Ontario Energy Board | Commission de l'énergie de l'Ontario

Market Surveillance Panel Report 36

MONITORING REPORT ON THE IESO-ADMINISTERED ELECTRICITY MARKETS

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Table of Contents

List of Figures

List of Tables

Role of the Market Surveillance Panel

The Market Surveillance Panel (Panel) 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 Panel monitors, evaluates and analyzes activities related to the IESO-Administered Markets and the conduct of Market Participants to identify:

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 Panel. To that end, the Panel has authority under the *Electricity Act, 1998* to compel testimony and the production of information.

The Panel reports on the results of its monitoring and investigations. The Panel 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.

Executive Summary

This is the 36th Market Surveillance Panel Monitoring Report published since market opening in 2002. The report includes a general assessment of the efficiency and competitiveness of the IESO-Administered Markets. The report also notes recent electricity sector events (Chapter 1), as well as events in the monitoring period November 1, 2020 to April 30, 2021 – referred to as the Winter 2020/21 Period (Chapter 2 and Appendix A).

This Monitoring Report is broken down into two chapters and two appendices:

- Chapter 1: General Assessment and Market Developments
- Chapter 2: Analysis of Anomalous Market Outcomes
- Appendix A: Market Outcomes for the Winter 2020/21 Period
- Appendix B: Status of Panel Recommendations

Chapter 1: General Assessment and Market Developments

In this Monitoring Report, the Panel provides its annual general assessment of the state of the IESO-Administered Markets (IAM), including their efficiency and competitiveness. Based on its general assessment, the Panel concludes the following.

On balance, the Panel finds the real-time energy market to be reasonably competitive and efficient on a short-term basis. Competitive and efficient market outcomes are currently achieved largely because of regulated or contracted incentives that induce generators to offer at marginal cost, including opportunity cost. Insofar as contracts continue to be required for reliability, the Panel encourages the IESO to use incentive terms that induce efficient marginal-cost offers.

However, known market design deficiencies, including the two-schedule system and the Real-time Generation Cost Guarantee program continue to negatively impact short-term market efficiency. Furthermore, as noted in previous Panel reports, certain contracts, such as fixed price generator contracts, and the revenue sharing elements of the OPG Hydroelectric Incentive

Mechanism, can distort the incentives for generators to offer in the wholesale market at prices that reflect their marginal cost (including opportunity) cost. Finally, the Industrial Conservation Initiative induces consumers to inefficiently reduce consumption in response to price signals that are well above the marginal cost of energy and new capacity.

Ontario Power Generation (OPG) and its subsidiaries control more than 50% of registered generation capacity. This level of concentration in a market generally raises competitiveness concerns. Measures such as regulatory licence conditions and direction from OPG's sole shareholder, the Ontario government, through a Memorandum of Understanding are designed to allay concerns about OPG's dominance by providing it with incentives to act competitively in the IAM.

The long-run efficiency of the IAM relates to optimizing investment decisions for electricity resources, including market entry and exit. Most investment in the past decade has not been competitive. There is a projected capacity need which the IESO plans to meet using both competitive and non-competitive processes. In the Panel's view, long-run efficiency can be improved by using competitive mechanisms wherever possible and by providing more transparent information on resource needs. Independent oversight of the IESO's needs assessments and procurement decisions would increase the accountability of the current process and foster a greater degree of confidence in the IAM.[1]

Chapter 2: Analysis of Anomalous Market Outcomes

This chapter deals with events in the Winter 2020/21 Period that exceed predefined thresholds established to identify outcomes considered anomalous and are therefore potentially significant for the IESO-Administered Markets. Of particular note is the high level of Congestion Management Settlement Credit payments, which totalled $65 million for the Winter 2022/21

[1] See the Panel's Monitoring Report 33 published December 2020, Section 3.5 "Oversight of Capacity Need Assessment and Procurements", page 59: https://www.oeb.ca/sites/default/files/msp-monitoring-report-202012.pdf

Period. Of this total, $22 million was paid to imports from Manitoba as a result of reliability challenges in the Northwest that led the IESO to take several actions to manage supply and demand conditions.

Chapter 1: General Assessment and Market Developments

1.1 General Assessment

Once a year, the Panel provides a report of its general assessment of the state of the IESO-Administered Markets (IAM), including their efficiency and competitiveness.[2]

Efficiency pertains to the allocation of goods and the inputs used to produce the goods in a market. A market is considered efficient when the goods and productive inputs are allocated to their most valuable uses and waste is eliminated or minimized.

Competitiveness pertains to the ability and performance of firms in a market in relation to the ability and performance of other firms in the same market. The extent of competition in a market may be influenced by the number of firms in the market and the relative size of each firm in terms of their share of output and productive assets. Markets with many firms, each owning a relatively small and similar share of output are more likely to exhibit vigorous competition than markets with one or a few firms owning a large share of output.

There is a relationship between efficiency and competitiveness: markets are more likely to be efficient when there is vigorous competition. Economists place importance on the ideal concept of perfect competition. A perfectly competitive market has many firms and buyers that can enter or exit the market with ease, and that have no influence over the market price. Perfectly competitive markets are "first-best" efficient, though they rarely, if ever, exist in the real world. Economists use the concept of perfect competition as a benchmark for evaluating the efficiency

[2] The IESO administers several separate but related markets, including the energy market, the operating reserve market, capacity markets, and transmissions rights auctions. IESO procurements may also indirectly affect the IAM. See OEB By-law #2, Market Surveillance, Article 7, available at: https://www.oeb.ca/sites/default/files/OEB-bylaw-2-20201002.pdf.

of a market and the extent to which the market outcomes deviate from the competitive equilibrium.[3]

The Panel applies these concepts in its general assessment of the state of the IAM. In conducting its assessment, the Panel recognizes that the Ontario electricity market, which includes the IAM, is a hybrid market in which energy and operating reserves (OR) are procured in day-ahead and real-time competitive auctions, while capacity is determined through a long-term planning process and procured by the IESO through bilateral contract negotiations, competitive contract tender, or a capacity auction. An additional feature of the hybrid market is the presence of a large government-owned generator, Ontario Power Generation (OPG). Most of OPG's generation capacity is rate regulated by the Ontario Energy Board (OEB). Furthermore, the Ontario Government sets policies for the hybrid market that are in addition to, and at times in tension with, the goals of efficiency and competitiveness. The Panel conducts its assessment of the efficiency and competitiveness of the IAM with recognition of government policies.

The Panel's last general assessment, incorporated in Monitoring Report 32, was released July 2020.[4] Monitoring Report 32 provided a broader and more in-depth look at the state of the IAM than previous general assessments. The Panel believed a more in-depth assessment was appropriate and timely given the significant market design changes under development – including changes to the energy market and expansion of the Demand Response (DR) Auction to include generators and other resources. While more in-depth than previous general assessments, the analysis in Monitoring Report 32 was still largely qualitative in nature. From a

[3] In a perfectly competitive market, firms produce up to the point where the last unit produced provides a marginal benefit to consumers equal to the marginal cost of production. The market clears at a price equal to the marginal cost of the marginal supplier, industry output is supplied by firms with a cost at or below this price, and it is consumed by all consumers and only those consumers whose willingness to pay to consume is no less than this price. At this price, total gains realized by consumers and firms from participating in the market are maximized; there is no waste or deadweight loss.

[4] See the Panel's Monitoring Report 32 published July 2020, Section 1.1: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

qualitative perspective, very little has changed in the IAM since the Panel's last general assessment. This assessment provides minor updates to the Panel's previous general assessment, and draws similar conclusions as follows:

- Ontario Power Generation continues to be the largest capacity, energy, and operating reserve provider in the IAM. OPG and its wholly owned subsidiary Atura Power control more than 50% of the province's registered generation capacity and more than 66% of the price-sensitive generation capacity.[5] This level of concentration in a market generally raises concerns regarding the competitiveness of the market. This concern is partially attenuated in the current IAM by the various regulatory measures imposed by the OEB on OPG and Atura Power, and the direction provided to OPG by its sole shareholder, the Ontario government, through a Memorandum of Understanding.
- The real-time energy and OR markets are reasonably competitive and efficient on a short-term basis. Competitive and efficient market outcomes are possible in highly concentrated markets if regulatory incentive measures are placed on suppliers that mimic the incentives facing suppliers in a perfectly competitive market. In Ontario, most generators are subject to regulatory or contractual terms that influence their participation in the IAM, including OPG as mentioned above. For the most part, these incentives encourage the generators to offer competitively, reflective of their marginal production cost.
- Nevertheless, two well-known market design deficiencies – namely the two-schedule system and the Real-time Generation Cost Guarantee (RT-GCG) program – contribute to short-term inefficiencies. These design inefficiencies can induce non-competitive offers and strategic behaviour that undermine the regulatory and contractual incentives for generators to offer reflective of their marginal cost.

[5] Atura Power was registered in October 2019 as the brand name for a wholly owned subsidiary of OPG which now operates four large gas-fired generating stations that OPG has acquired since 2019. The OPG transaction to acquire assets (Napanee Generating Station (GS), Halton Hills GS and the remaining 50% stake in Portlands Energy Centre GS) from affiliates of TC Energy closed on April 29, 2020, with the assets now being owned and operated by Portlands Energy Centre L.P. The OPG transaction to acquire the remaining stake in the Brighton Beach Generating Station from Canadian Utilities Limited was completed in August 2019.

- Much of the long-term investment over the last decade has not been very competitive, imposed unnecessarily high costs on Ontario consumers and removed the transparency of price signals that lead to economic-based decision making. Looking forward, the IESO projects an emerging need for peak capacity in the middle of the decade, as well as for energy towards the end of the decade. In the Panel's view, to restore the long-run efficiency of the IAM, comprehensive and transparent needs assessments and competitive procurement processes should be used as much as possible. Furthermore, as contracts expire, competition should be opened to both new and existing resources to allow the retirement of older, less efficient resources. Independent oversight of the IESO's needs assessments and decisions around choice of competitive vs. bilateral procurements would increase the accountability of the current process and foster a greater degree of confidence in the IAM.

The Panel intends to build on the approach it uses in this general assessment in its future assessments, by adding more quantitative measures of the relative efficiency of the IAM. The Panel believes that the use of these quantitative measures, prior to and post implementation of the Market Renewal Program (MRP) initiatives, will offer a firm, objective foundation for evaluating the evolving market, and to highlight areas of the new design that would benefit from further improvement.

The remainder of the general assessment is organized according to the two assessment objectives of competitiveness and efficiency. Given that the IESO administers several interrelated markets, the Panel has presented the information both individually and by combined products/markets.

1.2 Competitiveness

The extent of competition of a market can be evaluated in terms of the degree of concentration in the market. From a structural point of view, markets are more competitive and require less regulation when ownership is diverse than when ownership is concentrated. The Panel applies two types of structural analyses to assess the competitiveness of the IAM: market share analysis and pivotal supplier analysis.

1.2.1 Market Share

One measure of market concentration is market share. Market share is the percentage share of total market capacity or output owned (or controlled) by a firm. A market with a (i) single firm owning 50%, or (ii) a group of firms that can coordinate with one another owning 65% of the capacity/output may be considered highly concentrated. When market shares exceed these thresholds, the potential competitiveness of the market becomes a cause for concern prompting additional analysis.[6]

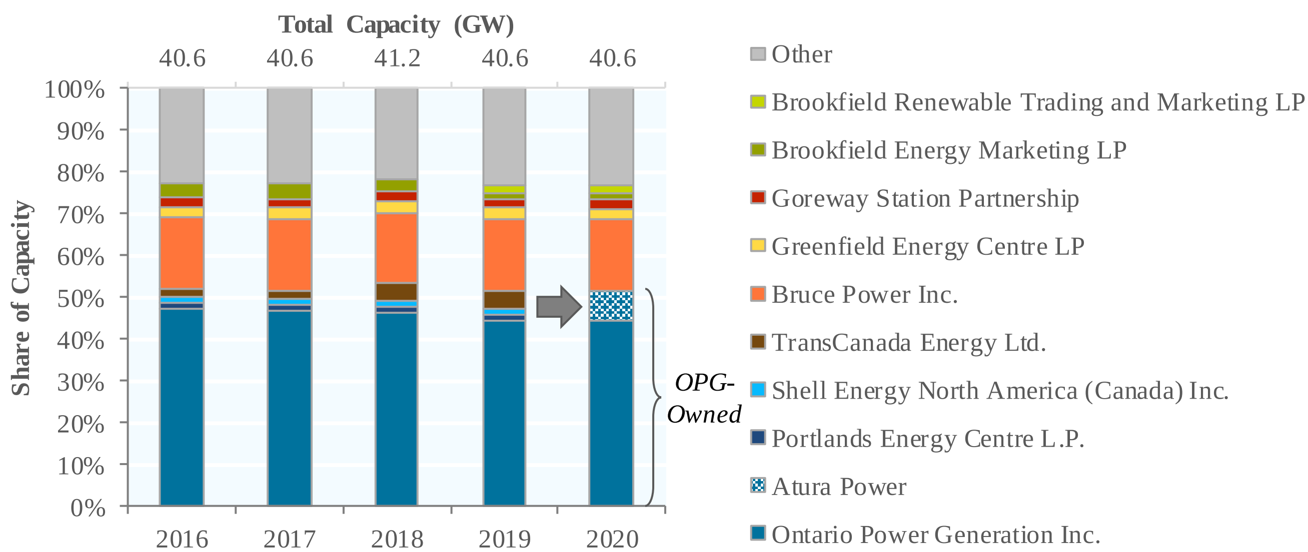
Figure 1-1 shows the share of total installed/registered capacity by registered Market Participant.[7,8] Most of the small Market Participants included in the Other category are limited partnerships which own and operate a single facility.

[6] For example, the Canadian Competition Bureau uses market shares as an initial screening mechanism to assess allegations of abuse of dominance. A single firm market share of 50% or more or a combined market share of 65% of a group of firms alleged to be jointly dominant prompts further examination for anti-competitive outcomes. See Competition Bureau Canada, "Abuse of Dominance Enforcement Guidelines": https://www.competitionbureau.gc.ca/eic/site/cb-bc.nsf/vwapj/CB-ADEG-Eng.pdf/$file/CB-ADEG-Eng.pdf

[7] A registered Market Participant is the Market Participant that is registered with the IESO to submit dispatch data with respect to a registered facility. The Market Participant may not be the owner of the facility. Many of the registered Market Participants in the IAM have complex ownership structures. For example, a single developer may have partial ownership of several limited partnerships which are registered separately. Market share analysis is typically conducted in terms of ownership or control. Market share in terms of ownership is not presented here due to data limitations.

[8] In these figures, generation capacity operating under the brand name Atura Power is displayed under that name. All other capacity is displayed using legal names as registered in the energy and operating reserve markets.

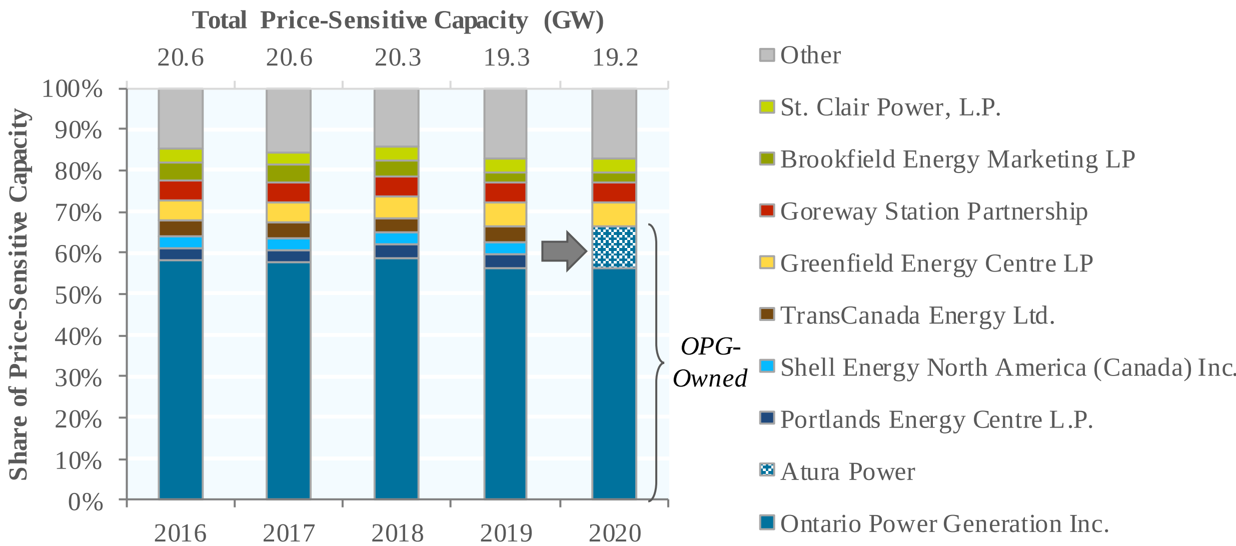
Figure 1-1: Registered Capacity by Market Participant, 2016-2020



Ontario Power Generation (OPG) is the largest Market Participant in the IAM in terms of share of capacity, with roughly 44% as a registered Market Participant and a combined share, including its subsidiary Atura Power, of more than 50%.

Figure 1-2 shows that OPG as a registered Market Participant controls more than 56% of Ontario's "price-sensitive" generation (including most hydroelectric, gas/oil and biofuel generation), while OPG and its subsidiary Atura combined control more than 66% of that generation. Hydroelectric and gas generation set the real-time Market Clearing Price (MCP) approximately 74% of the time in 2020. OPG's high concentration of Ontario's price-setting generation and its large share of infra-marginal "baseload" generation, absent mitigation, creates an incentive for OPG to distort the energy MCP.

Figure 1-2: Price-Sensitive Generation Registered Capacity by Market Participant, 2016-2020

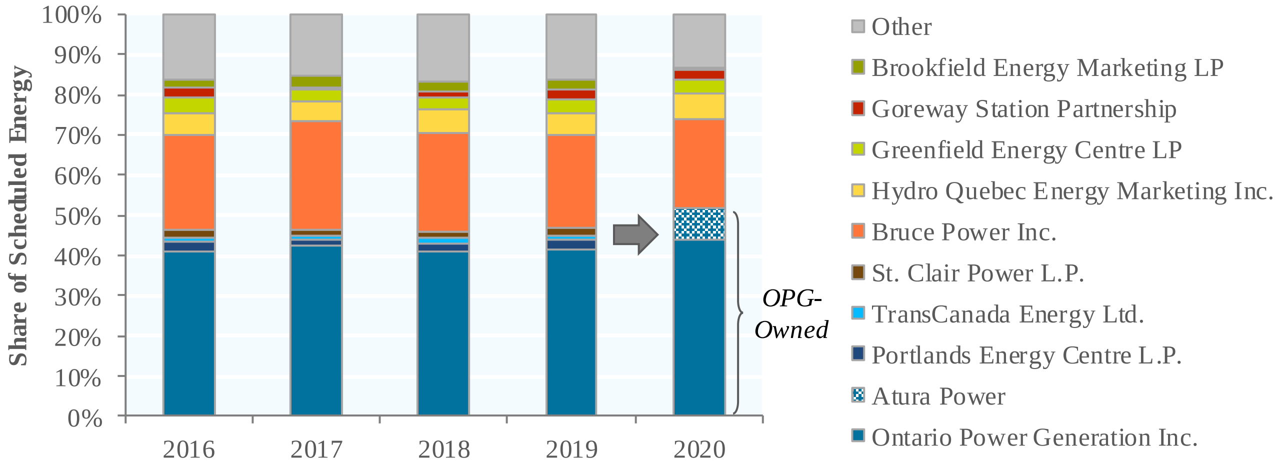


Concentration of the IAM can also be examined in terms of a Market Participant's share of output (measured as unconstrained energy and OR schedules) for the supply of energy and OR in the real-time market. Although market power can be exercised at any time, high demand hours warrant additional attention. When surplus supply is limited, there is a greater risk that a supplier could exercise market power. Periods of high, inelastic demand also tend to have higher and more volatile energy prices, which increases the potential impact of market power.

Results for the real-time energy market are presented in Figure 1-3. Again, this figure shows that the market is concentrated with OPG controlling approximately 52% of energy supply in the highest demand hours. The supply of OR in those hours, however, is somewhat more diverse.

In short, market share analysis indicates that the IAM are highly concentrated. OPG with its wholly owned subsidiary Atura is the dominant supplier in the IAM. OPG's share of registered capacity and energy output exceeds the typical threshold for single-firm market dominance.

Figure 1-3: Constrained Energy Schedule by Market Participant (MP), Top 100 Market Demand Hours, 2016-2020



1.2.2 Pivotal Supplier

Another structural measure of the competitiveness of a market is the pivotal supplier test. The pivotal supplier test provides insights into a participant's potential to influence the price of energy and OR. A Market Participant is said to be pivotal if offers from at least some of the generation under its control are required for the market to clear.[9] When a large participant is pivotal, in principle, there is insufficient competition from other suppliers to discipline the large supplier's price setting ability. If one or more Market Participants is frequently pivotal, it is a sign of a highly concentrated market. The pivotal supplier test is an indicator of suppliers' ability to exercise market power. It is not evidence that an actual exercise of market power has occurred. More direct measures of market power are required to establish the actual exercise of market power.

[9] More formally, the residual supply index (RSI) is defined on an hourly basis as [(Ontario generation offers + net imports – dispatchable load bids) – offers of the largest Market Participant)] / (Ontario non-dispatchable demand + OR requirements). A Market Participant is said to be pivotal in an hour if the RSI is less than or equal to 1 (see Table 1-1). Because the RSI is based on offers, it does not consider capacity that is available but chooses not to submit an offer. When calculating RSI for Price-Sensitive Resources, offers from nuclear, wind, solar, and self-scheduling supply and net imports are removed from the numerator, and demand served by those suppliers is removed from the denominator.

Table 1-1 shows the percentage of hours in the year in which there was at least one pivotal supplier in the energy market. Two pivotal supplier measures are presented. The first considers total supply to consumers in the Ontario market, and the second considers the same price-sensitive generators as Figure 1-2. The second measure excludes self-scheduling generators and low marginal cost fuel types (i.e. nuclear, wind and solar) which are typically incented by their contracts to generate without regard to price unless manually curtailed by the IESO. The remaining 19 GW of resources, mainly gas/oil and hydroelectric, are expected to operate only if their energy and OR payments exceed their variable costs. The alternative pivotal supplier measure focuses on a subset of resources which are more active in the real-time market and more likely to set prices above $0/MWh.

Table 1-1: Percentage of Hours with a Pivotal Supplier, 2016-2020

Year	All Resources	Price-Sensitive Resources
2016	82%	100%
2017	43%	99%
2018	33%	99%
2019	36%	99%
2020	42%	98%
2016 to 2020	**47%**	**99%**

Between 2016 and 2020, OPG was a pivotal Market Participant in approximately 47% of hours. When considering only price-sensitive resources, OPG was a pivotal Market Participant nearly 100% of the time. In some hours with relatively tight supply there was more than one pivotal Market Participant. The high pivotal supplier measure for price-sensitive resources is a consequence of OPG’s high share of price-sensitive generation capacity.

1.2.3 Assessment

The results of the market share and pivotal supplier analyses are indicative of a highly concentrated market structure with the provincially owned generator OPG the dominant supplier in the IAM. This does not mean there is uncompetitive and inefficient market behaviour or outcomes but instead provides an initial screening prompting additional analysis.

The Ontario Energy Board and the Ontario government have implemented various measures within the hybrid market that are intended to address concerns with respect to OPG's dominance. For example, the OEB imposed a "Must-Offer Condition" on OPG and its wholly-owned subsidiary Atura to address market power concerns. The OEB requires "OPG at all times to offer all available generating capacity" into the markets administered by the IESO to "ensure that [OPG's] generation assets… fully participate" in the IAM.[10] Atura Power is subject to the same requirement. Furthermore, under Section 78.1 of the *Ontario Energy Board Act, 1998*, the OEB is authorized to determine the payment amounts to be made to OPG with respect to the output of its prescribed nuclear and hydroelectric generation assets. Under that authority the OEB sets the rates for these assets as well as, in the case of hydroelectric assets, incentives to offer energy in a manner which reduces overall system costs. Finally, OPG's Memorandum of Agreement with its sole shareholder, the Province of Ontario, among other things requires OPG to serve the public interest and operate in a way that moderates overall prices and supports the efficient operation of the electricity market.[11]

[10] The Must-Offer Condition Agreement signed by OPG and the IESO also sets out the IESO's role in monitoring compliance with this Must-Offer Condition. The OEB indicated that it expects the Panel to monitor and report on the impact of OPG's acquisitions on the IAM.
For more on the licence conditions, see the OEB Decision and Order dated April 9, 2020 (EB-2019-0258 / EB-2020-0110):
http://www.rds.oeb.ca/HPECMWebDrawer/Record/674020/File/document
For more on the Must-Offer Condition Agreement, see the OEB correspondence dated October 15, 2020 (EB-2020-0110):
http://www.rds.oeb.ca/HPECMWebDrawer/Record/689938/File/document and
http://www.rds.oeb.ca/HPECMWebDrawer/Record/689936/File/document
[11] Memorandum of Agreement between Her Majesty the Queen in right of Ontario, as represented by the Minister of Energy (the "Shareholder" or "Minister") And Ontario Power Generation, Inc. ("OPG"):
https://www.opg.com/about-us/corporate-governance-and-leadership/our-operating-principles/memorandum-agreement/

These measures are designed to allay concerns about OPG's dominance by providing it with the incentives to act competitively in the IAM. While the sheer size of OPG, its government ownership, and its inevitable ability to affect prices – either above or below efficient levels – through its production decisions means it will remain a focus of the Panel's monitoring, the Panel will continue to assess competitiveness across the entire market.

1.3 Efficiency

In this section, the Panel provides a brief update to the efficiency assessment it conducted in Monitoring Report 32. The assessment includes a qualitative review of the short-term efficiency of the real-time energy and OR markets and the long-term efficiency of the current capacity mix.

1.3.1 Short-term Efficiency of the Real-time Energy and OR Markets[12]

Contract and Regulatory Incentives

Competitive and efficient market outcomes are possible in highly concentrated markets if regulatory incentive measures are placed on suppliers that mimic the incentives facing suppliers in a perfectly competitive market. In Monitoring Report 32, the Panel's qualitative assessment of the short-term efficiency of the IAM involved a review of the effectiveness of the various regulatory and contractual terms at inducing generators to offer in the IAM competitively (i.e., reflective of their marginal production cost). In Ontario, most generators are subject to regulatory or contractual terms that influence their participation in the IAM.

[12] The short-term efficiency of a market is evaluated at a specific point in time using two concepts: productive efficiency and allocative efficiency. *Productive efficiency* occurs at a specific point in time if a given level of output is produced with the least amount (or cost) of inputs. The Ontario electricity market achieves productive efficiency when resources are operating at their lowest possible costs and if the least cost resources are dispatched to meet demand. *Allocative efficiency* occurs at a specific point in time if output is produced by the cheapest suppliers and it is consumed by all consumers and only those consumers whose willingness to pay to consume is no less than the cost to produce the output. In the Ontario market, allocative efficiency is largely about getting the price right for consumers so that they can make efficient consumption decisions.

Monitoring Report 32 considered three types of regulatory and contractual incentive mechanisms – “deeming” contracts, OPG’s Hydroelectric Incentive Mechanism (HIM) and fixed-price contracts – and evaluated each in terms of their effectiveness at inducing competitive marginal cost offers.[13]

Deeming contracts stipulate that when prices rise above the generator’s variable costs, as described in the contract, they are *deemed* to have run in the market and collected revenue at the market rate. The generator’s deemed operating profits are clawed back from the monthly contract payments whether the generator *actually* ran or not.[14] This provides an incentive for the generator to offer the plant’s actual marginal cost, precisely the efficient incentive.

Most gas-fired plant capacity (more than 60%) operates under deeming contracts (also called Clean Energy Supply contracts) and hence are generally induced to offer competitively.[15]

Effective April 1, 2008, the OEB set the regulatory rate, referred to as “payment amounts”, for a portion of OPG’s hydroelectric fleet, with additional hydroelectric facilities being brought under rate regulation since that date. At that time, OPG proposed and the OEB approved a Hydroelectric Incentive Mechanism (HIM), under which OPG could increase its revenue by reducing output during low-price hours and increasing output in high-price hours. The HIM became fully effective in December 2008, and 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 when it is efficient to do so based on the generator’s expectations of market prices (i.e., Hourly Ontario Energy Price (HOEP)). The HIM provides OPG an incentive to offer supply at the

[13] See the Panel's Monitoring Report 32 published July 2020, Section 1.1.4, page 16: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

[14] A generator’s deemed operating profit is calculated as (HOEP less the generator’s deemed variable costs) multiplied by the generator’s deemed output.

[15] The largest fossil fuel generator in Ontario – Lennox Generating Station – has a 2,000 MW contract with the IESO that has not been reviewed by the Panel. Gas-fired plant capacity figures are based on the IESO’s active generation contract list as of September 30, 2021, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/power-data/supply/IESO-Active-Contracted-Generation-List.ashx

opportunity cost of the limited water while providing the generator revenue security like a fixed-price contract. Approximately 80% of the transmission-connected hydroelectric capacity in Ontario operates under the HIM.

The Panel noted in Monitoring Report 32 that the effectiveness of the OPG 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. In the same report, the Panel recommended that the OEB consider revisiting the sharing arrangement to strengthen OPG's incentives to offer at opportunity cost.

Fixed-price contracts induce generators to offer below marginal cost when the fixed price they receive is above their marginal cost and to offer above marginal cost (or not offer at all) when the fixed price they receive is below their marginal cost. A fixed-price contract can lead to inefficiencies if it induces the generator to produce "out-of-merit" (i.e., produce before a generator with a lower marginal cost or produce after a generator with a higher marginal cost).

Ontario's nuclear plants, grid-connected wind and solar plants, and non-utility generators (NUGs) operate under fixed-price contracts or, in the case of OPG nuclear, an OEB regulated rate.[16] Because these contracts pay for all energy produced with prices designed to cover fixed costs as well as variable costs, it is expected that all these resources would be offered into the market at a price near zero or negative to induce the most energy production (NUGs are allowed to self-schedule with the same effect). However, inefficiencies occur when these facilities are scheduled to operate while others with lower marginal costs are not. This is especially inefficient during low demand hours when there is a surplus of supply (i.e., periods referred to as surplus

[16] Approximately 20% of the transmission-connected hydroelectric capacity in Ontario is not rate-regulated and holds a contract with the IESO. Roughly 1,000 MW of this capacity operates under a Hydroelectric Contract Incentive (HCI) which pays a fixed price but provides some incentives to produce in peak hours through the application of a Peak Performance Factor. Some smaller hydroelectric generators (approximately 70 MW) also operate under an early fixed-price Feed-in-Tariff or Renewable Energy Supply contracts. OPG operates 6 new hydroelectric units (approximately 438 MW of capacity) on the Lower Mattagami River under a Hydroelectric Energy Supply agreement (HESA) with the IESO.

baseload generation). During these surplus hours, in addition to the economic inefficiencies, there are reliability reasons to have an orderly mechanism to dispatch-off resources. To accommodate this in periods of surplus, the IESO has imposed price floors on the different nuclear, wind and solar generators to induce offers that establish a merit order consistent with marginal and opportunity costs.

Finally, as noted above, regulatory and other measures are placed on OPG, as the province's dominant generator, that are intended to encourage OPG to offer all its assets competitively.

Figure 1-4: Regulated and Contracted Capacity by Type, 2020[17]

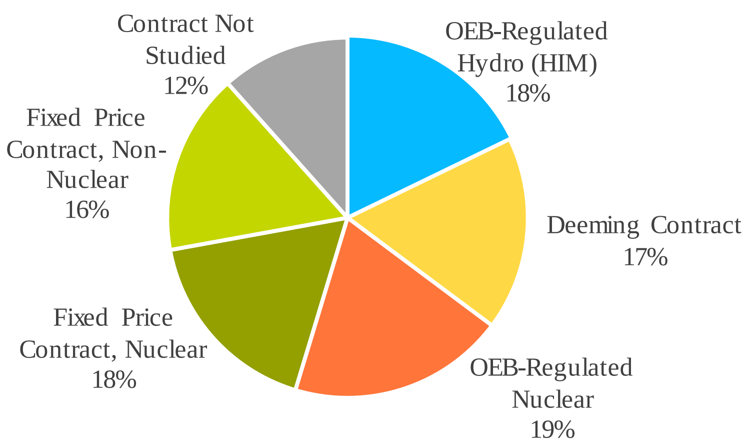


Figure 1-4 presents the share of total regulated and contracted capacity registered in the IAM (36 GW) at the end of 2020 according to the type of contract or regulated rate.

On balance, the Panel finds the real-time energy market to be reasonably competitive and efficient on a short-term basis. Competitive market outcomes are currently achieved largely because of regulated or contracted incentives that induce generators to offer at marginal cost,

[17] Nuclear capacity includes the registered capacity of generators on outage for refurbishment. Capacity for OEB-regulated hydro is from OPG's Overview of Regulated Hydroelectric Facilities in its 2022-2026 Payment Amounts Application (EB-2020-0290), available at: https://files.opg.com/wp-content/uploads/2021/01/A1-04-02-Overview-of-Regulated-Hydroelectric-Facilities.pdf

including opportunity cost. Insofar as contracts continue to be required for reliability, the Panel encourages the IESO to use incentive terms that induce efficient marginal-cost offers.

Two Well-known Market Design Deficiencies

Regulated and contract incentives can encourage efficient offer behaviour and induce efficient market outcomes. However, the effectiveness of these regulated and contracted incentives at inducing efficient outcomes can be undermined by the incentives created from deficiencies in market design.

The Panel has frequently discussed two well-known deficiencies in the IAM that the IESO plans to resolve through the Market Renewal Program (MRP): the two-schedule system and cost guarantee programs.

The two-schedule system, specifically the use of a uniform provincial price for settlement instead of nodal prices, results in three inefficiencies.

- To the extent the electricity demand has some elasticity in the short-term (i.e., consumers are responsive to prices) the uniform price set in the two-schedule system can encourage excess consumption in high-cost locations, and too little consumption in low-cost locations (i.e., allocative inefficiency).
- Energy traders buy energy from low-cost jurisdictions to sell to high-cost jurisdictions. In the two-schedule system, export trades can be inefficient when the price that exports pay, the uniform price, is less than the cost of generating the energy within Ontario due to transmission constraints (i.e., as reflected in the relevant nodal price). In this case, energy traders may buy energy in a high-cost area of Ontario for delivery to a lower-cost jurisdiction (i.e., productive inefficiency).
- The two-schedule system may distort prices, in turn affecting decisions on where new supply should be added or retired and where new consumer demand should locate. Entry and exit decisions should be based on prices that reflect the marginal cost or benefit at each location (i.e., nodal prices). All else held constant, the price in areas with surplus

capacity should be low to discourage new investment (or induce exit) or encourage new consumer demand, while the price in areas with limited capacity should be high to encourage new generation investment and discourage the location of new consumer demand. Similarly, these price differences could also be used to support investments in transmission to facilitate the movement of energy from low price zones to higher price zones. The two-schedule system undermines these types of price signals, encouraging inefficient investment and consumption (i.e., long-term investment efficiency). The uniform provincial price also creates incorrect price signals for new transmission investment to relieve congestion. Note, in the current hybrid market, where the IESO determines the amount and location of new generation and transmission capacity needs, inefficient entry and exit of capacity is less germane, although inefficient consumer location decisions are relevant.

The Real-Time Generation Cost Guarantee (RT-GCG) program compensates combined-cycle generators certain start-up and no load costs using a non-competitive process. Non-quick start generators are asked to start based on energy that would be dispatched from these units, not accounting for their start-up costs. RT-GCG payments are then based on after-the-fact cost calculations. This can result in the inefficient commitment of non-quick start generation units by failing to properly account for fixed start-up and speed no-load costs and intertemporal supply and demand conditions in the dispatch ("optimization") process. In particular, the current RT-GCG process can lead to the start and multi-hour scheduling of a generation unit that incurs higher costs than would be incurred by alternative sources of supply over the multi-hour scheduling period (i.e., productive inefficiency).

The Panel notes that the inefficiencies that can arise from these two well-known design deficiencies would exist even if the Ontario electricity market was perfectly competitive. That is, the inefficiencies are due to the limitations in the market pricing, optimization and scheduling process rather than a result of non-competitive generator offers or strategic behaviour. As a result, even if generators are induced to offer at marginal cost through regulatory and contract incentives (as indicated above), market outcomes may be inefficient because of the design flaws.

The Panel further notes that these design flaws can also induce non-competitive offers and strategic behaviour from generators, including from generators with deeming contracts.

For example, a generator under a deeming contract, located in a constrained area of the province, with a marginal cost above the HOEP but below the local area nodal price (i.e., the local area marginal supply cost) may have an incentive to increase its offer above marginal cost and just below the local area nodal price to maximize its constrained-on Congestion Management Settlement Credit (CMSC). The deeming contract is based on the HOEP and not the local area nodal price. In this situation, the generator is not deemed to earn revenue so there is no deemed revenue claw-back from the generator's monthly contract payment. The generator does keep the CMSC payment it receives. As such, while the deeming contract mitigates the generator's incentives to exercise market power with respect to the uniform Ontario HOEP, it does not mitigate market power incentives with respect to CMSC payments.[18]

The Panel has previously termed this behaviour as "nodal price chasing" in the context of imports and exports, but the same incentives can apply to generators with deeming contracts. Nodal price chasing increases the amount of uplift that consumers pay to generators above what they would have paid had the generators submitted marginal cost offers. It can also lead to inefficiencies when the generator "guesses wrong" and offers above the local area nodal price. In this case, the generator is no longer constrained-on; instead, a higher cost generator is constrained-on. This represents a productive (dispatch) inefficiency as costlier supply is used to meet a given amount of demand.

[18] A similar incentive can exist in the case of a constrained-off payment, where the generator with a deeming contract has an incentive to offer below its marginal cost but just above the local area nodal price to maximize its constrained-off CMSC payment (which is calculated based on the amount that the HOEP exceeds the generator's offer price). This offer price is not used in the deeming process, which instead uses a formula to calculate deemed marginal costs. However, the generator keeps the constrained-off CMSC, and hence is better off by offering below its marginal cost.

The HIM is also based on HOEP and not local area nodal prices. This means that energy limited hydroelectric generators are incented to offer their limited output in the highest HOEP hours which may not coincide with the highest local area nodal price hours. This can induce inefficient use of hydroelectric output, another productive inefficiency.

Other Market and Program Design Issues

The import and export process is not contributing to market efficiency as it could be. In the Ontario market, imports and exports are scheduled in the hour-ahead pre-dispatch sequence (PD-1) and settled on the basis of a real-time price.[19] While other resources can be dispatched up or down in response to each of the 5-minute real-time MCPs, imports and exports are scheduled at a constant rate for the whole hour. To the degree that supply and demand conditions change from PD-1 to real-time, imports or exports may be over or under-scheduled relative to real-time prices resulting in productive inefficiency. For instance, an exporter that is willing to pay the PD-1 MCP may not want to pay the real-time price if it is higher, but would be required to do so. Conversely, if prices fall, the exporter could see a higher profit but the volume of exports could be sub-optimal. Importers are protected from the risk of price decreases between PD-1 and real-time, but the volume of imports can be similarly sub-optimal when real-time prices rise.[20] The day-ahead market, another component of MRP, is expected to improve the efficiency of import and export scheduling.

Finally, the Industrial Conservation Initiative (ICI) continues to allocate out-of-market costs in a manner that encourages inefficient behaviour.[21] The ICI exposes Class A consumers to Global

[19] Importers and exporters are settled on the Intertie Zonal Price for their location, which is the sum of the real-time Market Clearing Price (MCP) in Ontario and the Intertie Congestion Price (ICP). The ICP is zero if there is no congestion on the intertie.

[20] The IESO's Intertie Offer Guarantee program limits importers' risk by ensuring they receive at least their offer price for energy scheduled and provided, even if the real-time price is lower.

[21] For an in-depth review of the ICI's effects on market efficiency, see the Panel's Industrial Conservation Initiative Report published December 2018:
https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

Adjustment (GA) payments based on their contribution to peak hours (in contrast to Class B consumers which are allocated the remainder of the GA based on their monthly energy consumption). Considering the peak energy prices during these hours and because GA is currently high, the GA payments Class A consumers can avoid has a similar effect to critical peak pricing. In principle, critical peak pricing programs can improve long-term investment efficiency by reducing capacity needs. However, the design of the ICI creates inefficient incentives resulting in allocative inefficiency (i.e. too little consumption by Class A loads) and the peak reduction incentive from the ICI is weaker in years with higher energy prices (i.e., tight supply) when the GA tends to be lower. The ICI reduces Class A customer costs at a rate many times higher than the avoided cost of future capacity additions.

Conclusion

In short, the Panel finds the real-time energy market to be reasonably competitive and efficient on a short-term basis. Nonetheless, the Panel has identified several potential short-term inefficiencies in the IAM. Some are driven by regulatory or contract incentives, such as the HIM revenue sharing mechanism or fixed price contracts. As existing generation contracts expire, there is an opportunity to strengthen incentives for competitive offer behaviour. Other short-term inefficiencies are caused by well-known market design issues which are planned to be addressed by MRP. The Panel’s concerns with other market or program design issues, such as the ICI and one-hour ahead intertie scheduling, remain largely unaddressed.

1.3.2 Long-term Efficiency of the Current Capacity Mix

Theoretically, long-term efficiency is about making optimal and timely decisions on the investment in new assets and the maintenance or retirement of existing assets. In a competitive market, short-term prices lead buyers and sellers to efficient technology choices and timely and efficient capacity exit, entry and expansion decisions. In the long-term, efficiency is achieved when the industry produces at the point where price is equal to marginal cost and industry long-term average cost is minimized.

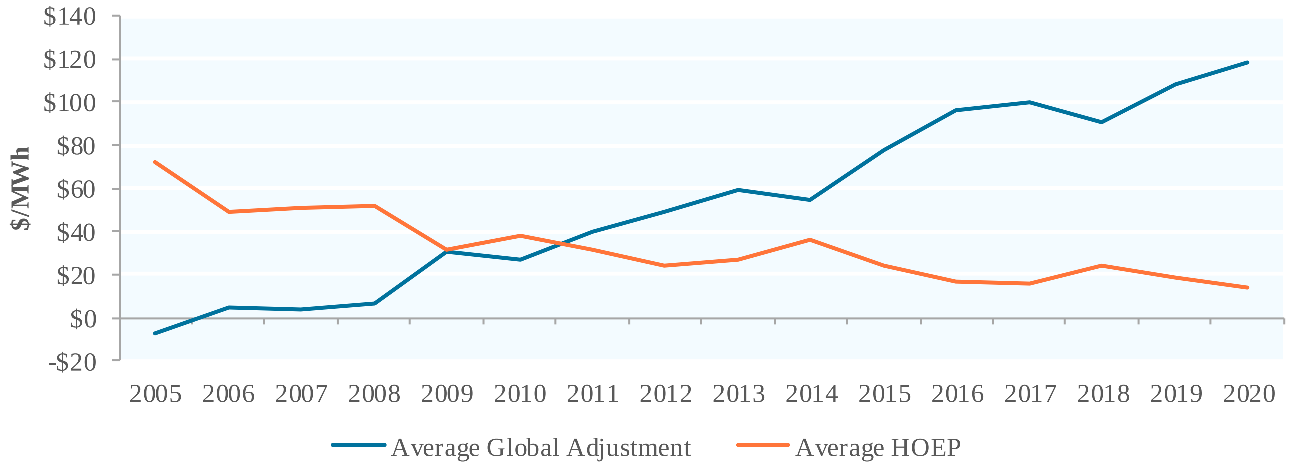
This does not describe the situation in the Ontario electricity market.[22] In contrast, much of the addition to Ontario's generation fleet since 2009 was procured further to Ministerial Directives as to amount, technology, and price, and not through market signals. Some resources have been procured competitively through the DR Auction – but that level of capacity was determined based on a government policy goal, not actual supply needs. Much of the capacity is signed to long-term contracts, limiting economic decisions to shut down a plant if it is no longer needed or economic relative to alternatives.

In Monitoring Report 32, the Panel concluded that while procurement prior to 2009 was reasonably competitive in response to public policy decisions, the procurement decisions regarding both the quantity and type of generation over the last decade have created capacity surpluses and have generally not used competitive processes, imposing unnecessarily high costs on Ontario consumers. Ministry-directed procurement continued through the decade despite a drop in demand which led to a near decade-long surplus of capacity. Over-procurement of capacity, combined with the extensive use of fixed price contracts for near-zero marginal cost generators such as wind and solar resulted in a substantial decline in wholesale energy prices over the last decade or so. Generators collect less and less revenue from the energy market, leaving more of the fixed costs to be paid through the Global Adjustment (GA). For example, the fixed costs associated with contracted and price-regulated generators are recovered from Ontario consumers (large and small) mainly through the GA. As Figure 1-5 illustrates, this has led to a divergence between the annual weighted average HOEP and the annual average GA

[22] Indeed, this does not describe how competitive wholesale electricity markets operate in most jurisdictions. Most jurisdictions do not rely solely on short-term energy prices alone to drive capacity investment decisions (i.e., "energy-only" markets). Instead, they use central planning to determine the amount of capacity needed to achieve a given resource adequacy standard, and competitive processes, such as RFPs and capacity auctions, to procure this amount of capacity. Many jurisdictions also have government influence on installed supply, for example through Renewable Electricity Standards.

per megawatt-hour. This divergence is indicative of the relative inefficiency of the current supply portfolio.[23]

Figure 1-5: Weighted Average HOEP and GA, 2005-2020



Looking forward, the IESO projects an emerging need for capacity in the middle of the decade, as well as for energy towards the end of the decade. The IESO indicates that it will use a multi-pronged approach to cumulatively address future capacity needs. The current framework includes: the Capacity Auction to address short-term fluctuations in capacity needs; competitive procurements such as Request for Proposals (RFPs) to offer medium-term commitments (three to five years) to existing resources and longer-term commitments (seven to ten years) to new resources; and bilateral negotiations to secure resources where needs cannot be addressed in a practical or timely way through competitive processes.[24]

[23] Specifically, if the weighted average HOEP reflects the industry marginal cost and the sum of weighted average HOEP and average GA reflects the industry average cost, then the market is currently operating at a point where industry average cost is well above industry marginal cost and minimum industry average cost. In an efficient market this would be a signal for less efficient capacity to exit or for new demand to enter thereby driving down average costs towards a more efficient long-run allocation of industry resources. The current central planning and procurement model does not allow for this competitive evolution towards long-run efficient outcomes.
[24] See the IESO's Annual Acquisition Report, published July 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2021.ashx

In the Panel's view, to restore the long-run efficiency of the IAM, comprehensive and transparent needs assessments and competitive procurement processes should be used as much as possible. Furthermore, as contracts expire, competition should be opened to both new and existing resources to allow the retirement of older, less efficient resources. Independent oversight of the IESO's needs assessments and decisions around choice of competitive vs. bilateral procurements would increase the accountability of the current process and foster a greater degree of confidence in the IAM.

1.4 Developments Related to the IESO-Administered Markets

This section contains an update on recent developments related to the IESO-Administered Markets since Monitoring Report 35.

1.4.1 Gas Phase-Out Impact Assessment

On June 24, 2021, the IESO held an engagement webinar to seek input on reliability, operability, timing, cost and wholesale market issues that would need to be resolved in consideration for the phase-out of natural gas generation. The engagement was intended to outline the current role natural gas generation plays in maintaining a reliable electricity supply across Ontario. The IESO will develop three scenarios to understand the implications of reversing the trend of emissions increases by 2030.

- Scenario 1: Complete phase-out of gas by 2030 with new resources in response to municipal city council resolutions.
- Scenario 2: Market based approach examining the potential of high gas prices leading to the reduced utilization of the gas fleet by 2030 and to provide market signals towards clean energy projects.
- Scenario 3: Reduce emissions by 2030 with a supply mix approach of new resources.

On October 7, 2021, the assessment was published.[25] In the study, the IESO only developed one of the three scenarios considered, Scenario 1, which represented a complete phase-out of gas by 2030. The IESO concludes that a complete decarbonisation of the grid by 2030 would be expensive and lead to blackouts. More importantly, the IESO discusses the opportunities in electrification of other sectors in providing a "more cost-effective pathway to decarbonisation than removing natural gas from the grid".[26]

Following the publication of the report, the Minister of Energy requested that the IESO evaluate a moratorium on procurements of new natural gas generating stations, develop an achievable pathway to zero emissions for the electricity sector and report back by November 2022.[27]

1.4.2 Resource Adequacy Update

The IESO is developing a set of competitive mechanisms to ensure resource adequacy, including the Capacity Auction for 6-month seasonal commitments, the medium term Request for Proposals (MT RFP) for three to five year commitments, and the long-term RFP for seven to ten year commitments. For needs that cannot be met competitively, the IESO can also enter into bilateral negotiations to procure resources.

The IESO's recent engagements were focused on the first MT RFP for a commitment period starting May 1, 2026. As described in the 2021 Annual Acquisition Report, the MT RFP will

[25] See the IESO's report "Decarbonization and Ontario's Electricity System" published October 7, 2021: https://ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Decarbonization-and-Ontarios-Electricity-System.ashx
[26] Ibid.
[27] See the letter from the Minister of Energy to the IESO, dated October 7, 2021: https://ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-Minister-Gas-Phase-Out-Impact-Assessment.ashx

procure up to 750 MW of unforced (adjusted for unplanned or forced outages) capacity and will be designed to recommit existing resources.[28,29]

In the first iteration of the MT RFP, the IESO has elected to exclude new build, expansions (e.g., adding storage to existing renewable generators), directly-connected loads with behind-the-meter generation, imports and demand response. The IESO is concerned that competition from less certain new build or expansion capacity in the MT RFP may lead to the exit of existing facilities that are unsuccessful, resulting in negative reliability impacts. New build and expansion projects are expected to participate only in the long-term RFP or a non-competitive mechanism. Additionally, the IESO has noted that allowing imports and/or demand response to participate in the MT RFP could pull those resources out of future Capacity Auctions. Most of the capacity that is eligible to participate in the first MT RFP is gas-fired. The IESO intends to broaden eligibility in future iterations of the MT RFP.

The Panel commented on the IESO’s decision to exclude new resources from the MT RFP, stating that the exclusion of new resources and facility expansions could unnecessarily lessen the procurement’s competitiveness and increase the potential exercise of market power in the procurement.[30] It is not clear that the exit of existing resources is a reliability risk if it occurs due to the successful procurement of new resources. To facilitate competition between new and existing resources, more information is needed on the risk of construction delays and the risk of the prompt exit of existing resources. Furthermore, the Panel also believes that each supplier

[28] See the IESO presentation "Medium Term RFP Engagement Kick-Off" dated August 26, 2021, slide 5: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210826-presentation-medium-term-rfp-engagement-kick-off.ashx

[29] See the IESO’s Annual Acquisition Report, published July 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/aar/Annual-Acquisition-Report-2021.ashx

[30] See the Panel’s comments dated September 17, 2021, “Comments on the IESO Presentation: Resource Adequacy Engagement (August 26, 2021)”: https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/rae/ra-20210917-market-surveillance-panel.ashx

should have the choice to offer into both the Capacity Auction and the multi-year RFPs, depending on their own availability, risk tolerance and price forecasts.

In late January 2022, the Minister of Energy directed the IESO to proceed with the first MT RFP to procure capacity from existing electricity generation or storage facilities, and identified that this and future MT RFPs should comply with a number of principles, including that: procurement should only occur when the products or services are required for reliability reasons; procurement should be at a price that minimizes the impact on ratepayers' electricity bills; and the IESO must set a maximum price at which it procures products and services through the MT RFP, with a maximum capacity price that is less than the net cost of new entry for a new-build electricity resource. The first MT RFP is to conclude in 2022. The Minister of Energy also directed the IESO to design a long-term Request for Proposals (LT RFP) to procure at least 1,000 MW of capacity, determined primarily on an unforced capacity basis. The IESO is to consult with stakeholders on a draft Request for Qualifications (RFQ) and report back to the Minister with a draft LT RFP and the results of the RFQ, if concluded, by November 30, 2022.[31]

In addition, through letters issued on May 13, 2021 and January 26, 2022, the Minister asked the IESO to proceed with negotiations for the Lake Erie Connector project and to report back, after which the government will determine whether to issue a directive requiring the IESO to contract for this project.[32] Furthermore, on August 27, 2021, the Minister issued a letter asking

[31] See the Directive from the Minister of Energy to the IESO dated January 27, 2022: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20220128.ashx

[32] See the letter from the Minister of Energy, Northern Development and Mines to the IESO, dated May 13, 2021, and the letter from the Minister of Energy to the IESO dated January 26, 2022: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/MC-994-2021-352.ashx and https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20220126-Lake-Erie-Connector-Project.ashx

the IESO to draft a contract for the Oneida Battery Park Project, and in late January 2022 the Minister directed the IESO to enter into a procurement contract for that project.[33]

Both the Lake Erie Connector project and the Oneida Battery Park Project were assessed by the IESO at the behest of the Ministry of Energy as "unsolicited proposals". According to the Ontario Government's website, unsolicited proposals "must demonstrate a clear value or benefit for the people of Ontario" such as "addressing capacity needs in the energy sector".[34] Although the IESO has mentioned both projects in the Annual Planning Outlook and Annual Acquisition Report, the IESO has not identified any system needs that these "unsolicited proposals" are meant to address. The IESO has not published any assessment of the impacts that these projects will have on market activities or system costs.

With an installed capacity of 250 MW, the IESO has noted that the Oneida Battery Park Project would be one of the largest battery storage facilities in the world.[35]

1.4.3 Engagements for Increased Participation in IESO-Administered Markets

In April 2021, the IESO launched the Enabling Resources Program. This program is intended to develop a plan to facilitate the inclusion of existing electricity resources that are partially or

[33] See the letter from the Minister of Energy to the IESO, dated August 27, 2021, and the Directive from the Minister of Energy to the IESO dated January 27, 2022: https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-Oneida-20210827.ashx and https://www.ieso.ca/-/media/Files/IESO/Document-Library/corporate/ministerial-directives/Letter-from-the-Minister-of-Energy-20220128.ashx

[34] See the Ontario Government's webpage "Unsolicited proposals submission and assessment guidelines" published September 12, 2019: https://www.ontario.ca/page/unsolicited-proposals-submission-and-assessment-guidelines

[35] See the IESO's report "Decarbonization and Ontario's Electricity System" published October 7, 2021, page 18: https://ieso.ca/-/media/Files/IESO/Document-Library/gas-phase-out/Decarbonization-and-Ontarios-Electricity-System.ashx

completely unable to provide electricity system services in the post-Market Renewal market.[36] The Enabling Resources Program plan will outline the sequencing, timing and scope of activities to be undertaken by the IESO to enable resource participation. The criteria for this are based on forecasted system needs, timing, capability, interrelationships between opportunities and IESO capacity.[37]

Several distinct projects will be launched under the Enabling Resources Program including the Hybrid Integration Project, which has been identified as a high priority opportunity. The Hybrid Integration Project is intended to enable increased participation for hybrid facilities (i.e., a combined facility consisting of electricity storage and generation facilities) in IESO-Administered Markets.

1.4.4 Adjustments to Intertie Limits by the IESO

On August 23, 2021, the IESO applied transmission constraints that restricted net exports from the Northwest. This was done by adjusting the flow limits on the Manitoba and Minnesota interties for both the dispatch schedule and the market schedule. The IESO's decision to restrict net exports from the Northwest was in response to an IESO-identified reliability concern in the region – that had persisted since the early winter, affected by drought-impacted hydro supply and transmission outages to the East-West tie – and to the increased amount of Congestion Management Settlement Credit (CMSC) payments made to resources in the region. Following the implementation of these adjusted flow limits, the IESO proposed a Market Rule amendment to clarify how internal transmission constraints inform the application of intertie limits in the Northwest.

[36] Examples of existing electricity resources that are partially or completely unable to provide electricity system services include off contract solar and wind facilities, Not-So-Quick-Start (NSQS) natural gas facilities, small flexible loads (i.e. <1 MW DR), off contract Distributed Energy Resources (DER), etc.
[37] IESO capacity includes human resources, budget availability, etc. for additional resources.

This topic was discussed at the Technical Panel meeting on October 5, 2021.[38] Concerns were raised that the adjustments applied by the IESO lacked transparency and that the proposed Market Rule amendment was too broadly applied to all of Ontario despite the localized impact. An IESO motion to vote on posting the proposed Market Rule amendments relating to intertie limits for stakeholder comment was defeated. The IESO has committed to further engage with stakeholders on this issue.

The Panel reviewed the large amount of CMSC payments paid to resources in the Northwest as an anomalous market outcome during the monitoring period. This topic is discussed further in Chapter 2.

1.5 Panel Recommendations

The Panel's Monitoring Report 35, published September 2021, included eight recommendations to the IESO. Appendix B: catalogues the eight recommendations, along with the IESO's responses and the Panel's comments on the IESO's responses.

[38] See the IESO's presentation to the Technical Panel "Adjustments to Intertie Flow Limits" dated October 5, 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/tp/2021/iesotp-20211005-adjustments-intertie-flow-limits-presentation.ashx

Chapter 2: Analysis of Anomalous Market Outcomes

This chapter provides data and analysis of the 6-month monitoring period from November 1, 2020 to April 30, 2021, referred to as the Winter 2020/21 Period, making comparisons to previous periods as appropriate.

A primary responsibility of the Panel is to monitor for anomalies in the IESO-Administered Markets. The Panel has established various thresholds to identify anomalous events that warrant additional analysis.

Anomalous event thresholds are defined for: energy prices, Congestion Management Settlement Credit (CMSC) payments, Operating Reserve (OR) payments and Intertie Offer Guarantee[39] (IOG) payments. The energy price thresholds are Hourly Ontario Energy Prices (HOEP) greater than $200/MWh, or less than or equal to $0/MWh.[40] The CMSC threshold is defined as days when total CMSC settled exceeds $1 million/day and/or hours when CMSC exceeds $500,000/hour. The OR threshold is any payment that exceeds $100,000/hour. The IOG threshold is any payment that exceeds $1 million/day and/or $500,000/hour.

[39] The Panel monitors IOG payments for both Day Ahead (DA) and Real Time (RT) to understand the frequency of high out-of-market payments and to understand the variability between pre-dispatch (or DA) and real-time commitment of imports at intertie zones. Since interconnection transactions are based on hourly commitments while the market operates on five-minute intervals, IOG payments are provided to cover the risk, when the final settlement price falls below the importers' hour-ahead (or if selected, the DA) offer price, and will ensure that the importers will, at a minimum, recover their as-offered prices on import transactions. For DA imports, this incentivizes importers to lower import offers after imports have been scheduled in the DA to increase the probability that the energy will flow in real-time while the importers will be guaranteed to receive, at minimum, their day-ahead offer price.

[40] The average of the twelve market clearing prices (MCPs) set in each hour is called the Hourly Ontario Energy Price (HOEP). Electricity consumers in Ontario pay this wholesale price, and other cost elements, either directly or through the Regulated Price Plan (RPP) prices set by the OEB, except for those who have entered into a retail contract. A new Market Clearing Price (MCP) is set every five minutes.

2.1 Threshold Analysis

Figure 2-1 and Table 2-1 provide context to the market price thresholds by presenting recent price trends for the median, top 5%, top 0.5%, and maximum HOEP from Winter 2018/19 through Winter 2020/21. In both the Winter 2019/20 and 2020/21 Periods, there were six hours where the HOEP exceeded $200/MWh. The percentage of hours when the HOEP was less than or equal to $0/MWh decreased to 13% (552 hours) in the Winter 2020/21 Period from 17% during the Winter 2019/20 Period (747 hours), a decline of 26%.

Figure 2-1: HOEP Percentiles by Price, 5 Periods

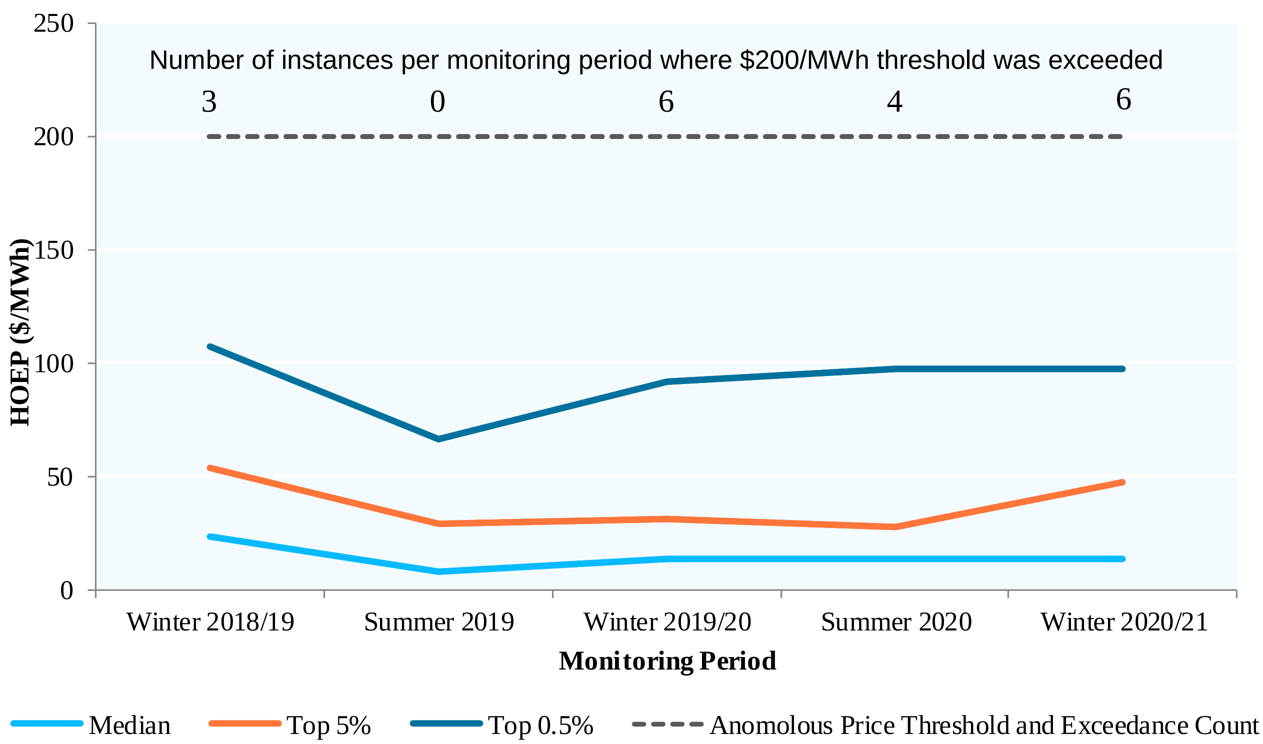


Figure 2-1 above displays the median, top 5% (95 percentile) and top 0.5% (99.5 percentile) of the HOEP for the last 5 periods (Winter 2018/19 Period to Winter 2020/21 Period). Additionally, at the top of the figure, the numbers of hours above the $200/MWh threshold are shown.

Table 2-1: Summary of HOEP Percentiles, 5 Periods

Period	Median HOEP ($/MWh)	Average HOEP ($/MWh)	Top 5% HOEP ($/MWh)	Top 0.5% HOEP ($/MWh)	Maximum HOEP ($/MWh)	Hours at or below $0/MWh (hours)	Hours above $200/MWh (hours)	Total Hours in Periods (hours)
Winter 2018/19	$23	$24	$54	$108	$366	373	3	4,344
Summer 2019	$8	$11	$29	$66	$181	1,281	-	4,416
Winter 2019/20	$13	$15	$31	$92	$1,258	747	6	4,368
Summer 2020	$13	$13	$28	$98	$381	662	4	4,416
Winter 2020/21	**$13**	**$16**	**$48**	**$97**	**$1,661**	**552**	**6**	**4,344**

Table 2-1 above displays the median, simple average, top 5% (95 percentile), top 0.5% (99.5 percentile) and maximum values for HOEP and the number of hours the HOEP crossed below the $0/MWh threshold or above the $200/MWh threshold in the last 5 periods (Winter 2018/19 Period to Winter 2020/21 Period).

Table 2-2: Summary of Threshold Exceedances for the Winter 2019/20 and Winter 2020/21 Periods

Payments Threshold	Winter 2019/20 (Nov 2019 to Apr 2020)		**Winter 2020/21 (Nov 2020 to Apr 2021)**	
	Average Payment	Threshold Exceedances	**Average Payment**	**Threshold Exceedances**
Daily Energy CMSC	~$173,000/day	11 instances >$1 million/day	**~$361,000/day**	**6 instances >$1 million/day**
Hourly Energy CMSC	~$7,000/hour	2 instances >$500,000/hour	**~$15,000/hour**	**0 instances >$500,000/hour**
Hourly OR	~$5,000/hour	3 instances >$100,000/hour	**$5,600/hour**	**7 instances >$100,000/hour**
Daily IOG	~$25,000/day	2 instances >$1 million/day	**~$78,000/day**	**0 instances >$1 million/day**
Hourly IOG	~$1,000/hour	4 instances >$500,000/hour	**~$3,300/hour**	**0 instances >$500,000/hour**

Table 2-2 above shows the average daily CMSC, OR and IOG payments and number of hours where the daily payments exceeded thresholds during the Winter 2019/20 and the Winter 2020/21. CMSC amounts are net of applicable claw backs.

Table 2-2 presents a comparison of CMSC, OR and IOG average payments and the number of hours the thresholds were exceeded in the Winter 2020/21 Period to the corresponding values for the Winter 2019/20 Period.[41] The total CMSC paid in Winter 2020/21 was $65 million, more than double the CMSC paid in Winter 2019/20 ($31 million).[42] The year-over-year increase in CMSC paid was largely due to market conditions affecting the Northwest region of Ontario. The Panel describes these conditions in more detail in Section 2.1.2.

The number of days when CMSC was greater than $1 million/day decreased to 6 days in the Winter 2020/21 Period from 11 days in the Winter 2019/20 Period. However, the average CMSC payment was approximately $361,000/day in the Winter 2020/21 Period, a 109% increase in average payment from the Winter 2019/20 Period (average ~$173,000/day). There were no instances in the Winter 2020/21 Period where CMSC exceeded the $500,000/hour threshold.

The total OR payment in the Winter 2020/21 Period was $24 million (average of approximately $5,600/hour). The total OR payment for Winter 2019/20 Period was similar at $22 million (average of approximately $5,000/hour). There were seven instances where OR payments surpassed the $100,000/hour threshold in the Winter 2020/21 Period as compared to three instances in the Winter 2019/20 Period. The highest OR payment for a single hour was $1.7 million on March 28, 2021.

There were no instances in the current monitoring period where the IOG payments surpassed the $1 million/day or $500,00/hour IOG monitoring threshold. However, the Panel notes that total IOG payments more than tripled from $4 million (average of approximately $25,000/day) in the Winter 2019/20 Period to $14 million (average of approximately $78,000/day) in the Winter 2020/21 Period, with the most significant increase in payments to Québec.

[41] Due to seasonal variations, the Panel compares instances of anomalous events occurring in the same 6-month monitoring period year over year.

[42] For comparison, the total energy charge from the HOEP was $1.1 billion in the Winter 2020/21 Period and $1.0 billion in the Winter 2019/20 Period.

Table 2-3: Date and Time of Threshold Exceedances for the Winter 2020/21 Period

High HOEP	High OR	Daily CMSC	Hourly CMSC	Daily IOG	Hourly IOG
Nov 13 | HE 10	Nov 13 | HE 10		No Events	No Events	No Events
Nov 18 | HE 10	Nov 18 | HE 10				
Feb 7 | HE 18	Feb 7 | HE 18				
Feb 12 | HE 18	Feb 12 | HE 18				
		Feb 13			
		Feb 14			
		Feb 15			
		Feb 16			
		Feb 17			
		Feb 18			
	Feb 27 | HE 11				
Mar 28 | HE 9	Mar 28 | HE 9				
Mar 28 | HE 10	Mar 28 | HE 10				

The table above shows the date and, where applicable, time (Hour Ending, HE) when thresholds were exceeded during the Winter 2020/21 Period. The HE naming convention represents the hours in a day, with HE 1 (Hour Ending 1) from 12 am to 1 am. Eastern Standard Time is used year-round.

Table 2-3 above presents the dates and, where applicable, times when the threshold exceedances occurred during the Winter 2020/21 Period. All daily CMSC exceedances occurred on six consecutive days from February 13, 2021 to February 18, 2021. The market conditions contributing to the high CMSC amounts paid on these days is explained in Section 2.1.2.

2.1.1 Energy Prices and OR Payments Above Threshold

Factors contributing to high HOEPs also contribute to upward pressure on OR prices and OR payments.[43] High real-time prices are often associated with sudden reductions in supply (i.e., generator outages, variable generation below forecast, import failures) or increases in demand relative to what was anticipated in the pre-dispatch time frame. The following table provides a

[43] The IESO's Dispatch Scheduling and Optimization tool (DSO) co-optimizes the energy and OR markets. The DSO evaluates bids and offers in the energy market and offers in the OR markets simultaneously, satisfying both the total electricity demand and the OR requirements. This allows the DSO to trade off resources between the energy and OR markets to find the schedule that meets the required demand while minimizing the cost.

succinct summary of the main causes of high HOEP and OR payments in the Winter 2020/21 Period.

Table 2-4: High HOEP and OR Payments for the Winter 2020/21 Period

Event Date	Event Hour Ending	HOEP ($/MWh)	OR ($/hour)	Contributing Factors
Nov 13	10	**219**	**112,795**	-Over-forecasted variable generation -Under-forecasted demand -Multiple gas units unavailable -OR shortfall throughout the hour
Nov 18	10	**942**	**934,806**	-Under-forecasted demand -Over-forecasted variable generation -OR shortfall -Gas unit forced outage -Gas unit derate
Feb 7	18	**370**	**315,331**	-Under-forecasted demand -Over-forecasted variable generation
Feb 12	18	**266**	**159,853**	-Under-forecasted demand -Limited nuclear generation online
Feb 27	11	199	**126,479**	-Over-forecasted variable generation -Under-forecasted demand
Mar 28	9	**245**	**155,555**	-Nuclear unit outage -OR shortfall -Over-forecasted variable generation -200 MW of flexibility reserve added
Mar 28	10	**1,661**	**1,722,745**	

The table above lists the factors contributing to high HOEPs (above $200/MWh) or OR payments (above $100,000/hour) for each relevant event. Bold figures represent exceedances.

2.1.2 CMSC Payments Above Threshold

CMSC payments are a feature of Ontario's two-schedule system. The two-schedules include the constrained schedule, which optimally balances supply and demand subject to the physical constraints on the province's transmission system, and the unconstrained schedule, which optimally balances supply and demand assuming there are no physical constraints within Ontario. The IESO uses the constrained schedule to dispatch supply and demand resources reliably and the unconstrained schedule to produce a uniform market price for all of Ontario. When a resource's constrained schedule is different from its unconstrained schedule, the resource is paid CMSC to ensure that it either: just covers its offered cost or bid price (a "constrained-on" CMSC), or earns an operating profit or benefit equal to what it would have earned, had transmission congestion not prevented it from producing or consuming its unconstrained schedule quantity (a "constrained-off" CMSC).[44,45] High hourly and daily CMSC events are frequently associated with at least one binding constraint on a key transmission line that contributes to either a shortage or an abundance of supply in a localized region of the province.

As noted above, the daily CMSC threshold exceedance of $1 million/day for the Winter 2020/21 Period occurred between February 13, 2021, and February 18, 2021. On these days, there was a relative tight supply in Ontario's Northwest region. The tight supply was a result of low water levels for hydro-electric generation in the Northwest, and outages on the East-West transmission line that limited available supply from the rest of Ontario to serve Northwest demand.[46] These tight supply conditions are due to ongoing reliability challenges in the Northwest associated with drought-impacted hydro supply and transmission limitations.

The ongoing reliability challenges in the Northwest have led the IESO to take several actions to manage supply and demand conditions in the Northwest during the 6-month monitoring period, including applying operating security limits (OSLs) to restrict net export (exports less imports) flows across the Manitoba and Minnesota interties and blocking dispatch instructions and issuing one-time manual dispatch instructions to resources in the Northwest to manage the use of

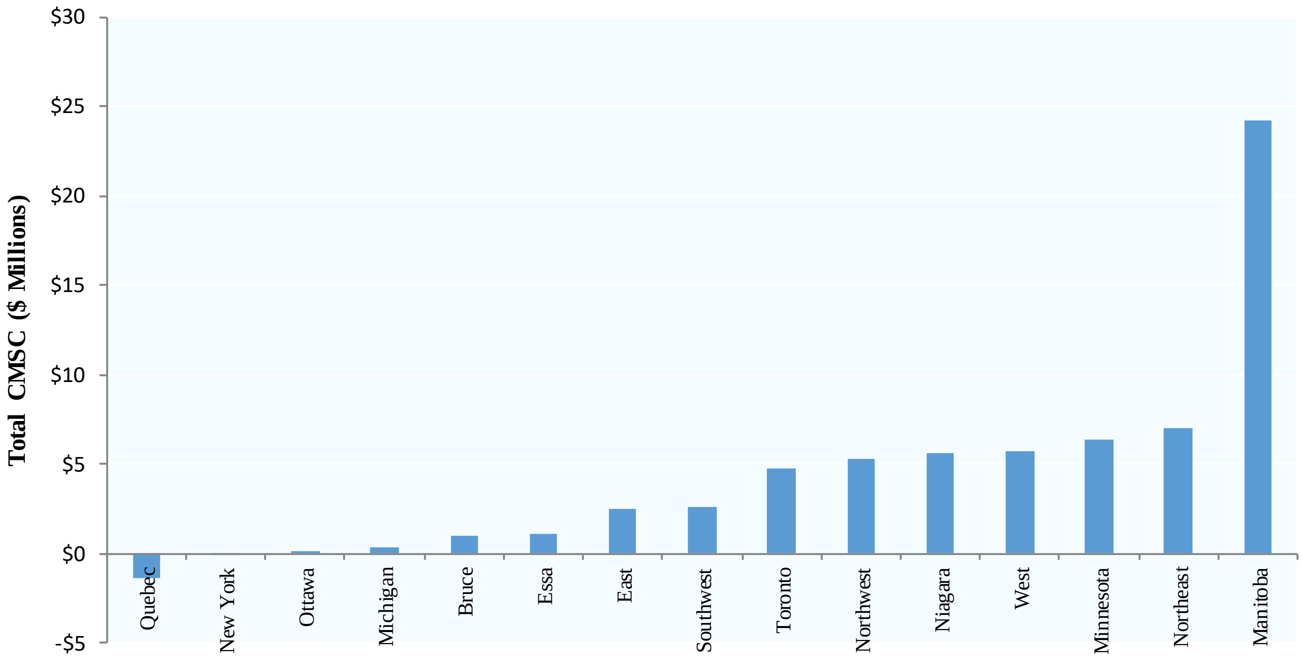
[44] Not all resources are eligible to receive a constrained-off payment. For example, as of December 11, 2015 exporters are no longer eligible to receive a constrained-off payment if the intertie transaction was constrained-off in pre-dispatch (Market Rules Chapter 9, Section 3.5.10). However, a Market Participant will receive a constrained-off payment if the transaction was constrained-off by the IESO for the purpose of reliability after the final pre-dispatch run.

[45] Although generators and dispatchable loads receive a proportionally higher share of CMSC payments, CMSC is also paid to importers and exporters for being constrained on or off. In addition to this, the IESO pays CMSC for generators constrained on and off in periods of demand where a slower ramping generator is not capable of meeting demand according to the dispatch algorithm. However, in order to mitigate price volatility, the IESO has also opted to use a "three times ramp rate multiplier". This is done in the market algorithm by treating generators and dispatchable loads as if they could ramp 3-times faster than they actually can. This creates a disparity in the market vs. dispatch algorithm and leads to constrained-off CMSC payments for the slower ramping generators or loads and constrained-on CMSC for faster ramping generators or loads.

[46] These outages are required to support construction on the East-West transmission line.

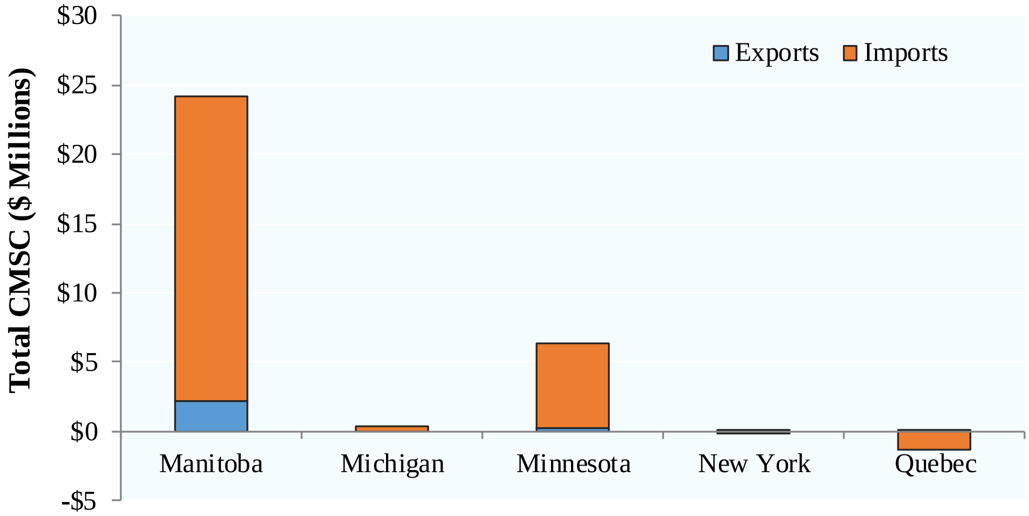
energy-limited hydroelectric output. Together, these conditions and IESO actions contributed to the high CMSC payments during the 6-month monitoring period. The graphs below detail the CMSC paid during the 6-month monitoring period by zone, import/export and constraint type.

Figure 2-2: CMSC by Electrical/Intertie Zone for the Winter 2020/21 Period



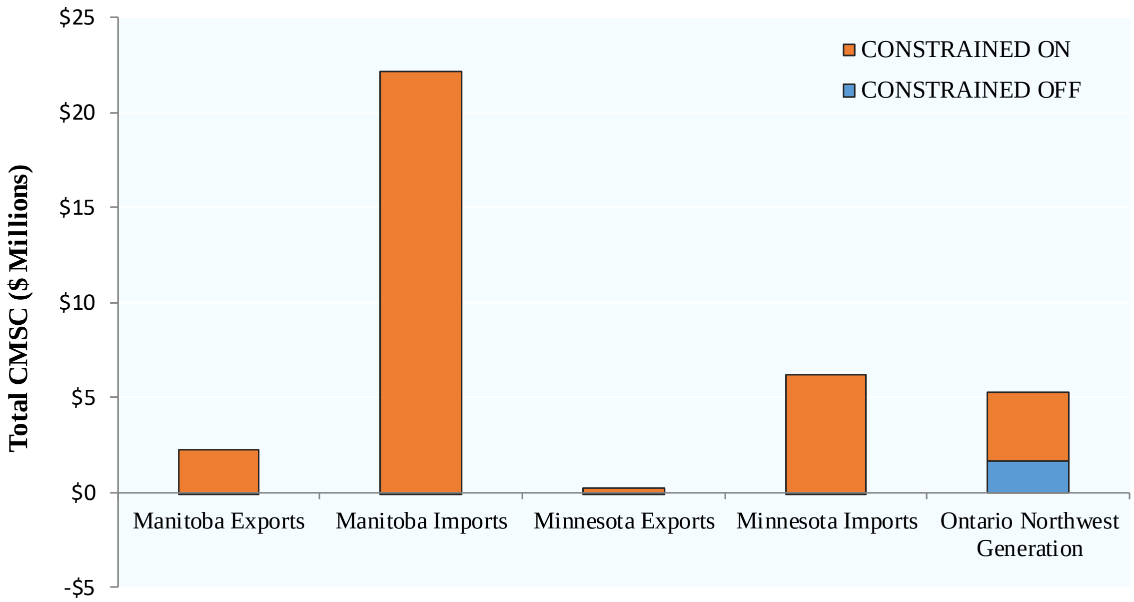
The figure above presents the amount of CMSC paid to resources located in each of the electrical/intertie zones in the province in the Winter 2020/21 Period. A significant portion of the payments ($24 million) were paid to Market Participants on the Manitoba interface.

Figure 2-3: CMSC by Import/Export for the Winter 2020/21 Period



The figure above presents the amount of CMSC paid to traders on the interfaces by imports or exports in the Winter 2020/21 Period. The vast majority of CMSC was paid for imports ($22 million) on the Manitoba interface.

Figure 2-4: Constrained-on/Constrained-off CMSC in the Northwest for the Winter 2020/21 Period



The figure above presents the amount of constrained-on and constrained-off payments made to imports, exports, generators and dispatchable loads in the Northwest in the Winter 2020/21 Period. The vast majority of CMSC was paid for constrained-on imports ($22 million) on the Manitoba interface.

As noted in Section 1.4.4, on August 23, 2021, the IESO applied transmission constraints that adjusted intertie flow limits in the dispatch and market schedules. Following the implementation of these intertie limits, the IESO proposed a Market Rule amendment to justify the internal procedure change. On October 5, 2021, the motion to post the proposed amendment for stakeholder comment was defeated at the Technical Panel meeting and the IESO commenced an engagement on the Market Rule amendment prior to seeking approval on the amendment. The Panel is of the opinion that the IESO has yet to provide evidence to justify the Market Rule amendment.

The Panel is continuing to study the events that occurred between February 13, 2021 and February 18, 2021 to assess whether Market Participant conduct, IESO activities, or potential flaws in market design or the overall structure of the IAM contributed to inefficiencies or impeded the efficient and fair operation of the market. As noted in Section 1.4.4, the conditions affecting the Northwest continue to be an area of concern for the IESO. The Panel will continue to monitor the evolving situation.

Appendix A: Market Outcomes for the Winter 2020/21 Period

This Appendix reports on outcomes in the IESO-Administered Markets for the Winter 2020/21 Period (November 1, 2020 to April 30, 2021), with comparisons to previous reporting periods as appropriate.

A.1 Pricing

This section summarizes pricing in the IESO-Administered Markets, including the Hourly Ontario Energy Price (HOEP), the effective price (including the Global Adjustment (GA)[47] and uplift charges), Operating Reserve (OR) prices and Transmission Rights (TR) auction prices.

Table A-1: Total System Cost by Period, 3 Periods[48]

	Winter 2019/20	Summer 2020	Winter 2020/21
Total Energy Charge (HOEP) ($ millions)	1,019	955	**1,141**
Total Global Adjustment ($ millions)	6,677	7,089	**5,377**
Total Uplift ($ millions)	141	170	**184**
Total System Cost ($ millions)	7,836	8,213	**6,702**

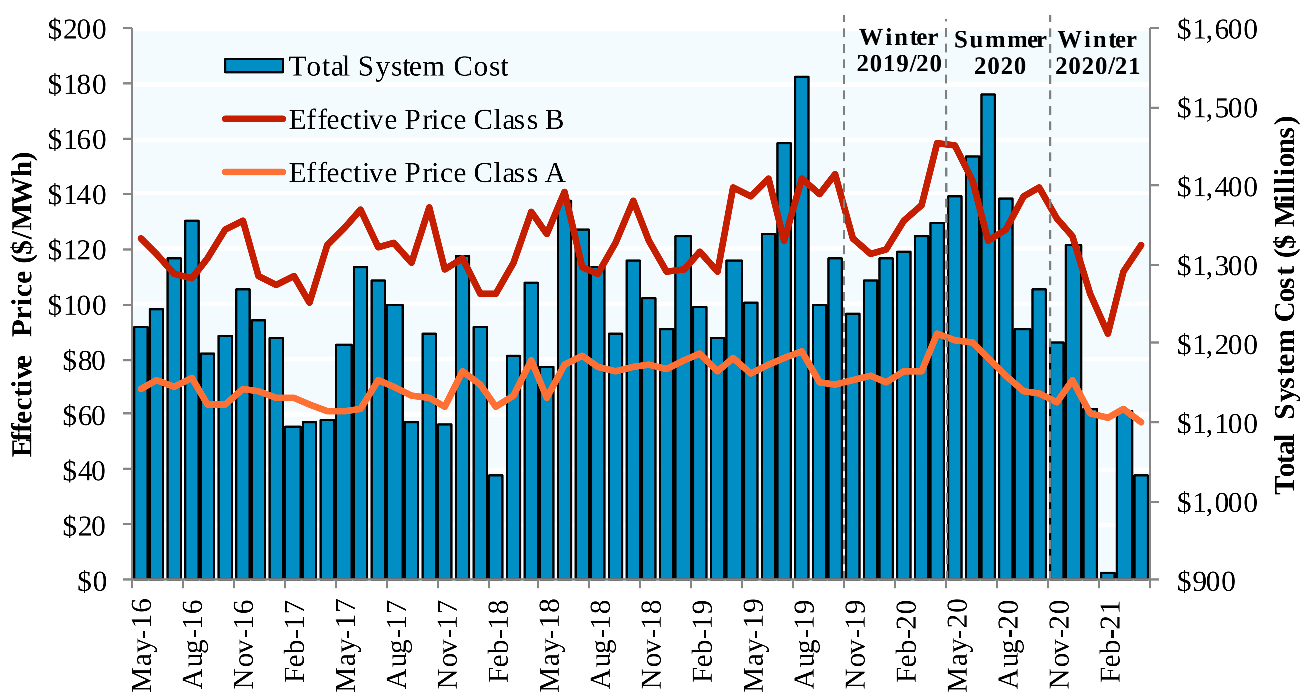
Table A-1 presents the total system cost for Ontario consumers in the Winter 2019/20, Summer 2020, and Winter 2020/21 periods. A significant reduction in the Global Adjustment occurred

[47] The GA is primarily composed of payments to rate-regulated and contracted generators to make up for the difference between the actual market revenues received by these generators (based on the HOEP), and their rates per IESO contracts or regulated by the Ontario Energy Board (OEB). The GA also includes net costs for deemed and other contracts as well as those associated with various IESO conservation programs. For more information regarding the GA, see the IESO's webpage "Guide to Wholesale Electricity Charges": http://www.ieso.ca/sector-participants/settlements/guide-to-wholesale-electricity-charges

[48] The Panel defines the total system cost as the sum of charges related to the HOEP, the GA and uplift components. The total system cost presented within this Appendix does not consider all charges reflected in the total cost settled by the IESO, such as charges related to transmission and distribution.

during the Winter 2020/21 Period due to a shift in a portion of GA costs from ratepayers to the tax base that was made effective in January 2021. Costs for 85% of the non-hydro renewable energy contracts were shifted to the tax base by the Ontario government, thereby reducing the burden on all ratepayers. As a result of the new regulation, approximately $260 million per month was removed from the total GA as the Non-Hydro Renewables Funding Amount.[49]

Figure A-1: Monthly Average Effective Price & System Cost, 5 Years



[49] This amount was derived based on a forecast of contract costs, and may not represent the actual monthly GA amounts that would otherwise be payable in relation to the contracts. For more information regarding the Non-Hydro Renewables Funding Amount, see the IESO's letter to the Minister of Energy on cost forecasts for the government's comprehensive energy plan, dated December 15, 2020, and the Minister of Energy's letter to the IESO and the OEB that identifies and forecasts the monthly GA amounts the government will fund in the fiscal year 2020/21, dated December 15, 2020: https://www.oeb.ca/sites/default/files/IESO-letter-to-the-Minister-20201215.pdf and https://www.oeb.ca/sites/default/files/letter-from-the-Minister-ENDM-20201215.pdf

Figure A-1 plots the monthly average effective price per MWh for Class A and Class B consumers, as well as the total monthly system cost for the previous five years. The total system cost borne by Ontario consumers in the Winter 2020/21 Period decreased by 18.4% compared to the Summer 2020 Period, and by 14.5% compared to the Winter 2019/20 Period. The total system cost fell by about $1.1 billion between the Winter 2019/20 Period and the Winter 2020/21 Period, consisting of a $1.3 billion decrease in the GA offset by a $0.2 billion increase in energy and uplift costs.

Table A-2: Average Effective Price by Consumer Class and Period ($/MWh), 3 Periods

	Consumer Class	**Winter 2019/20**	**Summer 2020**	**Winter 2020/21**
Average Weighted HOEP ($/MWh) [50]	Class A	13.76	12.22	**15.08**
	Class B	16.21	15.70	**18.40**
Average Global Adjustment ($/MWh)	Class A	60.21	62.28	**44.84**
	Class B	111.78	119.45	**91.98**
Average Uplift ($/MWh)	Class A	2.01	2.33	**2.63**
	Class B	2.17	2.69	**2.87**
Average Effective Price ($/MWh)	Class A	75.97	76.83	**62.54**
	Class B	130.16	137.84	**113.25**
	All Consumers	**114.65**	**120.55**	**98.48**

Table A-2 presents the average effective price paid by different consumer classes in the Winter 2019/20, Summer 2020, and Winter 2020/21 periods. The average effective price is calculated

[50] The average weighted HOEP reported for each class is an average of the HOEP values in the monitoring period weighted by that class's consumption during each hour in the period. It was assumed that embedded Class A follows the same load profile as directly connected Class A consumers.

as the sum of the average weighted HOEP, GA and uplift in dollars per MWh, reported for three consumer groups: “Class A consumers”, “Class B consumers” and “All Consumers.”[51,52]

The average effective price for both Class A and B consumers decreased in the Winter 2020/21 Period compared to the Winter 2019/20 Period. The average effective price for Class A consumers decreased by 17.7%, while the average effective price for Class B consumers decreased by 13.0%. The decrease in average effective prices marks a sudden change in the five–year trend for winter reporting periods. Between the Winter 2015/16 Period and the Winter 2019/2020 Period, the effective price increased an average of $1.12/year for Class A consumers and $2.98/year for Class B consumers. The decrease in the Winter 2020/21 effective prices was due to the reduced GA amount from the Non-Hydro Renewables Funding Amount. Furthermore, GA costs in February 2021 were lower than usual due to lower payments to nuclear generators (see Figure A-11).

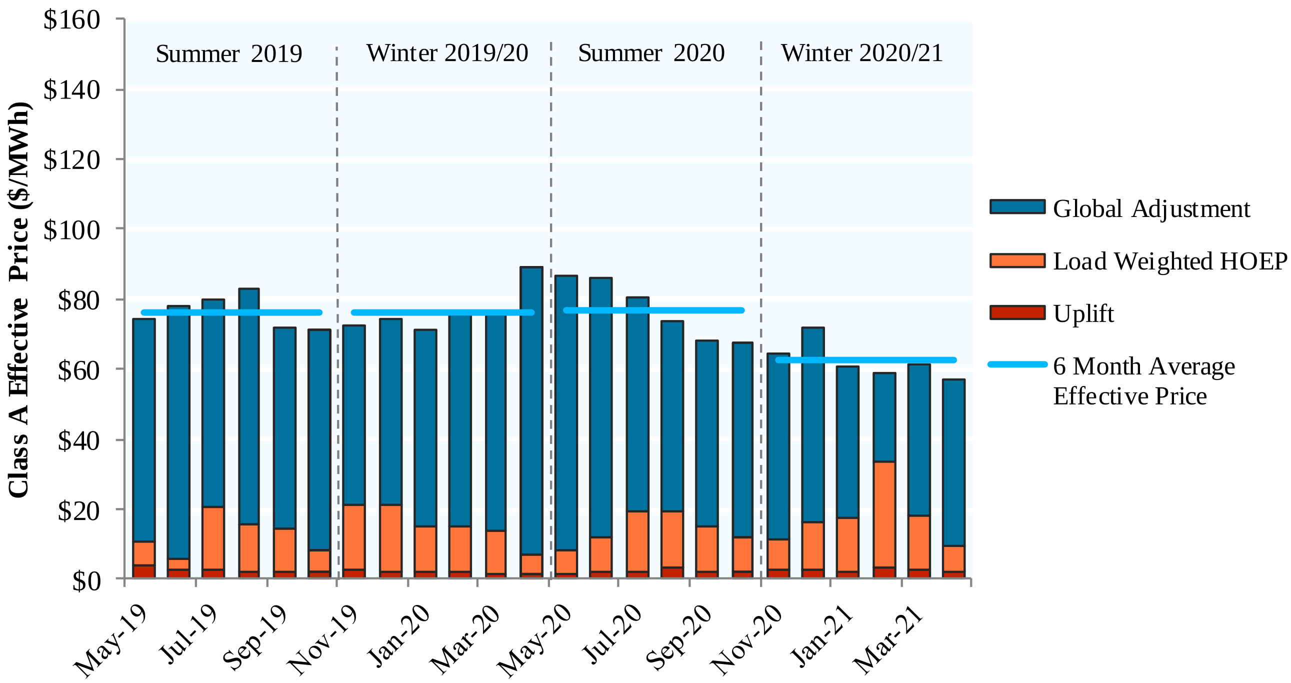
Figure A-2 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class A consumers for the previous two years. The figure also shows the total effective price averaged over each 6-month period. While the GA and the HOEP have an inverse relationship, this is not necessarily a one-

[51] Consumers are divided into two groups: Class A, being consumers with an average monthly peak demand less than 5 MW but greater than 1 MW (or 500 kW for some sectors) that have opted into the class as well as consumers with an average monthly peak demand greater than 5 MW that have not opted out of the class, and Class B, being all other consumers. For more information, see Ontario Regulation 429/04 (Adjustments under Section 25.33 of the Act) made under the *Electricity Act, 1998*: http://www.ontario.ca/laws/regulation/040429

[52] Since January 2011, the GA payable by Class A consumers has been based on the ratio of their electricity consumption during the five peak hours in a year relative to the total consumption by all consumers in each of those hours. This ratio for Class A consumers is calculated for a given year and is applied to the Total GA for each month of the following year. To the extent that Class A consumers reduce their demand during peak hours, their share of GA is reduced in the next year. Once the Class A portion of the monthly GA is allocated, the remaining GA is allocated on a monthly basis to Class B consumers based on their total consumption in that month. For more information on the GA allocation methodology and its effect on each consumer class, see the Panel’s Industrial Conservation Initiative (ICI) Report published December 2018, pages 4-12: https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

for-one relationship, nor does it impact each consumer class equally. A higher GA tends to increase the effective price more for Class B than Class A consumers because the current GA allocation methodology allocates to Class A consumers a lower share of GA per MWh consumed than to Class B consumers. Conversely, a lower GA tends to decrease the effective price more for Class B than Class A consumers.

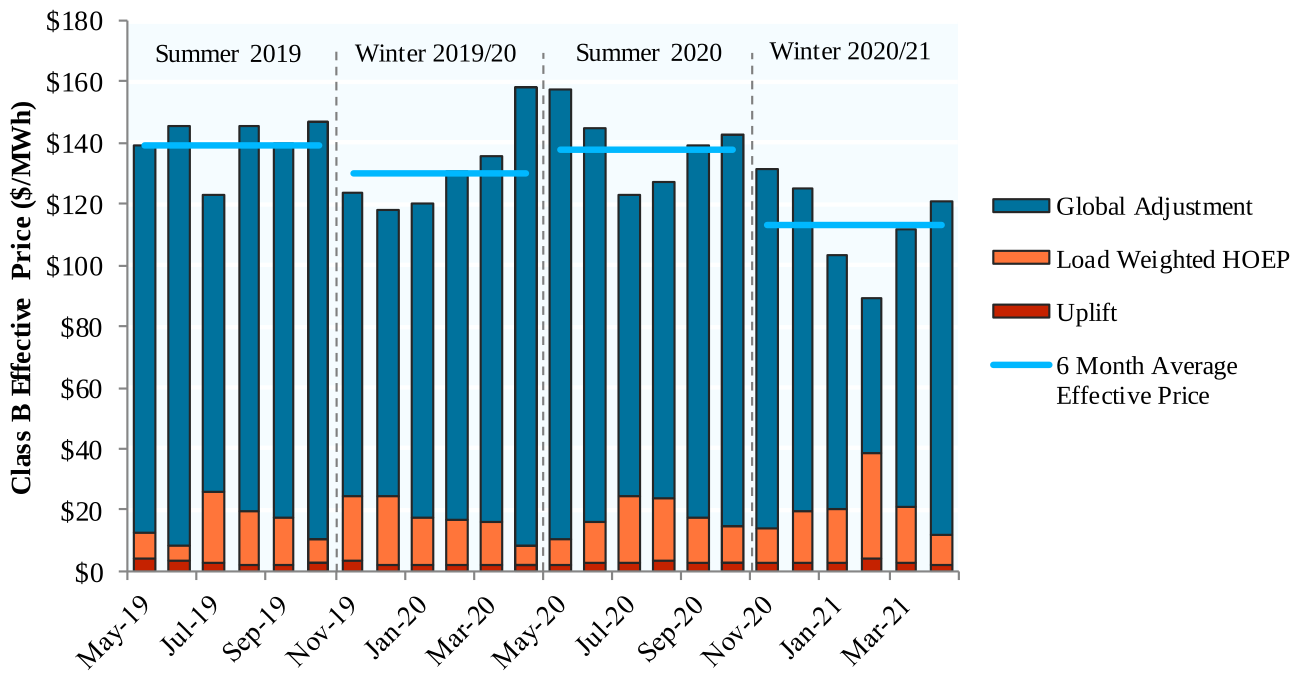
Figure A-2: Average Effective Price for Class A Consumers by Component, 2 Years



The 6-month average effective price for Class A consumers decreased significantly from $75.97/MWh in the Winter 2019/20 Period to $62.54/MWh in the Winter 2020/21 Period. On a monthly basis, higher Class A prices did not necessarily occur during the months where the HOEP was the highest during the Winter 2020/21 Period, which deviated from the tendency for the Class A average effective prices to be more greatly impacted by changes in HOEP.

Figure A-3 separates the monthly average effective price into its three components (average load weighted HOEP, average GA and average uplift charges) for Class B consumers for the previous two years. The 6-month average effective price for Class B consumers decreased from $130.16/MWh in the Winter 2019/20 Period to $113.25/MWh in the Winter 2020/21 Period. On a monthly basis, the average effective price for Class B consumers experienced greater variations throughout the Winter 2020/21 Period. As a result, changes in the GA continued to have a greater impact on the average effective price for Class B consumers in the Winter 2020/21 Period.

Figure A-3: Average Effective Price for Class B Consumers by Component, 2 Years



Most Class B consumers are subject to the Regulated Price Plan (RPP) and pay prices that are set by the Ontario Energy Board (OEB).[53] As a result, most Class B consumers are not affected by monthly effective price variations in comparison to Class A consumers, who do not pay the

[53] For more information on the RPP, see: https://www.oeb.ca/industry/policy-initiatives-and-consultations/regulated-price-plan-rpp

RPP. The decrease in the average Class B effective price was primarily driven by a decrease in the Class B GA in the Winter 2020/21 Period.

Figure A-4: Monthly & 6 Month (Simple) Average HOEP, 2 Years

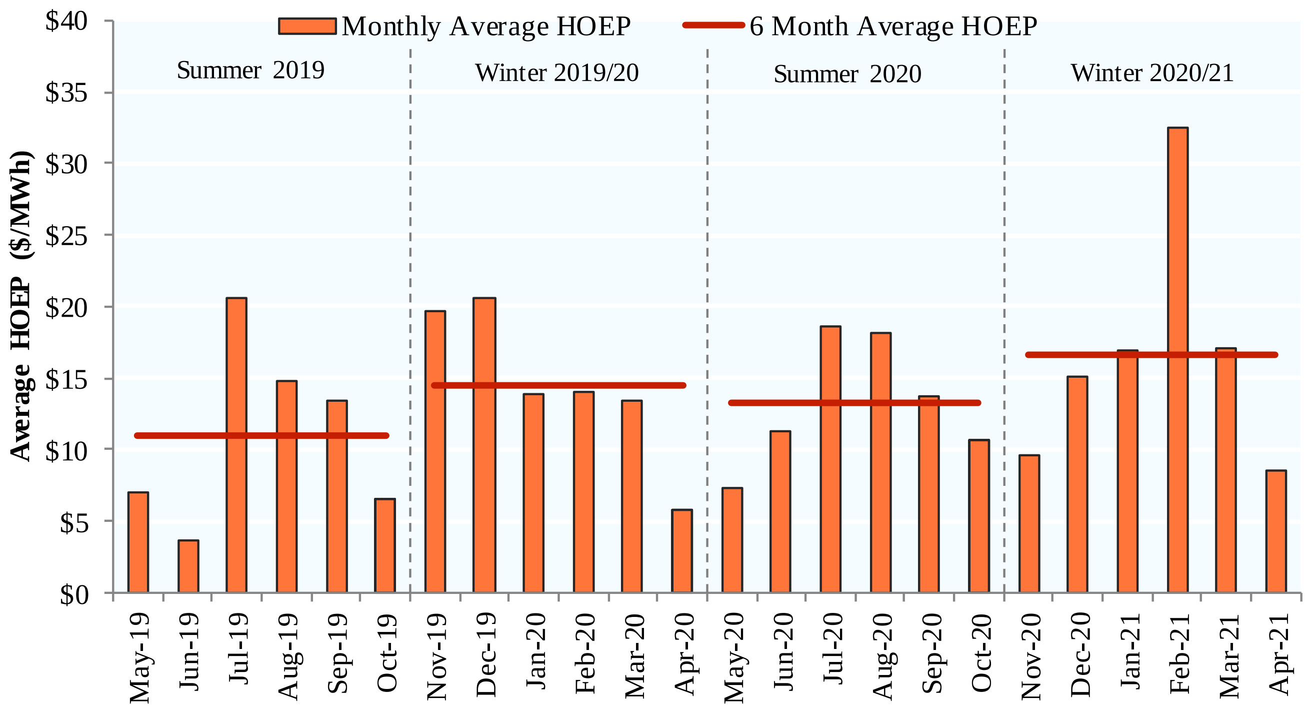


Figure A-4 displays the monthly unweighted average HOEP and the 6-month period average since May 2019. During the Winter 2020/21 Period, there was an increase in the unweighted 6-month average HOEP compared to the Winter 2019/20 Period, rising from $14.56/MWh to $16.61/MWh. Although the average Ontario demand changed minimally across the winter periods, the increase in unweighted 6-month average HOEP was likely in part driven by a high monthly average HOEP in February 2021. February 2021 experienced high gas prices throughout North America due to cold weather that put upward pressure on the HOEP.[54]

[54] Cold weather in the US during the month of February 2021 resulted in cold-weather related interruptions in natural gas production amidst increased demand for heating, resulting in the highest monthly average of Henry Hub natural gas spot prices since February 2014. See the Energy Information Administration: https://www.eia.gov/todayinenergy/detail.php?id=47016

Figure A-5: Natural Gas Price & HOEP during Peak Hours, 5 Years

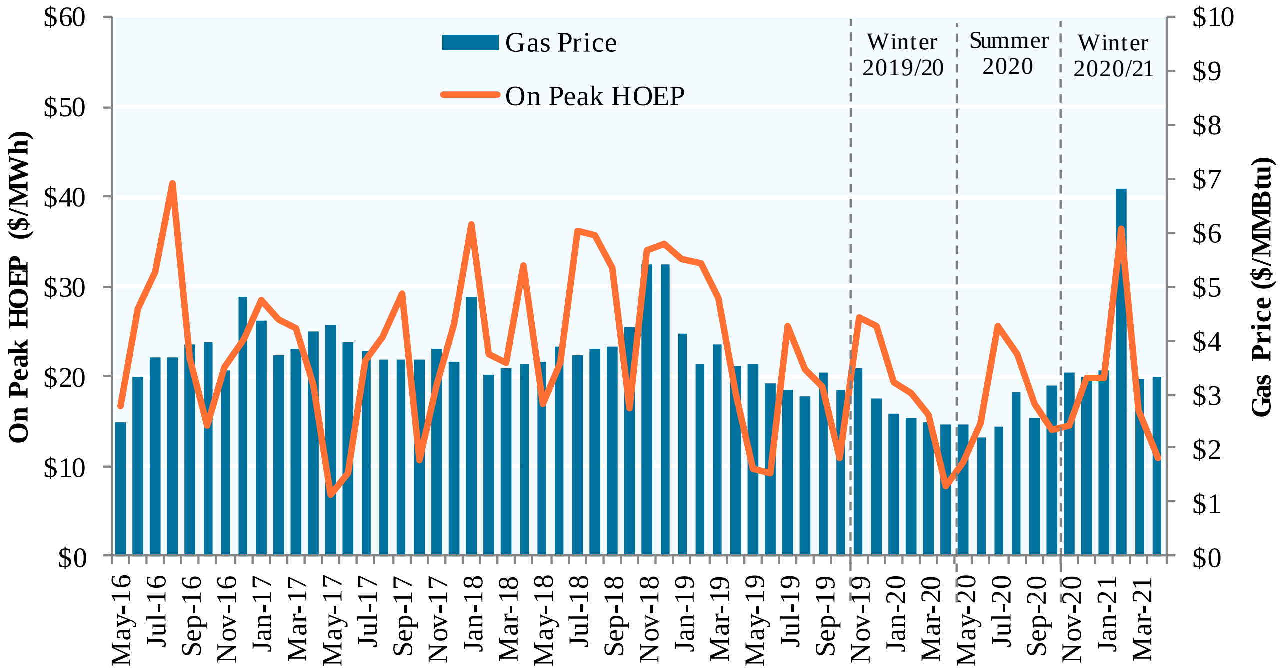


Figure A-5 plots the average monthly HOEP during on-peak hours and the monthly average of Henry Hub natural gas spot prices for days with on-peak hours for the previous year.[55] Natural gas prices are compared to the HOEP for on-peak hours as natural gas resources frequently set the price during these hours. The average gas price during on-peak hours was $3.93/MMBtu in the Winter 2020/21 Period, much greater than the $2.76/MMBtu in the Winter 2019/20 Period. The gas price decreased from $3.21/MMBtu in the Summer 2019 Period to $2.63/MMBtu in the Summer 2020 Period.

[55] On-peak hours here are defined as 7:00 AM to 11:00 PM, Monday to Friday (excluding holidays) to capture all hours when gas generators are likely to be running. Off-peak hours are all other hours. Previous Monitoring Reports used Dawn Hub day-ahead natural gas prices for this figure. Daily Henry Hub spot prices are adequate for illustrating monthly trends. Data is available from the Energy Information Administration: https://www.eia.gov/dnav/ng/hist/rngwhhdD.htm

A correlation coefficient of 0.62 was observed between average daily natural gas prices and daily averages of on-peak HOEP values during the Winter 2020/21 Period. This correlation was much higher than the value of 0.38 observed in the Winter 2019/20 Period, and is the highest correlation value observed since the Winter 2014/15 Period. When the supply of baseload generation is low, or when the demand for energy is high, higher cost natural gas resources often set the Market Clearing Price (MCP). When these conditions occur, there is usually a stronger positive correlation between the on-peak HOEP and the price of natural gas.

Both the on-peak HOEP and natural gas prices increased in Winter 2020/21 and peaked in February 2021 due to cold weather. Natural gas resources set the real-time MCP in 58.3% of the 5-minute intervals in February 2021. The on-peak HOEP was highest during months when gas prices were also high and when the number of intervals where gas set the real-time MCP peaked.

Figure A-6: Frequency Distribution of HOEP, 2 Periods

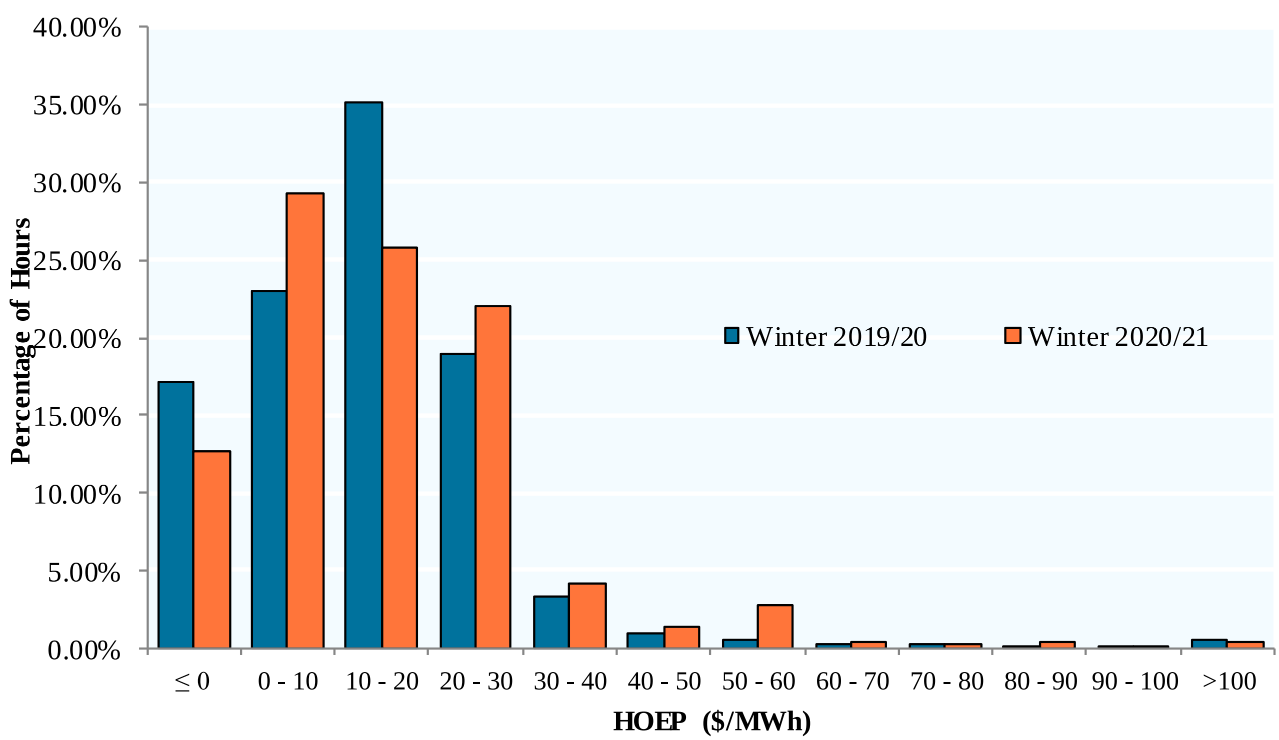


Figure A-6 compares the frequency distribution of the HOEP as a percentage of total hours for the Winter 2020/21 and Winter 2019/20 Periods. The HOEP is grouped in increments of $10/MWh, except for all negative-priced hours which are grouped together with all $0/MWh hours. During the Winter 2020/21 Period, about 13% of hours had a negative HOEP, compared to 17% in the Winter 2019/20 Period. Additionally, 32% of hours in the Winter 2020/21 Period had HOEPs of at least $20/MWh, up from 25% in the Winter 2019/20 Period. The increase in unavailable capacity and nuclear outages (see Figure A-23) in the Winter 2020/21 Period, contributed to the reduction in the number of negative-priced hours and to an increase in the number of hours with a HOEP of at least $20/MWh.

Table A-3 presents the share of intervals in which each resource type set the real-time MCP in the Winter 2019/20 Period, the Summer 2020 Period, and the Winter 2020/21 Period. The percentage of intervals where natural gas resources set the real-time MCP dropped slightly from 32% in the Winter 2019/20 Period to 31% in the Winter 2020/21 Period, while the percentage of intervals that wind set the real-time MCP decreased significantly from 24% to 19%. Nuclear and solar resources rarely set the real-time MCP in the Winter 2020/21 Period, down minimally from 0.02% and 0.01% in the Winter 2019/20 Period. The reduced availability of nuclear capacity in the Winter 2020/21 Period contributed to the increase in intervals where hydro resources set the real-time MCP from 42% to 49%. Natural gas resources set the real-time MCP more often in the month of February 2021 than in any other month in the Winter 2020/21 Period.

Table A-3: Share of Resource Type Setting the Real-Time MCP, 3 Periods[56]

Resource Share (%)	Winter 2019/20	Summer 2020	Winter 2020/21
Hydro	41.8%	38.5%	48.7%
Wind	24.1%	21.1%	19.3%
Gas	32.5%	38.2%	30.8%
Nuclear	0.02%	0.8%	0%
Solar	0.01%	0.09%	0%
Biofuel	1.7%	1.2%	1.3%

[56] Shares may not add up to 100% due to rounding.

Figure A-7 presents the share of intervals in which each resource type set the real-time MCP in each month of the previous two years.

Figure A-7: Share of Resource Type Setting the Real-Time MCP, 2 Years

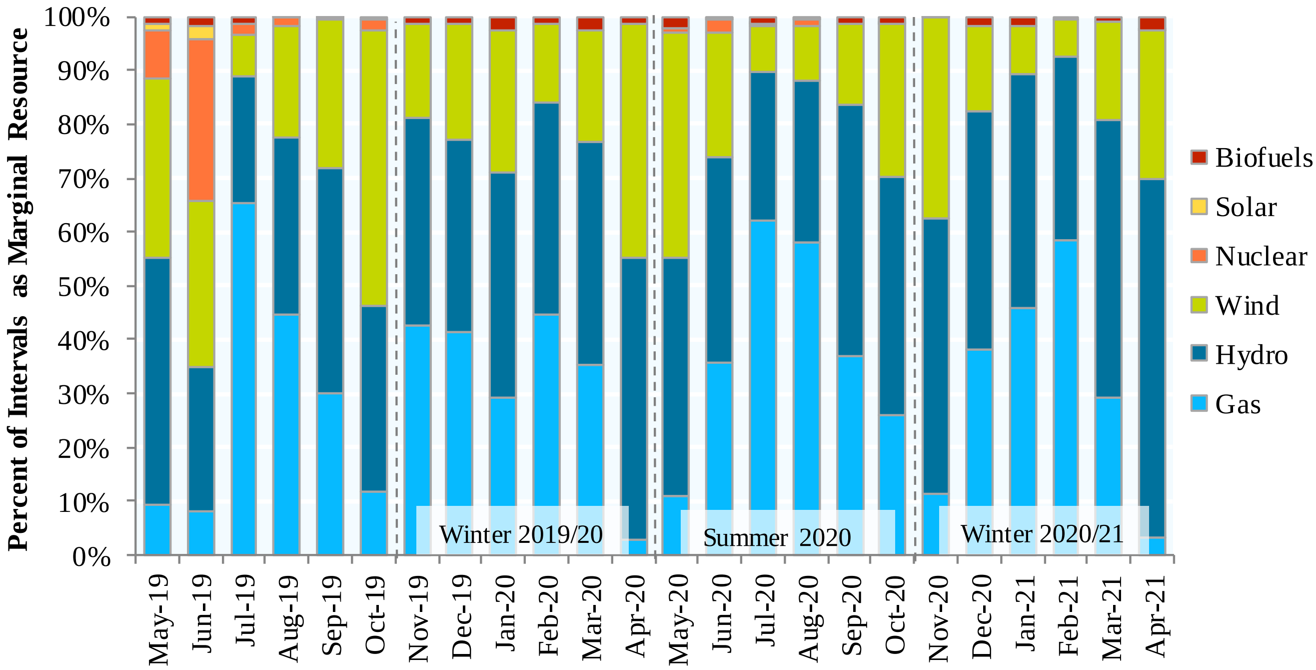


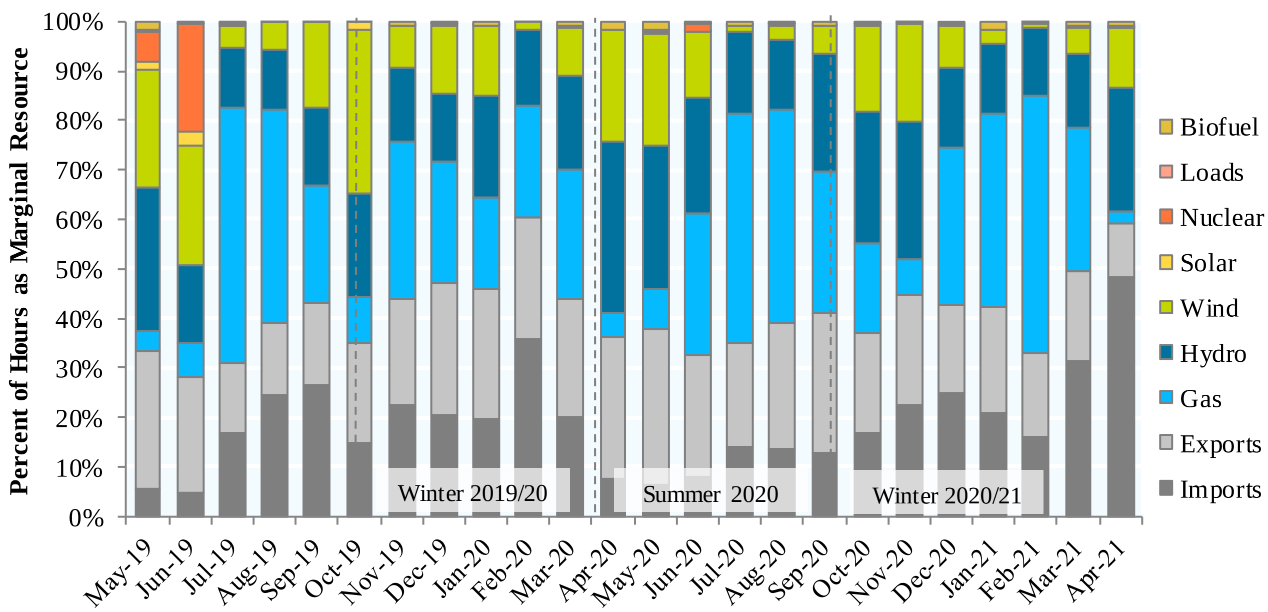
Table A-4 presents the share of hours in which each resource type, including imports and exports, set the one-hour ahead pre-dispatch MCP in the Winter 2019/20 Period, the Summer 2020 Period, and the Winter 2020/21 Period. The frequency with which imports and exports set the pre-dispatch (PD-1) MCP is important, as these transactions are unable to set the real-time MCP.[57] When the price is set by an import or export in pre-dispatch, a divergence between the pre-dispatch and the real-time MCP is more likely to occur.

[57] Due to scheduling protocols, imports and exports are scheduled hour-ahead. In real-time imports and exports are fixed for any given hour. Accordingly, imports and exports are treated as non-dispatchable in real-time and scheduled to flow for the entire hour regardless of the price, though their schedules may be curtailed within an hour to maintain reliability.

Table A-4: Share of Resource Type Setting the Pre-Dispatch MCP, 3 Periods[58]

Resource Share (%)	Winter 2019/20	Summer 2020	Winter 2020/21
Hydro	19.7%	22.2%	18.8%
Wind	11.7%	10.5%	8.2%
Gas	21.4%	28.8%	26.8%
Nuclear	0%	0.3%	0%
Solar	0.02%	0.2%	0.04%
Biofuel	0.9%	0.8%	0.8%
Imports	20.9%	12%	27.5%
Exports	25.2%	25.2%	17.8%
Loads	0.08%	0.08%	0.2%

Figure A-8: Share of Resource Type Setting the One-Hour Ahead Pre-Dispatch MCP, 2 Years



58 Shares may not add up to 100% due to rounding.

Figure A-8 presents the share of hours in which each resource type set the one-hour ahead pre-dispatch (PD-1) MCP in each month of the previous two years. When compared with Figure A-7, Figure A-8 shows how the marginal resource mix changes from pre-dispatch to real-time.

The PD-1 MCP and the PD-1 schedules are used for import and export transactions for real-time delivery. Intertie transactions are scheduled based on the PD-1 Intertie Zonal Price (IZP) although they are settled based on the real-time IZP. In the Winter 2020/21 Period, there was a positive or negative variation of less than $10/MWh between PD-1 and real-time prices for 87% of hours, up slightly from 86% in the Winter 2019/20 Period. The average absolute deviation between PD-1 and real-time prices in the Winter 2020/21 Period increased by 4.4% from the Winter 2019/20 Period average deviation ($6.10/MWh compared to $5.84/MWh), likely due to increases in average hourly forecast deviation and wind forecast deviation (see Table A-5).

Real-time prices diverge from PD-1 prices because of price-setting eligibility alongside changing conditions from pre-dispatch to real-time.[59,60] Identifying the factors that lead to deviations between the PD-1 MCP and the real-time MCP provides insight into the root causes of the price risks faced by participants, particularly importers and exporters, as they enter offers and bids into the market.

[59] The Panel has identified the following as the six main factors that contribute to the difference between the PD-1 MCP and the Hourly Ontario Electricity Price (HOEP): Supply: i) Self-scheduling and intermittent generation forecast deviation (other than wind), ii) wind generation forecast deviation, iii) generator outages and iv) import failures/curtailments. Demand: v) Pre-dispatch to real-time demand forecast deviation and vi) export failures/curtailments. Imports or exports setting the PD-1 MCP can also result in price divergences as these transactions cannot set the price in real-time.

[60] Intertie transactions can set PD-1 prices and are fixed for any given hour in real-time, which can cause a price deviation from pre-dispatch to real-time.

Figure A-9: Difference between HOEP and PD-1 MCP, 3 Periods

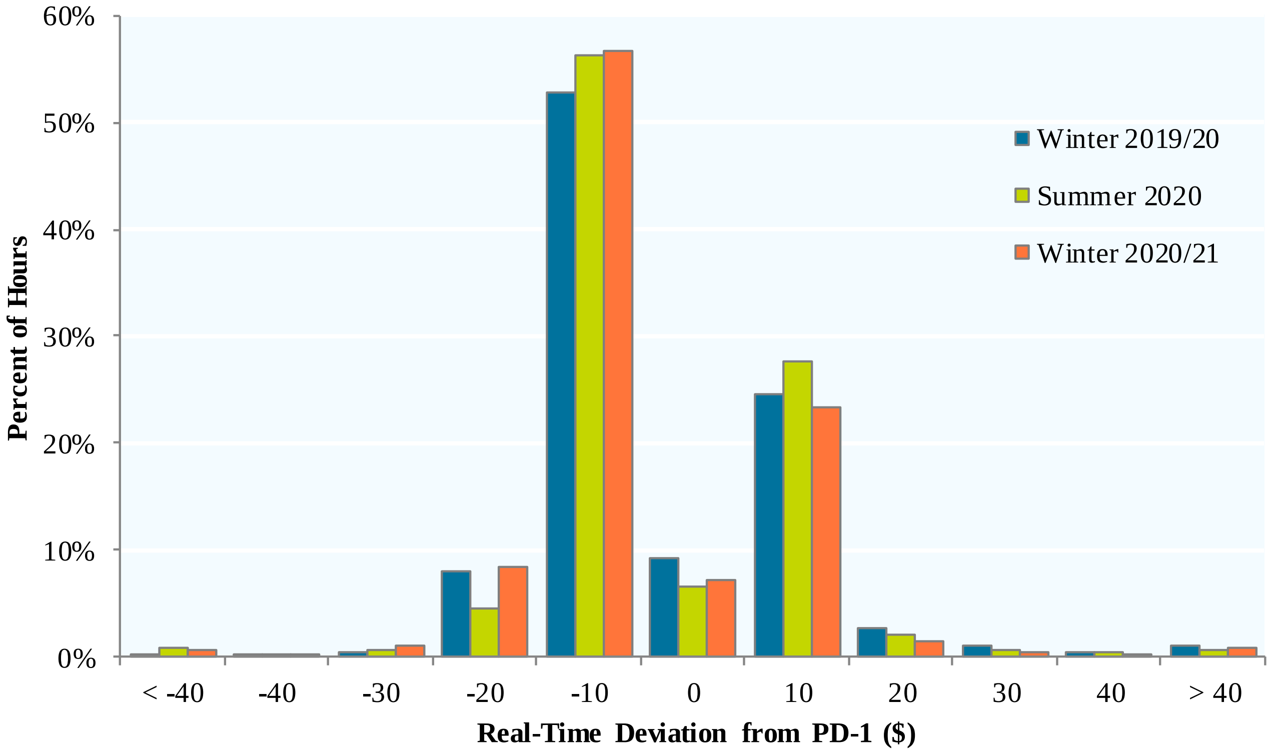


Figure A-9 presents the frequency distribution of differences between the HOEP and the PD-1 MCP for the Winter 2020/21, Summer 2020, and Winter 2019/20 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-1 MCP and the HOEP, as well as the categories where the absolute difference between the PD-1 MCP and the HOEP exceeded ±$40/MWh. Positive differences on the horizontal axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease.

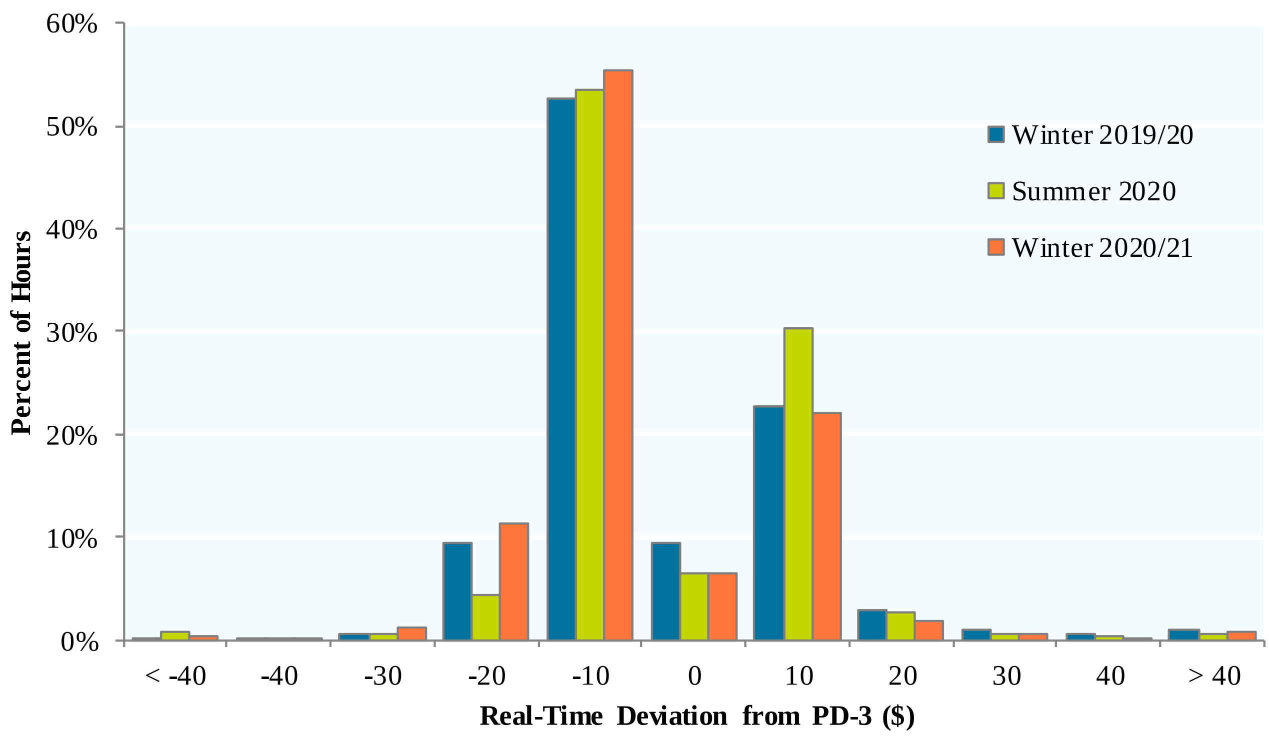
Table A-5: Factors Contributing to Differences between PD-1 MCP and HOEP, 3 Periods

Factor	Winter 2019/20: Absolute Difference		Summer 2020: Absolute Difference		Winter 2020/21: Absolute Difference	
	Average (MW)	Maximum (MW)	Average (MW)	Maximum (MW)	Average (MW)	Maximum (MW)
Ontario Demand	15,386	20,801	15,043	24,990	15,395	20,554
Forecast Demand Deviation	216	1,089	242	2,213	242	1,461
Self-Scheduling Generation and Intermittent Forecast Deviation (Excluding Wind)	29	666	15	81	12	70
Wind Generation Forecast Deviation	166	1,012	156	1,430	172	1,427
Net Export Failures/Curtailments	78	1,261	68	951	64	968

Table A-5 displays the average absolute difference between PD-1 and real-time for all factors identified by the Panel as contributing to the difference between PD-1 and real-time, save for the effect of generator outages. Generator outages tend to be infrequent relative to the other factors, although short-notice outages can have significant price effects. Ontario demand is also included to provide a relative sense of the size of the deviations.

Figure A-10 presents the frequency distribution of differences between the HOEP and the PD-3 MCP during the Winter 2020/21, Summer 2020, and Winter 2019/20 Periods. The price differences are grouped in $10/MWh increments, save for the $0/MWh category which represents no change between the PD-3 MCP and the HOEP, as well as the categories where the absolute difference between the PD-1 MCP and the HOEP exceeded ±$40/MWh. Positive differences on the x-axis represent a price increase from pre-dispatch to real-time, while negative differences represent a price decrease from pre-dispatch to real-time. The PD-3 MCP is the last price signal seen by the market prior to the closing of the offer and bid window. Changes in price between PD-3 and the HOEP are particularly relevant to non-quick start facilities and energy limited resources, both of which rely on pre-dispatch prices to make operational decisions.[61] Price changes are also important to intertie traders, whose bids and offers are often informed by pre-dispatch prices in Ontario.

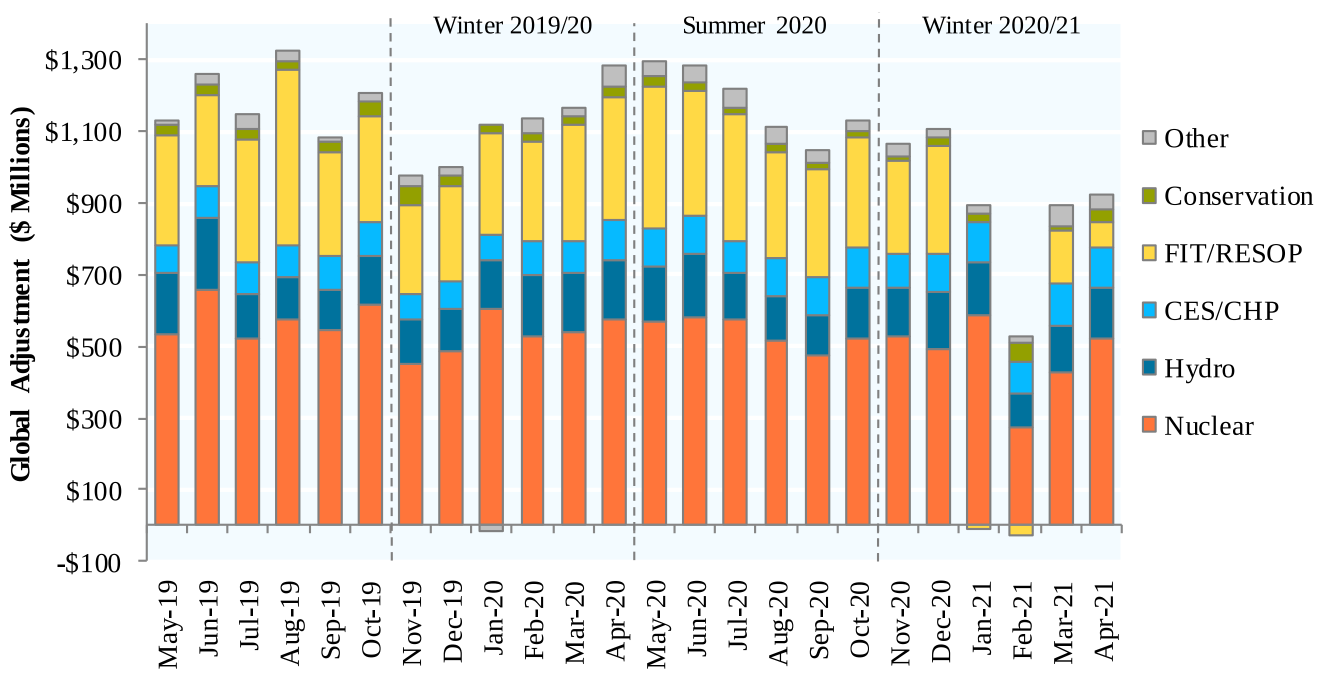
Figure A-10: Difference between HOEP and PD-3 MCP, 3 Periods



[61] Energy limited resources constitute a subset of generation facilities that experience fuel restrictions such that they cannot operate at capacity for the entire day but can optimize their production over their storage horizons. For example, some hydroelectric facilities regularly experience fuel restrictions due to limited water availability.

Pre-dispatch (PD-3) prices had a positive or negative variation of $10/MWh of the real-time MCP in 84% of the hours in the Winter 2020/21 Period, similar to the 85% of the hours in the Winter 2019/20 Period. The percentage of prices within $10/MWh of the real-time MCP for PD-1 prices also increased slightly from the Winter 2019/20 Period to the Winter 2020/21 Period. The average absolute deviation between PD-3 and real-time MCPs increased modestly by 6.4% in the Winter 2020/21 Period ($6.57/MWh) from the Winter 2019/20 Period ($6.18/MWh). The change in the percentage of prices that had a positive or negative variation of $10/MWh of the real-time MCP were stable between the Winter 2020/21 Period and the Winter 2019/20 Period for both the PD-1 and PD-3 prices. The change in average absolute deviation also increased for both the PD-1 and PD-3 prices by similar margins, indicating that the PD-1 and PD-3 prices are closely aligned. In short, these deviations in the Winter 2020/21 Period were similar to those in the Winter 2019/20 Period.

Figure A-11: Monthly Global Adjustment (GA) by Component, 2 Years



Total GA is divided into six components:

- Payments to nuclear facilities (Bruce Nuclear Generating Station (contract) and Ontario Power Generation Inc.'s (OPG) nuclear assets (regulated price));
- Payments to holders of Clean Energy Supply (CES) and Combined Heat and Power (CHP) contracts;
- Payments to regulated or contracted hydroelectric generation;
- Payments to holders of contracts for renewable power (Feed-in Tariff, including microFIT (collectively FIT), and the Renewable Energy Standard Offer Program (RESOP));
- Payments related to the IESO's conservation programs; and
- Payments to others (including to holders of Non-Utility Generator contracts and OPG's Lennox Generating Station).

Figure A-11 plots the payments to various resources that are recovered through the GA, by month and by component for the previous two years. Effective January 1, 2021, the costs for 85% of non-hydro renewable energy contracts were shifted to the tax base by the Ontario government. This net reduction in the GA from the "Non-Hydro Renewables Funding Amount" is reflected in the FIT/RESOP amounts in Figure A-11.[62]

The total GA throughout the Winter 2020/21 Period was about 19% less than the total GA during the Winter 2019/20 Period, decreasing from $6.7 billion to $5.4 billion. Most of the change is due to the introduction of the Non-Hydro Renewables Funding Amount that effectively reduces the GA costs for consumers. There was also a 11% decrease in GA payments to nuclear facilities, driven by a substantial decrease during the month of February 2021.

[62] A new regulation effective January 2021 specifies the renewable contract costs that can be funded by the Province rather than being funded by ratepayers through the GA, resulting in a decrease in FIT/RESOP payments from the GA. For more information regarding the Non-Hydro Renewables Funding Amount, see the IESO's webpage "Monthly Market Report":
https://www.ieso.ca/en/Power-Data/Monthly-Market-Report

Regulatory Charges

Regulatory Charges include the cost of services provided by the IESO to operate the wholesale electricity market and maintain the reliability of the high voltage power grid. These charges are included in the "Regulatory charges" line item of low-volume consumer bills, and are recovered from wholesale Market Participants through "uplift" charges that are captured by the IESO under the rubric of "wholesale market service charges".[63] Regulatory charges include both amounts set or approved by the OEB (e.g. IESO Administration Charge and the Rural or Remote Electricity Rate Protection (RRRP) charge) and amounts that are not set or approved by the OEB such as charges associated with reliability or transmission losses.[64]

Hourly uplift components are charged to wholesale consumers (including distributors) based on their share of total hourly demand, while monthly uplift components are charged to wholesale consumers (including distributors) based on their share of total daily or monthly demand.[65]

Table A-6 below summarizes a number of components of regulatory charges, the majority of which are "uplift" costs for wholesale Market Participants.[66] Charges are split into hourly charges (including Congestion Management Settlement Credits (CMSC), transmission losses, Intertie Offer Guarantee (IOG), Operating Reserve (OR), and hourly reactive support and voltage control) and monthly charges (including the Day Ahead Production Cost Guarantee (DA-PCG)[67]

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63 For convenience, this section refers to "regulatory charges".

64 See the OEB's webpage "Understanding Your Electricity Bill": https://www.oeb.ca/rates-and-your-bill/electricity-rates/understanding-your-electricity-bill

65 This applies to all monthly and daily uplifts with the exception of costs associated with DR. These costs are allocated with the same methodology as the GA, where Class A consumers pay the fraction of costs corresponding to their fraction of Ontario demand during the five highest demand peaks of the year, and Class B consumers are billed the remaining sum volumetrically.

66 The table separates previously aggregated charges and considers two other Wholesale Market Service Charges previously omitted from Panel reports: IESO Administration Charge and the Rural and Remote Electricity Rate Protection Charge.

67 Although the settlement resolution for the DA-PCG program is daily, it has been grouped with monthly charges as all other charges considered are hourly or monthly.

and Real-Time Generation Cost Guarantee (RT-GCG) programs, ancillary services, Demand Response (DR), IESO Administration Charge, Rural or Remote Electricity Rate Protection and other charges). Figure A-12 shows the Wholesale Market Service Charges by month.[68]

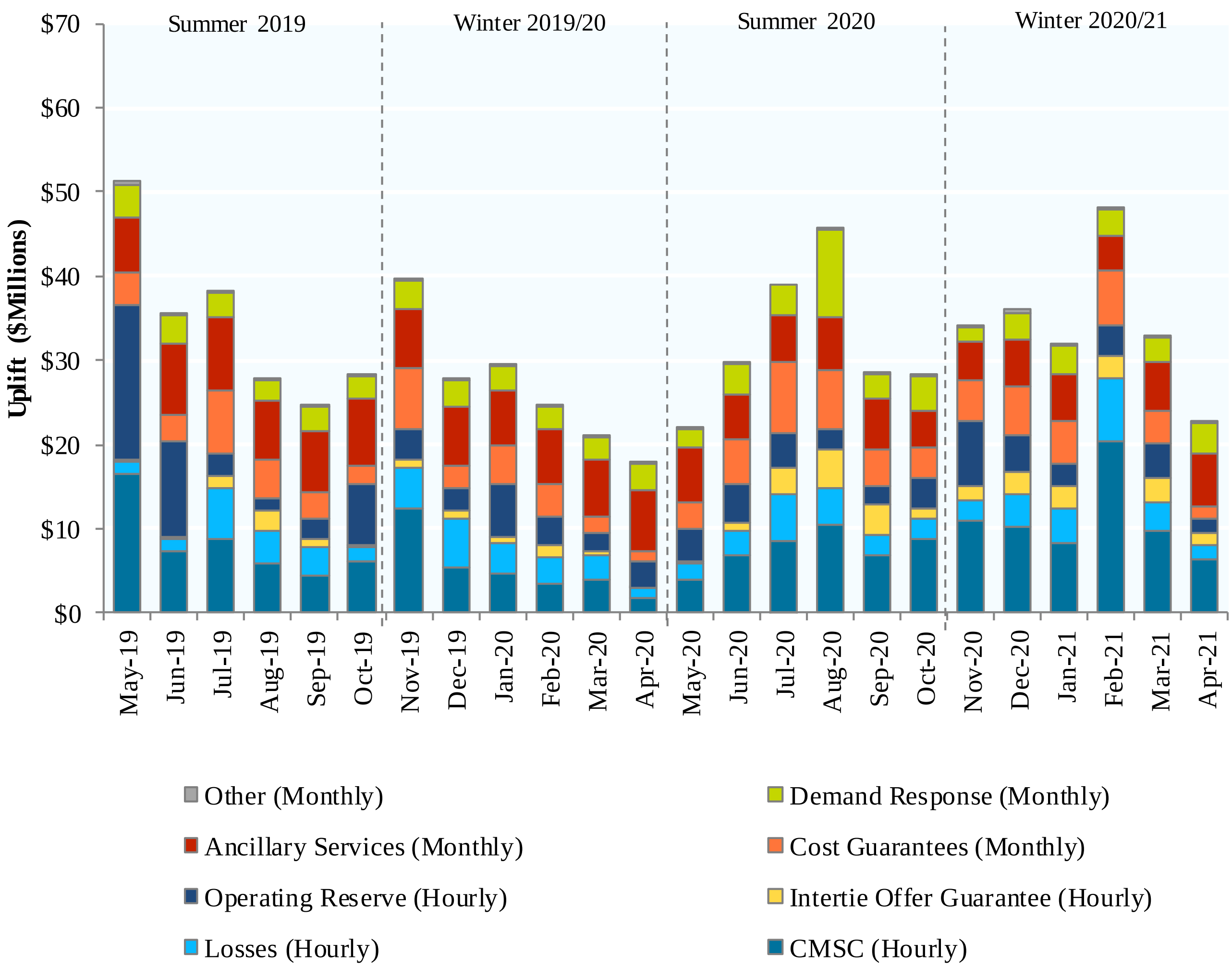
Total Wholesale Market Service Charges in the Winter 2020/21 Period were $327 million, a 15% increase from the Winter 2019/20 Period of $285 million. Notable increases compared to the previous Winter Period include: CMSC (108% increase or $34 million), IOG (215% increase or $9.7 million), 10-minute spinning OR (49% increase or $3.6 million), RT-GCG (32% increase or $5.0 million) and ancillary monthly reactive support and voltage control charges (287% increase of $2.0 million). These increases were partially offset by substantial decreases in ancillary regulation charges (56% decrease or $10.8 million).

[68] For consistency with previous reports, the Intertie Failure Charge Rebate, the IESO Administration Charge and the Rural or Remote Electricity Rate Protection Charge were omitted from Figure A-12.

Table A-6: Regulatory Charges by Charge Type and Period, 3 Periods

Settlement Resolution	Regulatory Charges	Winter 2019/20 ($ million)	Summer 2020 ($ million)	Winter 2020/21 ($ million)
Hourly	Congestion Management Settlement Credits (CMSC)	31.40	45.18	65.43
	Transmission Losses	21.44	19.93	23.35
	Intertie Offer Guarantee (IOG)	4.48	13.80	14.13
	Intertie Failure Charge Rebate	-0.37	-0.51	-0.46
	Operating Reserve: 10-minute spinning reserve	7.43	9.68	11.05
	Operating Reserve: 10-minute non-spinning reserve	8.65	6.65	8.37
	Operating Reserve: 30-minute reserve	5.65	4.25	4.79
	Hourly Reactive Support and Voltage Control	9.01	11.46	8.39
	Hourly Charges Subtotal	**87.70**	**110.43**	**135.05**
Monthly	Cost Guarantee: RT-GCG program	15.54	17.73	20.54
	Cost Guarantee: PCG program	5.75	14.24	6.90
	Ancillary Services: Black Start	0.86	0.83	0.87
	Ancillary Services: Regulation	30.85	20.69	20.02
	Ancillary Services: Monthly Reactive Support and Voltage Control	0.71	0.92	2.73
	Demand Response Capacity Payments	17.75	27.03	17.77
	IESO Administration Charge	91.95	89.67	89.28
	Rural or Remote Electricity Rate Protection	32.91	32.56	32.79
	Other (Charge Types 163, 169, 170)	1.10	2.46	1.39
	Monthly Charges Subtotal	**197.43**	**206.11**	**192.30**
Total Regulatory Charges		**285.12**	**316.54**	**327.36**

Figure A-12: Total Uplift Charge by Component on a Monthly Basis, 2 Years



Operating Reserve Prices

The three OR markets are co-optimized with the energy market, so prices in these markets tend to be positively correlated. The OR demand is based primarily on reliability standards set by the North American Electric Reliability Corporation (NERC) and the Northeast Power Coordinating Council (NPCC). At minimum, the IESO must schedule sufficient OR to allow the grid to recover from the single largest contingency (such as loss of the largest generator) within 10 minutes, plus additional OR to recover from half of the second largest contingency within 30 minutes. The IESO made a Market Rule change to enable increases to the 30-minute OR requirement, which has mainly been used to increase the scheduled amount of 30-minute OR by 200 MW to enable system flexibility.[69,70]

Uplift from OR was $24.2 million for Winter 2020/21 Period, greater than the $21.7 million in the Winter 2019/20 Period. The 10-minute spinning price ($6.20/MW) and 10-minute non-spinning price ($4.41/MW) increased by 33% and 16% compared to the Winter 2019/20 Period. The 30-minute reserve decreased by 16% compared to the Winter 2019/20 Period. The Winter 2020/21 Period experienced higher OR prices than the Winter 2019/20 Period, likely due to an increase in the operating reserve provided by natural gas resources in the Winter 2020/21 Period, particularly in February 2021.

[69] See the Market Rule Amendment “MR-00436: Enabling System Flexibility: Thirty-Minute Operating Reserve” approved by the IESO Board April 11, 2018: http://www.ieso.ca/-/media/Files/IESO/Document-Library/mr-amendments/mr2018/MR-00436-R00-Enabling-Flexibility-Amendment-Proposal-v5-0.pdf?la=en

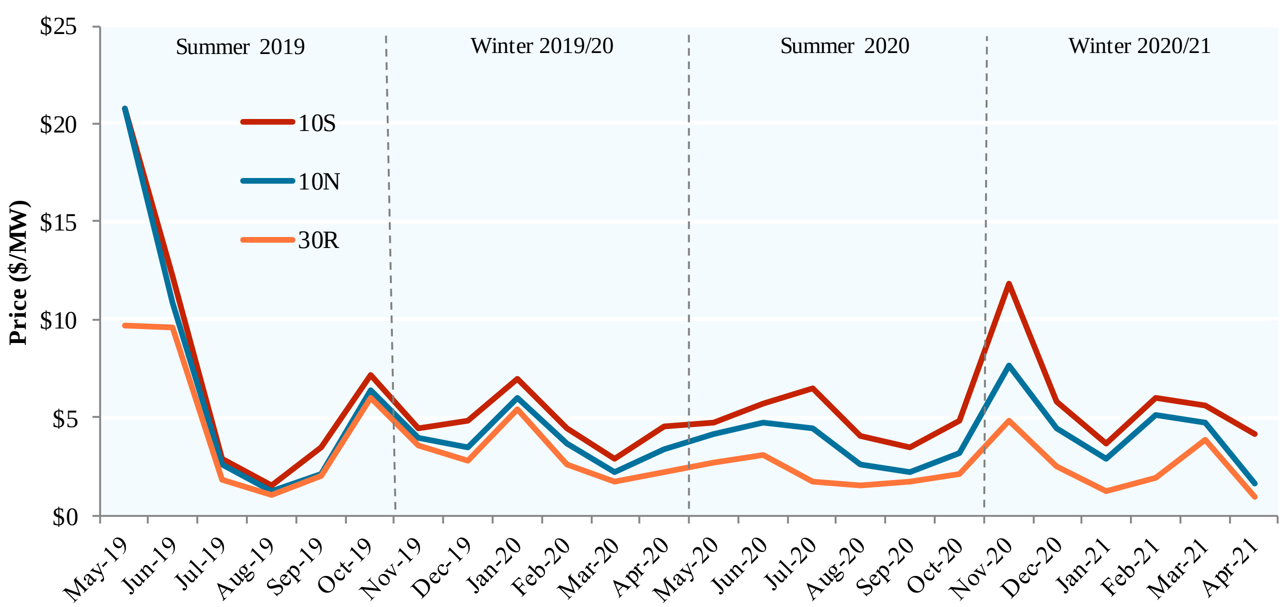
[70] This Market Rule Amendment and its justification was discussed in the Panel’s Monitoring Report 32 published July 2020, Section 3.2: https://www.oeb.ca/sites/default/files/msp-monitoring-report-20200716.pdf

Table A-7: Average Operating Reserve Prices by Period, 2 Years

Operating Reserve Markets	Summer 2019 ($/MW)	Winter 2019/20 ($/MW)	Summer 2020 ($/MW)	Winter 2020/21 ($/MW)
10-minute spinning (10S)	8.02	4.67	4.88	6.20
10-minute non-spinning (10N)	7.32	3.79	3.57	4.41
30-minute reserve (30R)	5.01	3.04	2.13	2.55

Table A-7 presents the average OR prices by period for the past 2 years for the three OR markets and Figure A-13 illustrates the monthly fluctuations of OR prices. Because OR prices are usually low, a single high-priced hour can lead to an increased monthly average price. The rise in average OR prices between the Winter 2019/20 Period and the Winter 2020/21 Period is largely due to a spike in OR prices that occurred in November 2020. Higher prices during November 2020 resulted from the November 13, 2020 and November 18, 2020 high-priced hours noted in Chapter 2, Table 2-3.

Figure A-13: Average Monthly Operating Reserve Prices by Category, 2 Years



Nodal Prices

Nodal prices approximate the marginal cost of electricity in each location and reflect Ontario's internal transmission constraints. High average nodal prices are generally caused by expensive or limited supply while low average nodal prices are generally caused by cheaper or abundant supply. Differences in nodal prices across zones reflect transmission line losses and congestion.

As shown in Figure A-14, most zones had lower average prices in the Winter 2020/21 Period compared to the previous winter, except for the West and Northwest.

In general, monthly average nodal prices outside the two northern zones are similar and move together. Most of the time, the nodal prices in the Northwest and Northeast zones are significantly lower than in the rest of the province because there is more low-cost generation (typically hydroelectric supply) than there is demand in these zones, as well as insufficient transmission to transfer this low-cost surplus power to the southern parts of the province. While this generally leads to lower prices in the North, this limited transmission capacity could also lead to high prices in the North when there is limited supply (mainly hydroelectric supply) in the North relative to the demand in the North. For these reasons, prices in the Northwest and the Northeast zones are generally highly sensitive to changes in demand, hydroelectric supply, and transmission outages.

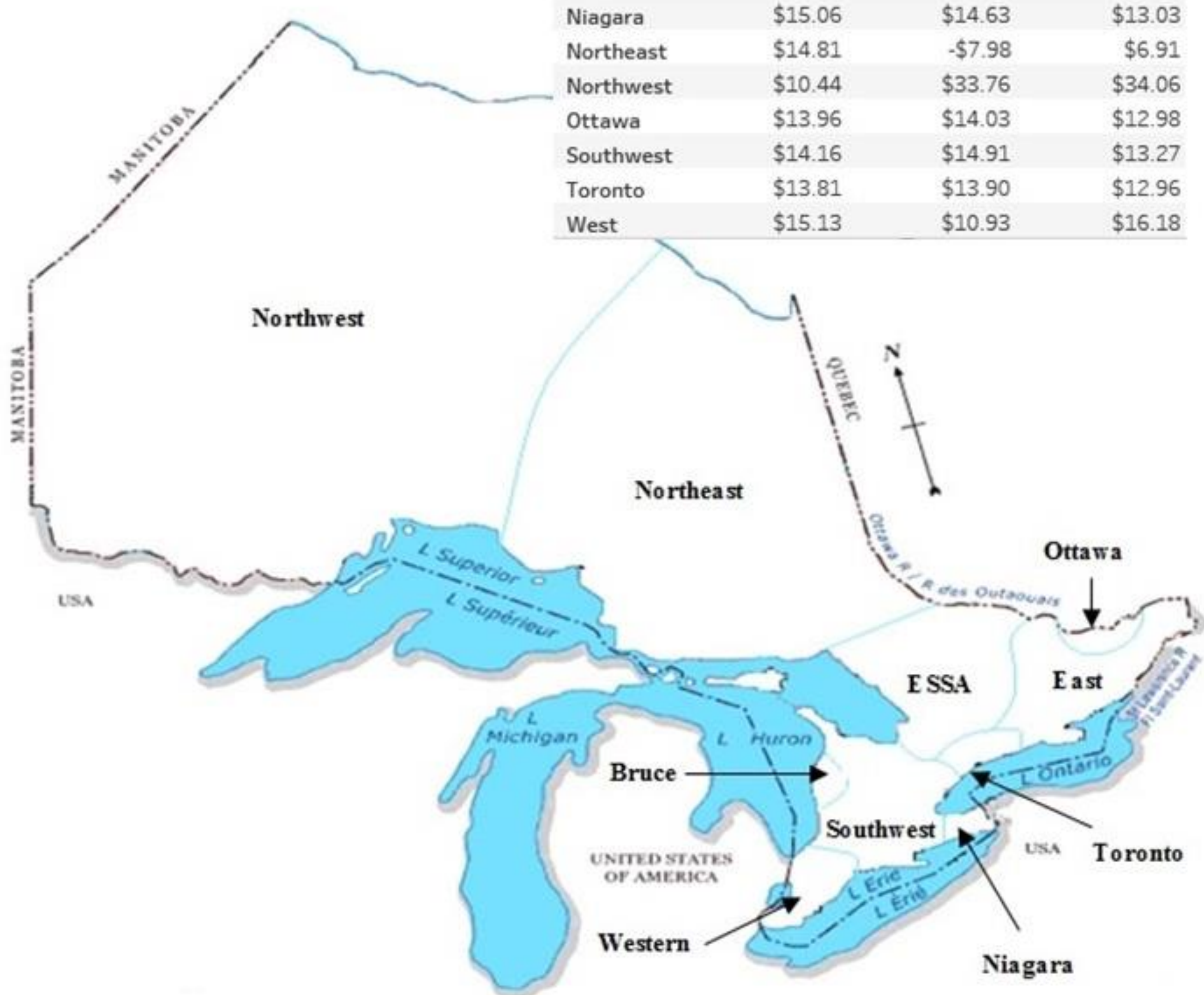
In addition, some hydroelectric facilities operate under must-run conditions, generating at certain levels of output for safety, environmental or regulatory reasons. Under such conditions, Market Participants offer the must-run energy at negative prices to ensure that the units are economically selected and scheduled. A surplus of water during a given period will likely increase production from hydroelectric facilities. The limited demand in the Northwest and Northeast, means that an increase in production from hydroelectric facilities could create local surpluses of power that exceed the capability of transmission lines required to move this power into southern load centres. An increase in output from hydroelectric resources by 31.2% in the Northeast likely caused the observed drop in nodal prices in the Winter 2020/21 Period, relative to the Winter 2019/20 Period.

The opposite of this effect occurred in the Northwest since the region's hydroelectric supply decreased and the nodal price increased substantially in the Winter 2020/21 Period, relative to historical averages. The nodal price in the Northwest was the highest nodal price across Ontario during the Winter 2020/21 Period. Prices in the Northwest were higher on average across all months in the Winter 2020/21 Period relative to the Winter 2019/20 Period, peaking between December 2020 and April 2021. The average monthly demand in Northwest increased minimally in the Winter 2020/21 Period relative to the Winter 2019/20 Period. However, supply from hydroelectric generators in the Northwest fell by 36% in the Winter 2020/21 Period, relative to the Winter 2019/20 Period.[71] There were also significant increases in the nodal prices of resources near the Ontario-Manitoba intertie and factors such as transmission limitations that contributed to the increase in zonal price (see Chapter 2, Section 2.1.2 for more details).

[71] Hydroelectric supply conditions in the Northwest were evaluated by comparing the total hydroelectric supply available during a 6-month period across winter seasons. Summer seasonal totals were not compared.

Figure A-14: Average Internal Nodal Prices by Zone, 3 Periods

Zone	Winter 2019/20	Summer 2020	Winter 2020/21
Bruce	$13.42	$14.21	$12.46
East	$13.62	$13.74	$12.78
Essa	$14.24	$13.20	$12.88
Niagara	$15.06	$14.63	$13.03
Northeast	$14.81	-$7.98	$6.91
Northwest	$10.44	$33.76	$34.06
Ottawa	$13.96	$14.03	$12.98
Southwest	$14.16	$14.91	$13.27
Toronto	$13.81	$13.90	$12.96
West	$15.13	$10.93	$16.18



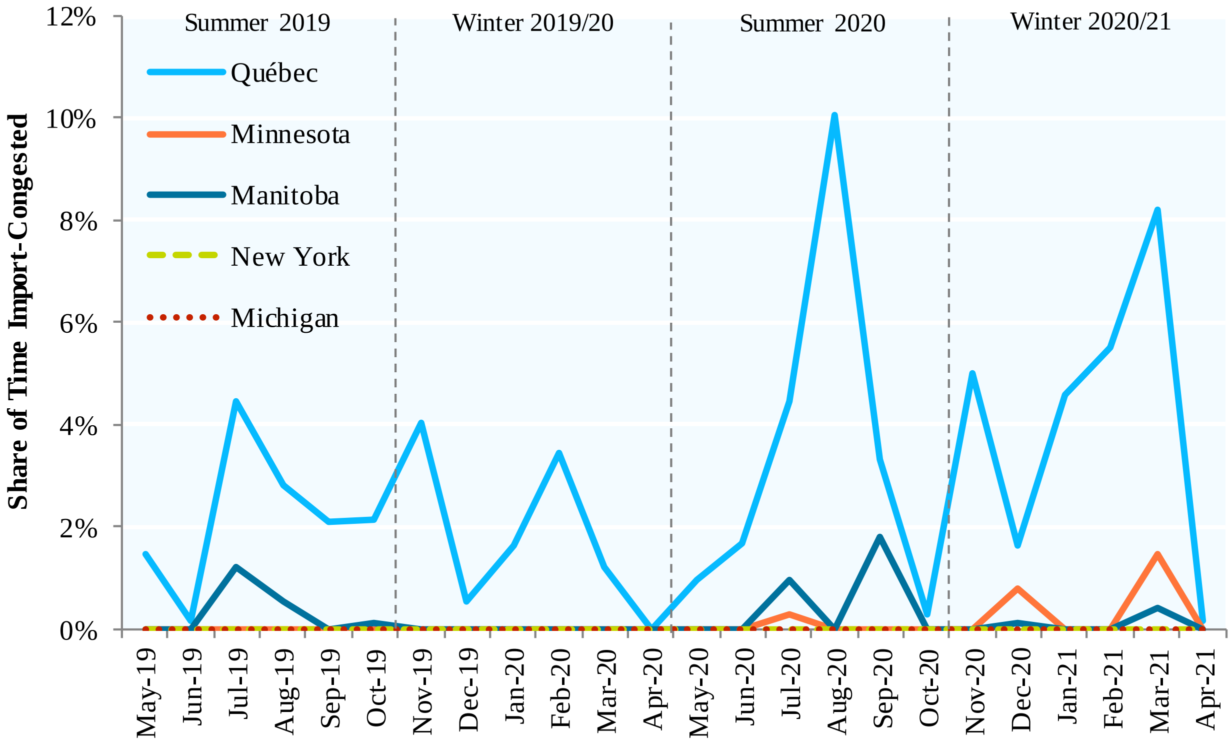
Import/Export Congestion and Transmission Rights

When an intertie has a greater amount of economic net import offers (or economic net export bids) than its transfer capability, the intertie will be import (or export) congested.

For a given intertie, importers are paid the Intertie Zonal Price (IZP), while exporters pay the IZP. The difference between the IZP and the Market Clearing Price (MCP) is called the Intertie Congestion Price (ICP). The ICP for a given hour is calculated in PD-1 and signals when there are more economic transactions than the intertie transmission lines can accommodate (if there is no congestion the ICP is zero). The ICP is positive when there is export congestion and negative when there is import congestion.

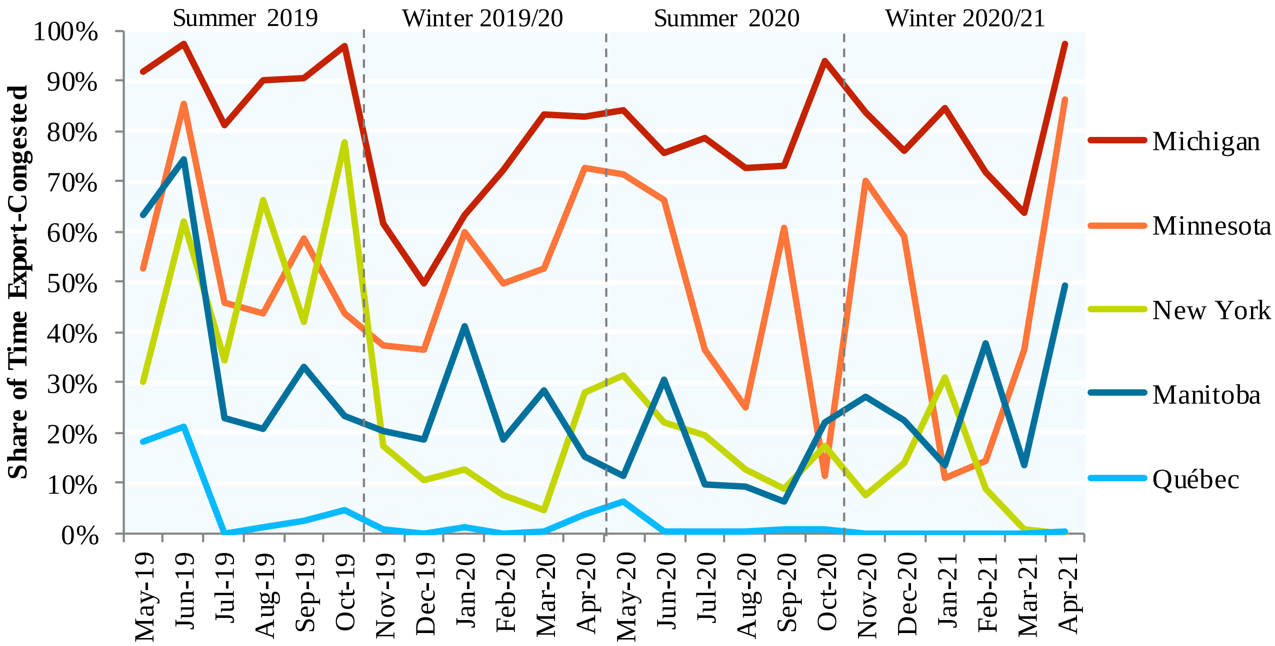
Figure A-15 reports the share of hours per month of import congestion by intertie and Figure A-16 reports the share of hours per month of export congestion by intertie for the previous two years. Unless otherwise stated, all references to the Québec intertie in this Appendix refer to the Outaouais intertie.

Figure A-15: Import Congestion by Intertie, 2 Years



There were 202 hours of import congestion during the Winter 2020/21 Period, a 159% increase compared to the Winter 2019/20 Period. For the Winter 2020/21 Period, Québec experienced the highest number of import-congested hours. The Québec intertie experienced a 132% increase in the number of import-congested hours relative to the Winter 2019/20 Period, likely due to the increase in imports from Québec during the Winter 2020/21 Period.

Figure A-16: Export Congestion by Intertie, 2 Years



There were 7,099 hours of export congestion in the Winter 2020/21 Period, a 3% increase compared to the previous summer. The Québec intertie experienced the greatest decrease in export-congested hours, from 42 hours in the Winter 2019/20 Period to just 3 hours in the Winter 2020/21 Period. The number of export-congested hours also decreased on Minnesota and New York interties and increased on Manitoba and Michigan interties during the Winter 2020/21 Period in comparison to the Winter 2019/20 Period. Michigan, Minnesota, and Manitoba had the highest number of congested hours during the Winter 2020/21 Period compared to other interties, which is reflected in the large difference in market price relative to Ontario's HOEP (see Table A-8).

Absent congestion at an intertie, importers receive, and exporters pay, the HOEP when transacting in Ontario. If there is congestion, however, importers and exporters in Ontario receive or pay the IZP rather than the HOEP.

Table A-8 lists the average hourly real-time spot prices for electricity, by month, in Ontario and the surrounding external jurisdictions with which electricity intertie traders operating in Ontario commonly trade. The Ontario price reported reflects only the HOEP and does not include the Global Adjustment (GA) or uplift. Québec does not operate a wholesale market, does not publish prices, and thus is not included in Table A-8. The prices listed for each jurisdiction reflect the marginal price of electricity excluding costs associated with capacity as traders do not pay these costs. The external prices reported are the real-time locational-marginal prices that correspond with the node on the other side of Ontario's intertie with each jurisdiction.

Table A-8: Monthly Electricity Spot Prices (CAD$) – Ontario & Surrounding Jurisdictions, 1 Period

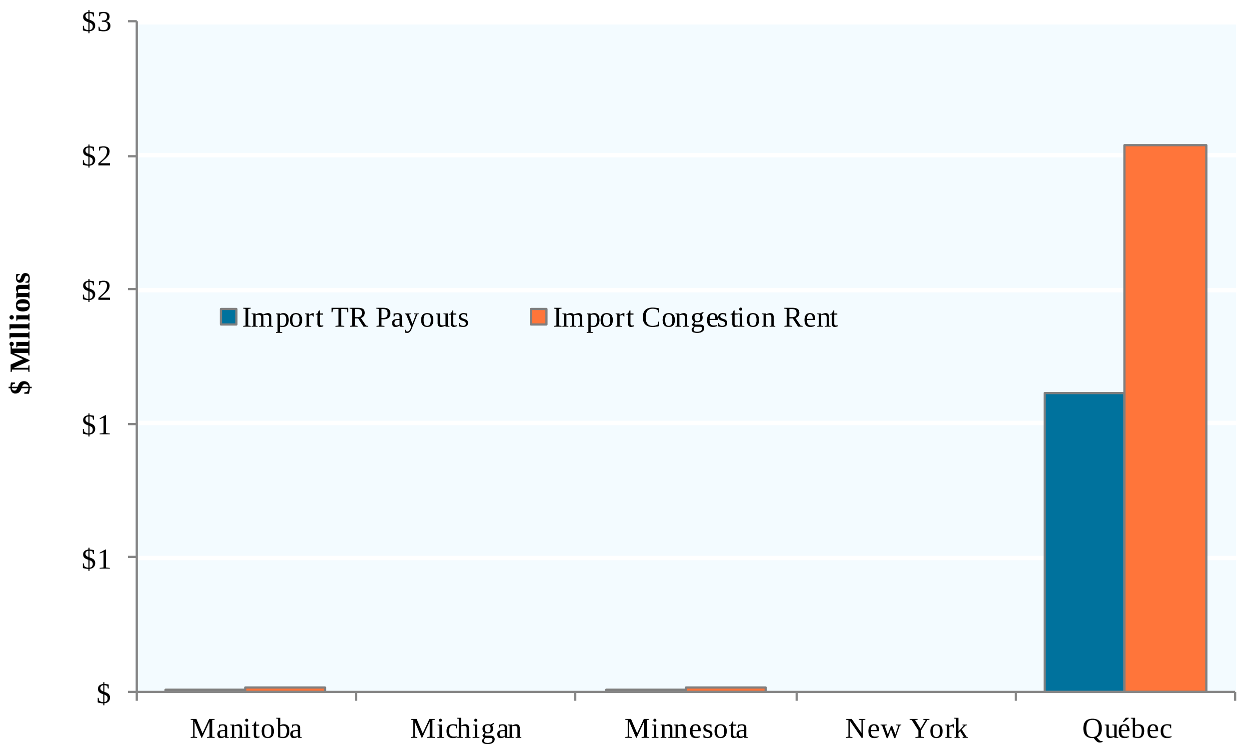
Date	Ontario (HOEP) ($/MWh)	Manitoba (MISO[72]) ($/MWh)	Michigan (MISO) ($/MWh)	Minnesota (MISO) ($/MWh)	New York (NYISO[73]) ($/MWh)	PJM[74] ($/MWh)
Nov 2020	9.54	23.29	26.90	25.81	13.73	24.93
Dec 2020	15.16	27.70	31.44	28.89	25.44	33.27
Jan 2021	16.86	26.72	30.17	27.74	26.80	39.95
Feb 2021	32.52	74.86	53.61	76.99	36.63	58.61
Mar 2021	17.07	21.05	27.20	23.82	18.87	28.31
Apr 2021	8.52	31.49	33.53	35.46	13.14	26.46

The average HOEP in Ontario continued to be the lowest market price compared to Manitoba, Michigan, Minnesota, New York and PJM. This price difference is mainly due to export congestion, which occurs when there is not enough transmission available to move low-cost energy from Ontario to other markets. Michigan, Minnesota, and Manitoba had the highest market prices relative to Ontario's HOEP, which contributed to the high number of congestion hours during the Winter 2020/21 Period.

[72] Midcontinent Independent System Operator
[73] New York Independent System Operator
[74] PJM Interconnection

Figure A-17 compares the total import congestion rent collected to total Transmission Right (TR) payouts by intertie for the Winter 2020/21 Period and Figure A-18 compares the total export congestion rent collected to total TR payouts by intertie for the same period.

Figure A-17: Import Congestion Rent & Transmission Rights (TR) Payouts by Intertie, 1 Period



An IZP is less than the Ontario price when an intertie is import congested; the difference in prices is the ICP and is equal to the difference (if any) between the pre-dispatch PD-1 Market Clearing Price (MCP) and the PD-1 IZP. While the importer is paid the lower IZP, the buyer in the wholesale market still pays the HOEP. The difference between the amount collected from the purchaser and the amount paid to the importer in such a case is import "congestion rent". Congestion rent accrues to the IESO's Transmission Rights Clearing Account (TRCA).

To enable intertie traders to hedge against the risk of price fluctuations due to congestion, the IESO administers TR auctions.[75] TRs are sold by intertie and direction (import or export) for periods of one month (short-term) or one year (long-term). Short-term TR auctions occur between the 1st and the 15th day of each month and sell TRs that are valid for the one-month period. Long-term auctions are held between 30 to 90 days prior to the beginning of the quarter for which long-term TRs are being auctioned. Long-term TRs are valid for a period of one year, beginning on the first day of the quarter. The owner of a TR is entitled to a payment (or “payout”) equal to the ICP multiplied by the amount of TRs the owner holds every time congestion occurs on the intertie in the direction for which a TR is owned.

While TR payouts should theoretically be offset by congestion rent collected, in practice this is often not the case. Any congestion rent shortfalls, which occur when TR payouts exceed the congestion rent collected, are generally covered primarily by TR auction revenues, (proceeds from selling TRs, a payment into the TRCA), unless these shortfalls arise due to improperly failed intertie transactions where the consumer makes up the cost of shortfalls.

Total import TR payouts in the Winter 2020/21 Period were $1.1 million, while total import congestion rent was $2.1 million, creating a congestion rent surplus of $0.9 million. This congestion rent surplus was essentially all on the Québec intertie.

Export TR payouts in the Winter 2020/21 Period totalled $50 million, while export congestion rent totalled $57.6 million. This $7.6 million surplus of congestion rent is primarily due to the $1.6 million excess of congestion rent over TR Payouts on the New York intertie, as well as the $9.3 million excess of congestion rent over TR payouts on the Michigan intertie. These surpluses in congestion rent in the Winter 2020/21 Period were partly offset by smaller congestion rent shortfalls on the Manitoba intertie.

[75] For more information, see Market Manual 4.4: Transmission Rights Auction: https://www.ieso.ca/-/media/Files/IESO/Document-Library/Market-Rules-and-Manuals-Library/market-manuals/market-operations/mo-TransmissionRights.ashx

Figure A-18: Export Congestion Rent & TR Payouts by Intertie, 1 Period

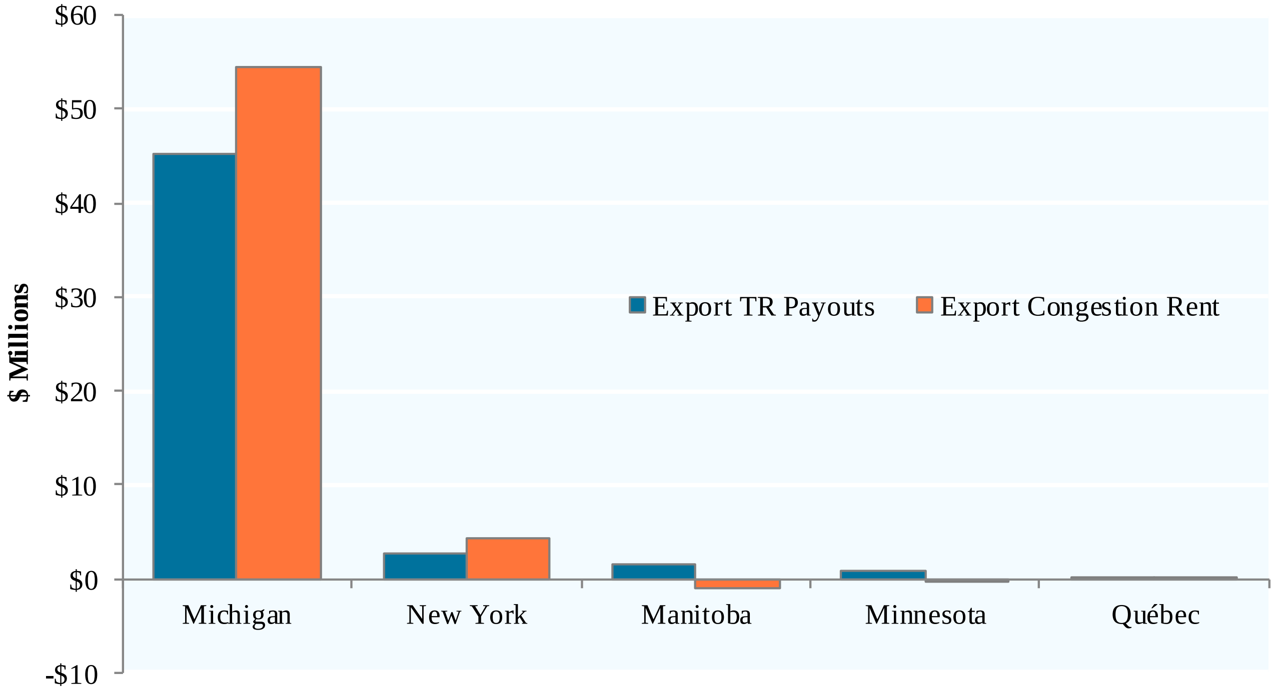


Table A-9 lists the average auction prices for 1 MW of long-term (12-month) TRs for each intertie in either direction for each auction since May 2020 and Table A-10 lists the auction prices for 1 MW of short-term (one-month) TRs for each intertie in either direction for each auction during the Winter 2020/21and Summer 2020 Periods.

Auction prices signal Market Participant expectations of intertie congestion conditions for the forward period. If an auction is efficient, the price paid for 1 MW of TRs should reflect the expected payout from owning that TR for the period. Prices signal Market Participant expectations of intertie congestion conditions for the forward period.

Generally, when long-term import and export TR prices increase from auction to auction – as the 12-month term shifts ahead by 3 months – it indicates that traders expect congestion to increase, and vice versa. Long-term import TR prices for the February 2021 auction increased for Manitoba and Michigan, decreased for Minnesota and were little changed for New York and

Québec when compared to the May 2020 auction, indicating that traders expected import congestion to increase for Manitoba and Michigan and to decrease for Minnesota.

Table A-9: Average 12-Month TR Auction Prices by Intertie & Direction

Direction	Month	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-20	Jul-20 to Jun-21	169	49	1,239	239	4,600
	Aug-20	Oct-20 to Sep-21	210	140	981	218	7,540
	Nov-20	Jan-21 to Dec-21	596	60	1,024	104	1,635
	Feb-21	Apr-21 to Mar-22	325	175	462	195	4,952
Export	May-20	Jul-20 to Jun-21	11,910	87,324	44,983	16,914	1,074
	Aug-20	Oct-20 to Sep-21	10,027	73,834	37,805	15,248	1,246
	Nov-20	Jan-21 to Dec-21	8,672	30,753	38,632	3,921	353
	Feb-21	Apr-21 to Mar-22	4,730	86,072	31,063	15,184	766

Table A-10: Average One-Month TR Auction Prices by Intertie & Direction, 1 Year

Direction	Period TRs are Valid	Manitoba ($/MW)	Michigan ($/MW)	Minnesota ($/MW)	New York ($/MW)	Québec ($/MW)
Import	May-20	23	0	-	5	306
	Jun-20	15	0	-	5	224
	Jul-20	14	0	-	1	655
	Aug-20	-	1	-	7	1,116
	Sep-20	-	0	-	6	900
	Oct-20	-	1	-	5	766
	Nov-20	-	2	-	6	185
	Dec-20	261	184	280	228	8,147
	Jan-21	-	0	-	15	134
	Feb-21	-	3	-	15	250
	Mar-21	-	4	-	8	306
	Apr-21	-	0	-	3	302
Export	May-20	-	7,320	-	781	67
	Jun-20	-	6,888	-	914	166
	Jul-20	-	5,335	-	1,999	112
	Aug-20	-	5,067	-	1,113	112
	Sep-20	-	6,415	-	890	49
	Oct-20	-	10,200	-	1,305	67
	Nov-20	-	-	-	1,663	70
	Dec-20	8,585	73,146	33,989	16,732	1,507
	Jan-21	-	3,758	-	1,049	312
	Feb-21	-	4,704	-	1,344	309
	Mar-21	-	7,633	-	1,488	112
	Apr-21	-	7,956	-	1,221	79

Short-term export TR prices continued to be volatile from month-to-month, with infrequent sales of short-term TRs for Manitoba and Minnesota interties.

Figure A-19 shows the estimated balance in the TRCA at the end of each month for the previous five years, as well as the cumulative effect of each type of transaction impacting the account. The balance of the TRCA increased to $77 million at the end of the Winter 2020/21 Period (April 2021), up from $75 million at the end of the Summer 2020 Period (October 2020).[76,77] The April 2022 balance was $57 million above the reserve threshold of $20 million set by the IESO Board of Directors. This change in balance was composed of:[78]

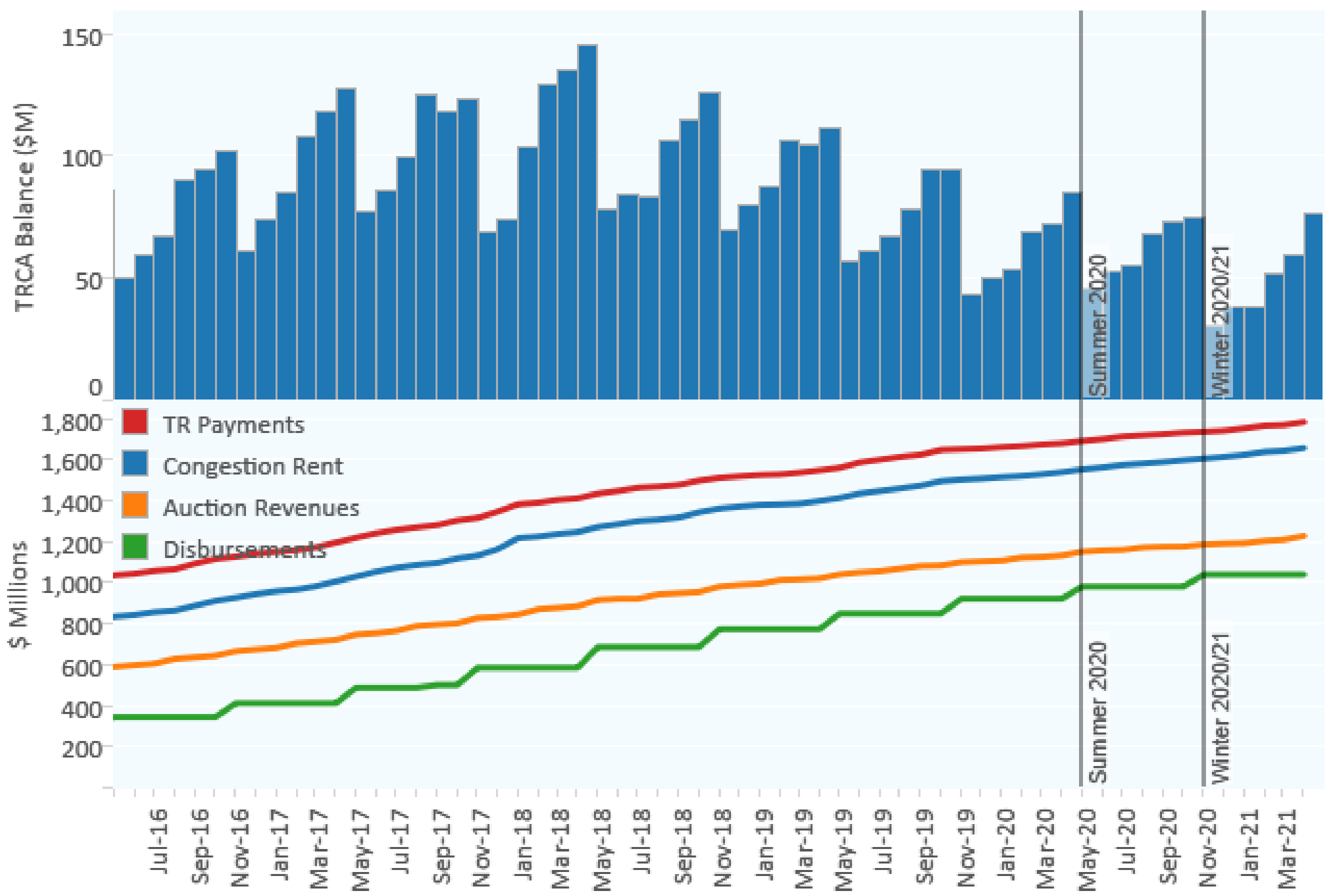
1. $111.7 million in revenue, specifically:
    - $59.7 million in congestion rent
    - $52.0 million in auction revenues
    - $0.1 million in interest
2. $109.8 million in debits, specifically:
    - $51.2 million in TR payouts
    - $58.6 million in disbursements to Ontario consumers and exporters.

[76] The balances given here differ from balances in the IESO Monthly Market Reports. This is because the IESO accounts for auction revenues on an accrual basis (long-term auction rights revenue allocated evenly over the relevant 12-month period, with revenue allocated for future months excluded) whereas the balances given here reflect the total amounts, including auction revenues, received and paid out on a cash flow basis in the reporting period.

[77] For reference, the balance at the end of the Winter 2019/20 Period (April 2020) was $85.1 million.

[78] Disbursement and interest amounts are referenced from the IESO's Monthly Market Report. Congestion rent, total auction revenue and TR payments are referenced from the IESO's settlements database and may differ from the IESO's Monthly Market Reports because the settlement database records revenue on a cash flow basis and not an accrual basis.

Figure A-19: Transmission Rights Clearing Account Balance & Cumulative In/Outflows, 5 Years



A.2 Demand

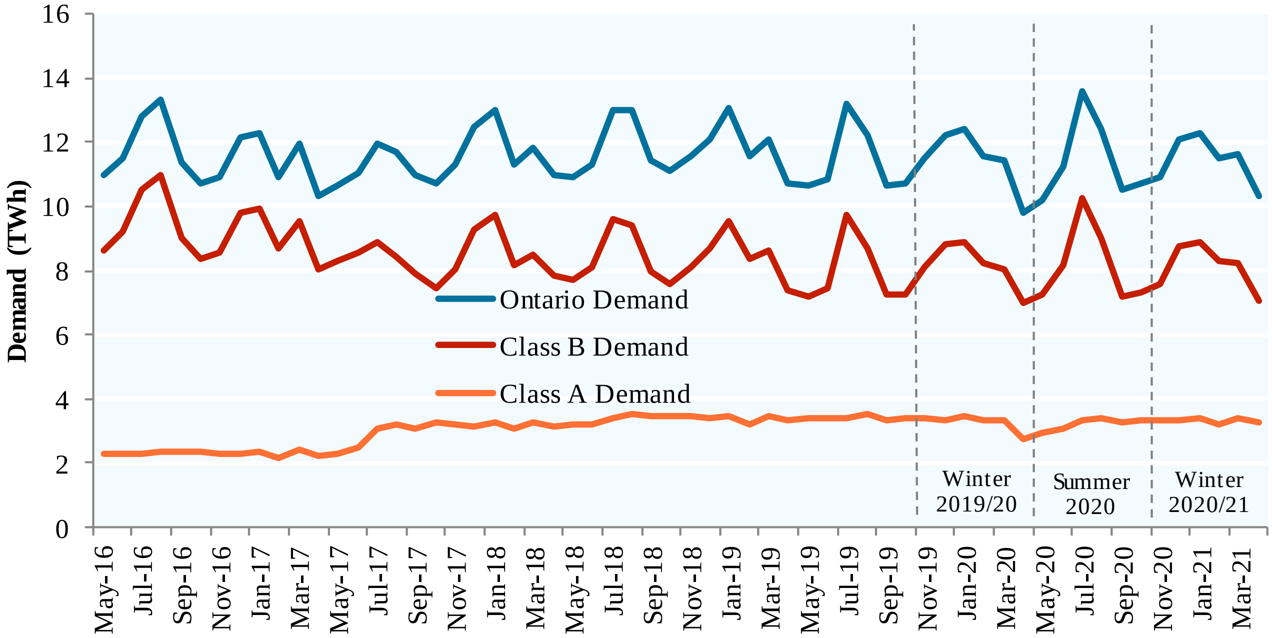
Figure A-20 displays energy consumption by all Ontario consumers in each month of the past five years, broken down by demand from Class A and Class B consumers. The figure represents total Ontario demand – not just grid-connected demand – in that it includes demand satisfied by embedded generators.[79]

Total demand in the Winter 2020/21 Period was 68.8 TWh – 0.2% lower than the total demand of 68.9 TWh in the Winter 2019/20 Period. The slight change in total demand is likely due to the little variation in average temperatures between Winter 2019/20 and Winter 2020/21.

In reference to the total seasonal demand, demand from Class A consumers in the Winter 2020/21 Period was 19.9 TWh – a 1.5% increase compared to the Winter 2019/20 Period. The Class B demand for the Winter 2020/21 Period was 48.7 TWh – a 0.9% reduction compared to the Winter 2019/20 Period. Generally, Class B consumers tend to be more weather sensitive than Class A consumers, and the small change correlates to the little variation in seasonal temperatures between the Winter 2019/20 Period and the Winter 2020/21 Period. There is no evidence from these data of any effect that the pandemic and associated restrictions during the Winter 2020/21 Period may have had on Class A and Class B. Demand has stayed flat across the winter periods since the introduction of Ontario's COVID-19 public health measures in March 2020.

[79] Class A demand may be understated as the Panel does not have access to behind-the-meter generation data, which serves to offset demand from the grid. For more information, see the Panel's Monitoring Report 24 published April 2015, pages 105-109, and the Panel's Industrial Conservation Initiative Report published December 2018: http://www.ontarioenergyboard.ca/oeb/_Documents/MSP/MSP_Report_Nov2013-Apr2014_20150420.pdf and https://www.oeb.ca/sites/default/files/msp-ICI-report-20181218.pdf

Figure A-20: Monthly Ontario Energy Demand by Class A & Class B Consumers, 5 Years



A.3 Supply

This section presents data on generating capacity, actual generation, and Operating Reserve (OR) supply for the Winter 2020/21 Period relative to previous years.

Table A-11 lists the quantity of nameplate generating capacity that completed commissioning and was added to the IESO-controlled grid's total capacity during the fourth quarter of 2020 and first quarter of 2021, as well as the quantity of nameplate IESO contracted generating capacity that was added at the distribution level. Total capacity of each type at the end of the first quarter of 2021 is also shown.

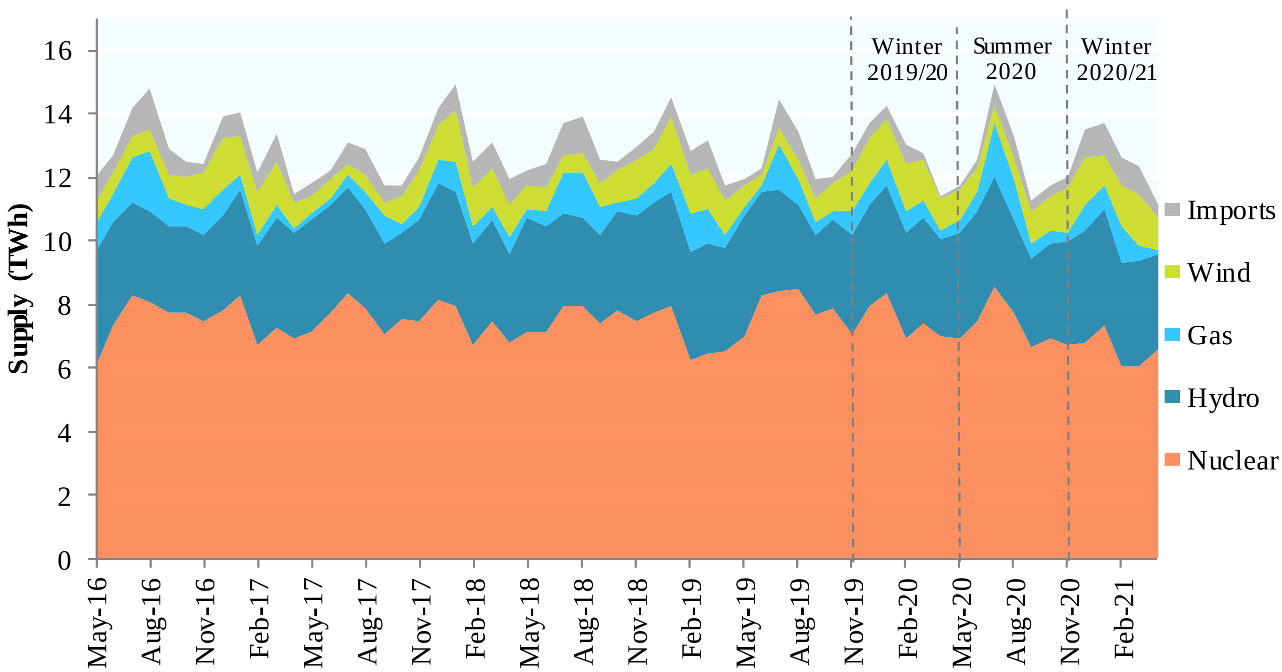
Table A-11: Changes in Generating Capacity, Q4 2020 to Q1 2021

Generation Type	**Grid-connected**		**Distribution-level ("Embedded")**	
	Increase (MW)	**Total (MW)**	**Increase (MW)**	**Total (MW)**
Nuclear	-	13,009	-	-
Natural Gas	-	11,317	-	-
Hydro	-	9,060	9	306
Wind	**300**	**4,786**	1	591
Solar	-	478	6	2,172
Biofuel	-	295	-	110
Gas-Fired and Combined Heat and Power (CHP)	-	-	21	320
Energy from Waste	-	-	-	24
Total	300	38,945	37	3,523

The 300 MW increase in wind capacity is from Henvey Inlet Wind Energy Centre, a new wind farm in Northeastern Ontario. All of the IESO-controlled grid's added capacity is variable generation that generally offers into the energy market at low prices, potentially contributing to the continuation of low spot prices in Ontario. Small amounts of embedded generation hydro, solar and CHP were also added by the end of the first quarter of 2021.

Figure A-21 displays the real-time unconstrained schedules from May 2016 to April 2021 by resource or transaction type: imports, wind, gas-fired, hydroelectric and nuclear. Changes in the resources scheduled may be the result of a number of factors, such as changes in market demand or seasonal fuel variations (for example, during the spring snowmelt or freshet when hydroelectric plants have an abundant supply of water).

Figure A-21: Resources Scheduled in the Real-Time Market (Unconstrained), 5 Years



Compared to the Winter 2019/20 Period, the Winter 2020/21 Period showed a 12% decrease in the output of nuclear generators from 44.7 TWh to 39.6 TWh, which likely resulted from the 41% increase in nuclear outages between the Winter 2019/20 Period and Winter 2020/21 Period. Imports increased by 92% from 2.3 TWh to 4.4 TWh, likely a result of the decrease in nuclear generator output.

Figure A-22 displays the real-time unconstrained OR schedules from May 2019 to April 2021 by resource or transaction type: voltage reduction, imports, dispatchable loads, gas-fired, and hydroelectric. Changes in the total average hourly OR scheduled reflect changes in the OR requirement over time.

Table A-12 reports the seasonal average quantity of hourly OR scheduled and the fraction of total OR that is provided by resource or transaction type. It is based on the same data as Figure A-22.

Figure A-22: Average Hourly OR Scheduled by Resource Type, 2 Years

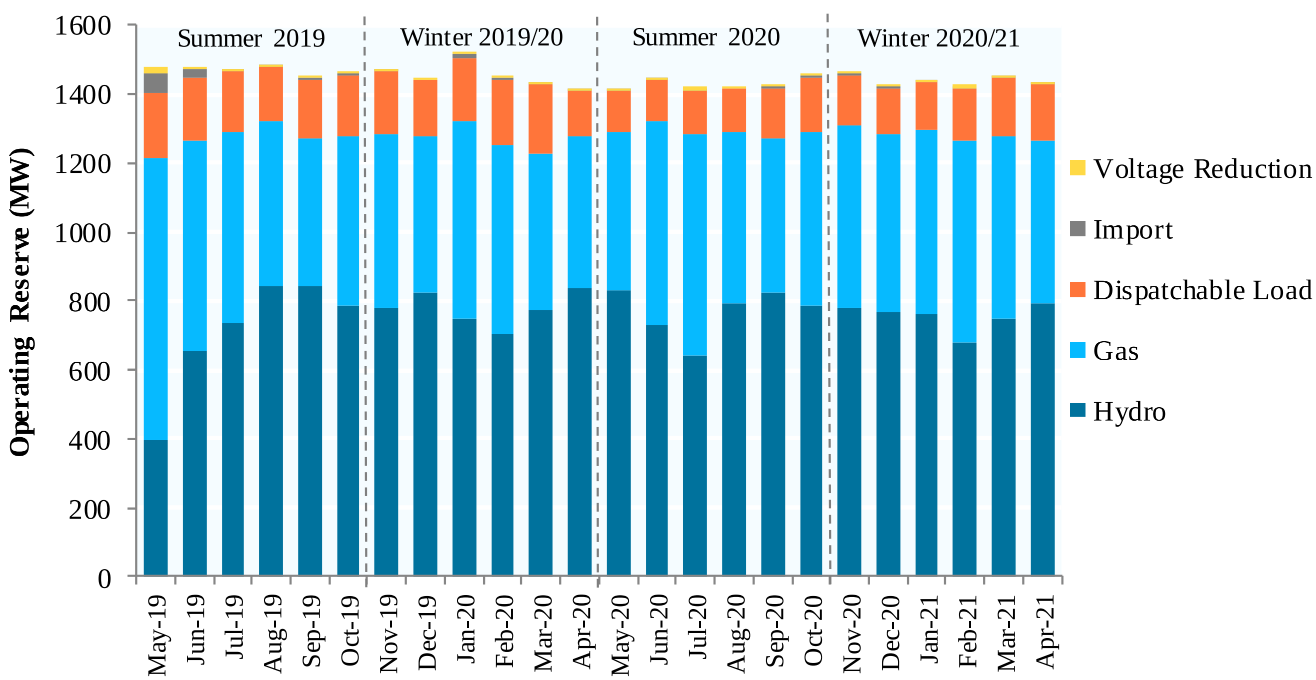


Table A-12: Average Hourly OR Scheduled by Resource Type and Season, 3 Periods

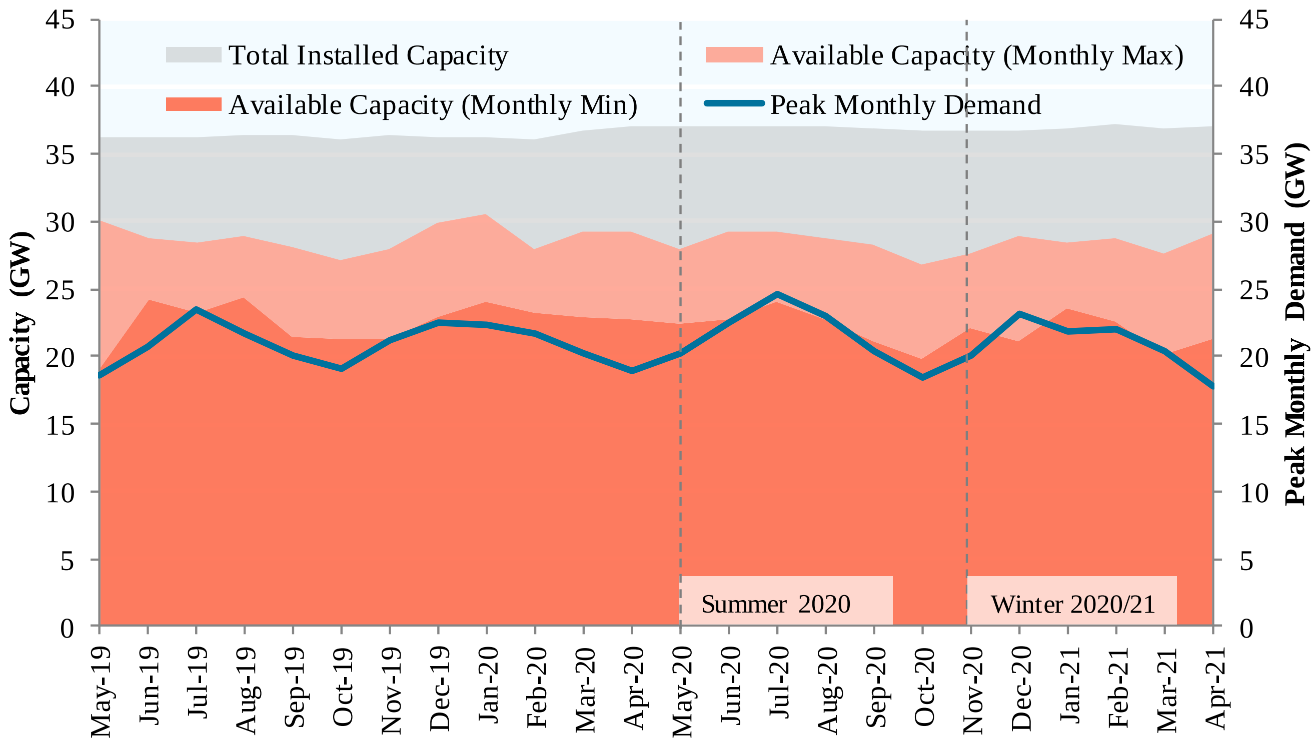
Quantity	Winter 2019/20	Summer 2020	Winter 2020/21
Average OR Scheduled (MW)	1,460 MW	1,435 MW	1,445 MW
Dispatchable Load Share (%)	12%	9%	10%
Natural Gas Share (%)	34%	37%	36%
Hydro Share (%)	53%	53%	52%
Other Share (%)[80]	1%	1%	1%

Figure A-23 plots the monthly minimum and maximum available generation capacity, accounting for unavailable capacity due to planned and forced (i.e. unforeseen) outages and de-rates, unavailable capacity from intermittent and self-scheduling generators and constrained generation capacity due to operating security limits from May 2019 to April 2021.[81] For a given month, the maximum megawatts on outage can be observed by comparing the total installed capacity to the minimum available capacity, and the minimum megawatts on outage can be observed by comparing the total installed capacity to the maximum available capacity. For reference, the figure also includes the monthly peak market demand, excluding demand served by imports.

80 “Other” refers to the sum of OR from imports and voltage reduction.

81 This figure is created using the final version of each day's Adequacy Report, available at: http://reports.ieso.ca/public/Adequacy2/PUB_Adequacy2.xml

Figure A-23: Installed Capacity, Available Capacity and Peak Demand, Monthly, 2 Years



As a whole, the Winter 2020/21 Period had, on average, 12.0 GW of unavailable capacity, which is 12% more than the average of 10.6 GW of capacity that was unavailable in the Winter 2019/20 Period. This difference was primarily driven by a 41% increase in nuclear outages between the Winter 2019/20 Period and the Winter 2020/21 Period. A majority of nuclear outages took place in March 2021.[82] There were smaller increases in wind, biofuel and solar outages, and a decrease in hydro outages. In the Winter 2020/21 Period, minimum available capacity was lower compared to the Winter 2019/20 Period by about 1.1 GW on average, and the maximum available capacity was lower compared to the Winter 2019/20 Period by about 0.7 GW on average.

[82] The highest imports observed during the monitoring period on March 6 and 7, 2021 likely resulted from a series of outages at a nuclear generating station that occurred between March 5 and 17, 2021.

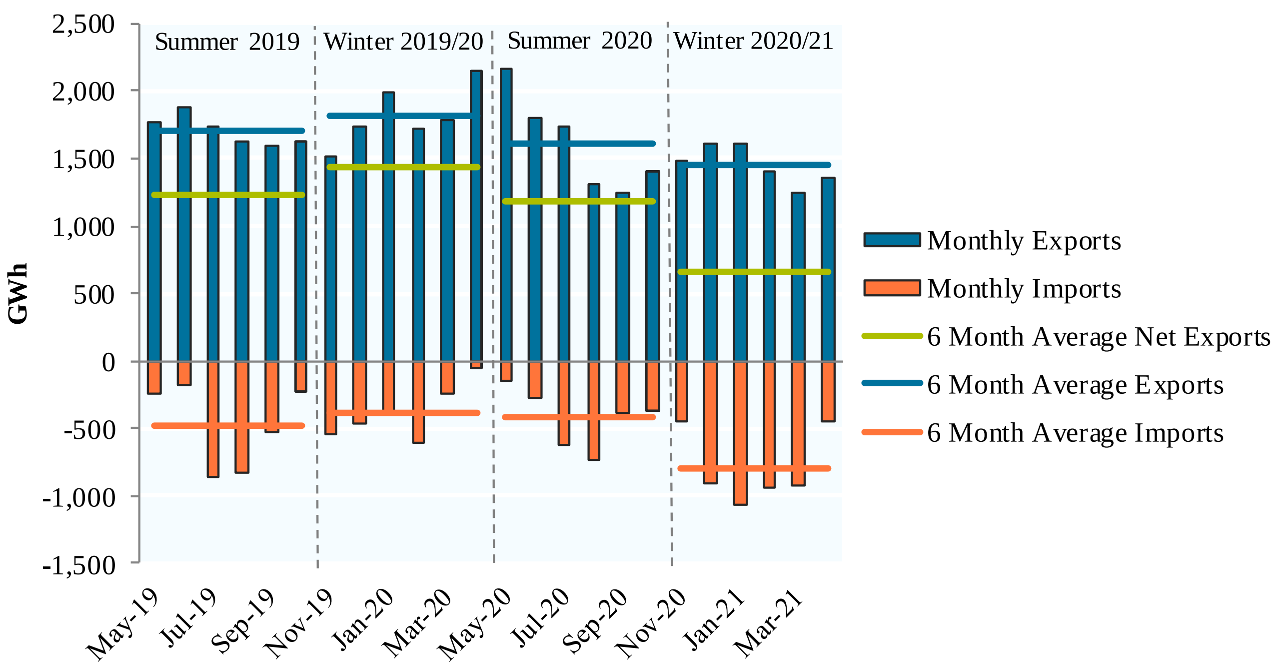
Although there was an increase in the overall amount of unavailable capacity during the Winter 2020/21 Period, the monthly minimum available capacity was highest during January 2021 and lowest during March 2021. Demand was highest during January 2021 and experienced the highest quantity of imports, while March 2021 experienced peak import congestion.

A.4 Imports, Exports and Net Exports

This section examines import and export transactions in the constrained sequence, as schedules in this sequence most closely reflect actual power flows.[83]

Figure A-24 plots total monthly imports and exports from May 2019 to April 2021, as well as the average monthly imports, exports and net exports calculated over each 6-month reporting period during those two years. Exports are represented by positive values while imports are represented by negative values.

Figure A-24: Monthly Imports and Exports, and Average Net Exports, 2 Years



Ontario remained a net exporter in the Winter 2020/21 Period, with net exports of 4.0 TWh over the six months, down from 8.6 TWh in the Winter 2019/20 Period. Compared to the Winter 2019/20 Period, exports fell by 2.2 TWh, and imports increased by 2.5 TWh. The decrease in

[83] Although the constrained schedules provide a better picture of actual flows of power on the interties, they do not impact ICPs or the Ontario uniform price.

net exports over the Winter 2020/21 Period was primarily driven by a large increase in imports from all five of Ontario's neighbouring jurisdictions: Manitoba, Michigan, Minnesota, New York and Québec. Exports also decreased across all neighbouring jurisdictions, with the exception of the increase in exports to Manitoba.

Figure A-25 presents a breakdown of exports from May 2019 to April 2021 to each of Ontario's five neighboring jurisdictions. The average monthly export quantities over the Winter 2020/21 and Summer 2020 Periods are given for each intertie in Table A-13.

Exports fell across all jurisdictions except Manitoba. Exports to New York fell from an average of 587 GWh per month in the Winter 2019/20 Period to an average of 544 GWh per month in the Winter 2020/21 Period. Generally, exports to New York and the average monthly HOEP have a moderate inverse relationship, indicating that New York generally purchased more energy from Ontario when Ontario prices were lower than average. In the Winter 2020/21 Period, exports to New York were the highest when the average monthly HOEP was higher than average. However, December 2020 and January 2021 experienced the largest price differences between the New York and Ontario prices, aligning with the trend that New York purchased more energy when the price difference between the two jurisdictions increased.

Figure A-25: Exports by Intertie, 2 Years

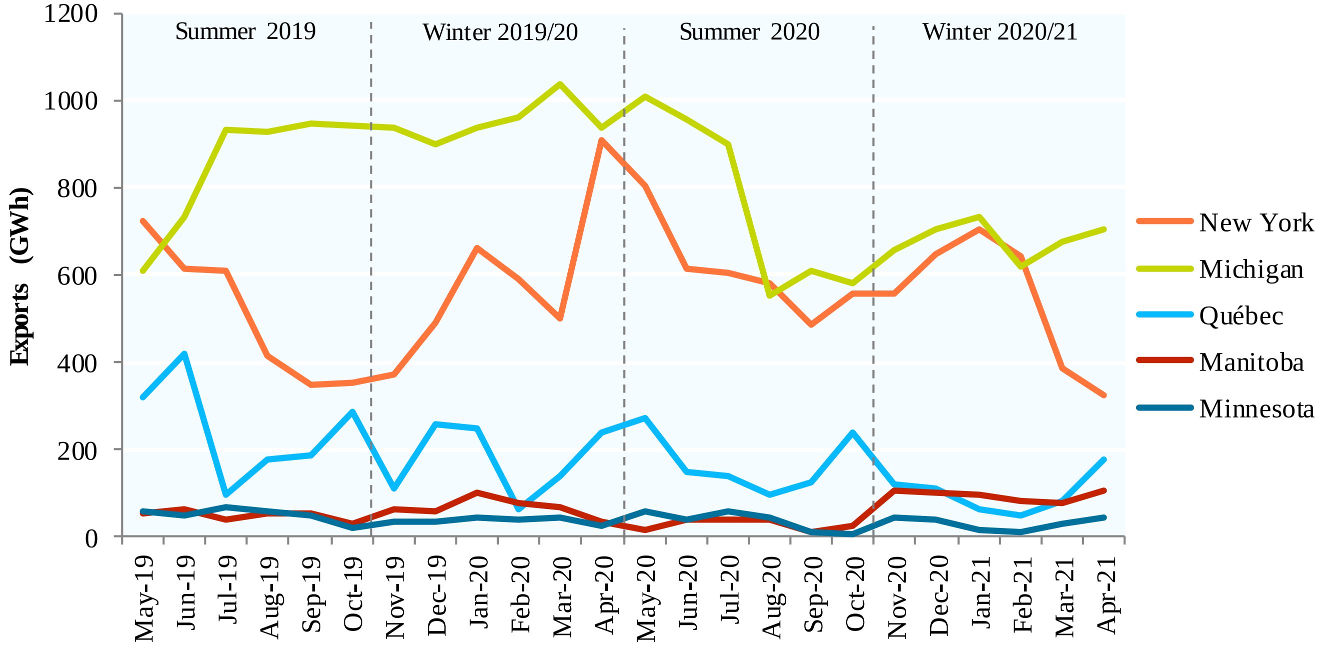


Figure A-26: Imports by Intertie, 2 Years

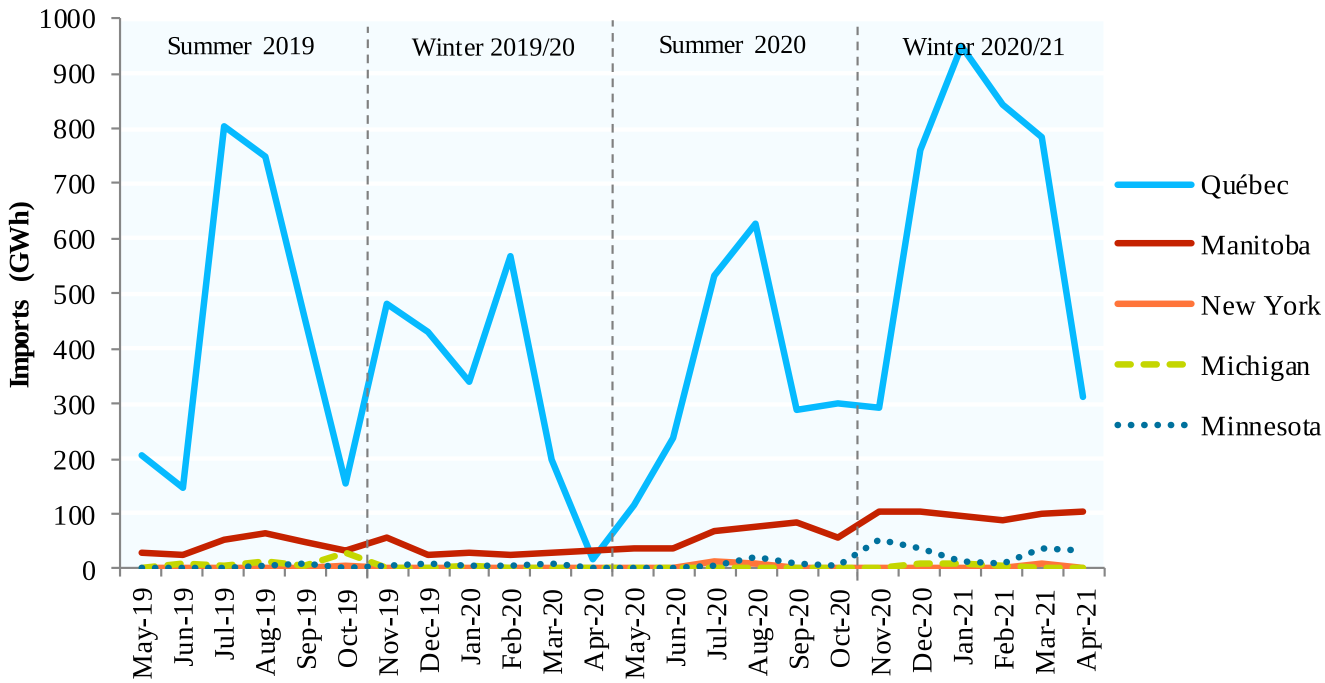


Figure A-26 presents a breakdown of imports from May 2019 to April 2021 from each of Ontario's five neighboring jurisdictions.. The average monthly import quantities over the Winter 2020/21 and Summer 2020 Periods are given for each intertie in Table A-14.

Imports from Québec increased from an average of 339 GWh per month in the Winter 2019/20 Period to an average of 656 GWh per month in the Winter 2020/21 Period. Imports from all other jurisdictions also increased significantly between the Winter 2019/20 Period and Winter 2020/21 Period, contributing to the overall increase in imports during this period that were likely a result of increased nuclear outages (see Figure A-23). In the Winter 2020/21 Period, New York and Minnesota supplied the largest increase in imports compared to the Winter 2019/20 Period. Imports from New York increased from 0.4 GWh to 2.3 GWh, and those from Minnesota increased from 6.7 GWh to 30.2 GWh.

Overall imports peaked in the month of January 2021, the month with the highest Ontario demand. However, the major driver of the increase in January 2021 imports was likely a series of forced nuclear outages that occurred at the beginning of the month as demand changed minimally from the Winter 2019/20 Period.[84]

Table A-13 reports average monthly export curtailments and failures over the Winter 2020/21 and Summer 2020 Periods by intertie and cause. The failure and curtailment rates are expressed as a percentage of total (constrained) exports over each intertie, excluding linked wheel transactions. Curtailment (Independent System Operator (ISO) Curtailment) refers to an action taken by a system operator, typically for reliability or security reasons. Market Participant (MP) Failure refers to a transaction that fails for reasons within the control of the Market Participant such as a failure to obtain transmission service.

[84] There were outages at two nuclear generating stations on December 29, 2020, with the first station back in service on January 1, 2021 and the second station back in service on January 9, 2021. The outage at the second nuclear generating station corresponds with days in January with the highest imports: January 1, 4, 5, 6 and 8.

Table A-13: Average Monthly Exports and Export Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Exports (GWh)		Average Monthly Export Failure and Curtailment (GWh)				Export Failure and Curtailment Rate			
			ISO Curtailment		Market Participant Failure		ISO Curtailment		MP Failure	
	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21
New York	621	553	0.6	0.7	13.2	9.0	0.1%	0.1%	2.1%	1.6%
Michigan	769	687	1.6	1.4	8.8	6.7	0.2%	0.2%	1.1%	1.0%
Manitoba	49	121	1.5	1.4	19.5	23.9	3.1%	1.2%	39.9%	19.8%
Minnesota	37	32	0.7	0.4	0.9	0.7	1.8%	1.4%	2.5%	2.1%
Québec	167	96	2.4	2.3	1.0	1.5	1.4%	2.3%	0.6%	1.6%

Failed or curtailed exports reduce demand between pre-dispatch (PD-1) and real-time. The Market Participant percentage failure rate of exports decreased in the Winter 2020/21 Period compared to the Summer 2020 Period on all interties except Québec. This rate continues to follow a seasonal pattern for Manitoba, with significantly higher failure rates in the summer and lower failure rates in the winter. As in previous periods, the Market Participant failure percentage rate for Manitoba remained much higher than for other interties in both periods.

The rate of ISO-curtailed exports in the Winter 2020/21 Period was relatively low for all of Ontario's interties. This rate tends to follow a seasonal pattern for Manitoba and Minnesota, with higher curtailment rates in the summer and lower rates in the winter.

Table A-14 reports average monthly import failures and curtailments the Winter 2020/21 and Summer 2020 Periods by intertie and cause. The Market Participant failure and ISO Curtailment rates are expressed as a percentage of total imports, excluding linked wheel transactions.

Table A-14: Average Monthly Imports and Import Failures by Intertie and Cause, 2 Periods

Intertie	Average Monthly Imports (GWh)		Average Monthly Import Failure and Curtailment (GWh)				Import Failure and Curtailment Rate			
			ISO Curtailment		MP Failure		ISO Curtailment		MP Failure	
	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21	Summer 2020	Winter 2020/21
New York	5	2	0.1	0.0	0.2	0.1	1.2%	0.0%	3.5%	3.4%
Michigan	1	5	0.1	0.3	0.2	0.3	4.1%	6.2%	15.7%	5.4%
Manitoba	66	104	4.7	2.0	1.1	2.8	7.1%	1.9%	1.7%	2.7%
Minnesota	8	33	0.7	0.2	1.2	2.3	8.5%	0.7%	13.9%	7.1%
Québec	340	651	4.0	3.6	0.3	0.4	1.2%	0.6%	0.1%	0.1%

Failed or curtailed imports reduce supply between the PD-1 and real-time. This change in supply can lead to a sub-optimal level of intertie transactions and may contribute to increases in price. The IESO may dispatch up domestic generation or curtail exports to compensate for Market Participant failures and ISO Curtailments.

The percentage rate of ISO Curtailments for imports decreased in the Winter 2020/21 Period compared to the Summer 2020 Period for all interties except for Michigan. The Market Participant Failure rate for imports significantly decreased in the Michigan and Minnesota interties in the Winter 2020/21 Period compared to the Summer 2020 Period. There was also a slight increase in Market Participant failure rates over the Manitoba intertie in the Winter 2020/21 Period compared to the Summer 2020 Period.

Appendix B: Status of Panel Recommendations

B.1 Status of Recent Panel Recommendations

The Panel's Monitoring Report 35, published in September 2021, included eight recommendations to the IESO. The IESO provided responses to the recommendations on September 22, 2021.[85] Table B-1 catalogues the eight recommendations, along with the IESO's responses and the Panel's comments to the IESO responses.[86]

Table B-1: Status of Recent Panel Recommendation and IESO Responses

Recommendation 3-1 **and** ***IESO Response***	**The IESO should develop structural solutions for Capacity Auction resource performance failures, with an emphasis on stronger penalties. In general terms, penalties should work together with a Qualified Capacity process to ensure that capacity payments net of penalties reflect each resource's ability to deliver capacity when dispatched.**
	The IESO agrees with the MSP's recommendation and is in the process of stakeholdering a capacity qualification process for all Capacity Auction resources (including Hourly Demand Response) where past performance will directly impact future qualified capacity and participant revenues. *The capacity qualification process will provide a financial incentive for resources to improve performance and much stronger financial consequences for poor performance. The capacity qualification process will work with performance*

[85] See the letter from Lesley Gallinger, President & CEO of the IESO, to Susanna Zagar, CEO of the OEB: https://www.oeb.ca/sites/default/files/IESO-MSP-Ltr-OEB-20210922.pdf

[86] The IESO may have taken additional actions in response to Panel recommendations since the original responses were provided by the IESO. The IESO publishes status updates for the last 5 years of Panel recommendations, updated annually in December, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-assessment/Annual-OEB-Status-Update-Report.ashx

	penalties to ensure capacity payments net of penalties reflect a resource's ability to deliver capacity when dispatched. *The IESO is targeting implementation of the capacity qualification process for the 2022 Capacity Auction. Further information on the capacity qualification process is available on the IESO's resource adequacy stakeholder engagement webpage.*

Recommendation 3-2 **and** ***IESO Response***	**For all Capacity Auction resources, the IESO should adjust penalties and payments such that there are no financial incentives to submit Capacity Auction offers that exceed expected capabilities.**
	The IESO agrees with the MSP's recommendation and is in the process of stakeholdering a suite of enhancements to the Capacity Auction performance assessment framework. Through this process, the IESO is reviewing the performance assessment framework holistically including testing criteria, performance deadbands, as well as penalties for non-performance. The changes to the performance assessment framework will work together with the capacity qualification process (referenced above with regard to recommendation 3-1) to ensure resources only offer their expected capability into the Capacity Auction. *The IESO is targeting implementation of the resulting performance assessment framework changes for the 2022 Capacity Auction. Further information on the changes to the performance assessment framework are available on the IESO's resource adequacy stakeholder engagement webpage.*

Recommendation 3-3 **and** ***IESO Response***	**The IESO should immediately cease reimbursements to gas generators of carbon cost payments.**
	The Real-Time Generator Cost Guarantee (RT-GCG) program ensures that non-quick start generators are available to meet reliability in real-time. The RT-GCG Program is not a full cost-recovery program. The objective of the program is to provide eligible generators recovery of certain incremental fuel, operating, and maintenance costs incurred as a result of starting up and ramping to minimum loading point, to the extent those costs are not recovered through market revenues. Carbon costs are an additional operating cost incurred by generators during the start-up period and the IESO considers recovery of these costs to be consistent with the program's methodology, and appropriately reimbursed. *In the short term, the RT-GCG program will continue to reimburse carbon costs to ensure reliability consistent with the current program design as set out in 2017. In the future, the Market Renewal Program (MRP) will introduce the enhanced real-time unit commitment process which will facilitate enhanced competition between generators based on their all-in costs, including carbon costs. MRP is expected to be in service by November 2023.*

Recommendation 3-4 **and** ***IESO Response***	**If the IESO insists on reimbursement of carbon cost payments, they should develop a methodology that preserves the incentives of the carbon price. Any reimbursement should amount to a small percentage of the carbon cost payments imposed by the carbon pricing system. Only facilities that have paid an annual carbon cost charge should qualify for the carbon cost reimbursement.**
	The RT-GCG's current carbon cost recovery methodology is designed to accurately reflect the eligible carbon costs incurred by generators. This methodology takes into account the heat rate of thermal generators by assessing the fuel consumed and energy produced specific to startup operations. With further carbon costs potentially incurred during the full run of a facility, an incentive to reduce emissions intensity and resulting carbon costs remains. The IESO also notes that based on the current emissions intensity benchmark and the dispatch patterns and efficiency of Ontario's gas fleet, all eligible RT-GCG participants are expected to incur an annual carbon charge. *As noted in response to recommendation 3-3 above, in the short term, the RT-GCG program will continue to reimburse carbon costs to ensure reliability consistent with the current program design as set out in 2017. In the future, the Market Renewal Program (MRP) will introduce the enhanced real-time unit commitment process which will facilitate enhanced competition between generators based on their all-in costs, including carbon costs. MRP is expected to be in service by November 2023.*

Recommendation 3-5 **and** ***IESO Response***	**If the IESO does reimburse gas generators for carbon cost payments, the total annual reimbursement from the IESO should be made public to improve transparency, beginning with the total reimbursement to gas generators for 2019 that was made in 2021.**
	The IESO agrees with the MSP's recommendation. The IESO will provide an update to the MSP with regards to the approach for publishing the total annual reimbursement for carbon costs under the RT-GCG by the end of 2021.

Recommendation 3-6 **and** ***IESO Response***	**The IESO should issue a Request for Proposals in all possible cases where it intends to secure a resource to meet an identified system need that cannot be addressed by existing competitive mechanisms (e.g., Capacity Auction).**
	The IESO agrees with the MSP's recommendation. Competitive mechanisms are preferred, in cases where it is possible to design and execute a competitive mechanism with a reasonable likelihood for a successful outcome. In accordance with the IESO's Resource Adequacy Framework, the IESO intends to use competitive mechanisms to meet identified system needs whenever possible. A competitive process may not be possible where addressing an urgent need to maintain reliability and: *a. Only one capable supplier exists;* *b. There is insufficient time or benefit to administer an effective competitive mechanism; and/or* *c. Ratepayers would incur additional costs with no benefit, and potentially incur higher costs, compared to a non-competitive mechanism.* *There may be instances where a competitive process is not possible, as the IESO has outlined in the 2021 Annual Acquisition Report, and the IESO would expect to*

	secure a better outcome for ratepayers in these cases by entering into bilateral negotiations. *The IESO expects to share additional information with stakeholders on the use of competitive procurement mechanisms designed to meet identified system needs in the 2022 Annual Acquisition Report.*

Recommendation 3-7 **and** ***IESO Response***	**In advance of full implementation of the IESO's Resource Adequacy Framework, when non-competitive procurements may be required, information should be published that clearly states why a non-competitive procurement was necessary, what effort was made to encourage competition, specific details for both the need and the proposed solution (e.g. amount of annual Unforced Capacity and location), and whether additional actions are necessary if the proposed solution provides more, or less, than what is required.**
	The IESO agrees with the MSP's recommendation. For planned non-competitive procurements designed to meet system needs, the 2021 Annual Acquisition Report sets out the need being addressed and the proposed solution, the negotiating party, and the justification for a non-competitive procurement. *With regard to efforts made to encourage competition, the IESO is taking a holistic approach across a series of reports and activities. By publishing reliability needs in the Annual Planning Outlook, bulk and regional plans, and Annual Acquisition Report, the IESO aims to transparently identify what system needs exist now and in the future and the steps being taken to address them. This information should inform existing and potential market participants who are interested in opportunities to compete to address system needs. Further, the IESO is also aligning the contract terms of non-competitive procurements with the timing of future competitive mechanisms in order to allow for greater competition going forward.*

	The IESO publishes details on system needs and whether additional actions are necessary if proposed solutions provide more or less than what is required within the applicable bulk and regional plans, and in the Annual Planning Outlook. For example, details on the system needs met by the Lennox GS were captured in the Annual Planning Outlook, and details on the system need to be met by Brighton Beach GS will be included in the forthcoming Need for Bulk System Reinforcements West of London planning report. *The IESO expects to share additional information with stakeholders on the use of non-competitive procurement mechanisms designed to meet system needs in the 2022 Annual Acquisition Report.*

Recommendation 3-8 **and** ***IESO Response***	**To facilitate the inclusion of projects with broader public benefits in competitive procurement processes, the IESO should separate non-electricity system costs and benefits from the electricity system cost-benefit analysis and publish the results.**
	The IESO is aware that some facilities or projects may provide public benefits beyond those related to the electricity system. Through the operationalization of the Resource Adequacy Framework via the Annual Acquisition Report and subsequent procurement activities, the IESO is shifting the procurement focus from a resource-centric to a system-centric approach, where eligible facilities compete to provide the electricity services needed to maintain a reliable electricity system. The identified needs, ensuing procurements, and ultimately procurement outcomes will help to transparently identify the benefits and costs to provide these electricity services. *However, accounting for any other non-electricity benefits that may materialize from a procurement, outside of the IESO's objects, is not part of the IESO's mandate. Other public benefits are best assessed and published by the appropriate branch of Government, who can assign a value to the public benefit,*

	and determine how much of the cost of that benefit should be attributed to electricity ratepayers. In these instances, the Government is best positioned to provide policy direction to the IESO in cases where these non-electricity benefits are to be factored into electricity system decisions. *With regard to bilateral arrangements, including those that are part of the Ministry of Energy's Unsolicited Proposal assessment process[87] specifically, the IESO would be unable to publish the results of its assessments as these contain third-party confidential information. Furthermore, as part of the Unsolicited Proposal process, this information is provided as confidential advice to government. Information on the project valuation framework used by the IESO to assess a broad range of projects, including Unsolicited Proposals, is available on the IESO's website.[88]*

B.2 Panel Commentary on IESO Response

- **Recommendations 3-1 and 3-2**: The Panel is encouraged by the effort made by the IESO to address issues raised regarding Demand Response. However, the success of the IESO's solution depends on the reliability of capacity tests. The IESO has proposed to designate a five-day window in each obligation period for testing, allowing each resource to choose the specific timing of their own capacity test. There is a risk that self-scheduled tests will not be predictive of performance in situations where the resource is needed on short notice for reliability. The Panel notes that Demand Response testing is

[87] See the IESO presentation "Unsolicited Proposals: Overview of Assessment Process" dated February 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/sac/2021/sac-20210217-unsolicited-proposals.ashx
[88] See the IESO presentation "IESO Project Valuation Framework" dated March 2021: https://www.ieso.ca/-/media/Files/IESO/Document-Library/sac/2021/sac-20210217-ieso-project-valuation-framework.ashx

scheduled by the system operator in NYISO, ISO-NE and PJM. The Panel will continue to monitor the issues raised by these recommendations.

- **Recommendation 3-3**: The carbon price in place across Canada is a federal government policy aimed at achieving the outcome of reduced emissions by increasing the overall cost for fossil fuels, including specifically gas-fired generation in Ontario. The IESO's rebate for gas generators diminishes the carbon price signal in the energy market and thus undermines this provincial (and federal) government policy.[89] The Panel remains of the view that the carbon costs incurred by gas generators should be fully incorporated into their offers to minimize market interventions by the IESO, in this case by stopping the IESO carbon cost reimbursement through the RT-GCG program, which reimbursements are paid for by Market Participants and ratepayers via uplift. On the RT-GCG program more generally, which has paid out nearly $1 billion dollars to non-quick start generators since 2003, the IESO has never conducted an in-depth evaluation of the costs and benefits of this program to assess whether it is necessary or whether alternatives could achieve reliability objectives at less cost.[90] The Panel's Monitoring Report 27, published November 2016, concluded that the RT-GCG program was only required in 1% of committed hours to meet real-time domestic demand and operating reserve.[91]
- **Recommendation 3-4**: The Panel disagrees with the IESO's view that its carbon cost reimbursement methodology "is designed to accurately reflect the eligible carbon costs incurred". The Panel notes again that the IESO's carbon cost reimbursements can provide gas generators more than the carbon costs the generator pays to the government. This can be illustrated using the IESO's data provided in their stakeholder engagement

[89] The Ontario Emissions Performance Standards came into effect on January 1, 2022: https://www.ontario.ca/page/emissions-performance-standards-program
[90] The IESO's rationale for the continued need for the program has principally been to provide qualitative statements relating to their obligation to maintain reliability, without providing any detailed analysis of alternatives.
[91] See the Panel's Monitoring Report 27 published November 2016, page 101: https://www.oeb.ca/oeb/_Documents/MSP/MSP_Report_May2015-Oct2015_20161117.pdf

on the topic, for a generator emitting approximately 200,000 tonnes in 2019.[92] For a total carbon charge from the government of approximately $110,000, the IESO would pay the gas generator more than $170,000. The Panel encourages the IESO to conduct a further review of how gas generators are compensated for actual carbon costs incurred under the RT-GCG program. The Panel will continue to monitor these reimbursements over time to quantify the market impact.

- **Recommendation 3-5**: The IESO has now indicated that it intends to publish the total annual reimbursement for carbon costs on the IESO's Market Assessment web page.[93] The Panel expects to review the published carbon cost reimbursements and may have further comments at that time.
- **Recommendation 3-6**: Bilateral negotiations should not be advanced without a clearly identified system need. The IESO has not clearly identified the needs for non-competitive procurements in the 2021 Annual Acquisition Report. The Panel expects that all system needs, especially needs addressed by non-competitive procurements, would be clearly outlined in the 2022 Annual Acquisition Report. The Panel is requesting a transparent Request for Proposals (RFP) for precisely the case that the IESO continues to insist should occur via bilateral negotiations, as a means to clearly indicate the need to be addressed by the procurement. An effective way for the IESO to discover that the chosen outcome is inevitable would be to use such a process. As an example, the IESO has used consecutive non-competitive procurements over the years to extend the use of the Lennox Generating Station. Had a competitive process been in place earlier, other

[92] Two examples are provided by the IESO in the October 2020 presentation, receiving 40% and 100% of their total carbon costs. The IESO has since updated its methodology to pay the generator in example 2 the full start-up costs (~$170,000), exceeding their total carbon costs (~$110,000). For more information, see the IESO presentation "Real-time Generation Cost Guarantee OBPS Carbon Cost Methodology Proposal" dated October 28, 2020, slide 21: https://www.ieso.ca/-/media/Files/IESO/Document-Library/public-info-session/2020/rtgcg-20201028-presentation.ash

[93] See the IESO's most recent annual update, available at: https://www.ieso.ca/-/media/Files/IESO/Document-Library/market-assessment/Annual-OEB-Status-Update-Report.ashx

potential resources could have developed alternatives and possibly lowered customer costs. The IESO should also provide evidence in the 2022 Annual Acquisition Report to reassure ratepayers that specific bilateral contracts are indeed a "better outcome for ratepayers".

- **Recommendation 3-7**: The Panel is encouraged by the Annual Acquisition Report and will continue to monitor increased transparency relating to non-competitive procurements in future.
- **Recommendation 3-8**: The Panel's recommendation calls on the IESO to focus only on the electricity system costs and benefits for all projects. The unsolicited proposals process, initiated by the government and with which the IESO has been involved. may include projects that also have non-electricity system costs and benefits. In keeping with its mandate and expertise, the IESO should identify the impacts (e.g., on costs, system and market operations, etc.) for all Market Participants and for ratepayers who will ultimately fund such projects. It is this responsibility that the Panel will continue to focus on, as the projects the IESO is assessing can directly impact the market, most notably the amount of capacity that can be competitively procured by other means.