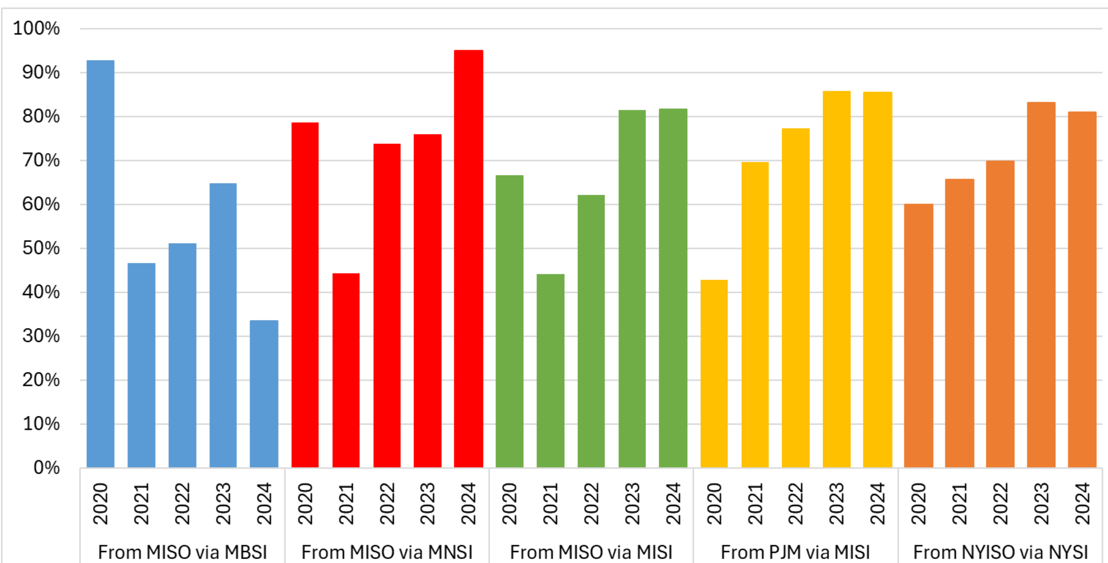
Figure 19 – Efficiency of Energy Exports to U.S. Markets by Intertie Zone, 5 Years



During the five years studied, the percentage of ex-post efficient exports was consistently at or above 80% across the interties and the destination markets. In contrast, the percentage of ex-post efficient imports was less than 40% across the interties and source markets, implying that most energy imports were dispatched when the U.S. markets had higher real-time marginal costs than Ontario.

The lower percentage of ex-post efficient import energy flows may be explained by the fact that intertie transactions are scheduled in the hour-ahead pre-dispatch (PD-1) process, and the nodal shadow price in the hour-ahead time frame (PD-1) tends to be higher than in real-time. That is, imports may appear efficient ex-ante when scheduled in PD-1 but then become inefficient ex-post in real-time. Figure 20 presents the hypothetical import efficiency assessments for the imports from U.S. markets. It compares the real-time LMP at the neighbouring markets with the PD-1 IESO nodal shadow prices near the interties. It shows that the efficiency of imports would be higher across the interties if the real-time IESO nodal shadow prices were the same as the PD-1 prices.

Figure 20 – Hypothetical Efficiency of Energy Imports from U.S. Markets using PD-1 IESO Nodal Shadow Prices, 5 Years




In contrast, the high percentage of ex-post efficient exports is partially due to the price discrepancy between PD-1 and real-time. Figure 21 below presents a hypothetical export efficiency assessment comparing the real-time LMP at the neighbouring markets with the PD-1 IESO nodal shadow prices near the interties. The efficiency of exports would be consistently lower across the interties if the real-time IESO nodal shadow prices were the same as the PD-1 prices.

Figure 21 – Hypothetical Efficiency of Energy Exports to U.S. Markets using PD-1 IESO Nodal Shadow Prices, 5 Years

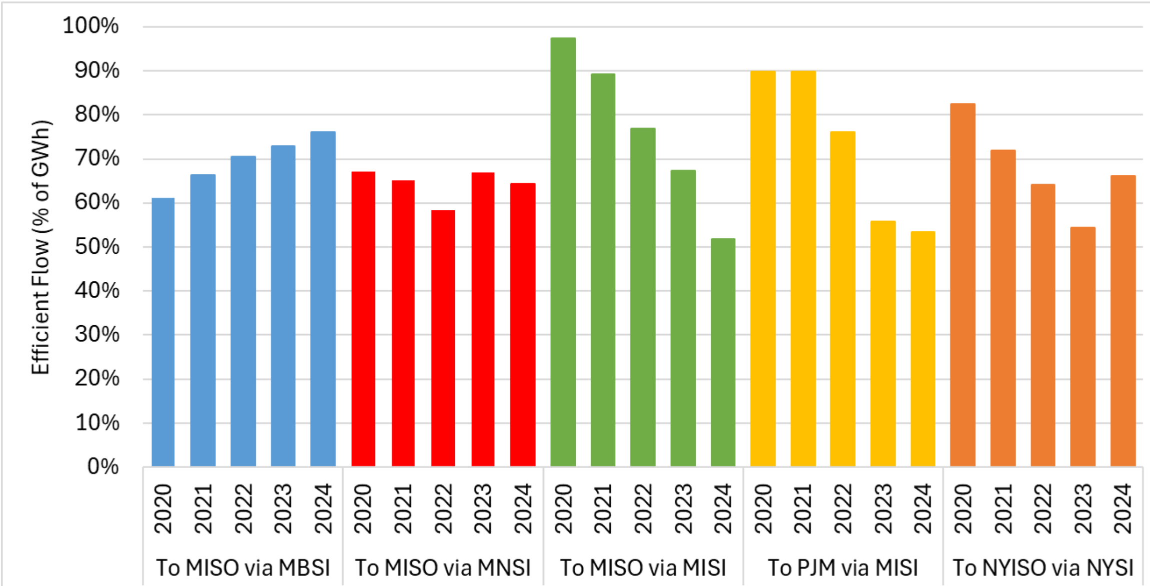



Figure 22 illustrates the average discrepancy between PD-1 and real-time IESO nodal shadow prices near the four interties when there were imports scheduled on the interties. The real-time prices were lower than the PD-1 prices by around $32/MWh in 2023, and by $47/MWh in 2024.

Figure 22 – Average Discrepancy Between PD-1 and Real-Time IESO Nodal Shadow Price Near the Interties during Importing Hours, 5 Years (real-time price minus corresponding PD-1 price)

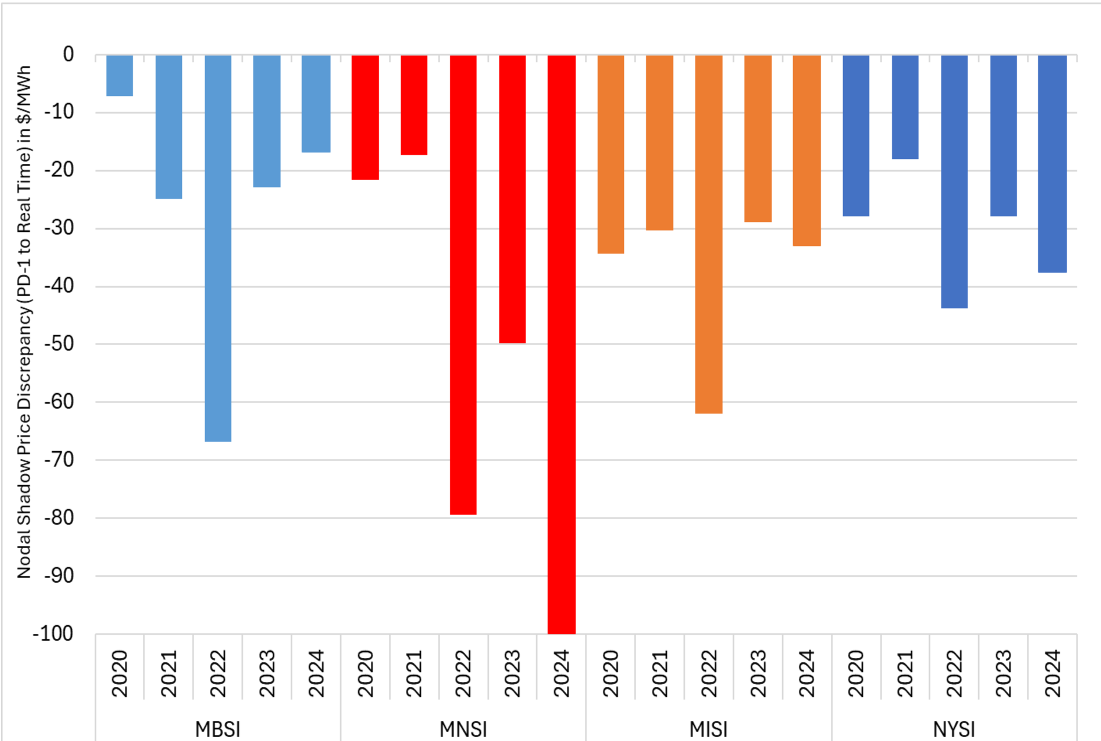
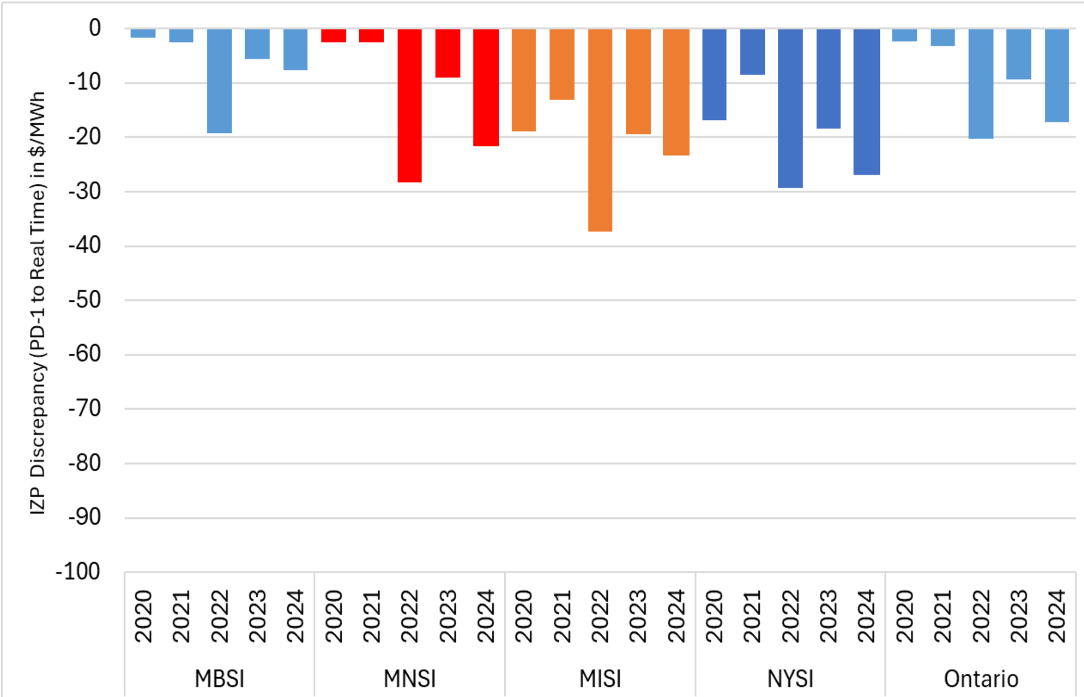



Figure 23 presents the average discrepancy between PD-1 projected intertie zonal price (IZP) and real-time IZP at the four intertie zones when there were imports scheduled on the interties. The real-time prices were lower than the PD-1 projected prices by around $13/MWh in 2023 and by $20/MWh in 2024. For reference, the average discrepancy between PD-1 projected Ontario MCP and real-time Ontario MCP during the same hours is also shown in the figure.



Ontario Energy Board

Figure 23 – Average Discrepancy Between PD-1 projected IZP and Real-Time IZP during Importing Hours, 5 Years




Previous MSP reports have discussed the divergence between the pre-dispatch and the real-time MCP.[32] Demand forecast deviation and wind generation forecast deviation between PD-1 and real-time have been identified as the two main contributing factors. When demand is over-forecast and wind generation is under-forecast in the pre-dispatch, the PD-1 projected MCP will be higher than the real-time MCP and imports could be over-scheduled.

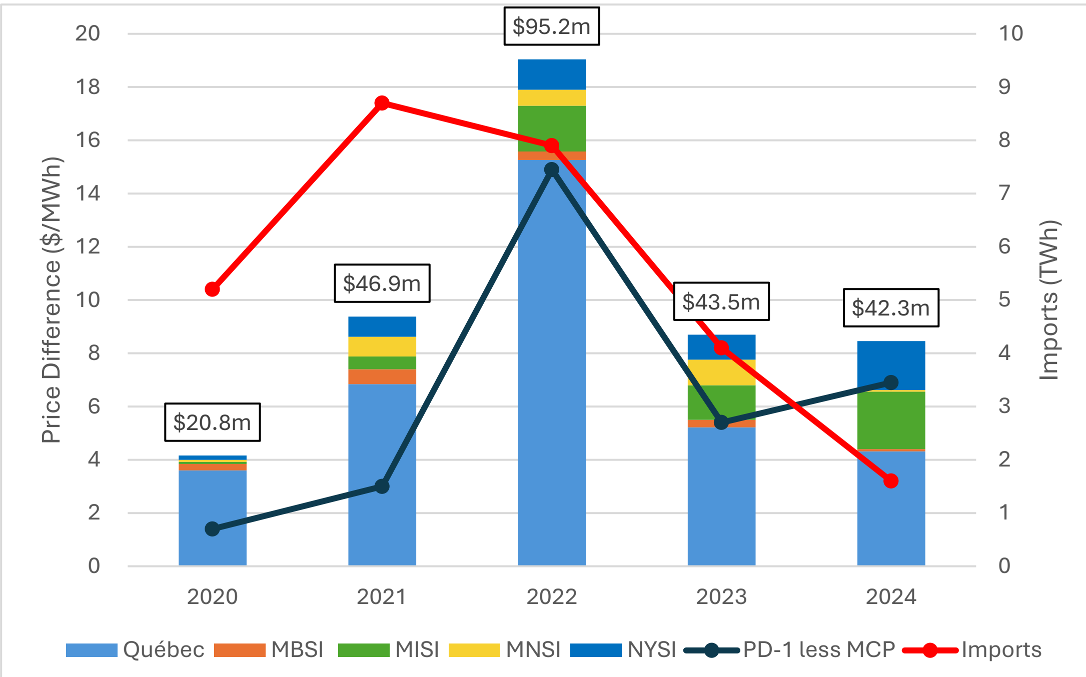
A lower real-time price than the PD-1 price would represent a price risk for import transactions scheduled in PD-1 if they were settled based on real-time prices. However, in the IAMs, this price risk is eliminated by the Intertie Offer Guarantee (IOG). The IOG stipulates that import quantities selected in PD-1 receive the higher of the real-time IZP or the import offer price. Export transactions face a price risk from higher real-time prices, however, they are not provided a guarantee to protect against this price risk. Figure 24 shows the total annual IOG payments from 2020 to 2024.

The IOG, by shielding importers from PD-1 to real-time price risk, is a contributing factor to the large share of ex-post inefficient imports. The IOG, which is recovered through IESO uplift, shifts the risk from importers to consumers. Markets are more likely to produce efficient outcomes when those best able to manage risk face the risk. The IOG is intended

[32] See, for example, MSP Monitoring Report 37, pp. 68-72.

to serve as a reliability assurance by reducing the incentive for importers to cancel their import transactions from the time the transaction was arranged to the time the transaction is scheduled to flow in real-time. With the IOG, importers have no incentive to consider the potential for lower real-time prices, and to manage their transactions efficiently in the face of this risk. In contrast, exporters must manage this risk when scheduling transactions.

Figure 24 – Annual IOG Payments, Import Volume and Average Price Difference of PD-1 & MCP, 5 Years




In the *State of the Market Report 2023*, the MSP noted that the large amount of IOGs paid may be contributing to unnecessary inefficiencies of import transactions compared to export transactions. At the root of this concern is the question of whether IOGs should be universally paid under all circumstances to hold importers whole to their offer prices, or only when imports are truly needed to assure the reliability of the electricity system. While the MSP did not specifically recommend a threshold, Recommendation 2024-1-1 underscored the need for further investigation.

Figure 25 illustrates the distribution of hourly supply margins (excluding imports) for the last five calendar years and the first four months of 2025, relative to total IOG payments. Supply margin is calculated as total available internal capacity less (1) Ontario demand, which includes OR requirements and exports; and, (2) imports. When the supply margin is positive, there is sufficient domestic supply to meet demand and imports are less likely to be needed for reliability. When supply margin is negative, some imports are needed to meet demand and imports are more likely needed for reliability. When the supply margin is below -2,000 MW, imports are more critically needed for reliability.

In 2024, the IOG payments continued the trend of the past several years:

- Approximately 4% of the time, IOG payments were made when the domestic generation supply margin for an hour was zero and therefore fully utilized to meet anticipated Ontario demand. At this threshold, there is a reasonable risk that one or more generation or transmission contingencies might cause Ontario to rely on imports for reliability during the ensuing dispatch hour. A contingency event such as the loss of a generator or transmission path may require imports even when supply cushion is somewhat above the zero level.

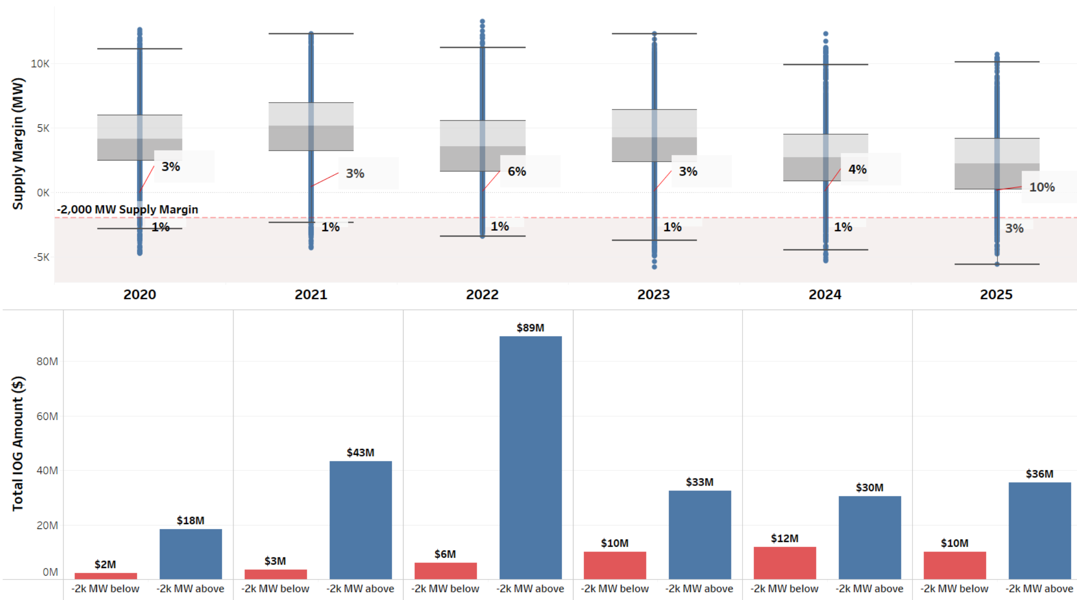
- Approximately 1% of the time, IOG payments were made when the domestic generation supply margin was at or below -2,000 MW.[33] At this threshold, Ontario relies upon imports to some degree, for the ensuing hour – setting aside any additional interventions the system operator might make and that market conditions don't sufficiently signal the readjustment of the market equilibrium. The bottom part of the figure provides the breakdown of the total IOG amount if the supply margin is within or above the threshold.

  In 2024, 71% ($30 million) of the total $42 million IOG payments were made during periods when the supply margin was above the -2,000 MW threshold and imports were not critical to meet demand.

At a supply cushion level of -2,000 MW and below, a total of $12 million was paid to importers through IOGs in 2024. This amount represents about 29% of the total IOG payments for that year. This proportion has been lower in past years, with the lowest registering at 6% in 2022. From January 2025 to April 2025, this amount reached $10 million and represented roughly 22% of the total IOG payments for that period. Noting the potential inefficiencies of the import market observed by the MSP over the past several years, and cost implications to ratepayers, the MSP will continue to monitor the performance of IOGs in the renewed markets.

[33] The IESO's Reliability Outlook Report uses the -2,000 MW threshold, called Reserve above Requirement, as an indicator of supply sufficiency. Under extreme weather conditions, the IESO forecasts that it may have to rely on up to 2,000 MW of imports and/or additional operating actions on top of the available resources to secure the reliability of the grid. According to the report, available resources include domestic installed resources minus total reductions in resources plus demand measures and firm imports/exports.

Figure 25 – Distribution of Supply Margin (less Imports) and Corresponding IOG Amount



# 4 COMPETITIVENESS

This section provides the MSP's assessment of competition in the IAM for the monitoring period January 2024 through April 2025. The MSP's assessment uses structural and behavioural measures of competition. In short, the IAM is a concentrated market with OPG its subsidiary Atura Power controlling approximately 50% of the province's generation capacity and 51% of the energy output during the monitoring period. However, most of the generation capacity in the IAM is subject to an IESO contract or, in the case of OPG's rate-regulated nuclear and hydroelectric assets, to payment amounts set by the OEB. For the most part, these contracts and regulated payment amounts incentivized competitive offer behaviour during the monitoring period.

## 4.1 Structural Measures of Competition

Structural measures of competition focus on the characteristics of a market's structure to assess the intensity of competition. They provide insights into how market structure might influence firm behaviour and market outcomes. Structural measures include concentration ratios, such as the market share held by the largest firms in an industry, the four-firm concentration ratio (CR4) or the Herfindahl-Hirschman Index (HHI), which sums the squares of the market shares of all firms. Higher concentration suggests less competition.

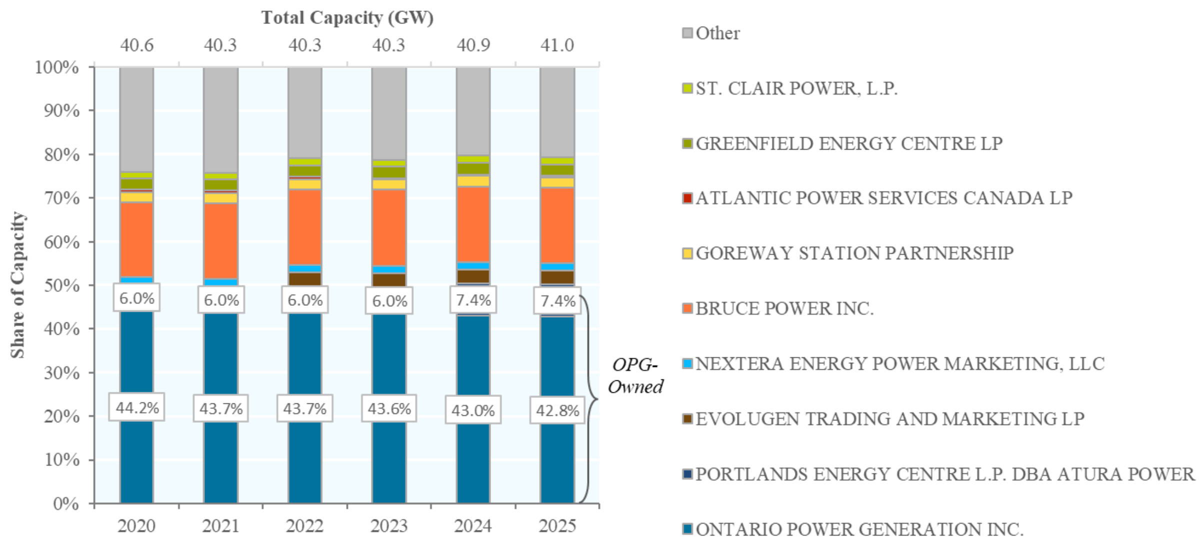
Structural measures provide a static snapshot of a market and are suggestive of competitive dynamics. However, they are not perfect predictors; they do not directly measure firm conduct or performance and may not fully reflect the intensity of competition. For this reason, the MSP augments its structural measures of competition with behavioural measures to assess the overall competitiveness of the IAM. This is discussed further below.

One of the most common indicators used by economists and anti-trust agencies to help measure the structural competitiveness of a market is participant market share. The market share of a firm is the percentage share of total market registered capacity or output owned (or controlled) by the firm. At the end of 2024, OPG and its subsidiary Atura Power controlled 50% of total capacity.[34] These percentages generally remained the same at the end of April 2025. The MSP notes, however, that from a total of about 4,000 MW of incoming capacity secured in recent procurements, only 20% will belong to OPG. The MSP sees this de-concentration in shares over time as a positive sign for a competitive market and encourages the IESO to continue to foster competition in both the day-to-day operation of the IAM and its procurement processes as it looks to acquire more resources to meet Ontario's future energy needs. Both measures indicate a high degree of concentration but on a downward trend since 2020.

[34] Market shares include capacity of generators where OPG holds the majority ownership interest and operational control.

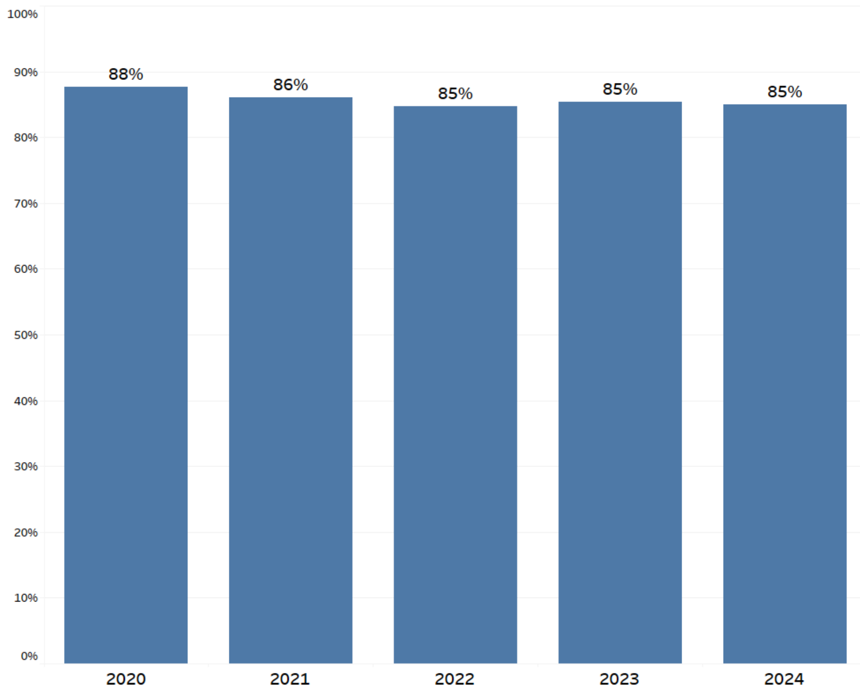
Figure 26 depicts shares of registered capacity since 2020 while Figure 27 plots the annual trend of the CR4 for the same period. Both measures indicate a high degree of concentration but on a downward trend since 2020.

Figure 26 – Registered Capacity by Registered Market Participant, January 2020 – April 2025[35]




[35] This is based on the registered capacity by the generating facilities under each registered market participant from January 1, 2020, to April 30, 2025.

Figure 27 – Concentration Ratio 4 based on Energy Output, Yearly, 2020 – 2024




When supply is tight and demand is highly (almost perfectly) inelastic,[36] there is greater chance that the supply of a given market participant will be needed to meet energy demand (i.e., the market participant is a pivotal supplier). This creates an opportunity and incentive for this market participant to exercise market power and influence prices.

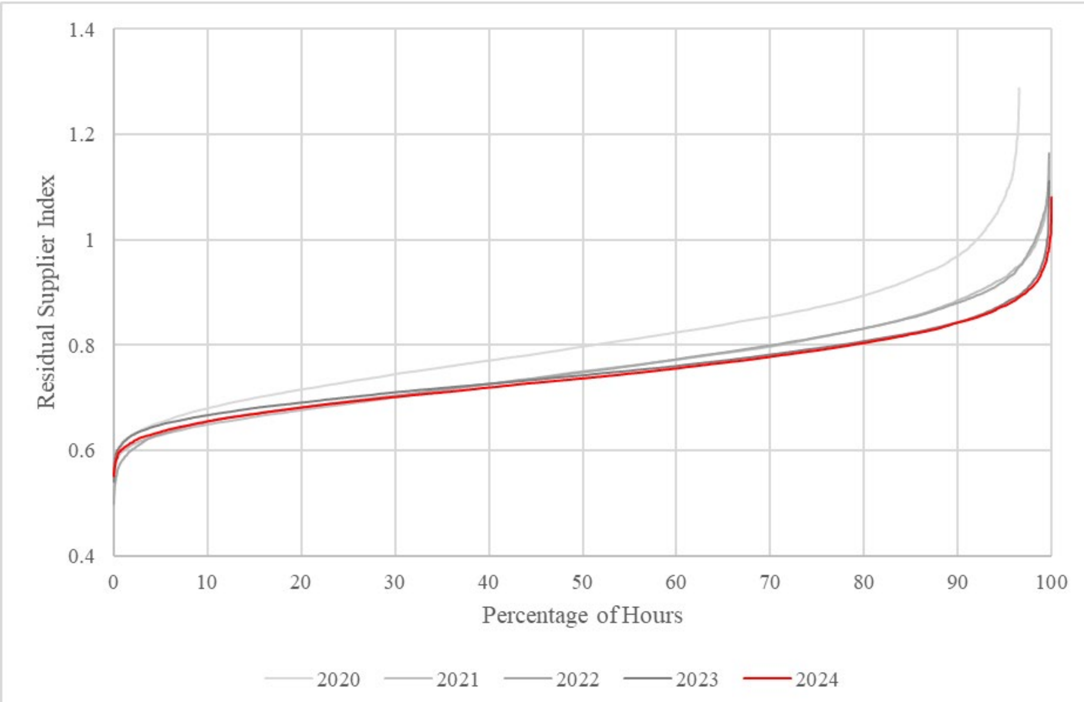
The Residual Supplier Index (RSI) is a structural measure used to identify when a market participant is a pivotal supplier by calculating the ratio between the aggregate hourly supply without the market participant and hourly demand.[37] An RSI score of less than one indicates that demand cannot be satisfied without the given market participant, thereby making it a pivotal supplier.

[36] There are several mechanisms at present that enable demand response and foster demand elasticity, such as dispatchable load market participation, the Industrial Conservation Initiative (ICI) program and demand response procured through the capacity auction. Time-of-use pricing for residential and small commercial consumers can also enable demand response.

[37] On an hourly basis, the RSI can be calculated as: RSI = (Total Energy Supplied – Energy Supply of Largest Firm)/(Total Ontario Demand and OR Requirements). The energy offer data (in MWh) is used to determine supply except for variable generation resources where energy output (in MWh) is used instead. Energy supplied includes imports. The denominator uses Ontario’s demand plus generation reserve holdback, plus capacity exports, minus dispatchable load scheduled off or forecasted, minus hourly demand response resources curtailed for the hour in MWh. Note that the aggregate hourly supply is without regard to congestion and losses. Further, OPG and its subsidiary Atura Power is treated as one supplier in the RSI calculation. The calculation in the previous *State of the Market Report 2023* treated both separately.

Figure 28 illustrates that there were 99% of hours in 2024 where a single market participant was pivotal. This percentage has trended up from 92% in 2020.

Figure 28 – RSI, Yearly, 2020 – 2024




## 4.2 Behavioural Measures of Competition

Behavioural measures of competition focus on observable actions of firms in a competitive setting. These measures help assess the intensity of competition by analyzing how firms respond to each other's actions and to market prices. Behavioural measures are a more direct measure of competition than structural measures.

In electricity markets, market participant behaviour can be observed directly through offers and bids. Evidence that market participants' supply offers consistently reflect short-run marginal cost is an indication that the market is functioning competitively.

In the IAMs, most generators are subject to IESO contracts or to payment amounts regulated by the OEB.[38] Well-designed contracts and payment regulation can be an effective way to incentivize competitive behaviour. In particular, well-designed contracts encourage generators to offer at marginal cost or in a manner that ensures they only produce when expected market prices are at, or above, their marginal cost of production,

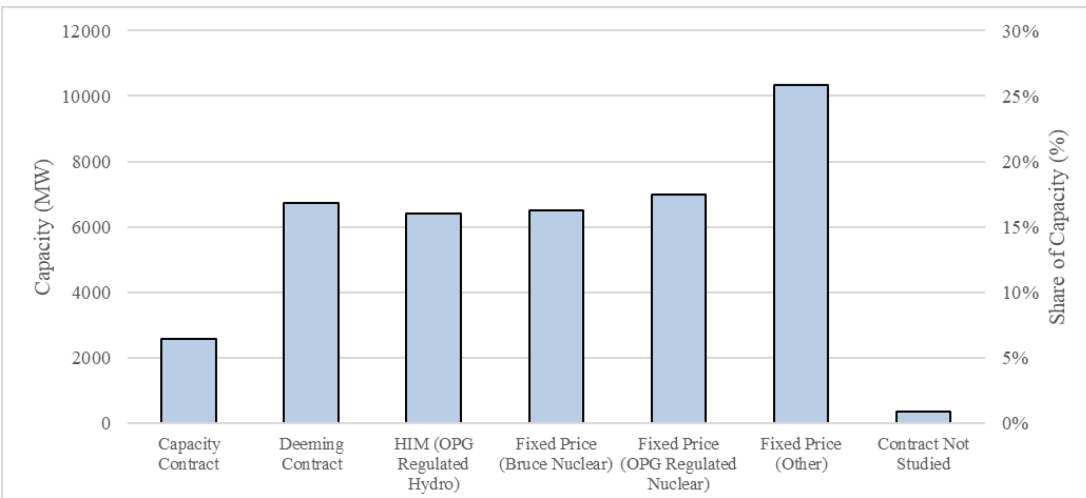
[38] See the IESO's "A Progress Report on Contracted Electricity Supply", Fourth Quarter 2024. A small number of contracts continue to be held by the Ontario Electricity Financial Corporation (OEFC), see OEFC's 2024 Annual Report.

as they would in a perfectly competitive market. Well-designed contracts can promote competitive behaviour and lead to efficient dispatch.

The IESO currently manages over 33,000 contracts with a combined 27 GW of capacity. About 100 of these contracts are for transmission-connected resources, including the 6.5 GW Bruce Nuclear facility, 9.1 GW of natural gas, 2.1 GW of hydroelectric, and 5.4 GW of wind and solar.[39] The remaining contracts include 3.5 GW of distribution connected resources. The OEB regulates the payments of 6.4 GW of OPG hydroelectric assets and the entirety of OPG's 7 GW nuclear capacity. Throughout the monitoring period, less than 1% of wholesale energy generation came from resources without a contract or rate regulation (not including imports).

Figure 29 illustrates generation capacity under payment regulation by the OEB and under each type of contract. The IESO contracts have been categorized into six groups in addition to a "Contract Not Studied"[40] group.

Figure 29 – Regulated and Contracted Capacity by Type, as of April 2025




In previous *State of the Market* reports,[41] the MSP has presented its evaluation of the effectiveness of each contract type at encouraging competitive offer behaviours. The following provides a brief summary of its previous analysis.

Fixed price contracts, which represented 63% of energy supplied during the monitoring period, do not encourage competitive offer behaviour. These contracts encourage

---

[39] Ibid.

[40] "Contracts not Studied" include Atikokan Biomass Energy Supply Agreement (ABESA), Chaudière Falls Contract (CFC), Hydroelectric Standard Offer Program (HESOP) and Non-Utility Generator Enhanced Dispatch Contract (NUGEDC).

[41] *State of the Market* Report 2022 and *State of the Market Report* 2023.

suppliers to produce, regardless of their marginal cost or the prevailing market price, as their revenue comes solely from the contract price which is above their marginal cost. In these instances, the supplier is incentivized to offer as low as the market would allow so it can produce and these offers would not reflect their marginal costs. In contrast, a supplier in a perfectly competitive market would be incentivized to offer its marginal cost to ensure it only produces when the prices are at, or above, their marginal cost, ensuring that there will be no loss in profits. Fixed price contracts offer incentives that will rarely align with competitive offer behaviour as fixed price contracts (i.e., the Feed-in-Tariffs) remove any market price exposure.

In Ontario, fixed price contracts are used primarily for supply resources with low (i.e., zero or even negative) marginal cost and high fixed costs. The contract prices for these resources are well above the marginal cost so that these resources want to run whenever fuel is available. The IESO's Market Rules require these resources to offer at or above certain price floors that reflect the marginal cost of each type of resource. This forces competitive offers by overriding the incentives created by the fixed price contracts.

Deeming contracts, which represented 17% of energy supplied during this monitoring period, are generally used for natural gas resources. These contracts incentivize resource owners to offer the resource capacity to ensure production when and only when expected market prices are above short-run marginal costs, with scope to recover incremental startup cost across the hours of production. Deeming contracts are well designed contracts that incentivize competitive offer behaviour.

The MSP has noted in previous Monitoring Reports[42] that certain aspects of the legacy market design can undermine the effectiveness of deeming contracts at inducing competitive offer behaviour.[43] For example, the interactions between the generator cost guarantee programs and deeming contracts may induce resources to offer below marginal cost in some hours to manage deeming price risk. This offer behaviour does not mimic the offer behaviour of a perfectly competitive supplier. As the MSP has noted, the deficiency rests with the design of the generator cost guarantee programs and not the deeming contracts themselves. The introduction of a Day-ahead market and an Enhanced Real-time Unit Commitment under the IESO's Market Renewal Program is expected to address this issue and improve the incentives for resources with deeming contracts to offer competitively.

Furthermore, the deeming contracts are designed to encourage competitive offer behaviour based on the HOEP. They do not account for the effects of congestion and revenues earned through Congestion Management Settlement Credit (CMSC) payments. As a result, resource owners under deeming contracts may have an incentive to exercise local market power under certain market conditions to maximize their CMSC payments.

[42]

[43] See MSP Report 36, Section 1.6.

They may do so by offering above marginal cost, when they expect to be constrained on, or below, their marginal cost when they expect to be constrained off. The introduction of locational marginal prices in the renewed markets and the amendments to contracts to affect deeming based on locational marginal prices is expected to address this issue and improve the incentives for resources with deeming contracts to offer competitively.

The MSP will monitor the effects of market renewal on the offer behaviour of generators with deeming contracts and report on this in future State of the Market reports.

The Hydro Incentive Mechanism (HIM) is a mechanism designed to encourage OPG to operate its energy-limited hydroelectric stations efficiently by offering its limited energy output in the hours with the highest expected market prices. The mechanism applies to the majority of OPG's hydroelectric generation. The structure of the HIM is preferred over regulated fixed price per MWh of production, which offer no incentives to adjust production according to market conditions.[44] The HIM is designed to encourage OPG's hydroelectric generators with a limited supply of water to hold back production in low-price hours and shift that production to high-price hours. The HIM provides OPG an incentive to offer supply, reflecting the opportunity cost of the limited water while providing the generator revenue security like a fixed-price contract.[45] In anticipation of market renewal, OPG applied in December 2023 for approval of changes to the HIM to align the mechanism with the locational pricing and the day-ahead market design. OPG also proposed the calculation of the HIM be changed from monthly production averaging to daily averaging. On June 13, 2024, the OEB approved the Settlement Proposal that was reached by parties to the proceeding.[46] The changes to the HIM apply from the effective date of market renewal until the effective date of the OEB's payment amounts order for OPG's next rebasing application (for payment amounts effective January 1, 2027).

Finally, a capacity contract is a contract type that provides a resource owner with a fixed monthly payment, designed to cover all or a portion of the resource's fixed operating costs and capital costs. The contract holder can also earn revenues through the wholesale market at market prices (and through CMSC) when it produces. The 2,160 MW Lennox gas and oil facility is under a capacity contract that is largely defined by a fixed $9 million monthly payment. The contract also includes provisions to compensate for select costs

[44] Fifty-four of OPG's 66 hydroelectric stations are rate-regulated and subject to the HIM. In 2024, the rate-regulated price for hydro was $47.52 – base regulated price plus deferral and variance account rate riders (see also OPG 2024 Financial Results).

[45] The MSP noted in Monitoring Report 32 that the intended objective of the HIM may be muted by an OEB-prescribed sharing arrangement that distributes revenue OPG earns above its regulatory approved forecast HIM revenue equally between OPG and Ontario consumers.

[46] See Decision and Order, EB-2023-0336. .

and share net revenues.[47] As of April 30, 2025, the majority of the incoming capacity from recently completed IESO procurements will also be under capacity contracts.

Capacity contracts preserve financial incentives to respond to market signals in the short run but do not mitigate the potential to exercise market power, as generators under a capacity contract can benefit from higher market prices. The implementation of the Market Power Mitigation framework in the renewed markets is expected to protect against the potential exercise of market power.

As of April 2025, the IESO has acquired roughly 4,000 MW of new build, expansion and upgraded capacities through a mix of competitive and bilateral procurements. The 250 MW Oneida battery storage facility was dispatchable effective April 23, 2025, and the 286 MW of total upgraded capacities from the Same Technology solicitation are expected to be online within the next two years.[48] In future *State of the Market* reports, the MSP will analyze the terms of these contracts and comment on their effectiveness at incentivizing competitive offer behaviours. The MSP will also look to assess the impact of the Market Power Mitigation framework on these dynamics.

## 4.3 Summary

In summary, there continues to be a high degree of concentration in the Ontario electricity market. However, for the most part, contracts along with mechanisms such as the market rules and OPG payment regulation incentivized competitive offer behaviour during the monitoring period.

[47] See the Amended and Restated Lennox Energy Supply Agreement, 2021.

[48] The IESO active contracted generation list provides the milestone commercial operation date for each awarded facility.

# Appendix A

The Market Surveillance Panel (MSP) is a panel of the Ontario Energy Board (OEB). Its role is to monitor, investigate and report on activities related to – and behaviour in – the wholesale electricity markets administered by the Independent Electricity System Operator (IESO).

The MSP monitors, evaluates and analyzes activities related to the IESO-Administered Markets and the conduct of market participants to identify:[49]

1. inappropriate or anomalous conduct in the markets, including gaming and the abuse of market power;
2. activities of the IESO that may have an impact on market efficiencies or effective competition;
3. actual or potential design or other flaws and inefficiencies in the Market Rules and procedures; and
4. actual or potential design or other flaws in the overall structure of the IESO-Administered Markets and assess consistency of that structure with the efficient and fair operation of a competitive market.

Market-related activities and market conduct may also be the subject of a more formal and targeted investigation by the MSP. To that end, the MSP has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The MSP reports on the results of its monitoring and investigations. The MSP does not have the legislative mandate to impose sanctions or other remedies in response to inappropriate conduct or market defects, but it does make recommendations for remedial action as it considers appropriate.

[49] See Section 4.1.1 of OEB By-law #2.

# Appendix B

## 1. Electricity Cost Data

Table 6 – Detailed Breakdown of Consumer Cost, 2023-2024

| | Total Consumer Cost ($ million) | | Average Consumer Cost ($ per MWh) | |
|---|---|---|---|---|
| | **2023** | **2024** | **2023** | **2024** |
| **Energy Charges** | **3,989** | **4,581** | **27.47** | **30.47** |
| **Global Adjustment** | **8,713** | **8,419** | **60.00** | **55.99** |
| Contracts | 3,887 | 4,009 | 26.76 | 26.66 |
| OPG Regulated Assets | 3,476 | 2,953 | 23.93 | 19.64 |
| LDC FIT/MicroFIT Contracts | 1,204 | 1,210 | 8.29 | 8.05 |
| Conservation | 147 | 247 | 1.01 | 1.64 |
| **Comprehensive Electricity Plan** | **3,190** | **3,155** | **21.96** | **20.98** |
| **Other Market Costs** | **765** | **809** | **5.27** | **5.38** |
| IESO Administration Charge | 205 | 230 | 1.41 | 1.53 |
| Congestion Management | 106 | 107 | 0.73 | 0.71 |
| Ancillary Services | 81 | 69 | 0.55 | 0.46 |
| Operating Reserve | 47 | 42 | 0.33 | 0.28 |
| Capacity Auction | 70 | 98 | 0.48 | 0.65 |
| Production Cost Guarantee | 54 | 60 | 0.37 | 0.40 |
| Generator Cost Guarantee | 47 | 31 | 0.32 | 0.21 |
| Intertie Offer Guarantee | 43 | 42 | 0.30 | 0.28 |
| Other | 113 | 131 | 0.78 | 0.87 |
| **Delivery** | **6,748** | **7,182** | **46.46** | **47.76** |
| Distribution | 4,467 | 4,733 | 30.76 | 31.48 |
| Transmission | 2,281 | 2,449 | 15.71 | 16.28 |
| **Total Before Government Programs** | **23,406** | **24,146** | **161.16** | **160.58** |
| **Government Programs** | **- 5,793** | **- 6,807** | **- 39.89** | **- 45.27** |
| Comprehensive Electricity Plan | - 3,190 | - 3,155 | - 21.96 | - 20.98 |
| Ontario Electricity Rebate | - 1,547 | - 2,477 | - 10.65 | - 16.47 |
| Other[50] | - 1,056 | - 1,175 | - 7.27 | - 7.81 |
| **Total Net of Government Programs** | **17,613** | **17,339** | **121.27** | **115.31** |

[50] "Other" government programs include: Fair Hydro Plan, Northern Energy Advantage Program, Rural or Remote Electricity Rate Protection, First Nations On-Reserve Delivery Credit, Distribution Rate Protection, and the Ontario Electricity Support Program.

Figure 30 – Total Consumer Cost (All-In Cost), Monthly, January 2023 – April 2025

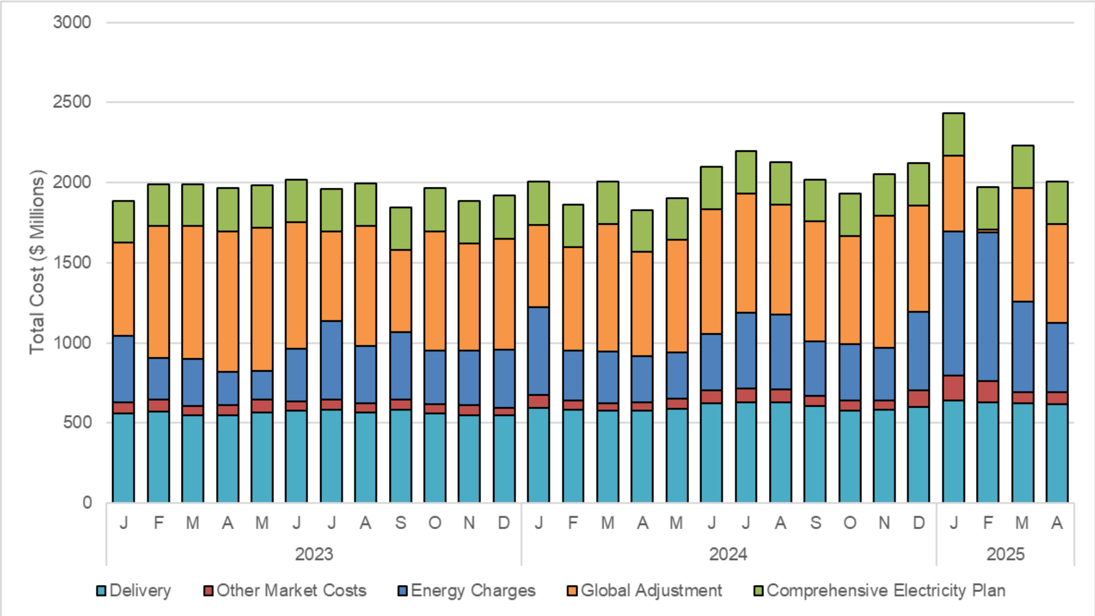
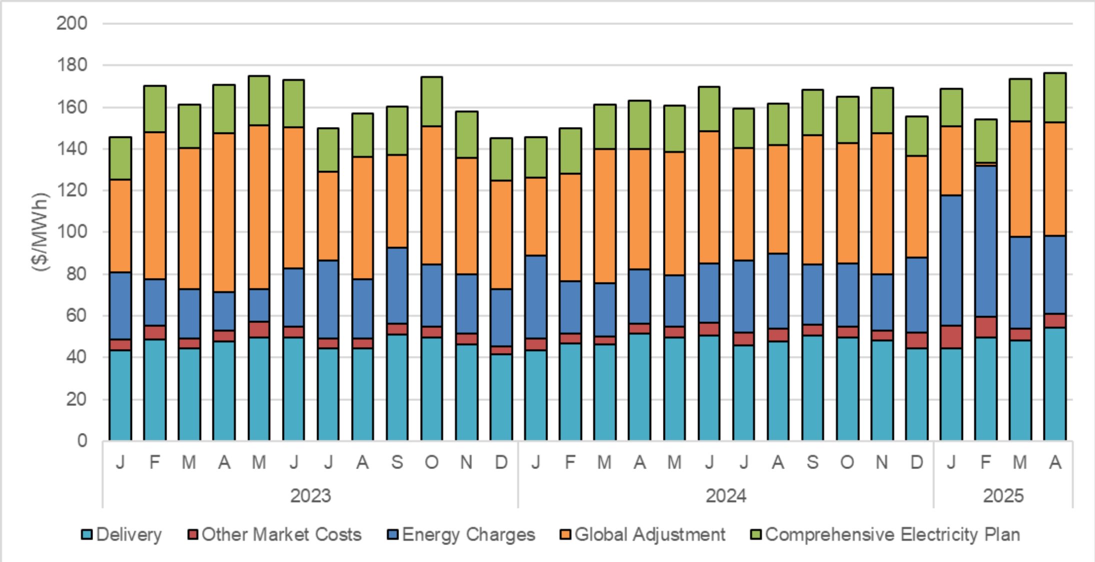



Figure 31 – Average Consumer Cost (All-in Unit Cost), Monthly, January 2023 – April 2025






Ontario Energy Board

Figure 32 – Annual Global Adjustment by Component, 2015-2024

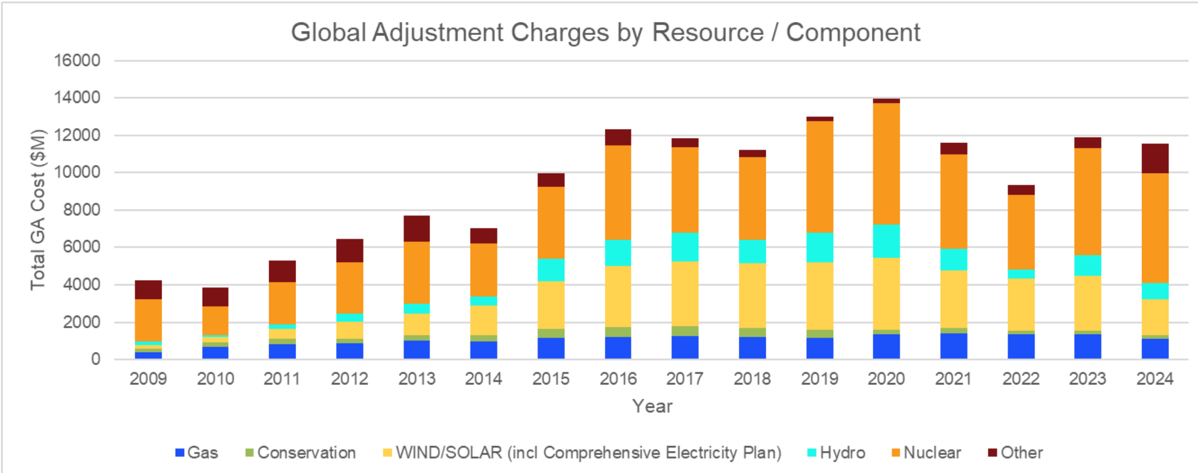
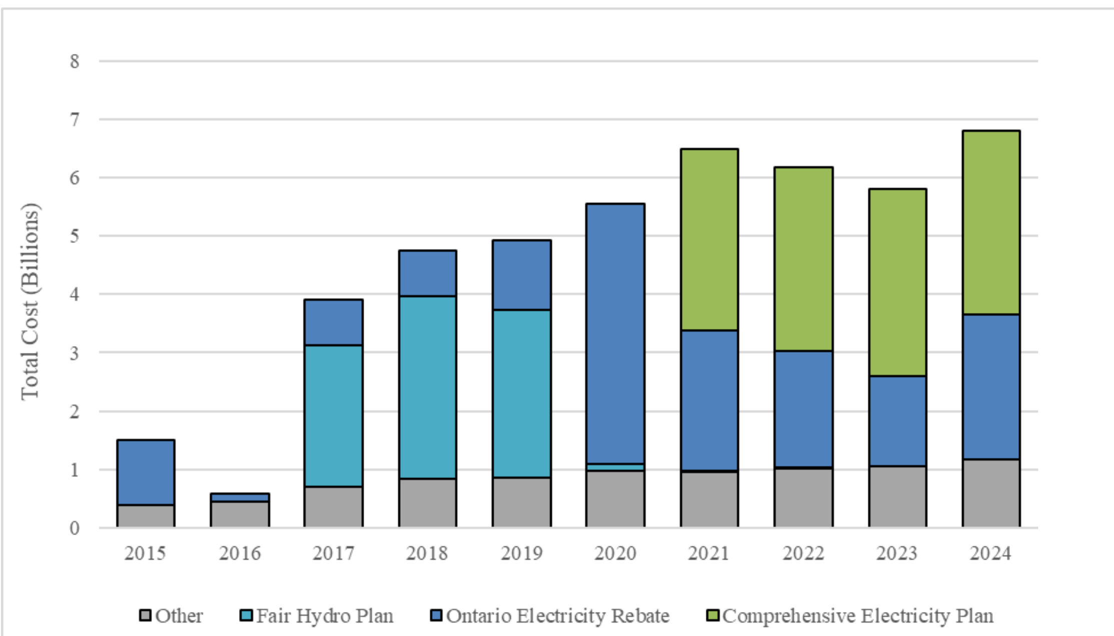



Figure 33 – Government Program Spending, 2015-2024



## 2. Demand, Supply, Price Outcomes

Figure 34 – Annual Ontario Demand, 1997-2024

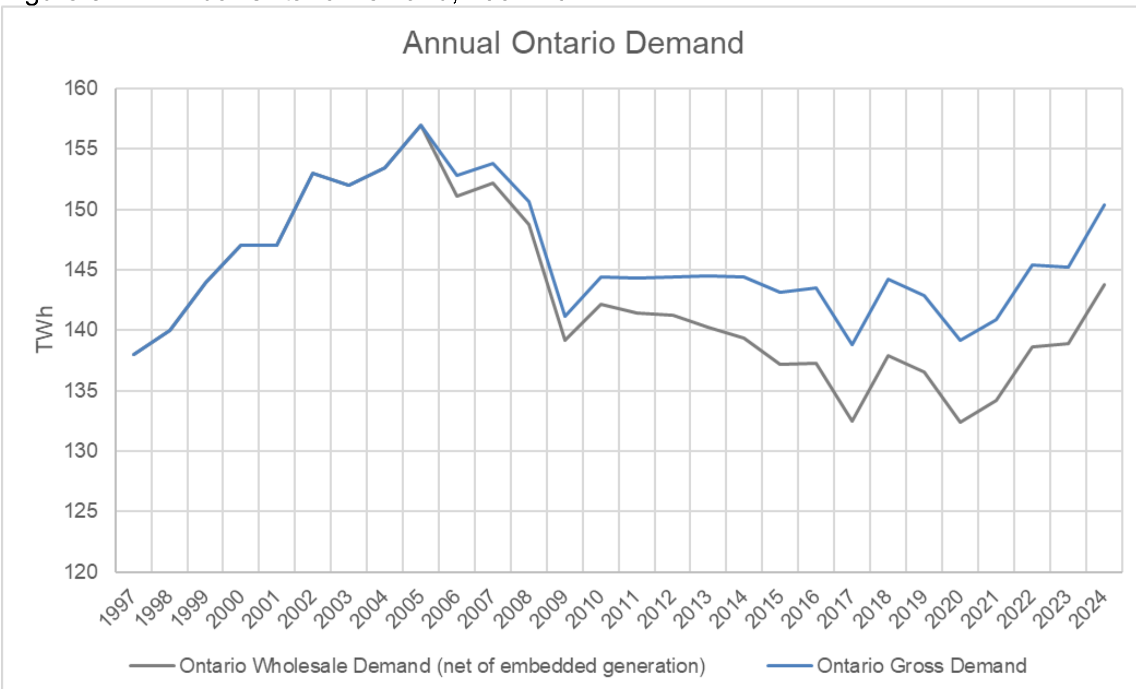
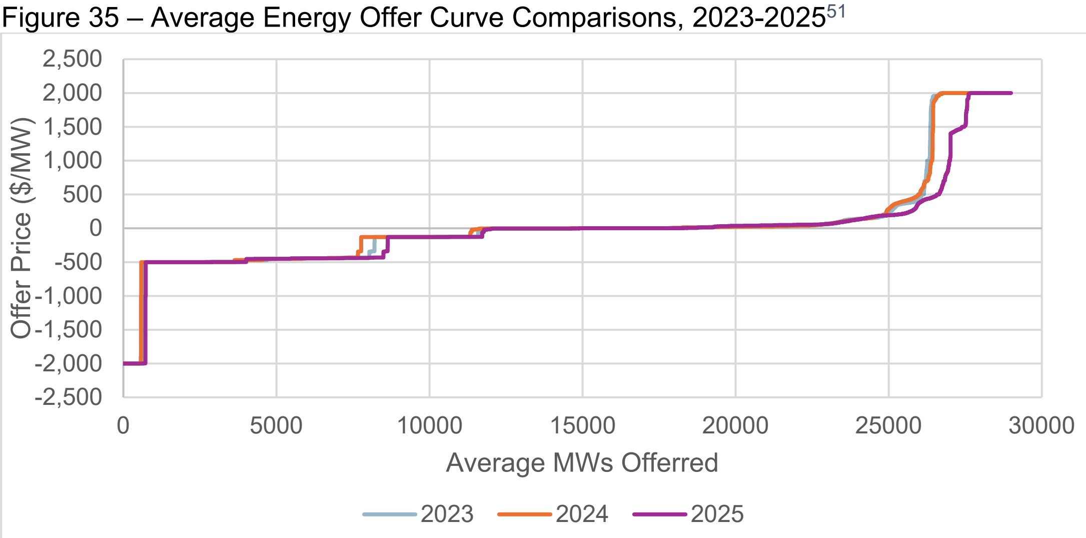



Figure 35 – Average Energy Offer Curve Comparisons, 2023-2025[51]




[51] Year 2025 is only up to end of April 2025.



Ontario Energy Board

3. Consolidated list of IESO capacity purchases (as of April 30, 2025)

Table 7 – Historical Capacity Auction Results: Summer Obligation Period

| (May 1 – Oct 31) | Target (MW) | Actual (MW) | Capacity Auction Clearing Price ($/MW-day) |
|---|---|---|---|
| 2021 | 700 | 992.1 | 197.58 |
| 2022 | 1,000 | 1,286.7 | 264.99 |
| 2023 | 1,200 | 1,430.6 | 313.78 |
| 2024 | 1,400 | 1,867.2 | 367.41 |
| 2025 | 1,600 | 2,122.2 | 332.39 |

Table 8 – Historical Capacity Auction Results: Winter Obligation Period

| (Nov 1 – April 30) | Target (MW) | Actual (MW) | Capacity Auction Clearing Price ($/MW-day) |
|---|---|---|---|
| 2022/2023 | 500 | 841.9 | 60 |
| 2023/2024 | 750 | 1,160 | 130.75 |
| 2024/2025 | 850 | 1,310.8 | 146.96 |
| 2025/2026 | 1,000 | 1,524.6 | 139 |

Table 9 – E-LT1 Result: Storage Category

| Proponent | Nameplate Capacity (MW) | Summer Contract Capacity (MW) | Winter Contract Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW- day)[52] |
|---|---|---|---|---|---|
| Hagersville Battery Storage Inc | 300 | 285 | 285 | 786.25 | 538.36 |
| Napanee BESS Inc. | 265 | 250 | 250 | 896.92 | 675.97 |
| Tilbury Battery Storage Inc | 80 | 76 | 76 | 774.50 | 530.48 |
| Walker BESS 4 Limited Partnership Walker BESS 4 | 4.999 | 4.749 | 4.749 | 997.00 | 682.88 |
| Walker BESS 4 Limited Partnership Walker BESS 5 | 4.999 | 4.749 | 4.749 | 998.00 | 683.56 |
| Walker BESS 4 Limited Partnership Walker BESS 6 | 4.999 | 4.749 | 4.749 | 998.99 | 683.56 |
| York (Battery) LP | 120 | 114 | 114 | 825.50 | 565.07 |
| 1000234763 Ontario Inc SFF 06 | 4.99 | 4.74 | 4.74 | 1,477 | 1,011.64 |
| 1000234763 Ontario Inc 903 | 4.99 | 4.74 | 4.74 | 1,477 | 1,011.64 |
| 1000234763 Ontario Inc OZ-1 | 4.99 | 4.74 | 4.74 | 1,477 | 1,011.64 |
| Arlen Energy Storage 1 LP | 20 | 19 | 19 | 1,224 | 838.36 |

[52] Calculated as (Fixed Capacity Payment * 250 business days)/no. of days in a year. Note that some IESO procurement mechanisms do not recognize bank holidays.

| Proponent | Nameplate Capacity (MW) | Summer Contract Capacity (MW) | Winter Contract Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW- day)[52] |
|---|---|---|---|---|---|
| Goreway (Battery) LP1 | 50 | 47.5 | 47.5 | 1,007 | 689.73 |
| Vaughan 1E Energy Storage 1 LP | 20 | 19 | 19 | 1,186 | 812.33 |
| Vaughan 3 Energy Storage 1 L.P. | 40 | 38 | 38 | 1,028 | 704.11 |
| Walker BESS 4 Limited Partnership | 4.999 | 4.749 | 4.749 | 969 | 663.70 |

Table 10 – E-LT1 Result: Non-Storage Category

| Proponent | Nameplate Capacity (MW) | Summer Contract Capacity (MW) | Winter Contract Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW-day) |
|---|---|---|---|---|---|
| East Windsor (Expansion) L.P | 106 | 81 | 100 | 894.75 | 612.84 |
| Greenfield South Power Inc | 212.5 | 175 | 195 | 1,195.00 | 818.49 |

Table 11 – Same Technology Upgrade Result

| Proponent | Facility | Average Capacity (MW) | Average Upgrade Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW-day) |
|---|---|---|---|---|---|
| Portlands Energy Centre L.P. | PORTLANDS ENERGY CENTRE | 550 | 50 | n/a | n/a |
| Portlands Energy Centre L.P. | HALTON HILLS GENERATING STATION | 641.5 | 31.5 | n/a | n/a |
| Goreway Station Partnership | GOREWAY POWER STATION | 839 | 40.4 | n/a | n/a |
| Greenfield Energy Centre L.P. | GREENFIELD ENERGY CENTRE | 1,005 | 35 | n/a | n/a |
| Thorold CoGen L.P. | THOROLD COGENERATION PROJECT | 241.6 | 23 | n/a | n/a |
| St. Clair Power L.P. | ST. CLAIR ENERGY CENTRE | 577 | 68.5 | n/a | n/a |
| York Energy Centre L.P. | YORK ENERGY CENTRE | 393 | 38 | n/a | n/a |
| | ***Total*** | ***4247.1*** | ***286.4*** | n/a | n/a |
| | | | ***Weighted average price*** | ***537*** | ***367.81*** |

Table 12 – Medium-Term RFP (MT1) Result

| Proponent | Nameplate Capacity (MW) | Contracted Seasonal UCAP (MW) – Summer | Contracted Seasonal UCAP (MW) – Winter | Capacity Price ($/UCAP MW – BusinessDay | Fixed Capacity Payment ($/MW-day) |
|---|---|---|---|---|---|
| Melancthon Wolfe Wind LP | 67.5 | 5.04 | 12.32 | 469.95 | 321.88 |
| Atlantic Power Limited Partnership | 20.9 | 20.506 | 22.182 | 250.00 | 171.23 |
| Cochrane Power Corporation | 42.0 | 25.02 | 28.73 | 265.00 | 181.51 |
| TransAlta (SC) LP | 499.0 | 186.44 | 239.04 | 469.95 | 321.88 |
| Greater Toronto Airports Authority | 127.64 | 71.66 | 77.69 | 470.00 | 321.92 |
| ***Total*** | ***757.04*** | ***308.67*** | ***379.96*** | | |

Table 13 – Long-Term RFP (LT1) Result: Storage Category

| Proponent | Nameplate Capacity (MW) | Maximum Contract Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW-day) |
|---|---|---|---|---|
| Almonte BESS Limited Partnership | 9.99 | 9.49 | 999 | 684.25 |

| Proponent | Nameplate Capacity (MW) | Maximum Contract Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW-day) |
|---|---|---|---|---|
| Edgeware BESS Project Limited Partnership | 75 | 71.25 | 888 | 608.22 |
| Elora BESS LP | 210.53 | 200 | 595 | 407.53 |
| Fitzroy BESS Inc. | 265.50 | 250 | 669.60 | 458.63 |
| Hedley BESS LP | 210.53 | 200 | 617 | 422.60 |
| North Glengarry BESS Limited Partnership | 16.30 | 15.48 | 949 | 650.00 |
| Oxford Battery Energy Storage Project Inc | 125 | 118 | 710 | 486.30 |
| Neoen Ontario BESS 1 Inc. | 400 | 380 | 651.50 | 446.23 |
| Skyview BESS Limited Partnership | 411 | 390 | 682 | 467.12 |
| Trailroad BESS Inc. | 159.30 | 150 | 699.94 | 479.41 |
| **Total MW** | 1,883.15 | 1,784.22 | | |

| Proponent | Nameplate Capacity (MW) | Maximum Contract Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW-day) |
|---|---|---|---|---|
| | | **Weighted average price** | 672.32 | 460.49 |

Table 14 – Long-Term RFP (LT1) Result: Non-storage Category

| Proponent | Nameplate Capacity (MW) | Maximum Contract Capacity (MW) | Fixed Capacity Payment ($/MW Business Day) | Fixed Capacity Payment ($/MW-day) |
|---|---|---|---|---|
| Bolton Manor Resilient Generation Inc. | 1 | 0.95 | 2,380 | 1,630.14 |
| Portlands Energy Centre L.P. (doing business as Atura Power) | 430 | 405 | 1,674.01 | 1,146.58 |
| Walker Resilient Generation Inc. | 4.99 | 4.74 | 2,150 | 1,472.60 |
| **Total MW** | 435.99 | 410.69 | | |
| | | **Weighted average price** | 1,681.14 | 1,151.47 |